

Global Analysis of Subsea Well Intervention Systems

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Global Analysis of Subsea Well Intervention Systems

1 Purpose and Scope

1.1 Purpose

This recommended practice (RP) provides guidelines for global riser analysis (GRA) of subsea well workover/intervention systems and is intended to serve as a common reference for designers.

This recommended practice is not intended to replace existing API recommended practices (RP) and standards, but rather to supplement them by illustrating accepted analysis practices and principles. The end users may elect to adopt a portion of or all the presented guidelines for global riser analysis, subject to their well-specific riser designs and any operational-related design constraints.

It is necessary that users of this recommended practice be aware of regulations from a jurisdictional authority that may impose additional or different requirements than those presented in this document.

The analysis techniques described herein focus on the best practices in global riser analysis, while providing the user flexibility to use other techniques to meet the requirements for subsea intervention systems.

1.2 Scope

The scope of this RP is limited to the following systems:

- open-water intervention riser system (OWIRS);
- through-BOP intervention riser system (TBIRS);
- subsea pumping well intervention system (SPWIS);
- riserless subsea well intervention system (RSWIS).

This RP includes input, output, and analysis as follows:

- data to serve as inputs to global riser analysis;
- modeling techniques, assumptions, and verifications;
- load case matrix;
- operability, weak point, and fatigue analysis;
- analysis outputs and interpretations.

This RP complements the API 17G sub-series documents (e.g., API 17G1, 17G5) as applicable for the system scopes listed above that identify the information required to conduct the analysis (inputs) and interpret the results of the analysis (outputs) to determine the system operating limits. Different global riser modeling techniques and assumptions are presented for consideration by the user. To increase user awareness, discussion of modeling techniques focuses on parameters that drive riser response, as well as typical areas of concern. The techniques proposed herein are considered best practices and serve as analysis guidance. Where possible, this document refers to existing industry standards and practices to avoid duplication while addressing the key issues facing workover/intervention GRA.

This RP outlines a detailed load case matrix for a GRA of a subsea well intervention system. The user may decide to modify the scope of work (or a subset of this matrix) deemed essential to meet project requirements

in agreement with the operator, service contractor, and regulatory bodies. The load case matrix encompasses anticipated operational scenarios; however, additional nonstandard cases may need to be assessed.

This RP also outlines typical GRA outputs and provides guidance on their interpretation, including guidance on mitigations and examples.

This RP does not assess fatigue performance of the well system.

2 Normative References

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

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

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

API RP 17G4, *Recommended Practice for Riserless Subsea Well Intervention Systems*

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

API RP 16Q, *Recommended Practice for Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems*

DNVGL-OS-E301, *Offshore Standard for Position Mooring*

DNVGL-RP-E104, *Recommended Practice for Wellhead Fatigue Analysis*

DNVGL-RP-F204, *Recommended Practice for Riser Fatigue*

DNVGL-RP-C203, *Recommended Practice for Fatigue Design of Offshore Steel Structures*

ISO 13624-1, *Petroleum and natural gas industries — Drilling and production equipment — Part 1: Design and operation of marine drilling riser equipment*

ISO/TR 13624-2, *Petroleum and natural gas industries — Drilling and production equipment — Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report*

Sparks, Charles P., “*Fundamentals of Marine Riser Mechanics, Basic Principles and Simplified Analyses*” 2nd edition.

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

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

3.1.1

accidental load

A load that is imposed on the riser system under abnormal and unplanned conditions.

EXAMPLE Loss of vessel station-keeping and heave compensator lock-up.

3.1.2

abnormal environment (or) scenario

A change to environment or operating condition outside of normal range.

EXAMPLE Monitored functions, alarms, excessive riser loading, environmental loads that exceed expected values for the operational stage, or a change in control pressure(s) or voltage(s).

3.1.3

component

An individual piece or an identifiable portion of equipment that performs a defined function.

3.1.4

corrosion allowance

The amount of wall thickness added to the pipe or component to allow for corrosion, scaling, abrasion, erosion, wear, and all forms of material loss.

3.1.5

cyclic load capacity

A combination of S-N curves and associated SAF values or M-N curves.

3.1.6

design basis

A set of project-specific design data and functional requirements that are not specified or are left open in the general standard.

3.1.7

design check

An assessment of a component for a load case by means of an application rule.

3.1.8

design criteria

Quantitative formulations that describe each failure mode the conditions shall fulfill.

3.1.9

design factor

A factor (usage factor) used in working stress design.

3.1.10

design load

A combination of load effects.

3.1.11

design pressure

The maximum difference between internal pressure and external pressure that is unlikely to be exceeded during the life of the riser, referred to a specified reference height.

NOTE Design pressure is often called “maximum allowable pressure,” “rated working pressure,” or “maximum allowable.”

EXAMPLE Design pressure is the maximum pressure considering shut-in pressure at the wellhead (seabed) or at the top of the riser with subsea valves open, maximum well fracturing pressure, maximum well injection pressure, maximum surge pressure, or maximum well kill pressure.

3.1.12

drift-off

Unintended lateral movement of a dynamically positioned vessel off its intended location relative to the wellhead, generally caused by loss of station-keeping control or propulsion.

3.1.13

drive-off

Unintended movement of a dynamically positioned vessel off location driven by the vessel's main propulsion or station-keeping thrusters.

3.1.14**dynamic positioning**

Computerized means of maintaining a vessel on location by selectively activating thrusters.

3.1.15**effective tension**

Axial tension calculated at any point along a riser by considering only the top tension and the apparent weight of the riser and its contents (tension positive).

NOTE Global buckling and geometric stiffness is governed by the effective tension.

3.1.16**emergency disconnect sequence (EDS)**

A controlled sequence that is designed to isolate the well subsea and disconnect the LMRP in the event of an emergency situation.

NOTE The EDS is a programmed sequence that leaves the subsea BOP stack in a desired state and disconnects the lower marine riser package (LMRP) from the lower BOP stack. An EDS is optional for moored vessels.

3.1.17**emergency quick disconnect (EQD)**

A controlled sequence that is designed to isolate the well subsea and disconnect the landing string/riser from the well in the event of an emergency situation; includes closing the barrier elements and unlatching the landing string/riser.

3.1.18**end user or operator**

The organization that authorizes the use of a subsea well intervention system for well operations.

3.1.19**environmental loads**

Loads that are the result of environmental conditions.

EXAMPLE Waves, current, and wind.

3.1.20**equipment**

A single completed unit that can be used for its intended purpose within the scope of this document without additional components.

3.1.21**failure**

An event causing an undesirable condition; e.g., loss of component or system function, or deterioration of functional capability to such an extent that the safety of the unit, personnel, or environment is significantly reduced.

EXAMPLE Structural failure (excessive yielding, buckling, rupture, leakage) or operational limitations (slick joint protection length, clearance).

3.1.22**fatigue analysis**

A conventional stress-life fatigue analysis using material S-N curves and specified fatigue design factors.

3.1.23**finite element analysis**

A numerical method for analyzing dynamic and static response by dividing the structure into small continuous elements with the given material properties.

NOTE The analysis can be local or global.

3.1.24

floating vessel

A buoyant installation that is floating and positioned relative to the sea bottom by station-keeping systems.

NOTE The following types of station-keeping systems are normally considered: catenary mooring systems and dynamic positioning (DP) systems based on thrusters. A combination of station-keeping systems can be considered.

EXAMPLE Semi-submersible drilling vessels, drill ships, mobile offshore drilling units (MODU), and multi-purpose vessels.

3.1.25

frequency domain

A dynamic analysis method based on the assumption that any applied irregular process is a superposition of fundamental, regular processes.

3.1.26

global riser analysis (GRA)

A structural analysis of the complete subsea well intervention system from below mudline to traveling block, including any applicable tensioning system, using beam elements.

NOTE Bending moments and effective tension distributions along the riser string due to structural loads, vessel motions, and environmental loads are determined by global riser analysis (GRA).

3.1.27

hang-off

A condition in which a riser is disconnected from the seabed and suspended from a spider or other supporting mechanism designed to support the riser for an extended period of time.

NOTE Hang-off is usually differentiated from “disconnected.” “Disconnected” is normally the condition directly after disconnecting the riser. Hang-off is normally associated with the riser suspended from the rotary table.

3.1.28

heave

The motion of a floating vessel in the vertical direction.

3.1.29

hydrodynamic loads

Flow-induced loads caused by the relative motion between the riser and the surrounding water.

3.1.30

inspection interval

The non-factored fatigue life estimate divided by the safety factor to be applied.

3.1.31

landing string

A jointed temporary riser used as part of the through-BOP intervention riser system that typically provides a conduit from the subsea test tree assembly or BOP spanner joint to the surface tree and that is typically used for well completion or intervention operations where hydrocarbons are expected.

NOTE A landing string may include pup joints, lubricator valve, cased wear joint, slick joints, and surface tree adapter joint.

3.1.32

load

The physical influence that causes stress or strains in the riser system.

3.1.33**load case**

A combination of simultaneously acting loads.

3.1.34**load effect**

The effect of a single load or combination of loads on the structure, such as stress, strain, deformation, displacement, motion, etc.

3.1.35**loading (load) classification**

An assignment of either normal, extreme, or survival load conditions to an operational stage or load case to be analyzed within the GRA.

NOTE Normal, extreme, and survival load limits for equipment are defined within API 17G.

3.1.36**low-frequency vessel motion**

Motion response at frequencies below wave frequencies, typically with periods ranging from 30s to 300s.

3.1.37**manufacturer**

The organization that is responsible for the design and manufacture of equipment for use in subsea well intervention systems and sub-systems.

NOTE The manufacturer can subcontract one or more of the above-mentioned tasks under its responsibility.

3.1.38**mean offset**

Static offset due to steady forces from current, wind, and wave, as well as offset due to low-frequency motions and active positioning of the vessel.

NOTE Also referred to as "static offset."

3.1.39**modes of operation**

The type of subsea well intervention equipment (e.g., equipment that is connected to a fluid conduit tieback riser) either inside the marine riser (TBIRS) or open water (OWIRS), riser subsea well intervention system (RSWIS), downline connected equipment, and remotely operated vehicle (ROV) intervention equipment.

3.1.40**open-water intervention riser system (OWIRS)**

A riser system that provides a conduit between the subsea well and the surface vessel that can be used for the installation and retrieval of subsea trees, well intervention, well tests, and flowbacks.

NOTE The OWIRS is run independently of the marine drilling riser and subsea BOP systems and incorporates its own well control features.

3.1.41**operability**

The ability to safely perform a planned operation without exceeding the capacity and performance limits of the equipment being used.

3.1.42**operating envelope**

The limited range of parameters in which operations will result in safe and acceptable equipment performance.

3.1.43**operating mode**

A condition that arises from the use and application of the equipment or riser system.

3.1.44**operational stage (scenario)**

The stages of the operation, intervention activities, and the use of safety functions.

3.1.45**response amplitude operator (RAO)**

The relationship between wave surface elevation amplitude and the vessel response amplitude, and the phase lag between the two.

3.1.46**return period**

The average time period between occurrences of a given event.

NOTE The inverse of the return period is the statistical probability of such an event occurring in any given year.

3.1.47**riser model**

A structural model established from the tabulated data of the riser to describe the actual riser and used in a global analysis of the riser system.

3.1.48**riserless subsea well intervention system (RSWIS)**

An intervention system designed to facilitate tool strings into/out of the wellbore while subsea, controlling pressure at the subsea tree and/or tubing head spool with subsea pressure control equipment.

NOTE The RSWIS do not include a riser conduit through the water column to surface, unlike OWIRS or TBIRS.

3.1.49**safety function**

A sequenced series of device actions intended to achieve a safe state in relation to a specific hazardous event.

NOTE Safety functions for subsea well intervention systems typically include process shutdown (PSD), emergency shutdown (ESD), emergency quick disconnect (EQD), deadman, and autoshear.

3.1.50**service life**

The duration of time in which the equipment performs under the specified design conditions; i.e., time in active connected riser operations, excluding storage periods.

NOTE The service life is normally a small fraction of the design life. Design life is the duration of time during which a riser can be used for its intended purpose with anticipated maintenance, but without substantial repair or replacement being necessary, including storage and working periods.

3.1.51**service provider**

An organization that provides subsea well intervention system services and products.

3.1.52**subsea pumping well intervention system (SPWIS)**

An intervention system that is typically deployed from multi-service vessels (MSV) and supplies large fluid volumes and pump rates needed for well remediation. It is also referred to as “rigless” or “hydraulic intervention.”

NOTE The SPWIS is run either stand-alone or in tandem with an adjacent stimulation vessel that supplies large fluid volumes and pump rates needed for well remediation work.

3.1.53**strength**

The mechanical property of a material, usually given in units of stress.

3.1.54**stress concentration factor (SCF)**

The local peak alternating stress in a component (including welds) divided by the nominal alternating stress in the pipe wall at the location of the component.

NOTE This factor is used to account for the increase in the stresses caused by geometric stress amplifiers, which occur in the riser component.

3.1.55**stress range**

The difference between stress maximum and stress minimum in a stress cycle.

3.1.56**stroke**

The total upward and downward movements of the vessel relative to the riser (e.g., travel of the riser tensioner, drawworks, and slick joint).

NOTE It includes effects from environmental loads, structural loads (e.g., top tension, temperature, mean static vessel offset, and pressure).

3.1.57**structural load capacity**

The minimum capacity of relevant structural failure modes; i.e., minimum of yielding, local failure, buckling, and mechanical disengagement.

3.1.58**submerged weight**

A weight that includes content minus any applicable buoyancy. It is also referred to as “apparent weight,” “weight in water,” “wet weight,” “net lift,” and “effective weight.”

3.1.59**system**

A collection of equipment used to perform an intended purpose within the scope of this document.

3.1.60**system integrator**

An organization that is responsible for bringing together subsystems, ensuring that those subsystems function together in a subsea well intervention system.

3.1.61**tension-split**

A tensioning system with tension sharing between the top-drive compensation system and the riser tensioning system.

3.1.62**tensioner system**

A device that applies a close-to-constant tension to the riser string while compensating for the relative vertical motion (stroke) between the floating vessel and the top of the deployed riser string.

3.1.63**through-BOP intervention riser system (TBIRS)**

A riser system that provides a conduit between the subsea well and the surface vessel that can be used for the installation and retrieval of the upper completion system, well intervention, well tests, and flowbacks.

NOTE The TBIRS is run inside of the marine drilling riser and subsea BOP system and may incorporate well control features in addition to those on the subsea BOP.

3.1.64

time domain

The timewise, incremental simulation of riser response.

NOTE Offers the capability of modeling hydrodynamic and structural nonlinearity.

3.1.65

upper components

Equipment located above the main riser pipe (OWIRS) or landing string (TBIRS).

3.1.66

vessel (mean) offset

The average offset created by steady forces from current, wind, and waves.

NOTE The term has been shortened in this document to “vessel offset.”

3.1.67

vessel trajectory

A curve that defines the time history of vessel position (i.e., its excursion from initial position during a loss-of-position scenario).

3.1.68

vortex-induced vibration (VIV)

The in-line and transverse oscillation of a riser caused by current-induced periodic shedding of vortices.

3.1.69

wave frequency motion

The motion of the vessel at the frequencies of incident waves.

3.1.70

wave scatter diagram

A table listing the occurrence of sea states in terms of significant wave height and wave peak period or mean up-crossing period.

3.1.71

well barrier

An envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the reservoir to environment.

3.1.72

well control device

A component that is designed to function as a well barrier.

EXAMPLE Blowout preventers, pipe rams, circulating heads, tubing injection heads, diverters, wireline lubricators and stuffing boxes, kelly cocks, stabbing valves, kill-lines, valves, choke lines, and manifolds.

3.1.73

well-specific operating criteria (WSOC)/well-specific operating guideline (WSOG)

Guidelines on the operational, environmental, and equipment performance limits for the location and specific operation.

3.1.74

well system

A combination of the subsea wellhead system and casing system installed.

3.1.75

workover riser

A jointed riser that provides a conduit from the subsea tree upper connection to the surface and allows for the passage of tools during workover operations of limited duration and can be retrieved in severe environmental conditions.

NOTE Historically, workover operations have been performed in open sea (i.e., for vertical tree systems), but can be performed inside a drilling riser provided sufficient barrier elements are available.

3.2 Abbreviated Terms

For the purposes of this document, the following abbreviations apply

ADCP	advanced Doppler current profiler
AHD	along hole depth
BHA	bottom hole assembly
BOP	blowout preventer
CT	coiled tubing
C/VO	completion/workover
DOF	degree of freedom
DP	dynamic positioning/dynamically positioned
ECA	engineering critical assessment
EDP	emergency disconnect package
EDS	emergency disconnect sequence
EQD	emergency quick disconnect
ESD	emergency shutdown
FAT	factory acceptance test
FEA	finite element analysis
FMEA	failure modes and effects analysis
FMECA	failure mode, effects, and criticality analysis
GA	general arrangement
GOR	gas oil ratio
GRA	global riser analysis
HP	high pressure
HPH	high-pressure housing
HPHT	high pressure, high temperature
ID	inner diameter
JONSWAP	joint North Sea wave project
LARS	launch and recovery system
LFJ	lower flex joint
LMRP	lower marine riser package
LOSK	loss of station-keeping

LP	low pressure
LPH	low-pressure housing
LV	lubricator valve
MBR	minimum bend radius
MODU	mobile offshore drilling unit
MSL	mean sea level
MSV	multiservice vessel
MWL	mean water level
OD	outer diameter
OEM	original equipment manufacturer
OWIRS	open-water intervention riser system
P&A	plug and abandonment
PCE	pressure control equipment
PCH	pressure control head
PM	periodic maintenance
P-M	Pierson-Moskowitz
POD	point of disconnect
PSD	process shutdown
P-Y	numerical model curves for soil resistance (P is force per unit length and Y is resulting deflection)
QTF	quadratic transfer function
RAO	response amplitude operator
RBW	remaining body wall
RMS	root mean squared
ROV	remotely operated vehicle
RP	recommended practice
RSM	riser sealing mandrel
RSWIS	riserless subsea well intervention system
SAF	stress amplification factor
SCF	stress concentration factor
SCM	subsea control module
SIT	system integration testing
SN	stress range vs. number of cycles
SPWIS	subsea pumping well intervention system
SSM	subsea safety module
SSTT	subsea test tree
SSTTA	subsea test tree assembly
STD	standard

TBIRS	through-BOP intervention riser system
TH	tubing hanger
THRT	tubing hanger running tool
THS	tubing head spool
TLF	tension lift frame
TOE	tension offset envelope
TSJ	taper/tapered stress joint
UFJ	upper flex joint
VIV	vortex-induced vibrations
WCP	well control package
WL	wireline
WSOC	well-specific operating criteria
WSOG	well-specific operating guidelines
XT	subsea tree

3.3 Symbols

For the purposes of this document, the following symbols will be used.

A_i	internal cross-section area of the pipe
A_p	cross-sectional area of the pipe
A	total piston area
B	net buoyancy in seawater by any marine riser buoyancy modules
C_k	linearized spring stiffness due to limited air pressure vessel volume (actual stiffness is nonlinear and close to adiabatic gas spring)
C_s	seal friction coefficient, assuming a Coulomb friction model (in reality, friction depends on speed and hydraulic pressure)
D	specified outside diameter
E	modulus of elasticity
g	acceleration due to gravity
H_s	wave height
$\log \bar{a}$	intercept constant for the design S-N curve
$\log \bar{a}_{\Delta M}$	intercept constant for the design M-N curve
M	bending moment
M_p	yield bending moment capacity of a pipe
m	inverse slope of S-N or M-N curve
n	number of cycles
N	number of maxima in sample
P_l	local primary membrane stress
P_m	general membrane primary stress
P_0	air pressure at mid-stroke

p_e	external pressure to the pipe
p_i	internal pressure in the pipe
P_{id}	internal design pressure in the pipe or the rated working pressure
p_o	external pressure
R	stress ratio
S	stroke displacement of tensioner piston, usually referred to as midstroke
$T_{e,tot}$	total effective tension from the drilling riser and subsea well intervention system acting at the flex-joint
T_e	effective tension in the pipe
T_w	true wall tension
T_p	spectral peak wave period
T	tension supplied by the tensioner
t	wall thickness
γ	(gamma) adiabatic coefficient for air: $\gamma \approx 1.4$.
ν	Poisson's ratio

4 Application

4.1 General

This section describes the types of subsea well intervention systems for which the RP is applicable, and provides guidance for when global riser analyses are needed and limitations they may have.

4.2 Types of Interventions

The global riser analysis methodology outlined herein is applicable for the following types of subsea well intervention systems:

- open-water intervention riser system (OWIRS);
- through-BOP intervention riser system (TBIRS);
- subsea pumping well intervention system (SPWIS);
- riserless subsea well intervention system (RSWIS).

Examples of operations that one or more of these systems can be used to perform include the following:

- installation of upper completion;
- installation of XT;
- mechanical well intervention;
- plug and abandonment (P&A).

Examples of subsea well intervention vessels include:

- using a dynamically positioned vessel;

- using a moored vessel;
- using a multi-service vessel (MSV).

NOTE 1 This list is not exhaustive, and the GRA methodology can be used for other similar cases.

NOTE 2 For systems incorporating a drill pipe string, it is the responsibility of the user/operator to ensure that the drill pipe string is of a type and condition such that it is suitable for the planned operation.

4.3 Guidance on When GRA is Needed

Global (riser and riserless) system analysis is performed to establish operating limits for a specific vessel, intervention (riser and riserless) system, and a specific well and location.

API RP 17G1 provides the criteria to determine acceptable risks.

NOTE For a group of wells with similar activity and conditions, a single analysis should be sufficient

5 Operational Stages (Scenarios)

5.1 General

This section lists operational stages (or scenarios) for each type of subsea workover/well intervention system. It includes simple schematics illustrating the configuration/arrangement for each operational stage, and discusses the interfaces between workover/intervention systems (riser and riserless), surface equipment (MODU/vessel), and a range of operational conditions/scenarios that may occur.

5.2 Open-water Intervention Riser System (OWIRS)

5.2.1 General

This section provides a description of the stages of an open-water subsea well intervention system, which is often referred to as a “completion” or “intervention” riser. It may also be appropriate to consider other intermediate configurations that occur as the riser transitions between the operational stages discussed herein.

[Figure 1](#) provides simple schematics for typical operational stages, including their associated boundary conditions as commonly applied in analysis models. As illustrated, the subsea stack may include the subsea tree (XT), well control package (WCP), and/or emergency disconnect package (EDP), depending on the operational stage. Most OWIRS also include several upper components that are located above the drill floor, such as:

- surface flow head;
- crossover/transition to the surface flow head;
- surface BOP;
- engineered weak link assembly (if in upper components).

This set of upper components spans the drill floor and allows for the attachment of a tension lift frame (TLF).

Procedures for mitigating actions should be accounted for in the global analyses and modeling techniques.

OWIRS can be deployed for a wide range of completion and intervention operations, including the following:

- installing a completion string;

- accessing the well for intervention operations;
- performing well testing;
- performing flowbacks;
- retrieving the completion string (as part of a re-completion).

Compensator stroke or vertical position of upper components (e.g., surface flow head and associated hoses, etc.) relative to the drill floor typically governs the available downstroke during a loss-of-vessel-position event.

The tensioning system can be a single tensioning system or shared tensioning systems where both a tensioner and a lift frame provide tensioning and heave compensation.

If the surface vessel is moored, the typical mean offset considered for most analyses is transient vessel offset in the event of a loss of a single mooring line failure. With respect to DP vessels, it is recommended that a range of mean offsets (both upstream and downstream of the dominant current direction) be evaluated for most operational stages, so limits can be established by comparison to defined acceptance criteria.

It is recommended to perform the pipe sizing checks discussed further in [Section 10.3.3.3](#) before any other global assessments are performed, since selection of the riser pipe can influence operability limits of the system.

Care should be taken to ensure that loads/stresses experienced by critical OWIRS components do not reach or exceed their limit/capacity for the associated operational stage.

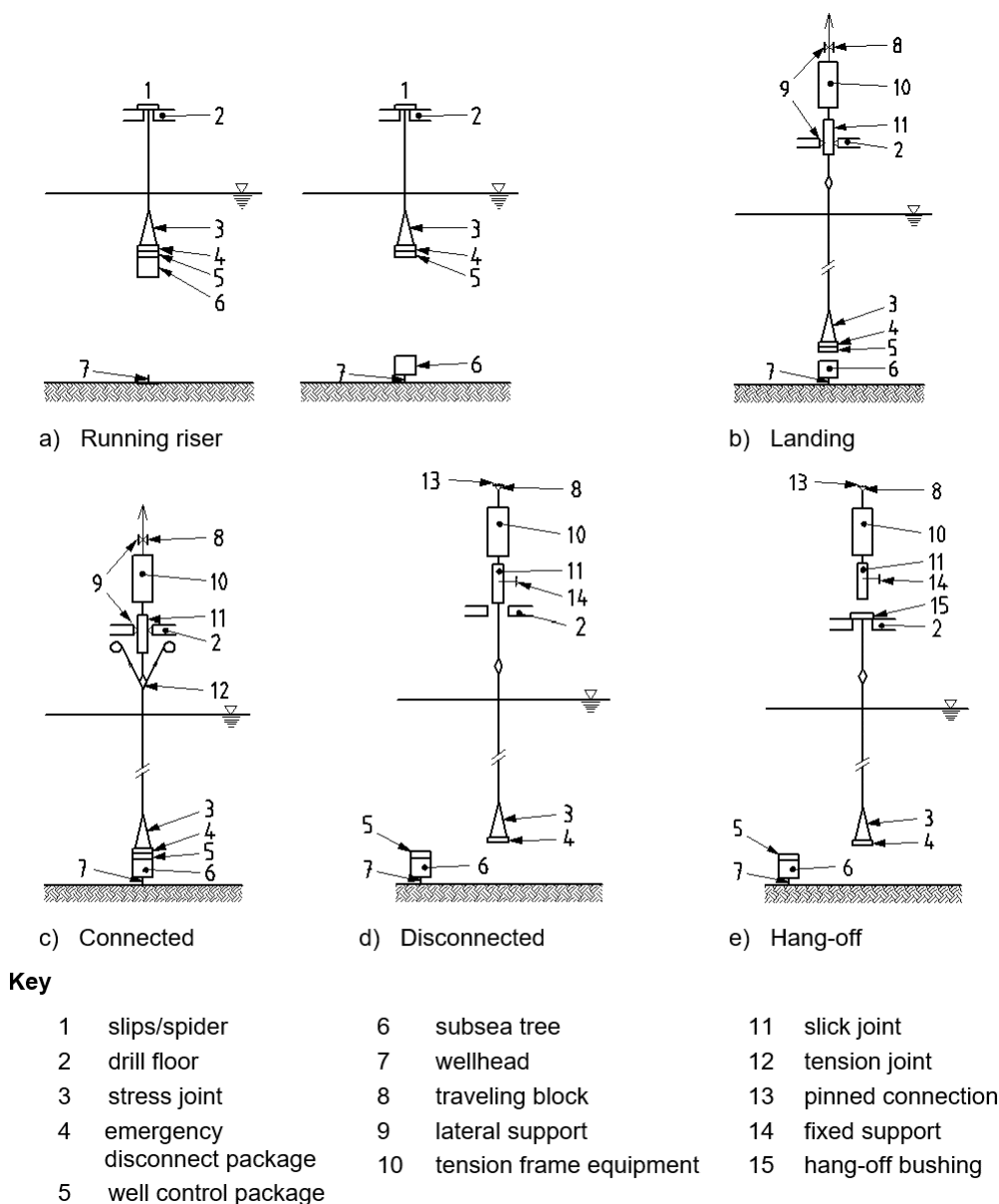


Figure 1—Schematic of Operational Stages for an OWIRS

5.2.2 Running and Retrieval

The first operational stage performed at a given wellsite is running (or deployment/installation) of a subsea stack using the OWIRS. Retrieval is simply the reversal of running and is typically performed once connected operations are completed.

During running/retrieval, the deployed riser will be held alternatively in the slips/spider at the drill floor or by the traveling block in the drawworks system. The riser is supported at the drill floor for the majority of time at each deployment depth, while the drawworks system is handling the next (or previous) stand of joints/pipe. Once the next stand is made up, the slips are released for a brief period of time, and the traveling block lowers the deployed riser to the next deployment depth.

Running/retrieval of the OWIRS may be performed for various configurations of the subsea stack (e.g., EDP+WCP+XT, EDP+WCP, EDP only) at bottom. All relevant subsea stacks shall be evaluated as part of analyses.

Response of the riser during running/retrieval can be greatly influenced by its deployment depth, since its total submerged weight and other parameters (e.g., amount of drag loading, total mass) continually change. Thus, analyses of the running/retrieval operational stage shall evaluate various lengths of the deployed riser, such as:

- first hang-off, typically above the water surface in the moonpool;
- second hang-off, typically in the splash zone;
- several intermediate depths (e.g., 25 % depth, mid-depth) with attention to any changes of material or structural properties of the main riser joints;
- near full depth:
 - prior to installation of the surface equipment, including landing of BOP;
 - when the last joint/component is run, prior to installation of the upper specialty joints (e.g., slick joint) and tension frame.

Operability limits for running/retrieval of an OWIRS are typically governed by one of the following:

- overloading of riser (typically the top-most joint) when supported in the slips;
- lateral interference with rig/vessel obstructions (e.g., diverter housing, moonpool, pontoon bracing) when supported by the traveling block or supported by a gimbaled spider (if available) at the drill floor.

A pressure test of the subsea intervention system may be performed during deployment to demonstrate its pressure integrity. Examples of discrete deployment depths commonly selected for pressure testing include below the wave zone, mid-depth, and near full depth. When pressure testing, the suspended riser is typically supported using the block to allow for the additional radial and hoop stresses induced by the internal overpressure.

5.2.3 Landing

The drawworks system is used to land the fully deployed intervention system once the tension frame (and its corresponding equipment) is installed in the derrick. A certain amount of mean set-down weight is required to perform the latching, which reduces stability (i.e., produces a local negative effective tension) near the bottom of the riser.

The landing operational stage is typically performed during benign environmental conditions. Still, operability limits (for landing) are typically governed by the maximum set-down weight (i.e., minimum tension or maximum compression in riser), bending moment experienced by TSJ/connectors, or limits on relative angle allowing for make-up of the connection.

Following landing and connection, the riser tension should be increased to the specified operating tension.

5.2.4 Connected

Once connected, the OWIRS can be used to operate in various completion and workover modes, each involving use of specialized equipment to be supported within the tension lift frame. Two common examples are E-line/Wireline mode and coiled tubing (CT) mode. All relevant operating modes should be considered; however, it may be possible to identify the one mode expected to have the most restrictive operability limits.

Examples of operation types that the connected riser is commonly used to perform include:

- overpull test to verify locking of the subsea stack (following landing and connection);
- pressure testing of the system;

- flowing at corresponding pressure and temperature;
- shut-in at the surface flow tree;
- subsea shut-in with pressure bled off above the WCP.

As further discussed in [Section 9](#), the operating parameters for the OWIRS (e.g., contents, internal pressure distribution, temperature distribution), as well as the mean applied tension(s), may be unique for each operational mode.

If the surface vessel is moored, the mean offsets typically considered are the maximum anticipated vessel offset with intact or a single failed mooring line. However, for DP vessels, it is recommended that a range of mean offsets (both upstream and downstream of the dominant current direction) be evaluated for most analyses, so limits can be established by comparison to defined acceptance criteria.

5.2.5 Planned Disconnect

When circumstances allow, a planned disconnect is performed to release the OWIRS from the well system. Since this is “planned,” below are typical steps in preparation for unlatching the riser:

- retrieve any coiled tubing from the well;
- circulate out any contents and flood riser with seawater;
- reduce applied tension(s) to achieve the target overpull (or target set-down weight) at the WCP connector, accounting for tension variations while still connected;
- re-distribute share of tension between the top-drive compensation system and the riser tensioning system (for “tension share” method only);
- select a more favorable vessel heading (relative to direction of the waves or current).

A planned disconnect is typically performed during benign environmental conditions. Still, operability is typically governed by limits on the maximum bending moment (or maximum relative angle) allowing the WCP connector to unlatch. In addition, the expected direction for motion of the suspended riser upon release should be away from any adjacent subsea structures and toward increasing vertical clearance with the mudline.

5.2.6 Emergency (or Unplanned) Disconnect

There are situations where an emergency (or unplanned) disconnect shall be performed to release the OWIRS from the well system. Examples of situations requiring an emergency disconnect include a loss-of-position event for DP vessels, an abnormal environment event, or an equipment failure (e.g., top drive compensation system, riser tensioning system) during connected operations.

Once the decision is triggered to perform an emergency disconnect, it is accomplished by manual initiation of the emergency disconnect sequence (EDS), which then automatically completes the following steps:

- cutting of any line or coiled tubing inside the subsea intervention system;
- complete shutdown of all process (surface) equipment;
- closure of all subsea and riser valves;
- release of the hydraulic connector between the EDP and WCP.

Since an EDS is completed soon after its initiation (i.e., EDS duration is commonly within 60 seconds but is system-dependent), there is typically not time to take any steps in preparation for release. For this reason,

is typically assumed that operating parameters for emergency disconnect (e.g., contents, vessel heading) and mean applied tension(s) are the same as during connected operations.

Operability limits for emergency disconnect are typically governed by properly controlling recoil response of the intervention system following its release. Moreover, operability limits for connected operations (e.g., minimum and maximum overpull, vessel heading, environmental limits) may also be governed by recoil response.

5.2.7 Storm Hang-off

Storm hang-off is typically performed following release of the OWIRS (either by a planned or emergency disconnect) from the well, as an alternative to fully retrieving the suspended riser back to the surface vessel. However, storm hang-off could also be performed before the riser is fully deployed (or run) to the seabed. Storm hang-off is particularly applicable in deep water since running/retrieval of the riser may take considerable time. Multiple running/retrievals may be required in shallow water during consistently onerous environments.

Keeping heavy components installed above the drill floor elevation during storm hang-off can present safety risks due to the possibility of large vessel motions. Therefore, it is recommended that the tension lift frame (TLF) is not within the derrick, nor the surface flow head and its crossovers installed. If this is followed, the topmost riser component following release from the well is likely to be the landing joint.

Examples of situations leading to storm hang-off include an approaching environment or an equipment failure that prevents the running/retrieval of joints.

All intended configurations/arrangements for supporting the topmost joint(s) of the suspended riser during storm hang-off should be established, examples for which include use of:

- traveling block only;
- spider only;
- split load between traveling block and spider;
- “purpose-built” hang-off system.

Storm hang-off configuration following disconnect or at any point during the running/retrieval process may be characterized by various combinations of the following operating parameters:

- subsea stack-up (e.g., EDP only, EDP+WCP+XT, EDP+WCP) at bottom;
- hang-off depth (e.g., near full depth, various intermediate depths).

Operability limits for storm hang-off of an OWIRS is typically governed by the loads at the uppermost riser joint (e.g., cased wear joint), lateral interference with vessel obstructions (e.g., diverter housing, moonpool, pontoon bracing), or angle limits for equipment used to support it (e.g., spider). More specifically, overloading of the riser does not typically govern when contact/interference and exceedance of angle limits is prevented.

5.2.8 Vessel (MODU, Rig, or MSV) Transit with Riser Suspended

In some situations, the vessel may transit or drift with the disconnected riser suspended at a specific hang-off depth. This may be in response to a worsening environment or possibly just a means of “hopping” between adjacent wells. It is common for the OWIRS to be filled with seawater and have no surface pressure applied.

A vessel transit/move may be initiated during other disconnected operational stages (e.g., running and retrieval, storm hang-off) or performed soon after an emergency disconnect or planned disconnect from the well. As such, all relevant combinations of the following operating parameters should be considered:

- type of top support (e.g., by the traveling block, in the slips/spider, on a purpose-built joint);

- elevation of top support (e.g., at drill floor);
- subsea stack (e.g., EDP+WCP+XT, EDP+WCP, EDP only) at bottom;
- hang-off depth.

Similar to the running/retrieval operational stage, operability limits for a vessel transit/move of an OWIRS are typically governed by lateral interference with vessel obstructions (e.g., diverter housing, moonpool, pontoon bracing) or overloading of the riser. Transit speed may also be limited by riser VIV response.

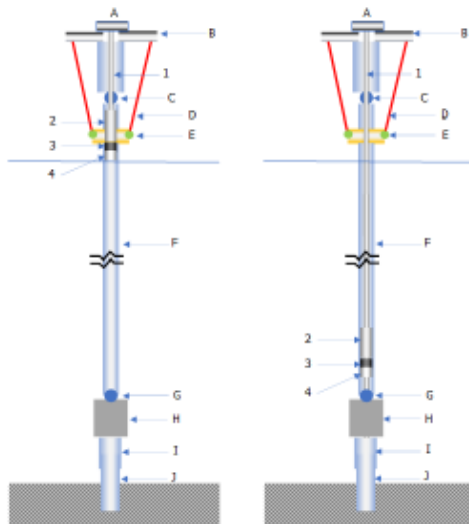
5.3 Through-BOP Intervention Riser System (TBIRS)

5.3.1 General

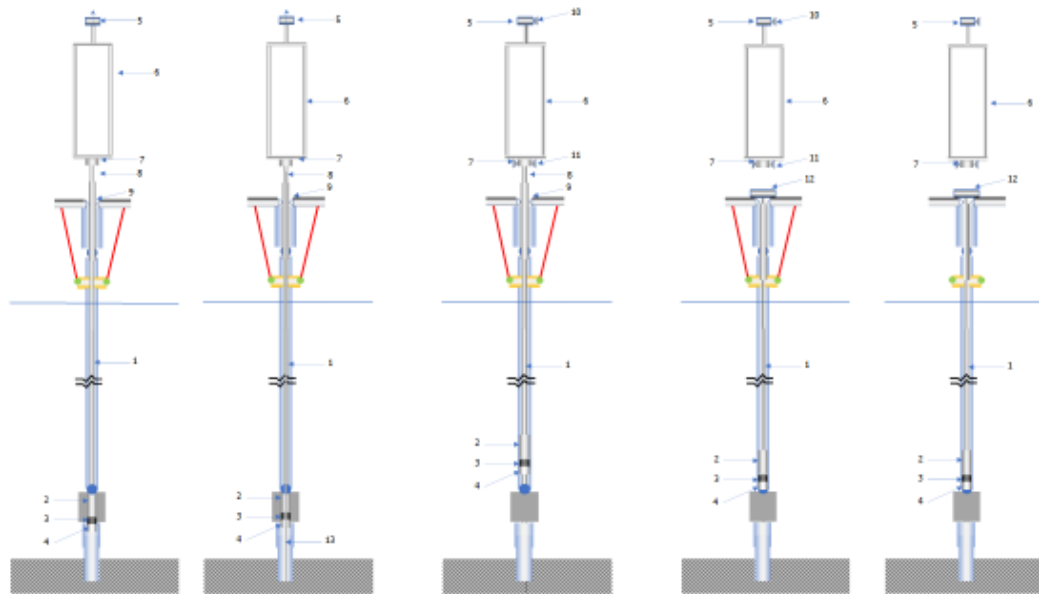
This section provides a brief description of different operational stages of a through-BOP intervention riser system (TBIRS). A TBIRS is deployed inside a marine drilling riser and then connected to the tubing hanger (TH) and the subsea tree or tubing head spool. It can also be deployed during well testing, where it is placed on top of a wellhead wear bushing with a fluted hanger.

[Figure 2](#) provides schematics for typical operational stages of a TBIRS deployed through a marine drilling riser, including the associated boundary conditions as commonly applied in analysis models. It may also be appropriate to consider other intermediate configurations that occur as the riser transitions between the operational stages discussed herein.

Procedures for any mitigation actions to be taken should be accounted for in global analyses and modeling techniques selected appropriately.



a) Running riser through marine drilling riser



b) Landing out c) Connected d) Disconnected e) Hang-off (with disconnected TLF)

Key

A	slips/spider	I	subsea tree, wellhead	7	surface equipment
B	drill floor	J	conductor, casing	8	slick joint
C	upper flex joint	1	landing string	9	lateral support (bushing cased wear joint)
D	tensioner	2	tubing head running tool	10	pinned support
E	tension ring	3	emergency disconnect package	11	fixed support
F	marine drilling riser	4	well control package	12	hang-off bushing
G	lower flex joint	5	traveling block	13	coiled tubing/annulus
H	BOP stack	6	tension frame equipment		

Figure 2—Schematics of Operational Stages for a TBIRS

TBIRS can be deployed for a wide range of completion and intervention operations, including the following:

- installing a completion string using subsea test tree assembly (SSTTA) on a landing string;

- accessing the well for intervention operations using the SSTTA on a landing string;
- retrieving the completion string (as part of a re-completion) using the SSTTA on a landing string;
- “land and lock” (L&L) involving installation/retrieval of a completion string using a BOP spacer joint (or crossover joint, etc.) on a landing string. The SSTTA is not deployed for this configuration.

There are several different types of TBIRS, i.e., various combinations of bottom assembly and landing string, depending on its intended purpose, sometimes referred to as hybrid systems, simplified landing string, etc.

In general, TBIRS that include a SSTTA will have more restrictive operability windows during running/retrieval and landing operations than those that do not. This type of TBIRS has a higher hang-off weight and larger diameters (i.e., smaller gaps/clearances) along the bottom assembly. However, TBIRS without a SSTTA may not allow for most operations once connected, such as pressure testing, flowback, etc.

Most TBIRS also include several upper components that are located above the landing string, such as the following examples:

- tension lift frame (TLF);
- surface flow head;
- crossover/transition to the surface flow head;
- landing joint and riser sealing mandrel (RSM);
- crossover/transition to the landing string;
- engineered weak link assembly (if in upper components).

This set of upper components spans the drill floor and allows for attachment of a tension lift frame.

Once the TBIRS is deployed, the contents inside the marine drilling riser typically remain the same. This is commonly a brine or mud weight with density slightly greater than that of seawater (8.56 ppg). The mean tension applied to the marine drilling riser (by the vessel's riser tensioning system) can vary depending on contents of the marine drilling riser.

Requirements related to the compensator stroke or vertical position of upper components (e.g., surface flow head and associated hoses, etc.) relative to the drill floor typically governs the available downstroke during a loss-of-vessel-position event, as opposed to limits for the marine drilling riser's telescopic joint or the riser tensioners. [Section 7.2](#) provides further discussion of checks for available downstroke and vertical interference.

If the surface vessel is moored, the mean offsets considered for most analyses may be limited to the maximum anticipated vessel offset with intact mooring lines. However, for DP vessels, it is recommended that a range of mean offsets (both upstream and downstream of the dominant current direction) be evaluated for most analyses, so limits can be established by comparison to defined acceptance criteria.

It is recommended to perform the pipe sizing checks discussed further in [Section 10.3](#) before any other global assessments are performed, since selection of the landing string can influence operability limits of the system.

Overloading of a TBIRS can be prevented by maintaining flex joint angles (along the marine drilling riser) within determined limits for each operational stage. Care should be taken to ensure that these limits are not exceeded to ensure that loads/stresses experienced by critical TBIRS components do not reach their limit/capacity.

For this reason, operability limits for all TBIRS operational stages are sensitive to angles experienced by either the lower flex joint (LFJ) or the upper flex joint (UFJ). Therefore, having an electronic riser angle system to

provide an accurate, real-time measurement of LFJ and UFJ angles can help to increase the up-time (i.e., improve the efficiency) of TBIRS operations.

5.3.2 Running and Retrieval

The first operational stage performed at a given well/site is running (or deployment/installation) of the TBIRS. Depending on the well's status and the purpose of planned operations, its bottom assembly can include any combination of the following components or none thereof:

- completion string, sometimes referred to as “tubing”;
- tubing hanger running tool (THRT);
- BOP spacer joint (or crossover joint, etc.);
- SSTTA.

Retrieval is typically performed once connected operations are completed. It is similar to running, although the bottom assembly could be different.

During running/retrieval, the deployed riser will be held alternatively in the slips/spider at the drill floor or by the traveling block in the drawworks system. The riser is supported at the drill floor for the majority of time at each deployment depth, while the drawworks system is handling the next (or previous) stand of joints/pipe. Once the next stand is made-up, the slips are released for a brief period of time and the traveling block lowers the deployed riser to the next deployed position.

Because of variation in well plans and associated completion length/weight and downhole friction, a range of loads at the THRT may be considered. Doing so produces different sets of allowable flex joint angle limits and corresponding operability limits.

Various running/retrieval depths should be assessed [e.g., splash zone, 25 % depth, 50 % depth, 100 % depth (just prior to landing out)] based on the criticality of the equipment and sensitivity to entanglement/overloads

Operational procedures may dictate to pressure test the TBIRS during deployment to demonstrate its pressure integrity.

The critical stage during the running/retrieval operational stage is when TBIRS components having large diameters and high bending stiffness are located at elevations across/near flex joints of the marine drilling riser. Once contact occurs (i.e., any radial gaps/clearances are closed), any further flex joint angle induces higher bending moments that can overload TBIRS components and cause difficulties running the equipment through the flex joint.

It is recommended that analyses of the running/retrieval operational stage evaluate several deployed positions, corresponding to the following:

- first hang-off across the UFJ elevation, e.g., SSTTA supported on the C-plate;
- second hang-off across the UFJ elevation, e.g., subsea control module (SCM) supported on the C-plate;
- any intermediate depths (e.g., mid-depth) at which pressure testing will be performed;
- just prior to passing through the LFJ, meaning the SSTTA or BOP spacer joint is located just above the LFJ elevation;
- while the LV is being picked up, the top of a deployed riser is supported at the drill floor in the slips;
- after the LV is made-up, the string is temporarily supported above the drilling floor by the traveling block.

Operability limits for running/retrieval of a TBIRS are typically governed by overloading of the topmost joint of landing string when supported by the slips. The most restrictive limits generally occur when passing through the UFJ elevation due to high bending loads or just prior to passing through the LFJ due to higher axial loads.

5.3.3 Landing Out

This operational stage represents the period when the TBIRS is landed out but not latched to the TH. During this stage, the bottom assembly is at the installed position within the THS, subsea tree, and BOP stack. Note that an overpull cannot be applied during the landing-out operational stage.

It is during this stage that any remaining TBIRS upper components (e.g., RSM, surface flow head) and the tension lift frame (and its corresponding equipment) are picked up within the derrick, although not necessarily at the same time. It is important to ensure that the derrick height is sufficient to lift the various assemblies. Installation of the entire system is finished once the final assembly (typically comprised of the surface flow head and tension lift frame) is made-up to the top of the deployed riser (commonly the RSM/landing joint).

Examples of operation types commonly performed during the landing-out operational stage include the following:

- entering the subsea stack;
 - The top of the deployed riser (e.g., landing string above LV) is supported at the drill floor in the slips.
 - Any remaining TBIRS upper components, except the surface flow head, are made-up, then the top of the deployed riser is supported at the drill floor in the slips.
 - The fully installed system is supported by the drawworks system once the assembly of the surface flow tree and tension lift frame is attached to the deployed riser.
- pressure testing prior to landing out in tubing hanger, which typically involves applying a nominal internal pressure while the weight of the system is supported by the drawworks system.

Operability limits for landing out of a TBIRS is typically governed by overloading of the topmost joint of landing string when supported by the slips, due to the high axial stresses and bending moment induced by the static hang-off weight.

Following connection/latching, the tension applied to the TBIRS should be increased to the specified operating tension as soon as possible.

5.3.4 Connected

Once connected, the TBIRS can be used to operate in various completion and workover modes, each involving use of specialized equipment to be supported within the tension lift frame. Two common examples are E-line/Wireline mode and coiled tubing (CT) mode. All relevant operating modes should be considered; however, it may be possible to identify the one mode expected to have the most restrictive operability limits.

Examples of operation types that the connected riser is commonly used to perform include the following:

- overpull test to verify locking (following landing and latching);
- pressure testing of the system;
 - It is recommended to perform tests both after landing/latched and before flowback to demonstrate pressure integrity of the landing string.
 - Additional tests may be needed to demonstrate pressure integrity of other components, such as tubing hanger seals, completion/tubing and its seals, burst disk on gas lift valve.

- flowing at corresponding pressure and temperature;
- shut-in at the surface flow tree;
- subsea shut-in with pressure bled off above the lower ball valve (with SSTTA);
- well kill (bull head);
- injection, which is only applicable for CT mode;
- overpull to release stuck tubing.

The operating parameters for the TBIRS (e.g., contents, internal pressure distribution, external pressure distribution, temperature distribution), as well as the mean tensions applied to the marine drilling riser and TBIRS, may be unique for each operation type.

Operability limits during connected operations of a TBIRS are typically governed by overloading at transitions to the landing string from the bottom assembly or the upper components. The proximity of these transitions (to the landing string) relative to the flex joints influences operability limits of the TBIRS.

5.3.5 Planned Disconnect of Landing String

When circumstances allow, a planned disconnect is performed to release the TBIRS from the subsea wellhead while the marine drilling riser (and its LMRP) remains connected. This is done by unlatching from the TH and does not involve shearing of any equipment. Common reasons for a planned disconnect of a TBIRS are the following:

- its connected operations have been completed (i.e., it will be fully retrieved); or
- its bottom assembly needs to be raised above the marine drilling riser's LFJ in preparation for storm hang-off.

A planned disconnect is typically performed during benign environmental conditions, and below are typical steps in preparation for unlatching the riser:

- retrieve any line or coiled tubing from the well;
- circulate out any contents and flood riser with seawater;
- reduce tension applied to the TBIRS such that the overpull is small when unlatching.

After unlatching and when pulling across the LFJ, higher tensions may need to be applied to the TBIRS if its bottom assembly gets stuck within the LFJ due to friction and weight of the completion string.

Acceptance criteria that govern operability limits during planned disconnect of a TBIRS are dependent on the position of the bottom assembly. When the bottom assembly is below the LFJ, operability limits are typically governed by overloading at transitions to the landing string from the bottom assembly or the upper components. When the bottom assembly is above the LFJ, operability limits are typically governed by overloading of the topmost joint of landing string due to static hang-off weight.

5.3.6 Emergency (or Unplanned) Disconnect of Landing String

In some situations, an emergency (or unplanned) disconnect shall be performed to release the TBIRS from the subsea wellhead while the marine drilling riser (and its LMRP) remains connected. Generally, emergency disconnect of a TBIRS involves shearing of a purpose-built component, e.g., shear sub within a SSTTA or disconnecting the latch below the retainer valve of the assembly from the isolating valves, thereby losing/dropping any line or coiled tubing inside of it. An example of a situation requiring an emergency disconnect

include an occurrence of an unanticipated environment or an equipment failure (e.g., top-drive compensation system) during connected operations.

Once the decision is triggered to perform an emergency disconnect of the TBIRS, it is accomplished by manual initiation of the EDS, which then automatically completes the following steps:

- complete shutdown of all process (surface) equipment;
- closure of all subsea and riser valves;
- performs TBIRS latch disconnect or uses the BOP shear ram to release the riser.

The operating parameters for emergency disconnect (e.g., contents, vessel heading) and mean applied tension(s) are the same as during connected operations. This is because an EDS is completed soon after its initiation (i.e., EDS duration is commonly within 60 seconds but is system-dependent), and typically do not have time to take any steps in preparation for release.

Operability limits for emergency disconnect are typically governed by properly controlling recoil response of the TBIRS following its release. More specifically, tension applied to the TBIRS should be sufficient to pull its bottom assembly above the marine drilling riser's LFJ following its release. Operability limits for connected operations (e.g., minimum and maximum overpull, vessel heading, environmental limits) may also be governed by recoil response.

There can also be situations requiring emergency disconnect of the marine drilling riser and TBIRS simultaneously, such as a loss-of-position event for DP vessels. Doing so requires coordination between timings for EDS of the marine drilling riser and EDS of the TBIRS.

5.3.7 Storm Hang-off of Landing String with LMRP Connected

Storm hang-off is most commonly performed following release of a TBIRS (either by a planned or emergency disconnect) from the well as an alternative to fully retrieving the suspended riser back to the surface vessel. However, storm hang-off could also be performed before the riser is fully deployed (or run) to the seabed. Examples of situations leading to storm hang-off include the approach of an unanticipated environment or an equipment failure that prevents the running/retrieval of joints.

It is assumed that the marine drilling riser has more favorable operating limits, and thus has remained connected to the subsea well (via its LMRP). Therefore, during storm hang-off, the TBIRS is released/free-hanging inside the connected outer riser with its bottom assembly located above the LFJ elevation.

Keeping heavy components installed above the drill floor elevation during storm hang-off can present safety risks due to the possibility of large vessel motions. Therefore, it is recommended that the TLF is not within the derrick, nor the surface flow head and its crossovers (of TBIRS) installed. If this is followed, the topmost riser component following release from the well is likely to be the landing joint, with the intent of placing the RSM below or above (i.e., not across) the UFJ of the marine drilling riser.

For storm hang-off, it is recommended to model the disconnected TBIRS as supported by the traveling block of the drawworks system at a selected height above the drill floor elevation as per vessel operation procedure. Use of the C-plate or slips could overload the topmost riser joint/component or cause it to accumulate excessive fatigue damage due to the possibility of large vessel motions. Still, all intended configurations/arrangements for supporting the topmost joint/component of the suspended TBIRS during storm hang-off should be established.

Since storm hang-off may be transitioned to following disconnect or at any point during running/retrieval operations, it may be performed for various combinations of the following operating parameters:

- bottom assembly;
- hang-off depth (e.g., near full depth, various intermediate depths).

Operability limits for storm hang-off of a TBIRS is typically governed by the overloading of upper components or their transition to the landing string. This is due to bending stresses induced by their proximity to the UFJ or by use of the C-plate/slips for top support.

5.4 Subsea Pumping Well Intervention Systems (SPWIS)

5.4.1 General

This section provides a brief description of the operational stages for a subsea pumping well intervention system (SPWIS), as defined in API 17G2, which is often referred to as rigless or hydraulic intervention. Subsea pumping intervention systems are typically deployed from multi-service vessels (MSV), which can work either standalone or in tandem with an adjacent stimulation vessel that supplies the large fluid volumes and pump rates needed during well remediation work.

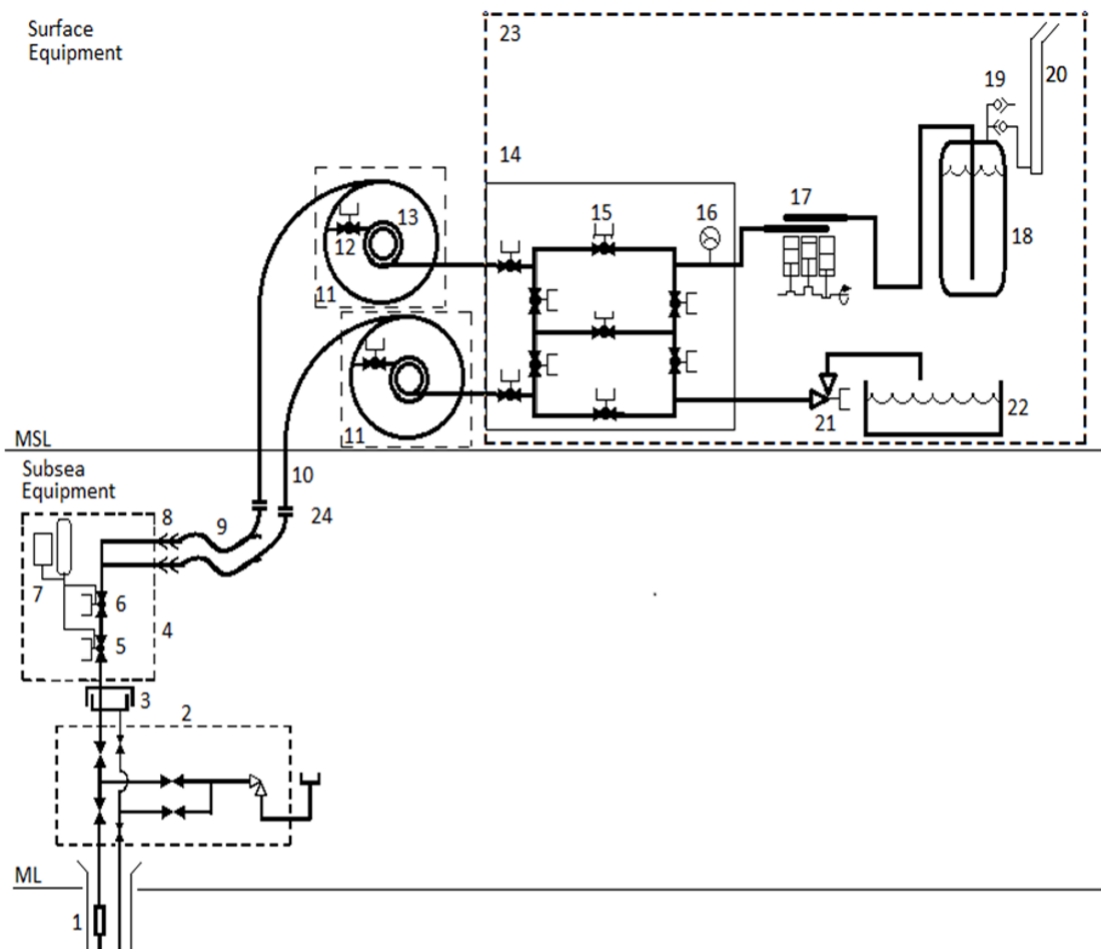
The configuration of the SPWIS equipment can vary but typically include the following components:

- topsides controls and umbilicals;
- subsea safety module (SSM) (stimulation tool);
- injection skid (subsea interface);
- open water fluid conduit lines (coiled tubing, hose, or composite) with clump weight on bottom;
- downline disconnects (engineered weak link); and
- disconnects between vessels: LP or HP (if applicable).

[Figure 3](#) provides a schematic demonstrating the typical components of the SPWIS in the surface to seafloor fluid conveyance mode with a pump located at the surface. [Figure 4](#) provides a schematic demonstrating the typical components of the SPWIS in the surface to seafloor fluid conveyance mode with a pump located subsea.

The succeeding subsections detail the operating stages for a SPWIS to be used at a specific well of interest. It is important to note that additional operational stages may be required and should be detailed on a case-by-case basis in the analysis basis.

Surface to Seafloor Conveyance Mode



Key

- | | | | |
|----|--|----|---|
| 1 | SCSSSV | 13 | vertical conduit power reeler |
| 2 | subsea tree | 14 | squeeze manifold |
| 3 | tree interface connector | 15 | surface isolation valves |
| 4 | subsea safety module | 16 | pressure gauge |
| 5 | barrier valve | 17 | triplex pump |
| 6 | barrier valve optional | 18 | surface fluid storage |
| 7 | subsea accumulation | 19 | double acting vent valve |
| 8 | subsea releasable connector | 20 | vent system |
| 9 | flying leads | 21 | surface choke or flow control valve |
| 10 | vertical fluid controls | 22 | surface waste fluid tank |
| 11 | vertical fluid conduit deployment system | 23 | surface processing system |
| 12 | vertical fluid conduit isolation valve | 24 | weak link connector and retainer device |

Figure 3—Surface to Seafloor Fluid Conveyance Mode with Pump Located at Surface (SPWIS)

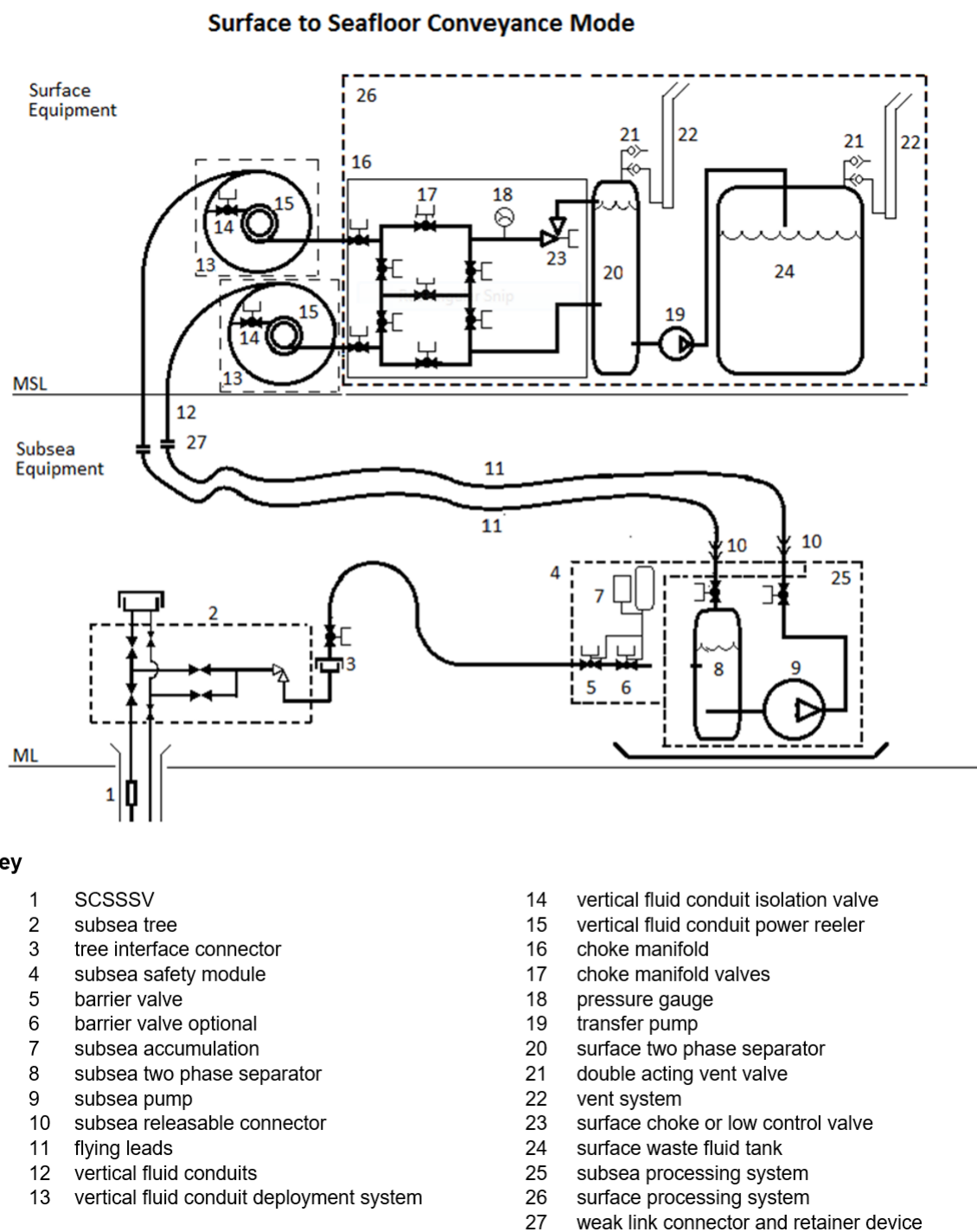


Figure 4—Surface to Seafloor Fluid Conveyance Mode with Subsea Pump (SPWIS)

5.4.2 Running and Retrieval

The SPWIS can be deployed either through the moonpool of the vessel or overboarded. During running and retrieval, the components of the subsea pumping well intervention system are deployed through the water column directly to the subsea tree or landed on a suction pile/mud mat. The system is continuously deployed until reaching installation depth and then landed on bottom before disconnecting and retrieving the deployment line. The fluid conduit lines are run subsea by their respective deployment systems and should be evaluated against the environmental conditions. These fluid conduits can consist of coiled tubing downlines, hydraulic hose, or drill pipe with a crossover to a flexible jumper.

Multiple components of the system are deployed independently; therefore, running/retrieval analysis can be performed for any relevant SPWIS components. Examples of these include:

- control and umbilical lines deployment;
- open water fluid conduit lines (coiled tubing, hose, or composite) with clump weight on bottom;
- subsea safety module; and
- injection skid.

Various running/retrieval depths should be assessed (e.g., splash zone, 25 % depth, 50 % depth, 100 % depth (just prior to landing out) based on the criticality of the equipment and sensitivity to entanglement/overloads. The equipment being run/retrieved and the mechanism of deployment (e.g., on wire rope via subsea access crane) can vary. Other considerations include:

- vessel offset (at surface to place downlines over well); and
- vessel heading.

It should be acceptable to analyze only the worst-case deployed component in situations where familiarity and experience have been gained with the SPWIS. This should be agreed to between the different parties and documented in the analysis basis.

Operability limits for running and retrieval of subsea pumping well intervention systems are commonly constrained by one of the following:

- heave compensation limits for the deployment system;
- environment limitations for ROV deployment;
- overloading of fluid conduit downlines and umbilicals;
- clashing/entanglement between the various suspended lines; or
- VIV limits of the various suspended lines.

5.4.3 Connected

In its connected state, the subsea safety module of the SPWIS is connected to the intervention vessel by one or more fluid conduit downlines. These downlines can be self-supported (i.e., hanging freely in the water column) or supported by clamps attached to a supporting structure (e.g., a wire rope deployed from a winch on the intervention vessel). The subsea safety module is in turn connected to the well of interest either directly via choke insert landed on top of the subsea tree, on the subsea tree mandrel, or alternatively by flexible hydraulic jumpers when landed nearby on a mud mat or suction pile. There are other versions of the SPWIS that may not include a subsea safety module.

Examples of operation types that a fully connected SPWIS is commonly used to perform, include the following:

- acid stimulation;
- tubing scale remediation (scale squeeze);
- chemical injection;
- formation fracking;

- bullhead kill.

For GRA purposes, these operation types have unique combinations of contents and internal pressure.

Operability limits for the connected mode of the SPWIS are primarily limited by the ability of the intervention vessel, or stimulation vessel when working in tandem, to maintain position at the wellhead location while connected to the injection skid or tree. Operability may also be limited in some cases by entanglement/overloading of SPWIS components from direct environmental loading when on location.

5.4.4 Planned Disconnect

In some situations, a planned disconnect is executed to release the SPWIS from the injection skid or subsea tree. A planned disconnect allows the crews to take the following measures in preparation of release from the well system:

- close the subsea safety module or stimulation tool well barrier valves;
- turn off pumps on stimulation vessel and bleed pressure in fluid transfer hose;
- shut-in tree valves;
- initiate EQD on MSV;
- use stimulation vessel to reel up hose.

Although the planned disconnect is generally executed in mild environmental conditions, the operability limits are still generally governed by the ability of the intervention vessel, or stimulation vessel when working in tandem, to maintain position at the wellhead location while connected to the injection skid or tree. The fluid conduit lines, once disconnected, should be retrieved sufficiently to avoid contact with the subsea infrastructure.

5.4.5 Emergency (or Unplanned) Disconnect

For SPWIS, unplanned emergency disconnects can result from any number of situations that limit the intervention vessel's ability to effectively manage or limit the tension in the fluid conduit downlines. Examples of this may include a DP loss-of-position event (e.g., drive-off/drift-off), unanticipated environmental event, or equipment malfunction. During these events, the fluid conduit downlines, or hoses connecting the intervention and stimulation vessels working in tandem, will be released or severed by active or passive systems (e.g., an engineered weak link).

Emergency disconnect for SPWIS involves active or passive equipment. A procedure may involve all the following steps:

- complete shutdown of all process equipment;
- shut-in tree valves;
- disconnect of stimulation vessel from intervention vessel;
- disconnect of all downlines.

The well barriers (e.g., subsea safety module) will remain subsea to provide well control. In the event of a vessel loss-of-position event, the fluid conduit downlines installed on the subsea safety module will part, allowing the vessel to move off location without damaging any subsea components.

5.5 Riserless Subsea Well Intervention Systems (RSWIS)

5.5.1 General

Riserless subsea well intervention systems (RSWIS) are designed to facilitate tool strings into/out of the wellbore while subsea, controlling pressure at the subsea tree and/or tubing head spool with the PCE. A RSWIS, as defined in API 17G4, does not include a riser conduit through the water column to surface from the subsea pressure control equipment (PCE) like with OWIRS or TBIRS. The succeeding subsections detail the operating stages for a RSWIS to be used at a specific well of interest. It is important to note that additional operational stages may be required and should be detailed on a case-by-case basis in the analysis basis.

5.5.2 Running and Retrieval

The RSWIS can be deployed either through the moonpool of the vessel or overboarded by means of a subsea deployment mechanism. The configuration of the equipment to be installed can vary, but typically includes the following components:

- WCP;
- lubricator assembly;
- subsea injector assembly (coiled tubing);
- pressure control head;
- control system umbilical;
- fluid conduit lines; and
- wirelines/guidelines (if applicable).

During running and retrieval, the components of the RSWIS will be deployed through the water column directly to the subsea tree and/or tubing head spool via a wireline/cabling apparatus. A RSWIS is continuously deployed until reaching installation depth and hung-off using the compensation system for the chosen method of deployment. This arrangement is different than a typical OWIRS or TBIRS, which are suspended at the vessel on slips/spider. The control system umbilical and fluid conduit lines are run subsea by their respective deployment systems and should also be evaluated against the environmental conditions. Due to the fact that the multiple components of the system are deployed independently, the following analyses shall be performed, at a minimum, for each piece of equipment:

- first hang-off above the water surface;
- second hang-off, inclusive of initial deployment through the splash zone;
- several intermediate depths;
- full depth, prior to latch.

It should be acceptable to analyze only the worst-case deployed component or deployment stage in situations where familiarity and experience have been gained with the RSWIS. This should be agreed to between the different parties and documented in the analysis basis.

Operability limits for running and retrieval of RSWIS are commonly constrained by one of the following:

- clashing with the vessel infrastructure, such as the moonpool or hull;
- current and sea state limitations for ROV deployment;

- loading on the launch and recovery system (LARS)—if installed—which uses rails to guide the equipment through the moonpool;
- stress limit in the tubing or wire;
- minimum bend radii of flexible/composite hoses.

See [Figure 5](#) for a schematic demonstrating the typical components of the RSWIS.

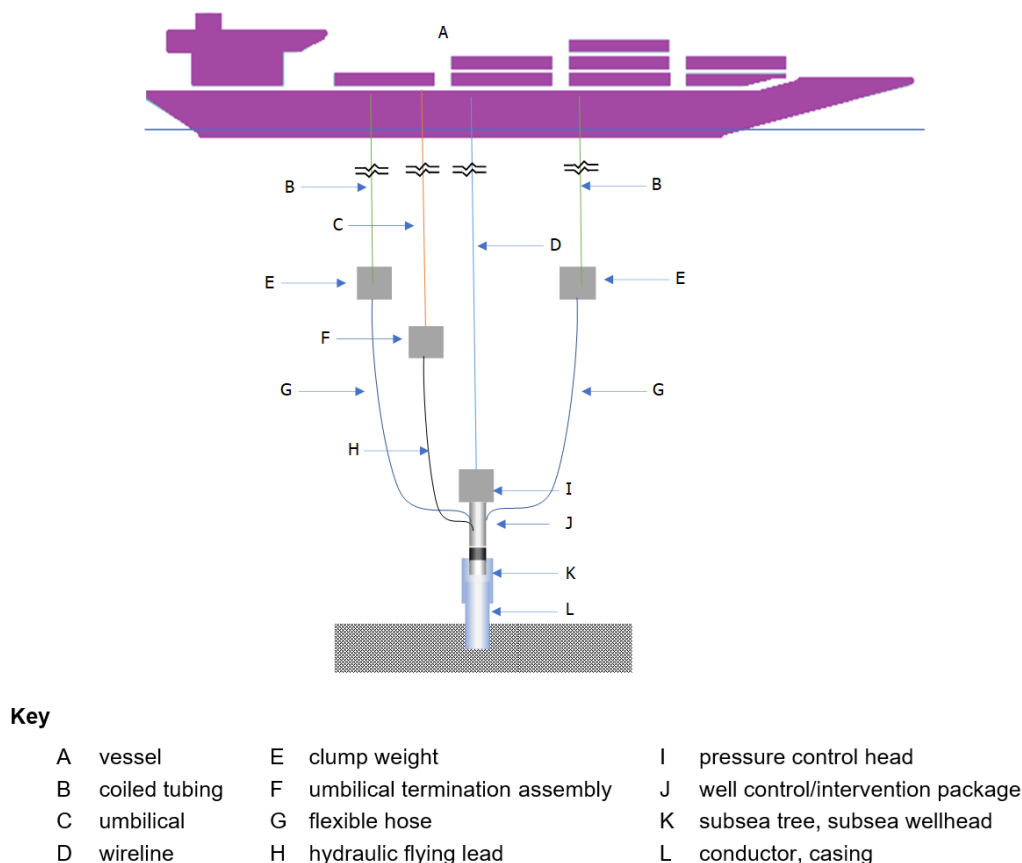


Figure 5—RSWIS Schematic

5.5.3 Landing

The compensation system of the particular deployment method is used to land the RSWIS once the component is at its fully deployed depth. As with the previously mentioned intervention systems, the landing operational stage is usually performed during mild environmental conditions. Operability limits for landing are normally governed by limits on relative connector angle, allowing for make-up of each connection of the system.

5.5.4 Connected

The RSWIS is in its connected operating stage once the entire system is landed and latched subsea. Typical modes of operation for which a RSWIS is evaluated are:

- hydraulic intervention;
- riserless wireline intervention; and
- riserless coiled tubing intervention.

Operations that a RSWIS is normally used to achieve include, but are not limited to:

- overpull to verify locking of the RSWIS;
- pressure testing of the system;
- shut-in at the subsea tree with pressure bled off above the WCP barriers;
- flowing at project-specific pressure and temperature;
- setting of mechanical wireline plugs; and
- pumping into the wellbore (e.g., bullhead kill, scale squeeze, acid stimulation).

Operability limits for the connected mode of the RSWIS include the freestanding stack structure's capacity to withstand VIV fatigue for long-duration deployment and strength assessment of the stack from bottom currents to evaluate the structural reliability of the RSWIS. In shallow water, waves also act directly on the structure, as well as indirectly via vessel-imposed loads through the guidelines, fluid conduit lines, etc. Finally, system stability (e.g., Euler buckling) and lubricator angle when stabbing the tool string may also limit operability and should be considered.

5.5.5 Planned Disconnect

In some situations, a planned disconnect is executed to release the RSWIS from the subsea tree and /or tubing head spool. A planned disconnect allows the crews to take the following measures in preparation of release from the well system:

- retrieve the wireline or coiled tubing from the well;
- close the barrier elements and secure the well;
- flush and displace the RSWIS of any hydrocarbon content; and
- select the appropriate vessel heading based on the environmental conditions.

Although the planned disconnect is generally executed in mild environmental conditions, the operability limits are still generally governed by the relative connector angle during the unlatch of the PCH, as planned disconnect is usually the reverse of landing the PCH on the RSWIS. The fluid conduit lines and wireline/guidelines will also be disconnected and should be retrieved sufficiently to avoid contact with the subsea infrastructure.

5.5.6 Emergency (or Unplanned) Disconnect

For RSWIS, an unplanned emergency disconnect can occur due to DP loss of station-keeping (LOSK) (e.g., drive-off/drift-off), an abnormal environmental event, or an equipment malfunction. Unlike TBIRS and OWIRS, there is not a disconnect and hang-off of riser at the rig floor—the wireline or coiled tubing will be severed and pulled out of the wellbore as the vessel moves off location. Emergency disconnect for RSWIS may involve all of the following:

- complete shutdown of all process equipment;
- cutting/shearing of the tool string (e.g., wireline, coiled tubing);
- closing of the barrier elements and securing the well;
- disconnect of the control system umbilical;
- disconnect of the fluid conduit lines; and