

Recommended Practice for Flowline Connectors and Jumpers

API RECOMMENDED PRACTICE 17R
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Recommended Practice for Flowline Connectors and Jumpers

1 Scope

This Recommended Practice (RP) addresses specific requirements and recommendations for subsea flowline connectors and jumpers within the frameworks set forth by recognized and accepted industry specifications and standards. As such, it does not supersede or eliminate any requirement imposed by any other industry specification.

This RP covers subsea flowline connectors and jumpers used for pressure containment in both subsea production of oil and gas, and subsea injection services. Equipment within the scope of this document is listed below.

— Equipment used to make the following subsea connections are included:

- pipeline end terminations to manifolds,
- pipeline end terminations to trees,
- pipeline end terminations to riser bases,
- manifolds to trees,
- pipeline inline sleds to other subsea structures.

— The following connection components and systems are included:

- jumper assemblies,
- monobore connectors systems,
- multibore connectors systems,
- pressure and flooding caps,
- connector tools.

The following components and their applications are outside the scope of this RP:

- subsea structures,
- hydraulic, electrical, and fiber optic flying leads,
- umbilicals,
- pig launcher/receiver equipment,
- diver-assist flanges or connections.

Equipment for use in high-pressure high-temperature (HPHT) environments is beyond the scope of this document (see API Technical Report 17TR8 for guidance on subsea HPHT applications).

2 Normative References

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any addenda) applies.

API Recommended Practice 1111, *Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)*

API Recommended Practice 2A-WSD, *Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*

API Recommended Practice 2EQ, *Seismic Design Procedures and Criteria for Offshore Structures*

API Recommended Practice 2X, *Ultrasonic and Magnetic Examination of Offshore Structural Fabrication and Guidelines for Qualification of Technicians*

API Specification 6A, *Specification for Wellhead and Tree Equipment*

API Standard 6X, *Design Calculations for Pressure-containing Equipment*

API Specification 17A, *Design and Operation of Subsea Production Systems-General Requirements and Recommendations*

API Recommended Practice 17B, *Recommended Practice for Flexible Pipe*

API Specification 17D, *Design and Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment*

API Recommended Practice 17H, *Remotely Operated Tools and Interfaces on Subsea Production Systems*

API Specification 17J, *Specification for Unbonded Flexible Pipe*

API Specification 17K, *Specification for Bonded Flexible Pipe*

API Recommended Practice 17N, *Recommended Practice on Subsea Production System Reliability, Technical Risk, and Integrity Management*

API Recommended Practice 17Q, *Recommended Practice on Subsea Equipment Qualification*

API Recommended Practice 17U, *Wet and Dry Thermal Insulation of Subsea Flowlines and Equipment*

ASME Boiler and Pressure Vessel Code ¹, Section VIII Division 2: *Alternative Rules for Construction of Pressure Vessels*

ASME Boiler and Pressure Vessel Code, Section VIII Division 3: *Alternative Rules for Construction of High Pressure Vessels*

ASME B16.9, *Factory-Made Wrought Butt welding Fittings*

ASME B31.3, *Process Piping*

¹ ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries* ASME B31.8, *Gas Transmission and Distribution Piping Systems* AWS D1.1/D1.1M,² *Structural Welding Code—Steel*

DNV³, *Rules for the Classification of Mobile Units*, Part 3, Chapter 1, Section 10

DNV-RP-B401, *Cathodic Protection Design*

DNV-RP-C203, *Fatigue Design of Offshore Steel Structures*

DNV-RP-C205, *Environmental Conditions and Environmental Loads*

DNV-RP-F112, *Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection*

DNVGL-RP-B204, *Welding of Subsea Production System Equipment*

DNVGL-RP-F105, *Free Spanning Pipelines*

DNVGL-ST-N001, *Marine Operations and Marine Warranty*

Energy Institute, *Guidelines for the avoidance of vibration-induced fatigue failure in subsea systems*

ISO 15590-1⁴, *Induction bends, fittings and flanges for pipeline transportation systems—Part 1: Induction bends*

SAE AS4059, *Aerospace Fluid Power - Cleanliness Classification for Hydraulic Fluids*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

accessory hardware

The tools, equipment, or materials required for the mounting, operation, and testing of the installed connector system.

NOTE This includes inboard hub pressure caps, outboard hub pressure caps, seal removal and replacement tools, ROV interface panel [including hydraulic manifold(s) and tubing] for connector actuation, soft landing system, jumper fabrication jigs, measurement interface caps, debris caps, hub cleaning tools, any tools used to run or make up the connection and seal test equipment.

3.1.2

bending capacity during installation

The maximum bending load which may be applied to the jumper during installation and connector make-up, necessary to overcome fabrication metrology tolerances, elastic deflections from self-weight or a combination thereof.

NOTE Vertical jumpers require self-weight or pull-down force and horizontal jumpers require pull-in force to deflect the jumper sufficiently to position the connector for connection onto the inboard hub.

² American Welding Society, 8669 NW 36 Street, #130, Miami, Florida 33166-6672, www.aws.org.

³ Det Norske Veritas, Veritasveien 1, 1322, Hovik, Oslo, Norway, www.dnv.com.

⁴ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.

3.1.3

boundary condition

The jumper geometry, external loads, contained fluid and contained fluid flow conditions, metocean conditions, and other parameters required to define the jumper at any point along its length.

3.1.4

clamp connector

A connector constructed from linked segments which is actuated by a drive screw. The drive screw is typically operated by an ROV torque tool.

3.1.5

collet connector

A connector constructed from a body with attached individual, longitudinally segmented collet “fingers” arranged in a circular pattern and secured with an actuator ring.

3.1.6

connector

A mechanical device which holds an inboard and outboard hub together. A connector may also aid in the alignment of the two hubs as well as bringing the hubs together.

3.1.7

connector system

The actuated mechanical connector and related accessories required for its function.

NOTE 1 This includes components such as the inboard hub with structure, outboard hub with connector, alignment guides, soft landing hydraulic cylinders, flowline connection structures at the flowline sleds, or tie-in manifolds, pipe, metal-to-metal seal ring, secondary seal, and fluid coupling for actuation and connector function and seal pressure test.

NOTE 2 The hydraulic actuators for connector make-up, soft landing or a combination thereof, may remain with the system or may be recovered with a separate connector actuation tool.

3.1.8

contingency seal

An alternate seal used in place of the connector primary metal seal.

NOTE A contingency seal may be used in the event the primary seal or the primary sealing surfaces in the hubs are unusable due to physical damage, corrosion, or other reasons. The contingency seal may utilize the same profile as the primary metal seal.

3.1.9

cool down

Time period during which the pipeline operating temperature decreases due to a pipeline flow decrease or stoppage.

3.1.10

flowline jumper

A length of pipe terminated by connector systems between two subsea structures.

3.1.11

hub face separation

Separation of the inboard and outboard hub faces at any point around the circumference caused by internal pressure, external loading, or a combination thereof.

3.1.12

inboard hub

A hub fabricated into tree or subsea structure piping.

3.1.13**integral connector**

A connector that has non-removable hydraulic actuators to make and unmake a connection.

3.1.14**lock**

The act or state of the connector being fully engaged on the inboard hub and having the full preload applied.

3.1.15**multibore connector**

Any connector that has more than a single bore for the transfer of fluids.

NOTE Bores may be concentric, symmetric, or non-symmetric; contained fluids may include produced hydrocarbons, injected liquids or gases, hydraulic control fluids, corrosion inhibitors, and others.

3.1.16**non-integral connector**

A connector that uses separate, removable, tooling to make and unmake a connection.

3.1.17**outboard hub**

The hub which mates with the inboard hub and is generally fabricated into a jumper assembly, pig launcher/receiver or module.

3.1.18**park**

The act of landing the flowline jumper on the subsea structures in the disconnected position.

NOTE 1 For a vertical flowline jumper, the connector is generally in the raised position directly above or adjacent to the vertical inboard hub on the same or separate structure. For a horizontal flowline jumper, the connector is generally in line with and retained in the retracted or pushed back position from the horizontal inboard hub.

NOTE 2 Other than having connector actuation tools installed in the case of non-integral connectors, the flowline jumper is usually stable in the parked condition which can be achieved by means of the jumper being self-supported or using seabed support as applicable.

3.1.19**preload**

The clamping force generated at the connection that is necessary to resist or counteract the separating forces caused by the internal pressure, externally applied forces, moments, or a combination thereof.

3.1.20**Pressure cap**

A device which connects to an inboard or outboard hub and acts to seal the bore to a differential pressure

3.1.21**primary seal**

Any seal that acts as the initial (or primary) barrier between process fluids and the environment.

3.1.22**rated working pressure**

Maximum internal pressure that the equipment is specified to contain and control when in operation.

3.1.23**rigid jumper**

A flowline jumper fabricated using steel pipe, as opposed to flexible pipe.

NOTE Rigid jumpers in a horizontal configuration are often referred to as spools.

3.1.24**secondary seal**

A metal or elastomeric seal between the inboard and outboard hubs, external to the primary seal, which acts as a back-up to the primary seal.

3.1.25**structural capacity**

The external loading with or without RWP which the connector system is able to sustain within the accepted stress limits of the weakest component.

3.1.26**thermal stress**

Stresses occurring in the subsea jumper, connected piping or a combination thereof, at start-up or shutdown due to the differential between ambient temperature and pipeline operating temperature.

3.1.27**well jumper**

A flowline jumper located between a subsea tree and another subsea structure (typically a manifold or PLET).

3.2 Acronyms and Abbreviations

BOP	blowout preventer
CP	cathodic protection
CRA	corrosion resistant alloy
DVL	Doppler velocity log
EFAT	extended factory acceptance testing
FAT	factory acceptance testing
FEA	finite element analysis
FIV	flow induced vibration
INS	inertial navigation system
IMU	inertial measurement unit
IOM	installation, operation, and maintenance
JSA	job safety analysis
LBL	long baseline
LiDAR	light detection and ranging
LP	liquid penetrant testing
MT	magnetic particle testing
MPFM	multiphase flow meter
NCR	nonconformance report
NDE	nondestructive examination
NORM	naturally occurring radioactive material
PDD	product design document
PLEM	pipeline end manifold
PLET	pipeline or flowline end termination
PQR	procedure qualification record

ROT	remotely operated tooling
ROV	remotely operated vehicle
RT	radiographic testing
RWP	rated working pressure
SIMOPS	simultaneous operations
SIT	system integration test
SPFM	single phase flow meter
USBL	ultra short baseline
UT	ultrasonic testing
UV	ultraviolet
VIV	vortex induced vibration
VSD	vibration suppression device

4 System Selection

4.1 General

A subsea jumper consists of a rigid pipe spool or flexible pipe length between two vertically or horizontally oriented hydraulic or mechanical type connectors for the purpose to complete the piping conduit between subsea facilities. [Figure 1](#) displays a few examples of possible connector types, including clamp, integral collet, and non-integral collet connectors. These particular examples are shown oriented vertically, but these types of connectors could also be oriented horizontally. Jumpers can be installed and removed independent of the subsea facilities.

This section provides the framework for making design selections between various subsea jumper configurations and components (e.g. flexible vs. rigid jumper pipe; vertical vs. horizontal jumper and connection systems; and integral vs. non-integral connections). This section outlines several of the variables that can drive and influence subsea jumper configurations and component choices and cover some of the advantages and disadvantages of each. The information provided in this section is intended to provide the end user with a means of supporting their decision making process and should be amended as necessary to ensure project specific requirements are appropriately addressed and incorporated during the evaluation process.

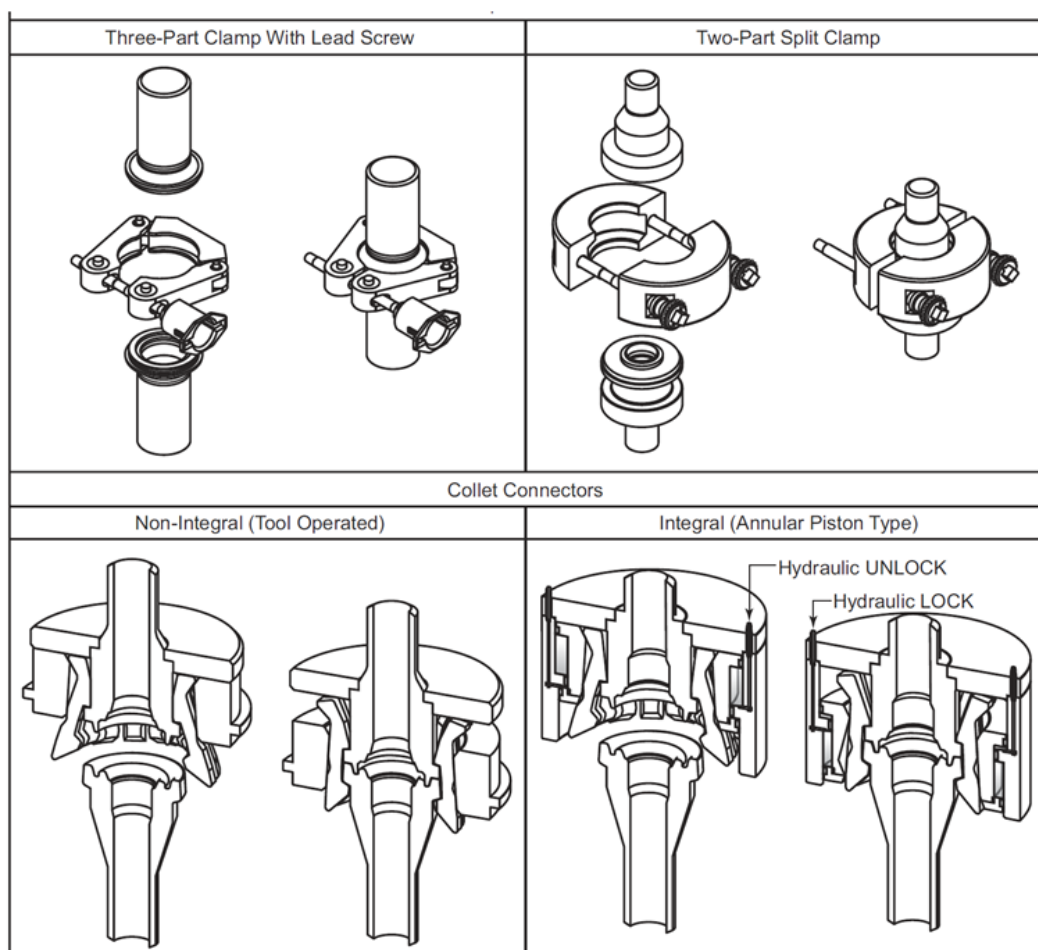


Figure 1—Examples of Connector Types

4.2 Subsea Jumper Selection Considerations and Comparisons

4.2.1 Flexible vs. Rigid

4.2.1.1 General

The technical evaluation of the jumper types should be performed with parallel consideration of the through life viability of the selected option, suppliers, lead times and other procurement variables.

4.2.1.2 Flexible

The following are some advantages of flexible pipe jumpers:

- precise metrology not required for fabrication or installation provided that the subsea equipment is installed in the specified locations so that measurements can be determined during detail design;
- less sensitive to loading conditions (e.g. thermal growth, well workovers) that may cause jumper movement during operations;
- less of a concern with VIV since pipe design/configuration is self-dampening;
- corrosion resistant terminations and carcass are available for flexible pipe for sour and chemical resistant service;

- reuse of a flexible jumper may be feasible within same subsea development/range limit;
- a flexible jumper could be used for very short length connections where rigid pipe may be too stiff;
- may be used for very long step outs (e.g. satellite wells) where rigid pipe jumpers would not be feasible.

The following are some disadvantages of flexible pipe jumpers:

- fabrication and termination of flexible pipe are complex and require special tooling;
- limited qualified size, internal and external pressure ratings, and temperature ratings;
- more stringent sparing requirements due to an inability to quickly obtain new pipe;
- special considerations required for pigging;
- flexible pipe can be designed with the necessary insulating properties, but difficult to add thermal insulation after manufacture;
- special installation vessels may be needed for long flexible pipe installation;
- torsional build up can occur during storage on reels or during flexible pipe installation, potentially spinning the connector on the inboard hub or generating torsional forces (if restrained, e.g. multibore). This can generate alignment problems if not accommodated by design of system, connector, tooling, or a combination thereof;
- special installation aids such as dead weights are sometimes required for installation of flexible pipe;
- flexible pipe with flanged or clamped end connections results in additional potential leak paths;
- typically difficult to integrate controls or ancillary equipment (e.g. valves, sand detectors);
- flexible jumpers require bend restrictors, and cathodic protection for metal bend restrictors that is usually facilitated via grounding straps/cables that run the length of the bend restrictor string;
- the corrugated surface of the inside diameter of flexible pipe can create flowline induced pulsations (FLIP) in gas service, exposing equipment downstream of the flexible to vibration loading.

4.2.1.3 Rigid

The following are some advantages of rigid pipe jumpers:

- fabrication is possible in a wide variety of working locations allowing incorporation of local content;
- ability to pig (wax, intelligent, and others) when used for flowline jumpers, including operational and maintenance pigging;
- HH trim CRA clad pipe is available;
- availability of a wide range of pipeline material, sizes, and pipe wall thicknesses to allow for flow rates and pressure range (internal and external pressure);
- less sensitive to sandy service;
- thermal insulation can be easily added to retain or preserve flowline content heat and extend cool down times for hydrate mitigation;
- can be welded directly to the outboard connector thus eliminating a leak path;

- allows easier insertion of components into the piping such as, but not limited to, flow meters, valves, pig detectors, and sand detectors.
- the precise geometry of a rigid jumper may facilitate ROV accessibility on structures and simplify layouts in congested areas (e.g. drill centers)

The following are some disadvantages of rigid pipe jumpers:

- precise metrology is required before final jumper assembly/welding and installation;
- sensitive to the deflection of wellheads and pipelines under loading (thermal, workover conditions, and others) which may cause jumper movement;
- susceptible to FIV, which may be mitigated by alternate jumper designs/configurations, restricting flow rates, or use of vibration suppression devices (VSDs);
- susceptible to VIV, but may be mitigated by alternate jumper designs/configurations or by use of strakes;
- limitation on the jumper span length which may congest subsea drill centers;
- reuse of a rigid jumper is most likely not an option without modifications to the piping weldment since it is fabricated to a specific subsea metrology.
- design typically relies on unconstrained movement of the jumper pipe during thermal cycles. Post installation burial of a section of the jumper (e.g. cuttings/cement from drilling a nearby well) may cause failure of the jumper pipe.

4.2.2 Horizontal vs. Vertical

4.2.2.1 Horizontal

The following are some advantages of horizontal jumpers.

- Horizontal jumpers are useful where the project requires self-draining jumpers or low profile jumpers for protection in shallow water depths from fishing activities, trawling boards, icebergs, or a combination thereof.
- Lifting height at quayside and on installation vessel may be limited.
- Tie-in porches may support horizontal jumpers in a parked or disconnected state prior to the installation or retrieval of the host structure (such as a manifold or tree), depending on subsea foundation.
- Metrology may be taken from the tie-in porch structure prior to the installation of the host structure in some cases.
- Lower jumper height minimizes interference with intervention and production equipment.
- Horizontal jumpers can be less susceptible to VIV depending on the spool geometry and whether it has seabed support.
- Horizontal jumpers are designed to lie on the seabed, which may reduce loads applied to the inboard hubs.
- Horizontal jumpers (both rigid and flexible) with considerable seabed support and limited free spans are easier to engineer for seismically active areas than free-spanning vertical jumpers.

The following are some disadvantages of horizontal jumpers.

- Stroking tools and tie-in porch are required to apply and react forces necessary for connector pull-in and push-

back from inboard hub.

- Horizontal jumper design can be prohibited due to horizontal connector actuation stroke for shorter length jumpers if the field layout is congested.
- A vertical run must be incorporated into the horizontal jumper configuration to incorporate a multiphase flowmeter in the preferred vertical orientation.
- Horizontal jumpers are typically designed in multiple planes and therefore stress (tension) may be left in a rigid horizontal jumper after making up the connections, depending on the design of the jumper. A rigid horizontal jumper requires more complex fabrication setup due to the need to factor in the specific inboard heading of the subsea tie-in point. A rigid horizontal jumper requires more deck space than a rigid vertical jumper during load out and transportation.
- Metrology for horizontal jumpers should include heading, and the survey points on the subsea structure varies depending on the connection system.
- Retrieval of a horizontal jumper may be difficult due to the multi-planar design of most horizontal jumpers.
- Jumper insulation may require installation of doghouses over connectors.
- More space is required to fabricate horizontal jumpers due to large footprint required for out of plane designs.
- Installation rigging for horizontal jumpers is more complicated in most cases and may be very large.
- Horizontal seabed supported jumpers require considerably more design analysis to cover variability in soil conditions.
- Horizontal seabed supported jumpers may incur more installation and operational risk from seabed changes caused by other field activities (e.g. drill cuttings deposits, excess well cement outflows and dropped objects) which may interfere with the installation or bury the jumper.

4.2.2.2 Vertical

The following are some advantages of vertical jumpers:

- do not require complex landing porches;
- gravity assisted; minimal pipe deflection/pull-in required when making up the connection;
- allow integration of a multiphase flowmeter in the preferred vertical orientation on the jumper;
- typically fabricated in a single plane which aid in installation and retrieval;
- metrology is simplified and can be taken directly from the structure hub. The following are some disadvantages of vertical jumpers:
- undesirable in shallower water depths where fishing nets/trawling boards are employed, icebergs may be encountered, or a combination thereof;
- typically cannot be parked without the use of a temporary wet parking stand to retrieve the host structure;
- are more susceptible to VIV and fatigue due to exposed profile.

4.2.3 Integral vs. Non-integral Connectors

4.2.3.1 Integral

The following are some advantages of integral connectors for jumpers:

- decreased installation time since no separate trips are required to retrieve connector actuation tools because all actuation and soft landing mechanisms are integral to the connector;
- advantageous for developments which require smaller number of connections;
- not dependent on availability of connector tools, especially when compared with non-integral connector designs that have been modified or replaced by newer models (not subject to obsolescence of changes in design);
- may not require as many service personnel to support the installation campaign;
- wet insulation can be pre-installed versus post-installation dog house. The following are some disadvantages of integral connectors for jumpers:
 - higher hardware complexity per connection, but simpler tooling requirements;
 - all hydraulic components remain subsea, which introduces additional potential failure modes.

4.2.3.2 Non-integral

The following are some advantages of non-integral connectors for jumpers:

- connector actuating hydraulics can be integrated into the stroking tool, which reduces hardware complexity by removing the hydraulics from each connector;
- advantageous for fields which require larger number of connections (also depends on the number of tools required during the installation campaign);
- increased reliability of the actuation system, because all hydraulic components are recovered with the connector actuation tools and can be maintained/repared prior to use;
- tooling availability can be maximized by using connector designs with nonproprietary or simplified ROV tool interfaces (e.g. clamp connectors with API Recommended Practice 17H interfaces).

The following are some disadvantages of non-integral connectors for jumpers:

- longer installation time because additional trips may be required for recovery of connector actuation tools;
- require upkeep, maintenance, and storage of the proprietary connector actuations tools over the course of the field life;
- typical tooling setup and preinstallation testing may require more service personnel on installation support vessel for the installation campaign;
- may require an increased number of tools and equipment for testing and transportation which will require additional logistical considerations.

4.3 Jumper Configurations

Jumper configurations include, but are not limited to, those shown in [Figure 2](#).

The jumper configuration should be optimized for transportation to the field and to minimize ROV obstacles.

A self-sustaining jumper configuration avoids support from the soil; accommodates buoyancy modules or bend restrictors; and positions supplemental hardware in an orientation/location to minimize the effect of bending loads. When seabed support is required, soil data should be obtained and used to analyze the jumper for support as well as the induction of loading. Seabed support design should also consider the effects of bottom currents and scour, as well as material deposition (e.g. mudflow, drilling spoils) for long-term validation.

The project requirement of supplemental hardware, such as, but not limited to MPFM, SPFM, and valve modules frequently requires an interface with hydraulic or electrical flying leads, which apply additional loads to the jumper connection.

Field commissioning and operating plans should specify whether the jumper configuration needs to facilitate pigging.

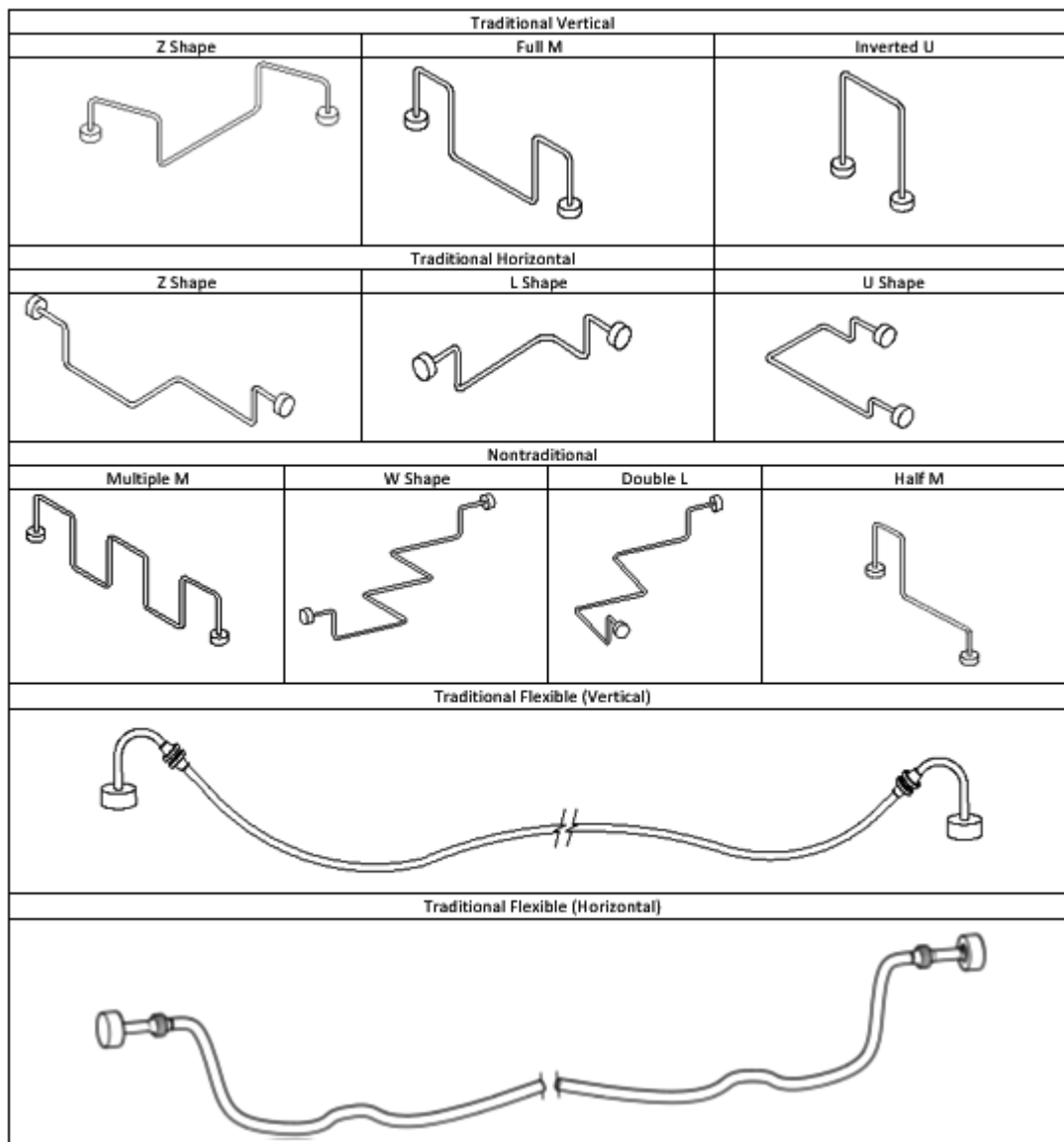


Figure 2—Typical Jumper Configurations

4.4 Drill Center Layout Guidance

When considering the drill center layout, the jumper configuration and routings should be evaluated in conjunction with all the other subsea system structures and components to minimize crossing of flowlines, umbilicals, flying leads, and other jumpers. In addition to [4.2](#), jumper selection should consider drilling sequence and impact of external accumulation of drill cuttings (particularly true if a new well is to be added close to an existing drill center, or if jumpers and flying leads are to be pre-installed/parked and shifted to final positions at a later date).

The arrangement of rigid vertical jumpers plays an important role in determining the location of the trees with respect to the manifold. Most 6 in. and 8 in. nominal pipe diameter rigid vertical jumpers have a typical range of 50 ft to 90 ft (15 m to 27 m). A shorter jumper may be too rigid and would need to be made more flexible to allow the deflections sometimes necessary for installation. A longer jumper may require a larger installation vessel. Both scenarios may result in increased jumper stresses and a jumper geometry which is more difficult to handle and install. A rigid subsea jumper with a nominal pipe diameter smaller than 4 in. is not normally considered due to excessive flexibility and short span length.

Larger diameter rigid vertical jumpers, such as those used in flowline/pipeline jumpers, have a slightly different length range. Most 10 in. and 12 in. nominal pipe diameter rigid vertical jumpers have a typical range of 80 ft. to 130 ft. (24 m. to 40 m).

Rigid horizontal jumpers do not have the same maximum length restrictions as rigid vertical jumpers.

Flexible jumpers do not have the same length restrictions as rigid jumpers and may be used where drill center layouts require very short or long length connections, or where restrictive subsea architecture would require an overly complex rigid jumper.

In the event that jumpers are crossed, jumper analysis, ROV accessibility analysis, metrology feasibility analysis, and any other analysis necessary should be performed, as well as any regulatory requirements for crossing permitted segments, to prove that the crossed jumper is the most feasible approach.

4.5 Requirements During Installation (that Influence Jumper Selection)

Certain installation requirements may impact selection of a jumper configuration. The inherent installation advantages/disadvantages associated with horizontal and vertical jumpers or integral and non-integral connectors are given in [4.2](#). Regardless of material or orientation, jumper configurations should be designed for the installed sea state, as installation loads can result in immediate failure. The jumper configuration should descend under its own self weight without causing significant slack in the supporting rigging equipment. Additionally, each jumper connector should be supplemented with the necessary hardware to facilitate alignment and prevent damage upon landing.

For rigid jumpers, unbalanced loads from differing connector sizes may increase the complexity of the spreader bar or lift line configuration. The installation vessel capabilities, including adequate deck space and sufficient crane hook height and lift capacity, should be evaluated during the installation vessel assessment.

For flexible jumpers, the minimum bend radius identifies the smallest degree of the curvature the flexible can experience at any one time. Typically multiple minimum bend radii are provided by the manufacturer of flexible pipe, including a storage MBR (typically on a reel with minimal tension or pressure) and an installation MBR with tension, pressure in the pipe as it is installed, or a combination thereof. The installation method should be designed to prevent bending of the pipe below the manufacturers stated minimum bend radius. Fitting bend restrictors on the flexible jumper outer coating can increase the installation time, specifically important for end connections where production shut-in may be required. In the event the minimum bend radius is exceeded, the flexible pipe should be evaluated for long-term performance effects. Subsea connectors for flexible jumpers should allow for lifting and orienting of the connector through the splash zone and water column that facilitates lifting the flexible load, which is usually facilitated via a hang-off/collar attached to the end termination. The subsea connector/gooseneck lifting design should also be able to orient the connector after deployment to make up a connection.

4.6 ROV/ROT Aspects

The connector design should meet the requirements of API Recommended Practice 17H to ensure the use of standard ROV tooling where possible. ROV interfaces should be accessible and able to withstand incidental ROV loadings as described in API Recommended Practice 17H. An ROV accessibility study should be completed to ensure that interfaces for both connector actuation as well as access to additional components within the pipe kit, (e.g. isolation valves, MPFMs) are ROV friendly and accessible. Any additional components to the pipe spool and connectors, such as isolation valves or subsea flow meters, warrants an ROV accessibility study to confirm clash checks with the surrounding subsea hardware.

4.7 Multibore Connection Systems

Multibore jumpers may incorporate production, chemical, and hydraulic lines in a bundle. This can result in decreased installation time, as a multibore connector allows these lines to be installed and connected simultaneously and allow for enhanced protection of the individual lines.

Multiple bores in a single outboard hub add complexity to the connection system. The following are advantages and disadvantages of multibore connection systems.

- Multibore connection systems may be concentric or nonconcentric. Concentric multibore connection systems do not require rotational alignment of the outboard and inboard hubs; nonconcentric multibore connection systems do require rotational alignment of the outboard and inboard hubs.
- Multibore connection systems may include integral bores with metal seals for production, water injection, chemical injection, and hydraulic fluid, as well as accommodate hydraulic, electrical, and fiber optic connectors.
- Multibore connection systems may require specialized manufacturing, assembly, and welding techniques.
- The individual metal seals used in a multibore application should be qualified to accommodate the axial and radial tolerances required for machining the outboard and inboard hub sealing surfaces.
- Subsea seal replacement in multibore connection systems may require complex seal replacement tools.
- Intervention requires disconnection of all bores.

Any internal components that are not integral to the multibore connection system outboard hub, inboard hub, and primary and secondary seals are outside the scope of this RP.

5 Connection Equipment

5.1 General

The requirements identified within this section apply to devices used to make and maintain a connection between two structures which are pressure containing. This includes, but is not limited to, connectors, caps, and closures.

5.2 Functional Requirements

The connection system should have the following functional requirements.

- The connector should be self-contained, such that its components are never in an unsecured or unstable position when actuated between the fully unlocked and fully locked positions, in particular for those designs that allow for additional locking stroke when not installed on an inboard hub.
- At the conclusion of FAT, the connector should be interchangeable on all hubs designed for the connector without requiring adjustment.