

# Recommended Practice for Subsea Pumping Well Intervention Systems

API RECOMMENDED PRACTICE 17G2  
FIRST EDITION, XXXX 2022  
BALLOT DRAFT 4D



AMERICAN PETROLEUM INSTITUTE

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## **Contents**

(To be developed prior to publication)

For Committee Review Only

## Introduction

The purpose of a subsea pumping well intervention system is to pump fluid into a subsea well. Pumping operations into or out of a flow line/pipeline or a subsea storage unit will not be addressed due to barrier philosophy differences. This document does not cover flow backs even though it is understood that the system is to be designed and operated in the presence of residual hydrocarbons in small quantity but not a full flow back scenario.

Subsea pumping systems typically involve a spooled fluid conduit with the fluid conduit not being rigidly attached to the subsea well similar to a top tensioned intervention riser system. No tooling is conveyed through the fluid conduit, therefore, the mode of operation for these subsea pumping well intervention systems is considered to be riserless. Commonly used fluid conduits typically consist of internally welded coil tubing, composite lines, umbilical lines, and other spooled products but can include jointed pipe. A subsea pumping well intervention system consists of a group of components and equipment packages that could comprise a standalone system or may supplement part of the permanent installed subsea system infrastructure operated together as a system. The whole of the system needs to meet all the requirements of API STD 17G and API RP 17G5 as modified or amended by this document.

The development of this document is based on input from API Subcommittee 17 (Subsea Production Systems) technical experts. The technical revisions have been made in order to accommodate the needs of industry and to move this document to a higher level of service to the petroleum and natural gas industry.

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

## 1 Scope

This recommended practice provides recommendations for the design, manufacture, testing and performance of subsea pumping well intervention systems deployed from a mobile offshore work unit such as a Multi-Purpose Vessel. The intervention vessel classification and equipment technical compliance shall be based upon risk assessment of the intended operational activity. This document contains the system level requirements and recommendations, and where not found elsewhere the information that applies to individual components. To the greatest extent possible, this document points the reader to the API document that is applicable to each system component or subsystem.

This information is applicable to all new and existing subsea pumping well intervention systems.

This is not a standalone document. It is to be used in conjunction with the API STD 17G (parent document), API RP 17G1 and end user requirements. Subsea pumping well intervention systems are intended to satisfy the requirements of API STD 17G and API RP 17G5 as modified by this document.

This recommended practice is intended to serve as a common reference for designers, manufacturers, and operators/users, thereby reducing the need for end user specifications. This RP also eliminates the need for interpretation of the applicability of requirements given by other codes and standards for permanent installed equipment.

Specific equipment covered by this recommended practice is as follows:

- Flying Leads
- Vertical Fluid Conduits
- Jumpers
- Fluid Conduit Connectors
- Subsea Safety Module
- Control Systems
- Disconnect Systems

Associated equipment not covered by this recommended practice is listed below:

- Subsea Pumps
- Subsea Process Packages
- Intervention vessels used to Execute Work in the Field

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- Winching, Spooling, Tensioners, Injector Heads, or other Equipment to deploy Fluid Conduits

## 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 Specification 5ST, Specification for Coiled Tubing

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

API Recommended Practice 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 Standard 17G, 3<sup>rd</sup> edition, 2019. Standard for Design and Manufacture of Subsea Well Intervention Equipment

API Recommended Practice 17G5, Recommended Practice for Subsea Intervention Workover Control Systems

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 Specification 17L1, Specification for Flexible Pipe Ancillary Equipment

API Recommended Practice 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment

ASME B31.3, Process Piping

ASME Boiler and Pressure vessel Code, Section VIII, Division 1

BS EN 14359, Gas-loaded Accumulators for Fluid Power Applications

DNV-OS-C501, Composite Components

DNV Standard for Certification 2.7-3, Portable Offshore Units

ISO 10945, Hydraulic Fluid Power-Gas-loaded Accumulators-Dimensions of Gas Ports

## NORSOK D002, Well Intervention Equipment

### 3 Terms, Definitions, Abbreviated Terms and Symbols

#### 3.1 Terms and Definitions

For the purposes of this document, the following terms, definitions, abbreviations and symbols apply in addition to the terms defined in API STD 17G, as applicable.

##### 3.1.1 auto shut in

Auto shut-in functionality is a function designed to automatically isolate the well subsea in the event of an unplanned disconnect from the subsea safety module.

Specifics of the design are based upon system architecture and safety strategy requirements.

##### 3.1.2 control system

Group of components, equipment packages, and/or part of the permanent infrastructure that provide all the control functions required to operate the Subsea Pumping Well Intervention System in its entirety.

NOTE The control system is inclusive of backup control system, shut down system and disconnect control system (if applicable).

##### 3.1.3 downline

Lines in the water column that perform various purposes other than to convey fluid

NOTE Downlines may be used to convey or suspend loads (crane or winch wires, synthetic rope), operate ROV's or support divers (ROV or diving bell umbilical's), send utilities or control subsea equipment.

##### 3.1.4 disconnect system

Group of subsea components, equipment packages, and or part of the temporarily installed subsea system infrastructure that provide the ability to disconnect the Intervention vessel from the subsea equipment packages. This functionality shall facilitate disconnection of the fluid conduits at suitable angles as justified through operational risk assessment and global riser analysis.

##### 3.1.5 fluid conduit

Enclosed conduit (e.g., pipe, tubing, hose, etc.) that connects various system packages to allow for the flow of fluid between the various equipment packages and the tree system; typically consisting of hose, steel coil tubing, or jointed pipe

NOTE There are four groups of fluid conduits:

- Deck Fluid Conduits used to connect the various equipment on the deck of the intervention vessel.
- Vertical Fluid Conduits, these are the conduits in the vertical water column
- Flying Leads, these connect the vertical conduits to the equipment located on the seafloor and may provide the heave compensation capability to the system.
- Jumpers, these provide the connection between equipment packages located on the seafloor.

##### 3.1.6 fluid conduit connectors

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**Assemblies that connect the various fluid conduits to the various equipment packages and the well**  
**NOTE** A fluid conduit connector may also provide a structural connection that supports loads from one or more equipment packages.

### **3.1.7 high cycle fatigue**

Accumulated material structural damage induced by successive, alternating, low amplitude, elastic strains.

**Note** High cycle fatigue is typically classified as requiring greater than 10,000 cycles to reach failure

### **3.1.8 intervention fluid storage**

Equipment that holds the intervention fluid upstream of the pump package

**NOTE** The storage may be located on a surface intervention vessel or subsea.

### **3.1.9 low cycle fatigue**

Accumulated material structural damage induced by successive alternating, high amplitude, plastic strains.

**Note** Low cycle fatigue is typically classified as requiring fewer than 1,000 cycles to reach failure

### **3.1.10 pumping manifold**

Assembly that contains the necessary piping and valves needed to direct the flow

### **3.1.11 pumping package**

Equipment that provides the motive force to the fluid.

**NOTE** This package may be either located on the intervention vessel, subsea, or both.

### **3.1.12 subsea equipment package**

A system of integrated equipment and equipment packages, deployed subsea, which contains one or more of the following components:

- pumping package
- fluid storage
- fluid conduits
- process package
- fluid conduit connectors
- pumping manifold
- subsea safety module
- control system components
- disconnect system

- flexible fluid conduit
- interfaces to the permanent installed subsea system infrastructure

### **3.1.13 subsea pumping equipment**

Subsea pumping equipment are pump systems that are located subsea and are typically used to pump from the sea floor to the surface or into subsea temporary infrastructure.

### **3.1.14 subsea safety module**

Group of components installed between the fluid conduit connector and tree and/or permanent infrastructure access point that provides some or all the barrier device(s) necessary to protect against uncontrolled flow to the subsea environment

### **3.1.15 Weak link**

Group of components or design feature intended to limit tension during unplanned events including but not limited to vessel drift or drive off.

### **3.1.16 Non-return Valve**

Group of components intended to allow fluid flow toward the well, but prevent fluid returns from the well toward the fluid conduits and topside infrastructure.

### **3.1.17 Safety Functions**

Functions undertaken either autonomously, or via operator action/intervention, in order to control fluid flow and prevent risk environment, personnel, or Pumping Well Intervention System Integrity.

### **3.1.18 Fluid Storage Package**

Group of components intended to temporarily store intervention fluids prior to pumping to the well.



## 3.2 Abbreviated Terms

For the purposes of this document, the following abbreviations and symbols apply in addition to the terms defined in API 17G, as applicable.

AMV	annulus master valve
ASV	annulus swab valve
EDS	emergency disconnect sequence
EQD	emergency quick disconnect
ESD	emergency shutdown
FMECA	failure mode, effects and criticality analysis
HAZID	hazard identification
HAZOP	hazard and operability study
IWOCS	Intervention and workover control system
MAOP	maximum allowable operating pressure
ML	mud line
MSL	mean sea level
NRV	non-return valve
OCTG	oil country tubular goods
PCV	production choke valve
PMV	production master valve
PSD	process shutdown
PSV	production swab valve
PWV	production master valve
ROV	remotely operated vehicle
RP	recommended practice

RWP	rated working pressure
SCSSV	surface controlled subsea safety valve
SPWIS	subsea pumping well intervention system
SSM	subsea safety module
VFC	vertical fluid conduits
XOV	crossover valve
XT	Christmas tree

## 4 System Requirements

### 4.1 Purpose

#### 4.1.1 General

For subsea pumping well intervention operations the main modes of operation covered within the scope of this recommended practice are:

- Surface to Seafloor Fluid Conveyance Mode
- Seafloor Fluid Conveyance Mode

Both modes are used principally to introduce fluid to the well bore.

The mode of operation and the type of operation to be performed are dependent on the type of subsea tree and barrier elements included in the subsea pumping well intervention system.

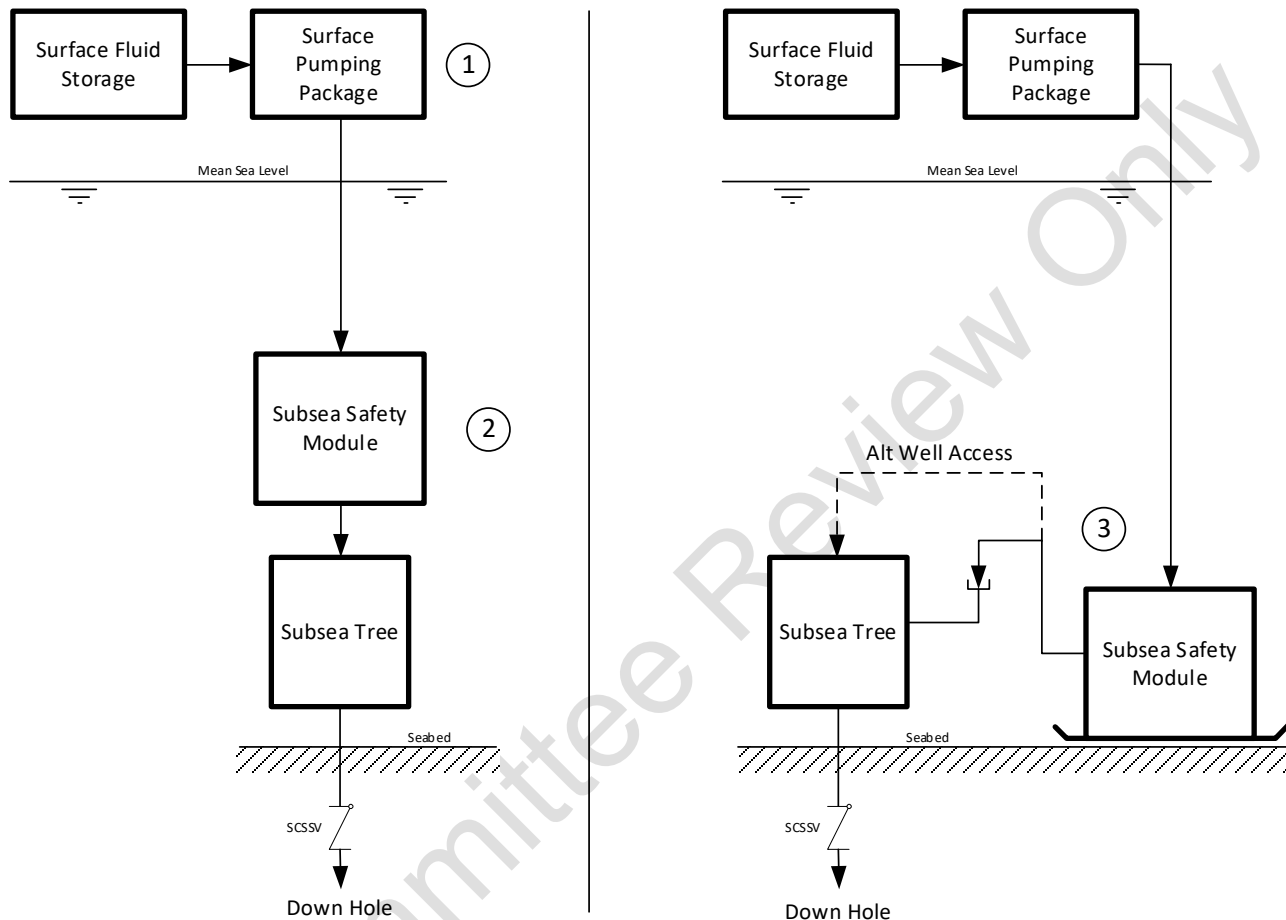
Two simplified flow schematics for Surface to Seafloor Fluid Conveyance Mode of operation is illustrated in Figure 1. A simplified flow schematic for Seafloor Fluid Conveyance Mode is illustrated in Figure 2.

#### 4.1.2 Surface to Seafloor Fluid Conveyance Mode

In this mode, one or more Pumping Packages are located on the intervention vessel. One or more vertical fluid conduits are deployed from the intervention vessel through the water column to convey the fluid to the subsea well on the seafloor. Flying leads connect the vertical fluid conduit to the subsea safety module which is located on a seafloor structure or landed on the subsea tree. A Subsea Pump Package may be incorporated into this system to boost the pumping pressure.

Equipment shall resist external loads and pressure loads and accommodate tools for necessary operations. In Surface to Seafloor Fluid Conveyance mode, equipment may be exposed to ocean environmental loads such as hydrodynamic loads from waves and current in addition to intervention

vessel motions.



1. Intervention fluids and/or pumping package may be aboard the SSM deployment vessel or a separate stim/frac vessel.

2. SSM secured directly to subsea tree.

3. SSM on seafloor (or alternate means to secure to seabed) with jumper(s) from the SSM to a subsea production/distribution manifold or directly into the subsea tree.

**Figure 1 – SPWIS for Surface to Seafloor Fluid Conveyance Mode**

#### 4.1.3 Seafloor Fluid Conveyance Mode

In this mode, no fluid is conveyed between the intervention vessel and the subsea infrastructure. The Fluid Storage and Pumping Packages are located on the sea floor and connected to the tree. Control of these packages is via umbilical back to the intervention vessel.

The diagram illustrates the architecture of a subsea system, divided into surface and subsea sections by a horizontal line representing the Mean Sea Level.

**Surface Components:**

- IWOCS (1):** Integrated Well Operations Control System.
- Utilities & Telemetry (power, chemical, etc.):** Provides essential services to the subsea system.

**Subsea Components (located below Mean Sea Level):**

- Subsea Tree:** The primary wellhead component.
- Subsea Safety Module:** Receives signals from the IWOCS and the Utilities & Telemetry unit.
- Subsea Pumping Package:** Receives signals from the Utilities & Telemetry unit and the Subsea Safety Module.
- Subsea Fluid Storage System:** Receives signals from the Subsea Pumping Package.

**Connections and Flow:**

- Control Lines (Solid):** Connect the IWOCS and Utilities & Telemetry unit to the Subsea Safety Module and Subsea Pumping Package.
- Fluid Flow (Dashed):** Connects the Subsea Tree to the Subsea Safety Module and Subsea Pumping Package.
- Seabed:** The Subsea Safety Module, Subsea Pumping Package, and Subsea Fluid Storage System are mounted on the seabed.
- Down Hole:** A line connects the Subsea Tree to the seabed, passing through a SCSSV (Safety Control and Shut-in Valve).

1. IWOCs/utilities supplied from surface vessels(s).
2. Wellbore access via jumper(s) from SSM to a production/distribution manifold or directly into the subsea tree.
3. SSM, Subsea Pumping Package and Subsea Fluid Storage may be separate subsea deployed packages or integrated into two or a single deployed package.

## 4.2 System Design

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components are suited for their intended use as specified by end user.

System design shall be based on the requirements given in the design basis and in the system definition. The system design shall as a minimum be documented in terms of the following:

- a) system design specification comprising the system's operational, functional and capacity requirements;
- b) system drawings;
- c) component design specifications;
- d) material selection;
- e) global analysis of fluid conduit system and equipment suspended in the water column as per API RP 17G1;
- f) FMEA or FMECA;
- g) subsea safety module system hydraulic analysis including emergency shutdown and disconnect response times;
- h) Verification and validation plan

### 4.3 Risk Assessment

Quantitative and qualitative risk analysis may be conducted to provide an estimation of the overall risk to health and safety, environment and assets and typically includes the following:

- 1. As per API RP 17G1.
- 2. HAZID;
- 3. HAZOP;
- 4. assessment of probabilities of failure events;
- 5. accident developments;
- 6. consequences assessment;

NOTE Legislation in some countries requires risk analysis to be performed, at least at an overall level to identify critical scenarios that might jeopardize the safety and reliability of the subsea pumping well intervention system.

### 4.4 Design Principles

SPWIS's system design shall be in accordance with API RP 17G1 and seek to eliminate or reduce hazards in lieu of hazard management or controls.

Common cause failures shall be identified, and measures shall be implemented to reduce their probability of occurrence or consequences.

On loss of control,

- a) all safety functions shall achieve a safe state;
- b) all well control devices designated as safety function class shall achieve a safe state;

For all operations, the system design shall account for the combinations of functional, environmental, and accidental loads, which can be predicted to occur simultaneously. It shall be documented that during the development of any identified accidental events that the subsea pumping well intervention system is unable to transmit forces of such magnitude as to compromise the well barriers.

## 4.5 Operational Principles

The subsea pumping well intervention system should be operated in accordance with the requirements specified in API RP 17G1 and the guidance given in API RP 17G5.

All activities associated with the subsea pumping well intervention system shall be conducted in such a manner that single failures shall not lead to an unacceptable risk to personnel safety, the environment and to loss of financial assets. This applies both to operational errors and to failure of equipment used directly in operations, as well as equipment used for auxiliary functions.

The operation of the subsea pumping well intervention systems shall be limited by the weakest component in the system.

NOTE This requirement is applicable to component rated working pressure, fluid conduit design pressure, design temperature class and allowable external loads.

## 4.6 Safety Strategy

The developed safety strategy shall be used in the design and operation of subsea pumping well intervention systems, in particular with API RP 17G1.

- a) The safety strategy should review the existing hardware and hardware being put in place to assure there is sufficient independence between protection layers (barriers) to the extent that the safety integrity of the protection layer (barrier) is not compromised by another, nor potential single point failures cause a cascade of successive failures.
- b) The safety strategy shall be used to guide the design of the system for the safety functions within the subsea pumping well intervention system. The safety strategy for subsea pumping well intervention systems, shall as a minimum address:

- PSD - stop pumping operations and closure of a surface barrier,

- ESD - close subsea barrier valves,
  - EQD - close subsea barrier valves, disconnect of attachment(s) from the subsea packages, and closure of the retaining device below the vertical fluid conduit.
- c) Periodic testing to demonstrate the safety functions availability as suggested by API RP 17G1.
- d) Systems using coiled tubing or other fatigue sensitive fluid conduits to convey process fluids should have a fatigue management system including records of use.

**Table-1 Definition of minimum safe state for safety functions**

Safety function	Barrier and surface facility safe state	Description of safety function	Operational modes	Intervention system safe state
PSD <sup>a</sup>	<ul style="list-style-type: none"> <li>— Shut down pumping operations.</li> <li>— Establish surface barrier.</li> </ul>	<ul style="list-style-type: none"> <li>— Isolate fluid conduit topside by closing surface valve(s).</li> </ul>	<ul style="list-style-type: none"> <li>— Surface to Seafloor Fluid Conveyance Mode.</li> <li>— Seafloor Fluid Conveyance Mode.</li> </ul>	<ul style="list-style-type: none"> <li>— Closed surface valve(s).</li> </ul>
ESD	<ul style="list-style-type: none"> <li>— Isolate well subsea.</li> <li>— Establish secondary well barrier.</li> </ul>	<ul style="list-style-type: none"> <li>— Isolate fluid conduit from the well/reservoir by closing the barrier valves in subsea safety module.</li> </ul>	<ul style="list-style-type: none"> <li>— Surface to Seafloor Fluid Conveyance Mode</li> <li>— Seafloor Fluid Conveyance Mode.</li> </ul>	<ul style="list-style-type: none"> <li>— Well isolated at the subsea safety module.</li> </ul>
EQD	<ul style="list-style-type: none"> <li>— Isolate well subsea.</li> <li>— Establish secondary well barrier.</li> <li>— Disconnect intervention vessel from subsea safety module.</li> </ul>	<ul style="list-style-type: none"> <li>— Isolate fluid conduit and disconnect from the subsea safety module.</li> </ul>	<ul style="list-style-type: none"> <li>— Surface to Seafloor Fluid Conveyance Mode</li> <li>— Seafloor Fluid Conveyance Mode.</li> </ul>	<ul style="list-style-type: none"> <li>— fluid conduit isolated by retainer valve</li> <li>— well isolated by subsea safety module</li> <li>— fluid conduit disconnected from subsea safety module at subsea connector.</li> </ul>
<sup>a</sup> PSD functionality is required when pumping out of the well and fluids are being “processed”.				

**Table-2 Automatic safe state for well control devices following loss of control**

Event	Pressure control device	Barrier safe state	Operational modes	Intervention system safe state
Loss of primary control to the SSM while connected subsea <sup>a</sup>	Surface	<ul style="list-style-type: none"> <li>Establish surface well barrier.</li> </ul>	<ul style="list-style-type: none"> <li>Surface to Seafloor Fluid Conveyance Mode</li> <li>Seafloor Fluid Conveyance Mode</li> </ul>	<ul style="list-style-type: none"> <li>Closed surface valve(s)</li> </ul>
	Subsea	<ul style="list-style-type: none"> <li>Well remains isolated due to not being opened to the environment during operations.</li> <li>Establish subsea well barrier if pressure envelope is lost.</li> </ul>	<ul style="list-style-type: none"> <li>Surface to Seafloor Fluid Conveyance Mode</li> <li>Seafloor Fluid Conveyance Mode</li> </ul>	<ul style="list-style-type: none"> <li>Well is always isolated by a pressure envelope from reservoir to the surface barrier.</li> <li>Disconnect system remains connected and incorporates an Auto Shut In feature if the vertical conduit is disconnected.</li> <li>Retainer valve provides containment of vertical fluid conduit during a disconnect event.</li> </ul>
Unintentional fluid conduit disconnect <sup>b</sup>	Surface	<ul style="list-style-type: none"> <li>Isolation of well topside.</li> <li>Establish surface well barrier.</li> </ul>	<ul style="list-style-type: none"> <li>Surface to Seafloor Fluid Conveyance Mode</li> <li>Seafloor Fluid Conveyance Mode</li> </ul>	<ul style="list-style-type: none"> <li>Closed surface valve(s) <sup>c</sup></li> </ul>
	Subsea	<ul style="list-style-type: none"> <li>Automatic isolation of well subsea.</li> <li>Establish subsea well barrier if pressure envelope is lost.</li> </ul>	<ul style="list-style-type: none"> <li>Surface to Seafloor Fluid Conveyance Mode</li> <li>Seafloor Fluid Conveyance Mode</li> </ul>	<ul style="list-style-type: none"> <li>Well isolated at subsea SSM <sup>b,c,d</sup>.</li> <li>Retainer valve provides containment of the vertical fluid conduit during a disconnect event.</li> </ul>



<sup>a</sup>Deadman functionality is required when the vertical fluid conduit is rigidly attached to the SSM (i.e. requiring an EDP). Riserless systems with an operated wink link connector do not require Deadman functionality due to the ability to continuously maintain a pressure envelope.

<sup>b</sup> Auto Shut-In functionality shall ensure automatic subsea isolation following a disconnect of the weak link connector.

<sup>c</sup> Well control devices that require stored power to isolate well for applicable operational modes following loss of control shall be equipped with power storage independent of top side supply.

<sup>d</sup> Disconnect of fluid conduit connector system may be a weak link or actuated design.

## 4.7 Barrier Requirements

Barrier philosophy and requirements shall be in accordance with API RP 17G1. For all operations, a barrier philosophy shall be established and implemented to meet the regulatory requirements under which the subsea pumping well intervention system shall be operating.

As a minimum the system shall have the following:

- At least two independent and testable barriers between the reservoir and the environment shall be available to prevent unintentional flow from the well. These barriers may be located in the subsea safety module or in the subsea tree. The barriers shall be testable when installed on the well.
- Both barriers cannot be disabled by a single point failure of a piece of the intervention system.
- The barriers shall not be compromised upon disconnect of any attachments.
- The barrier elements located on the subsea safety module shall have ROV or diver override capability.
- Additional assurances are required when a well barrier envelope extends beyond the mechanical interfaces installed directly on the well. The user shall demonstrate that the design, testing, operation, and risk of damaging any system components between the well and the remote located well barrier device have been mitigated and is fit for purpose.
- No “barrier elements” located downstream (i.e., in the direction of flow from the well bore) from the subsea safety module are considered barriers unless they are testable and remain connected to the subsea architecture upon disconnect of the fluid conduits and/or any other attachments.
- System shall contain a retainer valve or other sealing device to retain fluid in the vertical fluid conduit upon disconnect.

- Testable barrier valve(s) should be located on the surface intervention vessel between the vertical fluid conduit and the surface process and pumping systems.
- The disconnect between the intervention vessel and the subsea pumping well intervention system shall be located upstream of the two barriers when pumping into the subsea well and downstream of the two barriers when pumping out of the subsea well.

## 4.8 Regulations, Codes and Standards

The subsea pumping well intervention system shall comply with the applicable regulatory requirements for the regions in which the system will be operated. User/operator shall specify the regulatory jurisdictions in which the system is intended to operate.

The subsea pumping well intervention system equipment included in the scope of API RP 17G2 shall be designed, manufactured, and tested in accordance with the references, codes and standards specified in API STD 17G (see Table 3).

Components which are outside the scope of this recommended practice, and have an influence on the design, manufacture, test and operation of the subsea pumping well intervention system shall be accounted for to ensure overall system safety. In particular, equipment supplied in accordance with component standards (e.g., API 6A, API 14A, API 16ST, API 17D and API 17K) are designed and qualified for designated sizes and rated working pressures only (i.e. pressure-based design). For subsea pumping well intervention system applications, it is normal industry practice to ensure that the load combinations determined in API STD 17G (i.e., normal, extreme and accidental loading conditions) do not exceed the rated capacity [i.e., normal capacity] of pressure based designed equipment.

NOTE References to Clause and Annexes given in Table 3 are references to Clauses and annexes in API STD 17G, 3<sup>rd</sup> Edition.

**Table 3 — Equipment References, Codes and Standards**

Subsea pumping well intervention System Components	Functional Requirements	Design Requirements	Materials and Manufacturing Requirements	Component Qualification Testing	System Integration Testing
Intervention Fluid Storage System	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Pumping Package	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Pumping Manifold	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Interconnecting Piping	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Fluid Conduit - Rigid	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Fluid Conduit - Flexible	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8

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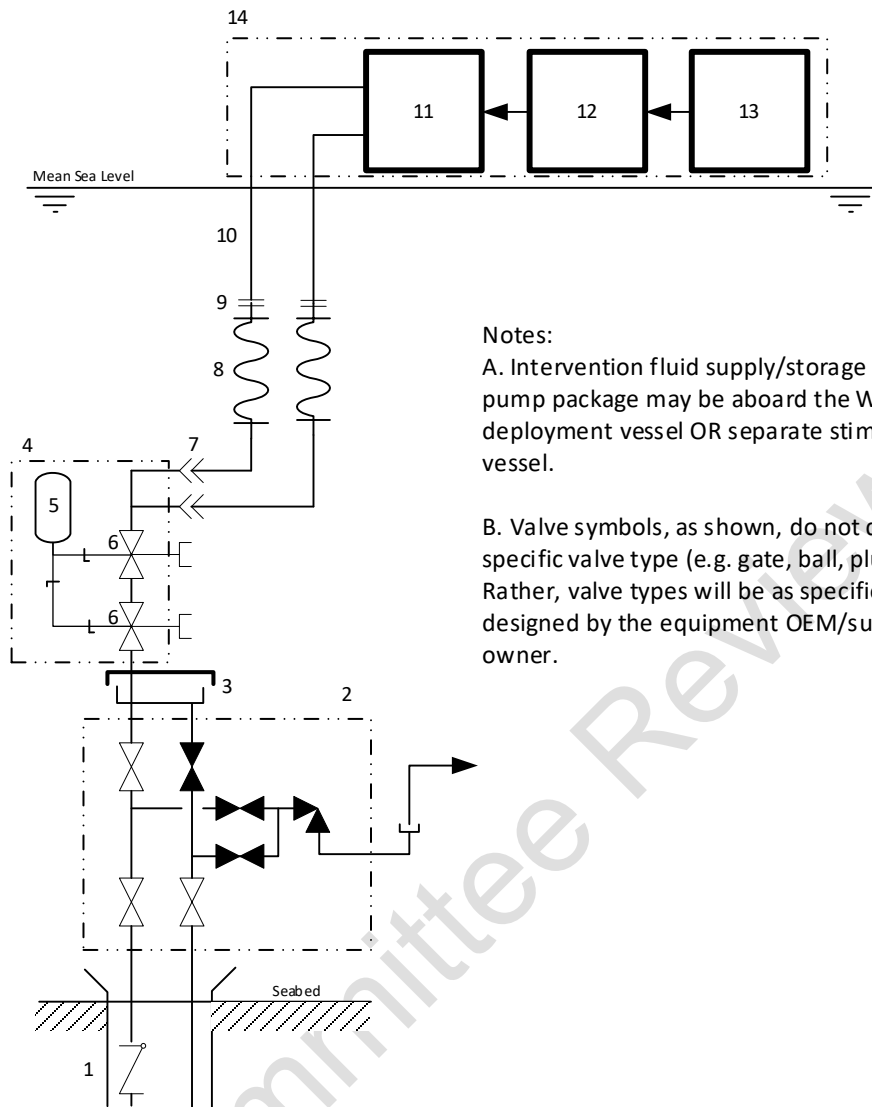
Fluid Conduit – Spooled	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Fluid Conduit - Segmented	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Fluid Conduit – Carbon Steel	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Fluid Conduit – Composite	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Downlines	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
IWOCS	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Process Package	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8
Subsea safety module barriers	Clause 5	Clause 6	Clause 7	Clause 8 Annex L	Clause 8 Annex L
Disconnect System	Clause 5	Clause 6	Clause 7	Clause 8	Clause 8

## 5 Functional Requirements

### 5.1 Purpose

Clause 5 specifies the functional requirements for the individual types of equipment included in a SPWIS (see Figure 3 and Figure 4). Each equipment type is defined in terms of its function and system interfaces.

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Notes:

A. Intervention fluid supply/storage and/or pump package may be aboard the WCP deployment vessel OR separate stim/frac vessel.

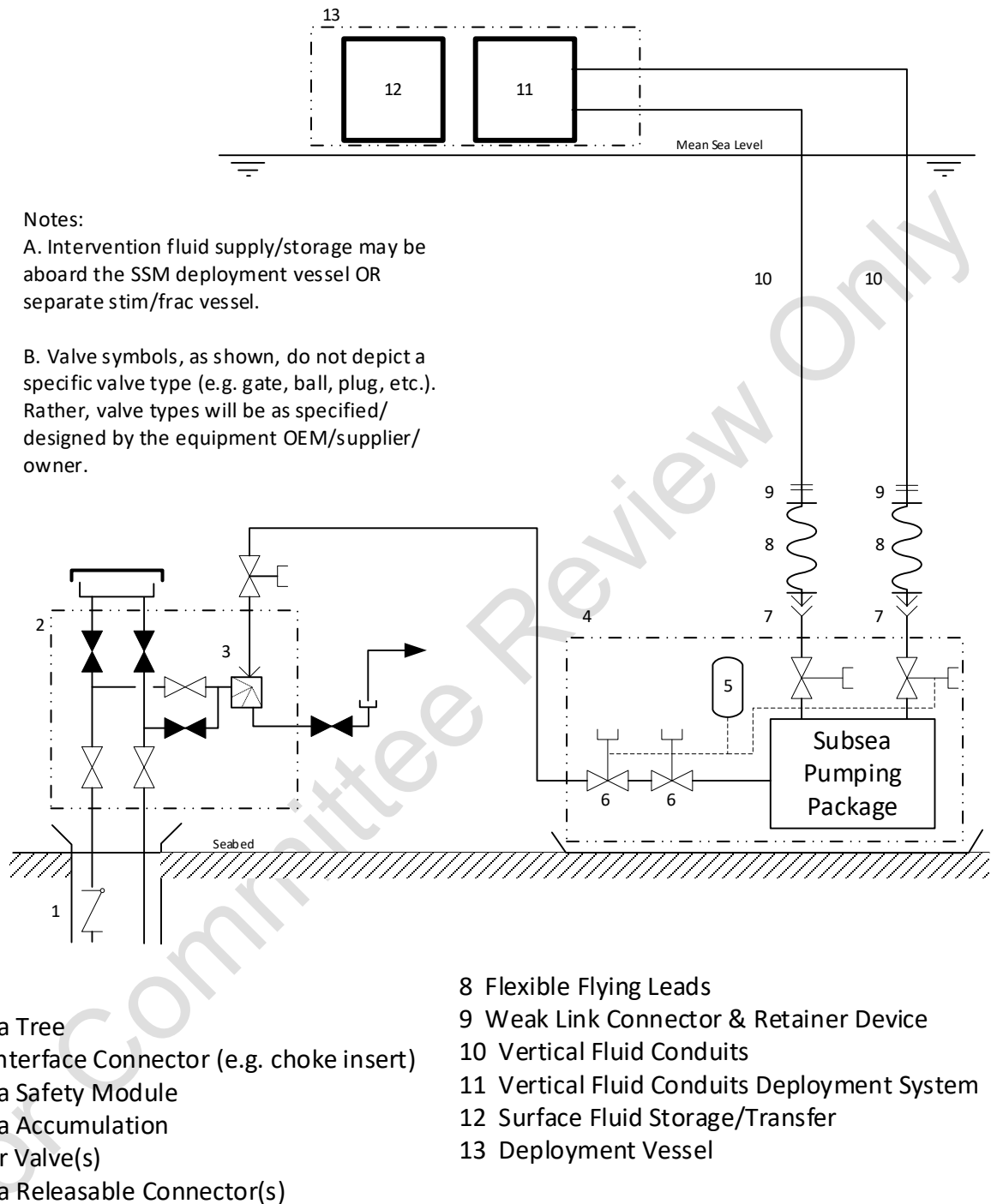
B. Valve symbols, as shown, do not depict a specific valve type (e.g. gate, ball, plug, etc.). Rather, valve types will be as specified/ designed by the equipment OEM/supplier/ owner.

- 1 SCSSV
- 2 Subsea Tree
- 3 Tree Interface Connector
- 4 Subsea Safety Module
- 5 Subsea Accumulation
- 6 Barrier Valve(s)
- 7 Subsea Releasable Connector(s)

- 8 Flexible Flying Leads
- 9 Weak Link Connector & Retainer Device
- 10 Vertical Fluid Conduits
- 11 Vertical Fluid Conduits Deployment System
- 12 Surface Pumping Package
- 13 Surface Fluid Storage
- 14 Deployment Vessel

**Figure 3—Surface to Seafloor Fluid Conveyance Mode with Pump Located at Surface**

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**Figure 4— Surface to Seafloor Fluid Conveyance Mode with Pump Located Subsea**

## 5.2 Common Component and System Requirements

In addition to the requirements listed in API STD 17G, the following requirements are specified for the subsea pumping well intervention system:

- a) All equipment that can be subject to pressure differential (i.e., from hydrostatic head or internal pressure greater or lower than ambient) shall be fully functional at rated pressures as designated by API RP 17G1;
- b) Allow passage of fluid through the single or multiple bores of the subsea tree from the pumping package;
- c) Provide a conduit to contain all fluids for the application and permit their circulation to and from the Subsea Safety Module;
- d) The system shall be maintainable. All parts of the system intended for maintenance shall be capable of being safely dismantled. Trapped volumes with potential pressure shall have a means to be safely evacuated;
- e) The system shall function as designed when in use with all chemicals and hydrocarbons that system is intended to be used;
- f) The system shall be able to apply closure to a minimum of two testable barriers between the reservoir and the environment in both normal and emergency operating conditions (ESD);
- g) The system shall be able to disconnect from the Subsea Safety Module in both normal and emergency operating conditions (i.e., an EQD);
- h) The EQD shall close the subsea barrier valves and disconnect the vertical fluid conduits;
- i) The EQD shall function under the highest expected loading conditions;
- j) A weak link connector disconnect resulting from a loss of station keeping or similar unplanned event shall automatically initiate an Auto Shut In function;
- k) A retaining device shall retain fluid in the vertical fluid conduit upon disconnect from the Subsea Safety Module;
- l) During installation, operation, and emergency situations the forces transmitted to the subsea infrastructure should not exceed the weakest component as demonstrated by a weak point analysis. These allowable forces shall be as recommended in API STD 17G, Annex B;
- m) System should allow full functionality of barrier elements to allow pressure and/or function testing or maintenance;
- n) The system shall not be able to expose parts of the system to undue pressures that may cause harm or damage to the system;
- o) A means to depressurize and flush the system safely following an emergency disconnect event shall be incorporated;
- p) The system shall contain protection from over pressurization from the pumping package.

### 5.3 Subsea Safety Module

Functions of the subsea safety module (see Figure 5, Figure 6, and Figure 7) are to serve as the manifold between the subsea conduit system and the subsea tree / wellbore access point; and may provide a place to locate barrier devices to isolate the well bore from the environment.

A subsea safety module may typically include the following components:

- a) foundation or tree connector,
- b) well access interface connector,
- c) ROV/Diver interfaces,
- d) control system,
- e) disconnect system,
- f) barrier valve(s),
- g) subsea releasable connector and/or weak link connectors.

The subsea safety module may be configured as a single unit or as a sectioned unit and may be equipped with an upper re-entry spool interface for a connector. A sectioned unit is one in which barrier devices; attachment interfaces for controls or fluid conduits, and/or piping may be physically located in more than one structure.

The primary structure must adequately support the elements of the entire subsea safety module including the tree interface connector, adapters, and subsea conduit connector system during all phases of operation including deployment, operation, and recovery;

Subsea safety module barrier valves should have a means to indicate valve position observable by ROV/diver

[illegible]

A. Valve symbols, as shown, do not depict a specific valve type (e.g. gate, ball, plug, etc.). Rather, valve types will be as specified/ designed by the equipment OEM/supplier/ owner.

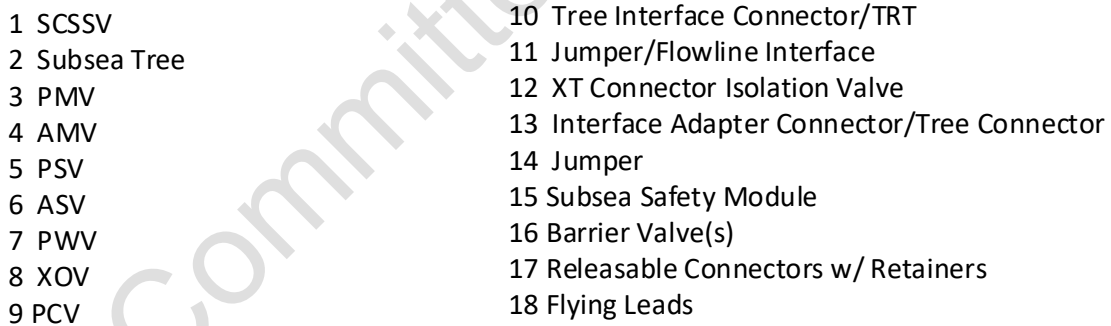
- |               |                                      |
|---------------|--------------------------------------|
| 1 SCSSV       | 8 PWV                                |
| 2 Subsea Tree | 9 PCV                                |
| 3 PSV         | 10 Jumper/Flowline Connector         |
| 4 PMV         | 11 Tree Interface Connector/TRT      |
| 5 ASV         | 12 Subsea Safety Module              |
| 6 AMV         | 13 Barrier Valve(s)                  |
| 7 XOV         | 14 Releasable Connectors w/ Retainer |
|               | 15 Flying Leads                      |

**Figure 5—Subsea Safety Module Interfaced with Vertical Tree Configuration**



[illegible]

A. Valve symbols, as shown, do not depict a specific valve type (e.g. gate, ball, plug, etc.). Rather, valve types will be as specified/ designed by the equipment OEM/supplier/owner.

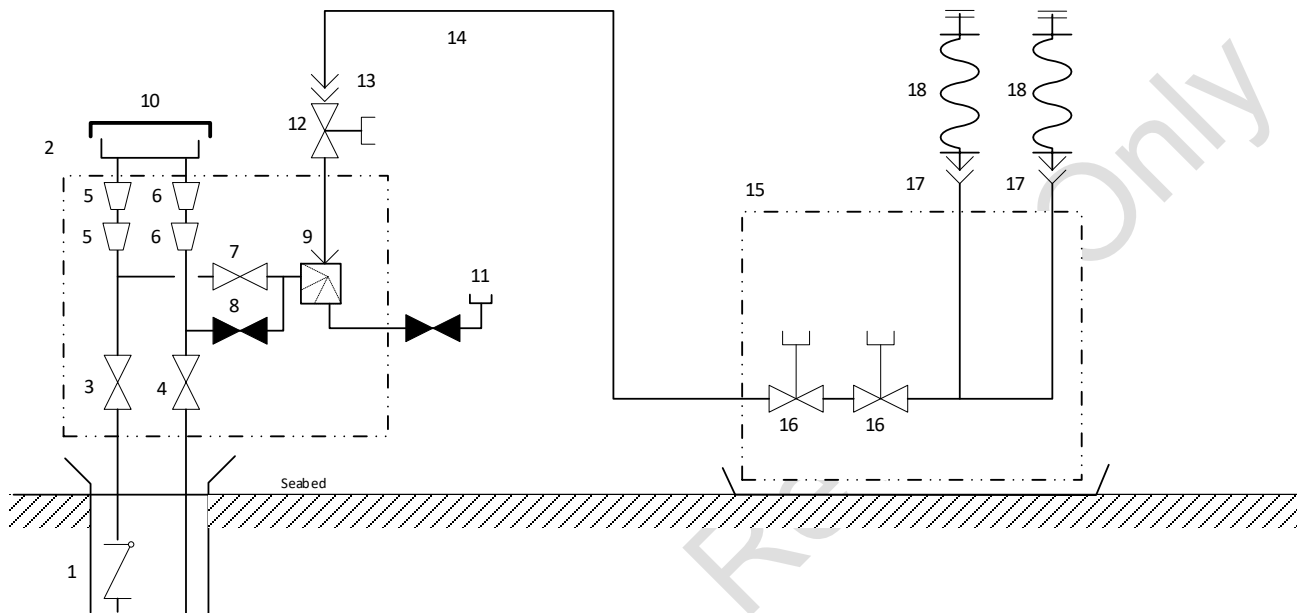


**Figure 6—Subsea Safety Module on Skid Interfaced with Vertical Tree Configuration**

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**Notes:**

A. Valve symbols, as shown, do not depict a specific valve type (e.g. gate, ball, plug, etc.). Rather, valve types will be as specified/ designed by the equipment OEM/supplier/owner.



- |                              |   |
|------------------------------|---|
| 1 SCSSV                      | 10 XT Cap   |
| 2 Subsea Tree                | 11 Jumper/Flowline Interface                        |
| 3 PMV                        | 12 Choke Isolation Valve                            |
| 4 AMV                        | 13 Choke Interface Adapter Connector/Tree Connector |
| 5 Production ITC/Crown Plugs | 14 Jumper   |
| 6 Annulus ITC/Crown Plugs    | 15 Subsea Safety Module                             |
| 7 PWV                        | 16 Barrier Valve(s)                                 |
| 8 XO                         | 17 Releasable Connectors w/ Retainers               |
| 9 Choke Interface Adapter    | 18 Flying Leads                                     |

**Figure 7—Subsea Safety Module Interfaced with Tree Choke Configuration**

## 5.4 Subsea Control System

### 5.4.1 General

The function of the subsea control system is to provide control and monitoring of the system in both normal operations and emergency situations. The subsea control system should perform in a manner which is efficient, safe, and protects personnel, ROV, subsea assets, the intervention vessel, and the environment.

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The following functional requirements apply to the subsea control system:

- The SPWIS shall be operated by the intervention vessel or jointly with Host Facility providing some control functions with the limitation of a minimum of two subsea barrier devices to be operated by the intervention vessel.
- The SPWIS shall have ESD, EQD, and Auto Shut-In capability.
- The ability to function the subsea safety module barrier devices upon operator command from the intervention vessel shall be available.
- An EQD control function as defined by API RP 17G1 only if the EQD connector is activated by the control system. The function will close the barrier valves and disconnect the connector in the proper sequence. If the SPWIS is designed to disconnect in an emergency via a weak link connector then only ESD and Auto Shut-In functions are required.
- Barrier device closure and flying lead connectors shall have ROV or diver operation capability.
- The SPWIS shall be able to close at least one barrier and disconnect from the well in the event of any control system component failure.
- If accumulators are used, there shall be a method to monitor accumulator status and recharge the system at depth.

#### **5.4.2 Primary and Back-up Control Systems for Normal and ESD Operations**

The following types of control systems are suitable for normal and ESD operations:

- IWOCs systems as per API RP 17G5
- ROV mechanical driven system
- ROV hydraulic driven system
- acoustic controlled subsea hydraulic system
- tree production control system
- proximity based mechanical / hydraulic system (i.e., mechanical load triggered ESD activation or a signal to a hydraulic triggered ESD when a proximity limit is reached).
- combination of the above

#### **5.4.3 Acoustic Control Systems**

Acoustic signal transmission may be used as a means for operating the SPWIS control system.

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The acoustic control system includes a surface electronics package, subsea electronic package and a subsea electro-hydraulic package.

The following functional requirements apply to acoustic control systems:

- The acoustic control system should be designed such that the electric control system functions can be tested without actuation of the ESD functions.
- Hydraulic components and piping systems should have a rated working pressure at least equal to the rated working pressure of the control system.
- The acoustic control electronic system should utilize security command signal coding to prevent operation by other equipment in close proximity.
- A frequency management plan shall be used to avoid interference with other equipment on and in the vicinity of the intervention vessel.
- Water depth and slant range capacity shall meet operational parameters.
- Two (2) actions shall be required to initiate the function(s) (i.e., actuate the “arm” function and actuate the “activity” control function).
- Subsea battery power to operate the acoustic control system shall be capable of sustaining operation for the anticipated time of deployment.
- A low battery alarm shall be provided.
- The entire acoustic control system shall be able to be tested on deck and at operating water depth.

## **5.5 Fluid Conduit Connectors**

### **5.5.1 Subsea Releasable Connectors**

The focus of this section pertains to the connector system that provides the interface between the subsea safety module and flying lead connected to the vertical conduit. Subsea releasable connectors can either be active operated (i.e., requiring human intervention to command functioning of the connector) or be a weak link (i.e., no human intervention involved with disconnecting of connector). The function of the subsea connector is to provide a subsea releasable connection. The release function of the connector should be designated in the system design basis to identify the functional requirements.

The following functional requirements apply to fluid conduit connectors:

- Connect and disconnect the flying lead to the subsea safety module subsea during installation and retrieval of the system;
- It may perform an active operated EQD function or the EQD function could be performed by

another device in the system such as a weak link connector;

- Shall be releasable from the subsea safety module at all expected angles of release and at all expected loading conditions as established through global riser analysis;
- The connector may or may not incorporate a retainer valve functionality (see Clause 5.6).
- The connector design and construction shall be fit for the anticipated well intervention activities. The connector (metallurgy, seals, etc.) shall be compatible for the service duration with all the chemicals that it will be exposed to;
- The connector rated working pressure shall be the same or higher than the SPWIS rated working pressure;
- The subsea connector shall perform to the standards set in API 17G, Annex E as applicable.
- Connectors that are designed to be subsea reconnect-able should incorporate reusable or replaceable seals when susceptible to seal damage;

### 5.5.2 Riserless System Weak Link Connectors

Riserless system weak link connectors are usually located between the flying lead connected to the subsea safety module and the vertical conduit. These connectors do not require human intervention to initiate a connector disconnect event. The function of the weak link connector is to provide a subsea releasable weak link that is triggered passively. In many cases, these connectors integrate a retainer valve functionality with the connector, but it is not required that this dual functionality be present in the connector design.

NOTE: Requirements for a weak link are contained in API STD 17G, 3<sup>rd</sup> Edition, Annex B.

The following functional requirements apply to riserless system weak link connectors:

- The passive functionality should be triggered by tension in the fluid conduit (i.e. not by human action) applied to the connector that results from a vessel loss of station of a predefined proximity;
- The connector must be designed to disconnect at a preset/designed mechanical load or input consistent with the system behavior during a vessel loss of station or other accidental loading, to prevent undesirable forces from being transferred to the fluid conduit and/or the subsea safety module.
- The connector must be designed to be the weakest link between the vertical fluid conduit and the subsea safety module as it pertains to the required load necessary to disconnect.

## 5.6 Retainer Valve or Retainer Device

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A retaining valve or other sealing device shall be included to retain the fluid in the vertical fluid conduit after disconnect and meet the following functional requirements:

- Shall be designed with a rated working pressure to retain full conduit pressure at the time of disconnect;
- Shall activate at the time of disconnect to minimize the discharge of fluids.

## **5.7 Subsea Pumping Equipment**

The following functional requirements apply to subsea pumping equipment:

- Subsea pumping control systems should be incorporated in to the ESD and EQD philosophy to prevent continued pumping after an ESD or EQD event.
- Subsea pumping equipment shall not impose loads to the subsea safety module or to existing well interface in the event of intervention vessel drive / drift off.
- If the subsea pumping equipment is connected to a surface intervention vessel by vertical fluid conduit, control umbilical, or power umbilical and can be damaged by intervention vessel drive / drift off then it shall incorporate the same EQD functionality as the subsea safety module.
- If the subsea pumping equipment is electrically powered and an EQD is incorporated, then the control system should shut down all electrical power to the subsea pumping equipment prior to the release of the electrical umbilical.
- If electrically powered, the system shall be intrinsically safe to divers, surface personnel, and ROV.

## **5.8 Subsea Intervention Fluid Storage**

The following functional requirements apply to subsea intervention fluid storage:

- Subsea fluid storage equipment should be designed with an appropriate structure and foundation that can adequately support the combined weight of the package and intended contents at full capacity;
- Subsea fluid storage equipment shall be pressure balanced with ambient pressure during deployment and recovery;
- Subsea fluid storage equipment shall be compatible with all chemicals or hydrocarbons anticipated in its use;
- Subsea fluid storage equipment shall have two functional methods to alleviate net differential hydrostatic pressure at any point in the water column or on deck;
- Subsea fluid storage equipment shall have a means in which to fill or de-inventory the system;

- Subsea fluid storage equipment shall be able to be flushed and cleaned internally without risk to personnel or the environment;
- Subsea fluid storage equipment shall have a method to isolate the contents subsea and on the surface;
- Subsea fluid storage equipment isolation valves shall be able to be controlled subsea;
- If the subsea fluid storage equipment is connected to a surface intervention vessel by vertical fluid conduits, control umbilical, or power umbilical and can be damaged by intervention vessel drive / drift off then it shall incorporate the same EQD functionality as the subsea safety module.

## 5.9 Vertical Fluid Conduits

This Clause refers to fluid conduit connecting a surface intervention vessel to the subsea safety module, subsea pumping equipment, or subsea fluid storage equipment.

Vertical fluid conduits allow fluids to be safely pumped from the surface equipment the subsea safety module. They are exposed to both internal pressure and external pressure. Internal pressure can be as high as the equipment maximum allowable test pressure, while external pressure can approach the ambient seawater pressure at the maximum reach of the conduit.

Vertical fluid conduits may be comprised of jointed pipe; semi-ridged products such as carbon steel coil tubing, composite coiled tubing; bonded products, or various hoses.

Vertical fluid conduits may be made up of different types of materials to fit environmental factors such as intervention vessel movement or depth, and other job requirements.

Typically, subsea conduits incorporate a flexible flying lead to aid in ease of handling subsea or to absorb intervention vessel movement.

The following functional requirements apply to vertical fluid conduits:

- Vertical fluid conduits shall conform to the common functional requirements found in API STD 17G, Clause 5
- The vertical fluid conduit plus any attachments during operating or deployment conditions must be self-supporting in the water column when suspended from a work platform. The use of secondary tensile members such as clamping to wire may be considered. If secondary tensile members are utilized, they shall be risk assessed to ensure the vertical fluid conduit arrangement remains self-supporting in all perceived operational scenarios.

## 5.10 Vertical Conduit Deployment and Recovery System

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Subsea conduit deployment and recovery systems primary function is to safely deploy, recover, and interface the subsea conduit to the surface pumping and processing system.

The following functional requirements apply to vertical conduit deployment and recovery systems:

- Shall be able to recover conduits when the conduit is filled with the heaviest fluid used.
- Shall contain the conduit at all times in the event of loss of tension control.
- Shall maintain the conduit within the allowable minimum bend radius.
- Reel process piping and components, which may include swivels, valves, instrumentation shall meet or exceed the MAOP of the conduit.
- System shall be designed to withstand the dynamic forces induced by intervention vessel motion. Particular consideration should be given to the point of over boarding of the conduit.
- Consideration should be given to an isolation philosophy that will allow repair of sealing components that could fail during operations, i.e. fluid swivels, seals, etc.
- Operator controls shall be in a safe location that is removed from potential hazards such as; high pressure leaks and parting of the conduit.
- Deployment and recovery system should have appropriate equipment or device(s) to allow proper management of conduit fatigue and deployment length.

## 5.11 Flying Leads

Flying leads connect the vertical conduits to the equipment located on the seafloor. Typically, they consist of single or multiple hoses with a single connector at each end. Functionally they enable a diver or ROV to manipulate a lighter and more flexible conduit than the vertical conduit when connecting to the subsea safety module. The flying lead also provides heave compensation capability to the conduit system and allows the intervention vessel a certain amount of maneuvering capability.

The following functional requirements apply to flying leads:

- Shall be rated for the maximum anticipated pressure to be encountered during the specific intervention task.
- Collapse rating should be considered when the flying lead may be subjected to sub-hydrostatic conditions.
- Shall be compatible with all chemicals or hydrocarbons anticipated in its use.

## 5.12 Jumpers

Jumpers are the fluid conduits between the various subsea equipment packages.



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The following functional requirements apply to jumpers:

- Shall be rated for maximum pressure of the entire system
- Shall be capable of handling max flow rate of the system
- Shall be pressure tested with entire system prior to initial operations
- The jumper between the subsea safety module and the tree shall be protected from over-pull from intervention vessel drive off situation

## **6 Design Requirements**

### **6.1 General**

This clause specifies requirements for design of Subsea Pumping Well Intervention Systems and associated components inclusive of pressure containing, pressure controlling and load-bearing components. Requirements include, but are not limited to:

- a) structural design of components;
- b) determination of component capacities;
- c) determination of loads;
- d) load effect analysis;
- e) code check, interference check, fatigue check;
- f) determination of operating limitations

### **6.2 Design Principles**

The unique configuration of Subsea Pumping Well Intervention Systems requires analysis and design techniques that differ from those contained in API STD 17G, however the requirements in Clauses 6.1 through 6.4 and the methods for the analysis and design of system components that are similar in nature, should be used.

The following requirements shall be included in the system design of SPWIS:

- Means shall be incorporated to ensure excessive loads are not transmitted into the subsea safety module that may compromise the structural and/or pressure containment integrity of the subsea safety module or permanent subsea equipment such as the subsea tree or

wellhead.

- There shall be at least one component, located between Vertical Fluid Conduits and the subsea safety module that is designated as a weak link and limits the transfer of excessive loads into the subsea safety module, fluid conduit connectors, permanently installed subsea equipment and any other mechanical attachments.
- Chemical and temperature compatibility of system components and conveyed fluid shall be assessed.

## **6.3 Global System Analysis**

### **6.3.1 General**

Global analyses should be performed as per API RP 17G1.

The subsea pumping well intervention system is characterized by smaller diameter fluid conduit that is not rigidly attached to a well control package and a more weather-sensitive multi-service intervention vessel as compared to a typical top tensioned intervention riser covered in API STD 17G. The following modifications and additions are recommended for subsea pumping well intervention systems:

### **6.3.2 Global Hydraulic Analysis**

Global hydraulic analysis is performed to verify the pumping system can deliver the required flow rate.

The analysis provides the system hydraulic profile, or flow rate versus pressure loss relationship along the fluid injection path from upstream chemical source tanks to downstream tree injection point.

Additionally, global hydraulic analysis should be used to identify sub-hydrostatic pumping conditions and drive verification of suitability of flexible conduits which are typically more prone to collapse.

### **6.3.3 Global Analysis**

Global analysis is performed to establish the behavior of the vertical fluid conduit(s), flying leads, downlines, rigid jumpers, and corresponding system boundary conditions. The analysis is used to provide the following data:

- Tension load in the vertical conduit(s) and flying leads, and loads imposed on the subsea safety module versus intervention vessel offset.
- Loads for the assessment of the weak link.
- Clashing conditions between the vertical fluid conduit(s) and the downlines.
- Clashing conditions between vertical fluid conduit(s) and the topside equipment (e.g., vessel hull).

- Bend radius vs intervention vessel offsets for the vertical conduit(s) and the flying leads.
- Harmonic or dynamic loads due to vessel heave during deployment or due to current-induced Vortex-Induced Vibration (VIV) and while connected subsea.
- Fatigue cycles at fatigue critical points along the fluid conduit system
- Evaluate for all flexible conduits for collapse pressures based on sub hydrostatic conditions that will be experienced during operations.

The above data is used in the selection of the conduit(s) and the final design of system components and connection devices.

API STD 17G should be used as a basis for the global analysis methodology and load case matrix.

#### **6.3.4 Computational Fluid Dynamics**

Computational fluid dynamics is performed to evaluate impact of transient flow on the equipment. The analysis provides the fluid characteristic and particle trajectory profile and the impact on the subsea equipment wall. Based on the time-variant stress function, any water hammer effects are better understood, and the erosion rate of equipment can be calculated. CFD analysis is recommended when the design basis calls for high flow rates or the use of abrasive fluids.

#### **6.3.5 Other System Analyses**

Other global analyses should be performed as per API RP 17G1.

### **6.4 Component Design Requirements**

#### **6.4.1 General**

Design requirements for the following components are covered in this Clause. Components not listed should adhere to API RP 17G1.

- vertical fluid conduits
- flying leads
- jumpers
- fluid conduit connectors
- rigid piping
- subsea control tubing and fittings
- isolation / well control valves

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- accumulator and pressure vessels
- pad-eyes and lifting devices
- ROV interfaces
- subsea equipment foundations and mud mats
- connectors other than fluid connectors
- retainer valves

## **6.4.2 Fluid Conduits**

### **6.4.2.1 General**

This clause defines design requirements for fluid conduits used to convey pumped fluids from an intervention vessel to the subsea safety module. The types of conduits typically used are:

- metallic coiled tubing
- rigid conduit such as OCTG (drill pipe)
- composite coiled tubing
- unbonded flexible pipe
- thermoplastic hose

### **6.4.2.2 Metallic Coiled Tubing**

The following design requirements apply to reeled coiled tubing that is deployed over a sheave or gooseneck/injector head type device.

- Coiled tubing shall conform to API 5ST.
- Suspended coil tubing has very limited axial compressive capacity. Deployment systems and interfaces to the subsea safety module or other equipment shall ensure that axial compressive loads are not applied to the suspended coil tubing.
- Shipping, handling and deployment apparatus for coiled tubing should limit the minimum bend radius of the coiled tubing to 48 times the coil tubing outside diameter in accordance with NORSOK D002. Apparatus may include product reels, sheaves, tubing injectors, deployment chutes and bend restrictors/limiters.

- The coiled tubing is highly stressed where it exits the deployment equipment. Spooling and unspooling of coiled tubing can result in a reduction of the yield strength up to 10% due to the Bauschinger Effect (per the note in API 5ST, Clause 6.2.1.3). As such, coiled tubing yield stress provided by the manufacturer shall be reduced by a factor of 10%. This reduction may be lessened or eliminated based on material testing of samples that have been subjected to reeling strains equivalent to at least 50% of the high stress fatigue limit of the coil material.
- Ovalization of the cross section and thinning of the tubing wall can result from multiple phenomena. These effects need to be considered when evaluating the ultimate strength of the tubing cross section.
- Two methods of estimating the strength of the coiled tubing cross section at the point where it leaves the sheave or injector head are recommended below. Additionally, the end user may use other methods to qualify the strength of a coiled tubing string by providing alternate calculations supported by material testing (See Annex B for example calculations and guidance).

Recommended Methods:

- Working Limit Curve as outlined in “Coiled-Tubing Pressure and Tension Limits,” written by K.R. Newman and D. Schlumberger presented at Offshore Europe Conference in September of 1991.
- Von Mises yield condition as outlined in the Coiled Tubing Manual by CTES.
- Coiled tubing used in subsea pumping operations accumulate fatigue damage from two sources: reeling and operation. Both types of fatigue damage should be accounted for when estimating the fatigue life limits of coiled tubing used as vertical conduits in subsea pumping operations. Recommended methods to account for both types of fatigue damage can be found in the following references (See appendix B for example calculations and fatigue modeling guidance):

#### **6.4.2.3 Rigid Conduit Requirements**

Design requirements for rigid fluid conduits that do not exceed plastic strain limits during the manufacturing process or during normal operations shall comply with the following:

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- OCTG (e.g., drill-pipe) shall comply with API STD 17G, Clause 5.5
- OCTG pipe shall have design loads specified by the manufacturer.
- Rated loads shall be checked against system loads produced via global analysis or mechanical testing.
- Design requirements shall be in accordance with Clause 5
- End connectors shall conform to API STD 17G, Clause 5.6
- Load capacity shall be in accordance with API STD 17G requirements

#### **6.4.2.4 Thermoplastic Composite Pipe Requirements**

The following design requirements apply to composite tubing and pipe fluid conduits. Design shall comply with requirements of 6.4, where applicable

- Structural design shall conform to DNVGL-ST-F119
- Design capacity/loads shall be specified by the manufacturer.
- Operational design capacity shall be validated by Global Riser Analysis

#### **6.4.2.5 Unbonded Flexible Pipe**

The following requirements shall apply to unbonded flexible pipe/hose fluid conduits.

Unbonded flexible pipe manufacturers may employ proprietary and differing design methodologies, materials and configurations than those specified below. Therefore, verification by an independent verification authority that review and certify the design methodology should be conducted for compliance with API 17J, Clause 5.2. The independent verification authority should have demonstrated expertise in verification of design of unbonded flexible pipe products.

Design Requirements:

- Design of unbonded flexible pipe consisting of metallic tensile and pressure armor shall conform to API 17J.
- Design of unbonded flexible pipe consisting of composite (non-metallic) tensile and pressure armor shall conform to API 17B and DNV-OS-C501
- Ancillary components as defined in API 17J should conform to API 17L1 and API 17L2
- Fluid conduit connectors shall conform to 6.4.4

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- End-fittings (e.g., clamp hubs, flanges) shall conform to an industry-recognized specification, where applicable
- Operational design capacity shall be validated by Global Riser Analysis

#### **6.4.2.6 Thermoplastic Hose**

The following requirements apply to “industrial” hose products only. Such products are generally manufactured from thermoplastic or rubber materials.

- Structural design capacity of end fittings and hose body shall be in accordance with API 17K.
- End fitting materials shall be compatible with all fluids, and mixtures thereof, that may come in contact with the fitting
- Shall be compatible with all operating temperatures
- Rated working pressure shall be the rated capacity, specified by the manufacturer, or the rated working pressure determined from combined global load effects determined by a global riser analysis.
- Operational design capacity shall be validated by Global Riser Analysis Jumper Requirements
- End user should design system to be collapse resistant if required (based on pumping requirements).

#### **6.4.2.7 Rigid pipe jumpers**

The follow applies to rigid pipe jumpers

- Design to ensure the jumper capacity meets operating, extreme and survival loading criteria (see API STD 17G, Annex C).
- Potentially high collapse pressures in deep-water applications, may induce ovalization and thinning of piping and should be assessed through detailed FEA to ensure integrity of the piping. The piping material in the bends can be very fabrication process dependent. Therefore, a specification and rigorous test program to confirm conformance to specification. Vendor/manufacturing process qualification may be required.

#### **6.4.2.8 Non-Traditional Pipe Types**

Non-traditional or new technology pipes can be used for subsea pumping operations if they meet the following design requirements:

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- The system/system components shall meet the requirements of any existing industry accepted standards (Example: DNV-OS-C501 for thermoset composite pipes).
- In the absence of an industry accepted standard, the manufacturer shall provide component design limits through material testing.
- Full system loads shall be derived through global analysis and checked against the manufacturers rated loads.
- The end user should perform detailed component level FEA for all end fittings and specialty components.
- The end user shall perform a SIT of end fittings and specialty components.

#### **6.4.3 Fluid Conduit Connectors**

Fluid conduit connectors are mechanical devices that provide a means for coupling fluid conduits to other fluid conduits or fluid conduits to the subsea safety module. Such connectors normally provide connect/disconnect functionality and may be installed by divers and/or an ROV.

The following design requirements shall apply to fluid conduit connectors:

- Shall conform to design requirements of 6.4 and API STD 17G, Clause 5.6
- ROV installed connectors shall conform to API 17H
- Means shall be incorporated that allow majority flushing of intervention fluids from within the connector assembly prior to disconnection
- Fluid and fluid pressure shall not become trapped within the connector assembly following disconnection
- Replaceable sealing elements should be located on the removable portion of the connector assembly. Thus, it is not required to retrieve the subsea safety module to replace connector seals
- Seal surfaces and sealing elements shall be protected from damage during connector deployment, installation, removal and retrieval operations

#### **6.4.4 Weak-Link Connectors**

Weak link connectors shall be designed with consideration to the following:



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- Weak Links shall be designed to disconnect at a maximum tensile value appropriate to ensure damage is avoided to the pumping well intervention system and interfacing subsea production system. Typical operational cases that should be considered include vessel drift-off, vessel drive-off and insufficient slack being available in the flying leads to account for typical dynamics seen in the vertical fluid conduit(s).
- Weak Links should be designed to disconnect at a minimum tensile value above typical tensile loads seen in operational and verified via global riser analysis.
- The tensile disconnect value of a weak link may be affected by operational conditions including, but not limited to, bore pressure and applied bending. The disconnect range of the weak link shall be verified in a manner representative of operational conditions.
- Upon disconnection, the weak link shall retain fluid on either side of the connection to avoid significant loss of fluid to the environment. In cases where the weak link is located in close proximity to barrier valves within the subsea safety module, retention of fluid in the downstream direction may be discounted if fluid lost upon disconnection remains less than 1 gallon per line.
- ROV installed weak links shall conform to API 17H
- ROV installed weak links should be designed in a manner that protects seal surfaces and sealing elements from damage during deployment, installation, removal and recovery operations.
- Weak links should be designed in a manner that allows safe flushing of contained fluids prior to maintenance.

#### **6.4.5 Rigid Piping**

Rigid piping shall conform to 6.4 and API STD 17G, Clause 5.5.

#### **6.4.6 Control Tubing and Fittings**

Control tubing and fittings:

- Shall conform to ASME B31.3 or other agreed upon piping code or standard
- Shall be of a rated working pressure equal to or greater than the design operating pressure of the control system
- Shall consider materials that mitigate internal and external corrosion
- Vibration-induced fatigue failure of control tubing systems and connections shall be considered
- All tubing runs shall be installed with sufficient and appropriate clamps

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- Design shall minimize possible seawater contamination of control lines

#### **6.4.7 Isolation and Well Control Valves**

Isolation and well control valves shall conform to API STD 17G, clause 5.4 and Annex I.

#### **6.4.8 Retainer Valves**

The purpose of the retainer valve is to serve as a barrier to the environment and contain the contents of the vertical fluid conduit in the case of a disconnect. The retainer valves shall be designed in accordance with API 14A and API 6A.

#### **6.4.9 Accumulators and Pressure Vessels**

The follow shall apply:

- All pressure-containing intervention vessels used for applications in excess of 15 psi shall conform to the ASME Boiler and Pressure Intervention vessel Code, Section VIII, Division 1; or BS EN 14359, or ISO 10945 or other agreed-upon pressure intervention vessel or accumulator code or standard
- Design shall consider and mitigate potential over-pressurization of filled or partially filled accumulators if recovered from subsea
- Should be located within the subsea safety module or other supporting structure in a manner that permits removal and maintenance of seals and bladders
- Accumulator system design shall consider the effect of water depth on accumulator size and shall size the accumulators as per API RP 17G5
- Should be mounted to the subsea safety module or other supporting structure in a manner that allows access for pre-charging and venting

#### **6.4.10 Pad-Eyes and Lifting Devices**

Pad-eyes and other lifting devices used for general handling and deployment of equipment shall be designed in accordance with API 17D, Annex K or DNV Standard 2.7-3.

#### **6.4.11 ROV Interfaces**

ROV interfaces shall conform to API 17H.

#### **6.4.12 Subsea Equipment Mud Mats and Foundations**

This clause provides design requirements for structural foundations used to temporarily place equipment on the seabed.

- Design shall conform to API 17A
- Design assessment and modeling should conform to API STD 17D.
- Stability analysis should be undertaken to verify foundation integrity under planned and unplanned events.

## **7 Material Requirements**

### **7.1 General**

All equipment used in subsea pumping operations shall conform to the material requirements defined in API STD 17G Clause 6. Additional requirements for specific component types are provided in the following subsections.

The material selection requirements are prescribed based on the assumption that no return of well fluid is allowed.

Fluid compatibility shall be considered for all components comprising a subsea pumping well intervention system. Intervention fluid shall be compatible with the intervention system and the existing well equipment (tree, manifold, etc.).

### **7.2 Surface Equipment**

The surface equipment is defined as pumping, storage, or deployment equipment staged on the vessel. Surface equipment is shown as items 23 and 11 in Figure 3 in Section 5.1. The vertical fluid conduit above the water line is not considered surface equipment. The surface equipment shall conform to the material requirements defined in API STD 17G Clause 6.

### **7.3 Vertical Fluid Conduits**

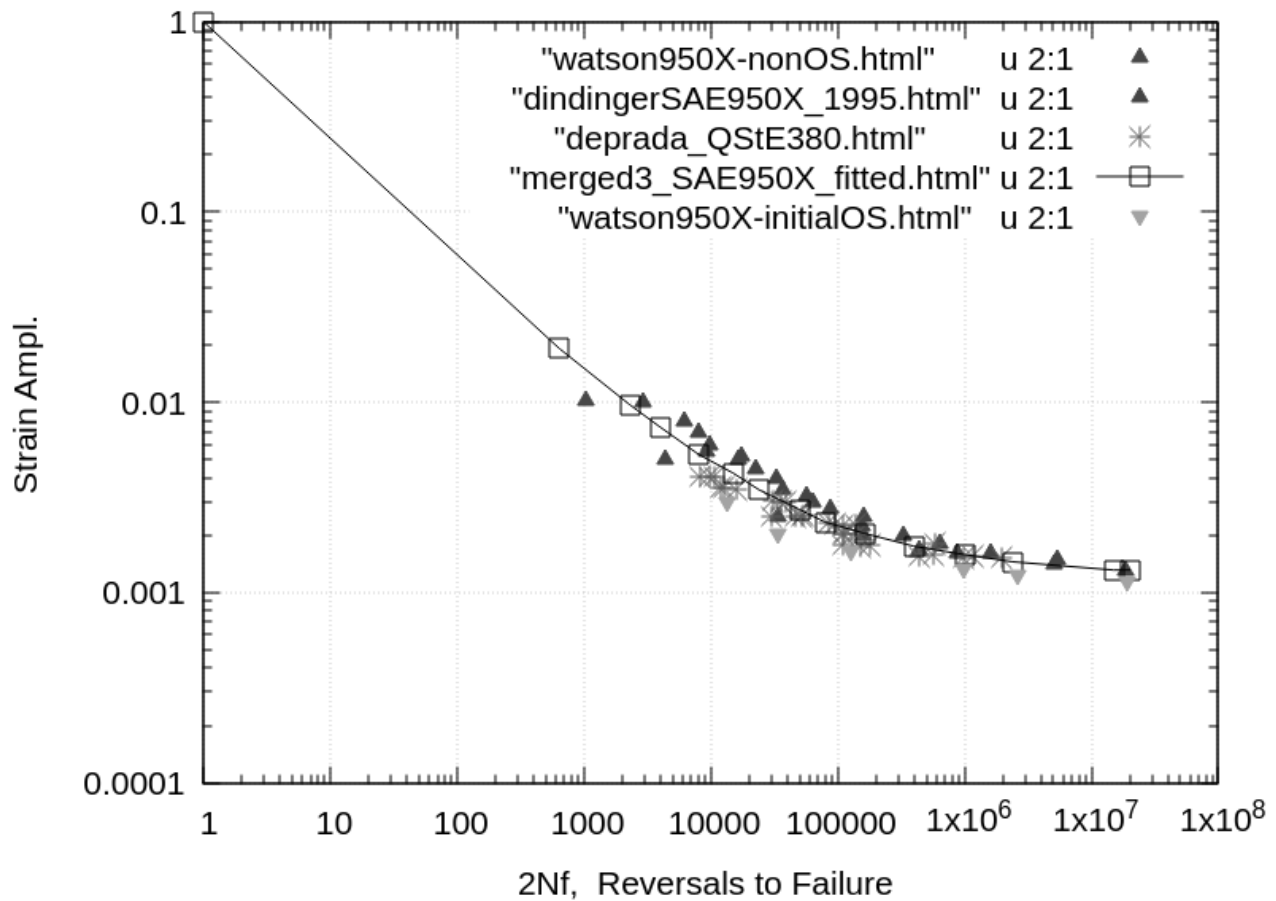
#### **7.3.1 General**

The following subsections provide material specification requirements for the vertical fluid conduits. The vertical fluid conduit is defined in Section 3.1.5 as the fluid conduit section traveling through the vertical water column. The vertical fluid conduit is shown as item 10 in Figure 3 in Section 5.1.

#### **7.3.2 Metallic Coiled Tubing**

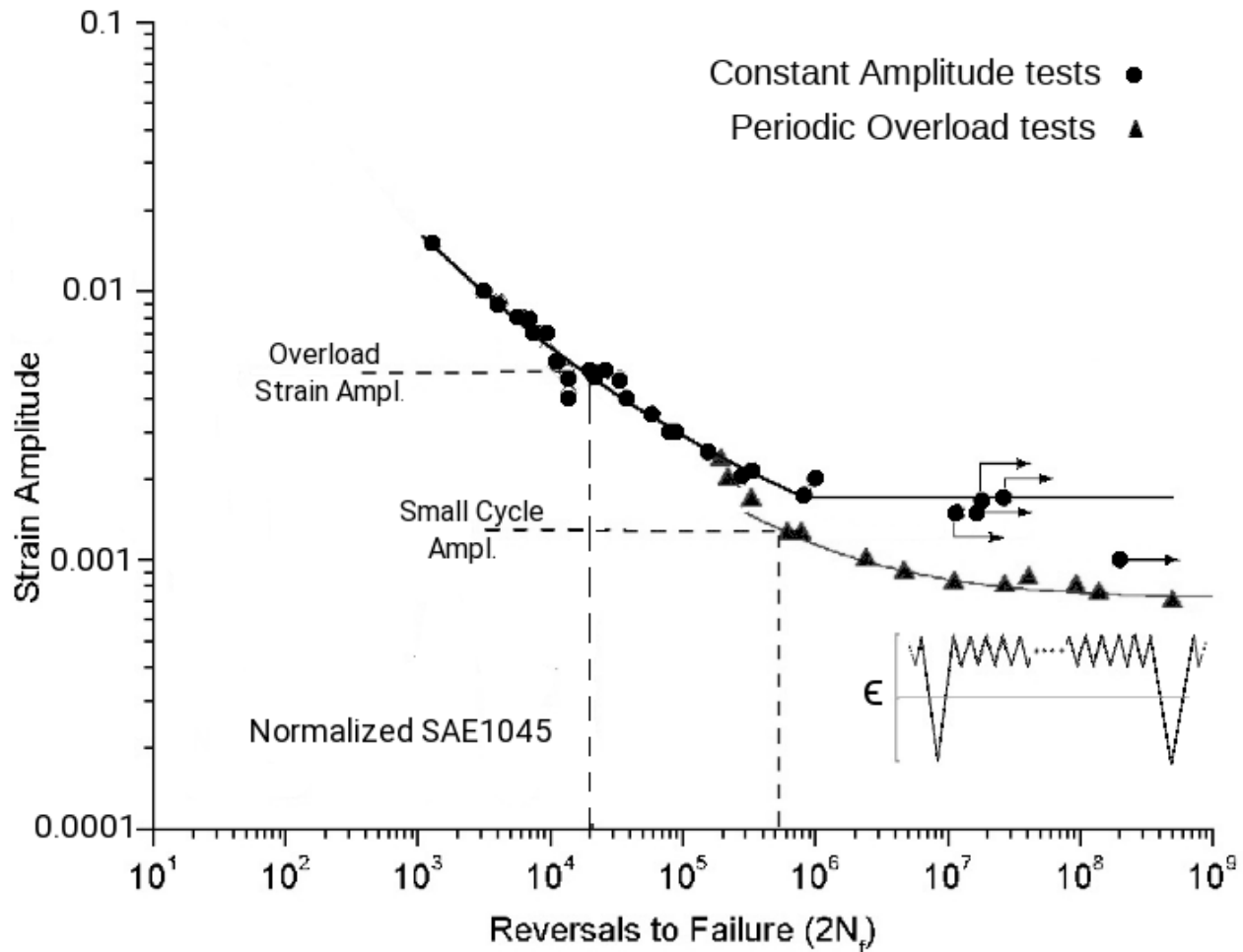
The material specifications of metallic coiled tubing used as vertical fluid conduits in subsea pumping well intervention systems shall conform to API SPEC 5ST. Table A.1 in 5ST provides the material composition for required tubing strength.

When performing a fatigue life assessment for coiled tubing used in subsea pumping well intervention systems, a fatigue life curve tested according to ASTM-E606 is recommended to be considered. Such curves are often available from steel suppliers or can be derived by the end user via material testing. An example for HSLA 50ksi yield is depicted below.



**Figure 8—HSLA 50ksi Yield Steel SN Curve (Constant Amplitude)**

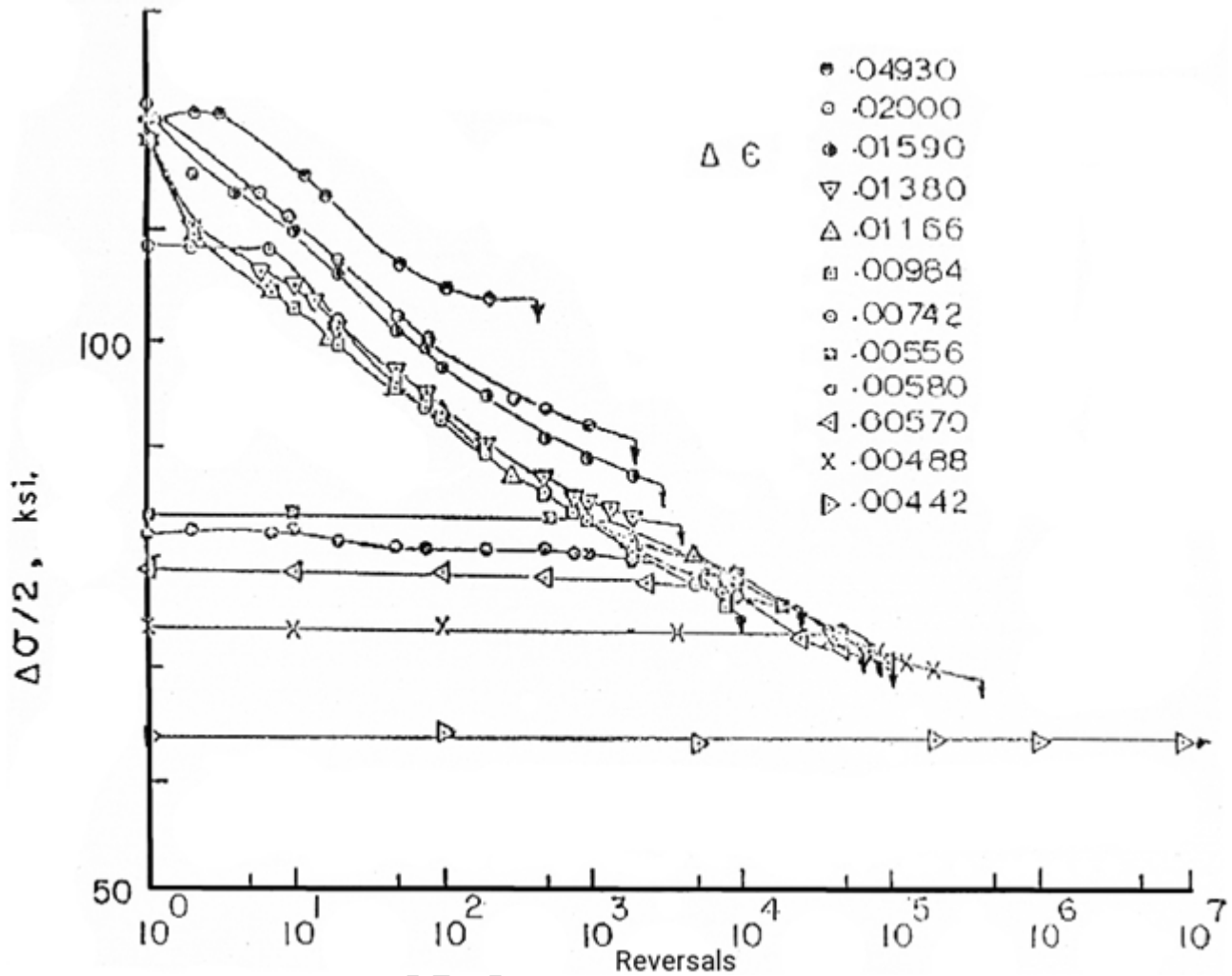
The fatigue loads or strains in a coiled tubing application consist of very large strain cycles due to reeling/unreeling which are interspersed amongst many smaller cycles due to wave action or service applications. This "Variable Amplitude" (VA) type loading can cause small cycles below the fatigue endurance limit to be damaging. It is recommended that the small cycles are assessed for fatigue using life curves that allow for fatigue damage below the fatigue limit. An example for a normalized steel is shown below:



**Figure 9—SEA1045 Steel SN Curve (Normalized from Variable Amplitude)**

Coiled tubing used as a vertical fluid conduit for subsea pumping well intervention systems can undergo strain cycles which can lead to cyclic strain softening or hardening. It is recommended to incorporate the effects of cyclic softening or cyclic hardening into the coiled tubing design. A severe example of a cyclic softening set of data is depicted in the figure below:

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**Figure 10—Cyclic Softening**

Cyclic hardening or softening is dependent upon the metallurgy and processing of the material. Cyclic hardening or softening can also be depicted by graphing the 1/2 life stress and strain from each of the ASTM E606 tests. The example below is taken from the previous cyclic softening plot. The figure depicts the "Cyclic Stress-Strain Curve" (lower curve) and the average tensile test curve of the material (upper curve). It is recommended to use a cyclic stress-strain curve for fatigue computations.

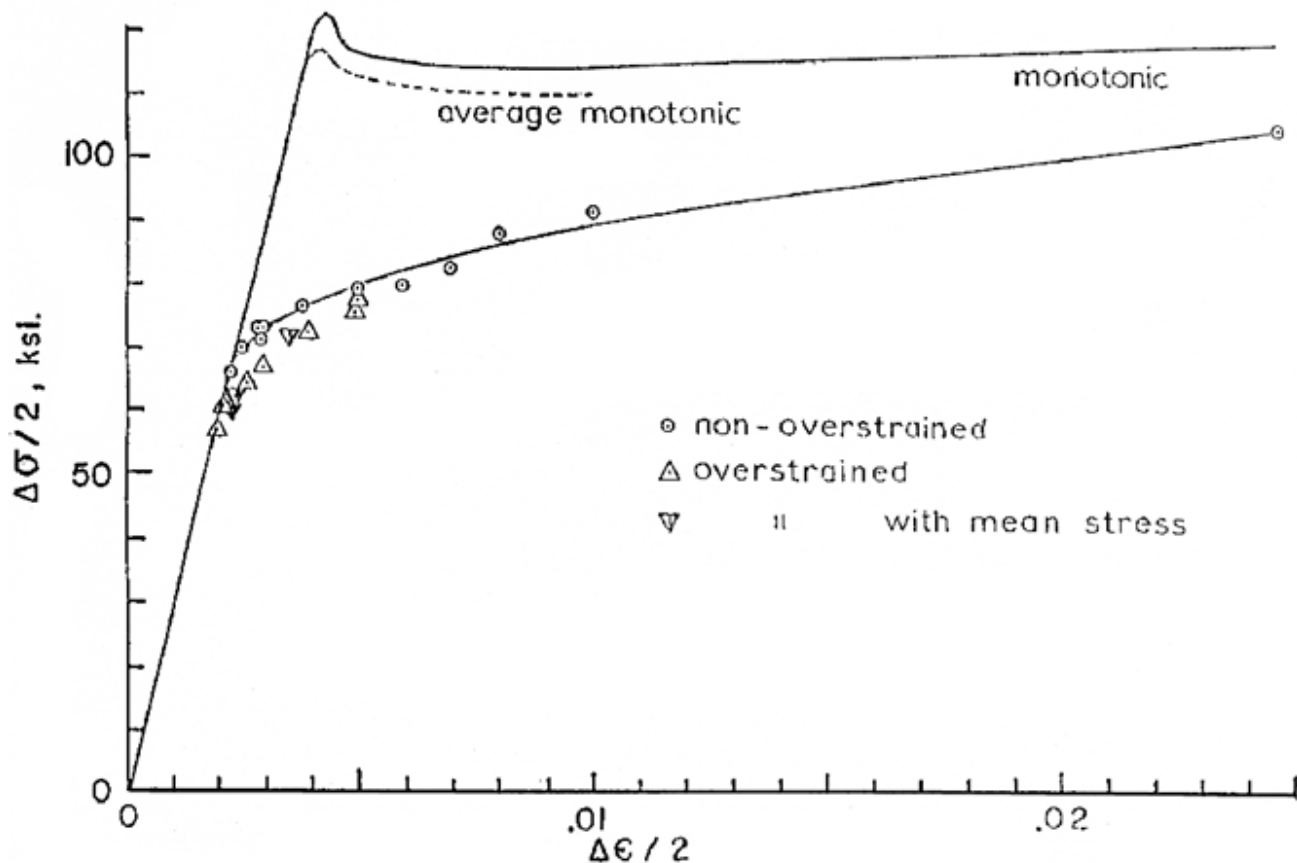


Figure 11—Cyclic Stress-Strain Curve Example

It is recommended to determine the degree of cyclic softening or cyclic hardening, as a function of strain amplitude and number of cycles, using ASTM E606 test methods or by testing of a conductor section specimen. Material fatigue properties can be determined by ASTM E606 at the cycle ranges expected in service. It is recommended to consider cyclic softening/hardening of the material as it pertains to its fatigue performance.

### 7.3.3 Thermoplastic Composite Pipe

The material specifications of the thermoplastic composite pipe used as vertical fluid conduits in subsea pumping well intervention systems shall conform to DNVGL-ST-F119.

### 7.3.4 Unbonded Flexible Pipe

The material specifications of the unbonded flexible pipe used as vertical fluid conduits in subsea pumping well intervention systems shall conform to API SPEC 17J.

### 7.3.5 Bonded Flexible Pipe

The material specifications of the bonded flexible pipe used as vertical fluid conduits in subsea pumping well intervention systems shall conform to API SPEC 17K.

## 7.4 Fluid Conduit Connectors

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A fluid conduit connector is defined in Section 3.1.6 as the equipment which connects the various fluid conduits to the various equipment packages and the well. The fluid conduit connector is shown as item 8 in Figure 3 in Section 5.1.

The material specifications of the fluid conduit connectors used in subsea pumping well intervention systems should conform to Section 7.4 of API SPEC 17D. However, the connector applications generally covered by 17D typically are designed for longer term flow. Alternatively, the end user can qualify the material selected for the fluid conduit connectors by performing a PR1 type qualification. The methodology and requirements for this qualification type is detailed in API SPEC 6A. The qualification should consider material, fluid, and temperature compatibility.

See Annex A for the System Validation of fluid conduit connectors.

## **7.5 Subsea Jumpers**

Subsea jumpers are shown as item 9 in Figure 3 in Section 5.1. They are also referred to as flying leads. Typically, thermoplastic composite, unbonded flexible, and bonded flexible pipes are used for subsea jumpers. The subsea jumper material requirements are congruent with the vertical fluid conduit material requirements for thermoplastic composite, unbonded flexible, and bonded flexible pipes as defined in Sections 7.2.2, 7.2.3, and 7.2.4 respectively.

Rigid jumpers can be used for subsea jumpers. The standard pipe section of rigid subsea jumpers used in subsea pumping well intervention systems shall conform to the material requirements specified in ASME B31.8, API 1111, and DNV-OS-F101.

## **8 Quality Requirements**

### **8.1 Passive Weaklinks**

Passive weaklinks shall be qualified per operational requirements for max angle disconnect.

Shear pins shall have heat destructive testing to ensure heat has consistent shear loads

Passive weaklinks shall be qualified per working conditions identified in API SPEC 17G2

Passive weaklinks shall meet API SPEC 17D and API SPEC 6A

### **8.2 Subsea Jumper/Fluid Conduit Connectors**

Subsea Jumpers/Fluid conduit connectors shall meet API SPEC 17D and API SPEC 6A



## **Annex A (normative) System Validation of Fluid Conduit Connectors**

### **A.1 Validation Tests**

Fluid Conduit Connectors (Subsea Releasable and Weak Link) shall be validated and qualified as Other End Connections (OEC) per API 17D and 17G, with reference to API 6A Annex F PR2. The manufacturer shall apply the principles, test methods, and acceptance criteria of API 6A, Appendix F for PR2 equipment to develop validation procedures to safely demonstrate connector performance. The manufacturer shall specify the location of the connector (releasable at the subsea safety module (WCP) and/or mid-depth) apply to the validation procedures. Pressure and temperature ratings shall be defined by the manufacturer.

Validation of umbilical disconnect connectors and connections are beyond the scope of this annex. Refer to API 17G5 for requirements.

Validation of Subsea Releasable (active or passive disconnect functionality) and Weak Link connectors shall include the following:

- a. Fluid Compatibility: Perform fluid compatibility testing for connector components per API 6A, F.1.13, meeting PR2 requirements. In addition, the connector's materials of construction screened for material compatibility with the fluids per API 17D, annex K.
- b. Validation Pressure/Temperature Cycles: Perform a minimum of 200 pressure and 3 temperature cycles per API 17D, for other end connection (OEC).
- c. Validation Endurance Cycles: Connectors shall demonstrate (a minimum of three cycles) the ability to disconnect via their corresponding trigger such as stimuli and/or signal that causes the release function of the connector via: hydraulic, mechanical, electrical, pull apart tension, etc. (the term trigger is to be utilized as described in this section), at expected angles of release and expected loading conditions including max angle disconnect (accounting for drift off or uncontrolled disconnect). The validation test shall demonstrate the connector's disconnect time at the expected loading conditions associated with a disconnect, meeting defined performance requirements. The manufacturer shall define the acceptance criteria necessary to meet performance requirements.
- d. Retention Closure Device Test: Connectors shall demonstrate (a minimum one of three endurance cycles) the ability to disconnect and subsequently retain contained fluids inside without leakage or damage at the separated ends of the connector. A pressure test meeting API 6A, F.1.11 acceptance criteria for leakage, shall be performed. Retained fluid pressure during the test shall be specified by the manufacturer. Test hold period shall be 60 minutes, minimum. The manufacturer shall specify the fluid test medium used during the test.
- e. Re-connection Test: Where applicable, connectors with re-connect ability (without redressing parts or seals after a disconnect), shall demonstrate that the performance of

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the connector and its seals is retained during the endurance test (a minimum of three cycles). Changing of seals or other components is not permitted throughout the endurance test. Connectors without a re-connect ability may be redressed and reassembled with new seals and replacement of sacrificial parts. A pressure test meeting API 6A, F.1.11 acceptance criteria for leakage, shall be performed after each make-up (re-connection). Test hold period shall be 5 minutes, minimum. The manufacturer shall specify the fluid test medium used during the test.

NOTE 1: The Pressure Endurance Cycles, the PR2 Pressure and Thermal Cycles, and the Shell Leakage Cycles shall be performed as a single test without replacing seals or other components.

NOTE 2: The prototype or production parts to be used in qualification/validation testing shall be tested to all PSL3 requirements prior to performing the Shell Leakage Cycles, the Pressure Endurance Cycles, and the PR2 Pressure and Thermal Cycles.

**Table A.1 Summary of Connector Design Validation Requirements**

(References in this table are to API Spec 6A, 21<sup>st</sup> Ed., November 2019 and API Spec 17D, 3<sup>rd</sup> Ed., December 2021)

Validation Requirement		Re-Connectable Connector	Re-Connectable Connector with Passive Disconnect	Single Disconnect Connector
Fluid Compatibility		Per API 6A F.1.13	Per API 6A F.1.13	Per API 6A F.1.13
Pressure and Thermal Cycles	Shell	Per API 6A F.1.11	Per API 6A F.1.11	Per API 6A F.1.11
	Retention	Per API 6A F.1.11	Per API 6A F.1.11	Per API 6A F.1.11
Pressure Endurance Cycles	Shell	Per API 17D 5.1.7.4 200 Cycles	Per API 17D 5.1.7.4 200 Cycles	Per API 17D 5.1.7.4 200 Cycles
	Retention	Per API 6A, F.2.2.2.2 and F.2.2.2.3.2 3 Cycles	Per API 6A, F.2.2.2.2 and F.2.2.2.3.2 3 Cycles	N/A
Bending and External Loads		PMR	PMR	PMR
Make and Break		PMR (3 Cycles min.)	PMR (3 Cycles min.)	N/A
Passive Disconnect		N/A	PMR	PMR

## A.2 Validation Tests for Retainer Valves

Fluid Conduit Connectors which feature retention valves as the retaining seal device (the retention feature in each half of the connector shall be qualified through validation testing described in A.1 (c and d)), shall have the retention valve qualified for its pressure and temperature rating, per API 6A, F.1.11 for pressure and thermal cycles. The pressure shall be applied as a differential across the seat/closure mechanism. The passive actuating mechanism for the retention valve shall be validated through testing to demonstrate that it closes the retention valve upon disconnect as a part of the validation tests described in A.1. For retention valves used with re-connect ability connectors, additional room temperature seat tests shall be performed according to API 6A F2.2.2.2.2 (3 cycles) and F.2.2.2.3.2.

## Annex B (informative) Coiled Tubing Response Calculation Methods

Two methods of evaluating the strength response of coiled tubing whereas it leaves the sheave or injector head are presented below.

### B.1 Working Limit Curve

The method determines the combined effect of Pressure and Tension loading. The effect of localized bending induced by deployment apparatus' is not included in the equations; however, the minimum coiled tubing bend radius must comply with bullet (c) in the general design requirements to apply the method to the system. It is assumed that compliance with bullet (c) in the general design requirements allows bending to be ignored.

The global strength check will be based upon pressure differential, axial tension, and yield strength.

The global strength assessment shall be based upon the works outlined in the paper, "Coiled-Tubing Pressure and Tension Limits," written by K.R. Newman and D. Schlumberger presented at Offshore Europe Conference in September of 1991. The equations used to perform the global strength analysis are given below:

$$P_i = \frac{\gamma \pm \sqrt{\gamma^2 - 4\alpha\delta}}{2\alpha} \quad (A)$$

$$\alpha = \beta^2 + \beta + 1 \quad (B)$$

$$\gamma = P_o(2\beta^2 + 3\beta + 1) + \frac{T_A}{A}(\beta - 1) \quad (C)$$

$$\delta = P_o^2(\beta + 1)^2 + P_o \frac{T_A}{A}(\beta + 1) + \left(\frac{T_A}{A}\right)^2 - (\sigma_y)^2 \quad (D)$$

$$\beta = \frac{r_o^2 + r_i^2}{r_o^2 - r_i^2} \quad (E)$$

Where,

$T_A$  is axial tension  
 $r$  is the coiled tubing radius  
 $\sigma_y$  is the yield strength  
 $P$  is pressure

In the above equations, the subscript  $o$  and  $i$ , refer to outer and inner, respectively, for both the pressure and the radius of coiled tubing.

$T_A$  shall be the maximum applied tension imposed by the combined effects of self-weight (submerged, fluid filled tubing with attached ancillary equipment); inertial effects due to vessel motions and sea conditions; and hydraulic friction due to vessel motions and sea conditions (i.e. added mass, hydraulic drag, etc.).

Equation (A) is used to plot allowable internal pressure, based on a constant external pressure, as a function of axially applied tension to create a conservative working limit curve. All pressure differential and axial tension combinations below the working limit curve are deemed fit-for-purpose. See figure B.1 as an example of a working limit curve:

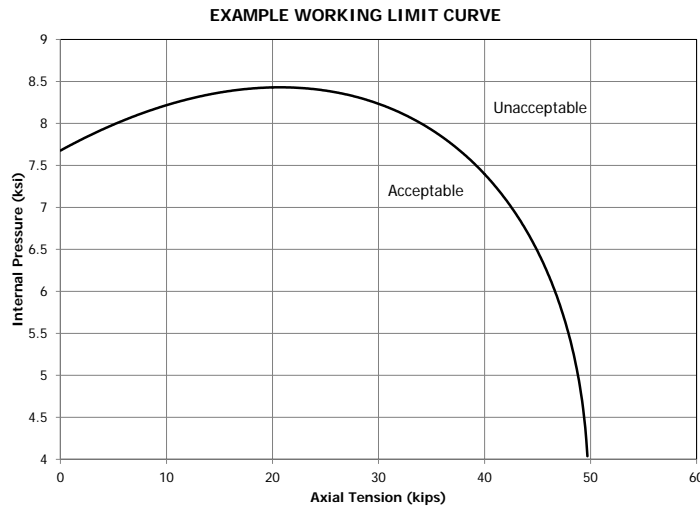


Figure B.1

## B.2 Von Mises Yield Condition

A von Mises yield condition equation can be used. The General form of the von Mises yield condition is given below.

$$\sigma_{VME} = \sqrt{\frac{1}{2} + [(\sigma_h - \sigma_r)^2 + (\sigma_h - \sigma_a)^2 + (\sigma_a - \sigma_r)^2] + 3\tau^2} \quad (F)$$

Where,

$\sigma_{VME}$  is the von Mises stress

$\sigma_h$  is the hoop stress

$\sigma_r$  is the radial stress

$\sigma_a$  is the axial stress

$\tau$  is the shear stress caused by torque

All stresses used in Equation F must account for dynamic loading effects. For the coiled tubing to be deemed fit-for-service, the von Mises stress must remain lower than 80% of the derated minimum yield stress at the deployment apparatus exit point.

## B.3 Power Law Damage Rule

An example of the power rule is provided in this Annex.

The power-law-damage rule provides an appropriate method to combine the fatigue damage from HC and LC loading cycles. This method converts the fatigue damage from different loading types into equivalent total damage value. High cycle and low cycle fatigue cycles must be calculated independently for these damage summation rules to be applicable. The general form of the power rule is given below.

$$\frac{n_e}{N_e} = \left[ \frac{n_p}{N_p} \right] \left( \frac{N_p}{N_e} \right)^P$$

Where,

$\frac{n_e}{N_e}$  is the equivalent elastic fatigue ratio

$\frac{n_p}{N_p}$  is the calculated plastic fatigue ratio

$N_p$  is the cycle limit for plastic strains

$N_e$  is the cycle limit for elastic strains

$P$  is the power law exponent

$n_e$  is the equivalent number of elastic cycles (determined from global riser analysis)

The power rule is a curve fit to actual test data. The power rule is fit to the material type and geometry through the use of an exponent,  $p$ . When no experimental data is available, the power law can still be used by assuming a  $p$ -value of 0.15 for coiled tubing as recommended by Bridge.

Additionally, the power rule requires knowledge of the loading sequence of the coiled tubing. This is suitable for pumping well intervention because the load sequence is predictable. The following is an example of how this technique can be applied.

Coiled tubing used in subsea pumping operations accumulate fatigue from two sources: plastic reeling cycles and elastic operational cycles. Coiled tubing used in subsea pumping operations accumulate fatigue from two sources: plastic reeling cycles and elastic operational cycles. Elastic cycles imposed on the coiled tubing in the water column are an order of magnitude smaller, but their mean stresses are dependent upon the prior plasticity. Thus, nonlinear stress/strain response modelling of the coiled tubing is required to determine the complete stress-strain and fatigue response.

Total Fatigue Damage from different loading cycles:

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$$d_i = \left[ \frac{n_{i-1,eq} + n_i}{N_i} \right] \left( \frac{N_i}{N_{Ref}} \right)^P$$

$$n_{i-1,eq} = (d_{i-1}) \left( \frac{N_{ref}}{N_i} \right)^P * N_i$$

- d<sub>i</sub>** Total Fatigue Damage in the End of ith Event  
**d<sub>i-1</sub>** Total Fatigue Damage in the End of (i-1)th Event  
**n<sub>i</sub>** Number of Cycles of ith Event  
**N<sub>i</sub>** Number of Cycles to Failure of ith Event  
**n<sub>i-1,eq</sub>** Previously accumulated fatigue (up to the i-1 event) converted to equivalent cycles for the ith event  
**N<sub>ref</sub>** Reference of Number of Cycles - Plastic Cycle Limit in this case  
**P** Constant from Material Testing

#### Inputs

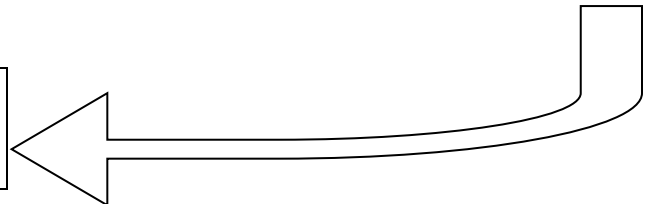
N <sub>ref</sub>	350
P	0.40

#### Calculation

Event	Description	Damage Type	n <sub>i</sub>	N <sub>i</sub>	(N <sub>ref</sub> /N <sub>i</sub> ) <sup>P</sup>	n <sub>i-1,eq</sub>	(N <sub>i</sub> /N <sub>ref</sub> ) <sup>P</sup>	d <sub>i</sub>
1	Unreeling/Previous Reeling Cycles	Plastic	2.0	350	-	-	-	0.006
2	Sheave Cycle	Plastic	1.0	200	1.25	0.31	0.8	0.018
3	Environmental Loading	Elastic	10,000	30,000	0.17	15239.16	5.93	0.359
4	Retrieval Sheave Cycle	Plastic	1.0	200	1.25	55.48	0.8	0.364
5	Spooling Back onto Reel	Plastic	0.5	350	1	127.37	1	0.365

#### Output

Combined Fatigue Damage	36.5%
-------------------------	-------



### B.4 Stress-Strain History of Sheave Deployed Coiled Tubing

The stress-strain history of the extrados (indicated with the ★) and intrados (indicated with the o) sides of a section of coiled tubing being deployed via a sheave into open water is shown in Figure 8.1. All stress-strain plots indicate the zero-zero stress strain position via a cross at the origin. Traveling up and down from the cross indicates positive and negative **stress** respectively at the indicated circumferential position. Traveling right and left from the cross indicates positive and

negative **strain** respectively at the indicated circumferential position.

The stress-strain is highlighted for 5 different deployment positions:

- A. Coiled tubing reeled position. There is positive stress and stress at the extrados and negative stress and strain at the intrados. The dual slope of the curves indicates that both circumferential points go through plastic deformation. The extrados is left with tensile residual stress. The intrados is left with compressive residual stress
- B. The coiled tubing is reeled off the spool. The coiled tubing is forced back to a straight (zero net strain position) by the tensile load in the tubing. The extrados side is plastically compressed eliminating all tensile residual stress and leaving compressive residual stress. The intrados side is plastically stretched eliminating all compressive residual stress and leaving tensile residual stress.
- C. The coiled tubing is bend around the turndown sheave. The intrados of the coiled tubing assumes the same bending radius as the sheave. The extrados of the pipe is plastically deformed in tension, and the intrados of the pipe is plastically compressed. Tensile residual stress is left in the extrados, and compressive stress is left in the intrados.
- D. The coiled tubing comes off the turn down sheave and enters the water. The coiled tubing is straightened again by the tensile loading in the tubing. The extrados side is plastically compressed eliminating all tensile residual stress and leaving compressive residual stress. The intrados side is plastically stretched eliminating all compressive residual stress and leaving tensile residual stress. Point D and point C' have the same stress-strain curve as the pipe has been straightened and does not go through a major strain cycle as it is reeled down to position D.
- E. The coiled tubing has been deployed to the required depth. Pressure is introduced. The pressure adds tensile loading to the pipe. The pressure further plastically deforms the intrados side of the pipe as it already has high tensile residual stress. The pressure elastically relieves the extrados side because it has high compressive residual stress.

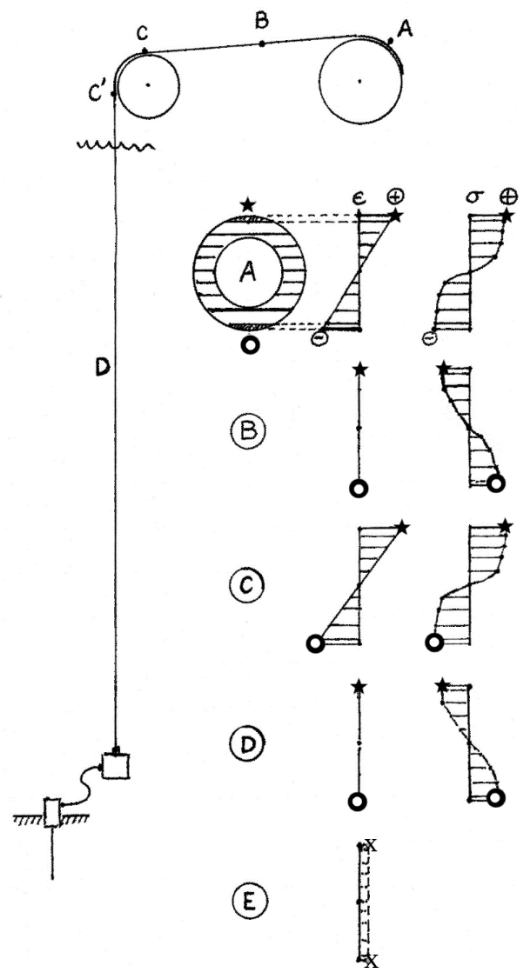
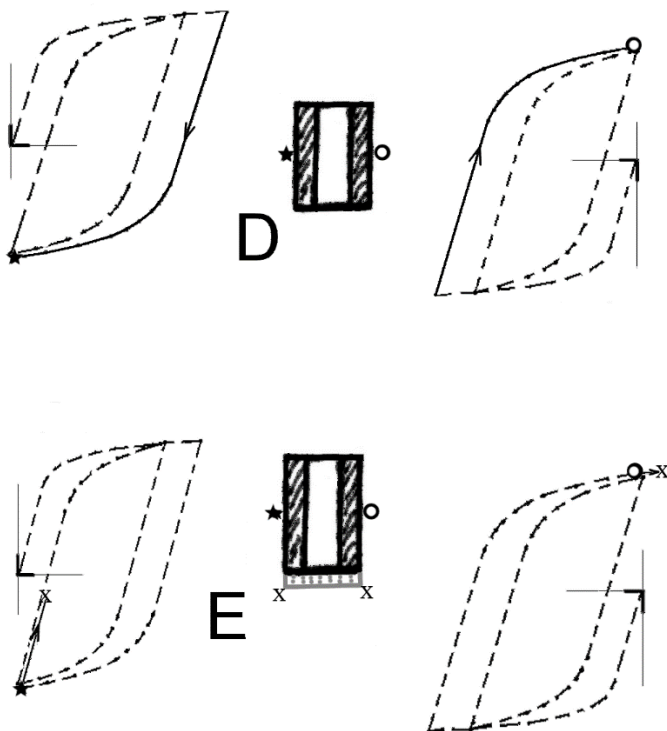
Consider that the hysteretic state of point C' (pipe as is it exits the turndown sheave and is straightened) is the same as point D. At this point the extrados side (left side of the pipe in Figure 8.1) has residual compressive stress and the intrados side (right side of the pipe in Figure 8.1) has residual tensile stress. The high cycle fatigue cause by wave motions should relieve the residual load on each side of the pipe because it should put more tensile stress into the extrados and compressive stress into the intrados. There will be no other type of bending at position C' because of the displacement-controlled nature of the turn down sheave boundary condition.

As such, the high cycle fatigue associated with vessel motions and wave loading (first order fatigue) at the coiled tubing fatigue hotspot (point C') will only have elastic cycles. The high cycle hysteresis should follow the **bold lines** on Figure 8.2.

Linear damage summation can be applied if the small cycles in a variable amplitude (VA) history are counted using an extension of the constant amplitude (CA) stress-strain-life curve much like the VA fatigue life curves defined by codes such as IIW (Ref.B4 [1]).

The same phenomenon of damage below the fatigue limit occurs in un-welded materials. Figure 9 (Materials clause) depicts an example of such a variable amplitude or "Periodic Overload" fatigue curve that extends below the normal CA fatigue limit. Since the large strain amplitude reeling cycles are interspersed between many small wave or service action cycles the coiled tubing loading is effectively a variable amplitude case and fatigue damage analysis should take this into consideration.





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Figure 8.1 – Coiled Tubing Strain History

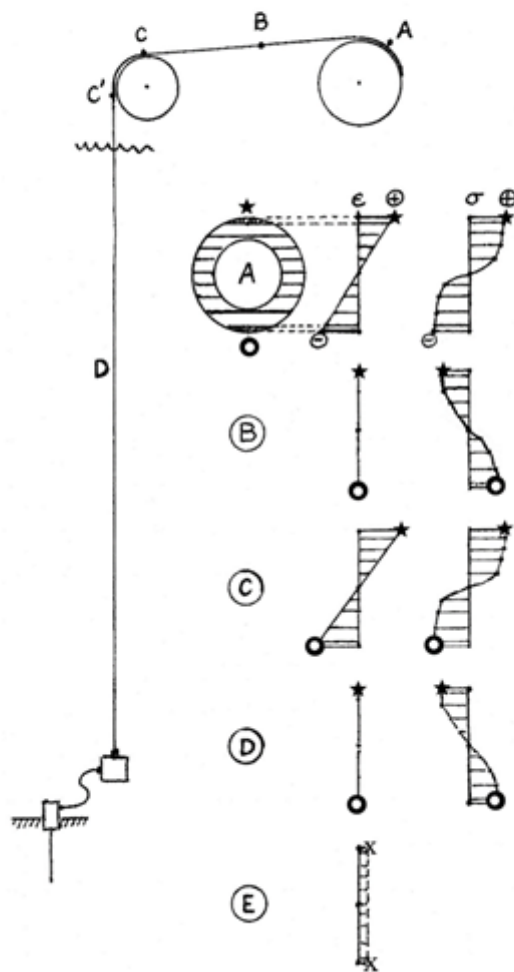
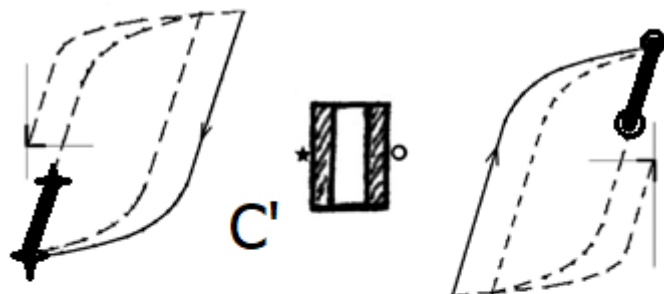


Figure 8.2 – High Cycle Fatigue Stress-Strain Curves

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- [9] Figures 8.1 & 8.2, Schematic of Extreme Fiber Stress-Strain Response During an Off-Shore Coiled Tubing Operation. Reprinted from *Using a Material Deformation Model to Predict Bending and Axial Straining Effect in Coil Tubing*, by A. Conle, University of Waterloo, April 14, 2015. <https://fde.uwaterloo.ca/Fde/CTube/pdStressStrain.html>.