Recommended Practice for Riserless Subsea Well Intervention Systems

API RECOMMENDED PRACTICE 17G4

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BALLOT DRAFT

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Contents

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Introduction

This document describes equipment, practices, and systems used for open water riserless subsea well interventions on subsea wells. Open water riserless subsea well intervention systems do not contain a riser throughout the water column or have a means to facilitate drilling. Riserless subsea well intervention systems are designed to allow a means of introducing tools into and out of a well whilst containing wellbore pressure at the wellhead or tree. The riserless subsea well intervention system must be capable of circulating seawater or wellbore fluid out of the subsea system prior to recovering the tool string to surface or deploying the tool string into the well.

This recommended practice is a supplementary document and should be used in conjunction with the other API 17G suite of documents;

— API Standard 17G, *Design and Manufacture of Subsea Well Intervention Equipment*

— API Recommended Practice 17G1, *Subsea Configuration and Operation for Subsea Well Intervention Systems*

— API Recommended Practice 17G2, *Subsea Pumping Well Intervention Systems*

— API Recommended Practice 17G3, *Design of Subsea Intervention Systems Using Non-Ferrous Alloys*

— API Recommended Practice 17G5, *Subsea Intervention Workover Control Systems.*

— API Recommended Practice 17G6, *Global Analysis of Subsea Well Intervention Systems.*

If an open water riserless subsea well intervention system is to be used for subsea pumping, it must meet the requirements of API RP 17G2.

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

This document is not intended to replace sound engineering judgment. It is necessary that users of this recommended practice be aware that additional or different requirements can better suit the demands of a particular service environment, the regulations of a jurisdictional authority or other scenarios not specifically addressed.

1 Scope

This recommended practice is intended to supplement API Std 17G and be used in conjunction with API RP 17G1, API RP 17G2, API RP 17G6, and contains recommendations for the design, manufacture, and operation of open water riserless subsea well intervention systems.

Most equipment used for riserless subsea well intervention is covered by standards widely used by the industry and as such shall be governed by those standards, see Section 2 for applicable normative specifications and standards. If there is not an applicable reference in this document, API Std 17G, API RP 17G1 and API RP 17G2 shall prevail, where appropriate.

API Specification 17G contains functional specifications for the following equipment which is typically used in riserless interventions;

— Tubing Hanger Orientation Joint;

— Tubing Hanger Running Tool Adapter;

— Bore Selector;

— Lower Workover Riser Package;

— Emergency Disconnect Package;

— Well Control Package;

— Connectors;

— Safety Joints/weak links.

This recommended practice is intended to serve as a common reference for designers, manufacturers, and end users.

Specific equipment covered by this recommended practice is as follows;

— Well Control Package;

— Lubricator Isolation Valve;

— Lubricator;

— Pressure Control Head;

— Control System;

— Disconnect Systems;

— Flushing/Kill System;

— Coiled Tubing retrieval and delivery system.

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

— Flying Leads (see API RP 17G2);

— Vertical Fluid Conduits (see API RP 17G2);

— Jumpers (see API RP 17G2);

— Fluid Conduit Connectors (see API RP 17G2);

— Intervention vessels used to execute work in the field;

— Topside wireline / coiled tubing motion compensation systems;

— Topside handling equipment for wireline / coiled tubing vessel-based equipment.

2 Normative References

The following documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Standard 17G, *Design and Manufacture of Subsea Well Intervention Equipment*

API Recommended Practice 17G1, *Configuration and Operation for Subsea Well Intervention Systems*

API Recommended Practice 17G2, *Subsea Pumping Well Intervention Systems*

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

API Recommended Practice 17G6, *Global Analysis of Subsea Well Intervention Systems*

3 Terms, Definitions, Abbreviations and Symbols

3.1 Terms and Definitions

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

3.1.1
Coiled Tubing (CT)
Continuous tubing spooled onto a reel that is used for well intervention operations. As used in this RP, the Coiled Tubing may be manufactured using metals or composite materials and in any nominal outer diameter.

3.1.2
Coiled Tubing retrieval and delivery system
The coiled tubing retrieval and delivery system provides the mechanical means to move the coiled tubing into and out of the well. This includes equipment used subsea and mounted on the vessel.

3.1.3
Downlines
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
Emergency Disconnect System (EDS)
Subsea equipment that provides the ability to disconnect all physical connections between the surface vessel and the WCP in the case of surface vessel drift-off, drive-off or other emergency that could move the surface vessel away from the well location.

3.1.5
Emergency Shut Down (ESD)
Control actions undertaken to shut down equipment or processes in response to a hazardous situation.

3.1.6
End User
Organization that authorizes the use of a riserless subsea well intervention system for well operations.

NOTE: The end user is also known as "Well Operator" within some industry documentation.

3.1.7
Extreme Load Condition
Condition, where individual and combined loads as a result of environmental and operational criteria exceed the Normal Structural Design factor but are equal to or less than the Extreme Structural Design factor.

NOTE: API Std 17G lists the Structural Design Factors.

3.1.8
Fluid Conduit
That which connects various system packages to allow for the flow of fluid between the various equipment packages and the tree system; typically consisting of collapse resistant hose, steel coiled 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.

3.1.9
Fluid Conduit Connector
That which connects 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.

3.1.10
Global Riser Analysis (GRA)
Analysis of the complete subsea well intervention system from below mudline to the vessel's heave compensation system.

NOTE: Bending moments and effective tension distributions imposed on the subsea equipment, fluid conduits and umbilicals due to functional loads, vessel motions and environmental loads, are determined by a global riser analysis (GRA). Once the loads are established, they are assessed against component capacities and thereby determine the operating limits for the system. Refer to API 17TR14 for more detail.

3.1.11
Lubricator
Tubular member(s) attached to the top of the WCP subsea that house the tool string during system flushing operations.

3.1.12
Loss of Control
Inability to initiate safety functions from surface due to loss of hydraulic supply and/or signal transmission.

EXAMPLE: Direct Hydraulic System – loss of surface hydraulic supply; Electro-hydraulic System – loss of electrical signal transmission and /or surface hydraulic supply.

3.1.13
Manufacturer (OEM)
Organization responsible for the design and manufacture of equipment for use in subsea well intervention systems and sub-systems.

NOTE: The manufacturer is responsible for the creation of; design documentation; validation testing documentation; manufacturing record books; and operating documentation for the equipment

3.1.14
Maximum Anticipated Wellhead Pressure (MAWP)
The highest pressure predicted to be encountered during a well intervention operation at the subsea wellhead and/or the tree.

3.1.15
Metocean Data
Meteorological and oceanographic data, such as wind, wave, water current, and tidal condition measurements

3.1.16
Normal Load Condition

Condition, where individual and combined loads as a result of environmental and operational criteria reach but do not exceed the Normal Structural Design factor.

NOTE: API Std 17G list the Structural Design Factors

3.1.17
Pressure Control Head (PCH)
Equipment used as a means to seal around the wireline or coiled tubing preventing egress of well fluids to the environment or ingress of seawater into the wellbore and/or the lubricator while also allowing conveyance of tools in and out of the well.

3.1.18
Primary Well Barrier
First well barrier that prevents undesired flow from a source of inflow / reservoir.

3.1.19
Re-entry Spool
Uppermost part of a subsea tree to which a subsea well intervention system is attached to gain vertical well access, or a point on a well control package to which a workover riser based intervention system can attach to gain vertical well access.

3.1.20
Safe State
Condition that exists when all safety class devices, defined by a safety function, have functioned as intended.

3.1.21
Safety Function
Sequenced series of device actions intended to achieve a safe state in relation to a specific hazardous event.

3.1.22
Secondary Well Barrier
Well barrier that prevents undesired flow from a source of inflow / reservoir if the primary well barrier fails.

3.1.23
Subsea Control System
That which includes the primary control system, backup control system, shut down system and disconnect control system (if applicable).

NOTE These systems are a group of components, equipment packages, and/or part of the permanent infrastructure that provide all the control functions required to operate the Riserless Subsea Well Intervention System in its entirety.

3.1.24
Survival Load Condition
Condition, where individual and combined loads as a result of environmental and operational criteria exceed the Extreme Structural Design factor but are equal to or less than the Survival Structural Design factor.

NOTE 1: API Std 17G lists the Structural Design Factors.

NOTE 2: A survival load condition of a component means that the component does not fail, but it can present one or more kinds of degradations that may impact its specified performance or service life.

3.1.25
System Integrator
Organization that is responsible for bringing together sub-systems, ensuring that those sub-systems function together in a subsea well intervention system.

NOTE: Responsible for the system integration, collection/collation of all manufacturing data and manufacturing record books (where applicable), collection of equipment assembled together, verification testing documentation, operation procedures, maintenance and storage procedures.

3.1.26
Umbilical (UMB)
Group of functional components, such as electric cables, optical fiber cables, hoses, and tubes, laid up or bundled together in combination with each other that provides hydraulics, fluid injection / return, power, and/or communication services.

NOTE: Other elements or armoring may be included for strength, protection, or weight considerations.

3.1.27
Subsea Umbilical Termination (SUT)
Mechanism for mechanically, electrically, optically and/or hydraulically connecting or disconnecting an umbilical or jumper bundle to a subsea system.

3.1.28
Well Barrier
Envelope of one or several well barrier elements preventing unintentional flow of fluids from the reservoir to the environment.

NOTE: In this document well barrier types are only physical barriers and not other types of barriers such as human, training or procedural as discussed in other industry documents, e.g. ISO 17776.

3.1.29
Well Barrier Element (WBE)
One or several dependent objects, i.e., packers, tubing, or casing, preventing formation fluids from flowing unintentionally into another formation or to the surface.

3.1.30
Well Control Device
A Component that is designed to function as a well barrier.

3.1.31
Well Control Package (WCP)
Portion of the riserless subsea well intervention system that extends from the Tree Running Tool (bottom of WCP) or the Tree Top Hub to the bottom of the lubricator (top of WCP). Its purpose is to provide pressure control at the mudline directly above the wellhead and/or Tree.

3.1.32
Wireline
A special wire, strand (known as slickline), or wire rope of high strength steel used to convey tools into a well. This includes an electromechanical/optomechanical cable that is electrical and optical cable(s) armored with high strength steel wires.

3.2 Abbreviated Terms

For the purposes of this document, the following abbreviations and symbols apply.

BHA	Bottom Hole Assembly
CT	coiled tubing
EDS	emergency disconnect system
ESD	emergency shutdown
GRA	global riser analysis
IWOCS	intervention workover control system
MAWP	maximum anticipated wellhead pressure
MEG	mono-ethylene glycol
ML	mud line
MOC	management of change
MSL	mean sea level
PSD	process shut down
PCH	pressure control head
ROV	remotely operated vehicle
RSWIS	riserless subsea well intervention system
RWP	rated working pressure
SCM	subsea control module
SUT	subsea umbilical termination
UMB	umbilical
WBE	well barrier element
WBS	well barrier schematic
WCP	well control package

4 System Requirements

4.1 Purpose

The modes of operation for a riserless subsea well intervention system are as follows:

a) riserless wireline intervention mode;

b) riserless coiled tubing intervention mode.

NOTE: If a RSWIS is used for stimulation / pumping into a subsea well only, then API RP 17G2 requirements would be applicable for the purposes of that operation.

The scope of equipment included in (but not limited to) the system requirements for the riserless wireline intervention mode is shown in Figure 1.

The scope of equipment included in (but not limited to) the system requirements for the riserless coiled tubing intervention mode is shown in Figure 2.

Equipment configuration is for the end user or system integrator to define. A system review is required to ensure that the RSWIS meets the requirements, is operated and maintained, for its intended use throughout its intended life.

A riserless subsea well intervention system shall include the following components;

— Well Control Package (WCP);

— Lubricator Assembly;

— Pressure Control Head;

— Emergency Disconnect System (EDS);

— Control System;

— Flushing/Kill System;

— Riserless In-Well Coiled Tubing system (riserless coiled tubing intervention mode only).

The system may also contain a re-entry spool to allow well access by a workover, riser based system. The decision to include or exclude a re-entry spool shall be risk assessed for the intended operation by the system integrator and / or the end user, as appropriate. Considerations are to include all planned operations and all reasonably foreseeable failure modes including downhole, subsea and at surface which may impact well control and a requirement to re-enter the well with a workover riser system. API 17G1 shall be used as a reference input.

Typical schematics for each mode of operation for the subsea equipment are shown in Figure 3 and **Error! Reference source not found.**.

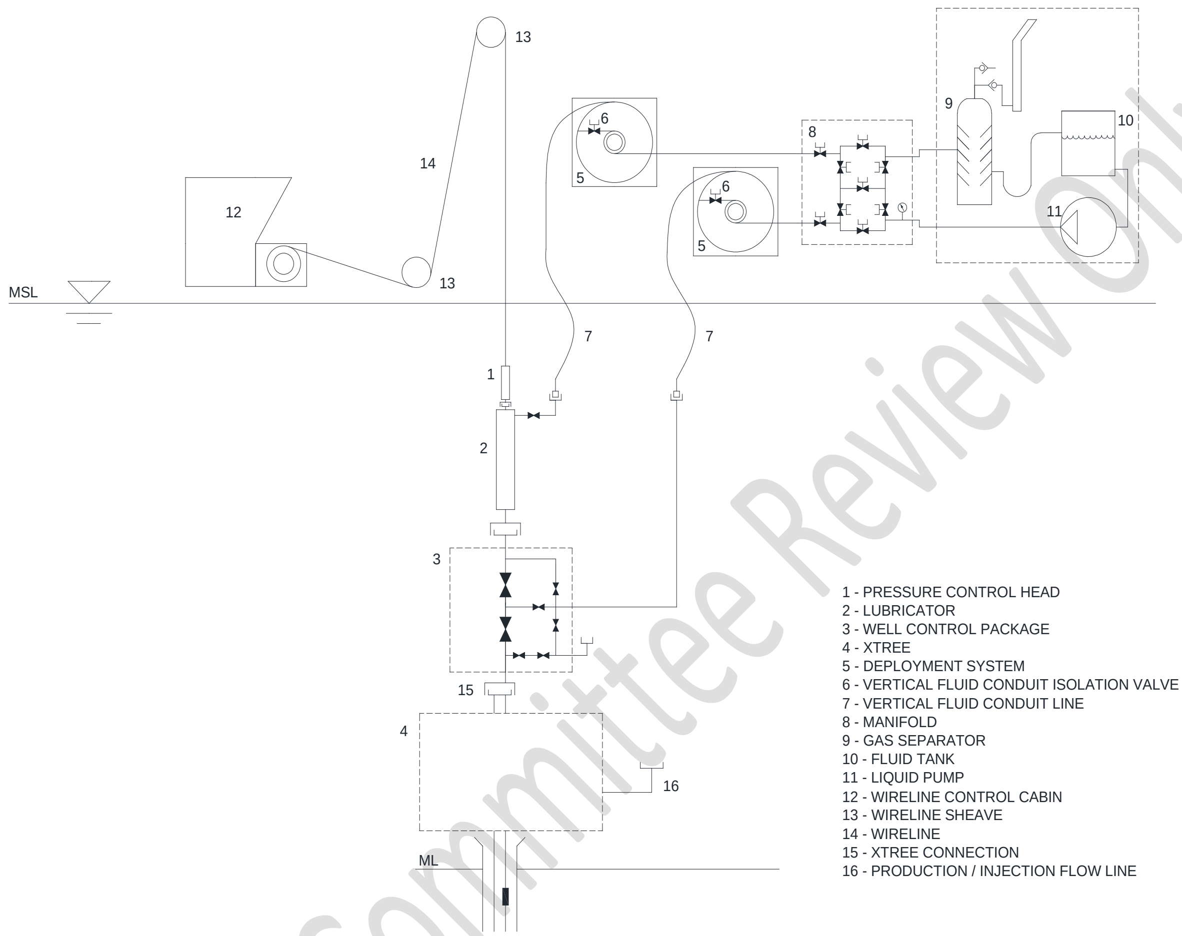

Figure 1 - Example of General Arrangement on a Subsea Tree for Riserless Wireline Intervention Mode

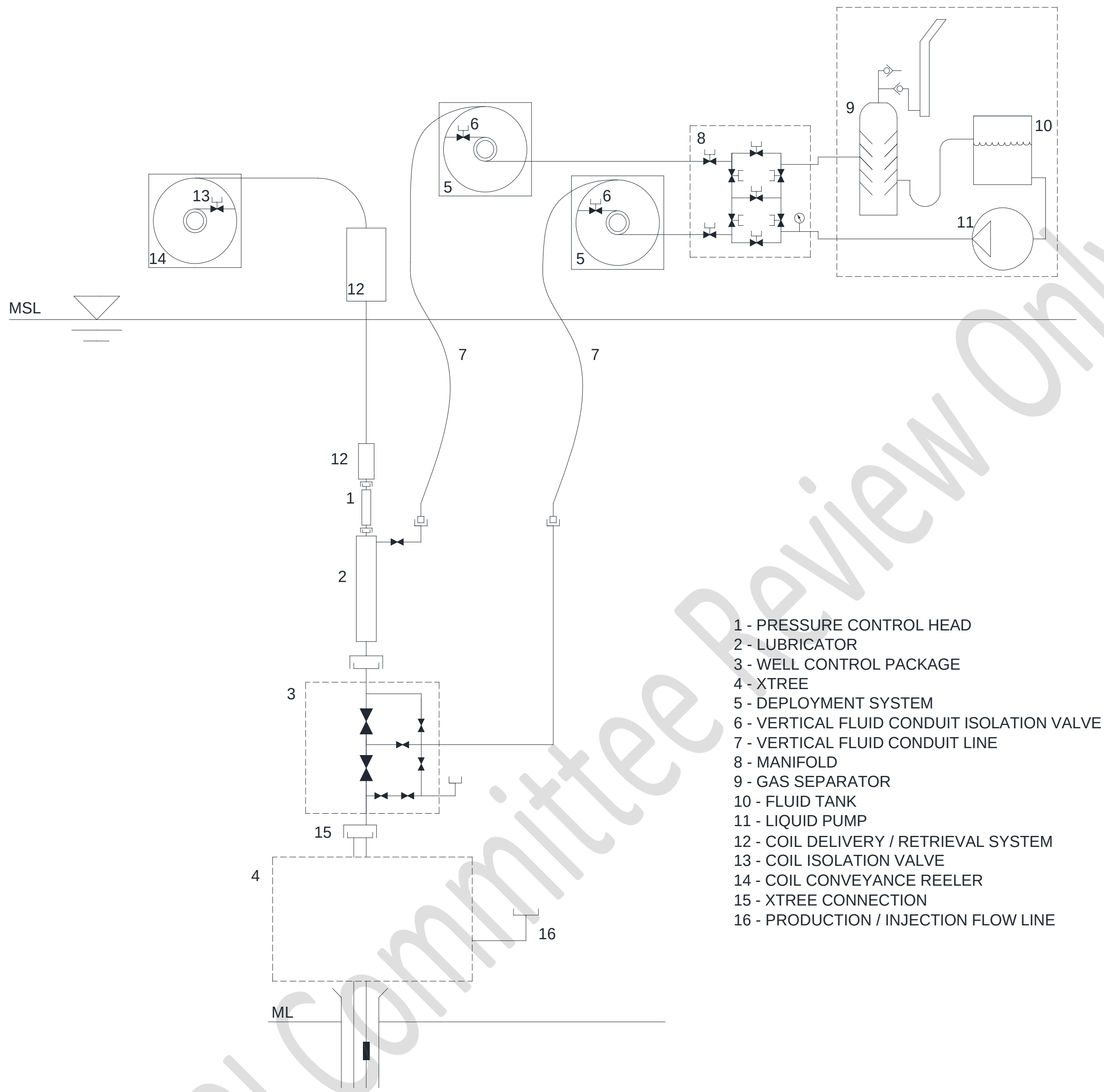

Figure 2 - Example of General Arrangement on a Subsea Tree for Riserless Coiled Tubing Intervention Mode

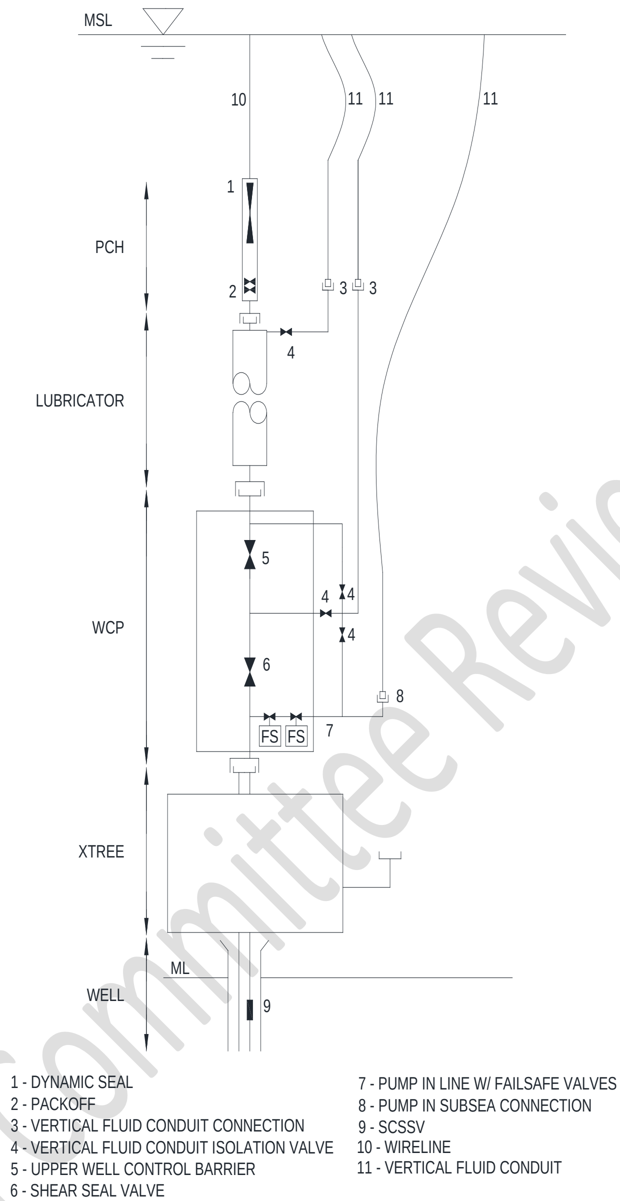

Figure 3 - Example of RSWIS attached to a Tree for Riserless Wireline Intervention Mode

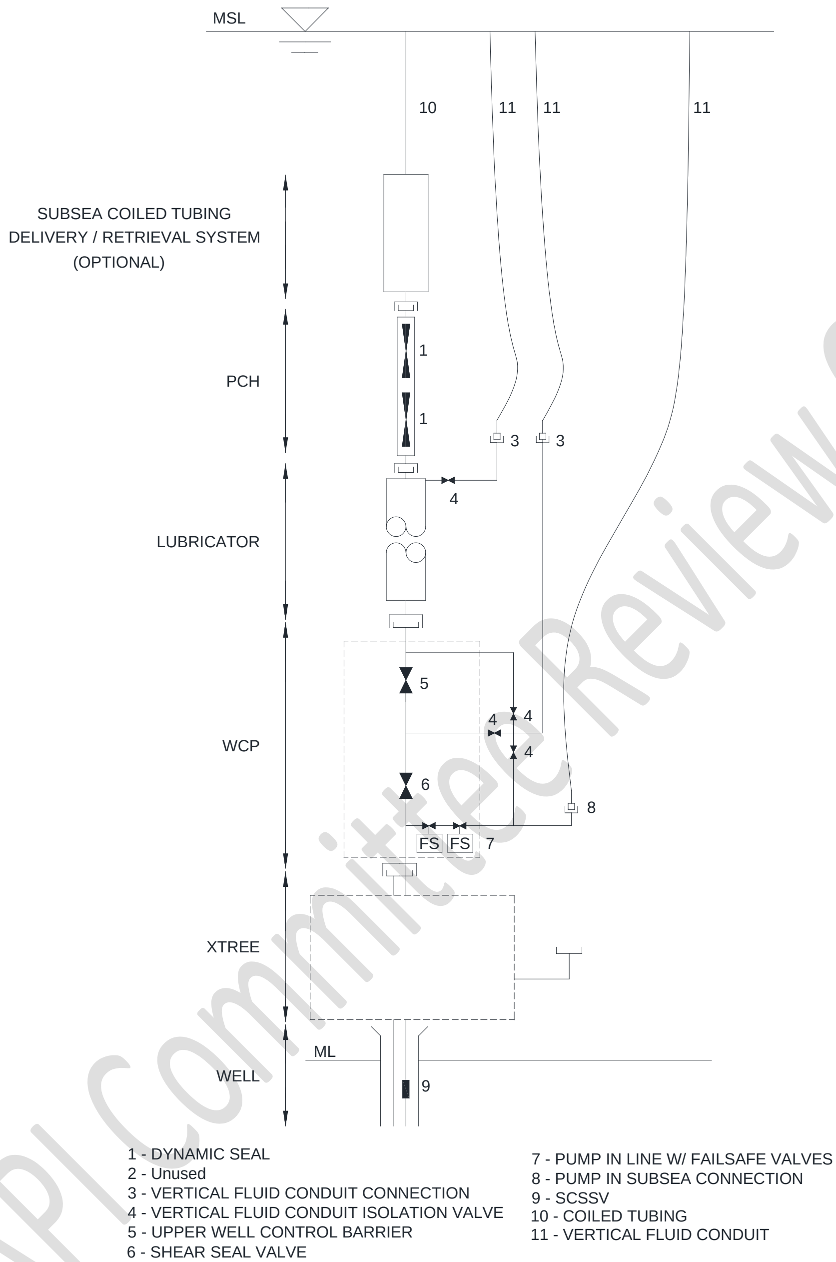

Figure 4 - Example of RSWIS attached to a Tree for Riserless Coiled Tubing Intervention Mode

4.2 System Engineering

The system engineering methods should conform with the requirements in API RP 17G1.

4.3 System Functional Requirements

A riserless subsea well intervention system shall fulfill the following requirements;

- Allow wellbore servicing with wireline tools and/or coiled tubing via the individual bore of a subsea tree or tubing head;

  NOTE: The reference to "individual bore" refers to the bores through the tubing hanger which may include both production and annulus bores in a dual bore system and both production bores and the annulus bore in a triple bore system

- Provide a means for well intervention tooling complete with intervention conduit (i.e. Wireline or Coiled Tubing) to access the well;
- Provide means of well control throughout all planned intervention and contingency operations. Contingency operations are defined by a project specific risk assessment;
- Provide a means to flush the lubricator and well control package during tool entry and retrieval operations;
- Provide a means to circulate fluids to and from the subsea system;

  NOTE: The capability to flow hydrocarbon fluids to surface via the circulation system for extended periods, such as when performing a well test or producing a well, is not a requirement in this recommended practice.

- Barriers shall be available to isolate well produced fluids / gas (e.g., hydrocarbons) from the circulation downlines and the environment;
- Where intervention tooling is run through open water independently of the intervention system, means shall be provided to ensure the intervention tooling (BHA) and the intervention conduit (e.g. Wireline or Coiled Tubing) and any additional components deployed with it, may engage with the intervention system subsea and provide a barrier interface to withstand all loading (i.e. structural and pressure end load).

A riserless subsea well intervention system should fulfill the following requirements;

- A means of fluid access to each individual bore at all times during intervention operations to enable pressure balancing / adjustments.

4.4 Safety Strategy

Refer to API 17G1 for general guidance of the Safety Principles, this section provides guidance specific to RSWIS.

A Safety Strategy shall be developed and applied to the design and operation of the riserless subsea well intervention system.

The safety strategy shall, at a minimum, review and document the requirements for;

- Process Shut Down (PSD);
- Emergency Shut Down (ESD);
- Emergency Disconnect System (EDS).

The objective of the Safety Strategy is to ensure, through a risk assessment process, that in all reasonably foreseeable operational, emergency and failure scenarios it remains possible for the RSWIS to fail into a Safe State (3.1.20).

4.5 System Design

System design shall be based on the requirements communicated by the Safety Strategy. In the event of a conflict between this document and a relevant law or regulation, the relevant law or regulation applies to the extent necessary to achieve full compliance.

The System Design should be documented to record how the system integrator will design, or has designed, the RSWIS to meet all the operational, functional, safety and contingency requirements identified in the Safety Strategy.

The format, layout and structure of the System Design documentation is not defined in this document.

4.6 Structural Requirements

The subsea equipment and system shall have a structural analysis performed for all intended normal, extreme and survival conditions to ensure that they can support the combined loads (see Section 5.2 for further detail).

4.7 Safety Functions

The minimum safety functions for riserless subsea well intervention systems shall include;

— Process Shut Down (PSD) - stop flushing / circulation operations at surface and close subsea fluid conduit valves to isolate flow from / to surface and flow within the surface process equipment;

— Emergency Shut Down (ESD), - activate PSD and close subsea well barrier elements;

— Emergency Disconnect System (EDS), - activate PSD, ESD and disconnect of attachment(s) from the subsea packages, and closure of the retaining device below the vertical fluid conduit(s).

NOTE: It is the responsibility of the system manufacturer (during the design and build phase) and the system user (during the operational phase) to prepare, review and update the Safety Strategy to ensure the ability of the system to fail into a Safe State.

Minimum requirements towards safe state for safety functions are specified in Table 1.

Minimum requirements towards safe state conditions for well control devices following loss of control are specified in Table 2.

NOTE: The EDS function is a safety function that can be activated to limit load. However, other physical protection (load limiting devices; weak links and safety joints) may be included to augment reaction time or address a particular threat to the subsea well intervention system's integrity in the event that the EDS fails to operate.

Table 1 - Minimum Safe State for Safety Functions – Riserless Intervention Mode

<table>
<tr><th>Safety Function</th><th>Barrier and Surface Facility Safe State</th><th>Description of Safety Function</th><th>Operational Modes</th><th>Intervention System Safe State</th></tr>
<tr><td>PSD</td><td>— Close subsea conduit barriers
— Close choke manifold ESD valve</td><td>Isolate circulation conduits and surface fluids handling systems from subsea system</td><td>— Wireline
— Coiled tubing</td><td>Well bore isolated from circulation conduits</td></tr>
<tr><td rowspan="2">ESD [a d]</td><td rowspan="2">— Isolate well subsea
— Establish secondary well barriers</td><td rowspan="2">Isolate the well by closing the WCP well control devices in production bore, annulus bore, crossover loops and injection system</td><td>— Wireline [d]
— Coiled tubing [e]</td><td>Well isolated by WCP [c]</td></tr>
<tr><td>Non-shearable tools over isolation device(s)</td><td>Compensating measures in accordance with Section 7.2.4</td></tr>
<tr><td rowspan="2">EDS [b d]</td><td rowspan="2">— Disconnect surface vessel from subsea system
— Isolate well from environment
— Isolate hydrocarbon and circulation fluids in vertical fluid conduits to prevent losses to the environment</td><td rowspan="2">Separate the vessel from subsea systems</td><td>— Wireline [e]
— Coiled tubing [e]</td><td>— Well isolated by WCP
— Circulation and hydrocarbon fluids contained within vertical fluid conduits</td></tr>
<tr><td>Non-shearable tools in work strings</td><td>Compensating measures in accordance with Section 7.2.4</td></tr>
</table>

a ESD shall also initiate PSD unless otherwise specified in the Safety Strategy. Activation of PSD shall not prevent activation of ESD or EDS.

b EDS shall initiate PSD and ESD unless otherwise specified in the project specific FMECA. Activation of PSD or ESD shall not prevent the activation of EDS.

c When a workstring (e.g. wireline, coiled tubing etc.) penetrates the well barrier, one of the barrier elements (well control device when used as an in-situ barrier element) shall be able to shear the workstring and seal the wellbore. End user is responsible to ensure that the shear capacity validated in API 17G Annex H meets project specific requirements.

d Refer to Clause 7.2.7 for barrier closure sequence and the timing requirements.

e WCP shall include either wireline class or wireline / coiled tubing class or safety head class well control device(s) validated in accordance with API 17G Annex H.

Table 2 - Automatic Safe State for Well Control Devices Following Loss of Control

Event	Well Control Device	Barrier Safe State	Operational Modes	Intervention System Safe State
Loss of control while connected subsea	WCP	— Automatic isolation of well subsea — Establish primary well barrier	— Wireline — Coiled tubing	— Well isolated by WCP fail-safe-close well control devices — Well isolated by fluid conduit fail-safe-close valves — EDS disconnected
For hydraulically operated systems, loss of control equals loss of ability to function primary well control elements remotely from surface. Loss of ability to re-charge hydraulic stored volumes subsea does not equal loss of control, so long as remaining pressures and volumes in accumulated volumes can be continuously monitored. For electro-hydraulically or electrically operated systems, loss of control must be addressed in the Safety Strategy and defined on a system specific basis, as loss of communications, loss of power and loss of hydraulic supply may be transitory and will impact each system differently depending on the control system design.				

4.8 Regulations, Codes, and Standards

The system shall comply with the applicable regulatory requirements for the region in which the system will be operated. The RSWIS equipment included in the scope of the API RP 17G4 shall be designed, manufactured, and tested in accordance with the applicable references, codes, and standards specified in API Std 17G.

Components and systems included in a riserless subsea well intervention system, which have not been designed and manufactured in accordance with API Std 17G, shall be identified. API RP 17Q should be used as a guide to qualify such components of the system.

5 Global System Analysis

5.1 General

Global analyses should be performed as per API RP 17G1, API RP 17G2 and API RP 17G6. The riserless subsea well intervention system is characterized by; smaller diameter vertical fluid conduits that are not rigidly attached to a well control package; wireline or coiled tubing deployed through the water and into the well; and a more weather-sensitive multi-service intervention vessel as compared to a typical top tensioned intervention riser as covered in API RP 17G1. The following modifications and additions to API RP 17G1 and API RP 17G2 are recommended for riserless intervention systems analysis. The analysis is performed to establish survival limits and the ability of safety devices to operate as intended.

5.2 Global System Structural Analysis

Global system structural analysis is performed to establish the behavior of the;

— vertical fluid conduits;

— wireline deployed into the well;

— coiled tubing deployed into the well;

— other connections between the vessel and the WCP, PCH, IWOCS, Subsea Tree or Wellhead.

The analysis is used to provide the following data:

— Tension load in the vertical fluid conduit and flying leads, and loads imposed on the WCP and lubricator versus intervention vessel offset;

— Tension and bending loads imposed by wireline or coiled tubing deployed in the well should they be restrained at the WCP & PCH, for example by a pipe slip or an attached downhole toolstring preventing movement, versus intervention vessel offset (including loss of station keeping);

— Loads for the assessment of weak links and accidental loads due to entanglement of downlines with the lubricator or PCH during a loss of station keeping event;

— Clashing conditions between the vertical fluid conduits, other downlines and the well intervention subsea equipment;

— Bend radius vs intervention vessel offsets for the vertical fluid conduits and their flying leads;

— Harmonic or dynamic loads in the downlines and intervention coiled tubing 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 and the intervention coiled tubing.

The above data is used in the selection of the vertical fluid conduits and the structural analysis of the main system components and connection devices, including any weak links or tension release devices. The analysis is also performed to establish Normal, Extreme and Survival conditions as detailed in API Std 17G.

If the intervention system's design includes a riser re-entry capability, the end user should refer to API RP 17G1 when this mode is to be used.

Global riser analysis and fatigue analysis methodology and load cases for all configurations are similar to those specified by API Std 17G and API RP 17G6.

5.3 Global Hydraulic Analysis

Global hydraulic analysis of the pumping and return system should be performed to verify that the pumping, flushing and kill system has the required performance to deliver the flow rate and pressure to flush the system and/or perform well kill operations (refer to API RP 17G2).

6 System Component Requirements

6.1 Common Requirements

In addition to the requirements listed in API Std 17G, the following additional requirements are common to all equipment in the RSWIS system;

— 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 de-pressurized;

— The well bore wetted components of the system shall be compatible with all chemicals and hydrocarbons that they may be reasonably likely to come into contact with;

— Wherever appropriate, the design of guidance systems shall define the functional requirements for; seal makeup tolerance; angle of re-entry and release.

6.2 Regulations, Codes and Standards

Functional and operational requirements for the following components are covered in this clause, API Std 17G or API RP 17G2 as noted. Components not listed should adhere to the design requirements of API Std 17G.

— Well Control Package – API Std 17G

— Lubricator – Section 6.7

— Pressure Control Head – Section 6.3

— Control System - API Std 17G

— Disconnect Systems – API RP 17G2

— Fluid conduits, Connectors, Flying Leads and Jumpers – API Std 17G, API RP 17G2 & Section 6.11

— Coiled Tubing retrieval and delivery to the WCP system – API RP 17G2

— Flying Leads – API RP 17G2

— Topside wireline / coiled tubing motion compensation systems – not covered in this document

Table 3 provides a guide for the codes and standards that should be used for the various components of an RSWIS.

Schematics of example riserless subsea well intervention systems are illustrated in **Error! Reference source not found.**.

Table 3 - Component Requirements

RSWIS Component	**Functional Requirements**	**Design Requirements**	**Materials and Manufacturing Requirements**	**Validation Testing**
	Document Section	**API Document or API Std 17G Clause**		
Vertical Fluid Conduit	Section 6.12	API RP 17G2	Clause 6	Clause 8
Fluid Conduit Connectors	Section 6.14	API RP 17G2	Clause 6	Clause 8
Vertical Fluid Conduit Deployment System	Section 6.13	API RP 17G2	Clause 6	Clause 8
Retainer Valve	Section **Error! Reference source not found.**	API RP 17G2	Clause 6	Clause 8
Pumping System	Section 6.3	API Spec 16C	API Spec 16C	API Spec 16C
Fluid Tank	Section 6.3.2	OEM Specified	OEM Specified	OEM Specified
Gas Separator	Section 6.3.3	API Spec 16C	API Spec 16C	API Spec 16C
Manifold	Section 6.3.4	API Spec 16C	API Spec 16C	API Spec 16C
Interconnecting Piping	Section 6.3.5	OEM Specified	OEM Specified	OEM Specified
Pressure Control Head (PCH) Wireline Mode [a]	Section 6.4	Clause 5	Clause 6	Clause 8
Coiled Tubing Stuffing Box [a]	Section 6.5	Clause 5	Clause 6	Clause 8
Tool Catcher [a]	Section 6.6	Clause 5	Clause 6	Clause 8
Lubricator Assembly [a]	Section 6.7	Clause 5	Clause 6	Clause 8
Tool Trap [a]	Section 6.8	Clause 5	Clause 6	Clause 8
Flushing System / manifold [a]	Section 6.11	Clause 5	Clause 6	Clause 8
Well Control Package	Section 6.10	Clause 5	Clause 6	Clause 8 Annex I
Flying Leads & Jumpers	Section 6.15	Clause 5	Clause 6	Clause 8

a These items are not uniquely identified in API Std 17G but the same design, material, manufacturing and quality principles as set forth in API Std 17G for subsea components should be used.

6.3 Pumping system

6.3.1 Functional Requirements

The pumping system is mounted on the vessel and is utilized to pump stored fluids into the vertical fluid conduits via a manifold.

The pump(s) shall have seals which are compatible with all fluids that will be pumped during the intended operations, including any contingency fluids.

The pump(s) shall be capable of pumping the intended fluids at a rate and pressure that is required for all intended operations including potential well killing operations via bullheading.

If the pump is to be placed in a hazardous area it should meet the applicable zone requirements (refer to API RP 505).

The pumps shall have the following;

— Overpressure protection device(s);

— Over speed protection device(s) if the prime mover is an internal combustion engine;

— Over temperature alarm(s);

— Discharge pressure gauge(s).

6.3.2 Fluid Tank

Several types of tanks are utilized and mounted on / or below deck(s). The functional requirements of each tank may differ depending on usage, for example storage of flush returns or well treatment fluids.

The system integrator will specify the requirements with the OEM.

6.3.3 Gas Separator

The gas separator is mounted on the vessel and is used to remove gases from any hydrocarbons flushed to the vessel during operations.

The type, capacity and specification of the separator required for the operation will be agreed between the system integrator and the end user.

The separator shall meet the requirements of API Spec 16C.

The gaseous exhaust from the separator should be located on the vessel so as to avoid gases defusing over working areas and accommodation (especially HVAC intakes) on the vessel.

6.3.4 Manifold

A manifold is sited on the vessel to direct pumped and/or returned fluids as required in the fluid/pumping system.

The manifold may also be used to close-in a flow path.

Typically, the manifold has adjustable and/or fixed chokes to assist with the control of flowing fluids, i.e. pressure and flow rate.

The manifold shall have an RWP that meets or exceeds the RWP rating of other parts of the pumping system, especially the maximum output from the pump(s).

The system integrator and the end user will agree the size, type and RWP of the manifold.

The manifold shall meet the requirements found in API Std 16C.

6.3.5 Interconnecting Piping

Interconnecting piping is piping which connects the components of the pumping package together.

The piping shall have a bore and service rating (RWP, temperature, material) suitable for the intended operation.

Specifications should be agreed between the System Integrator and the piping OEM.

6.4 Pressure Control Head (PCH)

6.4.1 Functional Requirements

The Pressure Control Head (PCH) provides a means for allowing the wireline or coiled tubing to move into, or out of, the well whilst preventing an egress of well fluids to the environment or ingress of seawater into the well. This is an operational pressure control device and, at all times when in use, barriers shall be available to be activated at the WCP to isolate the well.

6.4.2 Wireline Operations

The wireline mode PCH typically contains a combination the following components;

— Dynamic grease seal;

— Dynamic mechanical seal;

— Dual Pack-off for a static isolation on the wire;

— PCH connector.

The PCH shall be able to create both a static and a dynamic seal around the wireline. The seals of the PCH shall be designed for the anticipated operating pressure and temperature and suit the wireline in use.

The PCH should include an automatic device to contain fluids within the lubricator, and/or prevent ingress into the lubricator, in the event of an unintended loss of wireline through the PCH.

6.4.2.1 Dynamic Grease Seal

A dynamic grease seal is typically employed to provide a seal around braided wireline. Grease is injected into the annular space between the wireline and the flow tube.

6.4.2.2 Grease Injection System

The grease system injection capacity should be designed to maintain the pressure seal for the intended operating time and conditions.

Consideration should be given to having the ability to refill the storage capacity whilst the system is subsea in the event that the consumption of the grease is higher than anticipated during operations.

The grease supply to the flow tubes and pack-off units shall be independent of each other.

An environmentally acceptable grease should be used for subsea operations.

Note: Environmentally acceptable is determined by the applicable local regulations.

6.4.2.3 Dynamic Mechanical Seal (slickline)

A dynamic mechanical seal is typically employed to provide an elastomeric seal around the wireline.

The elastomeric sealing material should be compatible with the service environment (refer to API Std 17G).

The seal should be capable of providing pressure containment to prevent flow of well fluids to the environment, as well as preventing flow of sea water into the well, for the wireline type and diameter being employed.

6.4.2.4 Dual Packoff

The dual packoff is incorporated into the RSWIS to provide a secondary sealing mechanism in the case of failure of the primary dynamic sealing system.

The dual packoff provides an elastomeric seal around a static wireline. A dual packoff contains 2 packoff elements.

For braided wireline, there should be the capability to inject grease between the pack-off elements in the dual pack off assembly to provide additional sealing capability, preventing gas migration between the wireline strands.

The packoff shall be suitable for the wireline type and diameter being used.

The sealing material should be compatible with wellbore fluids and pumped fluids

The dual pack-off shall be capable of providing pressure containment to prevent flow of well fluids to the environment, as well as preventing flow of sea water into the well, for the wireline type and diameter being employed.

6.5 Coiled Tubing Stuffing Box

6.5.1 Functional Requirements

A dynamic mechanical seal is typically employed to provide an elastomeric seal around the coiled tubing.

The elastomeric sealing material should be compatible with both the wellbore fluids and any fluids which will be pumped into the well.

The seal should be capable of providing pressure containment to prevent flow of well fluids to the environment, as well as preventing flow of sea water into the well, for the specific coiled tubing and diameter being employed.

The seal is normally energized to establish and maintain an effective seal between the coiled tubing and the body of the stuffing box.

The pressure rating for the seal and stuffing box body is usually compatible with the rated working pressure and temperature of the WCP and PCH. As a minimum, the pressure rating will be greater than the MAWP plus the well kill margin.

6.6 Tool Catcher (Head Catcher)

6.6.1 Functional Requirements

A tool catcher is used in wireline mode to prevent the BHA from being accidentally dropped into the well or onto the top of a well barrier element, should the wireline part or be pulled out of the BHA's rope-socket. The tool-catcher should be located below the PCH.

A tool catcher has a mechanism to secure the toolstring below the PCH. The intent is that the catcher will automatically secure the toolstring should the wireline unintentionally be pulled free from the toolstring at the PCH.

The decision to use a Tool Catcher in the PCH assembly will be determined by the operation and the system integrator.

The Tool Catcher pressure rating, strength and material selection performance should be compatible with the specifications of the PCH.

Tool Catcher, if used, shall be suitable to engage with the BHA being used.

6.7 Lubricator Assembly (LA)

6.7.1 Functional Requirements

The Lubricator Assembly (LA) is located above the WCP and below the PCH.

The lubricator may consist of the following components;

— PCH connector;

— Lubricator pipe sections;

— Tool Trap (optional);

— Lower connector (typically to the top of the WCP).

The primary function of the LA is to house the BHA prior to entry into, or after extraction from, the well such that the BHA does not hang through barrier elements which may not have the capacity to shear the BHA. If a Tool Trap is used (See Section 12.7) the bottom end of the BHA, when retrieved into the LA, shall sit high enough to allow the Tool Trap to close.

The lubricator shall be capable of containing the MAWP.

The lubricator shall be rated to withstand the hydrostatic head at the operating water depth considering an evacuated load case (collapse resistance).

The internal usable length of the LA should accommodate the longest BHA to be used for planned well bore activities.

6.8 Tool Trap

6.8.1 Functional Requirements

The tool trap can be used in wireline and/or coiled tubing modes to prevent the BHA from being accidentally dropped into the well or onto the top of a well barrier element, should the wireline part or be pulled out of the BHA's rope-socket or from the end of the coiled tubing. The tool-trap should be positioned at the bottom of the lubricator or above well barrier elements in WCP.

The trap should allow the free passage of the wireline or coiled tubing and prevent the BHA from falling through.

Typically, the flapper mechanism is such that it allows free passage of the BHA when the BHA is moving upwards.

The tool trap rated working pressure shall be, at a minimum, the same as the lubricator assembly.

There should be an indicator, external to the trap, to show the position of the flapper.

6.9 Re-entry Spool

6.9.1 Functional Requirements

A re-entry spool can be incorporated into the subsea system architecture. The re-entry spool is a subsea mate-able connection system capable of providing a cross-over connection to a workover riser or other well containment equipment. The re-entry spool should be located above a minimum of two well barriers on the WCP. The re-entry spool may be the bottom half of the lubricator connector.

The Spool design shall allow for multiple make up and breaks appropriate for the application and design life.

The internal bore should be smooth to allow for passage of BHAs, wireline and coiled tubing.

The WCP upper re-entry spool interface with the lubricator or PCH shall have a defined minimum combined structural capacity to handle operations, including contingent operations, defined by the system integrator and/or the end user.

6.10 Well Control Package

6.10.1 Functional Requirements

The function of the WCP is to provide the well barrier elements and connection points for the vertical fluid conduits.

A WCP shall, as a minimum, contain the following components (also refer to API Std 17G1);

— Lubricator connector;

— Well control barrier element;

— Shear-sealing device;

— Flushing / well kill manifold and connector for the vertical fluid conduits;

— Two flushing / well kill side outlet valves on each outlet;

— Subsea control system (if utilized);

— Interface to Tree connector;

— ROV/Diver interfaces.

The lower most device should be a shear device.

NOTE: If a shear only function is used, a means to clear the sealing devices of obstructions will be necessary.

All barrier elements shall have visual position indicators observable by ROV/diver/surface personnel.

The outlet valves shall have the ability to seal from either direction.

The shear device(s) and/or shear-sealing device(s), and the side outlet valves shall have ROV override capability.

The WCP shall provide all structural support and be able to withstand the combined survival loading from the wireline, coiled tubing, and vertical fluid conduits and guidewires where used and they remain connected during operations.

In Coiled Tubing Intervention Mode, a coiled tubing shear device shall be capable of shearing the CT body that will pass through it during operations (and any spoolable components inside the coiled tubing) at the MAWP without tensile loads applied to the CT.

In Wireline Intervention Mode, the shear-sealing device shall be capable of shearing and sealing any wireline that is deployed through the WCP

Note: See API Std 17G for verification requirements of shear-sealing barrier devices

The shear or shear-sealing device shall be capable of two or more cuts. The shear cut should facilitate subsequent through coiled tubing pumping and well killing operations. The geometry of the shear cut should also enable fishing operations.

6.11 Flushing / Well Kill System

6.11.1 Functional Requirements

This system has the following functions;

— Flushing of the WCP and lubricator.

— Depressurize and flush the WCP and lubricator of hydrocarbons prior to opening the system to the sea after tool retrieval from the well;

— Bullhead fluids for well treatment or well kill;

— Perform stump and subsea pressure testing of all well barriers;

— Provide chemical injection points for hydrate prevention.

The flushing/kill system should contain the following components;

— WCP and lubricator flushing manifold;

— Vertical fluid conduits connecting the WCP to the intervention vessel;

— Connection points for the vertical fluid conduits;

— EDS system for the fluid conduits.

The WCP and lubricator should be configured such that flushing or kill fluids may be circulated to obtain a complete flush of the bore the system.

Additional bore entry points may be added to facilitate hydrate prevention and pressure testing.

The kill side outlet shall have two fail-closed barrier valves that can withstand pressure in both directions. Refer to Section 4 for the timing of these fail close valves.

All barrier elements of the WCP shall have the same RWP.

6.12 Vertical Fluid Conduits

Refer to API RP17G2 for the functional requirements.

NOTE: API RP 17G2 specifies compliance with API Spec 5ST but some commercial grades of metallic coiled tubing are not contained in this specification. If the system integrator is choosing to use such a grade of coiled tubing they will need to obtain the equivalent data and information from the OEM.

6.12.1 Retainer Valve or Retainer Device (optional)

Retainer Valves are used in Riserless Subsea Well Intervention Systems to retain the fluid in the fluid conduit upon an unplanned disconnect. These valves or retainers should not prevent flow during normal operations. Refer to API RP17G2 for further functional requirements.

6.13 Vertical Fluid Conduit Deployment (and Recovery) System

Refer to API RP17G2 for the functional requirements.

6.14 Fluid Conduit Connectors

Refer to API RP17G2 for the functional requirements of the following;

— Subsea Releasable Connectors;

— Riserless System Weak Link Connectors.

6.15 Flying Leads and Jumpers

Refer to API RP17G2 for the functional requirements.

7 Operational Requirements

7.1 General

The purpose of this section is to define and ensure component selection and system design achieves barrier requirements and conforms with the agreed safety strategy. The scope of Operational Requirements builds from System Requirements in Section 0 to provide guidance on procedures, how barriers are achieved and maintained during subsea well interventions with hydrocarbon bearing reservoirs and/or pressurized formation with potential to flow to mudline.

RSWIS component specific requirements are detailed in Section 6.

7.2 Operational Requirements

For operations in wells with hydrocarbon-bearing reservoirs and/or pressurized formation with the potential to flow to the mudline, two independently tested well barriers shall be available at all times.

Before commencing well intervention operations;

— The end-user, or party designated by the end-user, shall confirm that the rated working pressure (RWP) of each barrier element shall meet or exceed the MAWP, plus a well kill margin.

— A documented risk assessment and barrier philosophy shall be established and implemented consistent with Section 4.4 and Section 7.2.2.

The barrier philosophy shall demonstrate the interaction of the equipment functionality and the operational requirements.

To configure a RSWIS, the functional requirements for the system need to be identified to establish the functional and operational performance criteria of the various components.

The components of a RSWIS require analysis and design techniques that are in accordance with those contained in API Std 17G. A RSWIS is similar in configuration and components to Subsea Pumping Well Intervention Systems addressed in API RP 17G2 and the overall design principles and analysis and design of like components should be as per API RP 17G2.

RSWIS's are classified as temporary systems and normally have a defined operating envelope relative to metocean conditions. In situations where operating conditions are expected to exceed the operating envelope (i.e. excessive sea state or wind conditions forecasted), barrier element devices shall be activated and the RSWIS system shall either be disconnected from surface lines or be retrieved.

7.2.1 Shear-sealing Devices

For a shear-sealing device to be considered as a barrier element, the device shall be validated as per API 17G.

In the case of two devices, one shearing, and one sealing, the risk assessment shall document how potential cut debris, or a remaining obstruction, is removed from the adjacent sealing device before its closure takes place. Shear consequences and a risk mitigation plan shall be defined if debris is dropped downhole.

NOTE: Further information can be found in API RP 17G1.

7.2.2 Well Barrier Selection and Principles

Well barriers to the environment shall be placed in one of two classes:

— intervention equipment barriers brought to the wellsite;

— in-well barrier devices, such as completion equipment, already in place.

Permanently installed subsea and downhole equipment may be a part of the well intervention barrier plan.

In-well barriers may be considered during those steps of the operation that do not prevent their ability to function either for immediate or delayed closure (i.e., mechanical overrides on tree valves or hydraulic trapped pressure on SCSSVs). Examples of in-well barriers are barriers in the completions such as SCSSVs, intervention barrier valves or subsea production tree valves.

Two fail safe close devices, or other barrier elements, in series between the production bore and the environment and between the production tubing annulus and the environment shall be available at all times.

The well barriers shall be selected to;

— withstand the maximum anticipated well pressure to which they may become exposed plus a well kill margin;

— be pressure tested and function tested, or verified by other methods;

— ensure no single failure of a well barrier or well barrier element can lead to loss of well control;

— re-establish a non-functioning well barrier or identify an alternative well barrier;

— operate reliably and withstand the environment to which it may be exposed to over time;

— have the physical location and integrity status of the well barrier element known during the operation.

Deviation from the above requirements shall be documented, risk assessed and mitigated prior to selecting the component as a barrier element. The primary and secondary well barriers shall be capable of being independently verified of each other. The well barriers shall, to the extent practicable, not have common well barrier elements.

In the event independently tested barriers are not possible, and/or common well barrier elements exist, a risk analysis shall be performed and risk reducing/mitigating measures applied to control the well and manage, health, safety and the environment.

The PCH provides a barrier element during operations and is an element of the primary well barrier, preventing flow of well fluids to the environment. Additional mechanical well barrier elements may be necessary to place the well in a safe state.

NOTE: The grease tube system will typically allow grease into the sea water as a part of its operating characteristic.

NOTE: Further information can be found in API RP 17G1.

7.2.3 Well Barriers in Operation

The PCH shall be capable of sealing with a net positive pressure to the environment to prevent hydrocarbon release and be capable of sealing with a net negative pressure from the environment to prevent seawater ingress in to the well and potential hydrate formation.

For operations requiring mechanical entry into the well, the well barriers shall have at least one (1) barrier element that can shear-sealing the workstring (coiled tubing or wireline, etc.) used to enter the well (See API RP 17G1 for additional information). The well barrier element(s) used for shearing shall be shear qualified to API Std 17G for wireline class, wireline/coiled tubing class or safety head class.

Well barriers and well barrier elements shall be tested according to Section 10.

If a shearing device is not designed to seal after shearing, the following requirements shall be in place:

a) an unobstructed barrier element is available to seal;

b) ensure any obstruction to the barrier element will be removed to obtain the seal.

If a shear function is performed the device(s) shall be function and pressure tested before being put back in service.

In the event of a failure or loss of a primary or secondary well barrier, immediate measures shall be taken to prevent escalation of the situation. The well barrier (or alternative) shall be established before activities or operations can be resumed.

7.2.4 Management of Non-shearable Tools

If components in the workstring (e.g. downhole tools) penetrate the well barrier element and cannot be sheared, the following requirements shall be in place;

a) all non-shearables in the workstring shall be identified;

b) when running non-shearables, a procedure for maintaining well containment shall be in place.

The anticipated duration that the well barrier elements will be exposed to non-shearable tools shall be identified and included in the hazard and operability studies/hazard identification (HAZID/HAZOP) assessments identifying the risk exposure (typically; elapsed time, stuck tooling, well control situation, loss of vessel position) and any compensating measures considered necessary to meet the risk mitigation criteria.

NOTE: Further information can be found in API RP 17G1.

7.2.5 Barrier Schematics for Well Intervention

During a well intervention operation, the number of available well barrier elements and the physical extent of well barriers may change as the well intervention operation progresses. A well barrier schematic (WBS) should be prepared for each well activity and included in the procedure.

Well barrier schematics should be developed as a practical method to demonstrate the presence of defined primary and secondary well barriers. Operational procedures (i.e., operational barriers) shall be included to address any activity where it is not possible to have a secondary barrier available.

Practical methods to demonstrate the presence of defined well barriers are tables, schematics, and descriptions. The tables and schematics should be tailored to, and aligned with, the objectives of each stage of the planned intervention. Multiple tables and schematics may be needed to address all the situations during planned activities but should not be limited to the content specific to each operation.

In the barrier philosophy, the barrier elements should be defined together with acceptance criteria and methods of monitoring their status throughout the operations.

For guidance on developing barrier philosophies refer to NORSOK D-010, API RP 17A and API RP 96.

7.2.6 Flushing System

The operation of the flushing the system should enable removal of well bore fluids from the system, with the configuration of the system ensuring minimal residual volume of trapped/un-flushable fluid in the subsea equipment.

The purpose of the flushing process is to;

— prevent the release of well bore fluids to the environment during BHA changeout and system retrieval;

— reduce the risk of hydrate formation within the subsea portion of the RSWIS.

The volume of well bore fluids flushed from the system is generally small, typically a few barrels. The flushing system is not normally used as a conduit through which to flow a well to surface. If the flushing system is intended to be used for this purpose during operations a risk assessment should be performed to assess its suitability.

A risk assessment, such as a HAZOP and/or HAZID, should be performed on the system with particular focus on the portion of the system sited on the vessel.

The Flushing System shall;

— be designed to manage wellbore fluids at surface in a safe manner as verified by HAZID/HAZOP;

NOTE: Surface can be the vessel or the host facilities

— have a pressure rating sufficient to overcome MAWP plus a margin for bullheading or well kill operations.

7.2.6.1 Hydrate Mitigation & Management

Consideration shall be given to the management of hydrates in the event that they are present. In particular, the effect of hydrate formation on the function of the Tool Catcher or Tool Trap (if fitted) due to interference with functional moving parts within the well bore. Consideration should be given to additional chemical injection points to suit the system configuration / flushing method.

When flushing, displacing and pressure testing the flushing system, hydrate formation inhibiting fluids are recommended to be used (e.g. mixture of water and MEG).

NOTE: Also refer to Functional Requirements, Section 6.11.1.

7.2.7 Emergency Disconnect System (EDS)

The EDS provides disconnection of all connections between the vessel and the subsea WCP, Wellhead and Tree. These connections typically include;

— UMB;

— Hydraulic lines;

— Electrical lines;

— Coiled Tubing / Wireline (see WCP Section for functional requirements);

— Fluid conduits;

— IWOCS umbilicals;

— Guidewires.

A risk assessment shall be performed to confirm that the EDS is activated prior to structurally overloading the WCP, Tree and Wellhead (survival load condition). The disconnection sequence of the EDS should not overload the WCP, Tree and Wellhead structure as it is functioned. The risk assessment should define the safety factors to be applied to the design of the EDS.

Typically, two types of disconnect systems are utilized in riserless subsea well intervention systems;

— A commanded disconnect device that disconnects when signaled via the control system;

— A passive disconnect device that disconnects without a signaled input.

Disconnection devices may incorporate auto ejection methodologies.

At a minimum, all flow conduits are to be equipped with a passive disconnect device. A risk assessment shall be performed to determine if the vertical fluid conduits are required to seal automatically upon disconnection.

The EDS is usually made up of the following equipment;

— A Subsea Umbilical Termination (SUT) or umbilical connection system that has a remotely operated disconnect function and/or a shear pin device that parts at a predetermined tension load in the umbilical;

— The emergency disconnect of the vertical fluid conduits and/or jumper lines is typically achieved with a shear pin device that separates and seals the conduits at a set tension in the lines.

The closure sequence and timing of fail-safe devices and barrier elements of the WCP in an emergency situation shall be in accordance with the requirements of API RP 17G1-Response Times.

7.2.8 Conversion to riser based system

The RSWIS may be designed to allow conversion to an OWIRS (either planned, or as a contingency). In all cases the resulting riser-based system shall conform to the requirements of API Std 17G and API RP 17G1.

7.2.9 Control System

The function of the control system is to provide control of the system in both normal operations and emergency situations.

In an emergency situation, some devices will be controlled via the control system while other barrier element devices are designed to be fail safe so that the well will be secured should communication between the surface control system and the barrier element be lost.

The system integrator shall specify which devices are to be of a fail safe type.

The control system shall be in accordance with API Std 17G and API RP 17G5, with the following clarifications;

At a minimum the control system shall allow surface control of the following functions;

— Open and close the shear-sealing devices;

— Open and close the side outlet valves;

— Grease delivery system (wireline mode);

— control of dynamic mechanical seal of the PCH (wireline mode);

— Open and close the dual static pack-off units in the PCH (wireline mode);

— Open and close all stuffing box (or equivalent) units in the PCH (coiled tubing mode);

— EDS function is included only if the system is equipped with commanded disconnect devices;

— An integrated ESD function that closes both shear-sealing devices and the side outlet valves is optional;

— Autoshear and Deadman functions are required.

All other functions or control valves can be direct ROV (or diver) operated or operated by the control system and remotely operated from the surface control panel. Pressure and temperature transducers can also be incorporated into the control system and/or ROV readable gauges can be provided. The system may also provide the ability to control tree functions or provide power and signal transmission to a tree subsea control module (SCM).

It is acceptable to rely only on ROV verification of a function's actuation, however actuation indication via the control system for critical safety functions is recommended.

7.2.10 Coiled Tubing retrieval and delivery system

The coiled tubing retrieval and delivery system provides the mechanical means to move the coiled tubing into and out of the well while maintaining the structural and pressure containing integrity of the tubing.

This system typically consists of three main components;

— Coiled Tubing Reel

— Surface coiled tubing injector

— Subsea coiled tubing injection device

The coiled tubing reel and surface injector are similar to those used in riser based coiled tubing operations including the means to provide motion compensation.

Subsea coiled tubing injection devices are used to convey the tubing into and out of the well, through the PCH. These coiled tubing injection devices are used primarily to resist the thrust imposed on the coiled tubing by the well pressure. The injection device may only be operational, or engaged, during certain stages of a well intervention operation in coiled tubing mode.

7.3 External Inspection and In-Service Maintenance

Systems shall be operated and maintained in a manner that ensures that the equipment functions as designed. An external visual inspection of riserless subsea well intervention systems should be conducted by remote operated vehicle (ROV) while deployed subsea at least once every three days, if weather and sea conditions permit. Alternatively, video camera(s) can be positioned on the subsea equipment and used to inspect the subsea equipment, if desired.

Dynamic seals, such as high-pressure fluid swivels, telescoping joints, PCH, should undergo regular visual inspections for signs of leakage.

The inspection results and corrective actions shall be documented by the system integrator.

7.4 Documentation

The following documentation should be available upon request (also see Section 11);

a) documented maintenance, repair and operational history (condition summary) of the relevant barrier elements;

b) verification and validation reports of well barrier elements;

c) system design revision history.

7.5 Operational Risk Assessment

A documented risk assessment shall be performed by the end user or system integrator prior to commencement of well intervention operations. The risk assessment shall, as a minimum, address the following;

a) Barrier philosophy & identification;

b) Ability to kill the well;

c) Detailed operational procedures;

d) Equipment availability, condition, and/or limitations;

e) Metocean conditions and limitations;

f) Condition of in-situ well equipment and hardware;

g) Emergency operations e.g., drift-off, drive-off;

h) Crew training and competence;

i) Crew accountability, responsibility and communications;

j) Normal, extreme, and survival loading events.

Operations shall be limited to activities identified in the risk assessment. Significant changes in the items above shall require a review of the risk assessment.

7.6 Crew Drills

Prior to commencement of well intervention operations, the system integrator or end user shall have a documented process for the planning and execution of crew drills. Crew drill planning and execution should, as a minimum, include the following;

a) Ability to execute emergency and non-routine safety procedures required for the upcoming operation

b) Responsibilities and accountabilities

c) Communication protocols

d) Awareness of key safety issues

During operations, personnel shall be prepared to secure the well in accordance with the barrier philosophy and the documented well control procedures.

7.7 Field Repair

Field repair is defined as any activity involving disassembly, reassembly, or replacement of components or assemblies in the riserless subsea well intervention system which is performed after the completion of the SIT and prior to, or during, well intervention operations.

NOTE Repair does not include machining, welding, heat treating, or other manufacturing operations.

The OEM should be consulted regarding replacement parts and assemblies.

If replacement parts and assemblies are acquired from a non-OEM supplier, the assemblies shall be equivalent, or superior, to the original equipment and fully tested, design verified, and supported by an MOC and traceable documentation in accordance with relevant specifications.

Field repairs which change any of the following shall undergo a documented risk assessment;

a) rated capacity;

b) operating envelopes;

c) interface changes (that influence form, fit, and function of the RSWIS);

d) safety strategy;

e) equipment performance parameters (that influence form, fit, and function of the RSWIS).

Designated barriers or barrier elements which undergo field repair shall be re-tested in accordance with Section 10.

All field repairs shall be documented by the system integrator per Section 9.3.3.

7.8 System Condition Summary

A condition summary record shall be maintained by the system integrator which reflects physical changes to equipment such as; wear, corrosion, or reduction of fatigue life due to use and environmental factors.

The end user shall provide (vessel specific) actual intervention data, as input to the condition summary, to the system integrator in order to determine residual fatigue life and for maintenance planning.

Typical intervention data examples used to determine consumed fatigue life and maintenance intervals is as follows as applicable:

a) Critical component cycle count;

b) fluid media (internal / external);

c) pressure/temperature (including cycles);

d) water depth;

e) equipment failure reports/analysis;

f) job test log

g) system configuration;

h) recorded metocean data

i) vessel information for GRA analysis

j) actual load cases;

— extreme or survival;

— exceedance of operability.

The system integrator will be responsible for preparation and issuance of condition reports. Previous condition reports shall be kept for the life of the equipment.

The system integrator shall be responsible for determining if individual components, or the entire system, should be inspected, repaired, replaced, or retired from service.

8 Quality Requirements

8.1 Equipment Design and Manufacturing

System quality requirements should follow the Quality Management System Requirements defined within API Std 17G. Equipment shall be manufactured in accordance with Quality Management System Requirements per API Std 17G.

The quality management system will be used to record design activities, for example design FMECA evaluations which are used to select or design components for the RSWIS.

The quality management system will be used to ensure that manufactured or purchased equipment is “fit for purpose” and meets the design specifications.

8.2 Quality System and Quality Control

System integrator should conform to the requirements of the quality management system for service supply organizations per API Spec Q2, or an equivalent code or specification.

8.3 Inspection

8.3.1 General

There are several compounding layers of equipment inspection. These levels are at the component, sub-assembly and assembly levels. For example, in the WCP, inspection criteria will be adjusted for inspection of individual WCP components and functions as well as inspection of the assembled WCP.

For riserless systems, attention should be paid to the PCH, Lubricator, Lubricator Connector and Flushing / Well Kill subsystems and their associated control systems. For details on WCP inspection refer to API RP 17G1.

Equipment inspection requirements shall be defined and performed on the systems in accordance with system integrator's written procedure which will establish the acceptance criteria and incorporates OEM recommendations. The procedure should include the following;

— overloaded/permanently deformed components;

— fatigue cracking (e.g., girth welds, connectors, anode attachment welds);

— leaks (e.g., loosening of mechanical connectors, seal ring damage);

— damage (e.g., dents, scratches, loosened or heavily distorted coating);

— internal and external wear;

— internal and external corrosion damage (e.g., girth welds, sealing faces);

— damage to anti-corrosion and/or abrasion coatings;

— degradation of cathodic protection;

— marine growth;

— loss of functionality;

— loss of performance.

Parts that are damaged, subsequently repaired, or determined to be such that failure will result in serious consequences shall be defined during the planning of inspection and maintenance processes / schedules.

Note: Also refer to API RP 17G1 for any further requirements that apply to equipment being used within the system.

8.3.2 Inspection Intervals

Inspection intervals shall be defined on the extent of use, location, and operating conditions. System level inspection intervals should be established by the system integrator.

The following factors should be taken into account when determining inspection intervals;

— regulatory requirements;

— OEM's maintenance recommendations;

— mean time between failure and degradation rate data;

— damaged, repaired, or particularly exposed parts;

— specific inspection intervals based on criteria discussed elsewhere in this document;

— present condition and service history, e.g., changes in design, age, previous inspection results, operating or loading conditions, or prior damage and repairs;

— presence of field performance history, established and field-proven technology, or new or frontier technology with limited field exposure;

— risk assessment for the intended operations.

8.3.3 Acceptance Criteria

The selection of inspection acceptance criteria, frequency, and type of inspection of the system shall be determined by the system integrator.

The system integrator shall document the basis of the inspection criteria based on system integrator's recommendations, regulatory requirements; OEM furnished recommendations and specifications; the risk assessment for the intend operations; or similar.

The system integrator and/or service provider shall use the following methods, or a combination of these, to establish inspection program intervals;

— recertification of well control equipment based on principles of DNVGLRP-E101 or equivalent;

— risk-based inspection based on principles of DNVGLRP-G101 or equivalent;

— condition-based inspection based on monitoring and operational history log, as well as system integrator/ OEM's recommendation;

— periodic inspection specified by system integrator, OEM, end-user, and regulatory authorities;

— standard specific inspection specified in international standards.

8.4 Monitoring

Monitoring of the equipment used for a subsea riserless subsea well intervention shall be recorded in an equipment log.

The monitoring should include, at a minimum, the following parameters;

— Operational Usage;

— Corrosive fluids exposure (acids, sour, caustics);

— Use of neutralizing fluids;

— Fatigue (if applicable);

— Overload conditions;

— Maintenance;

— Inspections & certification;

— Equipment/component failures;

— Storage and preservation.

9 Maintenance, Preservation, Storage, Transportation and Recertification

9.1 General

The purpose of this section is to define expectations for maintenance, preservation, storage and handling over the design life of the riserless system.

The scope of this section includes system, equipment and replacement components and specifies requirements for maintenance frequency, preservation, manuals, storage conditions and handling of the system and assemblies.

The system integrator shall use a quality management system such as API Spec Q1 or API Spec Q2, or equivalent.

9.2 Maintenance

Systems shall be operated, inspected, and maintained to minimize failure and to ensure an acceptable performance level throughout the design life.

The objective of maintenance is to anticipate and address issues before or during failure and may include inspection, replacement of expendable components, repair, remanufacture, and testing. Repair and remanufacture may include machining, welding, heat treatment, or other manufacturing operations.

It is the responsibility of the Equipment Manufacturer to define the maintenance strategy (preventive, predictive, corrective, etc.), identify critical components, and provide details of the maintenance activities. The Manufacturer should specify any activities or procedures that are to be performed solely by the manufacturer's representative.

Thereafter, it is the equipment owner and system integrator's responsibility to work with the equipment manufacturer to implement the Inspection, Maintenance, Repair, and Remanufacture procedures in consideration of the maintenance strategy, equipment application, loading, work environment, usage, and other operational conditions. It is also the responsibility of the equipment owner and system integrator to implement a schedule for when inspection and maintenance activities need to occur, based on input from the Equipment Manufacturer. A maintenance schedule should incorporate, but not be limited to, the following factors;

— Regulatory requirements;

— Risk assessment (including FMECA);

— Equipment reliability data;

— Specific time intervals or usage-based intervals based on manufacturer's recommendation;

— Present condition and service history of equipment based on monitoring data and operational history log;

— Present storage and/or operating conditions of the system;

— Technology readiness level of equipment.

Periodic maintenance documentation (manual) shall be established by the system integrator and OEM and provided at the time of product delivery or by contractual agreement.

The periodic maintenance manual shall contain requirements and inspection criteria, maintenance activities, recommended frequency, and at a minimum, the following;

— guidance for safe and efficient maintenance of the equipment to maintain the level of performance to all products, subassemblies, and assemblies that make up the system;

— listing of critical areas including weld locations (e.g. welded pad eyes for lifting and/or other welds identified as critical welds) that may be subject to high stress, wear, and fatigue that should be periodically inspected along with recommendations for inspection and maintenance forms or checklists;

— recommended spare parts list;

— recommended procedures for testing;

— recommended procedures for preservation, storage, and shipping in accordance with this section.

9.2.1 Maintenance activities

Maintenance may include any of the following: inspection, adjustment, cleaning, lubrication, expendable component replacement, and testing.

9.2.2 Schedule

The maintenance schedule and strategy may be based on, but not limited to, specific time intervals, measurable wear limits, load cycle accumulation, function cycle accumulation, non-performance of equipment, environment, reliability data, regulatory requirements, and any monitoring data.

9.3 Repair and Remanufacture

9.3.1 Repair and Remanufacture activities

Actions performed on equipment that involves the replacement of parts (other than expendables), and actions that involve a special process or machining. These activities are the results of the inspection and should follow the manufacturer's recommendations.

9.3.2 Acceptance criteria

Processes, methods and inspection procedures, test procedure, and acceptance criteria following repair and remanufacture are to follow the manufacturer's original specifications and quality requirements. Any deviation is to be recorded accordingly. Replacement parts should meet or exceed the original equipment manufacturer's criteria.

9.3.3 Documentation and traceability

The equipment Owner is responsible to ensure the records of maintenance work performed on the system, parts, and assemblies are maintained on file and are readily available. The records may include the following, but are not limited to;

— Original manufacturing records from the manufacturer;

— Inspection records;

— Maintenance, Repair, Remanufacture, Recertification records;

— Recertification Statement / Completion Certificate;

— Inspection and testing records following maintenance, repair or re-manufacture;

— Manufacturer's product alerts, equipment bulletins or similar, issued during the lifespan of the equipment.

If any critical component has been repaired, remanufactured, or replaced during the maintenance process, the traceability of the component is to be maintained following the manufacturer's original quality requirements and the testing that follows documented accordingly.

9.4 Preservation

All systems shall have a documented procedure with identified time intervals for the preservation and inspection to prevent equipment damage or deterioration caused by environmental conditions, in accordance with API Std 17G.

9.5 Storage and Shipping

The system integrator shall have documented procedures for Storage and Shipping in accordance with API Std 17G.

9.6 Refurbishment / Recertification

The system integrator shall have documented procedures for refurbishment and recertification in accordance with API RP 17G1.

10 System Readiness

10.1 Purpose

System Readiness defines the system level testing scope, frequency, and acceptance criteria to demonstrate conformance to the original design specifications. Additional testing may be required by the end-user based on job specific or contractual requirements.

The scope of System Readiness includes the following types of testing:

— System Integration Test (SIT);

— Stump / Deck Test prior to deployment;

— Subsea Testing following initial latch-up;

— Periodic Testing;

— Subsea Testing following subsea well-hop.

10.2 Requirements

A defined testing program shall be implemented or overseen by the system integrator. The completed test documentation shall be available for end user and regulatory review.

References within API RP 17G1 to LWRP shall be interpreted to mean the subsea portion of the RSWIS, namely;

— PCH (wireline and/or coiled tubing mode)

— Lubricator Assembly

— Well Control Package

— Flushing System

All conduits (deck, vertical, flying leads and jumpers) are to be assessed for readiness in accordance with the requirements in API RP 17G1 and API RP 17G2.

If the RSWIS uses a method of recovering or deploying toolstrings that requires a connection to be broken, the connection, at a minimum, shall be pressure tested upon re-make, prior to access to the well bore being opened.

In addition to these testing requirements, testing shall be performed to ensure that the RSWIS is capable of meeting the requirements for the specified application or intended use.

All testing invalidated by remanufacture or modification shall be re-performed as outlined in API RP 17G1 and API Std 17G.

Equipment and components not covered by API 17G shall be reviewed against a program specified by the manufacturer and agreed upon by the system integrator and end user. Additional information on qualifying subsea equipment can be found in API RP 17Q.

10.3 Test Fluids

Hydrostatic pressure tests should be conducted with water or water with preservation, anti-freeze, or colorant additives.

NOTE During operations, the fluid in use is acceptable to perform subsequent tests of the intervention system.

Control system fluid should adhere to the OEM specification.

11 Records Requirements

11.1 Purpose

The system integrator shall maintain system documentation in accordance with the requirements of this RP. Additionally, the purpose is to ensure the intent of the system design, safety strategy, configuration, operational capabilities, modifications are recorded and preserved

11.2 General

For the records required refer to API RP 17G1.

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