

INTERNATIONAL STANDARD

ISO
13628-3

First edition
2000-12-15

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

Part 3: Through flowline (TFL) systems

*Industries du pétrole et du gaz naturel — Conception et exploitation des
systèmes de production sous-marins*

Partie 3: Systèmes d'injection TFL



Reference number
ISO 13628-3:2000(E)

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Printed in Switzerland

Contents

Page

Foreword.....	v
Introduction	vi
1 Scope	1
2 Normative references	1
3 Terms, definitions and abbreviated terms	1
3.1 Terms and definitions	2
3.2 Abbreviated terms	3
4 TFL system.....	4
4.1 Description of system	4
4.2 TFL components.....	4
4.3 System/equipment design	5
4.4 Pressure rating.....	6
5 TFL surface equipment	6
5.1 General.....	6
5.2 Service pump	9
5.3 TFL control manifold	9
5.4 TFL control console and instrumentation.....	9
5.5 Lubricator	11
5.6 Fluid storage and working tank.....	13
5.7 Separator	13
5.8 Testing	13
6 TFL piping system	13
6.1 General.....	13
6.2 Design	14
6.3 Fabrication.....	20
6.4 Testing	26
7 Subsea tree, tubing hanger, diverters and selectors.....	26
7.1 Subsea tree design.....	26
7.2 Subsea tree testing.....	35
7.3 Tubing hanger design	35
7.4 Tubing hanger testing	36
7.5 Diverters, deflectors and selectors.....	36
7.6 Diverter design.....	42
7.7 Diverter testing.....	43
8 Completion equipment and tools.....	43
8.1 General.....	43
8.2 Completion design.....	44
8.3 Tubing.....	44
8.4 Surface-controlled subsurface safety system.....	44
8.5 Packers	45
8.6 Telescoping joints	45
8.7 Landing nipples	46
8.8 Circulation members	46
8.9 Circulation controls.....	47
8.10 Standing valves and isolation/production devices.....	47
8.11 TFL tool design	48
9 Operations	48

9.1	General.....	48
9.2	Personnel and training.....	48
9.3	Completion equipment.....	49
9.4	Satellite well and template well control systems.....	49
9.5	Service planning and documentation.....	49
9.6	Fluid selection/well preparation.....	50
9.7	Pumping operations.....	50
9.8	Returning well to production.....	51
10	Summary of capabilities.....	51
Annex A (normative) TFL pipe.....		52
A.1	Technical delivery conditions.....	52
A.2	Dimension and grades.....	52
A.3	Length.....	52
A.4	Drift tests.....	52
A.5	Hydrostatic tests.....	52
A.6	Marking.....	52
Annex B (informative) TFL operating pressure.....		53
B.1	General.....	53
B.2	Example problem.....	53
Annex C (informative) TFL completions.....		58
C.1	General.....	58
C.2	Single string, single zone, annular circulation completion.....	58
C.3	Single string, single zone, side string circulation completion.....	60
C.4	Dual-string, single-zone completion.....	62
C.5	Dual-string, multi-zone completions.....	62
Annex D (informative) TFL capabilities.....		65
D.1	Flow controls.....	65
D.2	Service work.....	65
Bibliography.....		67

Foreword

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

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

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

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

International Standard ISO 13628-3 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

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

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

Annex A forms a normative part of this part of ISO 13628. Annexes B, C and D are for information only.

Introduction

This part of ISO 13628 is based on API RP 17C:1991 [5].

The TFL systems and tools described herein permit both horizontal transport and vertical entry into the wellbore.

Users of this part of ISO 13628 should be aware that further or differing requirements may be needed for individual applications. This part of ISO 13628 is not intended to inhibit a vendor 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. Where an alternative is offered, the vendor should identify any variations from this part of ISO 13628 and provide details.

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

Part 3: Through flowline (TFL) systems

1 Scope

This part of ISO 13628 specifies requirements and gives recommendations for the design, fabrication and operation of TFL equipment and systems.

The procedures and requirements presented are for the hydraulic servicing of downhole equipment, subsea tree and tubing hanger, and flowlines and equipment within the flowlines.

This part of ISO 13628 primarily addresses TFL systems for offshore, subsea applications but it may also be used in other applications such as highly-deviated wells or horizontally-drilled wells.

Subsea separation, boosting, metering and downhole pumps are outside the scope of this part of ISO 13628.

2 Normative references

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

ISO 3183-1, *Petroleum and natural gas industries — Steel pipe for pipelines — Technical delivery conditions — Part 1: Pipes of requirement class A.*

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

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

API RP 14E, *Design and Installation of Offshore Production Platform Piping Systems.*

API Std 1104, *Welding of Pipelines and Related Facilities.*

3 Terms, definitions and abbreviated terms

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

3.1 Terms and definitions

3.1.1

bend radius

radius of curvature as measured to the centreline of a conduit

3.1.2

circulation control valve

valve normally placed across the circulation point to allow isolation of the tubing strings or tubing/casing during production

3.1.3

circulation point

location where communication is established between supply and return fluids for TFL servicing

3.1.4

diverter

device used to direct tools at a branch connection

NOTE

Used generically, it refers to that category of equipment which includes deflectors, diverters and selectors.

3.1.5

drift

gauge used to check the minimum radius of curvature and minimum ID of loops, flowline and nipples

3.1.6

H-member

nipple assembly that provides fluid communication and circulation between strings of tubing in the wellbore

3.1.7

loop

curved section of pipe allowing change in direction of TFL flowlines

3.1.8

lubricator

tube and valve assembly that permits tool-strings to be inserted into and removed from a pressurized system

3.1.9

parking system

system whereby tools/equipment for a particular tubing size are transported through a flowline of a larger size by a transport (carrier) piston string which is left behind or "parked" outside the well while the remaining equipment continues into the tubing

3.1.10

profile

internal conduit configuration (receptacle) used to engage tools

3.1.11

recess

enlargement in conduit bore, normally concentric with the bore

3.1.12

sealing bore

polished section of conduit that receives a packing element

3.1.13

flowline

service line

line from a platform or land facility to a subsea facility used for TFL servicing

NOTE

It may also be used for production or other testing of the well.

3.1.14**flowline signature****service line signature**

particular set of pressure pulses (spikes) read or recorded at the surface that identifies a certain point in the service/flowline or well as tools are pumped past

3.1.15**subsea tree**

christmas tree placed at the seabed

3.1.16**TFL piping system**

all piping from the surface lubricator through the flowline and tubing to the deepest point in the well to which TFL tools can be circulated

3.1.17**tubing-retrievable safety valve**

downhole safety valve run in the well on tubing

NOTE It is normally surface-controlled and has an ID close to the size of the tubing bore, thereby providing an almost unrestricted bore.

3.1.18**wye spool**

piping section of a subsea tree where the loop joins the vertical tubing bore

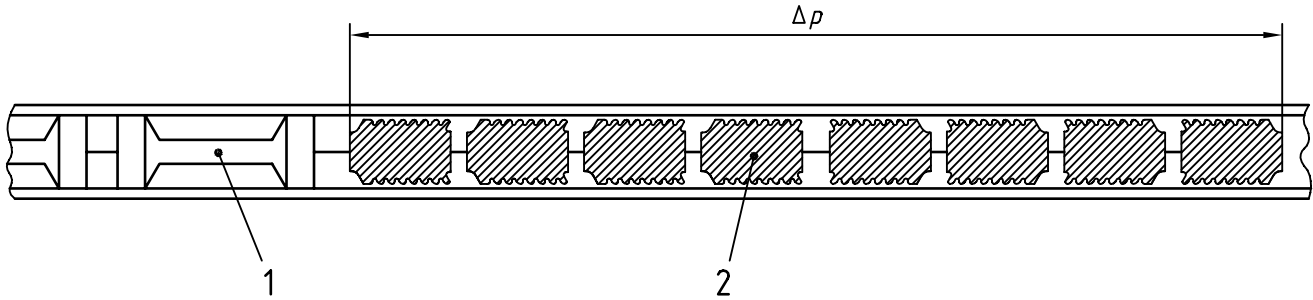
3.2 Abbreviated terms

BHP	bottom-hole pressure
CCV	circulation control valve
EUE	external upset end
ID	inside diameter
OD	outside diameter
SDC	side door choke
SCSSV	surface-controlled subsurface safety valve
SVLN	safety valve landing nipple
TFL	through flowline
TRSV	tubing-retrievable safety valve
TMD	total measured depth
TVD	true vertical depth

4 TFL system

4.1 Description of system

The TFL method allows various well servicing operations to be performed by utilizing fluid to transport tools through flowlines and loops into and out of tubing strings. The differential pressure of the transport fluid across the tool-string provides the force required to perform the various operations as shown in Figure 1.



Key

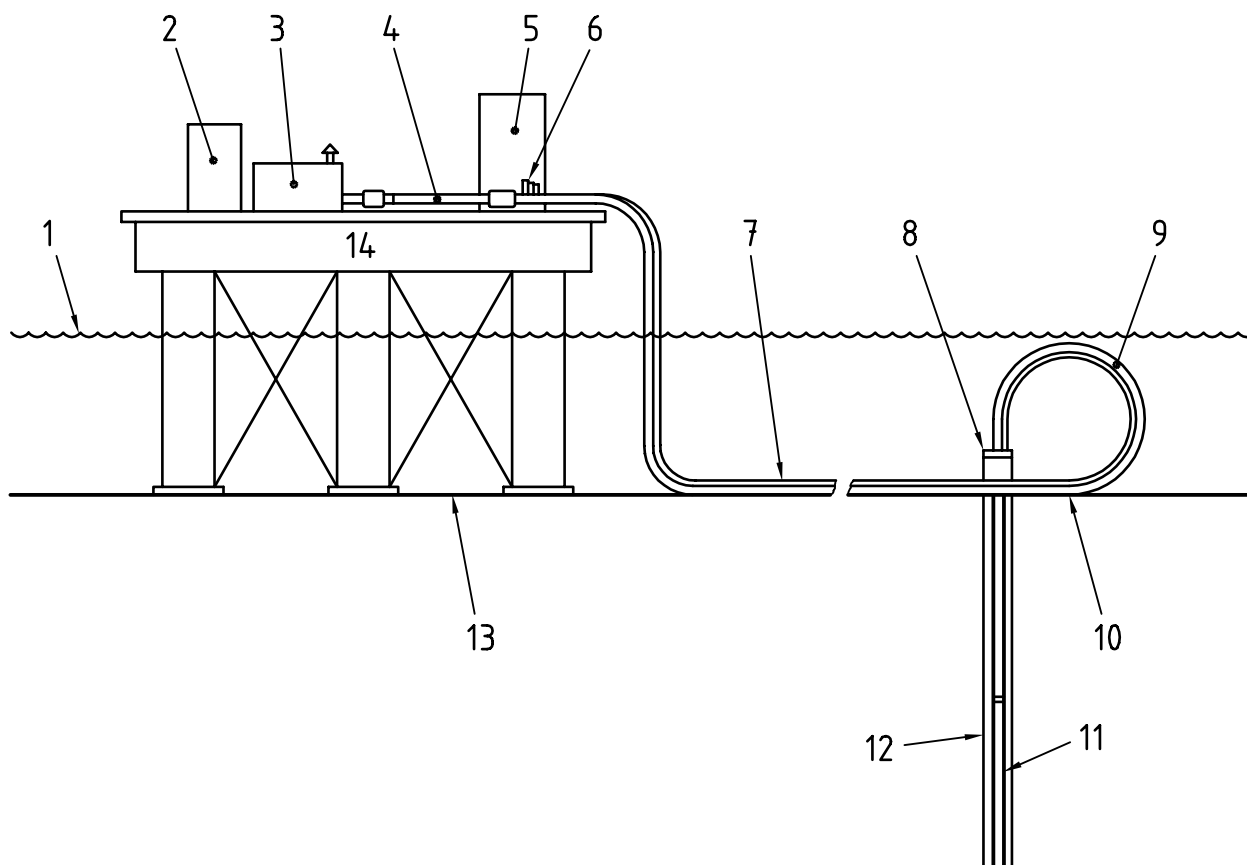
- 1 Tools
- 2 Pistons

Figure 1 — Differential pressure, Δp

4.2 TFL components

Figure 2 is a representation of a typical TFL system. The basic components of a system include the surface equipment, flowlines, subsea tree, TFL service tools and associated downhole equipment. The function of this system is to provide the means of transport and control of TFL tools. The transportation of tools is provided by the pumping equipment while the control of these tools is provided by the pumping rate, instrumentation and TFL control manifold. The basic criteria of a TFL system are

- to have an appropriate pressure rating for the system;
- to provide necessary volumes of fluid required by the TFL operations;
- to control the equipment within operating specifications.



Key

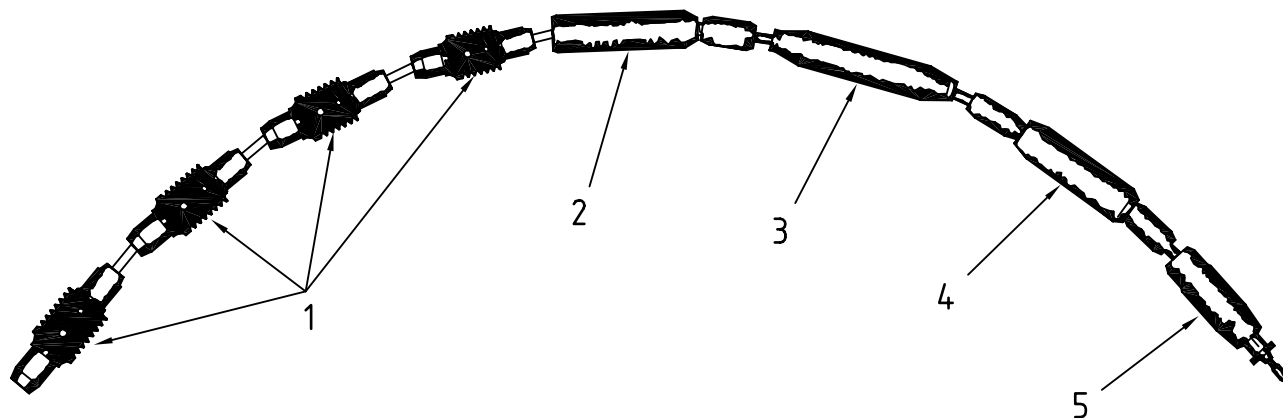
1	Water	8	Subsea tree
2	Tank	9	TFL bends
3	Pump	10	Subsea wellhead
4	Lubricator	11	Circulation point (H-member)
5	Manifold and instrumentation	12	Well
6	Pressure transducers	13	Mudline
7	Flowline/service line	14	Platform

Figure 2 — Typical offshore TFL installation

4.3 System/equipment design

TFL tools (see Figure 3) have been designed to operate in various tubing sizes commonly used in subsea wells. TFL tool design is dependent upon the tubing ID and the minimum radius of curvature of tube bends. The design of a TFL piping system shall take into account the internal diameters of the conduit and receptacles and the pressure ratings of the pipe and tubing. The ID of the service line should be the same as the ID of the downhole tubing strings, otherwise it should incorporate a parking system. If the ID is too large, fluid will bypass the tool-string piston units, reducing their force capability and resulting in inaccurate measurement of tool position. Conversely, if the ID is too small it can prevent tool passage, can cause excessive drag or can damage and wear the tool, seals and piston units.

Annex A specifies the requirements for TFL pipe and Table A.1 lists pipe ID dimensions that are compatible with tubing sizes.



Key

- 1 Piston units
- 2 Accelerator
- 3 Stem
- 4 Hydraulic jar
- 5 Pulling tool

Figure 3 — Typical TFL service string

4.4 Pressure rating

The pressure rating of a TFL system shall be greater than the maximum pressure to be encountered during TFL operations throughout the life of the installation. As a guide, consideration should be given to practical combinations of the following:

- maximum static bottom-hole pressure of the well, minus the hydrostatic pressure of the fluids in the TFL system;
- pressure to overcome frictional losses when circulating fluids and tool-strings;
- pressure required to operate all the TFL devices. This includes not only service tools but also downhole isolation and plugging equipment;
- hydraulic shocks or surges in the system which may occur during operations such as jarring;
- pressure required to kill the well if the TFL system is to be used to pump well kill fluids into the producing formation.

Multiple-well systems shall consider the effect of the higher pressure wells in the system.

Additional information about the system pressure rating and TFL fluids is provided in clause 9 and annex B.

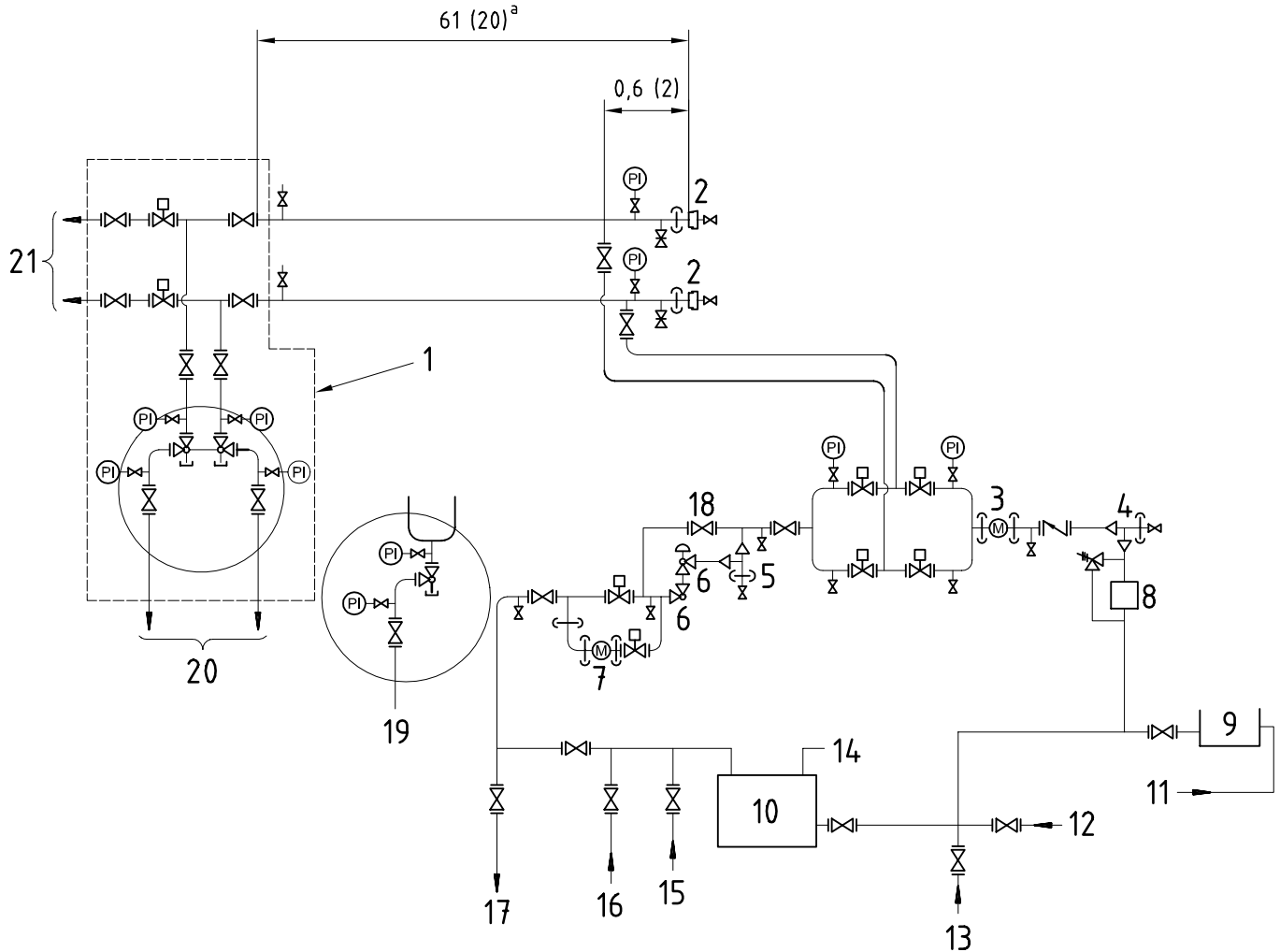
5 TFL surface equipment

5.1 General

TFL surface equipment (see Figure 4) includes a service pump, TFL control manifold, TFL control console, lubricator, fluid storage, separator and piping system. The pump pressure and flow rating should be compatible with the design of the system, taking into account the tool transport speeds referenced in clause 9 (see Table 1), tool-string actuation pressures and the fluid bypass that may occur during these operations. Sufficient volume (see 5.6) should be provided in the tanks and tubing strings to assure that all operations can be handled effectively. The surface facility (see Figure 5) should provide space to accommodate the TFL facilities, and the equipment

layout should be arranged with due regard to the proximity of the control console, pump, manifolding and lubricator, and the space needed to easily insert and remove extended-length tool-strings. If this equipment is located on a drilling/production platform, the use of basic platform equipment (such as high-volume mud pump or kill pump) may eliminate the need for dedicated equipment.

Dimensions in metres (ft)

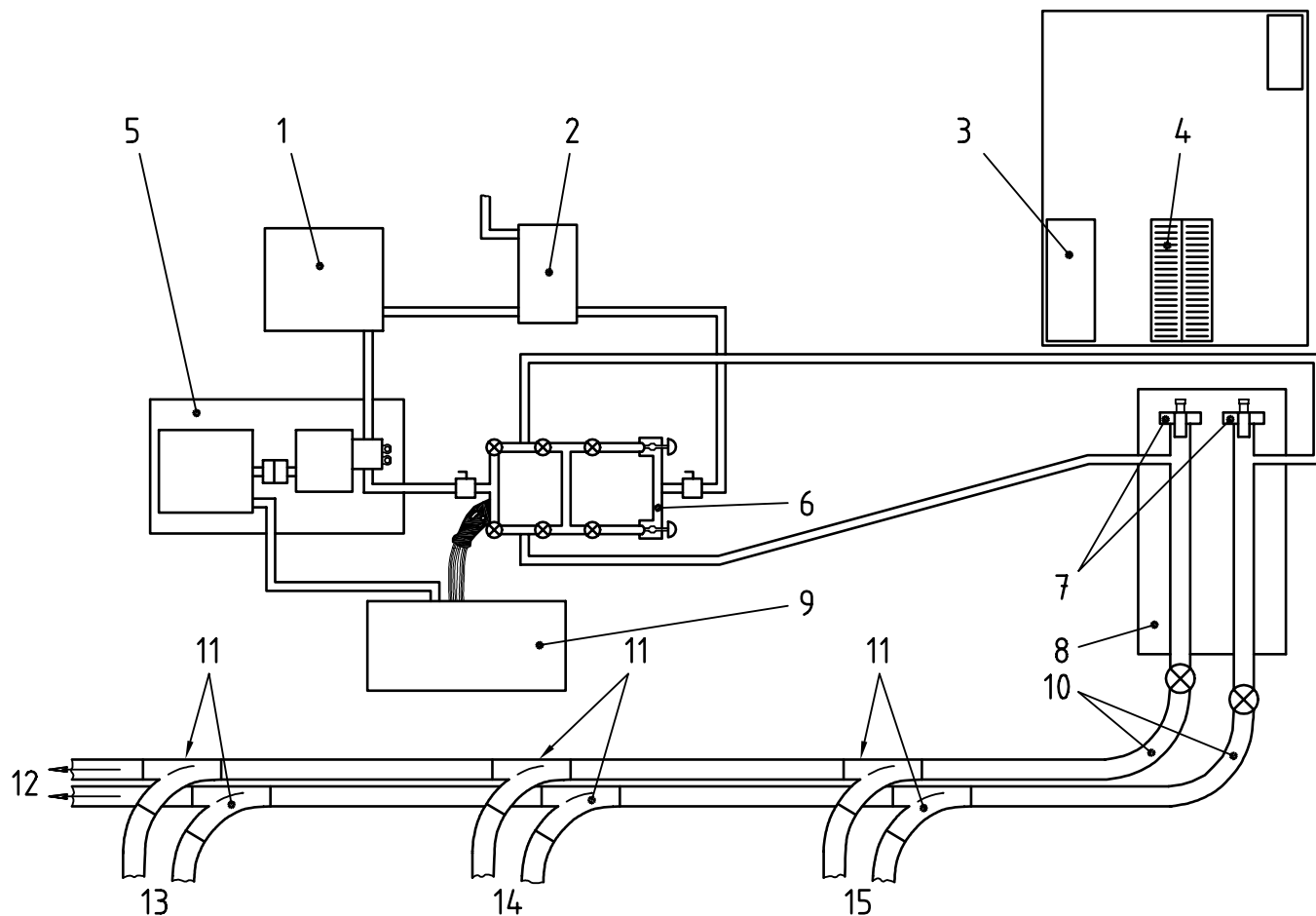


Key

- | | |
|--|---------------------------------------|
| 1 Production control manifold | 12 From mixing tank |
| 2 Threaded quick connection with plug | 13 From dry oil tank (optional) |
| 3 Flowmeter | 14 Gas blanket |
| 4 High pressure strainer | 15 Fill-up line |
| 5 High pressure strainer | 16 From separator liquid dump |
| 6 Choke | 17 To separator |
| 7 Flowmeter | 18 Optional valve |
| 8 High pressure/high volume triplex pump | 19 Optional surface choke arrangement |
| 9 795 l (5 BBL) open tank | 20 To production manifold |
| 10 Working tank | 21 To well |
| 11 From platform saltwater system (optional) | |

^a Recommended minimum straight level section.

Figure 4 — Example of TFL platform piping



Key

- | | |
|------------------------------|-----------------------------|
| 1 Fluid mixing tank | 9 Control console |
| 2 Storage tank | 10 Entry loops |
| 3 Work table | 11 Diverters |
| 4 Roller table | 12 To other wells in system |
| 5 Pump unit | 13 Well 3 |
| 6 Surface control manifold | 14 Well 2 |
| 7 Tool feeders | 15 Well 1 |
| 8 Dual horizontal lubricator | |

Figure 5 — Typical surface equipment arrangements for installations

Table 1 — Recommended flow rates for TFL tools

Feature	Nominal tubing ID				
	mm (in)				
	50,8 (2)	63,5 (2 1/2)	76,2 (3)	101,6 (4)	127 (5)
Flow rate					
l/min (bbl/min)					
Tool transport	318 (2,0)	477 (3,0)	636 (4,0)	795 (5,0)	954 (6,0)
Restricted line (max.)	159 (1,0)	159 (1,0)	318 (2,0)	318 (2,0)	318 (2,0)
Locating and landing (max.)	79,5 (0,5)	79,5 (0,5)	159 (1,0)	159 (1,0)	159 (1,0)

5.2 Service pump

Generally, triplex-type positive displacement pumps have been used for TFL operations although slow speed duplex and high-pressure multi-stage centrifugal pumps have also been successfully used by some operators. The primary recommendations for the pumps are as follows:

- pressure and flow rate capability should be in accordance with clause 9;
- a relief valve should be provided on the pump discharge to protect the pump and piping system against over-pressure or hydraulic shocks and surges;
- pump suction piping should have connections for auxiliary tanks or mixing facilities;
- the TFL pump drive should be designed to allow smooth changes to be made over the range of operating conditions described in clause 9.

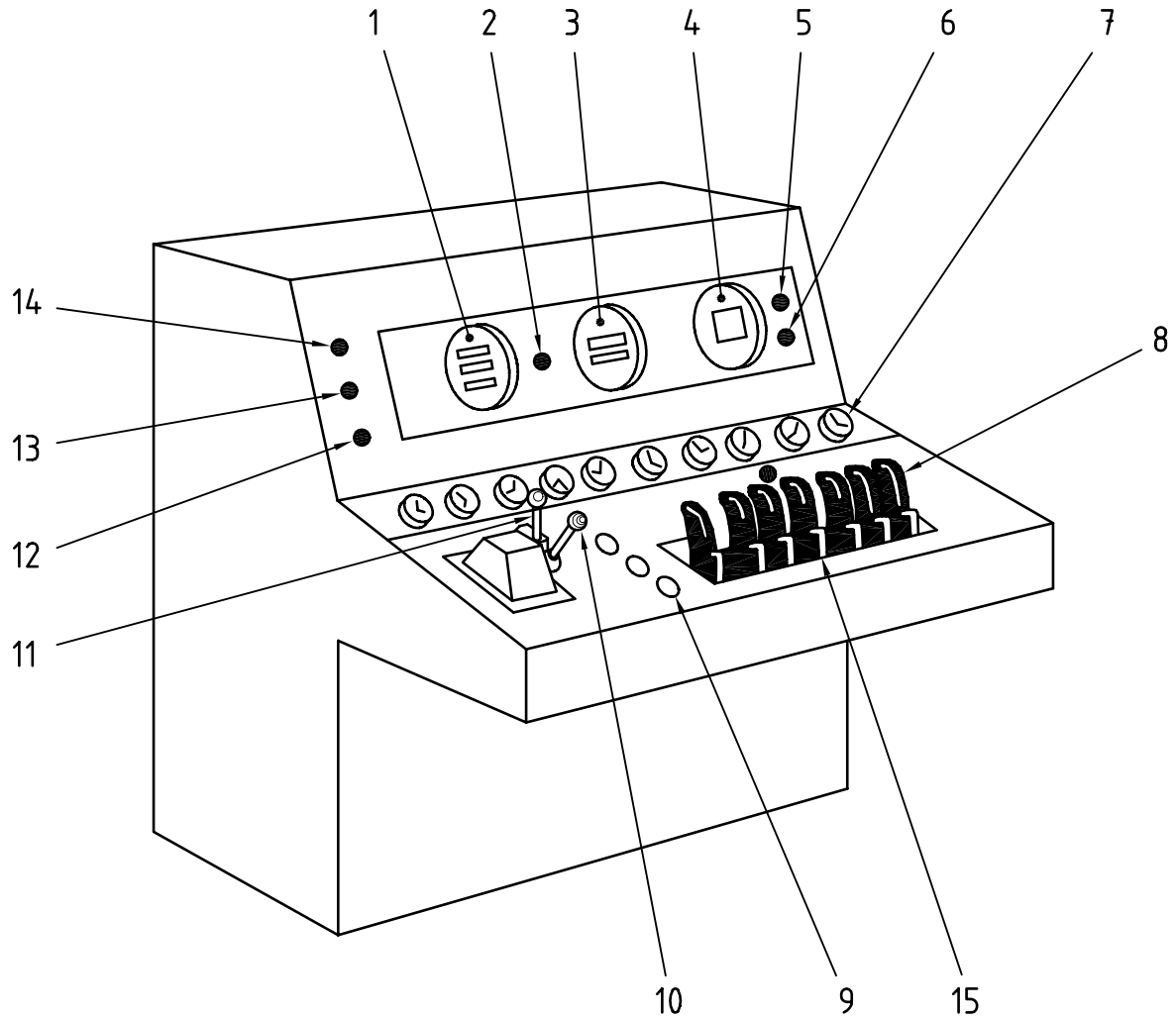
5.3 TFL control manifold

Valving arrangements shall be designed to direct pump flow and fluid return to the service lines, tanks, separators, etc., as needed to perform TFL operations. Piping and valves should be capable of handling the maximum working pressure of the system. Valves and actuators should be selected to permit rapid line switching (i.e. within 2 s or less). Valving should provide for return of fluids through an adjustable back pressure regulator or choke and through flow meters. The regulator or choke is used to regulate back pressure on the return line to control inflow from the well or fluid loss to the formation during downhole TFL operations.

5.4 TFL control console and instrumentation

Figure 6 shows a typical TFL instrumentation/control console. This instrumentation enables the monitoring of tool progress, tool operation and well fluid gain or loss. Instrumentation generally includes pressure gauges with strip chart recorders, pressure transducers located on the lubricator or manifold, and flow rate meters and volume totalizers on both the pump discharge and return lines. The instrumentation should be designed to withstand the vibrations and pressure surges that can occur. High-pressure screens or filters should be installed upstream of turbine flow meters to minimize damage to the meters by debris. Other types of meter may be used without the need for such filters.

In addition to control console instrumentation, pressure transducers with surface readout may be installed at the wellhead to assist in monitoring the tool location. Other special tool detection systems may be installed to monitor the location of a tool as it moves through the TFL system.



Key

- | | |
|--|--|
| <p>1 Dual flow meters and totalizers</p> <p>2 Explosion-proof instrumentation box (Class 1 Div 1 Grp 0)</p> <p>3 Dual pressure gauges</p> <p>4 Two-pen strip-chart recorder</p> <p>5 Chart recorder on/off switch</p> <p>6 Power-off switch</p> <p>7 Monitoring gauges (engines, pumps and transmission)
 Pump – oil temperature
 Pump – oil pressure
 Back-pressure signal
 Transmission – oil temperature
 Transmission – oil pressure
 Engine – water temperature
 Engine – oil pressure
 Engine – tachometer
 System hydraulic pressure
 System air pressure</p> | <p>8 Hydraulic choke and manifold – control valves</p> <p>9 Engine – start, stop and emergency kill</p> <p>10 Engine – throttle</p> <p>11 Transmission – gear selector</p> <p>12 Totalizer reset</p> <p>13 Power-on switch</p> <p>14 Totalizer reset</p> <p>15 Back-pressure control</p> |
|--|--|

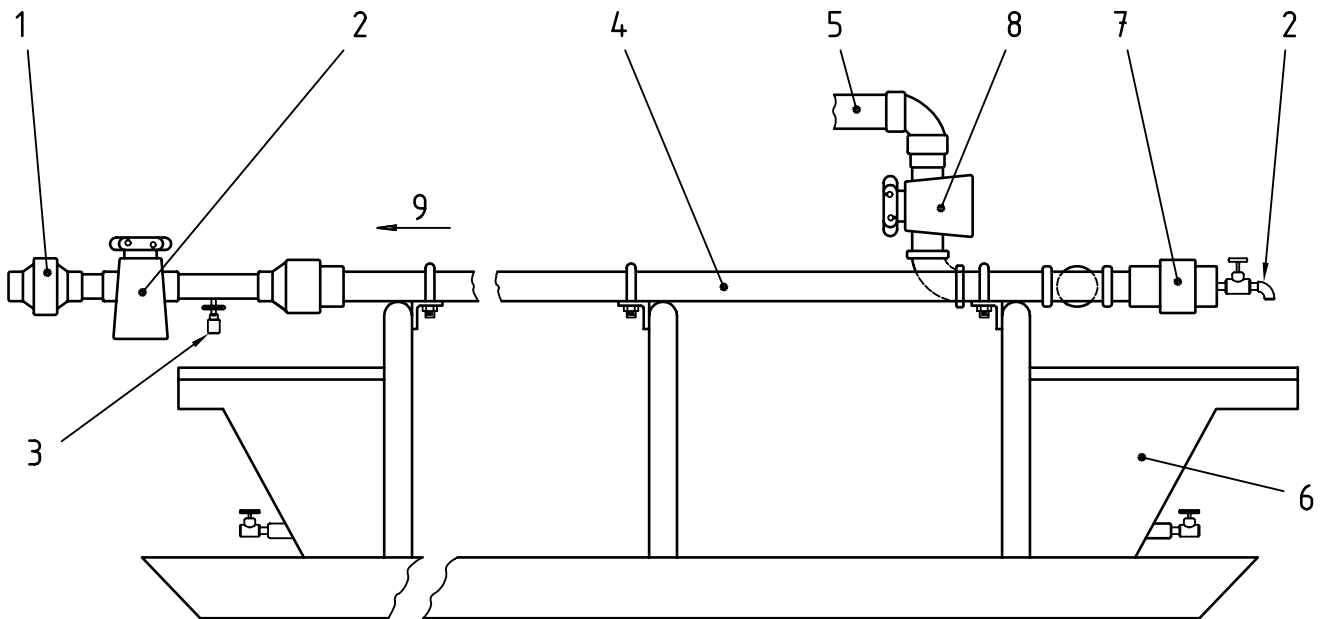
Figure 6 — Typical TFL instrumentation control console

5.5 Lubricator

5.5.1 General

A lubricator allows tool-strings to be inserted into and removed from a pressurized system. Generally, a TFL lubricator consists of a horizontal launch tube section 6 m to 18 m (20 ft to 60 ft) long with quick-connecting unions at the ends, a full-opening block valve, bleed valves and a connection for pumping fluid into the lubricator. Figure 7 shows the principal features of the lubricator.

During some fishing and remedial operations that need extended-length tool-strings, it may be necessary to use the service line to the subsea tree as part of the lubricator. The line pressure shall be bled off during each use.



Key

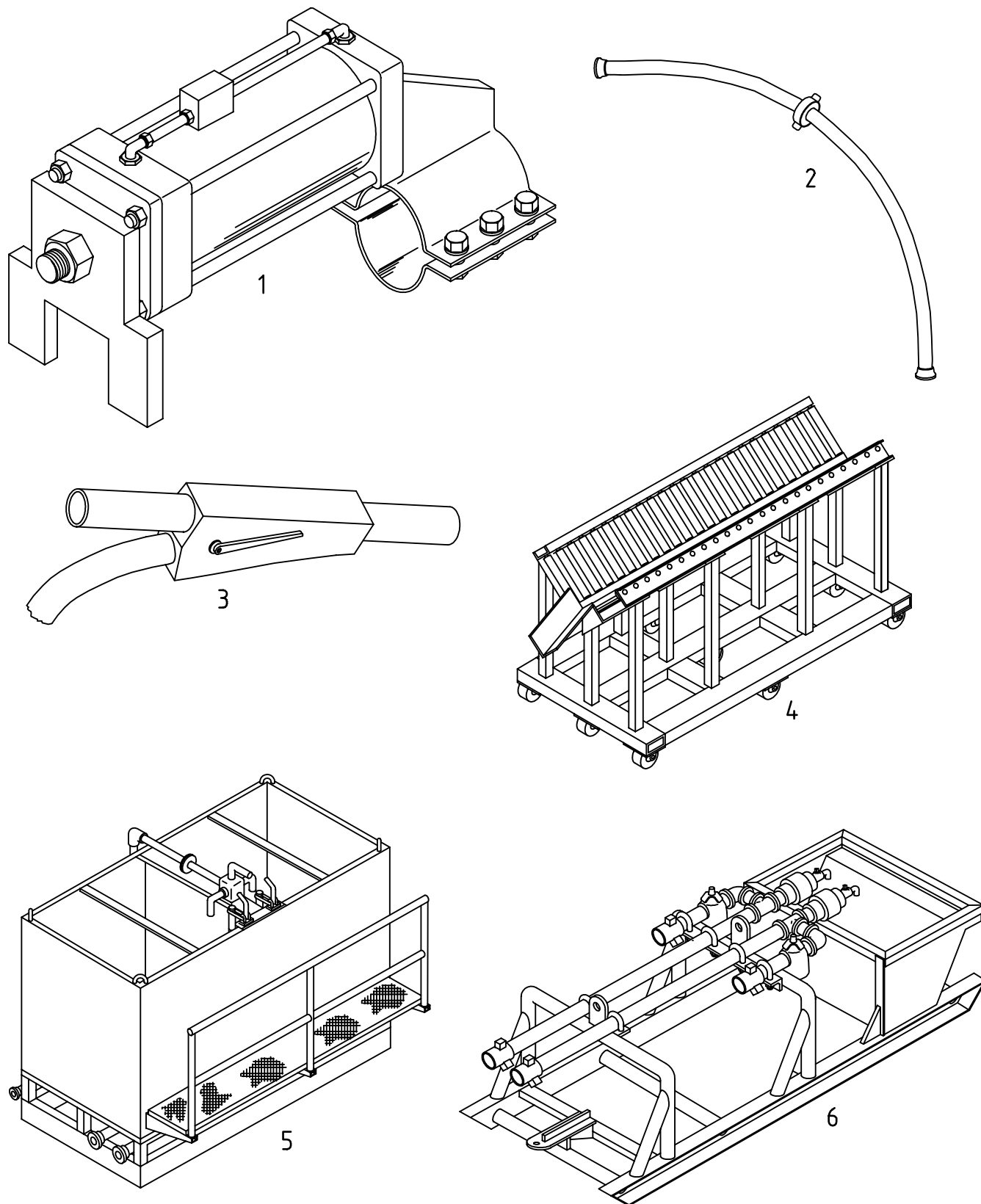
- | | | | |
|---|-----------------------|---|-------------------------------------|
| 1 | Quick union or flange | 6 | Sumps |
| 2 | Bleed valve | 7 | Bull plug assembly with quick union |
| 3 | Full-opening valve | 8 | Valve |
| 4 | Oversized tube | 9 | Tool direction |
| 5 | Pipeline | | |

Figure 7 — Typical lubricator skid

5.5.2 Design

A primary consideration in designing a TFL lubricator is preventing ID reductions or misalignments that could impede tool passage or cause seal damage or other tool damage. The lubricator ID should be sufficiently larger than the flowline ID, in order to permit the tools to be loaded and removed easily, but not so oversized that a high pump rate would be required to move the tools from the lubricator into the flowline. In general, if the lubricator ID is 1,6 mm to 4,8 mm (1/16 in to 3/16 in) larger than the service line nominal ID, these criteria will be satisfied.

As a safety feature, pressure bleed-off valves should be provided at both ends of the lubricator launch tube to ensure blow-down of pressure on both sides of the tool-string before removing the tool from the lubricator. The design should allow collection of excess fluids from the lubricator. Branch connections should be located so as to ensure the tool-string can be launched and will not slam into the lubricator end when it returns to the surface. A power-assisted tool feeder (providing push/pull) and work tables may be necessary for loading and/or removing larger/longer tool-string sizes (see Figure 8).



Key

- 1 Hydraulic tool feeder
- 2 Entry loops
- 3 Diverters

- 4 Roller table
- 5 Working tank
- 6 Horizontal lubricator

Figure 8 — TFL surface equipment

5.5.3 Fabrication

The lubricator piping shall be designed and fabricated in accordance with API RP 14E and clause 6.

5.6 Fluid storage and working tank

A working tank or other fluid storage vessel should be provided in the surface facilities. The storage capacity should be at least equal to the volume of the flowlines and tubing strings. However, if the available space restricts the size of the tank, and if make-up liquid is available, and if excess fluids can be safely disposed of, smaller tanks may be used. A working tank is very useful for keeping track of allowances for lost circulation or well fluid influx. A split 6,3 m³ (40 bbl) tank (see Figure 8) has been found to be a workable size for this function. The working fluid type may vary (diesel, dead crude, inhibited water or brine, etc.) and suitable connections should be available to access these sources. Special precautions shall be taken to satisfy the relevant area classification when using crude oil or handling fluid returns.

5.7 Separator

A separator is generally required to remove gas from the return stream. Removal of the gas helps to obtain repeatable performance in tool operations and tool location and is covered further in clause 9.

The separator should be sized and pressure-rated as appropriate to handle the well fluids, the maximum pumping rate and any fluid surges when switching flow paths during TFL operations.

5.8 Testing

The entire TFL platform facility assembly (see Figure 4) should be pressure tested in accordance with API RP 14E. In addition, the ID of the piping through which TFL tools are to pass should be gauged using the tests described in clause 6.

6 TFL piping system

6.1 General

The TFL piping system consists of the following:

- a) the surface piping between the lubricator and the top of riser;
- b) the riser from the seabed;
- c) a relatively straight flowline section;
- d) the preformed TFL loops or bends used to change tool direction in restricted spaces;
- e) the subsea tree;
- f) the tubing string, downhole accessories and their end connections.

All piping connectors and connecting methods shall provide free, unrestricted passage of tools and shall not cause damage to either metallic seals or non-metallic seals on the TFL tools, TFL pistons or other TFL tool-string components.

6.2 Design

6.2.1 Piping

6.2.1.1 General

TFL pipe shall be either a rigid metallic tubular or a flexible tubular, the latter being constructed of composites of metallic and non-metallic materials.

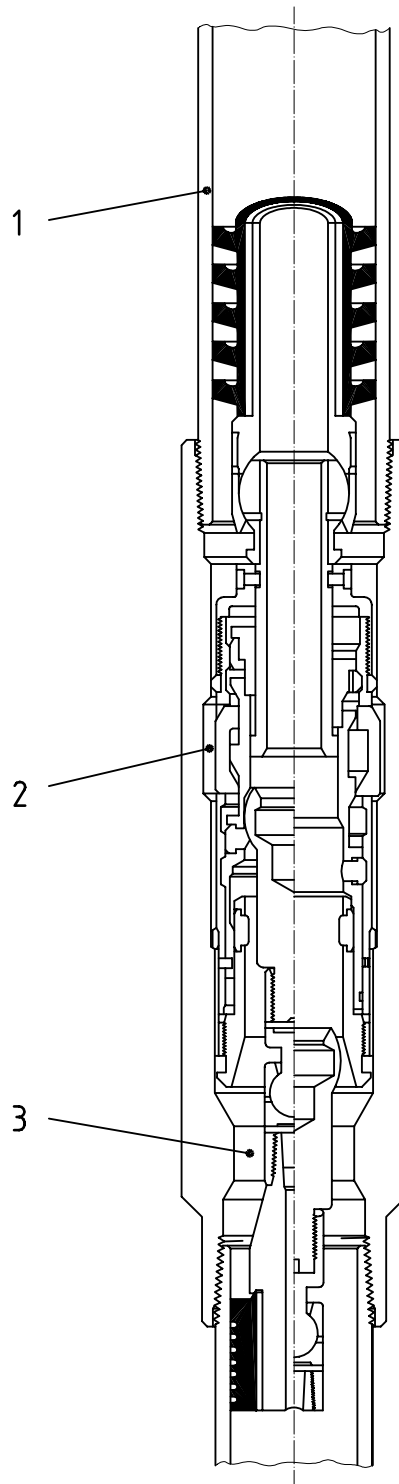
6.2.1.2 Materials

Various metal grades have been used for TFL piping, including carbon steel (ISO 3183-1 and ISO 3183-2 [6]), austenitic-ferritic ("duplex") stainless steel, martensitic stainless steel ("13-chrome"), and others.

More detailed information on the appropriate materials can be found in API RP 17A [4] and ISO 13628-1 [8] for subsea production control systems and in ISO 10420 [7] for flexible pipe.

6.2.1.3 Diameters

Except as noted below, the flowline(s) and other straight portions of the piping system shall have the same minimum ID and maximum ID as the well tubing string(s) (see Table A.1); this practice minimizes the amount of fluid bypassing between the TFL pistons and the pipe wall and improves TFL tool-positioning control. There are situations, however, when the flowline ID must be larger than the well tubing. This occurs when flowlines are particularly long, and large IDs are needed in order to reduce the pressure drop along the line. For this case, a parking system should be employed as is shown in Figure 9. A large diameter TFL tool carrier transports the downhole service tool-string to the subsea wellhead and releases or picks up the smaller diameter downhole tool-string.



Key

- 1 Carrier string
- 2 Parking latch
- 3 Service tool-string

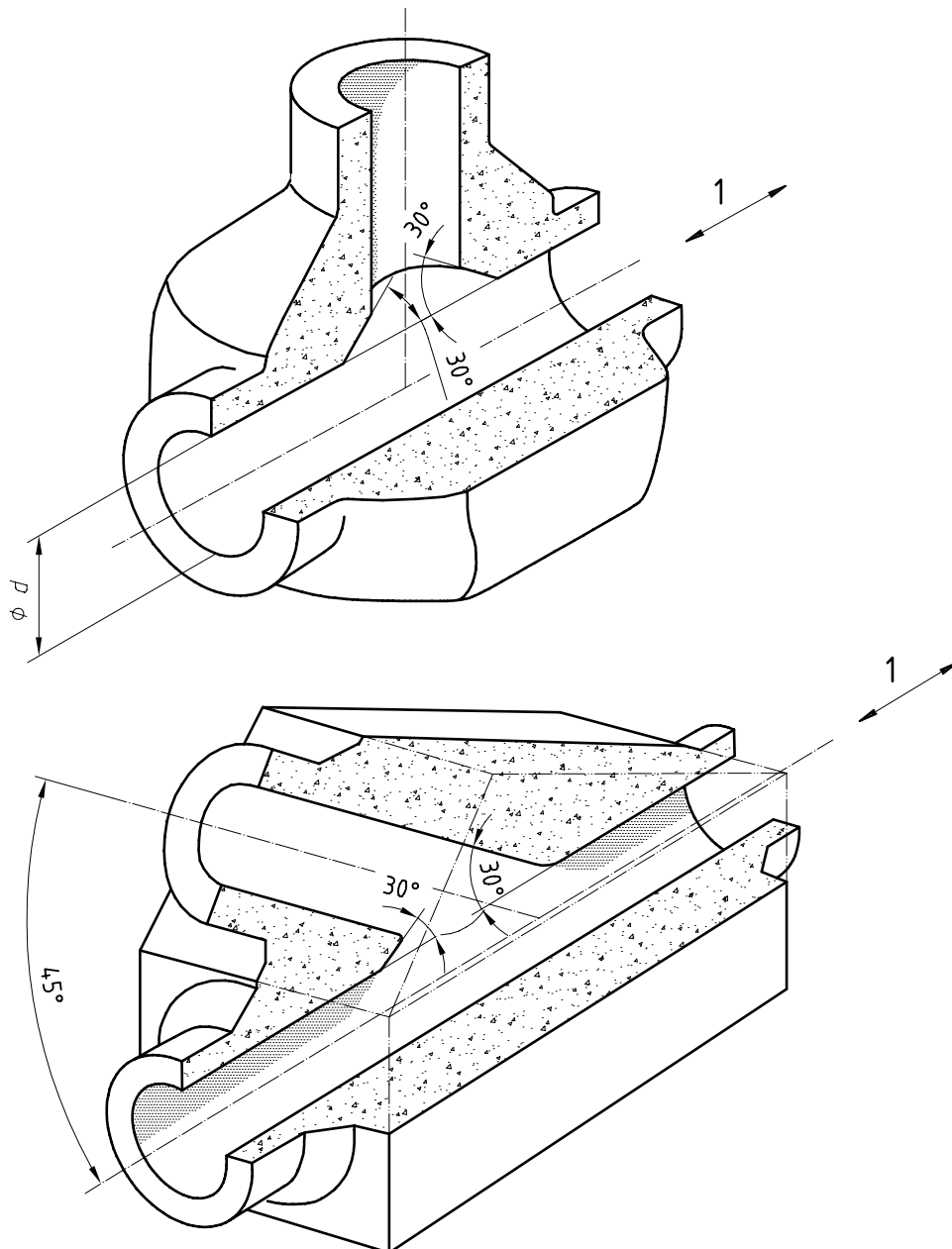
Figure 9 — Parking system

6.2.1.4 Pressure ratings

TFL piping systems shall have a working pressure compatible with the TFL system design pressure. Wall thickness and material strength shall be selected so that all the piping system components comply with the design codes applicable in the country of operation or with those specified by the operator.

6.2.1.5 Side-entry ports

In straight portions of the piping system, side-entry ports should intersect the TFL flowline at an angle of 90°. However, if this is not achievable, the angle shall be at least 45° to the longitudinal axis of the TFL flowline. This minimizes the exposed side-port opening. The intersection should be higher than the longitudinal axis of the TFL flowline. All corners of the intersecting bore should be bevelled as shown in Figure 10 to prevent interference with the TFL tool or damage to its components.



Key

1 Tool travel

Figure 10 — Bore junction configuration for a non-TFL pipe intersecting TFL piping

6.2.1.6 Position locator devices

Restrictions in the flowline or tubing which cause momentary pressure increases during passage of the TFL pistons are useful for locating the TFL service string. The restrictions may be introduced intentionally, as with a specially-manufactured, short, heavy-walled section of pipe, or they may be restrictions that normally occur in any flowline (flowline signature). These restrictions typically cause a 1,4 MPa to 2,1 MPa (200 psi to 300 psi) pressure increase at normal tool transport velocity. Blast joints and flow couplings have been used successfully for this purpose.

If these restriction devices are intentionally introduced downhole to identify the tool-string location, sufficient distance should be provided between the devices and any landing nipple to allow the tool position to be identified and the tool to be slowed down before it reaches the landing nipple. The required distance between such a device and a landing nipple depends on the pumping rate, the fluid volume and the flow rate response time at the pump (i.e. these parameters govern the ability to slow down the tool to the proper speed for the appropriate operation). Since the pressure pulse in the fluid travels at sonic speed, the speed of detection is affected by the fluid properties, the temperature and pressure, and the distance between the pressure detector and the restriction device. Spacing of these restriction devices should ensure that the piston elements are not positioned within the device while the tool is being actuated or force is being generated. This is to prevent difficulties in fishing operations due to reduced fluid bypass.

6.2.1.7 Ovality

Installation methods shall consider the effects of installation forces and stresses causing ovality that would restrict drifting and tool passage.

6.2.2 Bends (loops)

6.2.2.1 Bend radius

Bend loops shall have a bend radius of not less than 1 524 mm (60,0 in). If space and geometry allow, a larger bend radius should be used to reduce fabrication and/or operating problems. The minimum bend radius applies to both rigid and flexible pipe.

6.2.2.2 Bend diameters

Table 2 specifies, for some typical tubing sizes, the maximum ID of loop material prior to bending and the minimum ID of loop material after bending. Minimizing the pipe ID in the bend should be considered in order to increase the efficiency of the TFL tool.

Table 2 — Loop material dimensions

Tubing OD mm (in)	Maximum loop material ID before bending mm (in)	Minimum ID after bending mm (in)
60,3 (2 3/8)	52,37 (2,062)	50,3 (2,000)
73,0 (2 7/8)	66,68 (2,625)	63,5 (2,500)
88,9 (3 1/2)	79,38 (3,125)	76,2 (3,000)
101,6 (4)	92,08 (3,625)	88,9 (3,500)
114,3 (4 1/2)	104,78 (4,125)	101,6 (4,000)
139,7 (5 1/2)	123,83 (4,875)	120,65 (4,750)

6.2.2.3 Bend geometry

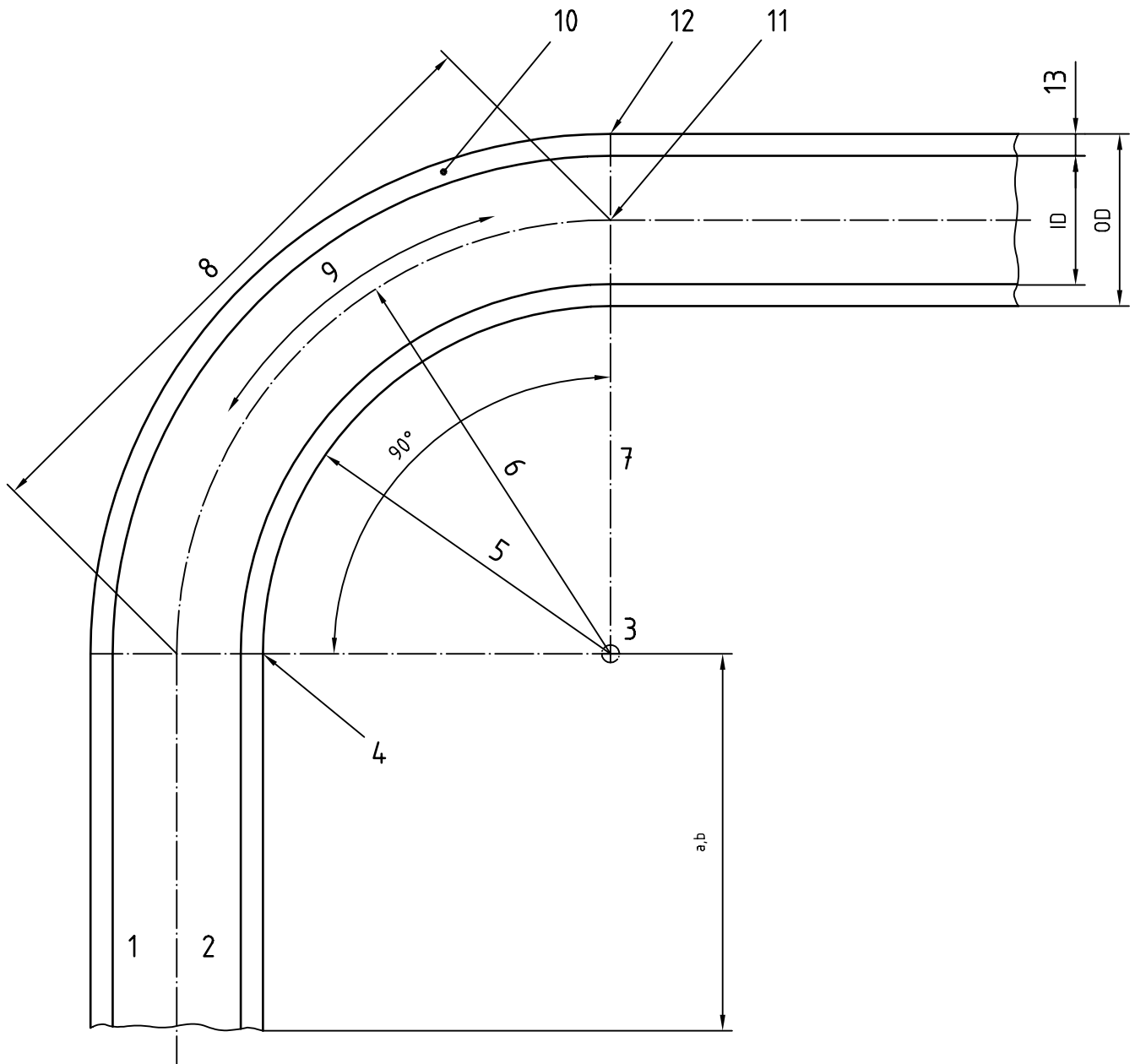
See Figure 11 for a description of terms.

Bend geometries that use tangent-coupled bends to provide a "marked" change in direction in more than one plane should be avoided unless compound bending is absolutely necessary, but in any case the bend geometry shall allow passage of the TFL drift as specified in 6.4.1.

For example, two 90° bends may be joined at their tangents to form a 180° turn in one plane because the two bends have a common centre of curvature. However, if the two bends are rotated at the tangent coupling so the two centres of curvature are no longer in the same plane, some TFL tool-strings will not pass. Installing a straight section with a length of at least nine pipe IDs between the tangent ends of the two bends will normally solve this problem.

If a "slight" change in direction is used, such as the continual helix or "ram's horn" configuration of the loops at the entrance to a subsea tree, the tool may still pass satisfactorily. The footnotes in Figure 11 give further information. During the design phase, drifting should assume the worst-case TFL tool-strings in order to assure the passage of the TFL tool-string.

Compound bends in one plane (coplanar "S" bends) may be used if the radius of curvature along the incremental length of the tube is, at all points, at least 1 524 mm (60 in). A reasonably oversized internal diameter of the compound bend, made following the guidelines given herein, in conjunction with a bend radius that exceeds the recommended minimum value can improve the suitability of the compound bend. Even so, the use of such bends is a trial-and-error process depending on the tools to be passed, and only sufficient drifting can assure the passage of the TFL tool-string.



Key

- | | | | |
|---|---------------------|----|--------------------------|
| 1 | Centreline axis | 8 | Chord |
| 2 | Starting tangent | 9 | Arc |
| 3 | Centre of curvature | 10 | Pipe heel |
| 4 | Tangent point | 11 | Finishing tangent |
| 5 | Throat | 12 | Tangent point a, b, c, d |
| 6 | Bend radius | 13 | Wall thickness |
| 7 | Degree of bend | | |

- a For joining bends which are non-planar, this length is typically 9 pipe IDs.
- b For joining connectors to bends with unlimited space this length is typically 6 pipe IDs.
- c Bends of any degree joined at the tangent point are regarded herein as tangent-coupled. Most all tangent-coupled coplanar bends are acceptable F/TFL use. Tangent-coupled non-planar bends may not be acceptable (see a).
- d See 6.2.2.

Figure 11 — TFL bend terminology

6.2.2.4 Materials

The materials used for bends shall have sufficient strength and wall thickness so that, after forming, the rated working pressure of the bend is at least that of the flowline and the applicable design codes.

6.2.2.5 Position of connections at ends of bends

With some success, connections have been attached tangentially with bend curvature in field installations where space is limited and connections are smooth inside. These connections shall be designed to allow passage of the appropriate TFL drift as specified in 6.4.1.

6.2.2.6 Connection ratings

All connections should meet service and pressure rating(s) of the associated piping.

6.2.2.7 Bracing

Support bracing for wellhead bends should allow for thermal changes. Flexible pipes shall be supported to limit the minimum radius of curvature to 1524 mm (60 in) along the centreline. ISO 10420 [7] provides further details regarding flexible pipe.

6.3 Fabrication

6.3.1 Flowline pipe

To be dimensionally compatible with TFL tools, flowline pipe shall be manufactured in accordance with annex A. Each joint of pipe should be drifted with the ID drift listed in ISO 3183-1 to identify and eliminate any damaged or undersize joints.

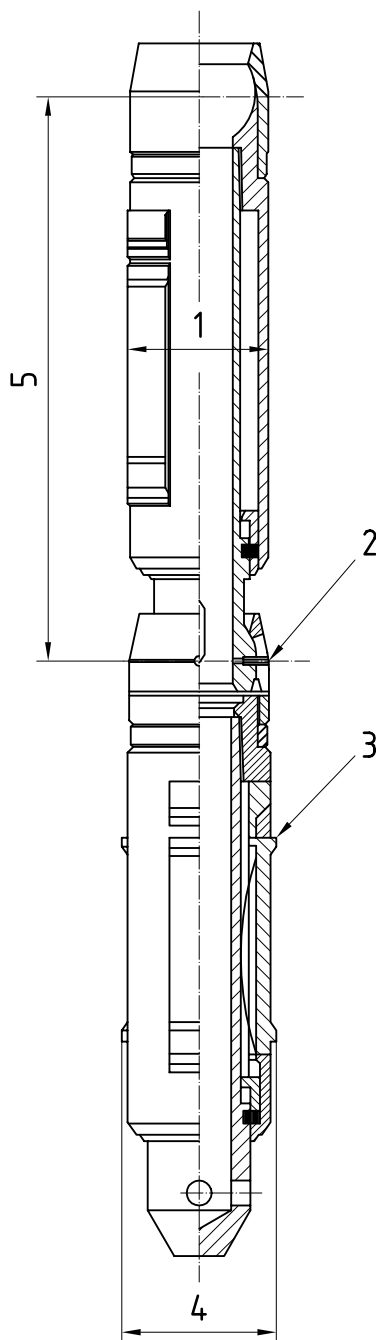
6.3.2 Drifting during fabrication

Flowlines fabricated by welding shall be drifted after welding using both the sharp-shouldered drift (see Figure 12) and the TFL flowline drift (see Figure 13) as described in 6.4, to ensure passage of TFL tools (typically this is performed manually, see 6.4.1).

6.3.3 Connections

6.3.3.1 General

Following the guidelines on joining techniques presented below should result in connections that are acceptable for TFL operations. Connections shall be concentric to each other within 0,76 mm (0,03 in) of true position and the maximum gap shall not exceed 4,8 mm (0,19 in). Joints with a recess shall be as shown in Figure 14. Valves, unions or other connections shall be aligned so that they are concentric to the piping within 0,76 mm (0,03 in) of true position. All piping connections shall be drifted using both the sharp-shouldered drift (see Figure 12) and the TFL flowline drift (see Figure 13) as described in 6.4. Internal surfaces should be free of weld slag, mill scale or other major surface imperfections.



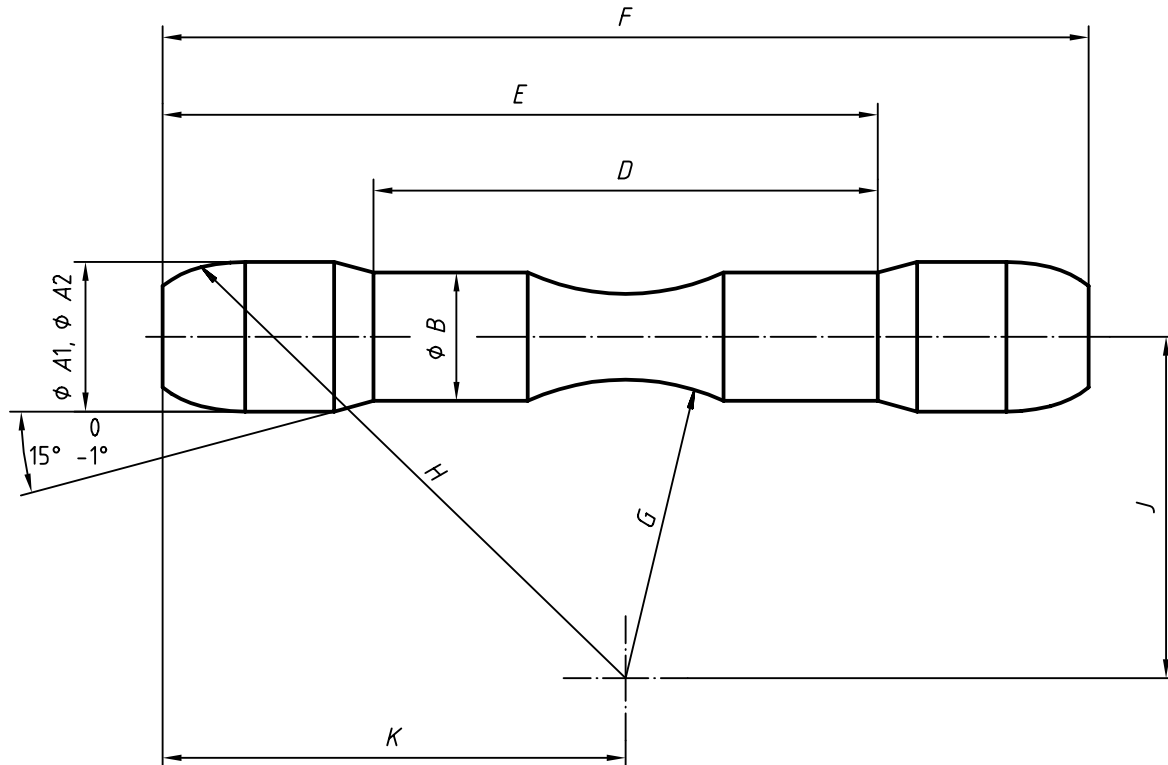
Key

- 1 Drift OD (see table)
- 2 Segments pinned and oriented at 45° to provide 360° of key clearance
- 3 Maximum radius 0,76 mm (0,03 in)
- 4 OD at shoulder = pipeline/loop ID plus 1,6 mm (1/16 in) minimum
- 5 Length, centreline swivel to swivel

Nominal tool size		Drift dimensions ^a			
		OD		Length	
mm	(in)	mm	(in)	mm	(in)
50,8	(2)	45,72	(1,80)	243,08	(9,57)
63,5	(2 ½)	68,07	(2,68)	280,68	(11,05)
101,6	(4)	90,68	(3,57)	311,15	(12,25)
139,7	(5 ½)				

^a Dimensions based on minimum loop IDs of Table 2 with 1524 mm (5 ft) radius to centreline.

Figure 12 — TFL sharp-shouldered drift



1		2				3		4		5	
Nom. size		Tubular drift OD		Flowline drift OD		Shaft OD					
		<i>A1</i>		<i>A2</i>		<i>B</i>		<i>D</i>		<i>E</i>	
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)
50,8	(2)	47,37	(1,865)	48,29	(1,901)	45,5	(1,79)	139,90	(5,508)	228,73	(9,005)
63,5	(2,5)	58,50	(2,303)	59,61	(2,347)	51,8	(2,04)	213,54	(8,716)	301,27	(11,861)
76,2	(3)	69,47	(2,735)	72,82	(2,867)	58,2	(2,29)	242,87	(9,562)	343,71	(13,532)
101,6	(4)	93,29	(3,673)	97,36	(3,833)	70,9	(2,79)	282,75	(11,132)	442,70	(17,429)
127,0	(5)	112,19	(4,417)	118,19	(4,653)	77,2	(3,04)	341,30	(13,437)	529,82	(20,859)

1		6		7		8		9		10	
Nom. size		Overall length		Inner loop radius		Outer loop radius		Centre distance		Centre distance	
		<i>F</i>		<i>G</i>		<i>H</i>		<i>J</i>		<i>K</i>	
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)
50,8	(2)	317,50	(12,500)	1 498,6	(59,000)	1 549,4	(61,000)	1 520,83	(59,875)	158,75	(6,250)
63,5	(2,5)	381,00	(15,000)	1 492,3	(58,750)	1 555,8	(61,250)	1 517,65	(59,750)	190,50	(7,500)
76,2	(3)	444,50	(17,500)	1 485,9	(58,500)	1 562,1	(61,500)	1 514,48	(59,625)	222,25	(8,750)
101,6	(4)	602,64	(23,726)	1 473,2	(58,000)	1 574,8	(62,000)	1 508,13	(59,373)	301,32	(11,863)
127,0	(5)	718,84	(28,281)	1 460,5	(57,500)	1 587,5	(62,500)	1 498,60	(59,000)	359,18	(14,141)

Tolerances

<i>A1, A2</i>	− 0,13 mm (− 0,005 in)	<i>F</i>	+ 0,51 mm (+ 0,020 in)
<i>B</i>	± 0,25 mm (± 0,010 in)	<i>G</i>	− 0,20 mm (− 0,008 in)
<i>D</i>	+ 0,51 mm (+ 0,020 in)	<i>H</i>	+ 0,20 mm (+ 0,008 in)
<i>E</i>	+ 0,13 mm (+ 0,020 in)	<i>J</i>	+ 0,13 mm (+ 0,005 in)
		<i>K</i>	± 0,13 mm (± 0,005 in)

Figure 13 — TFL drift mandrel dimensions

6.3.3.2 Welded connections

Typical end preparations for welding are shown in Figure 15. This figure shows the U-shaped preparation. However, the V-shaped preparation shown in API Std 1104 may also be used.

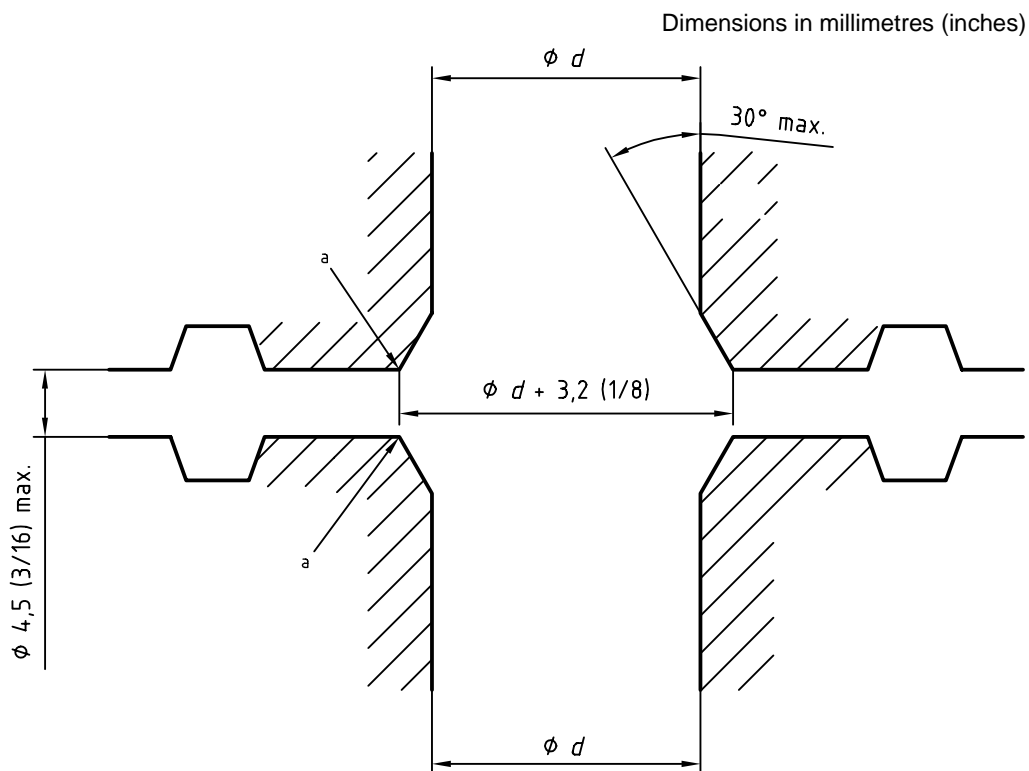
The following should be noted when selecting either U-shaped or V-shaped weld preparations for TFL applications:

- the V-shape is more likely to cause slag inclusions in the weld and excess penetration into the pipe bore, the latter will normally require post-weld broaching or reaming. The U-shaped preparations are designed to allow a gas-tungsten-arc welding tip to enter the weld groove for the root pass, often eliminating the need for post-weld clean-up operations;
- either V-shaped or U-shaped configurations may be used for subsea tree or surface equipment welds, as judged most efficient by the manufacturer or as specified by the purchaser. The U-shaped preparation should be selected for flowline connections so as to minimize post-weld work.

Welding should be in compliance with applicable codes and standards. Typically, API Std 1104 or ASME Boiler and Pressure Vessel Code, Section IX, [5] are specified in accordance with other piping specification requirements such as ANSI/ASME B31.3 [1], ANSI/ASME B31.4 [2] or ANSI/ASME B31.8 [3]. Other welding standards may be used if appropriate and documented.

After welding, a sharp-shouldered drift as shown in Figure 12 shall be passed through each joint in both directions to check for restrictions and to assure passage of the TFL tool. To achieve a smooth-bore ID, it may be necessary to use broaches and/or grinders to remove the slag, excess weld metal, eccentricities or distortion caused by welding.

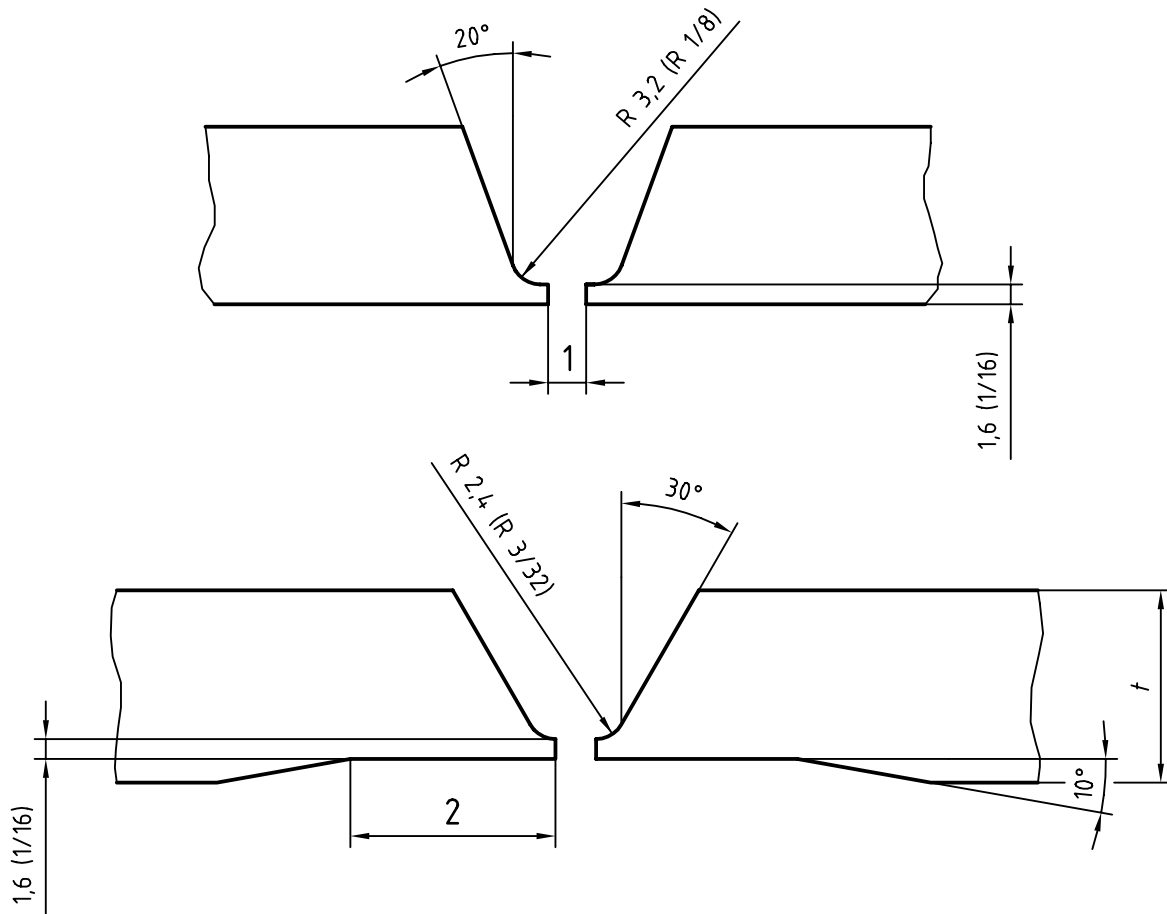
Non-destructive examination of welds shall be as specified in 6.4.5.



- a 0,25 mm to 0,50 mm (0,01 in to 0,02 in) chamfer 43° to 47°

Figure 14 — Connection recess

Dimensions in millimetres (inches)



Key

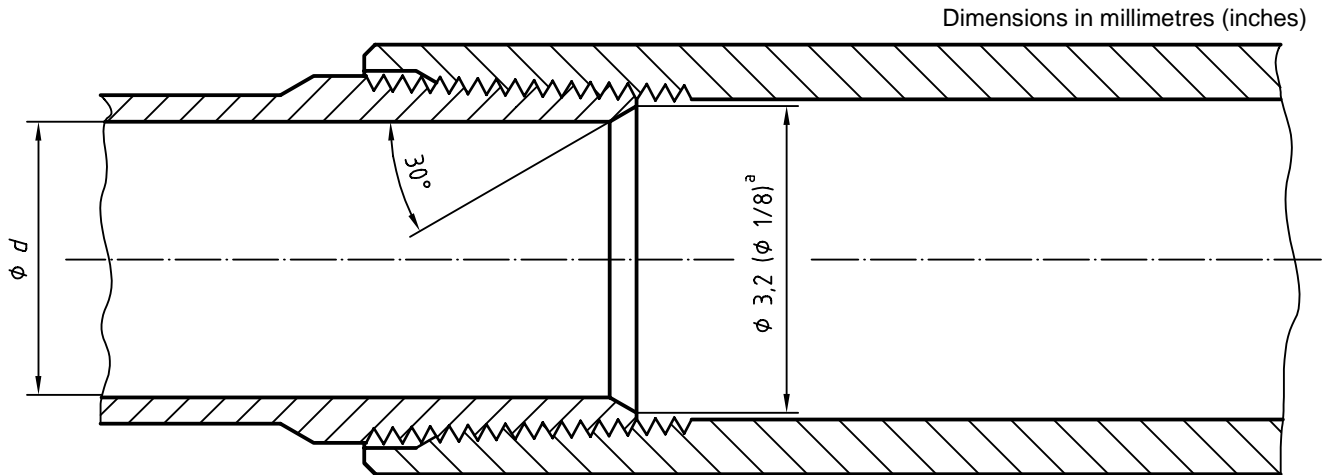
- 1 Root gap (= electrode diameter)
- 2 Machined distance (= t)
- t = pipe thickness

Figure 15 — TFL pipe U-shaped weld configurations

6.3.3.3 Threaded-and-coupled connections

Threaded-and-coupled connections shall be fabricated to maintain ID concentricity of the pipe. Where eccentricity is a problem, field experience has shown it is often possible to rotate (tighten) API EUE type connections to reduce the eccentricity of the two pipe segments. However, caution should be exercised as over-torquing can cause ID reduction. The gap between threaded pipe shall not exceed 25,4 mm (1,0 in) in a fully made-up, properly torqued connection based on measured thread length dimensions, and the end of each threaded pipe shall be bevelled as shown in Figure 16.

When economically appropriate, the use of a premium (proprietary) type of thread, with a flush or near-flush ID at the joint preparation, should be considered.



^a Root diameter at tip

Figure 16 — Reduced-entry profile dimensions

6.3.3.4 Flanged or clamped connections

Flanged or clamped connections shall maintain concentricity of piping ID within 0,76 mm (0,03 in) of true position. The end fitting shall be properly welded to avoid ID reductions, otherwise they shall be removed to eliminate sharp shoulders and maintain smooth transitions. Gaps between mating flanges should be minimized and the edges of each flange opening shall be chamfered to minimize TFL tool damage. Refer to Figure 14 for additional details.

Flanged or clamped connections shall have a metal seal-ring which assists concentric alignment. Flat, gasket-type, flanged connections should be avoided. Novel methods to achieve concentricity may be incorporated if appropriate, e.g. tongue-and-groove features, alignment jigs placed in the ID (also applicable for welded connections), etc.

6.3.4 Bends

6.3.4.1 General

TFL tool designs are based on a minimum bend radius of 1524 mm (60 in). For practical measurement reasons, the radius is often measured at the inside surface of the bend but still enforcing the same minimum radius, resulting in a slightly conservative bend radius. Bends shall be drifted using TFL flowline drift (see Figure 13) as described in 6.4.

Table 2 summarizes the critical dimensions of bends measured before and after forming. Serious consideration should be given to performing "test" bends with some spare, duplicate pipe material prior to forming production bends.

6.3.4.2 Finish

The internal surface finish of the pipe after bending should be free of mill scale, gross wrinkles or buckles, weld slag and other surface imperfections which could interfere with tool passage or degrade tool performance.

6.3.4.3 Material

Metallurgical tests should be performed after bending to ensure that the material still meets the minimum design requirements of the manufacturer.

6.4 Testing

6.4.1 Drifts

TFL flowline and tubing drifts are designed to simultaneously verify both the minimum bend radius and the ID of the pipe. These drifts are described in detail in Figure 13. A sharp-shouldered, spring-loaded drift shown in Figure 12 may be used to locate internal restrictions at the flowline connections. Such a drift shall be collapsible to a diameter less than the drift diameter of the pipe being used. The drift tool shoulder shall be maintained to within the 0,76 mm (0,03 in) maximum radius to assure that all undesirable shoulders and other impediments are located. This drift shall be passed through the joint in both directions. The assembly consists of two segments in series, oriented at 45° to obtain 360° coverage. A "worst-case" drift is the tool-string that covers the largest or most critical tool-string envelope to be used in the TFL system as recommended by the TFL equipment manufacturer.

6.4.2 Manual drifting

For flowline drifts, tubing drifts or "worst case" tool-strings, no more than 445 N (100 lbf) above the weight of the drift shall be applied in a pushing or pulling manner to move the drift. For sharp-shouldered drifts, no more than 890 N (200 lbf) above the weight of the TFL tools shall be applied.

6.4.3 TFL drifting

In addition to the drifting described in 6.3, all assembled piping shall be re-drifted using the flowline drift and the "worst case" tool-string.

Flowlines shall be re-drifted after installation using the flowline drift and the "worst case" tool-string.

6.4.4 Pressure test

TFL piping shall be tested in accordance with 7.2.2 and ISO 13628-4:1999, 7.16.

6.4.5 Non-destructive examination

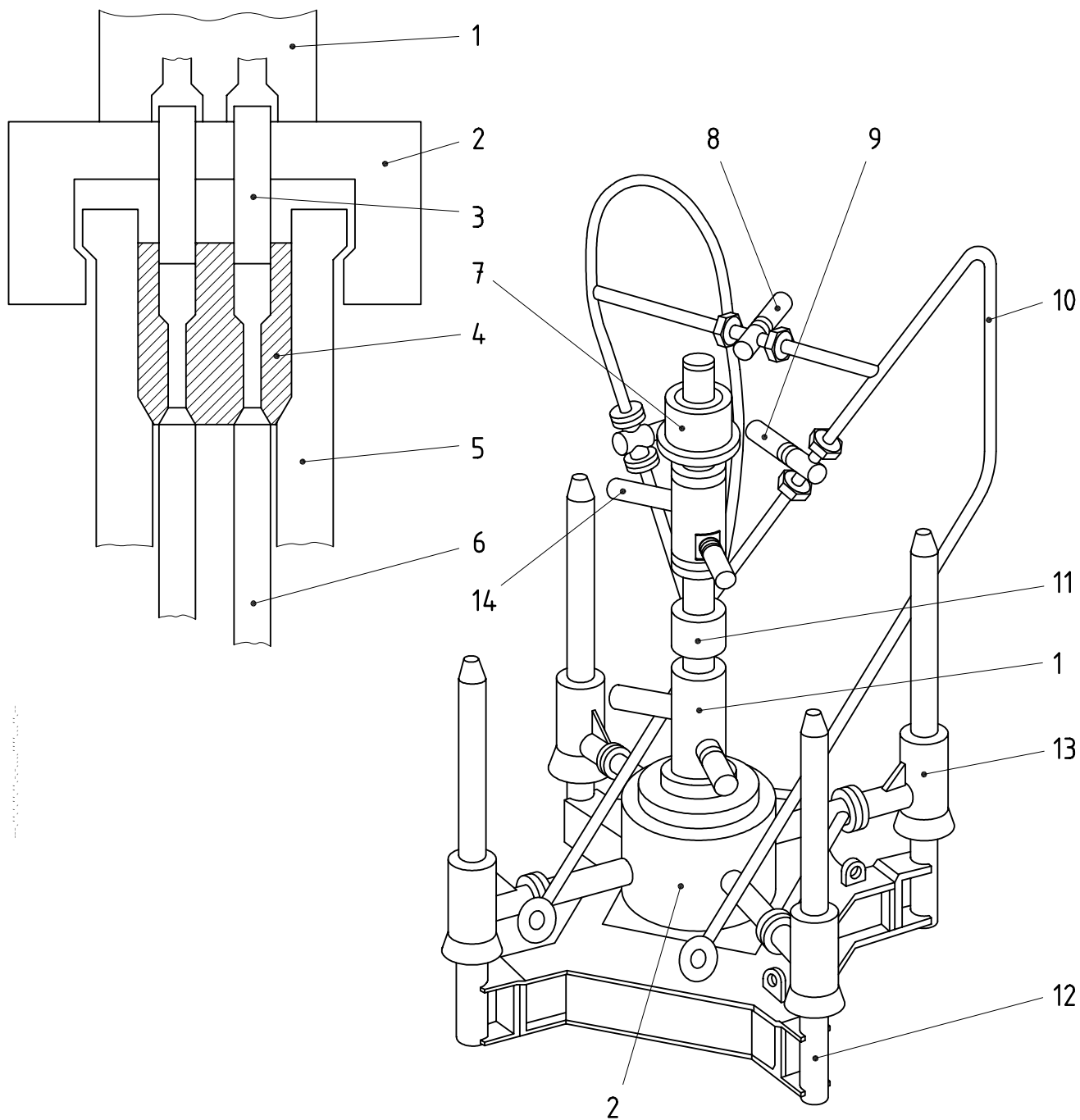
TFL piping shall be examined in accordance with ISO 11960 and API Std 1104.

7 Subsea tree, tubing hanger, diverters and selectors

7.1 Subsea tree design

7.1.1 General

The subsea tree (see Figure 17 and Figure 18) is that portion of the TFL system between the tubing hanger and the flowline. The subsea tree consists of specialized valves, completion hardware and wellhead equipment used to complete a well underwater. The subsea tree includes the connector, the master and wing valves, the wye spool, the tree loop and the flowline connector.

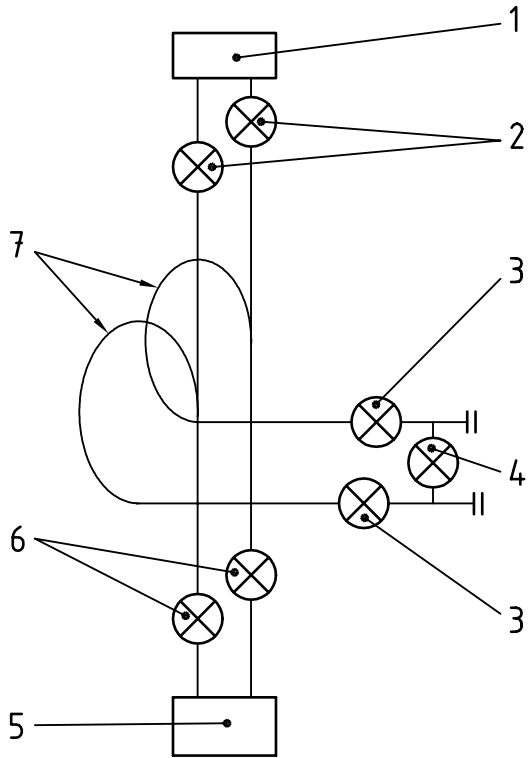


Key

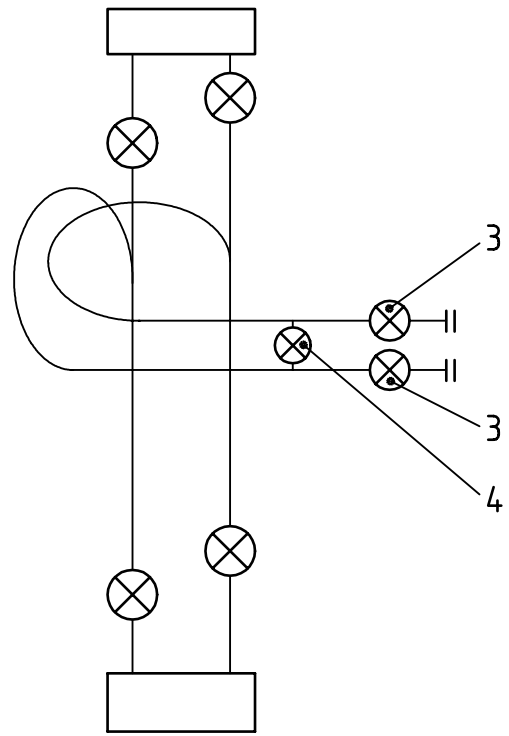
- 1 Master valve block
- 2 Tree connector
- 3 Tree tubing stabs
- 4 Tubing hanger
- 5 Subsea wellhead
- 6 Well completion tubing
- 7 Tree cap

- 8 Crossover valve
- 9 Wing valves
- 10 TFL tree loop
- 11 Wye spool
- 12 Wellhead guidebase
- 13 Tree guide frame
- 14 Swab valves

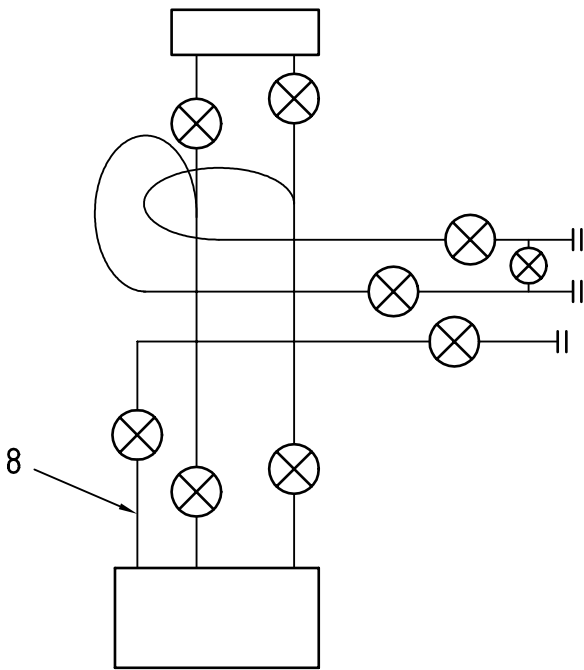
Figure 17 — TFL tree and wellhead completion



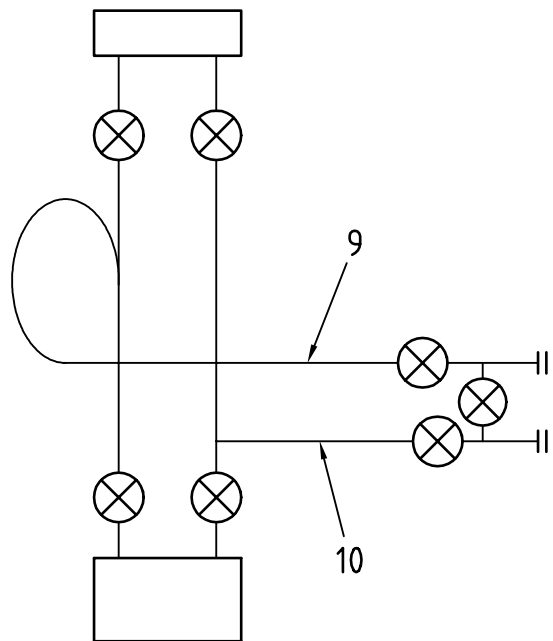
a) Typical TFL tree schematic



b) Alternative TFL tree schematic with crossover valve upstream of wing valves (not common)



c) TFL tree with separate annulus access



d) "Partial" TFL tree

Key

- 1 Tree cap
- 2 Swab valves or crown plugs
- 3 Wing valves
- 4 Crossover valve
- 5 Tree connector
- 6 Master valves
- 7 TFL tree loops
- 8 Annulus monitor
- 9 TFL tools pass only through this line
- 10 TFL fluid passage only

Figure 18 — Various TFL tree configurations

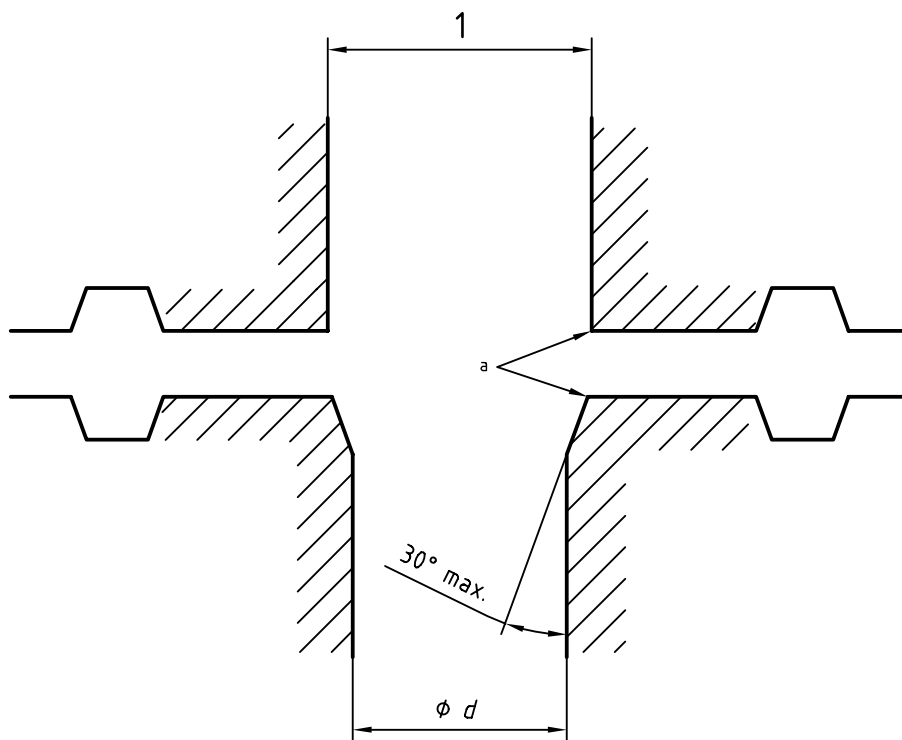
7.1.2 Wellhead bore

The bore through the subsea tree shall have IDs as listed for the valve in Table 3. Any internal profile recesses should meet the requirements of clause 8. Mechanical connections to other subsea tree components with bores shall provide conical transition surfaces and minimum gap lengths as shown in Figure 19 or Figure 20. Welded connections shall meet the requirements of clause 6.

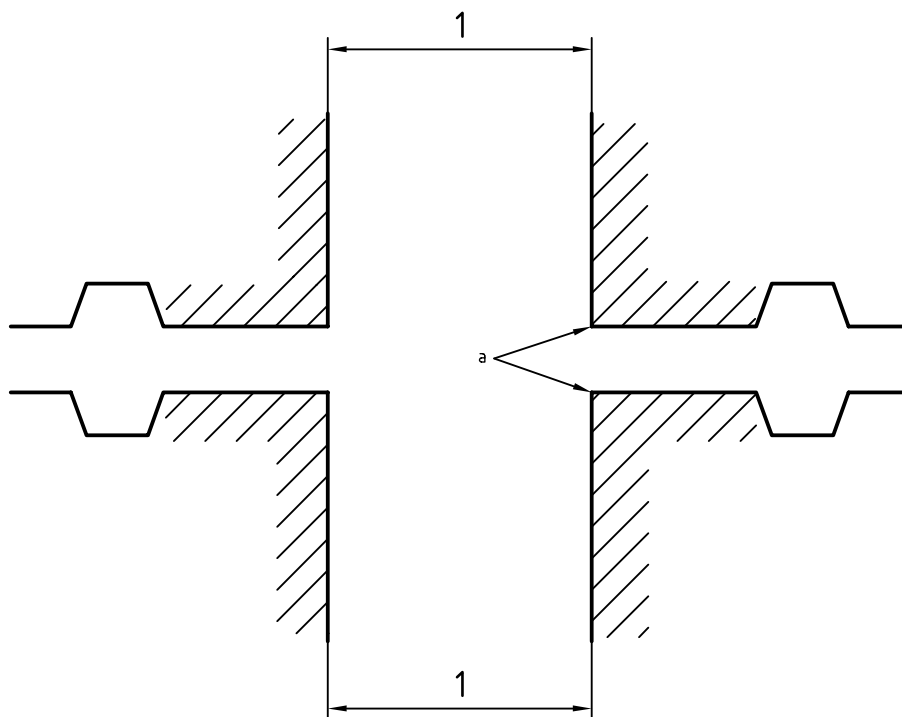
Table 3 — Wellhead bore dimensions

Tubing		Production bore		Valve	Tubing hanger
OD	ID	min.	max.	Bore	Plug bore ^a
mm (in)	mm (in)	mm (in)	mm (in)	mm (in)	mm (in)
60,3 (2 3/8)	50,67 (1,995)	49,15 (1,935)	50,8 (2,000)	52,4 (2,063)	47,63 (1,875)
73,0 (2 7/8)	62,0 (2,441)	60,45 (2,380)	62,1 (2,445)	65,1 (2,563)	58,75 (2,313)
88,9 (3 1/2)	76,0 (2,992)	74,55 (2,935)	76,2 (3,000)	77,79 (3,063)	69,85 (2,750)
114,3 (4 1/2)	100,53 (3,958)	99,06 (3,900)	100,84 (3,970)	103,2 (4,063)	93,68 (3,688)
139,7 (5 1/2)	124,26 (4,892)	123,22 (4,851)	125,63 (4,964)	130,02 (5,125)	112,7 (4,437)

^a Other optional sizes are available and may be used if compatible with the overall TFL system requirements.



a) Face-to-face bore recess



b) Bore transition profile for face-to-face flange connections

Key

- 1 Valve bore
- a 0,25 mm to 0,50 mm (0,01 in to 0,02 in) chamfer at 43° to 47°

Figure 19 — Face-to-face flange connection profiles

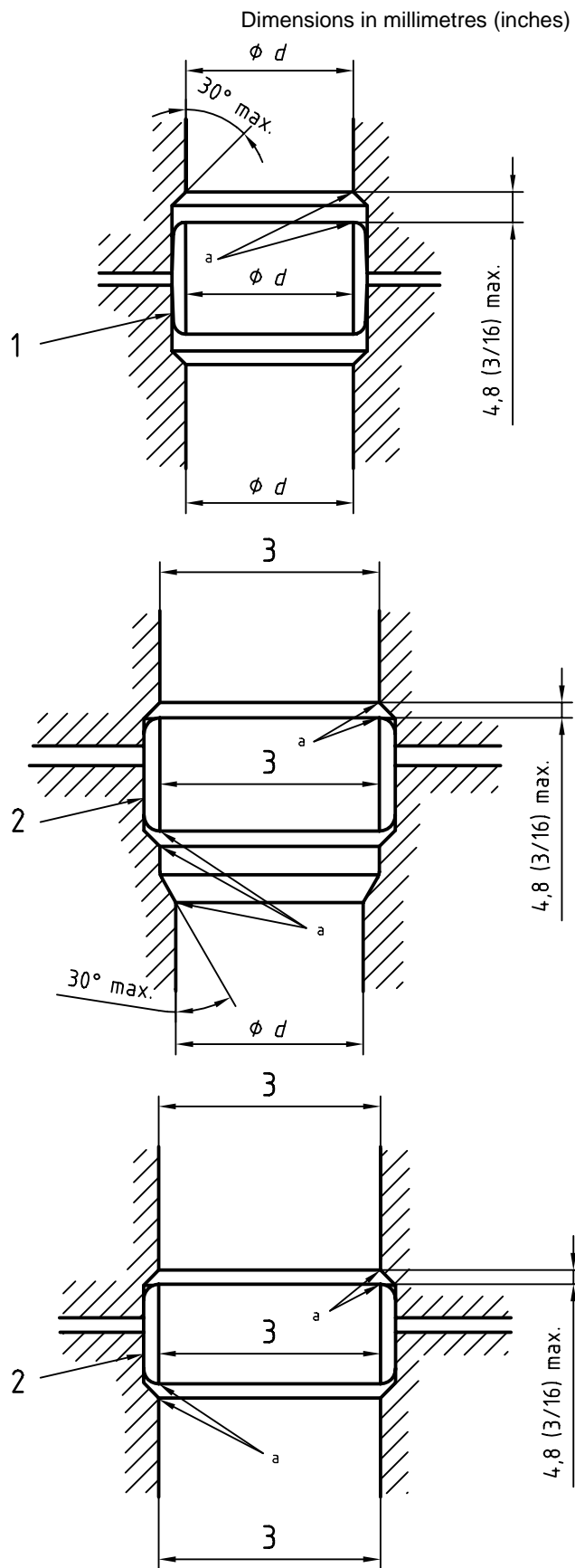
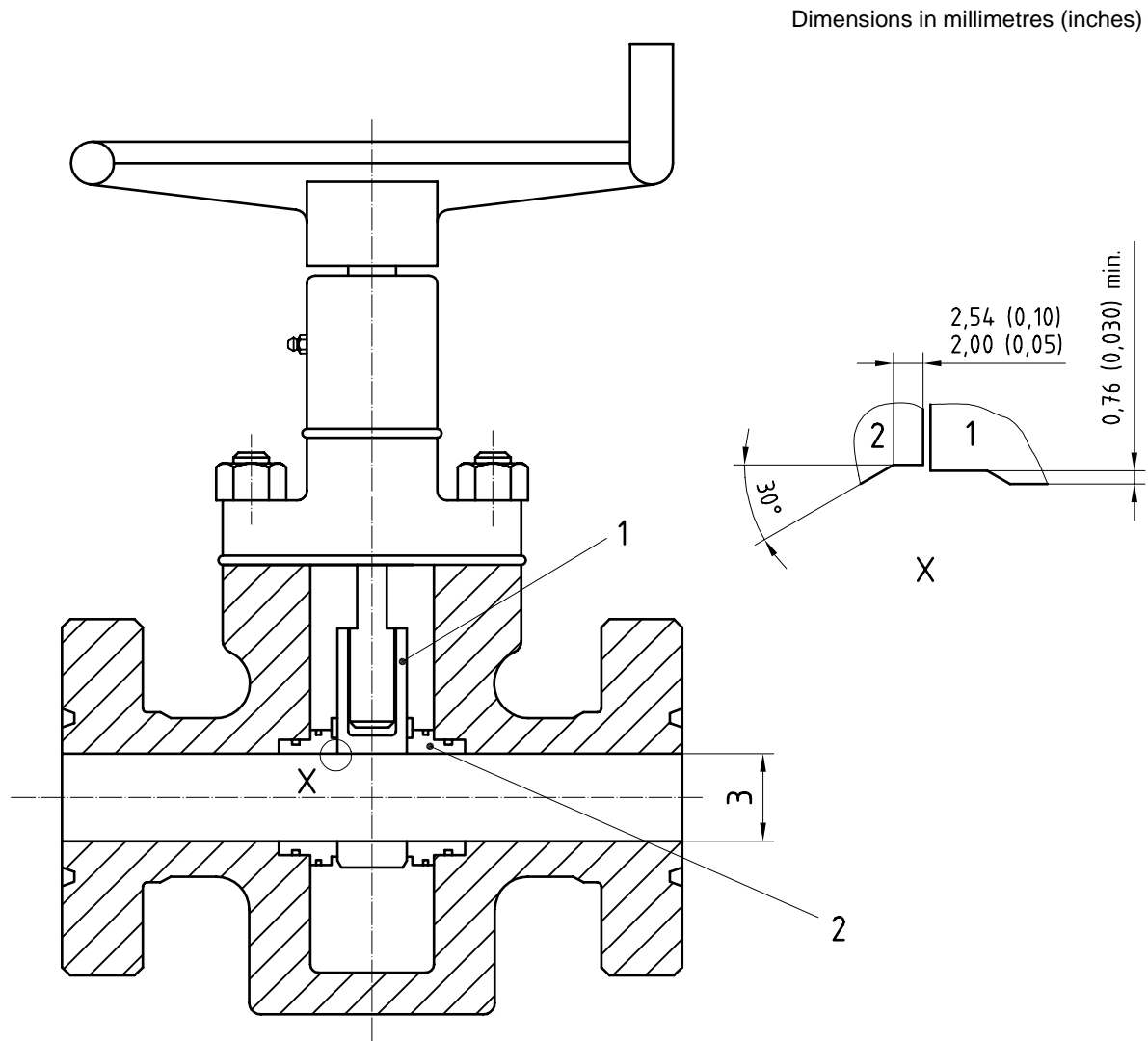


Figure 20 — Bore transition profiles with internal bore seals

7.1.3 Valve and valve block bores

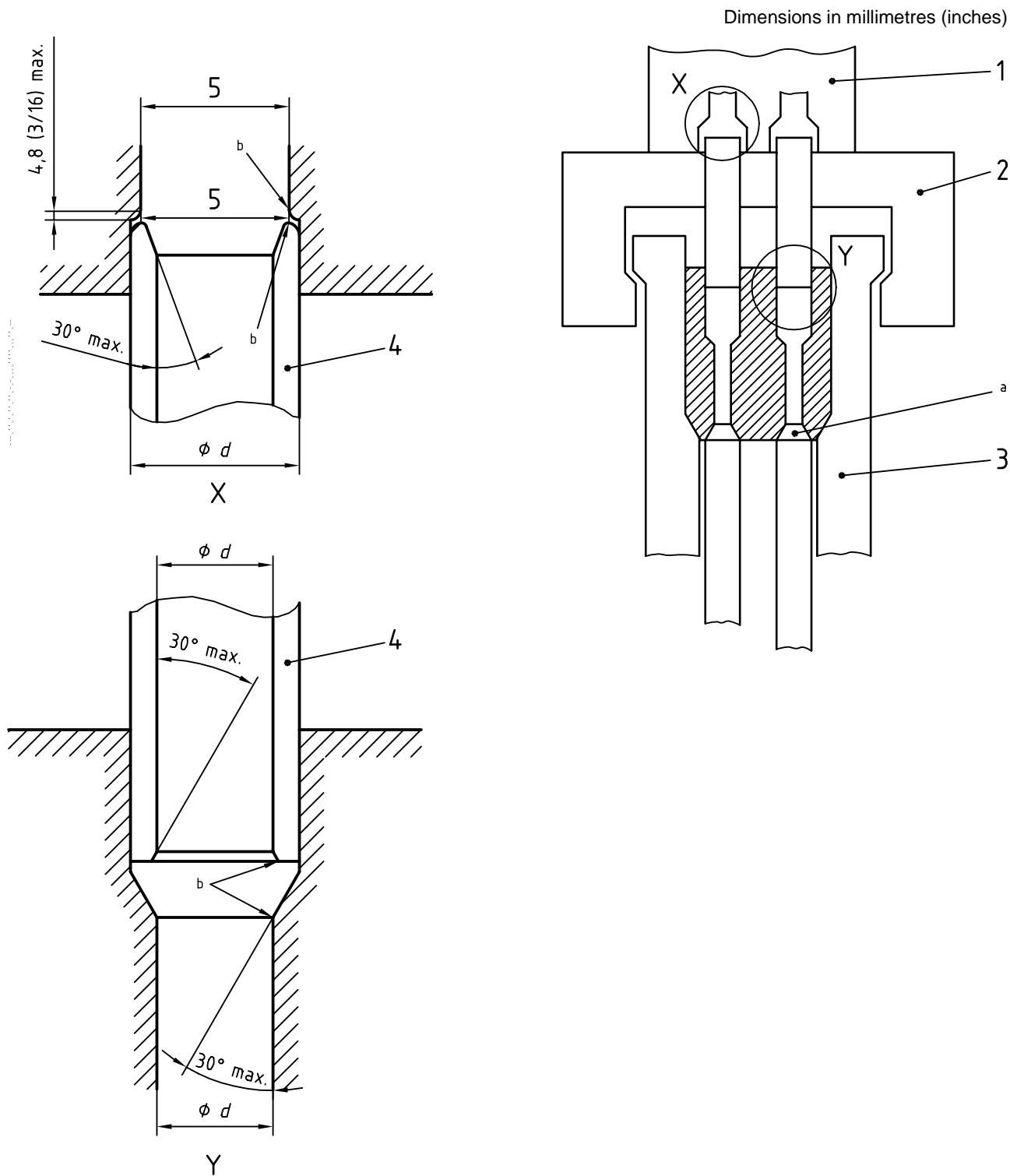
The bores of blocks that contain valve assemblies and the bore inside an individual valve body shall conform to the values for the tubing hanger in Table 3. The interface configuration between a valve gate and a valve seat shall conform to the recess dimensions shown in Figure 21. The bore of the valve body, the valve gate and valve seats shall all be concentric with each other within 0,76 mm (0,03 in) of true position.



- Key**
- 1 Gate
 - 2 Seat
 - 3 Valve bore

Figure 21 — Bore transition profiles between a gate and seats in a valve

Mechanical connections to other valves or wellhead bores shall provide conical transition surfaces and minimum gap length, as shown in Figure 19, Figure 20 or Figure 22. All bores shall be concentric with respect to each other to within 0,76 mm (0,03 in) of true position. This is done to minimize valve damage from tool passage. Except for transition surface requirements, all other provisions of ISO 13628-4 shall apply.



Key

- | | | | |
|---|--------------------|---|--|
| 1 | Master valve block | 4 | Tree tubing stab |
| 2 | Tree connector | a | See Figure 16 |
| 3 | Tubing hanger | b | 0,25 mm to 0,50 mm (0,01 in to 0,02 in) chamfer 43° to 47° |

Figure 22 — Bore transition profiles for the tubing hanger

7.1.4 Wye spool

TFL trees contain a wye spool (see Figure 17, Figure 23 and Figure 24) to allow both vertical and TFL access to the well. The wye spool contains a deflector to properly direct TFL tools through the wye spool. The wye spool shall provide smooth transition IDs that do not impede passage of TFL tools. The deflector's surface shall provide a smooth cross-section transition from the cylindrical passageway to the curved passageway inside the wye spool. Both vertical bores and TFL-access bores shall have an ID of not less than the minimum ID after bending as listed in Table 2. The bend radius of the TFL-access bore shall meet the bend requirements of clause 6. Mechanical connections to other tree components that provide TFL access shall provide conical transition surfaces and minimum gap length as shown in Figure 19 or Figure 20. Welded connections shall meet the requirements of clause 6.

7.1.5 Tree loops

TFL tree loops should be incorporated into the subsea tree design to provide proper supply and return paths for circulating TFL tools into and out of the well, as shown in Figure 17 and Figure 18. Tree loops designed to pass TFL tools shall be fabricated in accordance with recommended practices discussed in clause 6. Mechanical connections to other tree components that provide TFL access shall provide conical transition surfaces and minimum gap length, as shown in Figure 19 or Figure 20.

In addition, any non-TFL piping designed to terminate into a TFL tree loop shall intersect the loop at an angle of not less than 45° (but preferably at 90°) to the axis of the loop as shown in Figure 10. This is done in order to minimize interference with the passage of the TFL tool. Corners at the intersections shall have bevelled transitions as specified in clause 6.

7.1.6 Crossover valve

The subsea tree design should include a crossover valve between the TFL tree loops to provide a crossover circulation point when the valve is opened (see Figure 17 and Figure 18). The purpose of the crossover valve is to provide a means to circulate and fill the flowlines with TFL fluids prior to TFL operations. It also provides a flow circulation point to transport TFL tools to the tree before they enter the well. If possible, the crossover valve should be located near the wye spool, except if TFL-retrievable chokes or plugs are to be used in the subsea tree, in which case the crossover valve should be located on the outboard side of the choke/ plug nipple. The crossover valve shall be designed and pressure tested as specified in ISO 13628-4.

7.1.7 Flowline connections

Flowline connectors and their design considerations are discussed in API RP 17A [4]. Flowline connectors designed for TFL service shall be in accordance with the following:

- any TFL passageway shall have a bore of not less than the minimum ID after bending listed in Table 2. Any loops and bends at the connector shall comply with clause 6;
- flowline connectors shall provide conical transition surfaces and minimum gap length as shown in Figure 19 or Figure 20;
- welded flowline connections shall meet the requirements discussed in clause 6;
- end connections between the bores of the flowline, flowline connector, and the tree loops shall be concentric within 0,76 mm (0,03 in) of true position.

7.1.8 Approaches to landing nipples

Piping in the subsea tree that incorporates a landing nipple profile shall have straight sections, each at least 0,3 m (12 in) long, above and below the landing nipple.

7.2 Subsea tree testing

7.2.1 Drift test

During drift testing, the following shall apply:

- the bores containing valves and valve block assemblies shall be drifted with the appropriate bore drift as specified in ISO 13628-4 prior to final stack-up and assembly of the subsea tree;
- vertical runs of the fully-assembled subsea tree shall be drifted with the appropriate tubing drift as specified in ISO 11960;
- all TFL-access bores of the fully-assembled subsea tree shall be tested throughout with the appropriate drifts specified in 6.4.

7.2.2 Pressure test

The fully-assembled subsea tree and tree loops upstream of the first wing valve shall be tested in accordance with ISO 13628-4:1999, 7.16. Piping downstream of the first wing valve shall be tested in accordance with the appropriate pipeline code.

7.3 Tubing hanger design

7.3.1 General

The tubing hanger (see Figure 17) is that portion of the TFL system between the subsea tree and the downhole tubing strings. The tubing hanger provides structural support for the tubing string, provides pressure containment and provides access between the tubing string and the subsea tree.

7.3.2 Tubing hanger bore

The hanger shall contain a profile to receive tubing hanger plugs with a sealing bore diameter consistent with that in Table 4. Any internal profile recesses should comply with clause 8. Recesses at the top of the tubing hanger designed to receive the tree tubing-stabs shall have conical transition surfaces and minimum gap length as shown in Figure 22. Thread preparations at the bottom of the tubing hanger require conical transition surfaces and minimum gap as shown in Figure 22.

Table 4 — Landing nipple sealing bore dimensions

OD mm (in)	Tubing size		Sealing bore diameter mm (in)
	ID mm (in)		
60,3 (2 3/8)	50,67 (1,995)		47,83 (1,875)
73,0 (2 7/8)	62,0 (2,441)		58,72 (2,312)
88,9 (3 1/2)	76,0 (2,992)		69,85 (2,750)
114,3 (4 1/2)	100,53 (3,958)		93,68 (3,688)
139,7 (5 1/2)	121,36 (4,778)		112,70 (4,437)

7.4 Tubing hanger testing

7.4.1 Drift test

Tubing hanger bores shall be drifted with the appropriate tubing drift as specified in ISO 11960.

All TFL access to the tubing hanger shall be tested throughout with the appropriate drifts in 6.4.

7.4.2 Pressure test

The tubing hanger should be tested in accordance with ISO 13628-4.

7.5 Diverters, deflectors and selectors

7.5.1 General

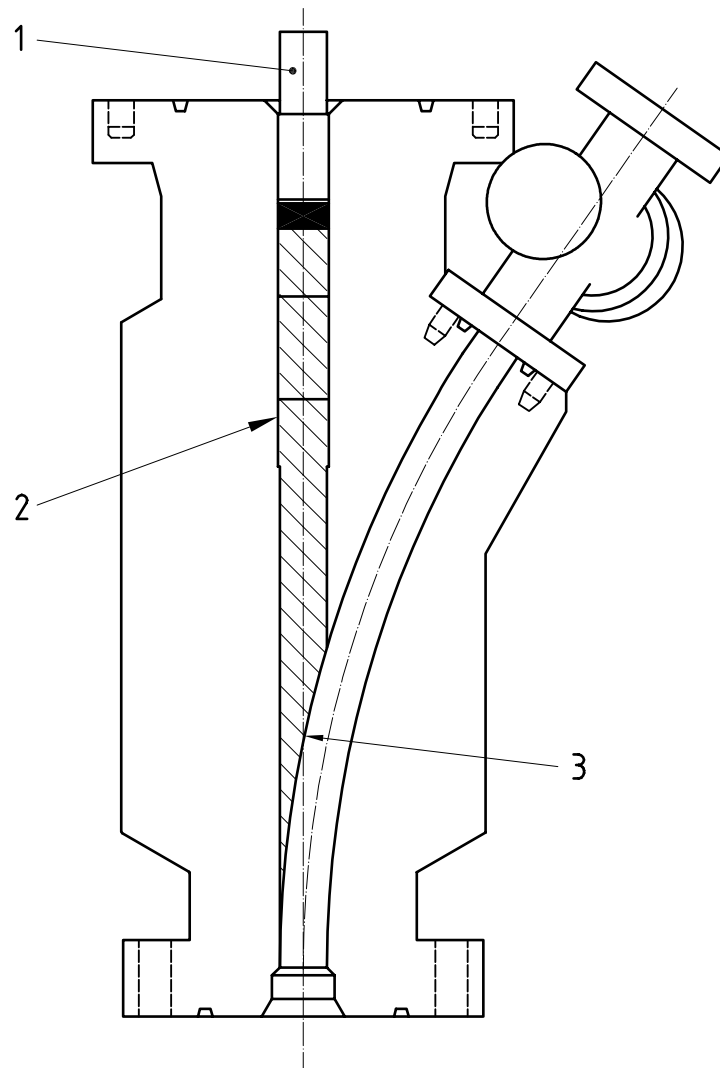
Diverters, deflectors and selectors are designed to direct TFL tools at a branch connection. Diverters are active devices, controlled by a TFL operator to direct tools along one of two possible passageways. Deflectors are passive devices that direct tools along only one passageway. Selectors are active devices that direct tools along multiple passageways.

7.5.2 Deflectors

There are two types of deflector, as follows:

a) wedge (or wireline) deflector

The wedge deflector (see Figure 23) is a wireline-installed device with a contoured bottom that conforms to the curved passageway of a wye spool. Once installed in the vertical bore, the deflector becomes a passive device blocking any further vertical access, directing tools into and out of the well along the TFL-access bore. During a workover, the deflector is pulled from the tree using wireline techniques to regain vertical access to the well.



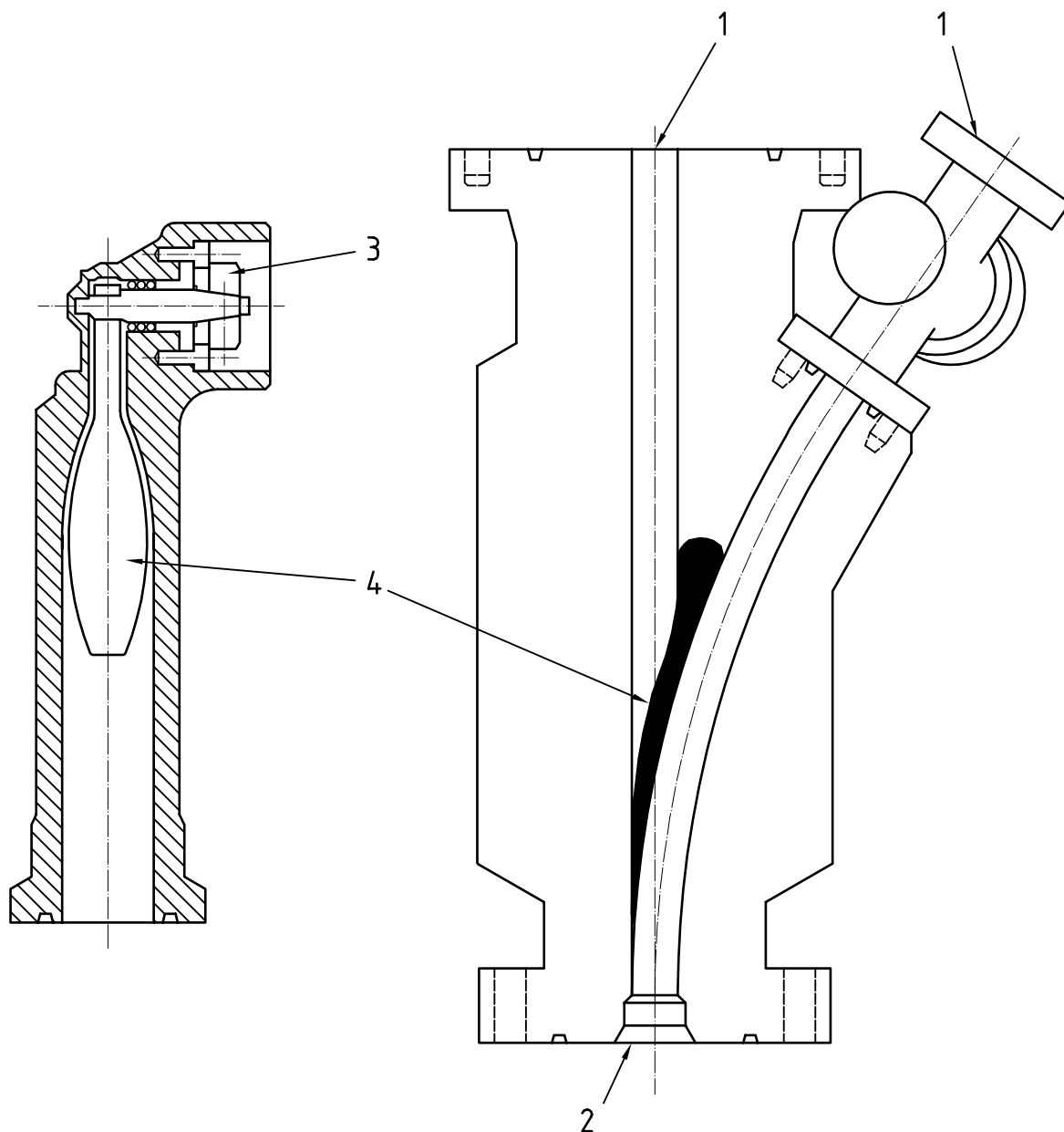
Key

- 1 Profile for wireline retrieval
- 2 Wireline internal profiles and recesses for orienting and locking wedge in wye spool
- 3 Wedge contour profile

Figure 23 — Wye spool with wedge deflection

b) paddle (or detent) deflector

The paddle deflector (see Figure 24) is a device fabricated into a wye spool with a "paddle" gate. The paddle is contoured on one side to conform to the vertical bore and on the other side to conform to the TFL access bore. The paddle deflector has a detent to keep the paddle in either of two positions. The paddle deflector is a passive device that is positioned by the passage of the tool-string. For example, if a tool approaches the wye spool from the vertical bore, the paddle is pushed aside to the vertical position and the tool continues through. During the return trip, the paddle directs the tool back the way it came. The paddle stays in this position until a tool entering from the TFL access bore pushes the paddle over to the TFL-access position. Again, the detent keeps the paddle in this position for the return trip.



Key

- 1 Entry port
- 2 Exit port
- 3 Detent device
- 4 Flapper

Figure 24 — Wye spool with flapper deflection

7.5.3 Diverters

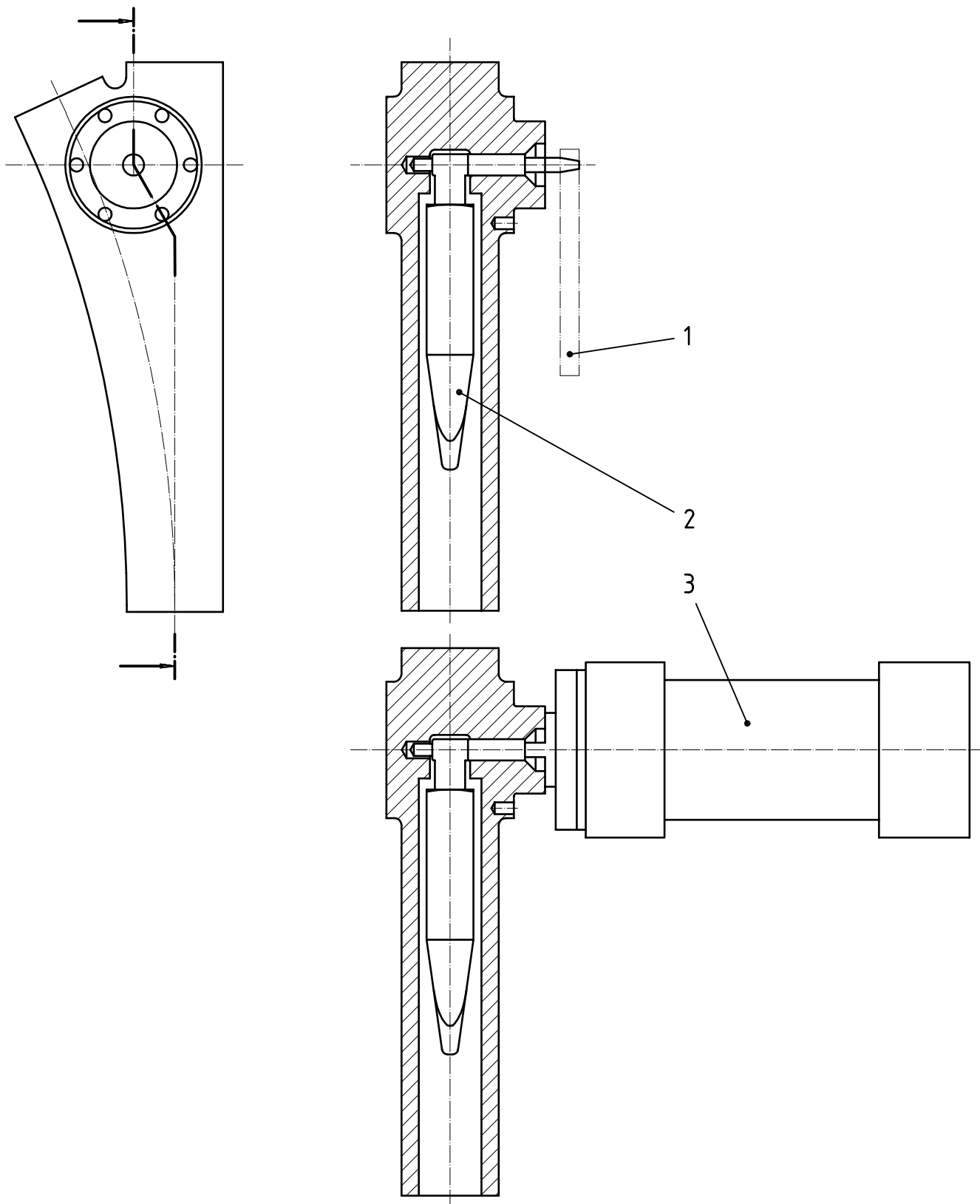
There are two types of diverter which typify the various options available:

a) paddle diverter

The paddle diverter (see Figure 25) is a device fabricated into a branch connection with a paddle gate. The paddle diverter is an active device with a rotary or manual actuator that rotates the paddle to either of two positions.

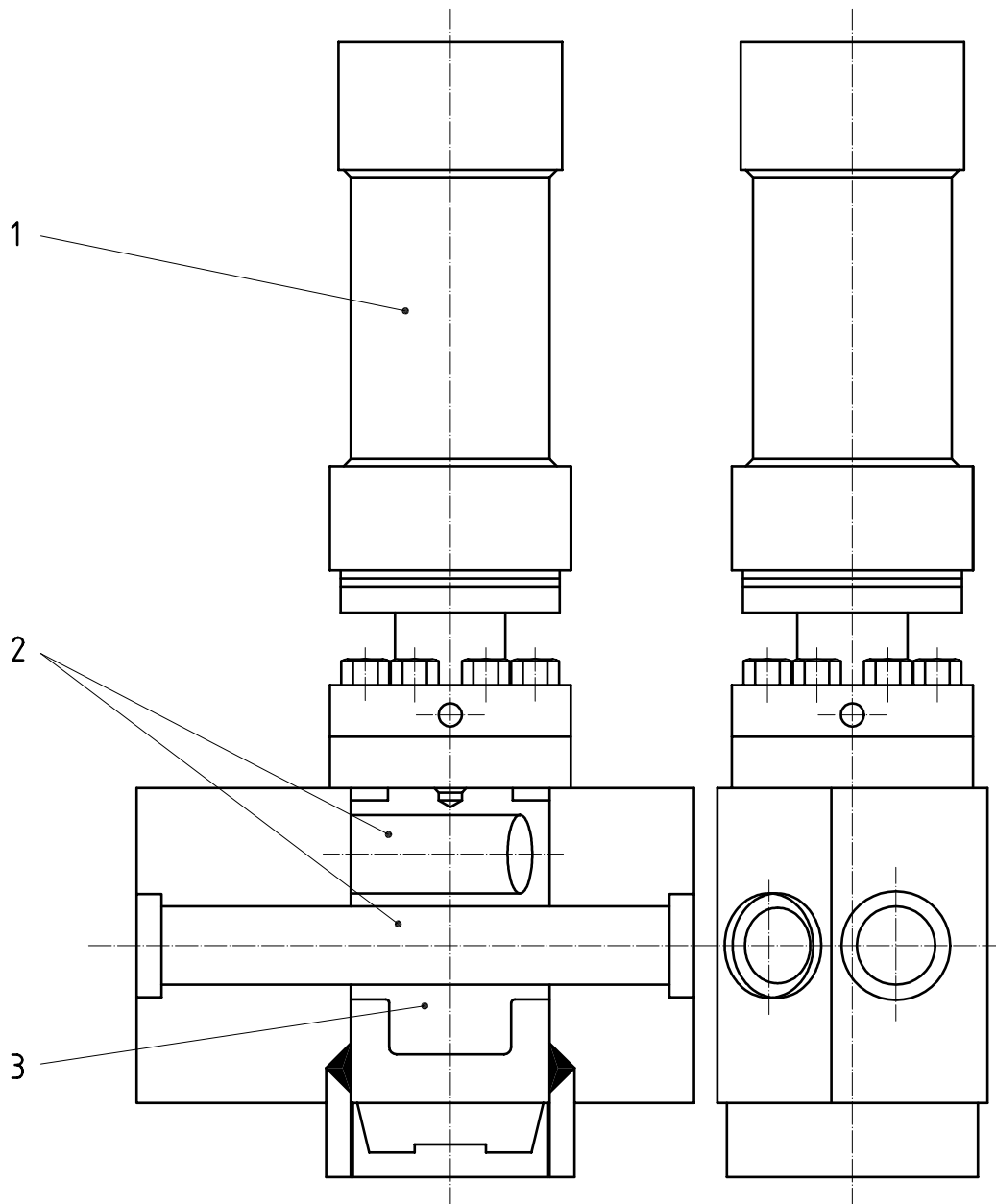
b) plug diverter

The plug diverter (see Figure 26) is a device fabricated into a branch connection with a cylindrical "plug" containing one or two holes. The holes are contoured to conform to either the straight or the curved passageway of the branch connection. The plug diverter is an active device which, depending on design, has a linear or rotary actuator which moves the plug to line up the holes with the appropriate passageway.



- Key**
- 1 External handle
 - 2 Diverter paddle
 - 3 Rotary actuator

Figure 25 — Paddle diverter



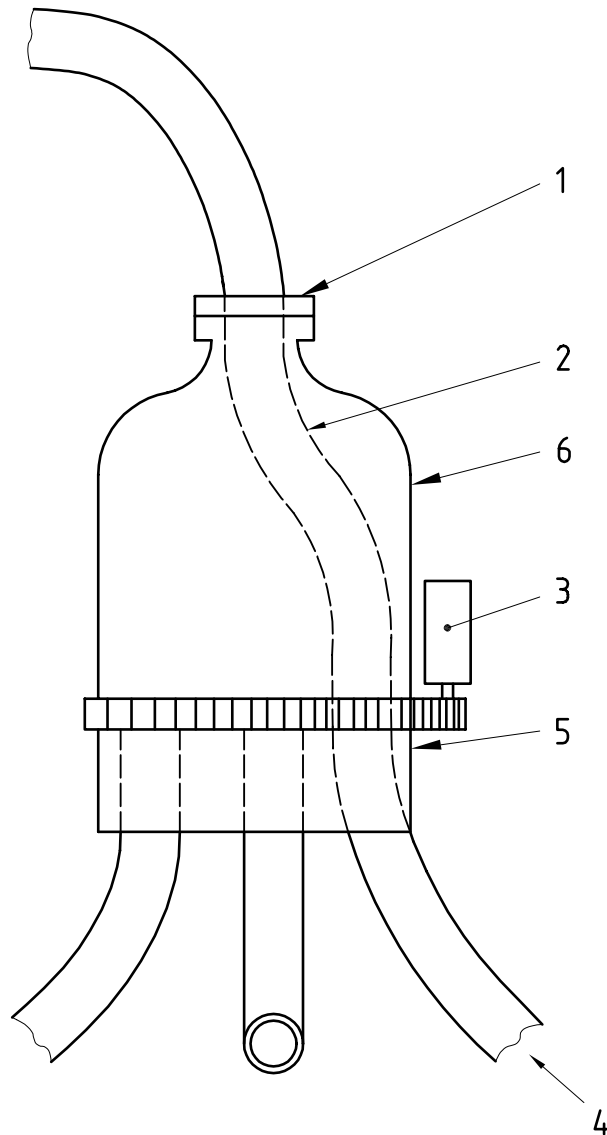
Key

- 1 Rotary or linear actuator
- 2 Contoured bores
- 3 Diverter plug

Figure 26 — Plug diverter

7.5.4 Selectors

A TFL selector (see Figure 27) is an active device fabricated into a multi-branched piping connection which directs TFL tools from a common entry point to any one of several outlets. The selector consists of a moving section, a fixed section, and a device that indexes the two sections to a particular orientation.



Key

- 1 Entry port
- 2 Curved bore
- 3 Indexing device
- 4 Exit port
- 5 Fixed section
- 6 Moving section

Figure 27 — TFL selector

7.6 Diverter design

Diverter designed for TFL service shall consider the following:

- any straight or curved TFL-access bore shall have a bore the same as the minimum ID after bending listed in Table 2. Bends shall comply with clause 6;
- mechanical end connections at the entry or exit ports shall provide conical transition surfaces and minimum gap length as shown in Figure 19;

- welded connections at the entry or exit ports shall comply with clause 6;
- selectors with reverse bends (S-bends) shall have a straight section between the tangent of the bends, of sufficient length to allow passage of the appropriate TFL drift and tools specified in clause 6.

7.7 Diverter testing

7.7.1 Drift test

The bores of a diverter shall be tested while connected to the piping, using the appropriate drifts specified in 6.4.

7.7.2 Pressure test

The diverter shall be tested in accordance with the piping test code appropriate to its location and function within the TFL system.

8 Completion equipment and tools

8.1 General

The completion equipment and tools include that portion of the TFL system between the wellhead and the production zone. The well completion should be designed so that tool manipulations during servicing are minimized. Figure C.3 shows an example of a completion which includes production casing, tubing, landing nipples, circulating valves, packers, etc. The completion design shall consider the effects of temperature and pressure variations caused by the circulation of cold fluids and the jarring and water hammer effects of pumping operations.

TFL completions differ from wireline completions in that a circulation member shall be used to complete a circulation path. Also, standing valves are normally installed to maximize TFL service capability and minimize fluid loss to the formation. Completion design also affects TFL service capability and procedures. Typically, a more complex completion design will allow more types of service with simpler service procedures.

Some general guidelines for completion design are as follows:

- determine production (or injection) and service requirements and design completion accordingly;
- depth of circulation member is a major determining factor in service potential. The deeper the circulation member in the completion, the greater the serviceability. This allows for circulation of the tools to the lowest point in the well and reduces the need for reach-rod and/or spacer-bar work;
- consider isolation/production devices (foot valves, sliding side-doors) for landing the standing valves. This allows retrieval of standing valves for maintenance while maintaining TFL service integrity, i.e. a closed system which minimizes ingress of TFL service fluids into the reservoir;
- consider alternative TFL service procedures in the event of problems with primary service procedures;
- maintain constant tubing and flowline IDs to maximize piston unit compatibility and performance.

Injection wells shall be given special consideration because standing valves shall not be in place during injection. Expendable standing valves may be pumped into place before TFL service and expended before resuming injection. Care shall be exercised in the completion designs to provide access for pumping these valves into place and for proper expending, particularly in dual-string completions.

In general, there are differences between wireline and TFL equipment beyond just the shorter, articulated components that make up the TFL assemblies. For example, in TFL wells the same size of packing bores are usually used throughout the completion. This generally results in the use of a selective location system because the use of no-go landing nipples would limit service potential. TFL tools are designed to allow for cyclic pressures and impact loads encountered in TFL operations. To allow for this cyclic pressure loading, TFL equipment usually uses

moulded seals instead of V-packing (chevron packing). Also, TFL tools shall be designed to allow for continuous circulation of fluids, even after they are landed in the downhole nipple.

8.2 Completion design

Annex C shows the following four basic completion designs:

- Figure C.1: Single string, single zone, annular circulation type;
- Figure C.2: Single string, single zone, side string circulation type;
- Figure C.3: Dual string, single zone type;
- Figure C.4: Dual string, dual zone type.

The selection of completion design should be determined with considerations given to

- economics;
- production and injection requirements;
- service requirements;
- secondary recovery requirements.

Annex C may be consulted for further details regarding completion concepts.

8.3 Tubing

Standard tubing sizes from 60,3 mm to 114,3 mm (2 3/8 in to 4 1/2 in) have been used in TFL installations. API and various premium thread joints have been successfully used for these installations. As a minimum, joint transitions should comply with clause 6 and Figure 16.

8.4 Surface-controlled subsurface safety system

Appropriate consideration shall be given to the design of the surface-controlled subsurface safety system. These are:

— valve selection

TRSVs are preferable to TFL-retrievable valves. Service times can be reduced by not having to retrieve and rerun a TFL-retrievable safety valve before and after service work below the valve. Since TFL flowlines can be quite long, the elimination of two service trips can significantly reduce service times and costs. TFL-retrievable insert valves should be planned as backups for the TRSV;

— control system pressure

Since TFL wells are typically subsea, control system pressure capability may be limited and the total control system pressures shall be carefully evaluated. Unlike wireline-serviced wells, the control system shall not only accommodate shut-in well pressures but shall also maintain the safety valve in the open position during periods of maximum TFL service pressure. If single line type valves are used, then the control system pressure shall be at least equal to the maximum tubing pressure or the maximum TFL service pressure, whichever is greater, plus the valve hold-open pressure. Control system pressure requirements can be reduced by using balanced type (dual-line) or nitrogen-charged safety valves which are insensitive to tubing pressure. When using any type of TRSV, the hold-open force shall be sufficient to overcome TFL-piston drag forces when they are being pumped up through the valve. A TRSV with a larger piston area provides more hold-open force to prevent the valve closing inadvertently during upward passage of the TFL tool. The manufacturer of TFL equipment should be consulted to determine safety valve and control system suitability;

— TFL service

TFL servicing requires circulation to be maintained at all times. If a TRSV is used with a TFL-retrievable SVLN back-up capability, special control line routing should be adopted. The control line should be run to the TRSV through a lockout isolation/redirection feature and then to the SVLN. This feature prevents control line access to the SVLN until the TRSV is locked out of service. This prevents TRSV control pressure loss due to inadvertent shifting of the SVLN sleeve;

— equipment design and service procedures

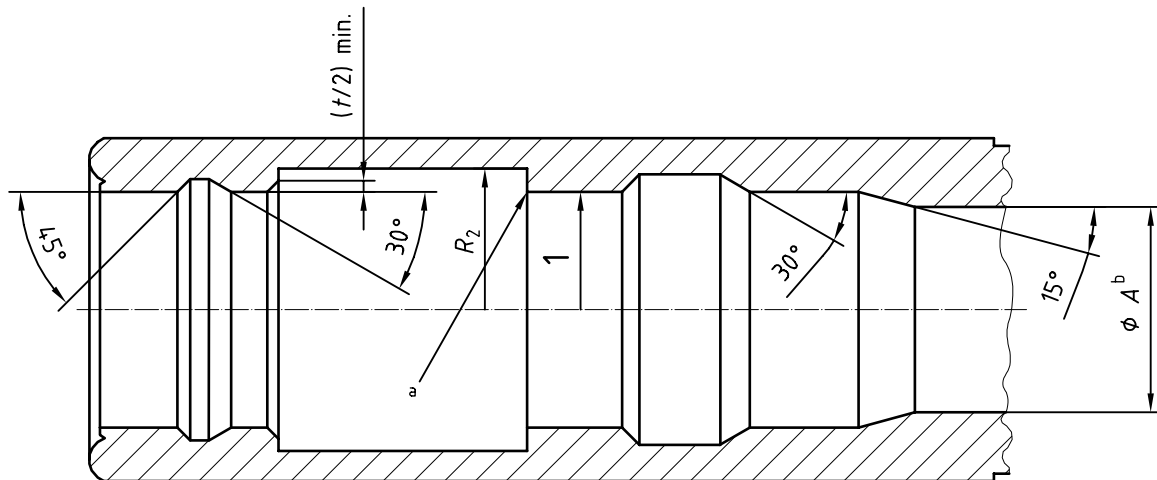
Design and procedures should provide the capability to maintain the TFL-retrievable safety valve in the open position until hold-open hydraulic pressure is established. Failure to incorporate this feature can result in loss of TFL circulation. An emergency shear feature should be incorporated in the running tool, allowing retrieval while the valve is kept mechanically in the open position, thereby allowing circulation;

— total valve depth

Total depth, including water depth, should be evaluated when designing the safety system. Minimum tubing pressure at the safety valve should be considered in single-line installations. This minimum tubing pressure may allow a reduction of control system pressure without compromising the fail-safe capability of the safety valve.

8.5 Packers

Normally, full-bore packers are used where conditions permit. Any shoulders or internal profiles shall have chamfers conforming to Figure 16 and Figure 28. Packers for TFL completions are usually special or upgraded designs which take into account the higher pressures involved in TFL operations. Hydraulic packers should be set at the maximum expected TFL operating pressure, thereby allowing maximum packer movement (stroking, seal compression, slip movement, etc.) to be achieved and tested during initial completion.



Key

- 1 ID or R_1
 - a 0,25 mm to 0,50 mm (0,01 in to 0,02 in) chamfer 43° to 47°
 - b See Table 4.
- $t = R_2 - R_1$ where t = wall thickness

Figure 28 — Nipple profile dimensions

8.6 Telescoping joints

Tubing strings in TFL completions are subjected to a wide range of temperature extremes, from heating during production to cooling during TFL operations. Telescoping joints are added to the completion to accommodate this expansion and contraction which would otherwise cause a build-up of forces that could unseat the packer or buckle the tubing.

Telescoping joints for TFL completions are also of special design, due to the following:

- the stroke length must be limited. Since TFL piston units must traverse the telescoping joint, the stroke of the joint should be less than 1,0 m (3 ft). This assures that the piston units will always span the enlarged ID when the telescoping joint is fully expanded;
- with the higher operating pressures, potential water-hammer effects and temperature variations in TFL operations, the movable sealing mechanism in the telescoping joint should be evaluated for high reliability when exposed to these conditions.

More than one telescoping joint per tubing string is usually required, due to the recommended 1,0 m (3 ft) stroke limitation. They should be positioned in the tubing string with at least one tubing joint between them to assure piston unit transport efficiency. The telescoping joints should be placed away from nipples and other items where service work will be performed. In dual-string completions, telescoping joints should not be placed adjacent to one another, in order to avoid potential interference during stroking.

8.7 Landing nipples

8.7.1 General

Landing nipples are tubular members that allow TFL retrievable equipment to be located, locked and sealed downhole.

8.7.2 Internal profiles

Landing nipple internal profiles are any transition to the nominal tubing internal diameter through which the piston units and retrievable tools must pass. Entry and exit surfaces should be designed to minimize seal element damage and interference with tool passage.

8.7.3 Preferred design practices

Design practices should include the following:

- TFL landing nipples should have internal profile entry and exit angles of 30° or smaller, as shown in Figure 28, to facilitate tool passage, minimize tool wear and prevent seal and piston damage;
- no-go shoulder and locking profile recess angles may be 45° or greater on load-bearing surfaces but should be 30° or smaller if non-load-bearing. As a minimum, sharp corners should be chamfered as shown in Figure 28;
- location-type profiles should conform to Figure 28 at their entry and exit. Square shoulders may be contained within the overall profile but corners should have a definite chamfer as indicated;
- sealing bores currently in use by industry for TFL operations are listed in Table 4. These sealing bores should have 15° entry and exit angles.

8.8 Circulation members

A circulating member is required to allow TFL tools to be pumped into and out of the well. The circulation member also allows well fluid to be displaced with TFL service fluids prior to any service operations. The circulation member or circulation point should be placed as near to the deepest point of anticipated service. This allows for circulation of tools to the lowest points in the well without the aid of long sections of reach rods or spacer bars. The circulation member shall be installed below the packer or at any convenient location in the tubing string. The various designs of circulation members are as follows:

- **standard**

A double-bored block for through passage of tools, with a communication port between the bores. Normally, no-go or selective landing nipples are run above them and polished subs are made up below the H-member

block. This allows setting of a CCV (see 8.9) or pack-off across the communication port to isolate the tubing string.

— **side-pocket H-member**

Similar to a side-pocket mandrel with the addition of a side string which is ported to the pocket section of the mandrel. Communication between the two strings can be controlled by setting a CCV in the mandrel pocket. This tool is useful as an emergency circulation member or as a primary circulation member where a through tubing bore is required while the CCV is in place.

— **circulation nipple**

Allows one tubing string to be run with a straight-through bore for TFL service with a smaller side-string offset and ported to the main tubing bore. The offset string is used only to complete the circulation path and TFL access is not provided (see Figure C.2).

— **wye block**

Similar to the circulation nipple except both upper and lower connections are of the same size. The design allows TFL access from either string to a point below the wye. This member would normally be used in a dual-string completion with a single packer.

— **ported nipple**

Provides for circulation between the tubing and casing for annular circulation completions (see Figure C.1). A landing nipple is provided above the ports and a polished bore is provided below the ports to allow isolation of the annulus during production (or injection) by means of a CCV.

— **side-pocket mandrel**

A side-pocket mandrel with suitably enlarged port area can be used as a circulation member in applications similar to those for the ported nipple. It allows setting of a CCV in the side-pocket while providing an unrestricted through-bore.

Up-hole or alternate circulation members are sometimes provided to permit fluid communication for operations such as gas-lifting, emergency circulation and sand-washing. These alternate circulation members shall have a provision for isolation of the communication to permit tool-string operation to the primary circulation member. Various retrievable devices such as SDCs, check valves or dummy plugs have been used to isolate the circulating port.

Exposed side outlets of a circulation crossover should be prepared in accordance with clause 6 to avoid damage to passing seals and to minimize pressure-differential-induced (suction-induced) lock-up of the tools.

8.9 Circulation controls

8.9.1 A circulation control device may be required in some completion designs to allow communication during TFL service and to isolate the tubing strings or tubing/casing during production or injection. The CCV may be installed either concentrically or in a side-pocket. This valve is run and set in the open position to allow circulation for retrieval of the TFL-service tool-string. Closing (after TFL service) and reopening (for the next TFL service) is achieved by manipulating the pressure in the system. CCVs are used in multi-zone completions where CO-mingling of zones is undesirable or prohibited.

8.9.2 Emergency circulation devices can also be set in circulation members. They are also pressure-manipulated valves that are run in the closed position. These SDCs are set in an up-hole or alternate circulation member and provide emergency circulation in the event that the primary circulation member becomes plugged with debris or sand.

8.10 Standing valves and isolation/production devices

8.10.1 TFL-retrievable standing valves (check valves) are run in TFL production completions. The standing valve, which allows production fluids to enter the tubing but prevents TFL service fluid entering the formation, provides maximum TFL service efficiency. By keeping the standing valve on-seat during TFL service, any produced gas can be circulated out of the well, the ingress of additional gas into the tubing is minimized, and the service fluid and pressure can be kept isolated from the formation. This reduces compressibility in the system, thereby improving the

pressure response at the TFL control console. Standing valves may be landed in selective landing nipples, no-go nipples or isolation/production devices. Standing valves may have shear-out capability to allow pumping into the formation.

8.10.2 An isolation/production device is tubing-retrievable. It opens when the standing valve is set and closes when the standing valve is retrieved, thereby isolating the well formation when the standing valve is retrieved. There are two types of isolation/production device: one type allows production through annular access to the tubing and shall be installed below the packer, the other type allows production through the bottom of the tubing and can be run anywhere in the tubing string. The latter type shall be installed near to a circulation member to allow TFL service.

8.11 TFL tool design

8.11.1 Tool design

TFL tools shall be designed for a bend radius of 1 524 mm (60 in). Loop bore IDs for the respective tool sizes are listed in Table 2 in the column headed "minimum ID after bending".

8.11.2 Other considerations

The following shall be considered in the design:

- avoid excessive tool-string articulation, i.e. maximize segment length. This will help to minimize handling problems;
- design the tools for running, activation, setting, etc. with a minimum of system manipulation;
- allow for tool manipulations and for dynamic loads encountered during TFL operations such as impact loads, cyclic pressures and water-hammer;
- design shear pins so that all pieces are retained in the tool, in order to prevent loose metal from interfering with the tools or falling into the flowline system;
- design threaded connections of all tools to have a mechanical locking device such as a roll pin, set-screw, jam nut, etc. since the impact and vibration of the tool-string tend to loosen threaded connections.

9 Operations

9.1 General

The following requirements and recommendations are presented for the operation of TFL equipment and tools in subsea satellite wells and template/manifold production systems. Many of these have evolved through experience and successfully applied methods. Operators may have their own preferred methods based on specific well applications. In addition, see API RP 17A [4] for further recommendations.

9.2 Personnel and training

9.2.1 Planning of all aspects of the TFL project from the earliest stages helps towards successful maintenance operations. This planning shall also include provisions for training of personnel involved in well-maintenance operations. TFL operators should be experienced maintenance personnel familiar with well completion processes, wireline maintenance operations, hydraulic parameters of TFL service and general offshore/subsea operations.

9.2.2 TFL operators shall be trained in the subsea control system, emergency shutdown procedures and pressure readings being received from different points.

9.2.3 Additionally, the operator shall be trained in the TFL equipment being run and the well completion being serviced. This training shall include how the equipment functions and what are the tool setting pressures, sliding sleeve shift pressures and shear pin shear pressures for the various tool operations.

9.3 Completion equipment

Items of concern are the TFL piping, the subsea tree and the downhole equipment. From the project planning stage, TFL piping as discussed in clause 6 and tree and tubing hangers as discussed in clause 7 shall be designed for the passage of TFL tools, in order to minimize TFL service problems. Items to be planned for are placement of in-line chokes, location of blast joint indicators and location of valving, diverters and plug bore recesses.

Downhole equipment shall be planned and checked for the following:

- **tool passage**

All downhole equipment shall be checked for compatibility with TFL tools.

- **spacing of the completion**

Because of the more severe temperature fluctuations of TFL operations, the tubing in the completion above the top packer, and between packers in multi-zone completions, should be properly spaced to avoid buckling of the tubing when the completion is landed and the packers are set.

- **equipment operation by pressure**

Certain items in the completion may be operated by differential or system pressures. Misapplication of pressure or improper tool set-up could cause accidental tool operation and negatively impact the serviceability of the completion. Tool operating pressures should be designed with sufficient pressure spacing to avoid accidental operation.

- **shifting of lockout profiles**

Consideration should be given to items which could cause accidental location with selective keys. If different manufacturers' profiles are involved, they should be assessed for compatibility.

9.4 Satellite well and template well control systems

9.4.1 The control systems for TFL satellite and template wells are usually complex. The TFL operator shall be knowledgeable of the control system basics and response times.

9.4.2 From an operational perspective, the subsea control system should be planned and designed so that during maintenance operations certain control functions for various valves, etc. on the well being serviced, can be transferred to the TFL operator. These functions are for all in-line valves and diverters through which the TFL tools pass or which affect TFL operations. These valves may include riser isolation valves, flowline and template isolation valves, tree master valves, wing valves, diverters, annulus access valves and downhole safety valves. These valve control functions shall be interfaced with the emergency shut-down systems. The TFL operator should be able temporarily to override the emergency shut-down so that the TFL tools can be pumped to a "safe" location (away from valves). The objective is to prevent valves from closing on a tool-string.

9.5 Service planning and documentation

9.5.1 The TFL operator shall review the up-to-date well history file prior to TFL operations. A detailed service procedure shall be prepared and reviewed. The operator shall be responsible for equipment preparation and set up. The set up includes shear pin size and material for the running and pulling tools, shear up/down mode of the pulling tool, shear pins in lock, shear pins/shear pressures of prongs, and kickover tool activation pressures. It should be considered to test equipment prior to use to confirm its operating condition.

9.5.2 The TFL operator should document all work and update the well history file. This documentation should include reports which contain sections of strip-chart recordings where necessary or applicable. The well history file shall be kept with the producing well's records.

9.6 Fluid selection/well preparation

Service fluid selection is very important to the capability of the TFL service system. Criteria to be considered when selecting a service fluid should include the following:

- **availability at site**
If not readily available, storage shall be provided.
- **fluid density**
This will affect the performance of the TFL system and the required pressures.
- **multiple fluids**
More than one fluid may be required for different wells and well conditions.
- **viscosity**
Pressure pulses, pressure loss and tool slippage will differ for fluids of different viscosities.
- **cost**
Use of a TFL service fluid that is not readily available may increase TFL service costs.

The ideal fluid should be readily available, inexpensive and allow sufficient TFL service pressure-differentials, and circulation rates shall meet the service requirements. Examples of these types of fluids include:

- dead oil from on-site processing;
- filtered and inhibited seawater;
- clear completion fluids.

NOTE These fluids can be effective in reducing the equipment pressure ratings. They can also be used effectively to shear the standing valve and kill a well via the TFL system.

Annex B may be consulted for details of TFL operating pressures and the effects of various service fluids.

Before service operations begin, the TFL system should be circulated to remove gas and well-bore fluids. Single-phase fluids should be used to obtain repeatable results with tool operations and to allow reliable tool location.

Two items of concern for the operator during circulation are that the standing valves are kept on seat while maintaining a constant back-pressure with a surface-regulated choke, and that bottom-hole service pressure is not exceeded. The maximum bottom-hole service pressure is the formation pressure (shut-in bottom-hole pressure), plus the standing valve shear-out pressure, minus a safety factor. To ensure these two criteria are satisfied, the pump pressure shall not exceed maximum bottom-hole service pressure minus the service fluid hydrostatic pressure. Also, the choke on the pump manifold (see Figure 4) should be adjusted with respect to the fluid hydrostatic pressure and flow rate when the pumping operations commence. This choke holds back pressure on the system, keeping the standing valves on seat to assure that well fluids do not enter the system during TFL operations.

9.7 Pumping operations

9.7.1 As a general rule in pumping operations, friction losses are less than 13,8 MPa (2 000 psi) and most tool manipulations require approximately 3,4 MPa to 13,8 MPa (500 psi to 2 000 psi) differential pressure across the piston units (see 4.4 regarding pressure rating). Some operations such as fishing may require up to 20,7 MPa (3 000 psi) pressure differential.

9.7.2 The operator should be aware of water-hammer and pressure waves that could result from closing a valve during high circulation rates or locating a tool-string at too high a pump rate. This can result in overstressing in-line equipment or prematurely shearing TFL tools. This is particularly true for long flowlines and/or deep wells where large masses of fluid are being circulated.

Prior to the start of pumping operations, the following procedures should be carried out by the TFL operator:

- transfer necessary valve monitoring and control to the TFL operator;
- check that a sufficient quantity of TFL service fluid is available;
- check that all valves and diverters are properly set for TFL service to the appropriate well;
- close subsea tree valves and open the crossover valve.

As pumping operations proceed:

- circulate TFL service fluid into the service/flowline and close the crossover valve;
- open subsea tree valves and circulate downhole while maintaining sufficient back-pressure to keep the standing valve(s) on seat;
- perform TFL operations as specified in the work plan.

Velocities at which TFL tools are pumped should be in accordance with the manufacturers' recommendations. Typical acceptable pumping rates are shown in Table 1.

During pumping operations, due to the positive pressure being applied to the system, i.e. standing valves on seat, the well is always under the control of the operator. Gas and live fluids should have previously been circulated out and system pressures reduced by the hydrostatic pressure of the service fluid.

9.8 Returning well to production

The following should be carried out when returning the well to production:

- if necessary, circulate the well with the required fluid to allow production to begin;
- isolate the well from service lines as appropriate;
- set all valves and diverters for resumption of well production;
- transfer valve monitoring and control to the main control system for resumption of well production;
- document TFL operations and update the well history file to reflect current status.

10 Summary of capabilities

A summary of the capabilities of TFL is given in annex D.

Annex A (normative)

TFL pipe

A.1 Technical delivery conditions

TFL pipe shall comply with all requirements of ISO 3183-1 except as specified in A.2 to A.6.

A.2 Dimension and grades

TFL pipe shall be furnished in the minimum/maximum IDs shown in Table A.1.

Table A.1 — Flowline ID dimensions (TFL pipe)

Typical OD mm (in)	Nominal ID mm (in)	Maximum ID mm (in)	Minimum ID mm (in)
60,3 (2,375)	50,67 (1,995)	51,97 (2,046)	49,02 (1,930)
73,03 (2,875)	62,0 (2,441)	63,3 (2,493)	60,2 (2,372)
88,9 (3,500)	76,0 (2,992)	77,37 (3,046)	74,12 (2,918)
114,3 (4,500)	100,53 (3,958)	101,93 (4,013)	98,65 (3,884)

A.3 Length

Unless otherwise specified, TFL pipe shall be furnished only in double random lengths and with no jointers (girth welds).

A.4 Drift tests

Each length of TFL pipe shall be tested throughout its entire length with a cylindrical drift mandrel. The leading edge of the drift mandrel shall be rounded to permit easy entry into the pipe. The drift mandrel shall pass freely through the pipe with a reasonable exerted force equivalent to the weight of the mandrel being used for the test. Pipe shall not be rejected until it has been drift-tested when it is free of all foreign matter and properly supported to prevent sagging.

A.5 Hydrostatic tests

TFL pipe shall be hydrostatically tested in accordance with ISO 3183-1.

A.6 Marking

TFL pipe shall be marked with the letters TFL in addition to the marking specified by ISO 3183-1.

Annex B (informative)

TFL operating pressure

B.1 General

This annex presents an example problem for determining TFL operating pressures, properly sizing equipment, and choosing service fluids. The calculations examine both static and dynamic operating conditions to determine desirable TFL service modes. Based on well-site data and TFL-service operational conditions as presented below, a trial set of TFL operating parameters can be generated in order to:

- check the proper wellhead and flowline pressure rating;
- define the pressure differential and maximum flow rate for optimum tool operation;
- define the surface pump's power requirements.

NOTE Manufacturers of TFL equipment should be consulted when determining adequate design pressures, service fluid, flow rates, etc. to perform required downhole service operations.

B.2 Example problem

B.2.1 Introduction

A subsea completion in 300 m (984 ft) of water is 4500 m (14764,5 ft) away from a platform and its surface facilities. Well depth is 3500 m (11483,5 ft) below the sea floor. The well produces oil at a static bottom-hole pressure of 40 MPa (5801 psi). Assuming the subsea wellhead, tree, and service/flowline's rated working pressure is 34,5 MPa (5000 psi), determine the best service fluid which will operate within the pressure rating of the given subsea equipment. Three service fluids will be examined: dead oil, saltwater and completion fluid. The properties of these three fluids are given in Table B.1.

Table B.1 — Service fluid properties

	Density	Viscosity	Hydrostatic pressure head per metre (foot)	Pressure loss per metre (foot) at flow rate of 0,477m ³ /min (3 bbl/min)
	kg/m ³ (lb/gal)	Pa·s (cp)	MPa (psi)	MPa (psi)
Dead oil	818,4 (6,83)	0,01 (10)	0,068 (0,355)	0,000498 (0,02204)
Saltwater	1 023,3 (8,54)	0,001 (1)	0,0101 (0,447)	0,000426 (0,01883)
Completion fluid	1 078,4 (9,00)	0,003 (3)	0,0106 (0,468)	0,000502 (0,02222)

B.2.2 Input data

B.2.2.1 Given parameters

The following parameters are given:

- well static BHP = 40 MPa (5 801 psi)
- water depth = 300 m (984 ft)
- flowline length = 4 500 m (14 764,5 ft)
- service well TVD (wellhead/below mudline) = 3 500 m (11 483 ft)
- service well TMD (wellhead/below mudline) = 3 500 m (11 483 ft)
- ID of tubulars = 76,2 mm (3 in)
- circulating fluid rate = 0,477 m³/min (3 bbl/min)

B.2.2.2 Assumptions

The following assumptions have been made:

- surface piping and equipment (including wellhead) working pressure = 34,5 MPa (5 000 psi);

NOTE The maximum service fluid flow rate will be assumed as 0,477 m³/min (3 bbl/min). This is only an example. Other flow rates may be appropriate depending on the application.

- minimum BHP produced by TFL system should be 3,0 MPa (435 psi) above the well's BHP to seat the standing valve;
- maximum standing valve shear pressure should be 3,0 MPa (435 psi) below the maximum BHP produced by the TFL system's surface pump. Maximizing the standing valve shear pressure maximizes the system pressure available to do work;
- maximum TFL service pressure should be 3,0 MPa (435 psi) below the pressure needed to shear the standing valve.

B.2.3 Calculated data

B.2.3.1 Round trip distance service fluid has to travel = $2 \times (\text{water depth} + \text{offset distance} + \text{well depth})$
= $2 \times (300 \text{ m} + 4 500 \text{ m} + 3 500 \text{ m}) = 16 600 \text{ m}$
[$2 \times (984 \text{ ft} + 14 764,5 \text{ ft} + 11 485,5 \text{ ft}) = 54 468 \text{ ft}$]

B.2.3.2 Hydrostatic pressure of service fluid from the pump to bottom-hole = fluid hydrostatic pressure per unit length \times (water depth + well depth):

- dead oil = $0,008 \text{ MPa/m} \times 3 800 \text{ m} = 30,4 \text{ MPa}$ ($0,355 \text{ psi/ft} \times 12 467,8 \text{ ft} = 4 426 \text{ psi}$)
- saltwater = $0,010 1 \text{ MPa/m} \times 3 800 \text{ m} = 38,38 \text{ MPa}$ ($0,447 \text{ psi/ft} \times 12 467,8 \text{ ft} = 5 573 \text{ psi}$)
- completion fluid = $0,010 6 \text{ MPa/m} \times 3 800 \text{ m} = 40,28 \text{ MPa}$ ($0,468 \text{ psi/ft} \times 12 467,8 \text{ ft} = 5 835 \text{ psi}$)

B.2.3.3 Pumping pressure loss along flowline and tubing = fluid pressure loss/ft \times (water depth + offset distance + well depth):

- for dead oil = $0,000 498 \text{ MPa/m} \times 8 300 \text{ m} = 4,13 \text{ MPa}$ ($0,022 04 \text{ psi/ft} \times 27 232,3 \text{ ft} = 600 \text{ psi}$)

- for saltwater = $0,000\,426 \text{ MPa/m} \times 8\,300 \text{ m} = 3,55 \text{ MPa}$ ($0,018\,83 \text{ psi/ft} \times 27\,232,3 \text{ ft} = 513 \text{ psi}$)
- for completion fluid = $0,000\,502 \text{ MPa/m} \times 8\,300 \text{ m} = 4,17 \text{ MPa}$ ($0,022\,22 \text{ psi/ft} \times 27\,232,3 \text{ ft} = 605 \text{ psi}$)

B.2.3.4 Round-trip pumping pressure loss = $2 \times$ pumping pressure loss along flowline and tubing:

- for dead oil = $8,26 \text{ MPa}$ ($1\,200 \text{ psi}$)
- for saltwater = $7,1 \text{ MPa}$ ($1\,026 \text{ psi}$)
- for completion fluid = $8,34 \text{ MPa}$ ($1\,210 \text{ psi}$)

B.2.3.5 Seawater hydrostatic pressure (on outside of wellhead) = fluid hydrostatic pressure \times water depth = $0,010\,1 \text{ MPa/m} \times 300 \text{ m} = 3,08 \text{ MPa}$ ($0,447 \text{ psi/ft} \times 1\,000 \text{ ft} = 447 \text{ psi}$).

B.2.4 Static condition calculations

B.2.4.1 Maximum pump pressure = equipment rated pressure + seawater hydrostatic pressure – service fluid hydrostatic pressure:

- for dead oil = $34,5 \text{ MPa} + 3,03 \text{ MPa} - (0,008 \text{ MPa/m} \times 300 \text{ m}) = 35,13 \text{ MPa} > 34,5 \text{ MPa}$ maximum pump pressure. Therefore, use $34,5 \text{ MPa}$.
[$5\,000 \text{ psi} + 440 \text{ psi} - (0,355 \text{ psi/ft} \times 984 \text{ ft}) = 5\,091 \text{ psi} > 5\,000 \text{ psi}$ maximum pump pressure. Therefore, use $5\,000 \text{ psi}$]
- for saltwater = $34,5 \text{ MPa} + 3,03 \text{ MPa} - (0,010\,1 \text{ MPa/m} \times 300 \text{ m}) = 34,5 \text{ MPa}$
[$5\,000 \text{ psi} + 440 \text{ psi} - (0,447 \text{ psi/ft} \times 984 \text{ ft}) = 5\,000 \text{ psi}$]
- for completion fluid = $34,5 \text{ MPa} + 3,03 \text{ MPa} - (0,010\,6 \text{ MPa/m} \times 300 \text{ m}) = 34,35 \text{ MPa}$
[$5\,000 \text{ psi} + 440 \text{ psi} - (0,468 \text{ psi/ft} \times 984 \text{ ft}) = 4\,980 \text{ psi}$]

B.2.4.2 Minimum system pressure to keep standing valves on seat = BHP (static) + $3,0 \text{ MPa}$ (435 psi):

- for all fluids = $40,0 \text{ MPa} + 3,0 \text{ MPa} = 43,0 \text{ MPa}$
($5\,801 \text{ psi} + 435 \text{ psi} = 6\,236 \text{ psi}$)

B.2.4.3 Maximum BHP produced by the TFL system = maximum surface pressure + service fluid hydrostatic pressure:

- for dead oil = $34,5 \text{ MPa} + 30,4 \text{ MPa} = 64,9 \text{ MPa}$
($5\,000 \text{ psi} + 4\,426 \text{ psi} = 9\,426 \text{ psi}$)
- for saltwater = $34,5 \text{ MPa} + 38,38 \text{ MPa} = 72,88 \text{ MPa}$
($5\,000 \text{ psi} + 5\,573 \text{ psi} = 10\,573 \text{ psi}$)
- for completion fluid = $34,35 \text{ MPa} + 40,28 \text{ MPa} = 74,63 \text{ MPa}$
($4\,980 \text{ psi} + 5\,835 \text{ psi} = 10\,815 \text{ psi}$)

B.2.4.4 Maximum standing valve shear pressure = maximum BHP produced by the TFL system – $3,0 \text{ MPa}$ (435 psi):

- for dead oil = $64,9 \text{ MPa} - 3,0 \text{ MPa} = 61,9 \text{ MPa}$
($9\,426 \text{ psi} - 435 \text{ psi} = 8\,991 \text{ psi}$)
- for saltwater = $72,88 \text{ MPa} - 3,0 \text{ MPa} = 69,88 \text{ MPa}$
($10\,523 \text{ psi} - 435 \text{ psi} = 10\,138 \text{ psi}$)

ISO 13628-3:2000(E)

— for completion fluid = $74,63 \text{ MPa} - 3,0 \text{ MPa} = 71,63 \text{ MPa}$
($10\,815 \text{ psi} - 435 \text{ psi} = 10\,380 \text{ psi}$)

B.2.4.5 Maximum service BHP = maximum standing valve shear pressure – 3,0 MPa (435 psi):

— for dead oil = $61,9 \text{ MPa} - 3,0 \text{ MPa} = 58,9 \text{ MPa}$
($8\,991 \text{ psi} - 435 \text{ psi} = 8\,556 \text{ psi}$)

— for saltwater = $69,84 \text{ MPa} - 3,0 \text{ MPa} = 66,88 \text{ MPa}$
($10\,138 \text{ psi} - 435 \text{ psi} = 9\,703 \text{ psi}$)

— for completion fluid = $71,63 \text{ MPa} - 3,0 \text{ MPa} = 68,63 \text{ MPa}$
($10\,380 \text{ psi} - 435 \text{ psi} = 9\,945 \text{ psi}$)

B.2.4.6 Minimum system surface pressure (back pressure choke setting) = minimum system pressure to keep standing valves on seat – fluid hydrostatic pressure:

— for dead oil = $40,0 \text{ MPa} + 3,0 \text{ MPa} - 30,4 \text{ MPa} = 12,6 \text{ MPa}$
($5\,801 \text{ psi} + 435 \text{ psi} - 4\,426 \text{ psi} = 1\,810 \text{ psi}$)

— for saltwater = $40,0 \text{ MPa} + 3,0 \text{ MPa} - 38,38 \text{ MPa} = 4,62 \text{ MPa}$
($5\,801 \text{ psi} - 5\,573 \text{ psi} = 663 \text{ psi}$)

— for completion fluid = $40,0 \text{ MPa} + 3,0 \text{ MPa} - 40,28 \text{ MPa} = 2,72 \text{ MPa}$
($5\,801 \text{ psi} + 435 \text{ psi} - 5\,835 \text{ psi} = 401 \text{ psi}$)

B.2.4.7 Standing valve shear differential = standing valve shear pressure – BHP static:

— for dead oil = $61,9 \text{ MPa} - 40,0 \text{ MPa} = 21,9 \text{ MPa}$
($8\,991 \text{ psi} - 5\,801 \text{ psi} = 3\,190 \text{ psi}$)

— for saltwater = $69,88 \text{ MPa} - 40,0 \text{ MPa} = 29,88 \text{ MPa}$
($10\,138 \text{ psi} - 5\,801 \text{ psi} = 4\,337 \text{ psi}$)

— for completion fluid = $71,63 \text{ MPa} - 40,0 \text{ MPa} = 31,63 \text{ MPa}$
($10\,380 \text{ psi} - 5\,801 \text{ psi} = 4\,579 \text{ psi}$)

B.2.5 Dynamic condition calculation at 0,477 m³/min (3 bbl/min)

B.2.5.1 Maximum pressure differential (pumping tool down) = maximum surface pressure + service fluid hydrostatic pressure – service fluid pumping pressure loss down – [well BHP + 3,0 MPa (435 psi)¹⁾]:

— for dead oil = $34,5 \text{ MPa} + 30,4 \text{ MPa} - 4,13 \text{ MPa} - 43,0 \text{ MPa} = 17,77 \text{ MPa}$
($5\,000 \text{ psi} + 4\,426 \text{ psi} - 600 \text{ psi} - 6\,236 \text{ psi} = 2\,590 \text{ psi}$)

— for saltwater = $34,5 \text{ MPa} + 38,38 \text{ MPa} - 3,55 \text{ MPa} - 43,0 \text{ MPa} = 26,33 \text{ MPa}$
($5\,000 \text{ psi} + 5\,573 \text{ psi} - 513 \text{ psi} - 6\,236 \text{ psi} = 3\,824 \text{ psi}$)

— for completion fluid = $34,35 \text{ MPa} + 40,28 \text{ MPa} - 4,17 \text{ MPa} - 43,0 \text{ MPa} = 27,46 \text{ MPa}$
($4\,9809 \text{ psi} + 5\,835 \text{ psi} - 605 \text{ psi} - 6\,236 \text{ psi} = 3\,974 \text{ psi}$)

B.2.5.2 Maximum differential up (pumping tools up).

¹⁾ To assure that 3,0 MPa (435 psi) differential from above keeps standing valve seated.

B.2.5.2.1 Maximum pump pressure = maximum service BHP – service fluid hydrostatic pressure + pumping pressure loss down:

- for dead oil = $58,9 \text{ MPa} - 30,40 \text{ MPa} + 4,13 \text{ MPa} = 32,63 \text{ MPa}$
($8\ 556 \text{ psi} - 4\ 426 \text{ psi} + 600 \text{ psi} = 4\ 730 \text{ psi}$)
- for saltwater = $66,88 \text{ MPa} - 38,38 \text{ MPa} + 3,55 \text{ MPa} = 32,05 \text{ MPa}$
($9\ 703 \text{ psi} - 5\ 573 \text{ psi} + 513 \text{ psi} = 4\ 643 \text{ psi}$)
- for completion fluid = $68,63 \text{ MPa} - 40,28 \text{ MPa} + 4,17 \text{ MPa} = 32,52 \text{ MPa}$
($9\ 945 \text{ psi} - 5\ 835 \text{ psi} + 605 \text{ psi} = 4\ 715 \text{ psi}$)

NOTE This confirms maximum wellhead pressure is not exceeded.

B.2.5.2.2 Maximum differential pressure (up) = maximum pump pressure – pumping loss f/total system:

- for dead oil = $32,63 \text{ MPa} - 8,26 \text{ MPa} = 24,37 \text{ MPa}$
($4\ 730 \text{ psi} - 1\ 200 \text{ psi} = 3\ 530 \text{ psi}$)
- for saltwater = $32,05 \text{ MPa} - 7,1 \text{ MPa} = 24,95 \text{ MPa}$
($4\ 643 \text{ psi} - 1\ 026 \text{ psi} = 3\ 617 \text{ psi}$)
- for completion fluid = $32,52 \text{ MPa} - 8,34 \text{ MPa} = 24,18 \text{ MPa}$
($4\ 715 \text{ psi} - 1\ 210 \text{ psi} = 3\ 505 \text{ psi}$)

B.2.6 Conclusions

B.2.6.1 From calculation B.2.3.2, careful consideration should be given before selecting completion fluid for TFL service. Completion fluid would only be necessary if dead crude or saltwater could not provide adequate operating downhole TFL service pressure differentials. If completion fluid is used, the well would have to be circulated to a lighter fluid after servicing to allow the well to produce $40,28 \text{ MPa}$ hydrostatic > $40,0 \text{ MPa}$ BHP ($5\ 835 \text{ psi}$ hydrostatic > $5\ 801 \text{ psi}$ BHP).

B.2.6.2 From calculation B.2.4.1, to maintain a working pressure of $34,5 \text{ MPa}$ ($5\ 000 \text{ psi}$) maximum for the wellhead, flowline and pump, it is seen that:

- for dead crude and saltwater, allow a maximum pump pressure of $34,5 \text{ MPa}$ ($5\ 000 \text{ psi}$)
- completion fluid would require limiting pump output to $34,35 \text{ MPa}$ ($4\ 979 \text{ psi}$)

B.2.6.3 From calculation B.2.5, all three proposed TFL fluids will provide sufficient differential at $0,477 \text{ m}^3/\text{min}$ ($3 \text{ bbl}/\text{min}$) pumping rate for TFL service in either direction.

B.2.6.4 Fluid selection order of preference based on TFL service performance would be: salt water, dead crude, completion fluids. Saltwater and dead crude are preferred to completion fluid because the well would not have to be circulated to a lighter fluid for production start-up. Saltwater is preferred to dead crude as it provides greater TFL service pressure differentials. Storage and other considerations may alter this order of preference.

Annex C (informative)

TFL completions

C.1 General

The following clauses contain a brief description of TFL completion designs. The completions are very basic and many options can be added to enhance versatility and serviceability, such as isolation/production devices, artificial lift, zone selectivity, etc.

C.2 Single string, single zone, annular circulation completion

The completion shown in Figure C.1 is especially suitable for large bore completions where a large tubing ID is required for high production (or injection) rates. TFL service circulation is accomplished through a ported nipple or side-pocket mandrel. During production (or injection) the annulus is isolated by a CCV. A standing valve can be set in a no-go landing nipple or foot-valve production/isolation device immediately below the circulation point. Another option is to set the standing valve in a sliding-sleeve production/isolation device below the packer. If this latter option is used, a plug shall be set in the no-go nipple below the sliding sleeve, and the circulation point shall be immediately below the packer. If a TRSV and a side-pocket mandrel circulation member is used, an expendable standing valve may be pumped in place prior to TFL service and expended when servicing is complete. This completion is not particularly suitable for gas-lift designs because of the large volume of annulus gas that will have to be displaced prior to TFL service. When designing this completion, special consideration should be given to the casing design as it will be exposed to TFL service pressures. During service, the TFL operator shall consider the difference between the casing and tubing volumes while pumping in each direction. Pressure response times will be affected.

Key

- 1 Y-spool pack-off
- 2 Orienting sleeve/Y-spool deflector
- 3 Flowline nipple for flowline choke
- 4 Profile insert for wireline annulus plug
- 5 Safety valve
- 6 S-20 landing nipple
- 7 Ported nipple or side pocket mandrel with CCV
- 8 NO-GO landing nipple of foot
- 9 Single packer
- 10 Sliding sleeve with standing valve
- 11 NO-GO nipple with plug
- 12 Profile insert for TFL wellhead plugs
- 13 Optional instead of item 8

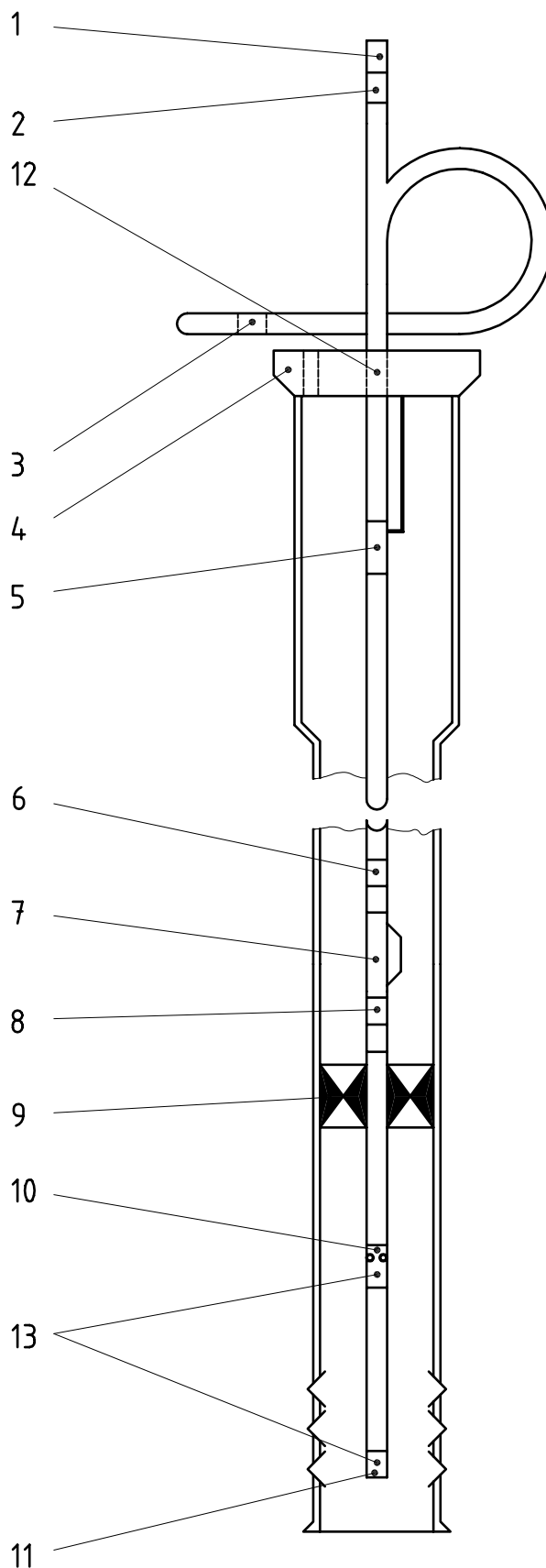
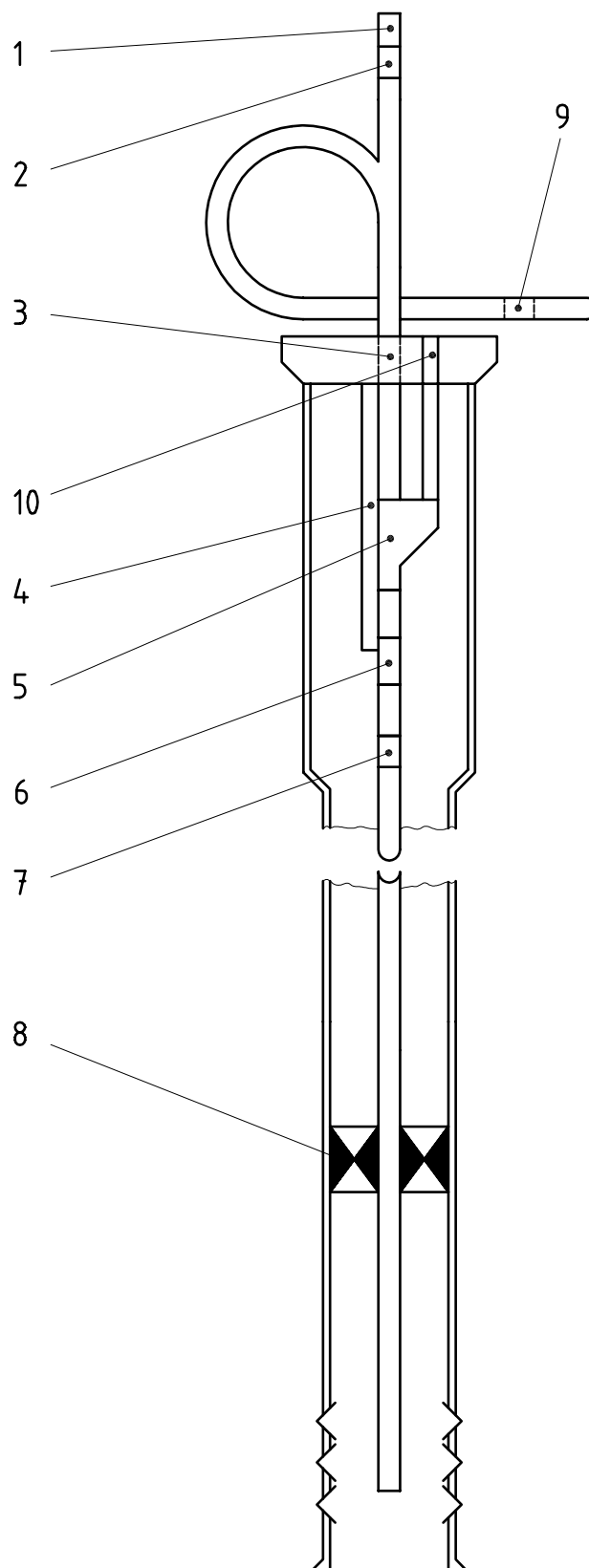


Figure C.1 — Single string, single zone, annular circulation completion

C.3 Single string, single zone, side string circulation completion

Figure C.2 shows a completion option with the safety system below the circulation nipple. This design provides a large production string along with a smaller circulation string. Placing the safety system below the circulation nipple allows the safety valve to protect both the production (or injection) string as well as the circulation string. The circulation point as well as the safety valve is set quite shallow and allows service only to the safety valve and wellhead. Safety valves designed for greater setting depths, such as the balanced type, allow moving the circulation point to deeper depths, thereby providing greater flexibility in service. A standing valve can be set in a no-go nipple or foot valve production/isolation device immediately below the safety valve. If the safety valve is placed immediately above the packer, the standing valve can be set in a sliding sleeve production/isolation device below the packer. If this latter option is used, a plug shall be set in the no-go nipple below the sliding sleeve and the circulation nipple shall be located immediately above the safety valve.

This design is adaptable to annular gas-lift (if a deep-set valve is used) with placement of multiple side-pocket mandrels. Single-point injection can be accomplished down the circulation string utilizing an orifice check valve run in conjunction with the CCV set in a circulation nipple. The design allows the use of an expendable standing valve if a side-pocket H-member is used along with a TRSV.



Key

- 1 Y-spool pack-off
- 2 Orienting sleeve/Y-spool deflector
- 3 Profile insert for TFL wellhead plug
- 4 S-20 landing nipple
- 5 Circular nipple with CCV
- 6 Safety valve
- 7 NO-GO landing nipple or foot valve with standing valve
- 8 Single packer
- 9 Flowline nipple for flowline choice
- 10 Profile insert for wireline annulus plug

Figure C.2 — Single string, single zone, with side string circulation completion

C.4 Dual-string, single-zone completion

Figure C.3 shows a dual-string, single-zone TFL completion. This design offers the most production (or injection) service versatility. With the dual-string design, production (or injection) can be maintained in the event of problems with one string.

This design uses a single packer which ties the tubing strings together with a wye block, providing both a circulation point and TFL access from either string. A standing valve can be set in a no-go nipple or foot valve/isolation device below the wye block and above the packer. Another option is to set the standing valve in a sliding-sleeve isolation/production device below the packer. If this latter option is used, a plug shall be set in a no-go nipple below the sliding sleeve. Annular gas-lift can be applied with side-pocket mandrels placed in either/or both tubing strings. The wye block, single packer design lends itself to gravel pack completions.

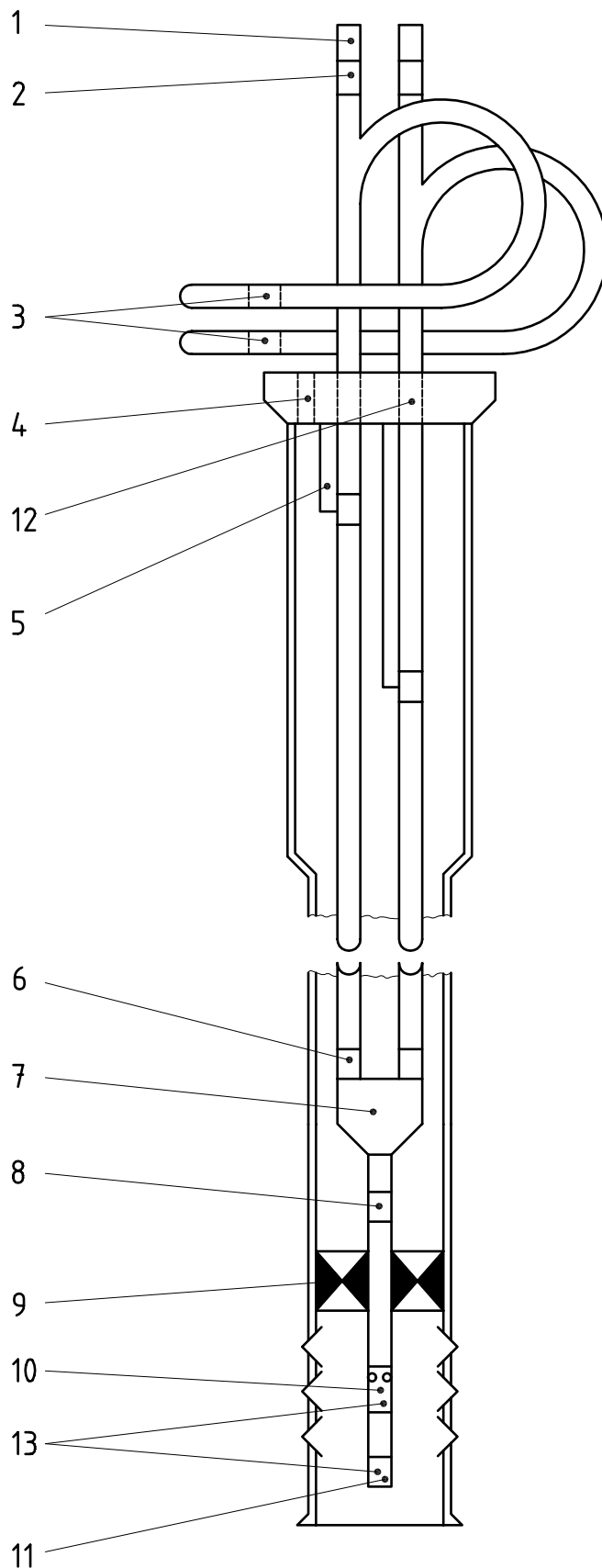
C.5 Dual-string, multi-zone completions

Figure C.4 shows a dual-string, dual-zone completion. This design incorporates a dual upper packer and single lower packer. A wye block ties the tubing strings together below the dual packer. This allows service access to the lower zone through either string increasing production and service versatility. Standing valves for the upper zone are placed in sliding-sleeve production/isolation devices run between the wye block and the upper packer. The standing valve for the lower zone can be set in a foot-valve below the wye block. Another option is to set the standing valve in a sliding-sleeve isolation device below the lower packer. If this latter option is used, a plug shall be run in a NO-GO landing nipple below the sliding-sleeve.

In multi-zone completions, a CCV is run to allow communication through the circulation member for TFL service while allowing isolation of the tubing strings for production (or injection). The above completion provides production versatility by allowing

- co-mingling all zones;
- production of two zones without out co-mingling;
- zone isolation;
- production of either zone through both strings;
- etc.

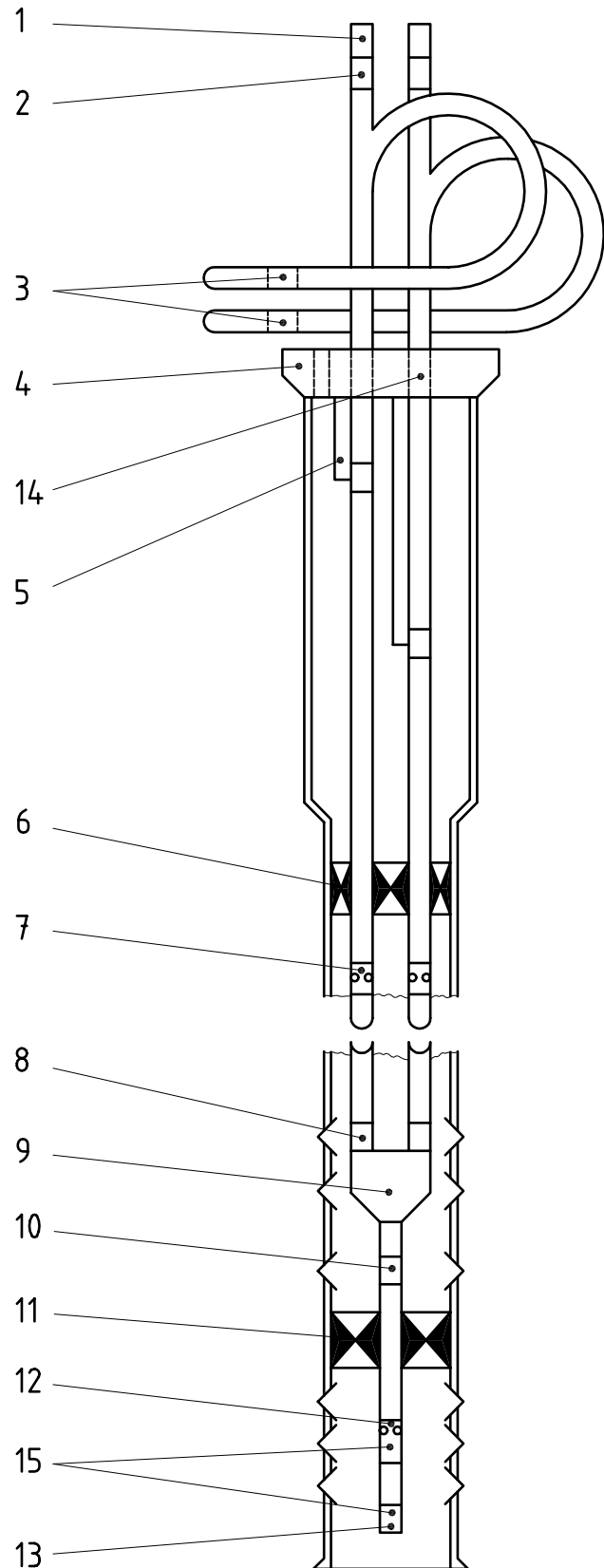
Annular gas-lift can also be added to this type of completion.



Key

- 1 Y-spool pack-off
- 2 Orienting sleeve/Y-spool deflector
- 3 Flowline nipples for flowline chokes
- 4 Profile insert for wireline annulus plug
- 5 Safety valve (both strings)
- 6 S-20 landing nipples
- 7 Wye block
- 8 NO-GO landing nipple or foot valve with standing valve
- 9 Packer
- 10 Sliding sleeve with standing valve
- 11 NO-GO landing nipple with plug
- 12 Profile insert for TFL wellhead plugs
- 13 Optional instead of item 8

Figure C.3 — Dual-string, single zone completion



Key

- 1 Y-spool pack-off
- 2 Orienting sleeve/Y-spool deflector
- 3 Flowline nipples for flowline chokes
- 4 Profile insert for wireline annulus plug
- 5 Safety valve (both strings)
- 6 Dual hydraulic-set packer
- 7 Sliding sleeve with standing valve installed
- 8 S-20 landing nipple
- 9 Wye block
- 10 NO-GO landing nipple or foot valve with standing valve
- 11 Packer
- 12 Sliding sleeve with standing valve
- 13 NO-GO nipple with plug installed
- 14 Profile insert for TFL wellhead plugs
- 15 Optional instead of item 8

Figure C.4 — Dual-string, dual-zone selective completion

Annex D (informative)

TFL capabilities

D.1 Flow controls

Flow controls include the following:

- CCVs;
- gaslift (side-pocket, concentric);
- jet pumps;
- plugs (downhole, wellhead);
- standing valves;
- TFL insert SCSSV;
- flowline chokes.

D.2 Service work

Service work includes the following:

- acidizing;
- bailing;
- bottom-hole pressure/temperature surveys;
- broaching;
- deviated/horizontal completions;
- drifting;
- fishing;
- pack-off;
- paraffin cutting;
- parking systems;
- perforating;
- reach rods;
- sandwashing;

ISO 13628-3:2000(E)

- tubing caliper;
- TRSV lockout;
- well killing/returning to production;
- zone changing.

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- [8] ISO 10420, *Petroleum and natural gas industries — Flexible pipe systems for subsea and marine riser applications*.
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ICS 75.180.10

Price based on 67 pages