Workover/Intervention Guidance for Global Riser Analysis

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1 Purpose and Scope

1.1 Purpose

This Technical Report (TR) 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 technical report is not intended to replace existing API Recommended Practices (RP) and Standards (STD) but 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 technical report 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 technical report 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 technical report includes input, output, and analysis as follows:

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

This TR complements API 17G1 which identifies the information required to conduct the analysis (inputs) and interpret the results of the analysis (outputs) to determine if the system meets the structural requirements. Different global riser modelling techniques and assumptions are presented for consideration by the user. To increase user awareness, discussion of modelling 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.

The TR outlines a detailed load case matrix for a GRA of a subsea well intervention system. The user has the discretion to execute a 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 non-standard cases may need to be assessed.

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

The TR does not assess fatigue performance of the well system.

2 Normative References

API Standard 2RD;	Dynamic Risers for Floating Production Systems.
API Standard 17G;	Design and Manufacture of Subsea Well Intervention Equipment.
API RP 17G1;	Configuration and Operation of Subsea Well Intervention Systems
API RP 17G2;	Subsea Pumping Well Intervention Systems
API RP 2A (WSD);	RP for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design
API RP 16Q;	Offshore riser systems
API RP 2SK;	Design and Analysis of Station keeping Systems for Floating Structures
DNV OS E301;	Position Mooring
DNV-GL-RP-E104;	Well head fatigue analysis
DNVGL-RP-F204;	Riser fatigue.
DNVGL-RP-C203;	Fatigue Design of Offshore Steel Structures.

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

Load(s) which are 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 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

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 design basis

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

3.1.6 design check

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

3.1.7 design criteria

Quantitative formulations which describe each failure mode the conditions shall fulfil.

3.1.8 design factor

Factor (usage factor) used in working stress design

3.1.9 design load

Combination of load effects

3.1.10 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 named maximum allowable pressure or 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.

3.1.11 drift-off

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

3.1.12 drive-off

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

3.1.13 dynamic positioning

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

3.1.14 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.

3.1.15 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. The sequence should activate at least one shear ram to seal the well prior to disconnect the LMRP connector. An EDS requires to be available on subsea BOP stacks that are run from a dynamically positioned vessel. An EDS is optional for moored vessels.

3.1.16 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.

3.1.17 end user and/or operator

Organization that authorizes the use of a subsea well intervention system for well operations

3.1.18 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 Table 2 of API Standard 17G lists the Structural Design Factors.

3.1.19 environmental loads

Loads due to the environment.

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

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

3.1.23 finite element analysis

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

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.

EXAMPLES Semi-submersible drilling vessels, drill ships, mobile offshore drilling unit (MODU), multi-purpose vessels.

3.1.25 frequency domain

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)

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). Once the global loads are established, then these loads should be assessed against component capacities, thereby determining the operating limits for the system.

3.1.27 hang-off

Riser when disconnected from 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

Floating vessel motion 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

Non-factored fatigue life estimate divided by the safety factor to be applied

3.1.31 landing string

Jointed temporary riser used as part of the thru-BOP intervention riser system that typically provides a conduit from the subsea test tree assembly or BOP spanner joint to the surface tree and are 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

Physical influence which causes stress and/or strains in the riser system.

3.1.33 load case

Combination of simultaneously acting loads.

3.1.34 load effect

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

Load classification refers to an assignment of either normal, extreme, or survival load conditions to an operational stage or load case to be analysed 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

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

Mean static offset (of vessel) includes static offset due to steady forces from current, wind and wave, 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

Used to describe 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 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 Table 2 of API Standard 17G lists the Structural Design Factors

3.1.41 open-water intervention riser system (OWIRS)

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.

3.1.42 operability

Ability to safely perform the planned operation without exceeding the capacity and performance limits of the equipment being utilized.

3.1.43 operating envelope

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

3.1.44 operating mode

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

3.1.45 operational stage (scenario)

Used to describe the stages of the operation, intervention activities, and the use of safety functions.

3.1.46 response amplitude operator (RAO)

Relationship between wave surface elevation amplitude and the vessel response amplitude, and the phase lag between the two

3.1.47 return period

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.

3.1.48 riser model

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.

3.1.49 riserless subsea well intervention system (RSWIS)

Intervention systems 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.

3.1.50 safety function

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

3.1.51 service life

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.

3.1.52 service provider

Organization that provides subsea well intervention system services and products.

3.1.53 subsea pumping well intervention system (SPWIS)

Intervention systems, also referred to as rigless or hydraulic intervention, and typically deployed from multi-service vessels (MSV) and supplies large fluid volumes and pump rates needed for well remediation.

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

3.1.54 strength

Mechanical property of a material, usually given in units of stress.

3.1.55 stress concentration factor (SCF)

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.

3.1.56 stress range

Difference between stress maximum and stress minimum in a stress cycle.

3.1.57 stroke

Total upward and downward vertical 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).

3.1.58 structural load capacity

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

3.1.59 submerged weight

Submerged weight including content minus any applicable buoyancy. Also, referred to as apparent weight, weight in water, wet weight, net lift, and effective weight.

3.1.60 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 Table 2 of API Standard 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.

3.1.61 system

Collection of equipment utilized to perform its intended purpose within the scope of this document.

3.1.62 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 manufacture data and manufacture record books (where applicable), collection of equipment assembled together, verification testing documentation, operation procedures, maintenance and storage procedures etc.

3.1.63 tension-split

Tensioning system with tension sharing between the top-drive compensation system and the riser tensioning system. Typically, applicable only for OWIRS.

3.1.64 tensioner system

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.

3.1.65 through-BOP intervention riser system (TBIRS)

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.

3.1.66 time domain

Time wise, incremental simulation of riser response

NOTE Offers the capability of modeling hydrodynamic and structural non-linearity

3.1.67 upper components

refers to equipment located above the main riser pipe (OWIRS) or landing string (TBIRS)

3.1.68 vessel (mean) offset

Average offset created by steady forces from current, wind, and waves

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

3.1.69 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

3.1.70 vortex-induced vibration (VIV)

In-line and transverse oscillation of a riser caused by current-induced periodic shedding of vortices

3.1.71 wave frequency motion

Motion of the vessel at the frequencies of incident waves

3.1.72 wave scatter diagram

Table listing occurrence of seastates in terms of significant wave height and wave peak period or mean up-crossing period

3.1.73 well barrier

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

3.1.74 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.

3.1.75 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.

3.1.76 well system

Combination of subsea wellhead system and casing system installed

3.1.77 workover riser

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 normally 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/WO	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 flexjoint
LMRP	lower marine riser package
LOSK	loss of station keeping
LP	low pressure (defined typically 2 MPa (300 ± 30 psi) for pressure testing purposes)
LPH	low pressure housing
LV	lubricator valve
MBR	minimum bend radius
MODU	mobile offshore drilling unit
MSL	mean sea level
MSV	multi-service 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	standards
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

TR technical report

TSJ taper / tapered stress joint

UFJ upper flexjoint

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 Abbreviated Symbols

For the purposes of this document, the following abbreviations apply

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;

Hs wave height

$log\bar{a}$ intercept constant for the design S-N curve;

$log\overline{a_{\Delta M}}$ 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 mid-stroke;
$T_{e,tot}$	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 TR is applicable, as well as provides guidance for when global riser analyses is needed and limitations it 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 & abandonment (P&A).

Examples of subsea well intervention vessels:

— 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

GRA is used for intervention operations where there is a risk to the subsea infrastructure, intervention equipment or the environment.

4.4 Limitations

The GRA is limited to the type of operations, loads and systems described in this document.

5 Operational Stages (scenarios)

5.1 General

This section lists operational stages (or operational scenario) 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 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 5-1 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 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:

— install a completion string;
— access the well for intervention operations;
— perform well testing;
— perform flowbacks;
— retrieve the completion string (as part of a re-completion).

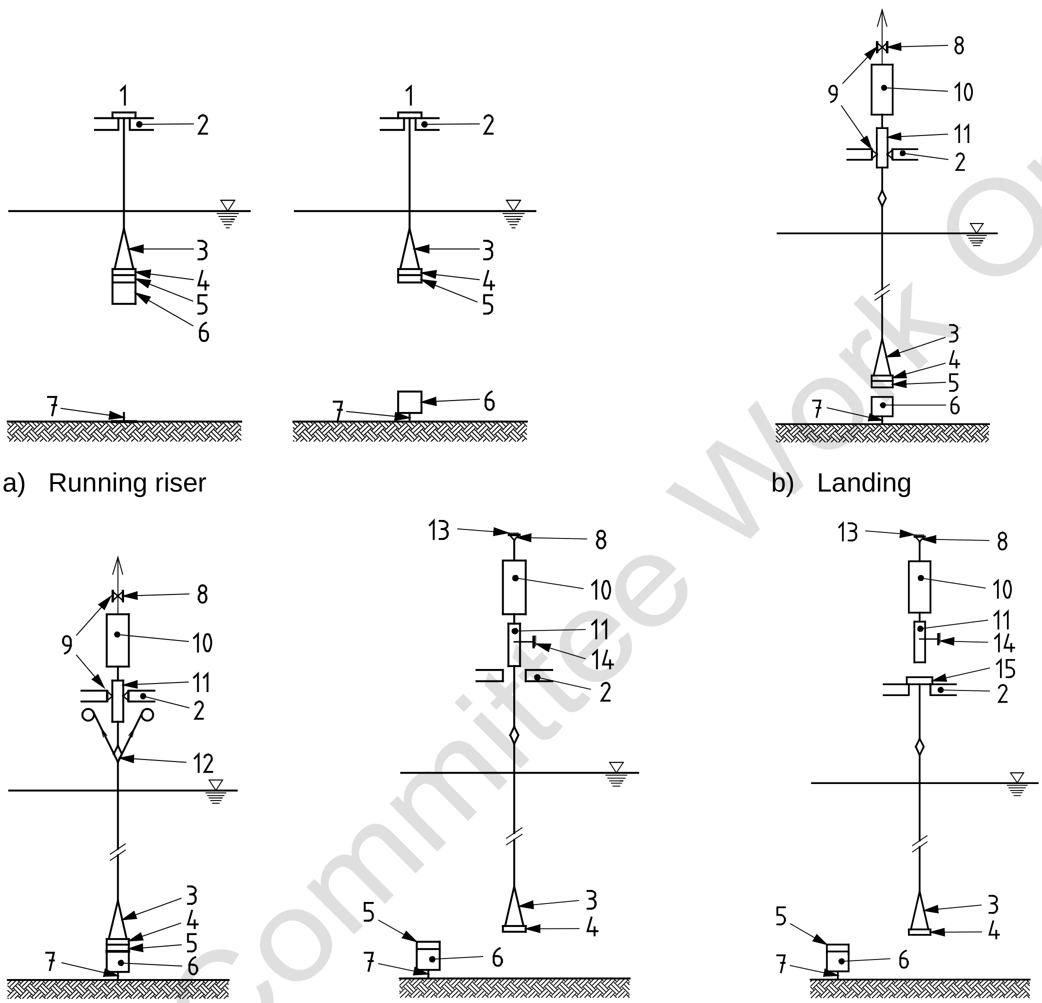
Compensator stroke or vertical position of upper components (e.g., surface flow head and associated hoses, etc.) relative to the drill floor typically governs the available down-stroke during a loss of vessel position event.

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 offsets 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.



a) Running riser

b) Landing

c) Connected

d) Disconnected

e) Hang-off

Key

1	slips/spider	6	subsea tree	11	slick joint
2	drill floor	7	wellhead	12	tension joint
3	stress joint	8	traveling block	13	pinned connection
4	emergency disconnect package	9	lateral support	14	fixed support
5	well control package	10	tension frame equipment	15	hang-off bushing

Figure 5-1—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 travelling 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 the following:

— 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 towards increasing vertical clearance with the mudline.

5.2.6 Emergency (or Unplanned) Disconnect

In situations where an emergency (or unplanned) disconnect must 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 decisioned 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, it 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 top most 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 top-most 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 (for 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 is typically governed by: lateral interference with vessel obstructions (e.g., diverter housing, moonpool, pontoon bracing) or overloading of the riser. Transits speed may also be limited by riser VIV response.

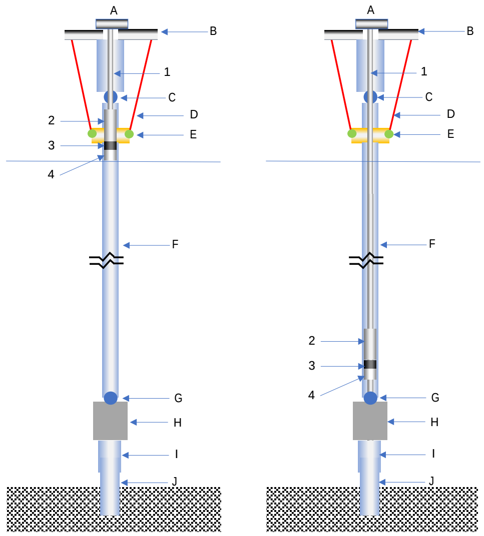
5.3 Through-BOP Intervention Riser System (TBIRS)

5.3.1 General

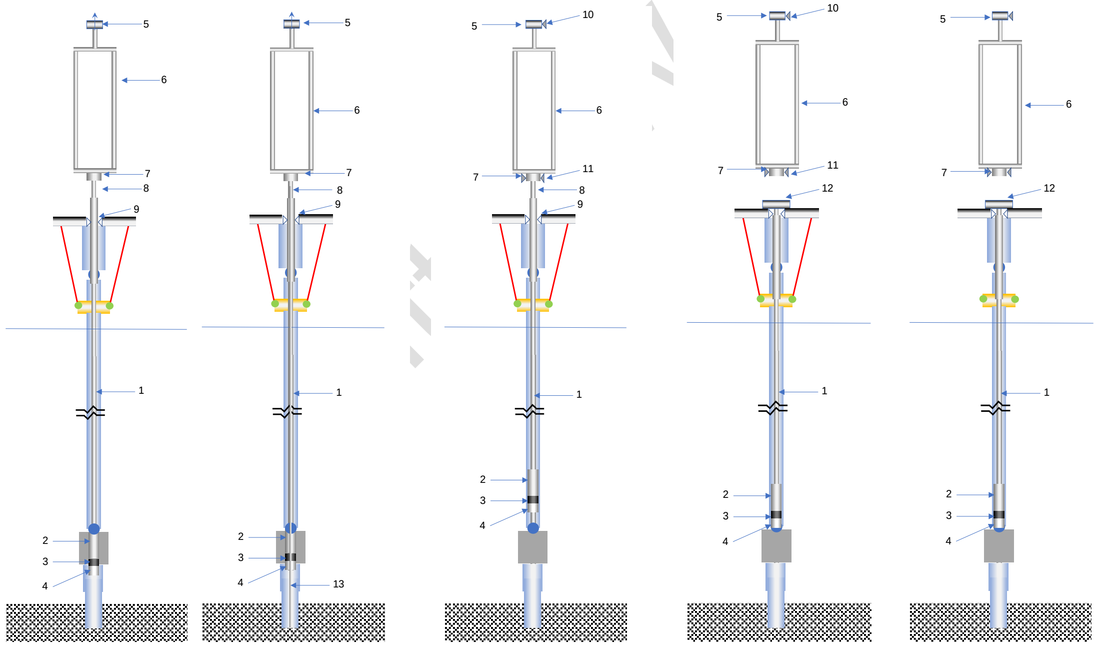
This section provides a brief description of different operational stages of a through-BOP intervention riser system (TBIRS). A TBIRS is deployed inside a marine drilling riser and then connected to the tubing hanger (TH) and the subsea tree and/or tubing head spool. It can also be deployed during well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

Figure 5-2 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 or cased wear joint)
D	tensioner	2	tubing head running tool		
E	tension ring	3	emergency disconnect package	10	pinned support
F	marine drilling riser	4	well control package	11	fixed support
G	lower flex joint	5	travelling block	12	hang-off bushing
H	BOP stack	6	tension frame equipment	13	coiled tubing/annulus

Figure 5-2—Schematics of Operational Stages for a TBIRS

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

— install a completion string using subsea test tree assembly (SSTTA) on a landing string;
— access the well for intervention operations using the SSTTA on a landing string;
— retrieve the completion string (as part of a re-completion) using the SSTTA on a landing string;
— L&L ("land and lock") 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 remains the same. This is commonly a brine or mud weight with density slighter 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 down-stroke 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 down-stroke 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 flexjoint 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 flexjoint (LFJ) and/or the upper flexjoint (UFJ). Therefore, having 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 travelling 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 flexjoint 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 diameter and high bending stiffness are located at elevations across/near flexjoints of the marine drilling riser. Once contact occurs (i.e., any radial gaps/ clearances are closed), any further flexjoint angle induces higher bending moments which can overload TBIRS components and cause difficulties running the equipment through the flexjoint.

It is recommended that analyses of the running/retrieval operational stage evaluate several deployed positions, such as 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 is 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, 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 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 and 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 is typically governed by overloading at transitions to the landing string from the bottom assembly or the upper components. Proximity of these transitions (to the landing string) relative to the flexjoints influence 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 TBRIS are the following: its connected operations have been completed (i.e., it will be fully retrieved) or because 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 is 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 must 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 is isolating valves thereby losing/dropping any line or coiled tubing inside of it. Examples of situations requiring an emergency disconnect include 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 shearing 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 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 travelling 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 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.

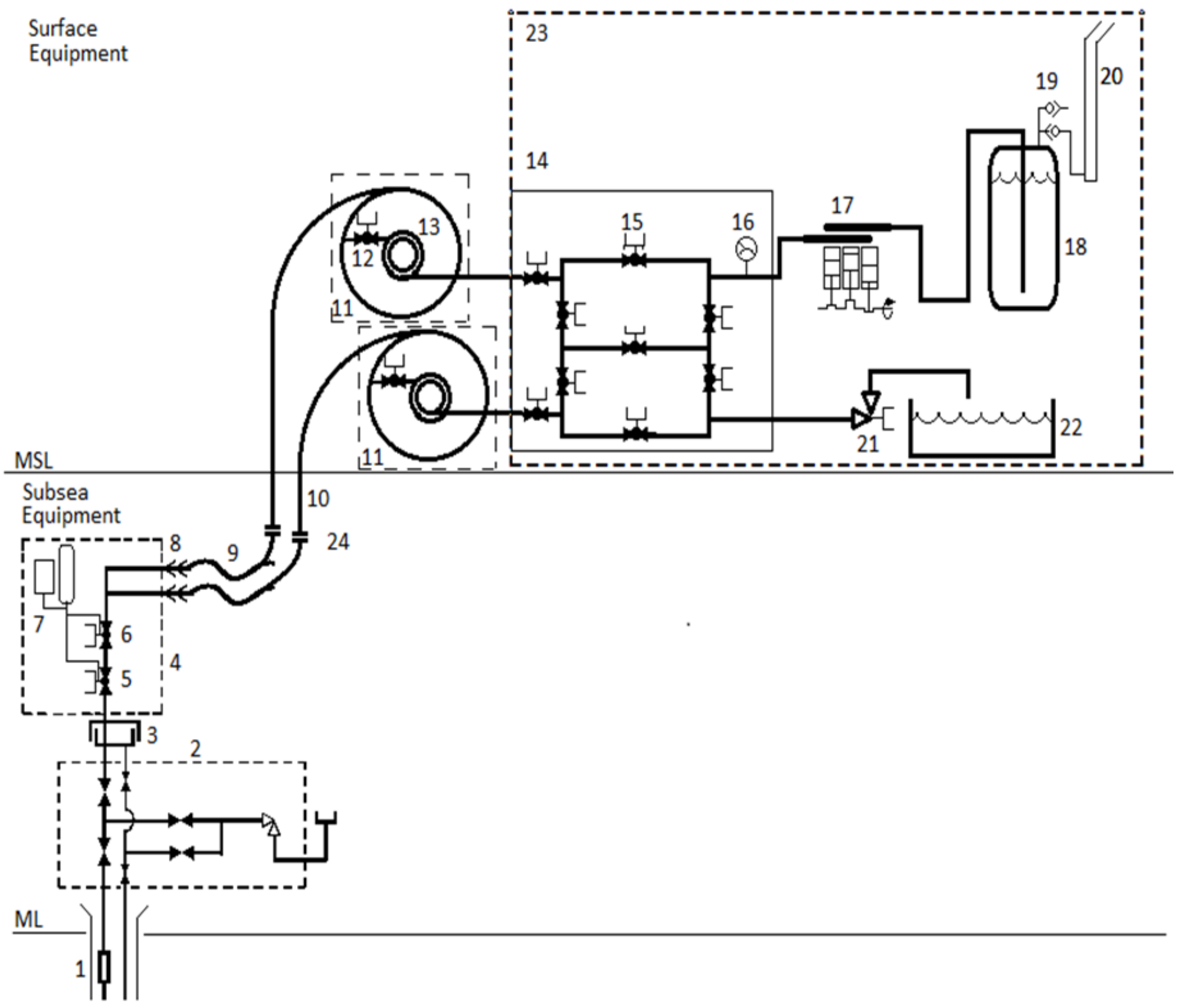
The configuration of the SPWIS equipment can vary but typically include the following components:

— 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 5-3 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 5-4 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 utilized 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.

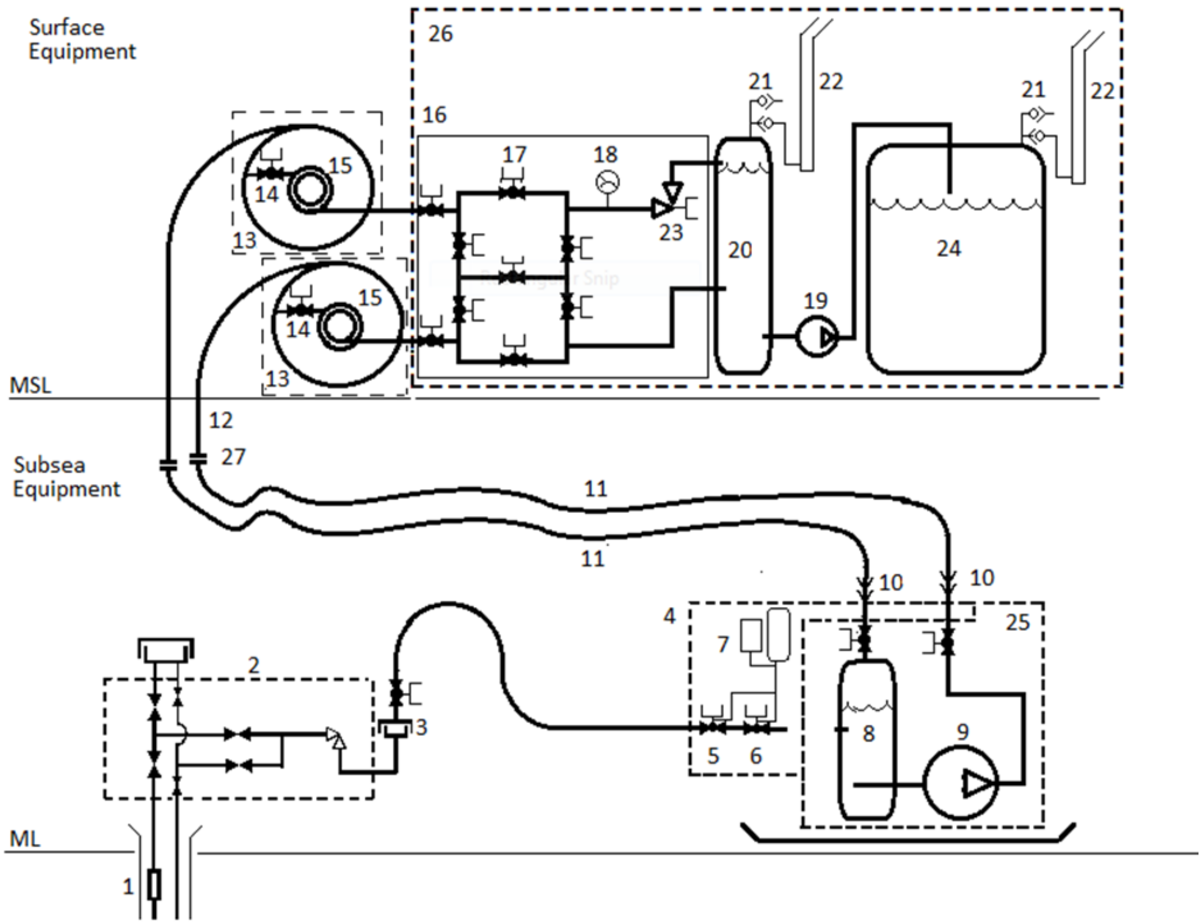
Surface to Seafloor Conveyance Mode



1 SCSSSV
2 Subsea Tree
3 Tree Interface Connector
4 Subsea Safety Module
5 Barrier Valve
6 Barrier Valve Optional
7 Subsea Accumulation
8 Subsea Releasable Connector
9 Flying Leads
10 Vertical Fluid Conduits
11 Vertical Fluid Conduit Deployment System
12 Vertical Fluid Conduit Isolation Valve
13 Vertical Conduit Power Reeler
14 Squeeze Manifold
15 Surface Isolation Valves
16 Pressure Gage
17 Triplex Pump
18 Surface Fluid Storage
19 Double Acting Vent Valve
20 Vent Systen
21 Surface Choke or Flow Control Valve
22 Surface Waste Fluid Tank
23 Surface Processing System
24 Weak Link Connector and Retainer Device

Figure 5-3 Surface to Seafloor Fluid Conveyance Mode with Pump Located at Surface (SPWIS)

Surface to Seafloor Conveyance Mode



1 SCSSSV
2 Subsea Tree
3 Tree Interface Connector
4 Subsea Safety Module
5 Barrier Valve
6 Barrier Valve (Optional)
7 Subsea Accumulation
8 Subsea Two Phase Separator
9 Subsea Pump
10 Subsea Releasable Connector
11 Flying Leads
12 Vertical Fluid Conduits
13 Vertical Fluid Conduit Deployment System

14 Vertical Fluid Conduit Isolation Valve
15 Vertical Fluid Conduit Power Reeler
16 Choke Manifold
17 Choke Manifold Valves
18 Pressure Gage
19 Transfer Pump
20 Surface Two Phase Separator
21 Double Acting Vent Valve
22 Vent System
23 Surface Choke or Flow Control Valve
24 Surface Waste Fluid Tank
25 Subsea Processing System
26 Surface Processing System
27 Weak Link Connector & Retainer Device

Figure 5-4 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 will be 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 which 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 (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 system 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; or
— clashing/entanglement between the various suspended lines.
— 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 x-mas 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 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 will be 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;
— 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 which limit the intervention vessel's ability to effectively manage or limit the tension in the fluid conduit downlines. Examples of this may include DP loss of position event (e.g., drive off / drift off), unanticipated environmental event or equipment malfunctions. During these events the fluid conduit downlines, or hoses connecting the intervention and stimulation vessels working in tandem, will be released and/or severed by active or passive systems e.g., an engineered weak link.

Emergency disconnect for SPWIS involves an active and/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 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. RSWIS, as defined in API 17G4, do 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 utilized 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 over boarded by means of a subsea deployment mechanism. The configuration of the equipment to be installed can vary but typically include 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. RSWIS are 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:

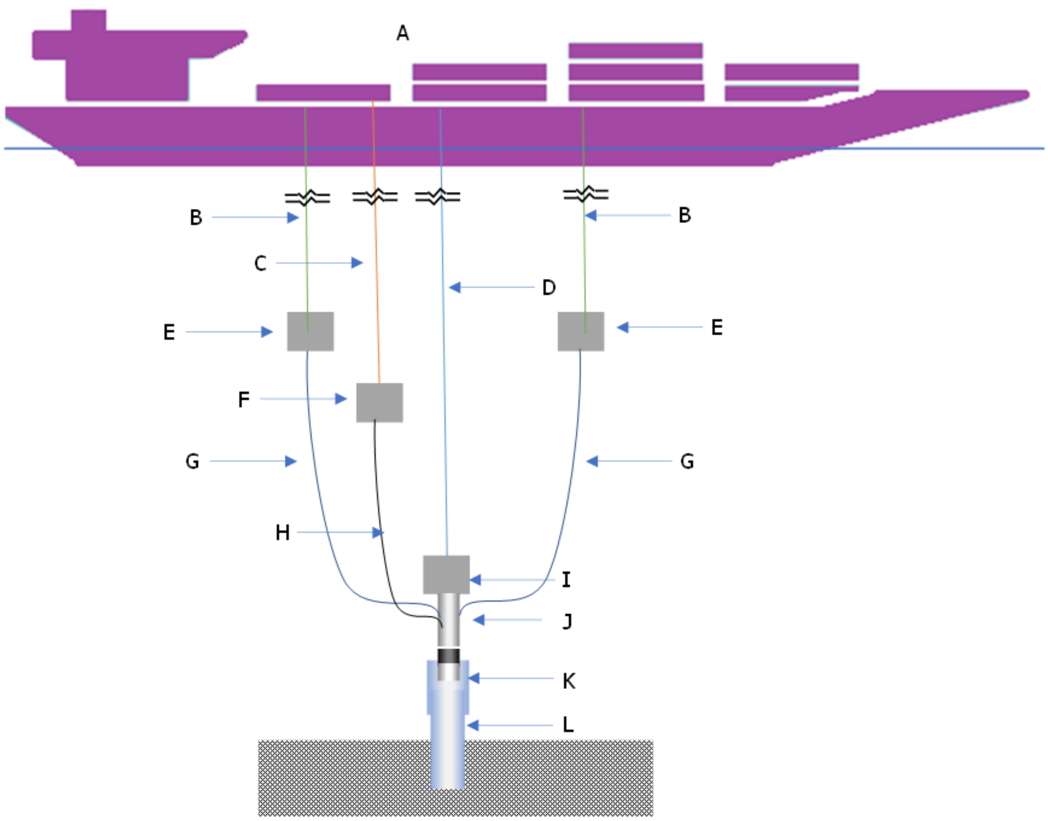
- first hang-off above the water surface
- second hang-off, inclusive of initial deployment through the splash zone;
- several intermediate depths;
- full depth, prior to latch.

It should be acceptable to analyze only the worst-case deployed component (and/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 5-5 for a schematic demonstrating the typical components of the RSWIS.



Key

A	vessel
B	coil tubing
C	umbilical
D	wireline
E	clump weight
F	umbilical termination assembly
G	flexible hose
H	hydraulic flying lead
I	pressure control head
J	well control/intervention package
K	tree/wellhead
L	conductor

Figure 5-5 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 RSWIS are evaluated are:

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

Operations that the RSWIS are 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 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 will be 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), abnormal environmental event or 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
- — disconnect of the wireline / guidelines (if applicable).

The RSWIS WCP, lubricator and PCH will remain subsea to provide the pressure control barrier on the wellbore. In the event of a vessel LOSK event, if the RSWIS is configured with downlines (fluid conduit, control system, etc.) installed to the system, there is potential for the downlines to be snagged on the lubricator as the vessel moves off location if they are not disconnected. In the case the disconnect does not work as intended, the weak point / disconnect sequence should be evaluated to ensure the system is properly configured such that the components fail in the desired sequence and the system maintains functionality.

Nevertheless, similar to OWIRS and TBIRS, it is assumed that the emergency disconnect is completed soon after its initiation and personnel will not have time to prepare for the release. Therefore, the operating parameters for emergency disconnect are modelled with the same values as during connected mode. Operating limits that govern emergency disconnect for RSWIS are vessel offset limit, vessel heave limit and sea state limit.

6 Analysis Basis and Data to Serve as Inputs

6.1 General

This section recommends development of an Analysis Basis for global riser analyses of the subsea well intervention system. This will address the content of a typical design basis and provide guidance on assumptions and parameters that need to be included upfront between different parties. Moreover, it is prudent for all parties, including the end user, to approve content of the Analysis Basis before global riser analysis is initiated.

An Analysis Basis shall be established by either the manufacturer or service provider. Since it should cover all instructions to the analysis engineer, the Analysis Basis typically includes the following content:

— objectives and scope of work;
— data/information to serve as inputs;
— assumptions and premises applicable to the analysis to be performed;
— load cases to be evaluated with corresponding loading classifications;
— design codes to be referenced;
— any other acceptance criteria;
— description of specific analysis methods (e.g., boundary conditions, assumptions), tools, or refinements to be used, if any;
— uncertainties and ranges for sensitivity analysis, if applicable;
— list of typical outputs and their formats from analysis.

Additional information can be found in API RP17G1 section 5.

6.2 Data to Serve as Inputs

6.2.1 General

This subsection provides a listing of data needed to serve as input to the global riser analyses. These are divided into four categories: surface vessel data, metocean data, project-specific data, and subsea well intervention system data. Parties (e.g., system integrator, end user) typically responsible for providing, as well as ensuring accuracy of, the data are assigned. See API 17G Annex F as a list of data that is required for conducting the GRA.

A wide range of data is needed to serve as input to the analyses. When these inputs are provided, the appropriate analysis methods, particulars of the analysis model, and the applicable load cases will be decided.

The end user shall be responsible for providing the following inputs:

— surface vessel data;
— project-specific (or site-specific) data;
— subsea well intervention system data.

The end user should be responsible for ensuring that the required data is obtained from the suppliers of equipment and vessel, although, the suppliers and vessel contractors should be responsible for the accuracy of the data.

The system integrator shall be responsible for providing the subsea well intervention system input data and should also be responsible for the accuracy of the data.

All input data should be included in the Analysis Basis with references to the original source.

6.2.2 Surface Vessel Data

The following types of surface vessel data shall be supplied for input to the global riser analysis typically by the rig/vessel operator:

— General vessel characteristics, dimensions and deck elevations;
— vessel motion characteristics (i.e., response amplitude operators [RAOs] and any associated definitions (e.g., RAO coordinate system, phase lead/lag) for all applicable drafts (e.g., operating, draft);
— vessel drift coefficients (i.e., wave QTFs, current and wind coefficients) and inertia (mass, added mass) characteristics;
— characteristics of the riser tensioning system, including any anti-recoil system, and top-drive (heave) compensation system to be used in supporting the intervention system during various operational stages;
— limits for rig lifting height in derrick during running and landing of riser;
— elevations and minimum openings describing any possible vessel obstructions in the lateral and vertical direction (e.g., at rotary bushing, diverter housing, main deck level, vessel keel, SFT bottoming out at the drill floor);
— minimum allowable clearances between the subsea intervention system and vessel structures;
— For moored vessels (i.e., when mooring lines are installed), mooring analysis including vessel offset envelope for intact mooring system and maximum transient excursion and equilibrium position following loss of constraining force from one mooring line, covering the range of relevant environmental conditions;
— For DP vessels (i.e., when mooring lines are not installed), vessel dynamic positioning analysis based on station-keeping capabilities intact covering the range of relevant environmental conditions.

6.2.2.1 Marine (Drilling) Riser (for TBIRS)

For TBIRS operations, the following types of marine (drilling) riser data shall be supplied for input to the global riser analysis:

— stack-up/configuration of the marine (drilling) riser to be used, as well as its combinations of contents, pressures and applied tensions during connected operations;

— relevant physical properties (e.g., dimensions, mass, buoyancy, materials) for each equipment/ component of the marine (drilling) riser;

— LMRP and BOP arrangements, weight and dimensions, including BOP ram(s) positions;

— for DP vessels, vessel trajectories under various loss of position scenarios (e.g., drive-off, drift-off), covering the range of relevant environmental conditions; This is optional if information needed to calculate the vessel trajectory is provided;

— marine (drilling) riser connectors load capacities, including cyclic load (fatigue).

6.2.3 Project-specific (or Site-specific) Data

The following types of data are typically supplied by the end user.

6.2.3.1 Details of Planned Operations

The following types of details describing planned operations (of the subsea well interventions system) shall be supplied as input to the global riser analysis:

— general design requirements of the subsea well intervention system, if any;
— interface requirements (to the well or surface vessel) for the subsea well intervention system, if any;
— details of any additional subsea equipment (e.g., template, spools/crossovers), including load capacities and fatigue status if this equipment is to be considered as part of acceptance criteria;

— details for drill pipe running string, including material mechanical properties, physical properties (e.g., dimensions, tolerances, corrosion allowance, mass, buoyancy), as well as load capacities and fatigue status;
— details (e.g., temperature, density, level) of all bores/lines contents/fluids and corresponding overpressures (if any) for each operational stage;
— overview of operation procedures for the subsea well intervention system, including a description of the support/tensioning method for each operational stage;
— a listing of elevations (e.g., rotary bushing, in moonpool) at which equipment (e.g., bushings/centralizer, roller, dolly) which be used to laterally brace the subsea intervention system to the surface vessel;
— For TBIRS operations, tubing hanger characteristics, load-capacities, landing limits and overpull necessary for removal, including axial friction, along with tubing weight to be installed/removed;
— automatic shut-down sequences and response times;
— any guidance on dates/timeframes to be considered;
— any target/desired operability limits (e.g., environment return period for an operational stage, total fatigue life).

6.2.3.2 Metocean Data

The following types of metocean data shall be supplied as input to the global riser analysis:

— currents;
— waves or seastates;
— wind;
— tidal variations and/or storm surge.
— seawater temperature profile
— ice effects, if applicable;

This data is typically contained within a metocean data report specific to the site / field being considered.

6.2.3.3 Soil Data

Unless p-y curves are provided discretely, the following soil data shall be supplied for each soil strata as input to the global riser analysis for the calculation/determination of p-y curves:

— type/description (e.g., clay, sand);
— range of applicable depths, expressed as relative to mudline;
— submerged unit weight, if applicable;
— undrained shear strength for undisturbed soil (for clays only);
— 50% strain to failure (for clays only), if available;
— angle of internal friction (for sand only);
— preferred soil modelling method, i.e., API design codes (e.g., API RP 2 GEO, API RP 2A-WSD), proprietary methodologies, or other documented methodologies.

6.2.3.4 Well System Data

The following types of subsea well system data shall be supplied as input to the global riser analysis:
— wellhead stick-up height, i.e., distance from mudline to top of high-pressure housing (HPH)
— wellhead inclination and azimuth, if applicable;
— general arrangement (GA) drawing and/or physical properties for the wellhead system, including the HPH, the low-pressure housing (LPH), locations for HPH weld and LPH weld, etc.;
— load capacity of the wellhead system, if to be considered as part of acceptance criteria;

— material mechanical properties and physical properties for each string (e.g., conductor, surface, intermediate) within the casing system;

— method used to install the conductor casing string, i.e., drilled-and-cemented, jetted in;

— cement levels;

— location of topmost connectors, expressed as relative to mudline, for each casing string;

— load capacity for each casing connector type, if to be considered as part of acceptance criteria.

6.2.4 Subsea Well Intervention System Data

The following types of data are typically supplied by the system integrator.

6.2.4.1 Common data

The following types of data describing the subsea well intervention system to be operated shall be supplied as input to the global riser analysis common to all systems:

— listing of all equipment/components within the system, including its owner of record;
— drawings of the stack-up/configuration for each operational stage, identifying any interfaces or lateral bracing to the surface vessel;
— general arrangement (GA) drawing for each equipment/component;
— material mechanical properties for the C/WO riser and landing string pipe;
— relevant physical properties (e.g., dimensions, tolerances, corrosion allowance, mass, buoyancy) for each equipment/component, including suspension equipment (e.g., elevator, bails, tension ring adapters) and surface equipment (e.g., surface flow tree, coiled tubing lifting frame, etc.);
— capacities for each equipment/component, including load capacities and cyclic load capacities, as well as proper reference to documentation where these have been determined, including possible deratings based on fluids characteristics and temperature;
— bending moment and / or angle at which EDP connector (OWIRS), and / or SSTT latch (TBIRS) releases;
— tension/load capacity of any passive disconnect devices within subsea pumping or riserless intervention systems.

6.2.4.2 Specific to OWIRS

The following types of data specific to OWIRS shall be supplied as input to global riser analysis:

— material mechanical properties for the C/WO riser and landing string pipe;

— bending moment and / or angle at which EDP connector releases;

— guidelines configuration, physical properties (e.g., dimensions, stiffness, mass, buoyancy, load capacity) for GL systems;

— bore arrangement and load sharing for dual-bore, concentric or similar systems;

— available pup joints list and space-out tolerance;

— VIV suppression devices characteristics (e.g., suppression performance, hydrodynamic coefficients) if applicable;

— relevant mechanical properties (e.g., stiffness, rotation limits) for flexjoints, if applicable;

— details of umbilicals (e.g., dimensions, mass, buoyancy) and clamping arrangement, if applicable;

6.2.4.3 Specific to TBIRS

The following types of data specific to TBIRS shall be supplied as input to global riser analysis:

— material mechanical properties for the C/WO riser and landing string pipe;

— bending moment and / or angle at which SSTT latch releases

— details of umbilicals (e.g., dimensions, mass, buoyancy) and clamping arrangement, if applicable;

6.2.4.4 Specific to SPWIS

The following types of data specific to SPWIS shall be supplied as input to global riser analysis:

— tension/load capacity of any passive disconnect devices.

— minimum allowable radius of any downline, as applicable;

6.2.4.5 Specific to RSWIS

The following types of data specific to RSWIS shall be supplied as input to global riser analysis:

— tension/load capacity of any passive disconnect devices.

— deployed tool weight for each stage of the operation, as applicable.

— tension variations caused by subsea coiled tubing injector or equivalent, as applicable.

— physical properties of wire being deployed into the well, if applicable.

— physical properties of coiled tubing being deployed into the well, if applicable.

— true vertical depth of wire or coiled tubing to be deployed into the well, as applicable.

— physical details of all downlines, (eg umbilicals, guidelines) and clamping arrangement, as applicable.

— minimum allowable radius of any downline, as applicable.

7 Load and Load Effects

7.1 General

This section describes the types of loads, and load effects, considered in global riser analysis of subsea well intervention systems. These are categorized into load class definitions, i.e., structural, environmental, and other load effects identified by FMEA/FMECA. Reference “Failure Modes” within Standard 17G., this section expounds on the table.

The load classes and basic load effect types considered in the analysis of subsea well intervention systems are described further in the following sections.

7.2 Typical loads and effects to be considered

7.2.1 General

Listed below are the typical loads and effects that can act on an intervention system and should be considered in any analysis carried out. Section 10 outlines the loads and effects to be accounted for in each operational stage.

7.2.2 Pressure

Pressure loads are due to internal and external pressure distributions along the length of the riser. These pressures can have two contributions – due to hydrostatic head and from overpressure (typically expressed at surface or at wellhead).

External pressure along open-water systems is solely due to hydrostatic pressure from seawater; however, systems inside a marine drilling riser may also experience external overpressure in some situations. Therefore, applied surface pressure may need to be calculated from the absolute internal pressure at the wellhead elevation.

Mean water level shall be used as the reference to determine external seawater pressure along the water column. For operations inside a marine drilling riser, the diverter outlet elevation shall be used to determine the external hydrostatic pressure experienced by the intervention system. The reference elevation for determining the internal hydrostatic pressure (along the intervention system) shall be clearly defined for relevant pressure regimes.

7.2.3 Temperature

Components along the subsea well intervention system can be heated by the internal contents that it contains. This creates a vertical temperature profile along the length of the connected riser, where components near the wellhead experience the highest temperatures**.**

7.2.4 Weight and Buoyancy

The weight of the subsea well intervention system shall account for all equipment/components within the configuration, as well as the density of its internal contents. This should also account for the weight of any coiled tubing string located above the emergency disconnect connector (but not the entire weight supported by tension in the CT injector).

For TBIRS, the apparent weight of the intervention equipment is influenced by the marine riser contents density.

Nominal weights for equipment/components of the subsea well intervention system are commonly used, although it may be appropriate to consider some amount of uncertainty in the system weight in some instances.

7.2.5 Applied Tension

The tension applied to the system can be separated into four separate loads:

- Mean tension

- Tension variations during connected operations
- Uncontrolled over tension applied to the riser
- Uncontrolled loss of tension applied to the riser

These four tension loads are discussed in the flowing sections.

7.2.6 Mean Tension

Tension is applied to OWIRSs using one of the following methods:

— use of the top-drive compensation system only (i.e., “top tension only” method);

— share between the top-drive compensation system and the riser tensioning system (“tension share” method).

Tension share between the top-drive compensation and tensioner systems shall be carefully selected. Considerations for this selection might include capabilities of the vessel’s tensioning/compensation system, response following an emergency disconnect, fatigue damage experienced by upper components, and relevant survival loads.

Tension applied to TBIRS is solely applied by the top-drive compensation system. Moreover, the tension setting applied to the marine drilling riser (by the riser tensioning system) should be established per guidelines in API RP 16Q. Minimum tensions (for the marine riser) should account for stability (per RP 16Q), although higher tensions can help to reduce lower flexjoint angles.

7.2.7 Tension Variations during Connected Operations

Environmental loadings may induce variations in the tension applied by a top-drive compensation system or riser tensioning system to the subsea intervention system during connected operations. Any tension variations are due to stiffness and mechanical inefficiencies of these systems.

Tension variations can refer to changes in the mean tension applied by the top-drive compensation or riser tensioning systems, as well as to dynamic oscillations about (i.e., both above and below) their corresponding mean settings.

7.2.8 Uncontrolled Over Tension Applied to the Riser

The following are examples of events that can lead to uncontrolled tension applied to the connected riser, when experienced in combination with vessel heave motions:

— lock-up of the top-drive compensation system;

— failure/lock-up/stroke-out of the riser tensioning system;

— vertical interference between well intervention system and rig obstructions (i.e., loss of riser stick-up above drill floor);

— downline entanglements during vessel excursions (for RSWIS and subsea pumping intervention system).

These events lead to the loss of heave compensation (in the upward direction, downward direction, or both) that can result in significant changes in applied tension, even for small vessel heave motions.

The immediate consequence is dependent on the water depth and prevailing seastate (and associated vessel heave). For deep water areas with benign wave conditions, the uncontrolled tension may be accommodated by elastic elongation of the riser string, thereby not resulting in overloading of the intervention system or subsea well barriers. However, for shallow water and considerable vessel heave, possible outcomes of an uncontrolled tension include immediate overloading of the riser system or damage to the top-drive compensation system.

7.2.9 Uncontrolled Loss of Tension Applied to the Riser

The following are examples of events that can lead to loss of all (or part) of the tension applied to the connected riser:

— failure of the top-drive compensation system, such as its piston falling to end position;
— failure of a single riser tensioner or a pair of riser tensioners (if plumbed together).

Regardless of whether the vessel is heaving or not, these events may result in global buckling of the riser and, possibly, excessive component utilization before the loss of tension is compensated for by increasing tension in the remaining system(s).

For OWIRS supported using the “tension share” method, it is commonplace to assume these events as separate cases, i.e., no combined failure. The consequence depends on the tension-split between the riser tensioning and top-drive compensation systems. In case of loss of a single riser tensioner, any increased component utilization due to skew (i.e., asymmetric) loading at the tension ring should be determined.

7.2.10 Current

Typically, a current profile is defined by its surface velocity, profile shape (i.e., variation of speed with depth), and percentage of time associated with its occurrence (or duration). All current profile regimes/shapes relevant to the specific site (e.g., wind/seas-driven current, loop/eddy current, bottom current) should be considered for selection.

Current profiles shall be defined for both short-term current events (e.g., corresponding to return periods of 1 or 10 years) and for several reduced conditions having alternate probabilities of exceedance, e.g., 95% (p95), 50% (p50), 5% (p05), and 1% (p01).

A set of current profiles describing long-term conditions and their associated probabilities shall be defined, if VIV fatigue analyses are to be performed.

Current may greatly influence (bias) analysis results, thus appropriate current profiles shall be selected. Higher velocities within the wave zone may increase dynamic response, while higher velocities below the wave zone produce damping and may reduce dynamic response. In other words, no current may produce the largest dynamic responses.

7.2.11 Waves (or Seastate)

Actual ocean waves are known to be irregular in shape, vary in height, length and speed of propagation, and approach a structure from one or more directions simultaneously. These features of a real seastate are often best described using a random wave model. A number of wave spectra have been developed to represent randomness of the sea surface elevation as a sum of components having various frequencies based on a linear random wave model. Although developed for different regions of the world, several of the most commonly used wave spectra include Pierson-Moskowitz (P-M), JONSWAP, Ochi-Hubble, and Torsethaugen. Each of these wave spectra is defined by a unique set of associated parameters. For example, a JONSWAP wave spectrum is defined by a single combination of significant wave height (Hs), spectral peak wave period (Tp), and peakedness factor (gamma).

Typically, a seastate is defined by its wave spectrum and associated parameters, as well as the percentage of time associated with its occurrence (or duration). All waves or seastates relevant to the specific site (e.g., day-to-day, squalls, winter storms, hurricanes) should be considered for selection.

Waves or seastates shall include any relevant wind-driven (also referred to as local seas) and swell contributions, which can be from different directions. In some situations, monohull surface vessel can experience larger motions when the two contributions are not aligned (e.g., wind-driven at head seas and swell-driven at beam seas). If directional information on waves is not available, it is common to use wind direction for wave direction.

Seastates shall be defined for both short-term seastate events (e.g., corresponding to return periods of 1 or 10 years) and for several reduced conditions e.g., alternate probabilities of exceedance, such as 50% (p50), 5% (p05), and 1% (p01) or selected wave heights such as Hs values of 2 m/ 4 m/ 6 m. Metocean data may provide these definitions discretely or provide contour plots of associated parameters (e.g., Hs and Tp for a P-M spectrum) from which they can be selected.

If wave fatigue analyses are to be performed, a set of seastate bins describing long-term conditions, commonly referred to as a wave scatter diagram, and their associated number of occurrences or probabilities shall be defined. Figure 7-1 provides an example of a wave scatter diagram, in which individual seastate bins are defined in terms of Hs range and Tp range (such as for a P-M wave spectrum).

				Zero Crossing Period, Tz (s)														SUM
	Lower			0	1	2	3	4	5	6	7	8	9	10	11	12	13	
		Upper		1	2	3	4	5	6	7	8	9	10	11	12	13	14	
			mid	0.5	1.5	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	
Hs (m)	13	14	13.5											1				1
	12	13	12.5												2			2
	11	12	11.5											1	4			5
	10	11	10.5								2	2	1	16	5			26
	9	10	9.5									4	25	21	1			51
	8	9	8.5								2	26	84	22	4			138
	7	8	7.5								6	162	101	20				289
	6	7	6.5							3	134	471	118	14	2			742
	5	6	5.5						2	68	1024	579	166	14	1			1854
	4	5	4.5						31	1788	2267	845	148	19				5098
	3	4	3.5					9	1232	5839	2227	643	102	25	1			10078
	2	3	2.5				6	1313	9127	6576	1880	490	100	19	2			19513
	1	2	1.5			2	1201	11680	10136	4247	1066	292	85	15	7	1	1	28733
	0	1	0.5			147	4304	6915	2618	971	265	116	60	25	9			15430
Sum				0	0	149	5511	19917	23146	19492	8873	3630	990	212	38	1	1	81960

Figure 7-1—Example Wave Scatter Diagram

7.2.12 Tidal Variations and Storm Surge

Both tidal variations and storm surge influence the elevation of surface intervention equipment relative to the vessel. As such, these shall be accounted for in the system stack-up. More specifically, effects from tide and storm surge shall be accounted for when evaluating stroke capabilities or clearances (or interference/clashing) with possible rig obstructions.

7.2.13 Occurrence of an Unanticipated Environment

Another source of loads experienced by a subsea well intervention system is the occurrence of an unanticipated environment, which can occur for a DP vessel even when station-keeping is functioning properly. Herein, the term "unanticipated environment" refers to one that is more severe than those evaluated as part of the GRA under the Normal or Extreme loading classifications (refer to Section 8.1). The following are examples for how an unanticipated environment may occur during planned operations:

- the most-recent weather forecast underpredicted the severity of the actual environment;
- the actual environment arrived on-location so quickly (e.g., a sudden hurricane) that rig personnel did not have enough time to transition between operational stages, such as from connected operations to storm hang-off;

— rig personnel are unable to transition between operational stages during the actual environment due to its suddenness or (underpredicted) severity;
— metocean data used for the GRA underestimated the severity of an environment for a given return period, possibly since it was not for the specific site/location;
— previously-completed GRA was based on assumed environments, since metocean data was not available at the time.

In combination with associated vessel motions, loads from an unanticipated environment can cause the subsea well intervention system to experience large mean or dynamic loadings, as well as high fatigue damage accumulation rates.

7.2.14 Vessel Offsets and Motion

Vessel offset and motions induced by environment constitute a source of static and dynamic loading on the riser. Vessel response data due to environmental loading that shall be considered and accounted for, when applicable, are the following:

— static offset, i.e., mean offset due to wave, wind, and current loads;
— wave-frequency motions, i.e., first-order wave-induced motions;
— low-frequency motions, i.e., motions due to wind and second-order wave forces;
— maximum transient excursion and equilibrium position for moored vessels following loss of one mooring line;
— vessel trajectories of DP vessels under various loss of position scenarios (e.g., drift-off, drive-off);
— set-down and draft variations due to surface vessel offset.

Operational procedures may permit relocation of the surface vessel to counteract offsets from changes in environmental loads. For a moored vessel, this is done by adjustment of mooring line tension.

A dynamically positioned (DP) vessel can experience a loss of position due to a number of reasons, such as failure of the dynamic positioning system, power failure, or unanticipated environmental occurrence, as well as some combination of these. Several examples of these causes and their failure scenarios are commonly described as the following:

— drift-off, typically caused by a power blackout or severe reduction in thruster power;
— drive-off, typically due to error in the position estimate (i.e., navigation error);
— force-off, typically cause by unanticipated environmental force, i.e., wind gust.

Of these scenarios, the drive-off scenario is potentially the most dangerous, since it might drive the vessel away from the well under maximum power for some period of time.

Vessel trajectories under various loss of position scenarios should be provided as part of the inputs.

The number of potential loss of position scenarios (i.e., combinations of failure scenario and environmental conditions assumed to occur simultaneously) to be considered is extensive. Careful selection is needed to identify combinations of failure scenario (e.g., drift-off, drive-off) and environmental conditions (wind, wave, and current) to be evaluated. As a starting point, it can be helpful to select environmental conditions based on operating limits predicted by initial (or preliminary) global analyses.

When a DP vessel experiences a loss of vessel position event (i.e., drift-off, drive-off, or force-off), rig personnel typically start the EQD once the mean vessel offset/position corresponding to the red watch circle is reached. However, it is possible that the EQD component, such as the EDP connector for an OWIRS, fails to promptly release from the subsea well system at the end of the emergency disconnect sequence (EDS). Failure to release induces loads as the vessel continues to move off-location and can eventually lead to overloading of components within the (still) connected system, including the intervention/workover riser, the wellhead system, or the casing system. GRA should evaluate if these loadings are expected to overload system components located below or above the critical subsea well barriers and if this is acceptable for ensuring well containment.

Careful selection is needed to identify combinations of loss of vessel position events (e.g., drift-off, drive-off) and environmental conditions for which loads from a failure to release should be evaluated.

In case of a moored vessel, the surface vessel will experience an unanticipated loss (or change) of position upon failure of anchor / mooring line(s). Due to the sudden loss of constraining force (and lateral equilibrium), the vessel will move swiftly away from the broken line and eventually become stationary at a new equilibrium position. In this process, the vessel may overshoot with temporary larger transient offsets (i.e., maximum transient excursion) before the new equilibrium is reached. Depending on the environmental conditions, the maximum transient excursion may be reached quicker than the (new) equilibrium position.

A mooring analysis should define the maximum transient excursion and equilibrium position following failure of anchor / mooring line(s). However, mooring analyses typically focus on verifying strength of the mooring spread for drilling operations, which is the vessel's primary business, under strong environments. This means that the environmental conditions evaluated (i.e., wind speeds and seastate) may be more severe than those during completion and workover operations.

For cases where such mooring analysis results are not available, reasonable assumptions should be made based on experience or industry guidelines for station-keeping systems (e.g., API RP 2SK, DNV OS E301).

7.2.15 Vessel Draft, Position, and List / Attitude

The nominal vessel draft (typically either operating draft or survival draft) shall be specified for each operational stage (e.g., connected, storm hang-off).

Mean vessel position may not be directly over the well for all operational stages. For moored rigs, the mean vessel position is dependent on the mooring line tensions. For DP rigs, the mean vessel position is specified by rig personnel based on its station-keeping capabilities.

Even when on-location, the vessel can experience a mean list/attitude (or inclination) from effects other than environment, such as mooring line tensions, thruster forces, or rig crane operations. It is commonly assumed that the nominal vessel list/attitude is trimmed to even keel. However, in situations when vessel list/attitude is deemed critical to riser loads and riser/rig clearances, a limit for the vessel's mean list-attitude shall be defined, thereby allowing the rig crew to adjust for these effects.

7.2.16 Specific to Subsea Pumping Intervention Systems

This section establishes additional loads experienced by the SPWIS caused by an undesirable event, as defined above. SPWIS impose relatively small loads on the subsea tree, tubing head spool and / or wellhead; nevertheless, it is recommended to assess the utilization of these components in the GRA to ensure their integrity is not compromised during any unplanned / abnormal events. In addition to the applicable loads specified in Sections 7.4.1 – 7.4.7, load transfer to sensitive equipment during excessive top tension event should also be assessed.

As described in Section 5.3.5, some SPWIS utilize an engineered weak link designed to limit the load transferred from fluid conduit downlines and hoses to sensitive equipment or infrastructure during excessive top tension events. For systems where weak link parting loads act directly on the x-mass tree and wellhead, the GRA should include an analysis of resulting component utilizations to ensure pressure integrity of the system is not compromised.

Excessive top tension events can result from any number of situations including vessel loss of position, compensation equipment malfunction, or environmental loads acting on the fluid conduit downlines.

For SPWIS that rely on the parting of engineered weak links in order to disconnect in a loss of position event, the worst-case load could be all lines applying load equal to their weak link parting loads.

7.2.17 Specific to Riserless Subsea Intervention Systems

This section establishes additional loads experienced by the RSWIS caused by an undesirable event, as defined above. RSWIS impose relatively small loads on the subsea tree, tubing head spool and / or wellhead; nevertheless, it is recommended to assess the utilization of these components in the GRA to ensure their integrity is not compromised during any unplanned / abnormal events. In addition to the applicable loads specified in section 7.2, vessel LOSK shall be evaluated in the GRA for RSWIS specific operations.

If the RSWIS has the capability for riser re-entry, then the GRA should be performed to include the OWIRS operations.

7.2.17.1 Vessel LOSK

During a vessel LOSK occurrence, leakage and structural bending capacities of the RSWIS can be influenced by:

— Downline entanglement;
— Stroke out during LOSK; and / or
— Riserless coiled tubing in the well during LOSK.

For TBIRS and OWIRS, the downlines and riser will follow the vessel as it moves off station and any loading due to a caught line would be relatively small. However, for the RSWIS, the lubricator / PCH will remain vertical as the vessel drifts off station unless a line snags the equipment or the heave compensation on the coiled tubing / wireline strokes out with the tool engaged downhole. As the vessel offsets, the entangled downlines pull on the RSWIS component(s) and apply increasing bending loads on the subsea equipment.

Some RSWIS actively shear the downlines while others rely on the anchor points failing in order to disconnect in a loss of position event. For wireline systems that rely on the anchor points failing, the worst-case load could be an entangled downline with heave compensation stroked out and all lines applying load equal to their anchor points breaking strength. For wireline systems that actively shear / disconnect the downlines, heave limits to the vessel shall be provided to ensure that the disconnect can happen before the heave compensation system(s) stoke out.

With coiled tubing in the wellbore as the vessel offsets, the tubing exerts a force from within the RSWIS against the PCH, lubricator and / or WCP. It is also prudent to evaluate the effect of heave compensation failure due to compensator lock up with coiled tubing in the wellbore, as with wireline.

The leakage and strength utilizations of each RSWIS element (inclusive of adapters), wellhead, conductor and downline termination release mechanisms shall be established to identify where the first allowable limits will be exceeded.

8 Guidance of Loading Classifications and Load Cases

8.1 General

This section provides guidance in defining the load cases to be evaluated as part of the GRA for each type of subsea well intervention system. Guidance to perform additional sensitivity cases as required is discussed.

8.2 Loading Classifications

8.2.1 General

Global analyses of subsea well intervention systems commonly consider three loading classifications: normal, extreme, and survival. A loading classification must be specified for each operation type (planned or unplanned scenarios) for all operational stages, which may be dependent upon the expected duration.

Structural loads and environmental loads are applicable and shall be evaluated for all loading classifications.

8.2.2 Defining Load Cases

To perform any analysis, it is important to define the load cases in such a way that it captures the unplanned events during the duration of the operation. Generally, well-specific global analyses for a subsea well intervention system consider a single combination of water depth, project-specific (or site-specific) data, intervention system configuration and vessel. A loading classification must be specified for each load case.

A load case is determine based on the combination of the following parameters:

— operational stage;
— operation type (or scenario);
— set of structural loads;
— set of environmental loads;
— set of accidental loads, if applicable;
— set of operating parameters.

8.2.3 Load Cases – Disconnected Riser System (OWIRS and TBIRS)

Operation types when disconnected (non-connected) refer to the scenario where the riser system is suspended from the vessel and is completely disconnected from the subsea system. Examples of disconnected operations include running/retrieval, storm hang-off, vessel transit, emergency disconnect, etc.

In general, load combinations shall be the most onerous (yet realistic based on planned operations or unplanned events) combination of loads that can be expected to occur simultaneously.

Various operating parameters in developing/designing the load cases for the disconnected operational stages include:

— the subsea well control package at bottom of the OWIRS (or bottom assembly for the TBIRS)
— deployment (or hang-off) depth
— vessel heading relative to seas direction
— contents (typically seawater)
— internal pressure (including overpressure during pressure testing)
— vessel draft (accounting for any deballasting from operating draft)
— method of supporting the riser
— presence / absence of surface equipment / tensioning frame.

8.2.4 Load Cases – Connected Riser System (OWIRS and TBIRS)

Operation types when connected refer to various activities performed with the riser system interfacing (Connected) with the subsea system. Examples of connected operations include over-pull test, pressure testing, flowing or shut-in test etc.

Connected operations involve many operating parameters and be considered when selecting combinations (or sets) defining each load case. Various operating parameters in developing/designing the load cases for the connected operational stages include:

- Tension lift frame - the equipment supported within it can vary with the operating mode (e.g., E-line, CT).
- Contents (e.g., gas, oil, seawater, kill fluid)
- Internal pressure (including overpressure during pressure testing)
- Overpull tension – range of tensions (i.e., from minimum to maximum), which can vary with contents.
- Vessel heading(s) - selected for each load case may be influenced by the operation type and corresponding environment (i.e., current and waves, station keeping capabilities);
- Mean vertical distance from surface equipment to the drill floor elevation (i.e., stick-up, space-out or set-down) when the vessel is on-location. The available mean space-out is dependent on the riser system configuration, riser elongation, tidal variations, vessel motion and storm surge.

8.3 Durations and Environmental Conditions

8.3.1 General

Subsea well intervention systems are most commonly operated for limited periods of time during environmental conditions that allow for the performing of planned operations. Environments considered as part of global riser analyses are therefore different from those evaluated for permanently-installed production riser systems. For example, it is usually not relevant to analyze short-term weather events defined for the 100-yr return period, since it is unrealistic that a subsea well intervention system is deployed during these non-favorable conditions.

In general, environmental conditions evaluated as part of global riser analyses for each combination of operational stage and operation type/scenario should reflect the following:

— site-specific metocean data;
— the time of year that the operation will be performed (e.g. specific season);
— the expected duration of operation;
— all relevant types of short-term weather events. Examples include a winter storm (i.e., wind-driven seastate with associated current profile), loop/eddy current (i.e., current profile with associated seastate), swell event (i.e., swell-driven seastate with associated current profile), etc.
— the ability to transition the riser to another operational stage (e.g., storm hang-off) or operation type (e.g., subsea shut-in during connected operations) within the time horizon of reliable weather forecasts.

When in use, the intent is for the subsea well intervention system to spend the majority of its time connected to the well system. For this reason, long-term statistics of environmental conditions should be considered for the connected operational stage due to the longer exposure time.

Generally, the environment return period evaluated for each operational stage (or operation type/scenario) reflects the anticipated environmental conditions (e.g., benign, severe) and its expected duration. Alternatively, recommended limits can be determined by global riser analyses. If weather conditions exceed the determined limits during running/retrieval, landing, or planned disconnect operations, the operations should transition the riser to another operational stage (e.g., emergency disconnect, storm hang-off). Load cases for emergency disconnect should evaluate the highest return period during which the operation may decide to transition from connected operations to storm hang-off by initiating an EDS. For storm hang-off, it is common to evaluate short-term weather events having higher return period than evaluated for other operational stages (e.g., running/retrieval, connected).

Environmental conditions selected for each operational stage (or operation type/scenario) may also be different based on its loading classification (i.e., normal, extreme, or survival). For example, it is not necessary to evaluate accidental loads in combination with environmental loads from short-term weather events having high return period, unless they can be reasonably expected to be correlated and occur together. However, loadings from these short-term weather events may increase the possibility of some accidents/incidents, which may require that coincidence be assumed.

Sections 8.3 to 8.6 list examples of load selection and load cases matrices for each type of intervention system with suggestions of durations and non-exceedance probabilities for weather events to be considered in GRA. Other values may be agreed to between various parties within the Analysis Basis or even determined by specific global analyses results or screening.

8.3.2 Sensitivity Cases to Consider

The analysis data inputs typically include a degree of uncertainty or are incomplete. In addition, assumptions are made for simplification and the modeling techniques rely on engineering judgement. Therefore, it is recommended to consider sensitivity cases for the main purpose of quantifying how these uncertainties and assumptions influence responses and recommended operability limits. Sensitivity cases can also be useful in justifying that assumptions/techniques used within models are conservative or identifying whether refined values/methods are needed to achieve results of sufficient quality.

The type and extent of sensitivity cases performed should reflect the criticality of each type of check/analysis, should focus on important inputs/assumptions, and may be limited to governing load cases. For this reason, sensitivity cases must be selected on a project-specific basis.

In some instances, the intent of global riser analyses is to evaluate operations over a range of water depths (possibly within a given field) or to assist in the selection of a preferred surface vessel. Similarly, the objective might be to develop a set of system joints/components that can be used for multiple sets of project-specific (or site-specific) data. For these situations, it is typically not feasible to select a single set of these conditions (e.g. water depth, site-specific data, and surface vessel) that will yield conservative results for all types of checks/analyses and all operational stages.

Examples of sensitivity cases to consider for each type of subsea intervention systems are given within the corresponding sections (e.g., Section 8.3.2 for OWIRS).

8.4 For OWIRS

8.4.1 Typical load case matrix

Table 8-1 provides a list of loading types (e.g., structural, environmental, and accidental) commonly applicable to global riser analyses for various operational stages of an OWIRS. Combinations of these loading types should be selected carefully and may be unique for different operation types/scenarios during each operations stages.

Similarly, Table 8-2 gives examples of scenarios and parameters that can be used to develop a load case matrix for global riser analyses of an OWIRS. Combinations of loading types, loading classification, environmental conditions, durations and (sets of) operating parameters should be selected carefully, since these may be unique for each operation type.

The load case matrix for global analyses should consider all relevant accidental loads that have been identified for the subsea well intervention system and included in the Analysis Basis.

Table 8-1: Basis for Selection of Representative Loads (OWIRS)

Operational Stage	Typical Structural Loads to Consider	Typical Environmental Loads to Consider	Typical Accidental Loads to Consider
Running/ Retrieval	- internal pressure - external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	Not applicable
Landing	- internal pressure - external pressure - weight and buoyancy - applied mean tension - vessel draft, position, and list/attitude	- current - waves - vessel motions - tension variations	Not applicable
Connected	- internal pressure - external pressure - temperature (if any) - weight and buoyancy - applied mean tension - vessel draft, position, and list/attitude	- current - waves - vessel offset and motions - tidal variations and surge - tension variations	- uncontrolled tension applied to the riser - loss of tension applied to the riser - loss of vessel position - failure to release during loss of vessel position event (for DP rig) - occurrence of unanticipated environment
Planned Disconnect	same as listed for the connected operational stage	same as for the connected operational stage	Not applicable
Emergency Disconnect	same as listed for the connected operational stage	same as for the connected operational stage	Not applicable
Storm Hang-off	- internal pressure - external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	- occurrence of unanticipated environment
Rig Transit with Riser Suspended	- internal pressure - external pressure - weight and buoyancy - vessel draft and list/attitude - transit speed and direction	- current - waves - vessel motions	Not applicable

Table 8-2: Typical Load Case Matrix for Global Riser Analysis (OWIRS)

Operational Stage	Operation Type (or Scenario)	Classification Commonly Assigned	Applicable Sets of the following Operating Parameters should be Evaluated	Weather Event	Duration
Running/ Retrieval	- running/deployment - retrieval/pulling	Normal	- subsea stack at bottom (e.g., EDP+WCP+XT) - type of top support (e.g., by slips/spider) - deployment depth (e.g., first-hang-off) - riser contents of seawater - surface pressure, if any - vessel heading(s)	up to 95% non-exceedance	short-term
	- pressure testing	Extreme		up to 90% non-exceedance (or as determined by GRA)	short-term
Landing	- once final riser joint is run - installing of upper specialty joints - installing of surface flow tree and tension lift frame	Extreme	- subsea stack at bottom (e.g., EDP+WCP+XT) - type of top support (e.g., by travelling block) - riser contents of seawater - surface pressure, if any - target set-down weight - vessel heading(s) - with or without TLF installed - operating mode (e.g., E-line/wireline, CT) - mean space-out of upper riser relative to rig - amount of tension share, if any	up to 90% non-exceedance (or as determined by GRA)	short-term
Connected	- overpull to verify locking	Extreme	- with or without TLF installed - operating mode (e.g., E-line/wireline, CT) - mean space-out of upper riser relative to rig - amount of tension	up to 90% non-exceedance (or as determined by GRA)	short-term
	- pressure testing				
	- flowing	Normal		95% non-exceedance to 1-yr return period	long-term

	- shut-in at surface	Extreme	share, if any - intended overpulls (i.e., ranging from minimum to maximum) - riser contents (e.g., gas, oil, seawater, kill fluid) - surface pressure, if any - vessel heading(s)	1-yr to 5-yr return period	long-term
	- shut-in subsea				
	- flowing(1)	Survival	applicable parameters from the Normal or Extreme classifications (listed above) in conjunction with one or more accidental loads, such as the following examples: - uncontrolled tension applied to the riser - loss of tension applied to the riser - loss of vessel position - failure to release during loss of vessel position event (for DP rig) - occurrence of unanticipated environment	up to 99% non-exceedance, or per unanticipated environment	short-term
	- shut-in at surface(1)				
Planned Disconnect	- intentional unlatching	Normal	same as for the landing operational stage	up to 90% non-exceedance (or as determined by GRA)	short-term
Emergency Disconnect	- EDS	Extreme	same as for the connected operational stage	1-yr to 5-yr return period(2)	short-term(3)
Storm Hang-off	Not applicable	Extreme	- subsea stack at bottom (e.g., EDP only) - type of top support (e.g., by travelling block) - selected hang-off depth - riser contents of seawater - vessel heading(s) - with or without TLF installed	5-yr to 10-yr return period	long-term

			- operating mode (e.g., E-line/wireline, CT), if applicable - mean space-out of upper riser relative to rig, if applicable - amount of tension share, if any		
		Survival	applicable parameters from the Extreme classification (listed above) in conjunction with one or more accidental loads, e.g., from occurrence of an unanticipated environment.	5-yr to 10-yr return period or per unanticipated environment	short-term
Rig Transit with Riser Suspended	Not applicable	Normal	- subsea stack at bottom (e.g., EDP+WCP) - type of top support (e.g., by travelling block) - selected hang-off depth - riser contents of seawater - vessel heading(s)	as determined by GRA	short-term

Notes:

(1) This is shown as an example. Any of the operation types/scenarios (during the connected operational stage) can be assessed under a Survival classification, i.e., with accidental loads applied.

(2) The initial weather event considered for a Emergency Disconnection analysis should match the harshest weather event for a Connected analysis, as the system transitions from one operational stage to the other in response to worsening or an unexpected condition. If this analysis proves to be more restrictive, the Connected case weather event should also be restricted to match the maximum acceptable condition.

(3) Short-term statisticas are usually derived for a specified event duration (i.e. 3 hours). For transient analyses such as Emergency Disconnect, shorter event durations may be considered (i.e. 10 minutes).

8.4.2 Sensitivity Cases to Consider

Examples of sensitivity cases to consider as part of GRA for an OWIRS include the following, which are listed in no particular order:

- mean space-out of the upper riser (relative to the rig floor / rotary), if applicable;
- amount of tension share, if applicable;
- mean list/attitude of the surface vessel;

— alternate lengths of pup joints or specialty joints within the intervention/workover system, assuming that options are available, or the project schedule allows for procurement to be completed;
— stick-up and/or initial inclination of the wellhead system, if applicable;
— soil properties (e.g., lowerbound, best estimate, upperbound), if applicable;
— current, as further discussed in Section 7.2.9;
— period defining a seastate (e.g., Tp for a JONSWAP wave spectrum), as further discussed in Section 10.4.1.1;
— vessel heading for a moored or dynamic positioned vessel, if applicable;

NOTE Suggest working with (vessel) contractor to devise plan for optimal moored heading.

— environment direction with respect to vessel heading, if applicable;
— environment direction with respect to orientation of the TLF/bails;
— assumed hydrodynamic properties (drag, added mass);
— structural assumed damping (in addition to hydrodynamic damping);
— cyclic load capacity (e.g., combinations of S-N curves and SAF values, MN curves) used for the governing components, such as when no input data is available from the OEM;
— pipe (remaining body wall) RBW / corrosion allowance, if applicable.

8.5 For TBIRS

8.5.1 Typical load case matrix

Table 8-3 provides a list of loading types (e.g., structural, environmental, and accidental) commonly applicable to global riser analyses for various operational stages of a TBIRS. Combinations of these loading types should be selected carefully and may be unique for different operation types/scenarios during each operations stages.

Similarly, Table 8-4 gives examples of scenarios and parameters that can be used to develop a load case matrix for global riser analyses of an OWIRS. Combinations of loading types, loading classification, and (sets of) operating parameters should be selected carefully, since these may be unique for each operation type.

The load case matrix for global analyses should consider all relevant accidental loads that have been identified for the subsea well intervention system and included in the Analysis Basis.

Table 8-3 — Basis for Selection of Representative Loads (TBIRS)

Operational Stage	Typical Structural Loads to Consider	Typical Environmental Loads to Consider	Typical Accidental Loads to Consider
Running/ Retrieval	- internal pressure - external pressure - weight and buoyancy - vessel draft, position, and list/attitude	- current - waves - vessel motions - tension variations	Not applicable
Landing Out	- internal pressure - external pressure - weight and buoyancy - mean tension applied to TBIRS - vessel draft, position, and list/attitude	- current - waves - vessel motions - tension variations	Not applicable
Connected	- internal pressure - external pressure - temperature (if any) - weight and buoyancy - mean tension applied to TBIRS - vessel draft, position, and list/attitude	- current - waves - vessel offset and motions - tidal variations and surge - tension variations	- uncontrolled tension applied to riser - loss of tension applied to riser - loss of vessel position - failure to release during loss of vessel position event - occurrence of an unanticipated environment when on-location
Planned Disconnect with LMRP Connected	same as listed for the connected operational stage	same as for the connected operational stage	Not applicable
Emergency Disconnect with LMRP Connected	same as listed for the connected operational stage	same as for the connected operational stage	Not applicable
Storm Hang-off with LMRP Connected	same as listed for the running/retrieval operational stage	same as for the running/retrieval operational stage	- occurrence of unanticipated environment

Table 8-4 — Typical Load Case Matrix for Global Riser Analysis (TBIRS)

<table>
<tr><th>Operational Stage</th><th>Operation Type (or Scenario)</th><th>Classification Commonly Assigned</th><th>Applicable Sets of the following Operating Parameters should be Evaluated</th><th>Weather Event</th><th>Duration</th></tr>
<tr><td rowspan="2">Running/ Retrieval</td><td>- running/deployment
- retrieval/pulling</td><td>Normal</td><td rowspan="2">- bottom assembly (e.g., completion string only, SSTTA)
- type of top support (e.g., by slips/spider)
- deployment depth (e.g., critical intervention riser components spanning the flex joints of marine riser)
- mean tension applied to the marine drilling riser
- riser contents of seawater
- surface pressure, if any
- vessel heading(s)</td><td>up to 95% non-exceedance (or as determined by GRA)</td><td>short-term</td></tr>
<tr><td>- pressure testing</td><td>Extreme</td><td>up to 90% non-exceedance (or as determined by GRA)</td><td>short-term</td></tr>
<tr><td>Landing Out</td><td>- entering the subsea stack
- installing of upper specialty joints
-installing of surface flow tree and TLF
- pressure testing prior to landing out in tubing hanger</td><td>Extreme</td><td>- bottom assembly (e.g., completion string only, SSTTA)
- type of top support (e.g., by slips/spider, drawworks system)
- mean tension applied to the marine drilling riser
- riser contents of seawater
- surface pressure, if any
- target set-down weight
- vessel heading(s)
- with or without TLF installed
- operating mode (e.g., E-line/wireline, CT)
- mean space-out</td><td>Up to 90% non-exceedance (or as determined by GRA)</td><td>short-term</td></tr>
</table>

			of upper riser relative to rig		
Connected	- overpull to verify locking	Extreme	- with or without TLF installed - operating mode (e.g., E-line/wireline, CT) - mean space-out of upper riser relative to rig - mean tension applied to the marine drilling riser - intended overpulls (i.e., ranging from minimum to maximum) - riser contents (e.g., gas, oil, seawater, kill fluid) - surface pressure, if any - vessel heading(s)	Up to 90% non-exceedance (or as determined by GRA)	short-term
	- pressure testing				
	- flowing	Normal		95% non-exceedance to 1-yr return period	long-term
	- shut-in at surface	Extreme		1-yr to 5-yr return period	long-term
	- shut-in subsea				
	- well kill (bull head)			95% non-exceedance to 1-yr return period	long-term
	- injection (for CT mode only)			95% non-exceedance to 1-yr return period	long-term
	- overpull to release stuck tubing			up to 95% non-exceedance (or as determined by GRA)	short-term
	- flowing[(1)]	Survival	applicable parameters from the Normal or Extreme classifications (listed above) in conjunction with one or more accidental loads, such as the following examples: - uncontrolled tension applied to the riser - loss of tension applied to the riser - loss of vessel	up to 99% non-exceedance, or per unanticipated environment	short-term
	- shut-in at surface[(1)]				

			position - failure to release during loss of vessel position event (for DP rig) - occurrence of unanticipated environment		
Planned Disconnect with LMRP Connected	- intentional unlatching	Normal	same as for the landing out operational stage	up to 90% non-exceedance (or as determined by GRA)	short-term
Emergency Disconnect with LMRP Connected	- EDS	Extreme	same as for the connected operational stage	1-yr to 5-yr return period$^{(2)}$	short-term$^{(3)}$
Storm Hang-off with LMRP Connected	Not applicable	Extreme	- bottom assembly (e.g., completion string only, SSTTA) - type of top support (e.g., by slips/spider, drawworks system) - mean tension applied to the marine drilling riser - riser contents of seawater - surface pressure, if any - vessel heading(s) - with or without TLF installed - operating mode (e.g., E-line/wireline, CT), if applicable - mean space-out of upper riser relative to rig, if applicable	5-yr to 10-yr return period	long-term
		Survival	applicable parameters from the Extreme classification (listed above) in conjunction with one or more accidental loads, e.g., from occurrence of an unanticipated environment.	5-yr to 10-yr return period or per unanticipated environment	short-term

Notes:

(1) This is shown as an example. Any of the operation types/scenarios (during the connected operational stage) can be assessed under a Survival classification, i.e., with accidental loads applied.

(2) The initial weather event considered for a Emergency Disconnection analysis should match the harshest weather event for a Connected analysis, as the system transitions from one operational stage to the other in response to worsening or an unexpected condition. If this analysis proves to be more restrictive, the Connected case weather event should also be restricted to match the maximum acceptable condition.

(3) Short-term statisticas are usually derived for a specified event duration (i.e. 3 hours). For transient analyses such as Emergency Disconnect, shorter event durations may be considered (i.e. 10 minutes).

8.5.2 Sensitivity Cases to Consider

Examples of sensitivity cases to consider as part of GRA for a TBIRS include the following, which are listed in no particular order:

— mean space-out of the upper riser (relative to the vessel), if applicable;
— mean tension applied to the marine drilling riser;
— mean list/attitude of the surface vessel;
— alternate lengths of pup joints or specialty joints within the intervention/workover system, assuming that options are available or the project schedule allows for procurement to be completed;
— stick-up and/or initial inclination of the wellhead system, if applicable;
— soil properties (e.g., lowerbound, best estimate, upperbound), if applicable;
— current, as further discussed in Section 7.2.9;
— period defining a seastate (e.g., Tp for a JONSWAP wave spectrum), as further discussed in Section 10.4.1.1;
— vessel heading for a moored or dynamically positioned vessel, if applicable;
— environment direction with respect to vessel heading; if applicable
— environment direction with respect to orientation of the TLF/bails;
— additional overpull required to release stuck tubing due to friction;
— coverage and efficiency of any VIV suppression device used along the marine drilling riser, if applicable;
— assumed hydrodynamic properties (drag, added mass);
— assumed damping (in addition to hydrodynamic damping);
— cyclic load capacity (e.g., combinations of S-N curves and SAF values, MN curves) used for the governing components, such as when no input data is available from the OEM;
— pipe (remaining body wall) RBW / corrosion allowance, if applicable.

8.6 For Subsea Pumping Systems

8.6.1 Typical load case matrix

Table 8-5 below, provides the loading types common to SPWIS global riser analyses for different operational scenarios.

Table 8-6 provides an example of a SPWIS GRA load matrix for different operational scenarios. Combination of loading types, loading classifications and operating parameters should be identified on a case-by-case basis and documented in the Analysis Basis.

Table 8-5 – Basis for Selection of Representative Loads (SPWIS)

Operational Scenario	Typical Structural Loads to Consider	Typical Environmental Loads to Consider	Typical Accidental Loads to Consider
Running / Retrieval	- external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	Not applicable
Connected	- internal pressure - external pressure - temperature (if any) - weight and buoyancy - vessel draft, position, and list/attitude	- current - waves - vessel offsets and motions - tidal variations and surge	Not applicable
Planned Disconnect	- external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	Not applicable
Emergency Disconnect	same as listed for the connected operational stage	same as listed for the connected operational stage	- loss of vessel position - failure to release during loss of vessel position event - abnormal environmental event when on location - downline entanglement - loss of heave compensation

Table 8-6 – Typical Load Case Matrix for Global Riser Analysis (SPWIS)

<table>
<tr><th>Operational Scenario</th><th>Load Condition</th><th>Classification Commonly Assigned</th><th>Applicable Sets of the Following Operating Parameters should be Evaluated</th></tr>
<tr><td rowspan="2">Running / Retrieval</td><td>- running/deployment
- retrieval/pulling</td><td>Normal</td><td rowspan="2">- SPWIS at bottom [(1)]
- deployment depth
- vessel heading(s)
- vessel offset at surface
- Environmental loading</td></tr>
<tr><td>- control and umbilical line deployment</td><td>Normal</td></tr>
<tr><td rowspan="3">Connected</td><td>- pressure testing</td><td>Extreme</td><td rowspan="3">- intended overpulls (e.g., ranging from minimum to maximum)
- contents (e.g., gas, oil, seawater, kill fluid)
- vessel heading(s)
- applied pressure in the downlines (e.g., hydraulic stimulation)</td></tr>
<tr><td>- flowing</td><td>Normal</td></tr>
<tr><td>- shut-in subsea</td><td>Extreme</td></tr>
<tr><td>Planned Disconnect</td><td>- intentional unlatch</td><td>Extreme</td><td>same as listed for the landing operational stage</td></tr>
<tr><td>Emergency Disconnect</td><td>- Excessive top tension</td><td>Survival</td><td>same as listed for the connected operational stage</td></tr>
<tr><td colspan="4">Notes:
[(1)] Individual running / retrieval of each component or worst-case deployed component in cases where familiarity and experience have been gains with the SPWIS are acceptable.</td></tr>
</table>

8.6.2 Typical sensitivity cases

Examples of sensitivity cases to analyze for SPWIS include, but are not limited to:

— mean vessel position/offset (i.e., from wellhead at surface), if any;
— stick-up or initial inclination of the wellhead system, if applicable;
— soil properties (e.g., lower bound, upper bound), if applicable;
— current;
— period defining a seastate (e.g., Tp for a JONSWAP wave spectrum);
— vessel heading for a moored vessel;
— environment direction with respect to vessel heading;
— assumed hydrodynamic properties (drag, added mass, drag diameter).

8.7 For Riserless Systems

8.7.1 Typical load case matrix

Table 8-7, below, provides the loading types common to RSWIS global riser analyses for different operational scenarios. Table 8-8 provides an example of a RSWIS GRA load matrix for different operational scenarios. Combination of loading types, loading classifications and operating parameters should be identified on a case-by-case basis and documented in the Analysis Basis.

Operational Scenario	Typical Structural Loads to Consider	Typical Environmental Loads to Consider	Typical Accidental Loads to Consider
Running / Retrieval	- external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	Not applicable
Landing	- external pressure - weight and buoyancy - vessel draft and list/attitude	- current - waves - vessel motions	Not applicable
Connected	- internal pressure - external pressure - temperature (if any) - weight and buoyancy - vessel draft, position, and list/attitude	- current - waves - vessel offsets and motions - tidal variations and surge	- loss of vessel position - failure to release during loss of vessel position event - abnormal environmental event when on location - downline entanglement - compensator stroke-out
Planned Disconnect	same as listed for the landing operational stage	same as listed for the landing operational stage	Not applicable
Emergency Disconnect	same as listed for the connected operational stage	same as listed for the connected operational stage	Not applicable

Table 8-7 – Basis for Selection of Representative Loads (RSWIS)

Table 8-8 – Typical Load Case Matrix for Global Riser Analysis (RSWIS)

<table>
<tr><th>Operational Scenario</th><th>Load Condition</th><th>Classification Commonly Assigned</th><th>Applicable Sets of the Following Operating Parameters should be Evaluated</th></tr>
<tr><td rowspan="2">Running / Retrieval</td><td>- running/deployment
- retrieval/pulling</td><td>Normal</td><td rowspan="2">- RSWIS at bottom [1]
- type of top support
- deployment depth
- vessel heading(s)
- Any installed downlines</td></tr>
<tr><td>- ROV controlled impact while grabbing PCH prior to unlatch</td><td>Normal</td></tr>
<tr><td rowspan="2">Landing</td><td>- hang-off at surface on compensation system while moving to well center</td><td>Extreme</td><td rowspan="2">- RSWIS at bottom
- type of top support
- deployment depth
- vessel heading(s)
- target set-down weight
- operating mode (e.g., WL, CT)</td></tr>
<tr><td>- ROV controlled impact while stabbing BHA into lubricator</td><td>Normal</td></tr>
<tr><td rowspan="5">Connected</td><td>- overpull to verify locking</td><td rowspan="2">Extreme</td><td rowspan="5">- operating mode (e.g., WL, CT)
- intended overpulls (e.g., ranging from minimum to maximum)
- contents (e.g., gas, oil, seawater, kill fluid)
- vessel heading(s)
- applied pressure in the downlines (e.g., hydraulic stimulation)
- stroke-out limit of tool strings</td></tr>
<tr><td>- pressure testing</td></tr>
<tr><td>- flowing</td><td>Normal</td></tr>
<tr><td>- shut-in subsea</td><td rowspan="2">Extreme</td></tr>
<tr><td>- overpull to release stuck tubing</td></tr>
<tr><td>Planned Disconnect</td><td>- intentional unlatching</td><td>Extreme</td><td>same as listed for the landing operational stage</td></tr>
<tr><td>Emergency Disconnect</td><td>- EDS (EQD)</td><td>Survival</td><td>same as listed for the connected operational stage</td></tr>
<tr><td colspan="4">Notes:
[1] Individual running / retrieval of each component or worst-case deployed component in cases where familiarity and experience have been gains with the RSWIS are acceptable.</td></tr>
</table>

8.7.2 Typical sensitivity cases

Examples of sensitivity cases to analyze for RSWIS include, but are not limited to:

— stick-up or initial inclination of the wellhead system, if applicable;
— soil properties (e.g., lower bound, upper bound), if applicable;
— current;
— period defining a seastate (e.g., Tp for a JONSWAP wave spectrum);
— vessel heading for a moored vessel;
— environment direction with respect to vessel heading;
— mean list/attitude of the surface vessel (if applicable);
— assumed hydrodynamic properties (drag, added mass, drag diameter).

9 Modeling Considerations Unique to Intervention Systems

9.1 General

This section discusses some of the key modeling considerations and/or assumptions used as part of global riser analysis, focusing on those that are unique to subsea well intervention systems, that may not be covered in existing academic or industry literature. The modeling considerations/techniques discussed herein are not intended to be prescriptive but instead merely serve as guidance. It is recommended that the user refer to other industry documents or existing published/academic literature regarding analysis methods and other considerations/techniques that are generally applicable to GRA of all riser (e.g., marine/drilling, production) or subsea well systems.

9.2 Subsea Stack

The term “subsea stack” is meant to refer to large equipment that is located between the subsea well and the external main pipe/string of the connected system. For OWIRS, this is typically the WCP and EDP, while for TBIRS, this typically refers to the BOP Stack (i.e., LMRP and BOP) of the marine drilling riser. In addition, both systems may include a subsea tree as part of the subsea stack.

Subsea stack components typically have prismatic shapes due to presence of handling frames, ROV panels, etc. Such frames/panels may or may not be load-bearing, depending on their design. Moreover, load-bearing sections housed inside these frames can have circular (e.g., flanges) or square cross-sections (e.g., valves).

In GRA models, the subsea stack is commonly represented as pipe elements based on the component dimensions (length, width, height), mass, and submerged weight. Each pipe element is defined by its structural outer diameter (OD), structural inner diameter (ID), effective weight, and hydrodynamic properties. Structural dimensions characterize the component’s axial and bending stiffness values, while hydrodynamic properties characterize the drag and inertial loadings that it will experience.

Similarly, for SRWIS and SPWIS, these may or may not be referred to as a Stack, but will need to be modeled accordingly.

Care should be taken in selecting properties of (circular) pipe elements used to represent subsea stack components within GRA models. The ID is approximately the same as the external main pipe/string (i.e., OWIRS or marine drilling riser). The axial/bending stiffness of subsea stack component is often several orders of magnitude greater than the nominal riser pipe, which can be reflected in the selected OD or stiffness values. Moreover, it may be appropriate to model varying stiffness values to represent different cross-sections or in regions where high curvatures are expected.

NOTE When possible, consult with manufacture to understand component load path to determine stiffness and pressure areas.

Guidance on assumed hydrodynamic properties for subsea stack components can be found in DNVGL-RP-E104 and other industry documents.

9.3 Interaction of Conductor casing and Soils

The conductor casing (outer most casing) is typically modeled to where bending loads have been reduced to negligible levels and constrained in all translational degrees of freedom (DOF) at its bottom.

Soil properties influence both static and dynamic responses of the riser and wellhead/casing systems and should be appropriately modeled to characterize global riser response. In GRA models, the most common approach to represent the soil-structure interaction is using discrete springs with a non-linear profile applied at various depths along the conductor casing, although other approaches may also be used. Calculations should reflect the installation method for the conductor casing. Where applicable, other effects such as dynamic stiffness and damping characteristics (due to any hysteretic effects) may also be considered.

Use of P-Y curves is the most common method of representing lateral resistance to conductor movement provided by the soil. Similarly, T-Z curves may be used to represent resistance in the vertical direction. Modelling of these P-Y (and/or T-Z) curves for characterizing the soil response can be done in accordance with methods outlined in API documents (e.g., API RP 2 GEO, API RP 2A-WSD), proprietary methodologies, or other documented methodologies. Other modeling considerations, include soils type (clay, sand), installation method (jetted vs drilled & grouted), and loading regime (large displacement/low frequency for ultimate strength including operability, or low displacement/high frequency for fatigue).

Soil is known to exhibit complex behavior, and soil data is quite uncertain in nature. Therefore, it is recommended that GRA evaluate sensitivities to soil properties (e.g., lower bound, “best estimate”, and upper bound), depending on the type of check/assessment performed. For example, Upper bound soil properties increase loads experienced by the subsea stack and wellhead system, while lower bound soil properties can increase responses of the casing system below mud line.

9.4 External Lines

Subsea well intervention systems may include several additional lines that run external to the main pipe/string along its length. These can be made of metal (i.e., hard pipe) or flexible materials. An OWIRS typically include an annulus line and a controls umbilical, while TBIRS may include a controls umbilical. External lines of a marine drilling riser, which TBIRS are deployed through, include several auxiliary/peripheral lines (e.g., choke, kill, mud boost, hydraulic lines) and typically extend from the telescopic joint to the subsea stack. SPWIS and RSWIS can also include one or more external lines.

For intervention/workover risers other than TBIRS, it is important to also understand how these external lines are attached to the main pipe/string. The most common method is either straps or clamps. It may also be necessary to use sets of multiple clamps, meaning a separate one for each external line. The attachment mechanism influences the radial offset/distance of the external line, as well as how its weight (including its contents) is supported by the intervention/workover riser.

In GRA models, the multi-tube arrangement along the intervention/workover riser are typically modeled as one equivalent (or composite) section. More specifically, properties (e.g., mass, stiffness) of all external lines are combined with the main pipe/string to create a single equivalent element. This method is intended to avoid unnecessary complexity in the GRA model and does not reduce the accuracy of its results for most applications.

Care should be taken when selecting properties of these “equivalent” elements within the GRA model. More specifically, the presence of any external lines (and their contents and attachment mechanisms) can influence the following characteristics of the multi-tube arrangement:

— mass – also accounting for the contents of and attachment mechanisms for the external line;

- weight and buoyancy – also accounting for the contents of and attachment mechanisms for the external line;
- axial stiffness – commonly assumed that flexible external lines make no additional contribution;
- bending stiffness – commonly assumed that flexible external lines make no additional contribution;
- assumed drag diameter – commonly calculated based on the maximum projected area for cross-section of the multi-tube arrangement, accounting for any gaps between external lines and the main pipe/string;
- assumed inertial diameter – commonly calculated using the sum of areas based on outer diameters of the main pipe/string and each external line. The assumed inertial diameter is commonly smaller than the assumed drag diameter.

Be aware that GRA software may use the defined “diameter(s)” for several purposes, e.g., internal fluid volume, buoyancy, stiffness, contact, hydrodynamic loads (i.e., both drag and added mass). In these situations, other software inputs must be used to achieve intended properties for the equivalent elements.

9.5 Concentrically-assembled Components

At points along their length, subsea well intervention systems may have multiple load-bearing cross-sections that are concentric to each other. These are typically located in regions where the riser system is exposed to large bending moments, such as where spanning the drill floor (possible contact with rotary bushings, sub structure). Two examples of concentrically-assembled components are the following:

- Cased wear joint of an OWIRS – a large metal cross-section (commonly referred to as a wear casing or wear sleeve) is concentrically-assembled with the main pipe/string of the riser;
- RSM of a TBIRS – a large cross-section made of metal or polymer is concentrically-assembled with the main pipe/string of the riser.

An accurate representation of concentrically-assembled components is essential to achieve realistic results for each load-bearing section. In GRA models, these components are represented either as a single equivalent (or composite) element or as separate beam elements, depending on the amount of interaction between the multiple sections. Use of equivalent elements is most appropriate when all cross-sections are expected to experience the same tensile elongation and curvature, and selection of equivalent axial/bending stiffness values must account for material properties of the individual sections.

Other modeling techniques can also be used. For example, modeling each load-bearing section as separate beam elements is recommended when they are expected to experience different elongations or curvatures along their length. In this method, constraints are applied to the separate beam elements for representing any interactions between the various cross-sections. This method allows each load-bearing section to experience unique motions/responses and associated loadings.

9.6 Internal lines

9.6.1 General

Subsea well intervention systems may include scenarios where a riser/string is run inside of another one, which is commonly referred to as “pipe-within (or in)-pipe” arrangement. The following examples of internal lines are discussed further in the following sections:

- TBIRS deployed inside a marine drilling riser;
- wireline or coiled tubing run inside the intervention/workover riser.

The friction force between the two strings is negligible in most applications, and they can be supported by different mechanisms. For these reasons, internal strings do not significantly influence axial stiffness.

In GRA models, internal lines along subsea well intervention system can be represented as separate beam elements (i.e., pipe-in-pipe method) or as one equivalent (or composite) section. Selection of the modeling method should be based on whether internal lines are expected to have an important influence on system responses.

When the pipe-in-pipe method is selected, properties of beam elements representing the internal line and its contents should provide realistic mass, weight/buoyancy, pressure/temperature, stiffness, and hydrodynamic effects. Moreover, expected contact/interaction between an internal line and the outer riser/string must be reflected, accounting for the initial mean positions of both. The most common contact formulation used for pipe-in-pipe modeling is linear or non-linear springs that are engaged after a specified gap is closed.

NOTE When springs are used for contact formulations, significant numerical noise may occur in dynamic analyses depending on the modeled spring stiffness and the modeled bending stiffness of the beam element that interact. Simulations using the time-domain solution type commonly slow down, and predicted response signals may be cluttered. This numerical noise might be reduced by introducing damping in the contact definition. However, it is not recommended to reduce the contact noise by introducing additional damping to other portions of the GRA model (e.g., global structural damping), since doing so may unintentionally affect overall system responses to yield non-conservative results. For these reasons, careful review and quality control of time series produced for system responses is recommended before performing post-processing to calculate their statistics values.

The method of modeling equivalent one equivalent (or composite) section reduces the complexity in the GRA model and is acceptable for some applications, such as when only the mass, weight/buoyancy, or tension effects of the internal line is of interest. Properties (e.g., mass, stiffness) of an internal line are combined with the outer pipe/string to create a single equivalent element, and interaction between the two sections is not explicitly modeled. Similar to as discussed for external lines (Section 9.4), care should be taken when selecting properties of these "equivalent" elements within the GRA model.

9.6.2 TBIRS Inside a Marine Drilling Riser

A TBIRS is deployed inside a marine drilling riser, which provides it with protection from environmental loading and lateral support. In essence, this type of intervention/workover riser (i.e., its bottom assembly, landing string, upper components, controls umbilical) is an "internal line" to the outer riser. As illustrated in Figure 9-1, the TBIRS may not be centered (within the outer riser) due to the presence of clamps between the main pipe/string and the controls umbilical, if present.

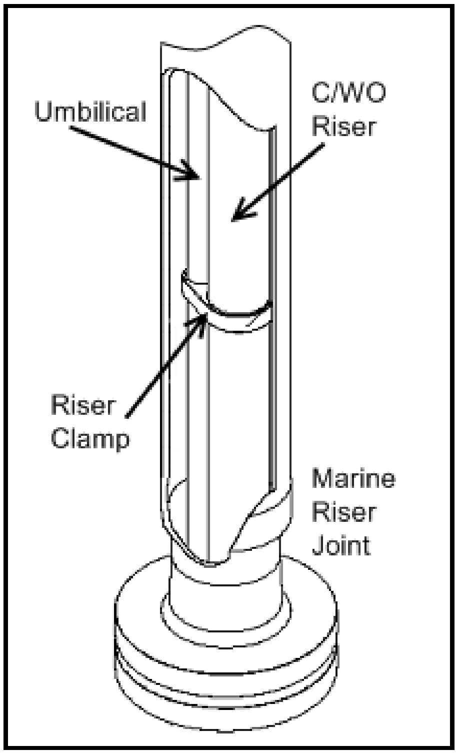


Figure 9-1 TBIRS (with Umbilical) Deployed through a Marine Riser

A TBIRS is sometimes laterally braced at discrete locations along its length by installed centralizers. Similarly, the radial gap/clearance to the outer riser is also reduced by clamps/couplings and other appurtenances along the landing string, as well as by other TBIRS components having large diameters.

As mentioned in Section 5.2, TBIRS components located across/near flexjoints of the marine drilling riser commonly experience high bending moments, even when flexjoint angles/rotations are relatively small. Therefore, in these regions, it is important that GRA models capture the interaction between the TBIRS (i.e., inner line) and the outer riser in a realistic manner. This should also reflect any clamps/couplings and other appurtenances along the TBIRS, as these may significantly increase bending moments experienced by the intervention/workover riser. Any eccentricity between the internal line and the outer riser, as illustrated in Figure 9-1 should be accounted for, e.g., by modeling it explicitly or by selecting the worst-case gap between the two sections.

The pipe-in-pipe method is commonly used to represent the TBIRS inside a marine drilling riser for some GRA models. For this method, beam elements representing the internal line should be selected appropriately, as well as having appropriate boundary conditions (e.g., applied mean tension, contact/interaction with the outer riser). Models having pipe-in-pipe elements (with associated contact formulation) may be used to perform a full dynamic analysis, although the deformed shape and contact conditions should be checked carefully to ensure that results are realistic.

Alternatively, GRA can be performed via a process having multiple steps that involves the following separate models:

— non-linear quasi-static analysis using a model with pipe-in-pipe elements, and
— dynamic analysis using a model with “equivalent” elements.

Determining loadings or fatigue damage experienced by the TBIRS involves applying results from one model/analysis as direct inputs (e.g., displacements/deflections) or response limits (e.g., flexjoint angles) for the other. When the “equivalent” elements method is used, it recommended that selected properties account the mass and bending stiffness of both TBIRS components and the outer riser, especially at elevations near the LFJ and UFJ of the marine drilling risers.

9.6.3 Wireline or Coiled Tubing Inside the Intervention/Workover Riser

Wireline (WL) or coiled tubing (CT) may be deployed inside several types of subsea well intervention systems, including OWIRS, TBIRS, and riserless systems. For WL and CT with negligible bending stiffness, the pipe-in-pipe method is normally not selected for GRA models, since it is too onerous and will increase the computational effort. Instead, it is deemed sufficient to include the mass and weight/buoyancy of WL or CT when selecting properties of the “equivalent” elements. Once the GRA is performed, post-processing can be used to subtract tensions experienced by the internal lines (WL or CT) when determining loads/stresses experienced by the outer riser/string.

9.7 Top Support/Arrangement for OWIRS and TBIRS

9.7.1 General

In most applications, the upper end of both OWIRS and TBIRS is attached to additional specialized equipment that is commonly supported within a tension lift frame (TLF). Since it is located above the drill floor elevation, the TLF must be suspended from the top-drive compensation system aboard the MODU/vessel. Figure 9-2 shows examples of equipment configurations for E-line/Wireline and CT modes inside a tension lift frame. There are other arrangements when the surface flowhead of the intervention/workover riser attaches directly to the top-drive compensation system via bails, meaning there is no TLF installed nor any specialized E-line/wireline/CT equipment.

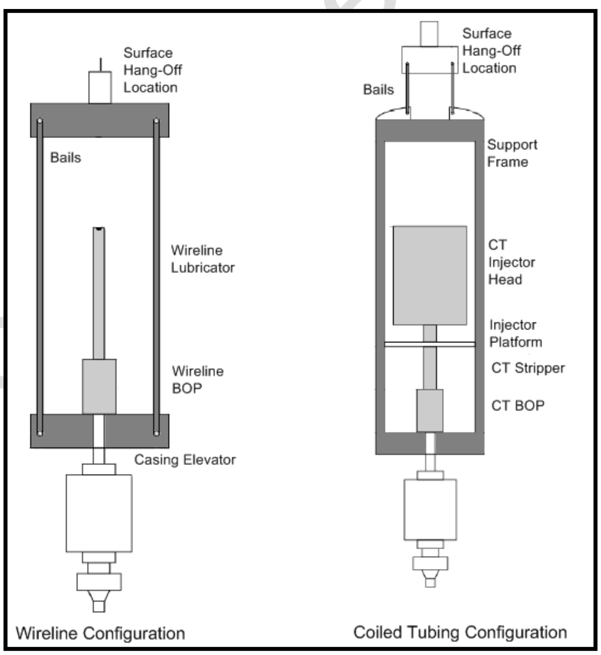


Figure 9-2 —Stack-up/Configuration of Specialized Equipment for Eline/Wireline and CT Modes

Moreover, both OWIRS and TBIRS are supported during connected operations by one or more systems that provide heave compensation. The following are several examples of tensioning arrangements for them:

— OWIRS using “top tension only” method – The entire system (e.g., riser, TLF, etc.) is supported by the top-drive compensation system.

— OWIRS using “tension share” method – The top-drive compensation system supports the TLF (with equipment inside it) and riser components located above the drill floor, while the riser tensioning system supports the remaining riser and its contents.
— Entire TBIRS and TLF (with equipment inside it) is supported by the top-drive compensation system. The riser tensioning system is used to support the marine drilling riser and its contents.

In all arrangements, it is important that GRA models correctly reflect the load path through the TLF. More specifically, specialized equipment within the TLF does not experience tension provided by the top-drive compensation system (i.e., they are not in its direct load path).

It is important that GRA models of subsea well intervention systems accurately represent these components (i.e., TLF and equipment inside it) and their connectivity to each other and the rig. In most cases, this equipment is very heavy and provides negligible damping; consequently, its presence can have a significant influence on dynamic loading experienced by the riser’s upper components.

9.7.2 Top-drive Compensation System

The MODU’s top-drive compensation system is used to provide tension to the TLF and other equipment during connected operations, as well as to provide heave compensation to the intervention/workover riser. The two most common types are a crown-mounted compensator (CMC), which is a passive pneumatic/hydraulic system, and an active heave drawworks (AHD), which is an active electric system. These systems typically have 25 ft of stroke, but not all usable.

Both types of top-drive compensation systems are designed to provided “near constant” tension. This is critical for their primary purpose of accurately maintaining the intended weight-on-bit during drilling operations. Therefore, in GRA models of intervention/workover risers, it is initially commonly assumed that these systems provide constant tension, further analysis may be conducted with more detailed compensation modelling for specific systems. Tension variations within these compensation systems can be described as having a static and dynamic component based on the amount of stroke change (static) and the speed of this change (dynamic). The impact of CT or WL on the system is discussed in section 9.6.3.

9.7.3 Tension Lift Frame (TLF) and Bails

When installed, the top of the tension lift frame (TLF) is suspended from the travelling block by a set of conventional bails, i.e., the upper bails. The bottom of the TLF typically attaches just above the surface flowhead (of OWIRS or TBIRS) via another set of bails, i.e., the lower bails. The TLF and bails may have a hinged connection in a single direction or in all degrees of freedom. In some instances, the TLF may be laterally restrained to guiderails within the MODU’s derrick structure at a discrete elevation.

It is important to represent the TLF and bails accurately in GRA models of subsea well intervention systems, since it can have significant influence on dynamic responses and fatigue accumulation along the upper riser. The TLF’s mass is not evenly distributed along its length, nor its radii of gyration the same in all directions. For this reason, the model must correctly represent the orientation of the TLF with respect to the MODU/vessel. The TLF typically is assumed to be rigid, meaning its axial and bending stiffness values are high compared to riser components. Special care should be taken to ensure the TLF and bails are modeled with the correct boundary conditions/restraints, either translational or rotational, for each degree of freedom.

In some situations (i.e., data is unavailable), the worst-case environment direction with respect to orientation of the TLF/bails may be used to determine loads experienced by upper components of the intervention/workover riser, especially those located near or above the drill floor elevation. A certain environment direction can produce more onerous loads because of asymmetric boundary conditions.

9.7.4 Specialized Equipment within the TLF

As shown by Figure 9-2, the stack-up/configuration of specialized equipment needed is typically different for various completion and intervention modes, i.e., E-line/wireline and CT. Examples for this type of equipment include (but are not limited to) the following: adapter spool, BOP, stripper, injector head/frame, lubricator, gooseneck, etc. This equipment is located within the TLF (and bails) but is rigidly connected to the top of the riser (e.g., surface flowhead) for pressure-controlling purposes. It may be possible to apply tension through this equipment using a winch at the top of the TLF. Moreover, the equipment could rest on a platform, thereby laterally bracing it within the TLF at a discrete elevation.

It is important to include the specialized equipment in GRA models of subsea well intervention systems, since its presence can potentially impose high loading to the upper riser components. This is commonly done using beam elements with properties based on structural dimensions and mass/weight of each equipment within the stack-up. Any tension through or restraint to surface equipment should also be accounted for. The impact of CT or WL on the system is discussed in section 9.6.3

9.7.5 Riser Tensioning System, if used

The riser tensioning system aboard the MODU/vessel is sometimes used to provide tension and heave compensation to a subsea well intervention system, e.g., OWIRS in a tension share arrangement. As further discussed in API RP 16Q, the two types commonly used are a wire rope tensioner system and a direct-acting tensioner (DAT) system, both of which are passive pneumatic/hydraulic systems. Marine riser tensioners typically have 50 feet of available stroke and individual capacity of at least 200 kips. Systems may be provided in either a single tensioner or a dual (i.e., paired) tensioner configuration, depending on the specific design. Lastly, the riser tensioners are usually equipped with recoil control systems to help mitigate riser responses following an emergency disconnect.

In GRA models, a riser tensioning system should be appropriately represented to capture its influence on responses on the subsea well intervention (or marine drilling riser) system. This is commonly done using a spring element, defined by a mean tension and stiffness as a function of stroke. It is sometimes also assumed that the riser tensioning system provides constant tension; therefore, any tension variation is not explicitly represented within GRA models. For some situations, it may be adequate to model a reduced number of “equivalent” tensioners, as opposed to each individual tensioner.

OWIRS can be quite sensitive to the amount of tension supplied by the riser tensioning system, when used. For this reason, fleet angle and tension variation effects, can become important and should be considered. Tension variation is induced by its stiffness/damping characteristics of the riser tensioning system, and it increases at low mean tensions (expressed as a percentage of their individual capacity). The impact of CT or WL on the system is discussed in section 9.6.3.

9.8 Top Support for SPWIS and RSWIS

In most applications, a SPWIS or RSWIS is supported by a non-compensating system, such as a crane, sheave arrangement, injector head, etc. Vertical motions of the vessel (e.g., heave) are directly applied at the attachment point to the riser, meaning the connected riser must either shorten or elongate to accommodate the change in length. Shortening (during a vessel down-heave) induces lateral displacements or bending moments near bottom of the riser, while elongation (during a vessel up-heave) induces axial strain and associated tensile loads/stresses to the riser. Since they do not provide any heave compensation, these top support systems are typically represented in GRA models as a fixed constraint in the axial direction between their attachment point (to the riser) and the vessel.

SPWIS and RSWIS intervention systems may be deployed over the side of the vessel, instead of through the moonpool. Doing so can amplify motions experienced at the interface of the top support system and the riser. For example, vertical motion (at this interface) now has components from both vessel heave and pitch/roll motions about the vessel’s center of gravity. This effect should be captured in GRA models.

10 Scope of Checks/Assessments Performed

10.1 General

This section lists the recommending checks/assessments to be performed as part of global riser analyses of subsea well intervention systems, as well as others types to include for some applications. These recommendations are based on consensus of common practices within industry. Further discussion is given about the objective, considerations, acceptance criteria, and typical outputs for each type of check/assessment performed.

10.2 Time and Frequency Domain - Solution Types for Dynamic Analyses

Riser systems are typically slender structures subject to small strains and large displacements. As such, the consideration of non-linear geometric effects is necessary for obtaining its correct dynamic response. Depending on the type of analysis being performed, loading conditions, system and site characteristics, frequency-domain or time-domain numerical integration solvers may be used.

Time-domain solvers perform time integration by time step discretization of the governing equations, outputting time series of responses based on time histories of input loads. Most solvers are non-linear, capable of modelling effects such as transient loads, geometric non-linearities and contact effects. Vessel dynamic response may also be included in the model for a fully coupled solution, which consider the intervention system influence in the coupled vessel response. Coupled models may be important in analyses such as drift-off/drive-off and mooring response. Time-domain solutions are more computationally intensive, but modern computers and software make running such models feasible for a growing scope of analyses.

Frequency-domain solvers assumes that all dynamic loads are combinations of periodic functions and yields response spectra based on input loads. Dynamic non-linear effects are linearized at static equilibrium position, so care should be taken if highly non-linear loads such as contact or transient effects are expected. For other non-linear effects, such as quadratic wave drag, there are appropriate linearization techniques that can be used with reasonable accuracy. Vessel response is limited to first-order wave effects and is considered in the model through RAO (Response Amplitude Operator) functions. Frequency-domain solutions are less computationally intensive, which make it especially suitable for analyses with many load cases and where non-linearities are small, such as wave fatigue analysis.

Another dynamic response technique that may be used is modal analysis. Classical eigenvalue obtaining techniques are used to obtain natural frequency and mode shapes around static equilibrium configurations. Like frequency-domain analysis, non-linear effects are linearized, so transient effects or highly non-linear loads are difficult to be adequately considered. Modal analysis is used with modal superposition techniques to obtain vibration response in analysis such as VIV fatigue. It is also useful to give insight to the analyst about the system response and ways to improve it if appropriate.

Waves are typically the dominant dynamic load for most analyses, either by vessel dynamic response as through drag and inertia loads acting directly on the intervention system itself. Real waves are irregular, modelled by a given wave spectrum. For time-domain analysis, time-series of wave elevation must be obtained from wave spectra to be input in the model. These time-series are obtained by a superposition of regular harmonic waves with random phases, which are typically generated by a random seed. As such, extreme responses obtained may vary based on the chosen random seed. Extreme value analysis shall be performed to estimate maximum expected responses in these cases. In frequency-domain analysis, wave spectra are used directly to obtain load spectra. As responses are also given as spectra, estimation of extreme values is more straightforward.

Typical application of the main dynamic analysis techniques shown is indicated in Table 10-1.

Table 10-1 – Typical application of dynamic analysis techniques

Method	Typical applications
Time-domain	Extreme load effect of systems with significant non-linearities (e.g. compliant configurations, high soil-structure dynamic displacements, contact loads). Loss of position assessment where transient loads are significant (e.g. drift-off/drive-off analysis). Riser recoil analysis.
Frequency-domain	Analysis where non-linearities are not significant or can be linearized with adequate techniques (e.g., wave fatigue, operability assessment for most top-tensioned riser systems).
Modal analysis	Modal superposition analysis of vibrations (e.g., VIV fatigue analysis). Qualitative assessment of system response.

10.3 Minimum Requirements

10.3.1 Estimation of Required Top Tension

The objective of this check/assessment is to identify a preliminarily range for tension applied near the top of the subsea well intervention system during the connected operational stage; therefore, it is primarily applicable to (and should be included as part of) GRA for an OWIRS and a TBIRS.

Top tension should be applied to a subsea well intervention system at all times to prevent its global buckling, which may cause excessive loadings (or structural damage) to the riser itself, the subsea stack, or the subsea well system. The applied tension setting should be sufficiently high to maintain positive effective tension along the entire length of the riser's main pipe/string, while also remaining less than capacities of riser system and the compensation/tensioning system(s) used to support it. Tensions limits defined for a top-drive compensation system should be at the same location (e.g., at top of the upper bails), and this location should be clearly stated.

Tensions are commonly expressed as such to achieve a specified intended overpull at a reference location near bottom of the intervention/workover riser. This target overpull is meant to eliminate the possibility of compression along the portion of the intervention/workover riser that is susceptible, as well as to assist with a planned or emergency disconnect. Common reference locations for overpull are the following:

— at the EDP connector (i.e. interface of the EDP/WCP) for OWIRS;
— at the interface with the TH (e.g., THRT or latch within SSTTA) for TBIRS.

Unlike marine drilling risers, emergency disconnect sequences (EDS) for subsea well intervention systems typically involve closure of a valve within the subsea stack or bottom assembly to retain the riser's contents (and any internal pressure) prior to release. Under this scenario, the specified intended overpull can be interpreted as a target "effective tension" at the refence location.

The total effective weight of the connected system is the sum of effective weights for all system components (and their contents) located at elevations between the overpull reference location and the location where top tension is applied. This commonly includes the following:

— (most of) the intervention/workover riser;

- any additional lines that run external to riser's main pipe/string along its length (e.g., annulus) and their attachment mechanism (refer to Section 9.4);
- TLF and bails for its attachment to the riser and the top-drive compensation system;
- any specialized equipment inside the TLF;
- any E-line/wireline or coiled tubing (CT) run downhole inside the intervention/workover riser. The length used for this calculation should be from the top support (e.g., injector head in TLF) down to the emergency disconnect location near bottom (e.g., EDP for OWIRS). It is not appropriate to include the downhole weight of line/CT below this elevation. Doing so could lead to excessive top tension that induces non-favorable recoil response following an emergency disconnect of the riser.

In some instances, it may be prudent to account for any tolerance/uncertainty regarding the final weight of various riser components. Moreover, the effective weight of all components/equipment (and contents) located above the mean water line (MWL) should be based on dry weight.

NOTE: For TBIRS, the effective weight for most components of the intervention/workover riser (and its annulus) should be based on the contents (e.g., mud weight) inside the marine drilling riser.

10.3.1.1 Method for Determining Minimum Tension

The intent is to calculate minimum tensions, or more specifically, the minimum value of (mean) applied top tension, for the connected operational stage based on principles outlined in API RP 16Q. As such, any expected dynamic tension variations and fleet angle effects, when applicable, should be accounted for. When the "tension share" arrangement is used, the minimum tension should also account for the possible sudden loss of tension from a single (or pair of) cylinders in the riser tensioning system.

When the "top tension only" arrangement is used, the minimum tension provided by the top-drive compensation system ($T_{min,top}$) during the connected operational stage can be determined by Equation (1):

$$T_{min,top} = \left(W_{total} + OP_{bottom}\right) / R_{f,top} \quad (1)$$

where

W_{total} is the total effective weight (W) of connected system (including contents) that is to be supported, as described above;

OP_{bottom} is the specified intended overpull (OP) at the reference location near bottom of the riser, as described above;

$R_{f,top}$ is the reduction factor for the top-drive compensation system. It relates the minimum vertical tension applied to the riser to tension setting to account for fleet angle, if any, and tension variation due to mechanical and hydraulic effects.

When the "tension share" arrangement is used for an OWIRS, care should be taken in determining the applied tensions provided the top-drive compensation system and the riser tensioning system. Generally, the top-drive compensation system is intended to support the effective weight for all system components (and their contents) located above the attachment point of the riser tensioners. This is typically defined by a specified intended overpull at a reference location along upper components of the OWIRS, such as top of the tension joint. Therefore, $T_{min,top}$ during the connected operational stage can be determined by Equation (2):

$$T_{min,top} = \left(W_{top} + OP_{top}\right) / R_{f,top} \quad (2)$$

where

W_{top} is the sum of effective weights (W) of all system components (including contents) to be supported by the top-drive compensation system. This commonly includes several upper riser components, the TLF with bails, and any specialized equipment inside the TLF.;

OPtop is the specified intended overpull (OP) at the reference location along the upper riser components;

Then, based on principles outlined in API RP 16Q, the minimum tension setting for a wire-rope riser tensioning system (T_{min} as defined in 16Q) can be determined by Equation (3):

$$T_{min} = \left[\left(W_{total} + OP_{bottom} - T_{min,top}\right) \times N\right] \Big/ \left[R_f \times (N - n)\right] \qquad (3)$$

where

Rf is the reduction factor for the riser tensioning system. It relates the minimum vertical tension applied to the riser to tension setting to account for fleet angle and tension variation due to mechanical and hydraulic effects. Further discussion is given in API RP 16Q.;

N is the number of (riser) tensioners supporting the OWIRS;

n is the number of (riser) tensioners subject to a single sudden failure (typically one or two depending on the tensioner plumbing arrangement).

Equations (1) through (3) provides unique variables for reduction factors representing the top-drive compensation system ($R_{f,top}$) and the riser tensioning system (R_f), since these system types are known to provide different amounts of tension variation. When used to support OWIRS, each riser tensioner is typically at a low percentage of its individual rating, which increases tension variation as a percentage of the applied mean tension. In other words, it may be appropriate to assume R_f values significantly different (e.g., 0.75-0.85) than values typically used in determining T_{min} for marine drilling risers (e.g., 0.90-0.95) for wire-rope tensioning systems).

The amount of tension variation accounted for (i.e., R_f and $R_{f,top}$ values used) may depend on the amount of heave experienced by the MODU/vessel. As such, it may vary with waves/seastate or vessel heading evaluated for each load case.

10.3.1.2 Method for Determining Maximum Permissible Tension

A separate calculation is performed to determine the maximum value that can be applied to the intervention/workover riser for the connected operational stage. This is referred to as the maximum permissible tension, but more specifically, it is the maximum value of (mean) top tension that should be applied. The maximum permissible tension for a Normal Operating classification is based on one of the following considerations:

utilization of axial/tensile strength of the intervention/workover riser (and its connectors);

capabilities of the compensation/tensioning system(s) used. Make sure to account for the weight of any other equipment located between elevations for which the load rating and applied tension are defined. The travelling block might be an example for a top-drive compensation system.

Section 5.3.3 of API RP 16Q provides discussion of other factors that should be accounted for (individually or in combination) when establishing the maximum permissible tension. Most are also applicable for subsea well intervention systems. Examples include the following:

bending moment from all sources, including unbalanced pressure end loads, dynamic response, and environmental loadings;

any expected tension variations induced by wave frequency-induced motions. The amount of tension variation accounted for may be dependent on the waves/seastate or vessel heading evaluated.;

changes in stroke/travel of the compensation/tensioning system(s) due to mean vessel offset (such as during a loss of position event);

pressure end loads in the external lines, if they cause the main riser/string to bear additional tension.

Any relevant accidental loads discussed in Section 8 should also be considered.

10.3.1.3 Acceptance Criteria

This initial assessment is intended to check that the intervention/workover riser system, as well as the compensation/tensioning system(s) used to support it, have sufficient capacity for each operation type/scenario (e.g., pressure testing, flowing) during the connected operational stage. Therefore, the only acceptance criterion needed is that minimum tension must remain less than the maximum permissible tension (including expected tension variation). Checks should focus on the heaviest contents and/or the highest surface pressure inside the riser.

10.3.1.4 Typical Outputs

The primary outputs for this assessment should be both of the following:

— minimum tension (or minimum overpull at reference location near bottom), and
— maximum permissible tension (or maximum overpull at reference location near bottom).

For an OWIRS using a "tension share" arrangement, separate tensions should be provided for both the top-drive compensation system and the riser tensioning system. Primary outputs should be provided for each operation type during the connected operational stage (e.g., pressure testing, flowing) and all applicable sets of operating parameters. These are then used as a starting point for subsequent assessment types (e.g., operability, fatigue) as part of GRA.

NOTE: The minimum and maximum permissible tensions calculated should not necessarily be interpreted as recommended tensions for operating purposes. At the time this initial calculation is completed, other assessments as part of the GRA have not been performed yet. Therefore, it is not known which applied mean tension (within the range of initial estimates) will produce the most favorable system responses and therefore the most sizeable operating window. Instead, selection of recommended tensions may be influenced by results of other GRA assessments and can be well above the minimum tension from this initial calculation.

As illustrated in Figure 10-1, minimum tensions are commonly summarized in plots showing calculated value over the applicable range of riser contents. Maximum permissible tensions can be summarized in tables showing calculated values for various combinations of inputs, e.g., loading classification, riser contents, surface pressure, tension variation, etc.

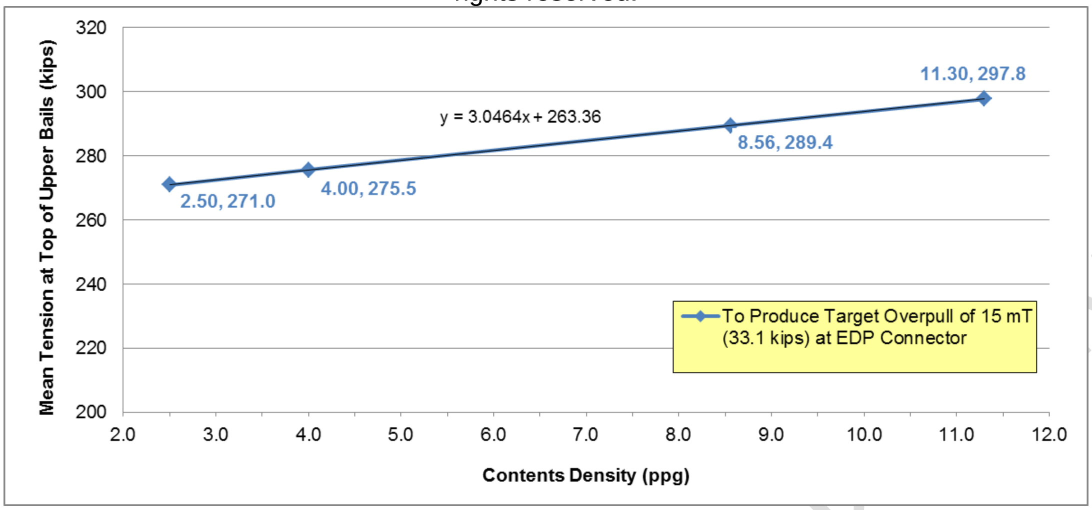


Figure 10-1 Example – Summary of Minimum Tensions Calculated for Top-Drive Compensation System

Examples of supplementary outputs from this type of assessment (for the connected operational stage) include:

— nominal (and/or factored) values for air/submerged weights of all system components, e.g., riser, TLF/bails, specialized equipment;
— calculation for total effective weight of connected system that is to be supported, Wtotal. When the "tension share" arrangement is used, it is helpful to sub-divide the total at the attachment point of the riser tensioning system.;
— listing of inputs/assumptions used to calculate maximum permissible tensions.

10.3.1.5 Possible Mitigations

There are several possible mitigations to increasing the preliminarily range of tension applied near the top of the subsea well intervention system during connected operations. The following are several examples that aim to reduce the minimum tension and/or increase the maximum permissible tension:

— use various wall thickness values along the riser's length;
— attach buoyancy modules to the riser, such as for OWIRS in HPHT applications;
— use a higher number of (riser) tensioners in the "tension share" arrangement;
— select/use a compensation/tensioning system with a suitable capacity, which could be a custom-built design.

10.3.2 Riser Space-out and Total Stroke Requirements

The objective of this study is to identify a range of mean space-outs for the upper intervention / workover riser such that all acceptance criteria (e.g., change of travel/stroke for compensation / tensioning systems, minimum vertical clearance to vessel obstructions) are satisfied during connected operations.

It is primarily applicable to (and should be included as part of) GRA for an OWIRS and a TBIRS.

10.3.2.1 Space-out Considerations

When establishing a nominal space-out, a qualitative vertical and lateral interference and clashing check should be conducted to ensure the connectors are spaced sufficiently away from any constrictions and openings. It is good practice to clearly define all riser reference elevations with respect to a selected vessel datum, such as the drill floor or moonpool deck elevation. The elevations of different specialty joints, their end connectors, and any large diameter flanges should then be specified and reviewed with respect to the selected vessel datum. Once the space-out is finalized, an associated space-out drawing should be developed. One example is defining elevation of a specific connector or bottom of surface flow head/tree with reference to the elevation on the vessel (e.g., drill floor).

While the objective of this study is to determine a nominal riser space-out, different system tolerances and variations in vessel and environmental parameters should also be accounted for and an upper and lower bound target space-out should be defined.

To prevent bottom-out of surface tree on drill floor or stroke-out of compensator system, the following parameters to prevent bottom-out of surface tree on drill floor should be included, as applicable, for all load conditions:

— riser stretch from top tension;
— elongation due to pressure (end-cap effects);
— elongation due to riser wall temperature;
— vessel draft variation;
— tidal water level variation;
— possible storm surge;
— wellhead stick up
— subsea tree and riser tally make-up;
— make-up tolerance.

Allowance should be considered for vertical displacements from vessel heave and rotational motions (roll and pitch) and riser downward sagging due to current load. A 10% margin on the physical available stroke amplitude should be included for both up-stroke and down-stroke. An example of available stroke based on the above considerations is shown in Figure 10-2.

NOTE Particularly for deep water, the thermal expansion/elongation of the riser should be calculated and accounted for, as necessary, because the elongation may consume capacity of the heave compensators and tensioners.

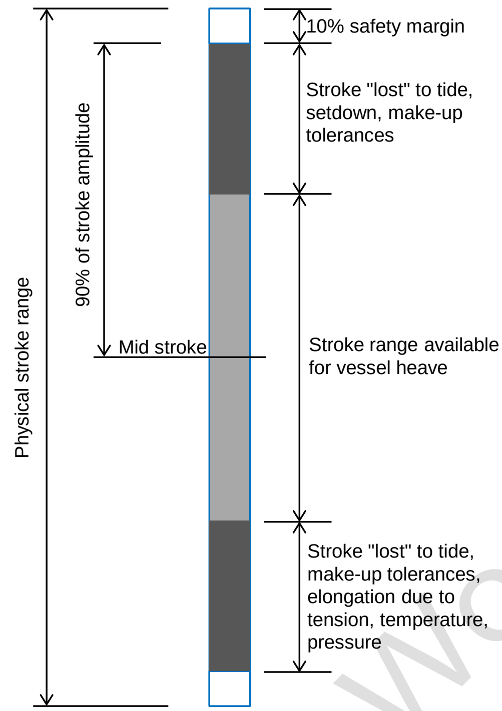


Figure 10-2—Available Stroke and Heave Limit

To determine the maximum environmental condition that can be accommodated without stroke-out occurring the following approach should be adopted:

- — determine the available stroke length at still water (nominal, stress-free state) for:
- — riser slick section stick-up above drill floor or clearance to surface flow tree;
- — top drive heave compensator;
- — tensioner system.
- — identify the quasi-static effects that utilize or add to the still water stroke or clearance:
- — tide;
- — storm surge;
- — riser elongation due to tension, temperature, and pressure;
- — riser make-up tolerance;
- — riser set-down due to mean vessel offset from well center;
- — riser set-down due to current.
- — sum the quasi-static effects to establish the available stroke or clearance left for dynamic effects (i.e. vessel heave);
- — for each relevant sea state in the wave scatter diagram, find the extreme value of vessel heave amplitude;
- — find the limiting sea states resulting in a vessel heave equal to the available stroke or clearance found in step c) above. The limiting sea states will depend on vessel offset (riser set-down).

10.3.2.2 Acceptance Criteria

This initial assessment is intended to check that the intervention/workover riser system, as well as the compensation/tensioning system(s) used to support it, have sufficient clearance and stroke range during the connected operational stage. Therefore, the only acceptance criterion needed is that minimum stroke is less than the allowable vertical displacement and the minimum lateral clearance does not result in clashing of critical components. Checks should focus on the components along the upper riser.

10.3.2.3 Typical Outputs

The primary outputs for this assessment should include the following (from connected operations):

— lowest and highest values for mean space-out of upper riser, and
— limits for available up- and down-stroke (when on-location) during various seastates.

Examples of supplementary outputs from these checks of connected operations include:

— schematics showing elevations of upper riser components for both the lowest and highest values for mean space-out;
— relationships between various ways of expressing stroke/space-out considerations (e.g., elevation for reference point along riser, vertical distance/clearance from possible obstructions, travel/stroke of a compensation/tensioning system).

10.3.2.4 Possible Mitigations

Some intervention systems are characterized by very small heave compensation stroke ranges and thus including all the allowances may suggest an inoperable scenario and the operations may seem not feasible. However, the stroke limitations can be overcome through meticulous operating procedures. If the operating procedures include a rigorous scheme for compensator adjustment, the effect of tension, pressure, temperature, and tidal amplitude may be disregarded when calculating the available dynamic compensator stroke, as appropriate for the scheme implemented.

In addition, all stroke allowances may not linearly stack in one direction i.e. highest internal pressure may not coincide with the highest temperature condition and hence associated riser conditions for each pressure (flowing, shut-in, pressure test) should be considered to reduce conservatisms. Effects where the maximum value may not be anticipated to occur simultaneously may be added using the root of sum of squared values.

$$Sum \text{ of quasi-static stroke} = \sqrt{Tide^2 + Surge^2 + \text{Make-up tol}^2 + Setdown^2 + Tension^2 + (Temp + Pressure)^2}$$

If custom length pup joints can be used to alleviate some of the stroke limitations, analysts may make recommendations for selection of optimum joint lengths (or) customized (i.e., well-specific) pup joint lengths.

10.3.3 Operability Assessment

The objective for an operability assessment is to determine the recommended operating limits (environmental and vessel position limits) within which the operations can be safely conducted, i.e., all design acceptance criteria defined for system responses (e.g., displacements, loads, stresses) are satisfied. Recommended operating windows can be obtained for the following operational stages:

— connected for operating, extreme, and survival loading classifications;
— running and retrieval for a range of deployment depths;
— storm hang-off.

Operability analysis is applicable to (and should be included as part of) GRA for any subsea well intervention/workover riser system.

The riser operating limits should be established by the designer/analyst and are identified for a combination of structural and environmental parameters corresponding to a specific top tension (Section 10.2.1), riser space-out and vertical/horizontal clearance (Section 10.2.2). These limits may be presented as easily understood graphs or as tabulated critical values of the structural and environmental parameters. While defining operating limits, all relevant failure modes should be considered with the safety margins given by the relevant design factors for each operating mode assessed.

The operating limits are typically defined in terms of parameters that can be monitored during operations, either directly (e.g., wave height, current speed, and vessel offset) or indirectly (e.g., via vessel heave, pitch, roll, etc.). The method of monitoring and accuracy of measurement of these parameters should be accounted for in the setting of operating limits.

10.3.3.1 Analysis Method

Commonly, riser operating limits for connected operations are conducted for a range of nominal vessel offsets/positions relative to the well location, associated environments and structural parameters. Riser operating limits for disconnected operations (running and retrieval, storm hang-off) are commonly conducted for given environments and a nominal vessel offset/position relative to the well location e.g., for TBIRS. The associated GRA for both types of assessments use linear elastic material properties, since limits (for each acceptance criterion considered) are typically defined prior to material yield.

Nominal vessel offsets/positions and current loads can be applied either statically or varied with time. Dynamic contributions to system responses induced by wave loads or vessel motions are varied with time, whether the assessment is carried out using time domain or frequency domain methods. The cumulative effect of offsets, environment and vessel motions can be accounted for using superposition. While operating windows for both connected and disconnected operations can be obtained using dynamic analysis, connected operating windows for no wave conditions can be obtained using nominal vessel offsets/positions and current loads applied quasi-statically.

The operating windows can be established by comparing system responses to the defined acceptance criteria. Utilization factors are determined for each parameter (pipe loads, connector loads, riser clearance, stroke, EDP disconnect angle), operational stage (running/retrieval, connected, hang-off) and loading classification (normal, extreme, survival). This is done by combining the loads (tension, bending moment, pressure) and/or displacements/rotations obtained and the associated component capacities (i.e., allowable limits (or) acceptance criteria). Load utilizations are calculated based on the pipe and connector capacities and acceptance criteria given in Sections 5.5-5.6 of API-STD-17G.

For dynamic analysis, the loads/load effects should be a characteristic “upper bound” value established by extreme value analysis of time series established by simulations. In other words, code check/utilization may be performed on time-series of loads (e.g., tension and bending moment), whereby utilization time-series are generated by combining applicable tension, bending moment and applicable pressure. The maximum or extreme response value of utilization may then be calculated. Alternatively, the analyst should determine the maximum or extreme response value of the loads individually and calculate the combined utilization. This approach may produce higher utilizations, since it assumes that maxima for tension and bending occur simultaneously.

NOTE Typically an extreme value analysis based on the Weibull distribution, the Rayleigh distribution or the Average maximum method, selecting the appropriate method will depend on the system and analysis.

For riser systems where the bending load is sensitive to tension variations (for e.g., due to losses in the tension system), the combination of loads and determination of utilization should be done for each time step and let the time-series of component utilization be subject to statistical processing. Care should be taken to fit the data to a distribution with enough parameters that captures the skewness from the non-linear responses.

10.3.3.2 Acceptance Criteria

Operating limits are typically defined by evaluating the riser response and based on acceptance criteria typically include system responses such as:

— loads/stresses experienced by riser pipe, i.e., component cross-sections along the riser length;
— loads experienced by connectors;
— loads/stresses experienced by component cross-sections along the subsea well system, if applicable (typically for TBIRS, OWIRS);
— riser horizontal displacements/clearances with neighbouring structures, especially for disconnected operations:
  1) Subsea equipment;
  2) Risers;
  3) Umbilicals;
  4) Vessel components;
  5) Moonpool.
— riser down-stroke and up-stroke (i.e., vertical clearance, for OWIRS/TBIRS);
  1) compensator stroke;
  2) tensioner stroke (in tension share or workover/intervention risers supported by tensioner).
— EDP release angle (for OWIRS);
— flexjoint angle (for TBIRS).

The acceptance criteria are driven by the component design capacities (e.g. yield strength, connector bending capacities), pre-determined allowable values from other analyses (e.g., EDP release angle, allowable flexjoint angle) and system physical limitations (e.g. moonpool clearance, stroke limits). As such, each specified parameter (stress, clearance, stroke) has a different design factor/allowable depending on loading classification (normal, extreme, and survival) and operational stage (running/retrieval, connected).

10.3.3.3 Riser Pipe Code Check/Utilization

The riser pipe operating limits are established based on cross-section/pipe loads along the riser length as obtained from GRA. Pipe capacity utilization is calculated for different pressure, tension and bending loads with appropriate design factors as per API code checks. Code check refers to the calculation of cross-section utilization and component utilization, i.e., the degree to which the combined load check is satisfied in terms of the ratio of the applied combined load effect (“numerators”) and load capacity (“denominators”). Code checks should be performed in accordance with the design principles, the functional design factors and structural design factors for different single and combined load conditions specified in Section 5.2 of API-STD-17G.

For OWIRS and TBIRS, code checks may be performed based on load capacities using net differential pressure as the design pressure, unless the analysis design basis requires the use of the rated working pressure.

For TBIRS, where the external pressure may exceed the hydrostatic pressure, external pressure due to setting of production packers, tubing hanger pressure testing, subsea drilling BOP pressure testing, annulus circulation to choke/kill lines, operation of landing string secondary functions, etc. should be included in the code check.

For SSTTA or spacer joints inside TBIRS, axial load effects due to external pressure acting on differential seal areas (i.e., piston effect) should be combined with all other applicable load effects in the code check.

10.3.3.4 Connector Loads, Load Capacities and Utilization

The connector operating limits are established based on connector loads from GRA and connector capacity charts typically established by the OEM for combinations of tension, bending moment and pressure for:

— structural load capacities for normal, extreme, and survival conditions with the following structural failure modes:
   1) yielding;
   2) mechanical disengagement;
   3) buckling when applicable;
— functional load capacities for:
   1) leak tightness;
   2) loss of functionality (malfunction).

The load capacities are typically determined from either elastic or elastic plastic analysis and calculated in accordance with Annex C of API-STD-17G, unless otherwise specified. Care should be taken to ensure that the axial load definition is effective tension or true wall tension and appropriate translation must be accounted for when determining the capacity. Also, design factors may already be embedded in the capacity charts and it is important to ensure that the appropriate capacity for the loading classification (normal, extreme, survival) is considered. An example format of a typical pipe and connection load capacity chart is provided in Figure C.7 of API-STD-17G.

There may be more than one code check for a component. Typically, a flange connector will be checked for structural strength, loss of bolt preload, and leakage. The relevant design factor associated with each operational stage and loading classification should also be accounted for in this calculation. Code checks for component failure modes should be carried out for all potentially critical cross-sections, connectors, well control devices, tubing hanger, tubing hanger running tool, subsea tree and wellhead.

NOTE Connector capacities may vary (e.g., be limited by) depending on bolting material and make up parameters.

10.3.3.5 Allowable Flexjoint Angle Determination (TBIRS)

The upper and lower flexjoint angle rotation limits should be considered in the operability analysis. These limits may be different for connected operations and for running and retrieval. These limits are based on a separate localized analysis conducted and criteria as described below.

Passage limitation analysis should be conducted to determine if the TBIRS components have adequate strength during passage of the disconnected TBIRS through the flexjoint of the drilling riser without placing any further restrictions on the maximum flexjoint angle during a planned disconnect. The purpose of this assessment is to evaluate the limiting flexjoint angles that facilitate passage of equipment before/after TBIRS connection/disconnection while maintaining component utilization for specified pull out tensions.

The allowable flexjoint angle limits are such that they should not overstress the riser pipe passing through the flexjoint and should not exceed the pull-out force required to safely pass the completion equipment through the flexjoint(s). The identified limits can then be used to define the associated flexjoint angle acceptance criteria for operability assessment.

10.3.3.6 Load cases assessed

Load case matrices for each operational stage (and loading classification) of different intervention/workover riser systems are given in Section 8. The information provided includes typical durations and environmental conditions (i.e., return period or exceedance for short- or long-term weather events) for different operational stages. The load effects for each load case should either be based on analytical calculations or numerical simulations or a combination of both.

10.3.3.7 Sensitivity Analyses

The system sensitivity to the various parameters is also of importance, mainly to quantify modelling uncertainties, support rational conservative assumptions and identify areas where a more thorough investigation is needed to achieve an acceptable model. For instance, a deep-water riser system may be less sensitive to vessel offset and seastate than a shallow-water system. In geographical areas with benign wave conditions, current speed may be of higher relative importance. Similarly, for operations from a vessel with ample drill floor lifting height and compensator stroke range, vessel heave may be less important than vessel offset.

10.3.3.8 Assumptions

Assumptions (modelling, operating parameters) and conditions inherent in the analysis method applicable for operating limits should be clearly stated. Modelling assumptions includes boundary conditions, GRA geometry, stiffness, and lengths, tension loads (top tension or shared tension, tension distribution, tensioner stiffness), fluid contents density, and pressure. An example of parameter assumption involves determination of allowable flexjoint angles for TBIRS from local GRA (i.e., passage limitation assessment).

Moreover, scope/system level assumptions should be stated. If the operating limits are based on structural analysis of a TBIRS (i.e., limits to flexjoint angles), additional (separate) analyses of the marine riser, BOP, and wellhead system will be required to define the limitations for the total system (e.g., limits to the vessel offset). For these other systems, design codes including API RP 16Q and DNV-wellhead, should be referenced.

10.3.3.9 Typical Outputs

The output of an operability assessment is the recommended operating windows for each selected combination of operational stage, operation type, and all applicable sets of operating parameters. For connected operations, the primary outputs are commonly expressed as combinations of:

— applied nominal tension (or nominal overpull);
— limits for nominal vessel position/offset in the up- and down-current directions, and
— environment (e.g., seastate, current).

Nominal values of tension and/or vessel position can be based on the mean value of the parameter.

For disconnected operations (running/retrieval and hang-off), the primary outputs are commonly expressed as combinations of:

— range of deployment depths;
— environment (e.g., seastate, current);
— surface pressure, if any (such as during pressure testing), and
— vessel transit speed/direction, if any.

Examples of supplementary outputs from operability assessment of connected operations include:

— Tension-offset envelopes (TOEs) based on governing acceptance criteria for a given environment. The vertical axis could be applied mean tension or intended (mean) overpull;
— environment envelopes based on governing acceptance criteria for a given applied mean tension;
— variation of system responses as a function of mean vessel offset for a selected combination of applied mean tension and environment;
— For TBIRS, limits for maximum flexjoint angles (of the marine drilling riser).

Examples of supplementary outputs from operability assessment of running/retrieval operations include:

— environment envelopes based on governing acceptance criteria applicable for a range of deployment depths;

— variation of system responses as a function of deployment depth for a selected environment;
— variation of system responses as a function of vessel transit speed/direction for a selected combination of deployment depth and environment;
— For TBIRS, limits for maximum flexjoint angles (of the marine drilling riser);
— For TBIRS, pull-out and set-down forces required to overcome contact loads at critical flexjoint angles.

When defining operating limits for intervention/workover riser systems, it should be made clear what limits the envelope. For example, in connected mode for OWIRS, riser operating limits are affected by limiting factors such as yield strength, riser stroke, riser clearance, maximum allowable emergency disconnect package angle for disconnect and vessel drift considerations. Typical operating limitations in terms of the following parameters should be specified (where applicable):

— maximum landing speed, applicable for disconnected operations;
— maximum vessel offsets;
— maximum current return period;
— maximum seastate;
— maximum set-down weights (i.e., minimum tension or maximum compression in riser end);
— maximum landing and connection angles.

10.3.3.10 Possible Mitigations

There are several possible mitigations to improving the operability limits (i.e., increasing the operating window) as obtained from analysis. These involve changes in modelling, boundary conditions, applied tension, environment and applicable acceptance criteria.

The following are examples of possible mitigations to consider as means of improving operability limits for disconnected operations (running/retrieval and storm hang-off):

— maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel.
— reassessment with associated seasonal seastates (wave height, period) or currents (current speed, through depth current profile);
— reduce the diameter and/or length of components (for TBIRS);
— reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1 (for TBIRS);
— find means of restraining motions of the stack when at the first hang-off depths;
— running two or more previously made-up riser joints to get the subsea package through the splash zone as quickly as possible (for OWIRS);
— drift (or transit) a DP surface vessel to reduce drag loading experienced during strong currents (for OWIRS);

NOTE Care should be taken with drift (or transit) of a DP surface vessel in order to avoid inducing severe VIV in the riser.

— offset the surface vessel upstream of the dominant current direction to reduce the relative angle between the deployed riser and the wellhead, thereby assisting in landing operations (for OWIRS);
— optimize the stack-up length such that the SSTTA (or other large/stiff members within the bottom assembly) is not across a flexjoint elevation when top of the deployed riser is supported by the slips (for TBIRS).

The following are examples of possible mitigations to consider as means of improving operability limits during connected operations:

— optimize the mean applied tension(s) (typically for TBIRS/OWIRS);
— optimize the mean position (also referred to as or mean offset) of the vessel, especially during strong currents;
— reassessment with associated seasonal seastates (wave height, period) or currents (current speed, through depth current profile);
— optimize the vessel trim, especially during strong currents;
— additional restraint of surface equipment within the lift frame through chains/beams (for OWIRS);
— tension share instead of top tension only, if applicable (for OWIRS).
— reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1 (for TBIRS);
— design iteration of TBIRS components. Generally, each SSTTA is optimized for a specific combination of THS, subsea tree, and BOP Stack, meaning it is intended for use at a specific well from a specific MODU. Moreover, upper components of the TBIRS (e.g., RSM) are optimized to the UFJ elevation for a specific MODU.

NOTE Once operability windows for different operations (disconnected or connected) have been determined, the suitability of the determined limits to carry out the operation can be addressed. This is often best expressed by providing the percentage of the year, or target time frame, in which the operations could take place. For example; the annual percentage operability for the system could be 50%; however, this percentage of occurrence could increase to 85% for the specific season (for e.g., June/July) during which the operations are carried out. If any of the operability limits are determined to be overly restrictive or the percentage operability is low, then this should be highlighted, and possible mitigations suggested. Determining what is considered restrictive or low in this instance will require discussion with all stakeholders.

10.3.4 Loss of Position Assessment

Objective & Applicability

The objective for this assessment is to determine the mean vessel offset at which the first limit (of the defined set of acceptance criteria) is reached when the rig/vessel experiences a loss of position event during connected operations. It is applicable when operations are performed from a DP rig/vessel or a moored rig/vessel, since as discussed in Sections 7.4.4 and 7.4.5, respectively, both types can experience loss of position events.

This type of assessment is applicable during the connected operational stage and therefore is likely applicable to (and should be included as part of) GRA for any subsea well intervention system.

General

A Loss of Position assessment aims to ensure that accidental loads induced by a loss of position event (i.e., drift-off/drive-off for DP vessel or a failed mooring line) do not overload the connected system. This is done by determining recommended operating windows such that all acceptance criteria defined for system response are satisfied. Recommended operating windows are commonly expressed as combinations of applied mean tension (or mean overpull), limits for mean vessel offset/position, and environment (e.g., seastate, current).

10.3.5 Estimation of Watch Circles

The objective for this check/assessment is to estimate watch circles when performing connected operations from a vessel that is dynamically positioned. More specifically, this type of assessment is not applicable when operations are performed from a moored vessel.

This type of assessment is applicable during the connected operational stage and therefore is likely applicable to (and should be included as part of) GRA for any subsea well intervention system.

"Watch circles" are limits determined for mean vessel offset/position such that acceptance criteria during a loss of position event of a DP vessel (i.e., drift-off, drive-off, or force-off) will not be exceeded. As defined in API RP 16Q, the yellow watch circle indicates the largest offset at which preparations for an EQD (or EDS) should begin, and the red watch circle indicates the largest offset at which EQD (or EDS) should be started. Estimation of watch circles involves combining of the following additional inputs:

— POD radius/distance for the load case (i.e., combinations of contents, applied mean tension, environment, etc.);

— vessel trajectory during the loss of position event. These are assumed to be provided as inputs for the necessary environmental conditions (see Section 6.2).;

— mean vessel offset/position relative to well location at start of the event (i.e., initial mean vessel offset/position);

— total time for the EQD (or EDS) to be completed;

— guidance for setting yellow watch circles from red watch circles, which may be based on time or radius/distance.

10.3.5.1 Analysis Method

Commonly, the POD radius/distance is defined as the recommended limit for mean vessel offset/position in the trajectory direction from the Loss of Position assessment (Section 10.2.4). A method for determining watch circles involves using the vessel trajectory to perform the following sequential steps:

— Determine the time corresponding to the POD radius/distance;

— Subtract the EQD/EDS time from the result of Step #1, which produces the time corresponding to the red watch circle;

— Use the result from Step #2 to determine the red watch circle radius/distance;

— Determine details for the yellow watch circle based on the guidance given. This is generally started either by subtracting the given time from the result of Step #2 or applying the given percentage to the result of Step #3.

10.3.5.2 Acceptance Criteria

Operating procedures for a DP vessel commonly aim to use consistent values for yellow and red watch circles during all connected operations. If so, these preferred/target values (for radius/distance or time) can be used as the only acceptance criteria for this type of assessment.

10.3.5.3 Typical Outputs

The primary outputs for this assessment should be all of the following:

— radius/distance and corresponding time for the POD (or black circle);

— radius/distance and corresponding time for the red watch circle;

— radius/distance and corresponding time for the yellow watch circle.

— Primary outputs should be provided for each operation type during the connected operational stage (e.g., pressure testing, flowing) and all applicable sets of operating parameters. Moreover, these outputs can be given for combinations of applied mean tension (or mean overpull) and environment (e.g., seastate, current).

As illustrated in Figure 10-4, estimated watch circles for a single set of conditions are commonly expressed in plots showing calculated radius/distance values as a function of time. Distance is generally expressed relative to the initial vessel offset/position, which may or may not be at the well location/center. Time is expressed from start of the loss of position event.

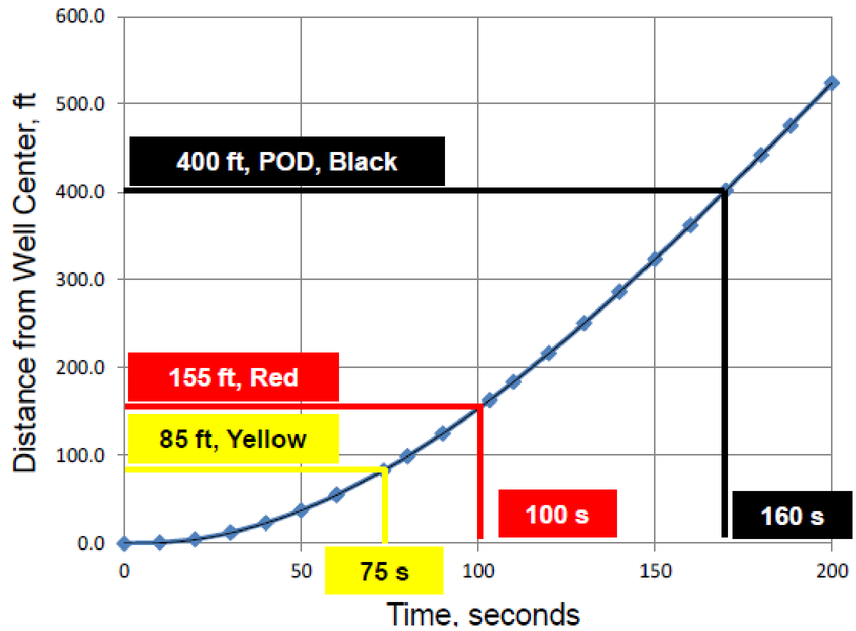


Figure 10-4: Example – Development of Watch Circles Using Vessel Trajectory

Examples of supplementary outputs from this type of assessment (for the connected operational stage) include:

— environment (and its direction) that estimated watch circles are applicable for;

— type of loss of position event (e.g., drift-off, etc.) that estimated watch circles are applicable for;

— limits for applied mean tension (or mean overpull) that estimated watch circles are applicable for;

— initial mean vessel position/offset that estimated watch circles are applicable for;

— vessel trajectory for the loss-of-position event (reproduction of the input provided).

10.3.5.4 Possible Mitigations

There are several possible mitigations to increasing the size of estimated watch circles during connected operations of the subsea well intervention system. One approach is to increase the POD size, and several ideas for doing so are discussed for the Loss of Position assessment (Section 10.2.4). The following are several examples of other means to increase the watch circle's radius/distance and corresponding times:

— evaluate more benign environmental conditions. This produces two favorable effects: the POD radius (determined by the Loss of Position assessment) typically increases and the vessel trajectory slows.;

— select/use a favorable initial mean vessel offset/position, which is generally opposite of the vessel trajectory direction;

— reduce the total EQD (or EDS) time.

10.4 Others to be Included for Some Applications

10.4.1 General

This section shows a list of other possible of checks/assessments that may be performed for intervention systems. It is not by any measure an exhaustive list, only the more commonly requested tasks required in new designs or in verification of existing designs in different operational conditions.

10.4.2 Additional Screening Tasks

Many of the analyses presented in section 10 require inputs that represent a large collection of raw data and/or many possible values for certain parameters. Also, some analyses may produce many outputs, not all of them critical to the intervention system design or to establish safe operational limits. To keep the analysis scope manageable in a timely manner, additional screening analyses may be performed to narrow the range of data and parameters that need to be considered. Some examples of these screening tasks are presented in the following sub-sections.

10.4.2.1 Wave (or Seastate) Periods

As shown in section 7.2.10, wave conditions are usually presented as wave scatter diagrams, such as the one presented in Figure 7-1. Considering every possible combination of significant wave height (Hs) and peak period (Tp) in scatter diagram may lead to a large number of load cases, not all of them critical to the check being performed. Also, short-term seastate events may also be given as Hs vs. Tp curves for determined return periods, as shown in the example below:

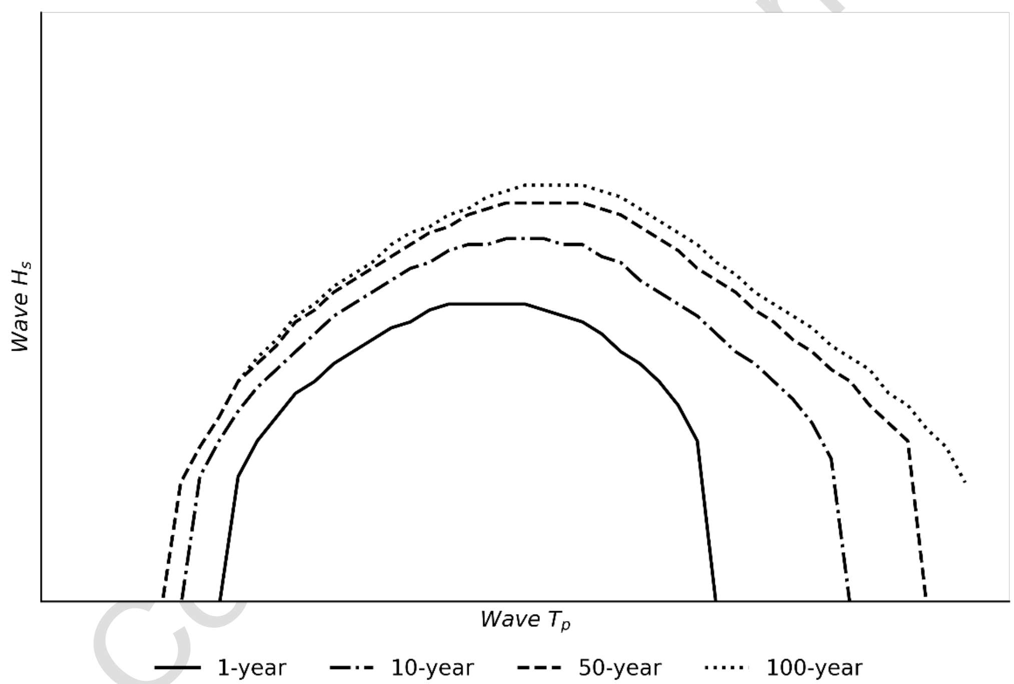


Figure 10-5: Example of Hs vs Tp curves for short-term seastate events by return period

Typically, vessels have significant motion response for a certain period range, characterized by their wave response functions (RAO for first-order response, QTF for second-order response). Also, some analysis or components being assessed are more sensitive to vessel movement in a certain degree of freedom (e.g. tensioner stroke is sensitive to vessel heave, while bending stress on top components is more sensitive to vessel roll/pitch). Therefore, a screening of possible Hs and Tp combinations may be performed to reduce the number of combinations to be considered. As an example, Figure 10-6 shows as typical pitch RAO for a ship shaped vessel:

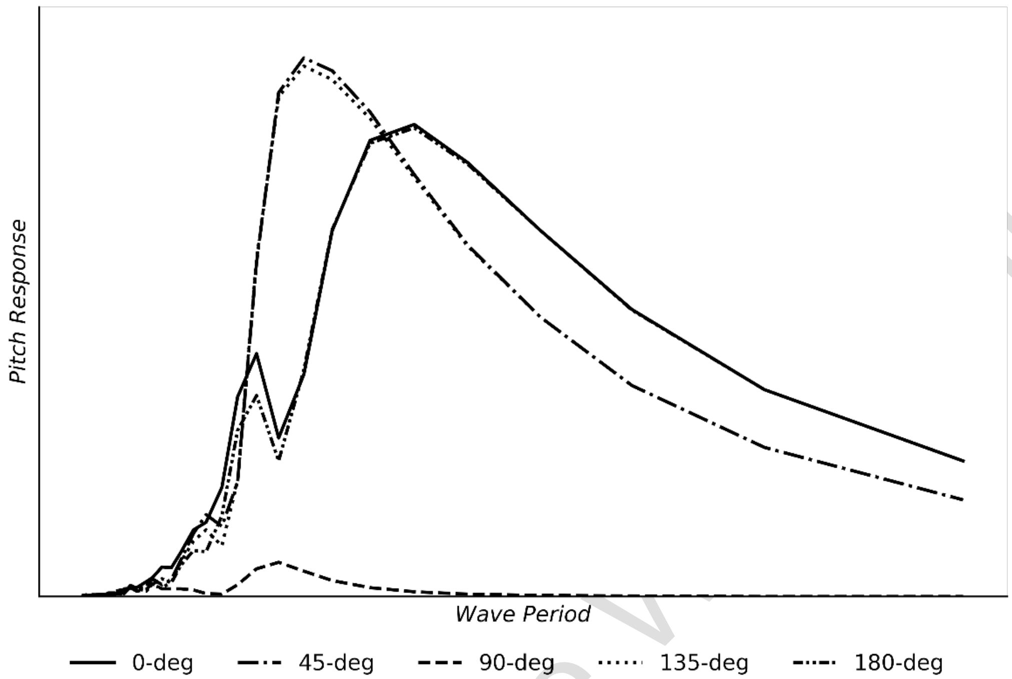


Figure 10-6: Example of Pitch RAO of a ship shaped vessel

In the example shown in Figure 10-6, the vessel has no significant pitch response for Tp values below a certain threshold. As such, Hs/Tp combinations in the wave scatter diagram with Tp values well below that threshold may be safely disregarded.

Some analyses (e.g. operability analysis) require the combination of a wave condition with variation of several other parameters, such as vessel offset or top tension. When selecting short-term seastate events for these analyses, it may not be immediately obvious which Hs/Tp combination is more critical for each specific analysis. In such cases, a screening assessment may be performed to choose the most appropriate Hs/Tp combination from a curve such as the one shown in Figure 10-5 to carry out the parametric analysis at hand.

The output of a wave period screening is the combinations of Hs/Tp to be considered in other checks/assessments.

10.4.2.2 Vessel Heading

Vessel heading for well intervention operations depends on the type of vessel performing the operation, i.e. dynamically positioned or moored. Dynamically positioned (DP) vessels usually have automated systems that choose a heading in relation to the prevailing metocean conditions based on minimum thruster energy usage, although it may avoid situations such as beam seas. Moored vessels have a predetermined fixed heading.

For DP vessels, it is typically assumed that it will be near a head seas configuration, as it usually results in lower thruster usage and first-order response, especially for ship-shaped hulls. However, as a result of misalignment of environmental conditions (i.e. wind, wave and current), the resulting heading may be off head seas by a certain margin. 15 to 30 degrees is a typical angle margin to consider as heading tolerance for DP vessels, but actual values to be considered may be verified with the vessel operator. As a screening task, verification of vessel response to incoming waves in this heading range may be performed to select the most critical heading for further analyses. This critical heading may be different for each vessel degree of freedom or system response being assessed, and as a result, different headings may be used for different analyses. As the vessel rotates to align itself to the prevailing conditions, omni-directional metocean data is used for this kind of assessment.

For moored vessels, heading is fixed according to the mooring design. Usually, the mooring heading is selected to keep the vessel aligned with the most critical or frequent conditions in a location. As such, the vessel heading in relation to the environmental conditions can be any value. As a screening task, the most critical heading may be determined for each vessel degree of freedom or system response and used for further analysis. In this case, directional metocean data is desirable to avoid excessively conservative combinations such as a critical direction for metocean data combined with an unfavorable heading.

In either case, the outputs of vessel heading screening are the vessel headings to be considered for further analysis.

10.4.2.3 Burst/Collapse and Strength Checks

During design, one of the tasks is determining pipe dimensions for riser joints. Usually, it starts with an internal diameter determined by drift requirements, and wall thickness is the minimum necessary to comply with API STD 17G provisions and strength verifications. This process is usually iterative, as pipe wall thickness affects the system weight, required top tension and GRA response.

To reduce the number of iterations in this process, screening calculations may be performed. Wall thickness may be determined by using burst/collapse checks, followed by weight and top tension estimation and a combined load check. A strength reserve may be assumed for bending at this stage (i.e. 10% of the yield stress). This kind of screening may significantly reduce the number of GRA models that need to be verified to design the wall thickness for a new system.

10.4.2.4 Initial Watch Circle Estimation and Setdown Analysis

Estimation of watch circles and operability assessments require the simulation of several vessel offsets to determine acceptable values. The offset range to be considered in such analyses can be determined by a screening of riser setdown, which is limited by the available stroke-down. As a simple approximation of riser setdown for a screening calculation, the riser may be approximated by a straight line, or an analytical formulation such as shown in [Reference to Spark's book].

If vessel trajectories for drift-off/drive-off scenarios are available, an estimation of watch circles based on the offset limits obtained by the quick setdown calculations may obtained, and it may indicate if mitigations (such as those shown in 10.3.5.4) are expected to be needed to obtain acceptable watch circles. Maximum offset ranges also set a target maximum offset to be considered in operability assessments.

10.4.2.5 Weak-Point/Critical Location Assessments

Numerical models typically used in GRA provide a large quantity of outputs, which require post-processing routines to extract responses to be checked against acceptable limits. To optimize the amount of post-processing required, especially for tasks that entail many analysis runs (i.e. operability assessments), a screening of critical locations in the system may be performed to filter the amount of post-processing necessary.

As examples, riser loads are usually more critical near its extremities, both upper and lower regions. Some subsea stack equipment may reach acceptable load limits before others. The casing connector nearest to the mudline is usually more stressed than the others.

10.4.3 Recoil Assessment

10.4.3.1 Objective & Applicability

The objective for a recoil assessment is to determine the recommended operating windows such that all acceptance criteria defined for system responses are satisfied (i.e., "safe recoil response is experienced") during a planned or emergency disconnect. It is applicable when operations are performed from a DP rig/vessel or a moored rig/vessel.

This type of assessment is primarily applicable to (and should be included as part of) GRA for any OWIRS and TBIRS. During the connected operations stage, the submerged weight of these intervention/workover riser (and surface equipment) require the top-drive compensation system and the riser tensioners (if used) systems apply relatively high mean tensions.

10.4.3.2 General

The purpose of a recoil assessment is to determine conditions for which the intervention/workover riser is expected to experience a safe recoil response following a planned or emergency disconnect. For TBIRS, this type of recoil event occurs following a planned disconnect (by unlatching from TH) or emergency disconnect (i.e., shearing of SSTTA component) of the intervention/workover riser, while the marine drilling riser remains connected.

Modeling should reflect details for equipment comprising the existing compensation/tensioning systems aboard the rig or vessel.

Recoil analyses are performed for each unique combination of riser contents, seastate, and vessel heading. For a given riser contents, the minimum tension used as a starting for the recoil assessment is commonly the minimum tension required during the connected operational stage, which is discussed in Section 10.3.1.

10.4.3.3 Analysis Method

Simulations will perform dynamic time-domain solutions with the selected heave cycle applied as a sinusoidal function. Care should be taken when selecting the amplitude and corresponding period of the "regular" heave cycle for a given combination of seastate and vessel heading.

Recoil assessments are known to be sensitive to several operational assumptions. Thus, the following additional details should be used to define meaningful load cases for recoil analyses of each individual combination of contents, tension setting, and vessel heave:

— riser weight: upper bound and lower bound of weight;

— stroke when the rig is on-location: minimum and maximum based on pup joint increments, tide, stretch, and other uncertainties;

— stroke increase to the vessel offset: no increase and maximum increase associated with maximum excursion at the point of disconnect;

— uncertainty in limit of any flow shut-off value within the passive top-drive compensation system, if applicable;

— uncertain about nominal positions of any throttling valves withing the compensation/tensioning systems, as applicable;

— consideration of slow (isothermal) and fast (adiabatic) stroke change.

Moreover, each individual set is simulated 8 times, where disconnect occurs at a different phase angle (typically from 45° to 360° in increment of 45°) within the heave cycle each time.

10.4.3.4 Acceptance Criteria

Recoil assessments are intended to determine conditions for which a safe (recoil) response occurs during a planned or emergency disconnect. This is achieved by satisfying acceptance criteria such as the following examples:

— prevent activation of a passive flow shut-off value within the passive top-drive compensation system, if any;

— provide sufficient vertical displacement (of the intervention/workover riser) to clear the subsea stack, accounting for any swallow;

— minimize any compressive experienced along the intervention/workover riser or slack experienced by the surface equipment;

— minimize any compressive forced experienced by topping out of the passive top-drive compensation system;

— for OWIRS only using “tension share” method, avoid slick in the tensioner ropes (or jump-out at the tension ring for direct-acting tensioners);

— for TBIRS only, avoid compressive force caused by the full closure of the marine riser’s Telescopic Joint for TBIRS only.

10.4.3.5 Typical Outputs

The primary outputs for this assessment should be separate recommended operating windows for all applicable sets of operating parameters during the planned or emergency disconnect operational stages. These are commonly expressed as combinations of the following:

— limits for applied mean tension or mean overpull;

— seastate limit for a selected vessel heading or vessel heave limit;

— acceptable range of mean strokes/travels for the riser tensioning or top-drive compensation systems when rig is on-location.

Examples of supplementary outputs from recoil assessments of an OWIRS using a tension share arrangement include variations of the following system responses as a function of time after release/disconnect:

— stroke/travel of the riser tensioner and/or top-drive compensation systems

— vertical displacement of EDP (or amount of vertical clearance) from its initial position

— tension experienced at locations along the intervention/workover riser

— tension (or amount of slack/jump-out) experienced by the riser tensioner

— velocity of the riser tensioner’s piston

— target overpull tension at EDP interface.

10.4.3.6 Possible Mitigations

The following are examples of possible mitigations to consider as means of improving results from recoil assessments:

— maintain a more favorable vessel heading (with response to the direction of waves) to reduce heave motions of the vessel;

— implement changes to the existing settings within any anti-recoil control equipment/system to improve recoil performance;

— For OWIRS only using a “top tension only” method, change to a “tension share” method;

— For OWIR only using a "tension share" method, modify the tension-split between the top-drive compensation system and the riser tensioning system. This can be achieved without changing the mean overpull at the reference location near bottom of the intervention/workover system.

10.4.4 Fatigue Assessment

10.4.4.1 General

The objective of this assessment is to estimate fatigue damage experienced by the subsea well intervention system. Results are used to determine if the system has sufficient fatigue capacity for planned and future operations.

Fatigue assessment are recommended for the following operational stages:

— running/retrieval (see note below);

— landing (see note below);

— connected;

— storm hang-off;

— vessel transit with the riser suspended.

NOTE: Although it is not typical, running/retrieval or landing operations may also need to be considered if certain scenarios involve prolonged exposure to waves/seastates for a given deployment depth or placing fatigue-sensitive riser components (e.g., connector or weld) near a rigid top support (e.g., slips). Other operation types (e.g., landing, planned disconnect) are typically not evaluated due to their short duration.

For any type of high-cycle fatigue assessment, typically, a fatigue assessment is conducted to estimate the fatigue damage accumulated by the intervention/workover riser during an upcoming well-specific operation. A limitation of this approach is that it does not predict the fatigue accumulation/utilization from previous operations of the equipment. This can be accounted for in the well-specific fatigue assessment by obtaining the total fatigue damage to-date (such as from a hindcast evaluation) as an input or by agreeing upon a safety factor that is deemed to provide sufficient margin to account for any past fatigue damage.

Estimates for fatigue damage rates (or fatigue life) should be given at selected fatigue critical locations for all components along the subsea well intervention system. Examples of fatigue critical locations include connectors, welds, changes in cross-sectional dimensions, and at elevations corresponding to lateral supports back to the surface vessel. For pipe body of the riser or tubulars, fatigue damage rates generally correspond to either the outer or inner fibers (i.e. location on the pipe where fatigue properties are defined), as opposed to mid-wall of the cross-section.

Fatigue predictions produced by numerical methods should be interpreted as a statistical datapoint, instead of an absolute result/magnitude, because fatigue calculations are highly non-linear. Moreover, several critical inputs to fatigue assessments are generally uncertain, and the numerical methods used involve multiple modeling assumptions.

For fatigue-sensitive applications (e.g., when predicted fatigue lives are insufficient, evaluating a new development/design, use of highly valued equipment, etc.), it can be helpful to install a monitoring system to the subsea well intervention system during planned operations. Monitoring data can be used to record fatigue damage accumulation under in-situ conditions, as well as to refine the inputs, assumptions, or approaches for future fatigue assessments.

Fatigue assessments should evaluate the intervention/workover system's exposure to both short-term and long-term environmental conditions for the time of year that planned operations will be performed. For relevant operational stages or operation types, the expected duration assists in deciding if fatigue assessments should evaluate only short-term events, only long-term conditions, or both. Section 8 shows typical examples of operational stage durations for analysis purposes and may be used as guidance in determining relevant events and their durations for fatigue assessments. Typically, fatigue assessments are not performed when the expected duration is very short, i.e., only a few hours, unless high fatigue damage rates are anticipated.

A single event fatigue assessment is based on continuous exposure to a single event (or extreme) condition, such as for return period of 1 year. A single event fatigue assessment should be performed for all operational stages listed, including both connected and some disconnected operational stages. When connected, it is recommended to evaluate several operation types (e.g., flowing, shut-in at surface or subsea, well kill, injection).

Fatigue assessments should be conducted at the nominal value for mean vessel position. Other than for SPWIS, this is commonly assumed to be at well center (i.e., on-location) for operations from a DP vessel, as well as for long-term assessments considering a moored vessel. As done for Operability assessments, single event fatigue assessments for a moored vessel may account for the mean vessel position induced by the considered seastate and current. Although wind loads are not usually considered in such assessments, its effect on mean vessel position may be considered when determining this mean vessel position, especially when the considered seastate is based on storm seas.

The wall thickness of various pipe/components tend to reduce from its nominal/original value over the service life of an intervention/workover system because of wear and corrosion, and this variation should be accounted for as part of fatigue damage calculations. A global analysis model should be based on the specified nominal wall thickness to represent the stiffness of the pipe/component most accurately; however, sectional stresses used for fatigue damage calculations can be based on a reduced wall thickness. The amount for this wall reduction can be based on provided inspection data, the specified Remaining Body Wall (RBW), or by applying a percentage (e.g., 50%, 100%) of the specified corrosion allowance.

When the inner diameter of an intervention/workover system is expected to have exposure to sour service, an additional knockdown factor should be applied to the selected SN curve used as part of fatigue damage calculations.

Safety factors applied as part of fatigue damage calculations for the subsea well intervention system should be selected based on several considerations, such as the expected duration of the operational stage (or operation type), inspectability of the equipment, and the criticality of failure. Selected safety factors should be consistent with applicable industry-wide or region-specific documents and codes (e.g., API or ISO), as well as any company-specific requirements.

NOTE While this section has focused on details specifically related to subsea well intervention systems, additional guidance related to Wave fatigue assessments can be found in industry-wide documents such as DNVGL-RP-E104 (titled “Wellhead fatigue analysis”).

10.4.4.2 Wave Fatigue Analysis

Wave fatigue is caused by wave/seastates acting directly on the intervention system and the associated vessel motion response. It is applicable to (and should be included as part of) GRA for OWIRS, TBIRS and SPWIS, as well as possibly for some equipment associated with RSWIS (e.g., hoses or composite tubulars).

Wave fatigue analyses should consider all relevant cyclic load effects acting on the subsea well intervention system, including the following:

— first-order wave effects (i.e., direct loads to the intervention/workover system, associated vessel motions);

— second-order vessel motions or vessel-induced motions (including quasi-static offset motions).

Typically, only first-order wave effects are evaluated for a DP vessel, since use of thruster assist can overcome/remove most second-order motions. Second-order motions are more relevant when the intervention/workover system is deployed from a moored vessel, but their contributions to accumulated Wave fatigue damage tend to be small.

A long-term wave fatigue assessment is based on exposure to long-term seastate conditions (i.e., a wave scatter diagram) and accounts for the probability of each individual seastate bin, up to a maximum acceptable condition for each operational stage, as the system is not expected to remain in that operational stage if this condition is exceeded. A long-term wave fatigue assessment only needs to be performed for the connected operational stage. More specifically, it generally focuses on the flowing operation type due to its longer expected duration.

Wave fatigue assessment(s) can be performed with analysis model(s) similar to those used for Operability assessments. As discussed in Section 10.2, fatigue loads usually have small amplitudes, especially for long-term events, so frequency domain solution techniques may be applicable to speed-up solution times, as wave scatter diagram derived seastate bins may result in many load cases to be analyzed. Nevertheless, a few updates may be needed for improving the accuracy of the fatigue-specific responses, including the following examples:

— hydrodynamic properties for the intervention/workover riser and subsea stack;

— structural damping;

— tension variation;

— soil data considered;

— method/approach used to model soils data;

— soil damping.

Once a suitable analysis model is developed, it is recommended that an eigenvalue assessment (i.e. modal analysis) as discussed in Section 10.2, be performed to determine the natural frequencies/periods (and associated mode shapes) for each operational stage. Results can be used to assess which weather conditions are expected to excite these natural frequencies, thereby inducing the highest fatigue damage accumulation rates along the intervention/workover system.

As discussed in Section 8.2.2, subsea well intervention systems are most commonly operated at a specific well/location for a limited period of time. For this reason, it is recommended that wave fatigue assessments initially apply an omnidirectional approach based on worst-case environment direction with respect to vessel heading and orientation of the TLF/bails, if installed. A directional approach can instead be used if these initial ("worst-case") results are deemed unacceptable or in other applications (e.g., certain regions where weather direction changes rapidly, when a single GRA will be used for several wells in a campaign). A directional approach evaluates multiple environment directions (and their corresponding intensity) and may consider the spreading of fatigue damage around the circumference of the intervention/workover riser's cross-section. For DP vessels, it should be noted that the vessel constantly changes its heading to optimize thruster usage and to avoid excessive 1st order motion response, especially roll motions for ship-shaped vessels. Usually, the system is equipped with torque-absorption devices (i.e. swivels), but as these devices are not ideal, some torque is transmitted to the system, and may result in riser orientation changes during the operation, especially in deep water systems.

For TBIRS, when using a pipe-in-pipe model, the properties of contact elements or gap elements used should be determined by conducting a convergence study. The purpose of the study is to demonstrate that the analysis responses show a converged solution. For systems deployed in deep water, small inaccuracies can have significant influence on predicted responses due to high number of non-linear gap elements needed along the intervention/workover riser's length.

10.4.4.3 VIV Fatigue Analysis

The objective of assessment is to estimate fatigue damage experienced by the subsea well intervention system well induced by vortex induced vibrations (VIV) of the riser caused by currents. Results are used to determine if the system has sufficient fatigue capacity for planned and future operations.

Generally, VIV fatigue assessments are performed using standard software/tools available to industry, such as SHEAR7 or VIVA, which are highly empirical in nature. For this reason, it is recommended that simulations be performed using recommended parameters or alternate parameters derived by data from previous monitoring of the subsea well intervention system.

As discussed for general fatigue assessments, it is recommended that an eigenvalue assessment be performed for each operational stage. Moreover, the resulting natural mode shapes (and associated frequencies/periods) are used as input to the software/tools for VIV fatigue simulations (e.g., SHEAR7, VIVA). Eigenvalue assessment(s) can be performed with analysis model(s) similar to those used for other fatigue assessments, although some inputs are neglected (e.g., added mass, tension variation, damping).

Since a different software/tool(s) are typically used, separate analysis model(s) must be created to perform VIV fatigue simulations. However, properties used to represent the intervention/workover system (e.g., structural stiffness, added mass, damping, etc.) and soils, as well as the method/approach used to represent soils, are intended to be consistent with those from models for other fatigue assessments, unless some of these properties are determined to be frequency-dependent.

For TBIRS, one method of performing VIV fatigue assessments involves 2 steps. The first step is to conduct an eigenvalue assessment and then VIV fatigue simulations for the marine drilling riser, which is exposed to the direct hydrodynamic loading. In the second step, response amplitudes determined for the marine drilling riser are then applied to a pipe-in-pipe model using either a frequency domain or a time domain approach that accounts for the nonlinear (or linearized) loading/deflections in these contact elements or gap elements. A convergence study should be conducted to demonstrate that the analysis response shows a converged solution. For systems deployed in deep water, small inaccuracies can have significant influence on predicted responses due to high number of non-linear gap elements needed along the intervention/workover riser's length.

For OWIRS, when evaluating the 'vessel transit with riser suspended' operational stage, special care should be taken in accounting for the vessel's speed-over-ground and its direction relative to current profile's direction. Moreover, it is recommended to add a load case for which this operational stage is performed through "still water", i.e., no current profile is present.

For wells/locations in shallow water or when wave-induced vibrations may be relevant, the effect of wave-induced-VIV can be accounted for by augmenting the current profile's speed with the wave particle velocity through the water column.

While this section has focused on details specifically related to subsea well intervention systems, additional guidance related to VIV fatigue assessments can be found in industry-wide documents such as DNVGL-RP-F204 (Riser Fatigue) and DNVGL-RP-C203 (Fatigue Strength Analysis of Offshore Structures).

10.4.4.4 Acceptance Criteria

A fatigue assessment is intended to check that the subsea well intervention system has sufficient fatigue capacity for planned operations at a specific well/location. Therefore, the only acceptance criteria needed is that the amount of fatigue damage accumulated by the intervention/workover system remains less (or the inspection interval remains longer) than thresholds agreed to by the OEM, equipment owner, and the end user. Typically, these thresholds are expressed target values of fatigue life (or inspection interval) for each selected combination of operational stage and operation type. Several examples of thresholds typically provided for comparison to GRA results include:

— target for long-term combined (wave+VIV) fatigue life during flowback operations when connected;

— target for single event (wave or VIV) fatigue life during subsea shut-in operations when connected;

— target for single event (wave or VIV) fatigue life during storm hang-off.

Thresholds for continuous exposure to a single/extreme event should be longer than the anticipated event duration, considering the appropriate safety factors. Similarly, thresholds for long-term exposure to anticipated seastates (i.e., long-term wave fatigue lives) and currents (i.e., long-term VIV fatigue lives) should be longer than the expected duration of planned operations.

10.4.4.5 Typical Outputs

The primary output of a fatigue assessment should be all of the following for each selected combination of operational stage and operation type:

— maximum wave fatigue damage rate (i.e., minimum wave fatigue life, sometimes expressed as inspection interval) based on long-term exposure to anticipated operational seastates;

— VIV fatigue damage rate (i.e., minimum VIV fatigue life, sometimes expressed as inspection interval) based on long-term exposure to anticipated operational current profiles.

— combined wave and VIV fatigue damage rate for long-term conditions. It should be noted that combining wave and VIV fatigue damage is a complex subject, as both events may occur at the same time, and simply summing damage rates may underestimate the damage caused by the resulting stress history due to the non-linear aspect of S-N curves.

— maximum wave fatigue damage rate (i.e., minimum wave fatigue life) based on continuous exposure to a short-term single event seastate.

— maximum VIV fatigue damage rate (i.e., minimum VIV fatigue life) based on continuous exposure to a single event current profile;

For each operational stage and operation type, this primary output should be determined for all appliable set of operating parameters and can be given for combinations of applied mean tension (or mean overpull) and environment (e.g., extreme event, set of long-term fatigue current profiles or wave scatter diagram).

The results obtained can then be used to predict the expected fatigue damage accumulated for planned operations based on the metocean seastate scatter diagram and planned duration for operations. Furthermore, it will be possible to estimate the fatigue utilization for completed operations based on environmental history, and thus track fatigue damage accumulation for highly loaded components.

For some system components, such as coiled tubing, flexibles, or composite pipe in SPWIS or RSWIS, the time history or histograms of minimum bending radius (MBR)/curvature should be provided to conduct a fatigue evaluation. This can be conducted either by the flexible OEM or the GRA analyst based on data provided by OEMs. Flexible pipes are usually not susceptible to significant VIV fatigue damage due to their high structural damping, but in some cases, this may need to be verified.

Examples of supplementary outputs from fatigue assessments include:

— Fatigue damage rate (or fatigue life) at all selected fatigue critical locations along the intervention/workover system, preferably segregated between wave and VIV events;

— allowable SAF values to meet an applicable fatigue life targets (based on the selected SN curve) for any connectors or welds along the interventions/workover riser for which the cyclic load capacity (i.e., fatigue properties) is not available from the OEM;

— distribution of fatigue damage rate along the length of the intervention/workover system for a single set of fatigue properties (e.g., for a base metal SN curve with assumed SAF=1.0);

— break-down of long-term fatigue damage rate at selected fatigue critical locations/components by each individual seastate bin and fatigue current profile;

— contribution to long-term wave fatigue damage rate at selected fatigue critical locations/ components per all seastate bins having a given wave height (e.g., Hs) or a given wave period (e.g., Tp);

— contribution to long-term VIV fatigue damage rate at selected fatigue critical locations/ components per all current profiles having a given surface velocity;

— histograms of mean and dynamic loads/stresses, expressed as either amplitude or range, at selected fatigue critical locations/components.

— distribution of drag amplification factor resulting from VIV analysis along the length of the intervention/workover system for select current profiles. This result can assist in the selecting drag properties in analysis models for Operability assessments.

10.4.4.6 Possible Mitigations

There are many possible mitigations for reducing the predicted fatigue damage (or increasing the predicted wave fatigue life) during planned operations of a subsea well intervention system at a specific well/location. As for Operability assessments, these mitigations can be different for disconnected and connected operational stages, as well as only relevant to a specific subsea well intervention system (e.g., TBIRS). Some mitigations work for wave fatigue, while others may work only for VIV fatigue.

The following are examples of possibility mitigations to consider as means of improving results from fatigue assessments, although no distinction is made based on the operational stage (i.e., disconnected or connected):

— maintain a more favorable vessel heading (with response to the direction of waves) to reduce motions of the vessel or to better align with orientation of the TLF/bails. For a moored vessel, this can be quite helpful for regions have predominately unidirectional environments;

— optimize the mean applied tension(s) during the connected operational stage. For TBIRS and OWIRS using a “top tension only” method, doing so would also changes the mean overpull at the reference location near bottom of the intervention/workover system;

— optimize the mean space-out of the upper riser relative to the vessel obstructions (rotary, moon pool) to reduce fatigue damage accumulated by in critical components near the top;

— select fatigue-resistant components for the subsea well intervention system. As an example, connectors with low SAF values are preferred when selecting the main riser pipe for OWIRS or the landing string for TBIRS.;

— change the material (i.e. polymer, instead of steel) or inner diameter (ID) for any insert bushings installed in the rotary. This assumes that options are available or the project schedule allows for procurement to be completed.;

— For OWIRS only using a “top tension only” method, change to a “tension share” method;

— For OWIRS only using a “tension share” method, modify the tension-split between the top-drive compensation system and the riser tensioning system. This can be achieved without changing the mean overpull at the reference location near bottom of the intervention/workover system.;

— For OWIRS, increase the coverage or improve the efficiency of any VIV suppression devices installed along the length of the intervention/workover riser;

— For TBIRS, reduce flexjoint angles experienced by the marine drilling riser, such as by increasing the mean tension applied to it;

— For TBIRS, revisit design of the SSTTA and upper components for the specific MODU and the specific well/location. The intent is to reduce loads experienced by fatigue critical components in two regions: near the flexjoints (of the marine drilling riser) and elevations at which the riser or TLF is laterally braced to the surface vessel (e.g., at the drill floor). This can be accomplished by moving or reducing the outer diameter of fatigue critical components (e.g., connectors) in these regions, as well as by changing the placement of centralizers, if any;

— For TBIRS, change the material (i.e. polymer, instead of steel) of the RSM, assuming project schedule allows for procurement to be completed.

— For TBIRS, increase the coverage or improve the efficiency of any VIV suppression devices installed along the length of the marine drilling riser.

10.4.5 Determine Fatigue Loads Applied to the Subsea Well

Objective & Applicability

The objective of this assessment is to obtain fatigue loads transmitted to the subsea well by the intervention system. It is usually performed in conjunction with the Wave and VIV Fatigue Assessments. Results are used in a subsea well fatigue analysis, which typically models the well structure and soil interaction in more detail than the GRA. DNVGL-RP-E104 provides guidance on how to perform a subsea well fatigue assessment.

Fatigue loads transmitted to the subsea well should be determined for OWIRS and TBIRS, for connected operational stages.

General

The model used for a typical subsea well fatigue assessment usually starts at the wellhead connector and extends below the mudline, including well tubulars and soil-structure interaction. Loads applied to this model are bending moment, shear, and axial forces at the top of the high-pressure housing. For a fatigue assessment, a load range/number of cycles histogram is the simplest way to convey the cyclic loads to be applied on the well structure model.

Cyclic stresses caused by alternating bending loads are typically the only stress ranges considered in the well structure fatigue assessment. As such, only bending moment and shear force cyclic loads at the wellhead are relevant. Only mean values of axial load and pressure are usually considered in this evaluation.

One complication of using load range/number of cycles histogram for well structure loads is the coupling between the bending moment and the shear force. Usually, the bending moment is the most significant load for fatigue assessments of the well structure, so only bending moment histograms are needed. In this case, the shear force can be estimated from the bending moment itself.

Alternatively, time series of bending moment and shear force may be used as input for a well structure fatigue assessment, which allow for the direct consideration of both loads. The downside of this approach is that it requires the fatigue GRA to be performed using a time-domain model that is more computationally intensive.

Analysis Method

As for the intervention system itself, fatigue loads in the well structure are caused by wave and VIV effects. The same provisions considered for the intervention system fatigue assessment, as shown in sections 10.3.2 and 10.3.3, are applicable for determining fatigue loads on the well structure.

If the wave fatigue GRA is performed in time-domain, load range/number of cycles histogram may be obtained by using cycle counting techniques, such as the Rainflow algorithm. In frequency domain, discretization of the response spectrum may be performed to obtain load range/number of cycles histograms.

For VIV fatigue loads, as stated in section 10.3.3, standard software/tools used by the industry for VIV assessment are highly empirical. Their results are usually expressed in RMS values, assuming a Rayleigh narrow-banded distribution. As VIV frequency response also usually varies in time, these programs often output a dominant vibration frequency, or frequency time-sharing information, which may be used when determining the number of cycles of each bending moment RMS stress range bin.

Care should be taken when assessing directionality of the subsea well loads. Usually, environmental loads in GRA models are conservatively all applied in the same direction, which tends to result in a strong directional response. However, the vessel response may induce an out-of-plane bending, especially for ship-shaped vessels in shallow water. In extreme situations, the true bending moment load range experienced at the well structure may be underpredicted if only the resultant bending moment is considered (e.g., for a perfect circular motion resultant bending moment is constant, however, there is a bending moment load range in each direction). Even if bending moment histograms are obtained for perpendicular directions, the simultaneity information between them is lost. If this is a possible issue in an analysis, bending moment histograms for several directions may be obtained and used in the subsea well structure fatigue assessment. If time series are used as outputs, only results in two perpendicular directions are needed, as simultaneity is preserved.

Fatigue loads applied to the well structure should be obtained for both short-term and long-term environmental conditions. Short-term loads are usually considered to assess the actual estimated fatigue damage accrued during a specific operation, while long-term loads are considered for well structural design and verification. Specific time of the year conditions may be considered if operational scheduling is well defined. Short-term conditions load range/number of cycles histograms are typically associated with a specified condition duration, while long-term conditions histograms are usually expressed in a yearly or seasonal basis.

As stated in section 9.3, lower and upper bound soil properties should be considered in the well fatigue load determination. Usually soil is modelled by p-y springs. Softer springs, often a result of lower bound soil properties, tend to result in lower loads at the wellhead, but higher bending moment in the conductor-casing below the mudline, while stiffer springs usually lead to higher loads at the wellhead, but lower and shallower bending moment below the mudline. The p-y spring formulation used should be adequate for high frequency fatigue loads.

Typical Outputs

The primary outputs of the determination of fatigue loads applied to the subsea well are load range/number of cycles histograms for each environmental condition and assessment (wave or VIV) performed. Long-term environmental conditions may be grouped in a single histogram. Soil properties considered for each histogram shall be clearly stated. Figure 10-5 shows an example of a load range/number of cycles histogram:

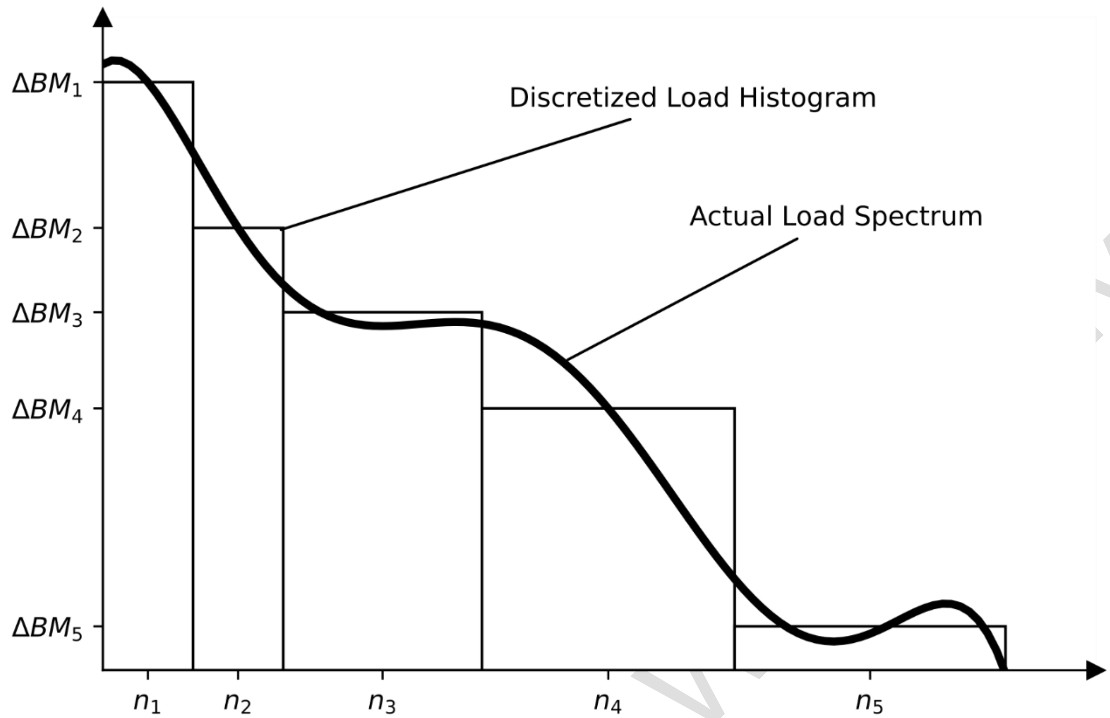


Figure 10-5 – Example of load range/number of cycles histogram

Load range/number of cycle histograms shall have the following information attached as a minimum:

— analysis type (wave or VIV);

— correspondent environmental condition, with its probability of occurrence or duration, if applicable;

— mean loads associated;

— soil properties (i.e. lower bound, “best estimate” or upper bound properties);

Alternatively, subsea well loads time histories may be the output from this analysis. In that case, each time history shall have the following information attached, in addition to the information listed for histograms:

— time series duration;

— associated time series (e.g., bending moment and shear force associations or multiple directions);

Possible Mitigations

Mitigations are not readily applicable for this assessment, as its objective is to provide information for a subsequent analysis. If the subsea well fatigue assessment performed with the provided loads result in insufficient fatigue load capacity for the well structure, most of the same mitigations shown in sections 10.3.2 and 10.3.3 also apply. Other possible mitigations include:

— for TBIRS, tethering the BOP to the seabed lowers well fatigue loading;

— reactive devices designed to lessen subsea wellhead loads;

— well reinforcement operations, like cement injection;

10.4.6 Stability Assessment of Free-Standing Well

Objective & Applicability

The objective for this assessment is to determine the stability of a free-standing well system once the intervention/workover riser is released, such as the POD value during connected operations. It is applicable when operations are performed from a DP rig/vessel or a moored rig/vessel, since as discussed in Sections 7.4.4 and 7.4.5, respectively, both types can experience loss of position events.

This type of assessment is applicable during the connected operational stage and therefore is likely applicable to (and should be included as part of) GRA for any subsea well intervention system.

General

This type of assessment primarily aims to check if the free-standing well system remains stable once the intervention/workover riser is released. This is done by displacing the vessel to a predetermined offset (e.g., POD at which the EQD must be finished) and then assessing the well's response following the riser's release. More specifically, the goal is to verify that the free-standing well "is stable", i.e., does not topple over.

A secondary objective might be to determine the largest vessel offset/position at which the free-standing well remains stable following release of the workover/intervention riser. In some situations, the vessel offset limit is established such that the post-disconnection wellhead/casing system angle (relative to vertical) is less than a given limit, thereby allowing for future connected operations on the well.

Analysis Method

The method/approach used for this assessment type may use elastic-plastic material properties, since loads experienced by the wellhead casing system could exceed yield. In addition, since it has a de-stabilizing effect, any plastic deformation experienced by soil strata due to vessel offset should be accounted for.

Initially, a single vessel offset/position relative to the well location is analyzed, which is the value at which the workover/intervention riser is presumed to be released. However, for a moored vessel, if a detailed mooring study is available as input (see Section 6.2), it is acceptable for the assessment to only evaluate the maximum transient excursion and its corresponding direction for the selected environment. For conservatism, a background current, if any, should be applied in the same direction as the vessel offset/position.

As for Loss of Position assessment, vessel offsets/positions (prior to disconnect) can be applied quasi-statically for most workover/intervention riser systems. However, for this assessment type, a dynamic analysis needs to be performed following release of the riser at the selected vessel offset/position, since response of the free-standing well (with soils) is not static.

Acceptance Criteria

The only acceptance criteria used for this assessment type is the limit for post-disconnection angle of the wellhead/casing system angle, which is typically expressed relative to vertical.

Typical Outputs

The primary output for this assessment should be one of the following:

— statement of whether the free-standing well is or is not stable following release of the riser (i.e., post-disconnect) at the pre-determined vessel offset.

— largest vessel offset/position at which the free-standing well is stable following release.

This primary output should be determined for each operation type (during the connected operational stage) and all applicable sets of operating parameters for each. Moreover, this output can be given for combinations of applied mean tension (or mean overpull) and background current.

Examples of supplementary outputs from this type of assessment:

— largest vessel offset/position at which any limit for post-disconnection wellhead/casing system angle (relative to vertical) is satisfied.

11 Documentation

11.1 General

This section describes documentation of global riser analyses (GRA) performed of a subsea well intervention system. Several topics that should be included for later reference by the end user are outlined. Moreover, guidance is given on means of incorporating recommended operability limits (from GRA) into operational guidelines. This section also gives guidelines on what GRA information is relevant to developing WSOGs, inspection criteria etc., inclusive of possible mitigations to improve operability limits, when applicable.

It is recommended that a document be established in the initial stages of the systems engineering process to outline any performance requirements and operability limits required of a particular system. This document can be used to evaluate the fit-for-service of components and establish performance requirements. The relevant parts of this initial document can be incorporated into the final the analysis basis document.

The global analysis shall reflect the requirements in this specification and end user, third party system integrator, or service provider’s requirements.

The GRA documentation shall include or reference the following items:

— summary, including concise table with design check results and illustrations in tables/figures;

— explanation of notations;

— analysis basis;

— results of analysis;

— conclusions and recommendations.

11.2 Definition of applicability

A definition of applicability should be provided to detail the scope of the GRA performed and the limitations for its use. The definition of applicability will vary depending on the scope of the GRA and the subsea well intervention system of interest. Several common details regarding applicability are given below; however, this listing is not exhaustive.

— pressure limits;

— temperature limits;

— specific to certain wells or fields;

— water depth(s);

— surface vessel;

— equipment and configuration;

— environmental limits.

11.3 Analysis Basis

11.3.1 General

The analysis basis for any work performed must be comprehensive enough that the analysis can be repeated by a third party exactly and all data should be referenced back to its original source. The following sections outline the likely content of the basis of analysis, however individual documents may differ on a case-by-case basis.

11.3.2 Inputs Used and Load Cases Evaluated

11.3.2.1 General

The following list outlines the likely input information to be included in the basis of analysis. This is not a fully prescriptive or comprehensive list as individual projects may have specific requirements. These items are further expanded in the following sections.

— General arrangement layout drawings showing component/assemblies key dimensions (Structural ODs, IDs, lengths, and weight),

— applicable codes, standards, and regulations;

— functional and operational requirements;

— external environmental data (including anticipated load spectrum);

— soil data

— surface vessel data (including applicable RAOs and anticipated watch circles for normal, extreme, and survival operating conditions). Input data regarding vessel drift off/drive off or mooring line failure should also be reported.

— load case definitions for all relevant (installation, retrieval, and hang-off), normal, extreme, and survival operating conditions for all anticipated modes of operation;

11.3.2.2 Structural Properties

The structural properties used should presented in the basis of analysis along with the methodology used to determine them or if applicable the reference for the source of the data. The structural properties should be summarized in a tabular format. It may also be useful to include any properties derived from these values i.e bending stiffness, torsional stiffness etc. This is particularly relevant if the derived value has been arrived at in a nonstandard way. For example, the bending stiffness of a protective cased wear joint consisting of half cylinders that have been bolted together. The following list outlines the minimum likely structural properties of each component required for the global riser analysis.

— Structural OD and ID

— Length

— Mass

— Flex joint rotational stiffnesses

11.3.2.3 Codes standards and Regulations

The codes and standards used in the course of the analysis should be defined along with justification for their use. Complex systems may require the use of several codes and standards. If this is the case how each of them is being used and the components/load cases they relate to should be outlined. Any regulations that apply to the analysis should also be reported.

11.3.2.4 Functional and Operational Requirements

The content of this section will vary greatly depending on the scope of the analysis, whether it is design of a new system or the use of an existing system at a new location. The following points outline likely contents for this section

— Water depths.

— Environmental limits i.e., 1 year return wave combined with 1 year return current, a justification should be provided for these requirements.

— Disconnect timing.

— System design, working and test pressures.

— System design and working temperatures.

— maximum set-down weights

— maximum landing and connection angles.

— Riser and or down line tensions/overpulls

— Tool/Tool string masses

This section should also include functional requirements needed to mitigate relevant failure modes, such as; emergency disconnect, deadman, autoshear.

11.3.2.5 External environmental data

All environmental data used in the course of the analysis should be presented. While it may be possible to only reference the source of the environmental data without providing the specific information used in the analysis this increases the probability of confusion. Therefore, it is best practice to include the specific environmental data used in the analysis. The following points outline likely data to be included in this section

— Time of year data covers, all year or seasonal

— Extreme Sea states and waves, e.g., 1 year to 100-year return

— Extreme current data e.g., 1 year to 100-year return

— Sea sate scatter diagrams, directional or omnidirectional

— Exceedance or occurrence based current profiles

— Extreme and Gust based wind data (likely only required for DP vessels)

11.3.2.6 Soil Data

All soil data used in the analysis should be outlined along with justification for any assumptions made in the process of incorporating the raw data into the model. While it may be possible to only reference the source of the data without providing the specific information used in the analysis this increases the probability of confusion depending on the analysis being carried out it may not be necessary to model soil explicitly if this is the case then the justification for this should be provided.

11.3.2.7 Surface Vessel Data

Surface vessel data should include all pertinent vessel dimensions, such as but not limited to, moonpool size and elevation, deck elevations, displacement and draft. Furthermore, the vessel data should include the RAOs used. It may be possible to simply reference this back to the original documentation. However best practice would be to include the data used in the analysis within the report. This can be achieved graphicly or in a table. If the RAO data has been manipulated to better fit the software being used then the manipulation along with the resulting RAOs should be included in the report, e.g., a change in phase from lag to lead. The reported RAO data should consist of the following for each vessel heading.

— Sign Convection
— Origin Point
— Phase Definition
— Phase angles
— Amplitude response

For moored vessels the pertinent information from the mooring analysis should be reported along with justification for its use, e.g., specific directions or sea states. Reporting of the mooring analysis should consist of environmental loads and their respective vessel offsets for intact and loss of anchor as applicable. Including transient vessel offsets for the loss of anchor condition. Depending on the analysis being carried out and the individual mooring study it may be necessary to report the individual components of vessel offset, e.g., low frequency response, along with the calculation used to determine the vessel offsets used in the analysis

For DP vessels drift/drive off may have been specified in one of two methods. A vessel position vs time for a given load condition or as vessel QTFs, these should be reported in tabular or graphical format. Along with an explanation of their use.

11.3.2.8 Load Case Definitions

Each load case considered in the analysis must be fully defined, and the load cases must be sufficient to cover all conditions outlined in the functional and operational requirements. The following outlines the likely requirements to define a load case;

— Verbal description e.g., Storm hang-off, running/retrieval
— Components considered
— System constrains
— Sea states
— Currents
— Pressures
— Temperatures
— Water depth
— Wind strengths (likely DP only)
— Design/Safety Factors

11.3.3 Analysis methods

11.3.3.1 General

The methods used in the course of the analysis should be provided along with reference to the original source if applicable. The following sections provide a general outline for the likely content required to fully document the analysis methods used. However, this may vary depending on the analysis being considered and therefore is not exhaustive.

11.3.3.2 Design Criteria

The design criteria should outline the failure modes being considered in the analysis; some likely modes are listed below.

— Excessive yielding
— Leakage

— Local buckling

— Fatigue

A brief description of the analysis being performed to assess each of these criteria should be provided along with any mitigations being implemented. The limitations of these mitigations should also be reported.

11.3.3.3 Environmental Methodology

The methodology being used for each load case to model sea states/waves, currents and wind should be reported. Depending on the analysis the content of this section may vary greatly. However, it will likely include the following;

— Description of the wave spectrum used along with the inputs into this spectrum and reference to the governing equations.

— Description of the of how the current profile is being modeled, accounting for directionality and current behavior above MSL.

— Description of how wind loading is being applied, accounting for directionality and any changes with elevation.

11.3.3.4 Load Case Methodology

For each load case outlined in the definitions, the report should include a description of how it is being assessed. This description should include the following.

— Governing considerations

— Loading being applied to the system

— Description of the method used to determine the loads on the system

— How acceptability will be determined

For similar load cases it may be possible to combine their methodologies into a single section rather than include significant repetition in the report. For example, assessment of a connected riser under normal and extreme vessel offsets may have the same methodology with the only differences being vessel offset and allowable loading

11.3.3.5 System Modelling Techniques

A brief description of the finite element techniques being used should be provided (time domain, frequency domain etc.), along with the specific software being used and its version number.

The soil model methodology being used should also be provided along with a justification for its selection and any limitations that may apply. It is likely that different methods for the soil model will be used for different load cases. Therefore, the applicable soil model for each load case should be reported. Furthermore, any assumptions used to generate this model should be outlined along with any inputs not previously discussed when describing the soil. This is likely limited to cementing and hole diameters. It can also be useful to provide graphical or tabular results of any soil calculation to aid third party review.

For each load case a general model description should be provided. As many load cases use the same model it is sufficient to outline which load cases each model description applies to. The model description should outline how the model has been built and any modeling simplifications made. Any modeling simplifications should be justified. Some likely content of the model description has been outlined below

— Component elevations (this is often best provided in a drawing)

— How tension has been applied to the system

— How flex joints have been modeled

— Where and how constraints have been applied

— How telescopic joints have been modeled

— How tension frames have been modelled, including the supported WL and CT equipment

A schematic drawing of the system can be used to clearly show how the system has been modeled including all elevations and constraints applied.

11.3.3.6 Hydrodynamic Inputs

For each component in the system that will be submerged its Hydrodynamic Coefficients should be provided along with appropriate drag and buoyancy properties. Furthermore, the methodology used to determine these properties should be referenced. All calculated inputs into the model should be provided, this is likely best done in tabular format.

This section should outline how properties of individual components have been determined along with a justification or a referenceable source for the property.

11.3.3.7 Equipment Structural Capacities

For each component in the system the methodology used to determine its structural capacity for each load case should be reported along with the applicable design/safety factors. Any input data required for the methodology used should also be reported (e.g. material grade, corrosion allowance). The source of all structural capacities should be provided. For capacities based on calculations preformed as part of the assessment it is enough to report the standards/codes used in the calculation. Data provided by component manufactures should be referenced to its source.

Any assumptions or conservatisms in the calculation of capacities should be outlined, justified and their implications discussed. For example, a connector capacity may only be available for design loads. However, this capacity has been used conservatively for survival events as it is not in a critical location within the system. The impact on the analysis is low, however if this connector becomes critical for a specific load case its capacity should be revised.

11.3.3.8 Allowable Deflections and Clearances

For each load case allowable deflections and clearances should be reported along with their source or governing calculation as well as any design/safety factor being applied. Some of the likely deflections and clearances are listed below, this is not exhaustive and specific assessments may have differing requirements

— Flex joint angles

— Moonpool clearances

— Clearances between down lines

— Disconnect / Connecting angle limits

— Clearance at the deck

— Stroke limits of tensioning systems

— Functional limitations (man riding limits etc)

11.3.3.9 Fatigue Data

The relevant fatigue properties of each load case and location being assessed should be reported. The specific fatigue properties to be reported will differ depending on the type of assessment. However, all fatigue data used in the analysis should be reported along with the corresponding source. Some of the likely fatigue properties to be reported are listed below

— S-N Curve

— SCF/SAF

— Reference OD and ID

— M-N Curve

Calculations carried out to determine any of these properties should also be outlined with the methodology referenced and any input data used in the calculation reported. Furthermore, If the fatigue properties are dependent on other loads such as tension or pressure in the component, then these limitations should be stated.

11.4 Results of Analysis and Reporting

11.4.1 General

The following sections provide guidance for reporting results of analysis carried out for intervention systems to aid in its integration into WSOGs. However due to the range of systems, vessels and environments that exist this is not comprehensive and best judgement should be exercised based on the guidance presented here.

11.4.2 Outputs Operability

Operating limitations shall be established for each mode of operation, for each loading condition and for each operating condition.

Operating limitations shall be presented in tabular and or graphic form.

The operating parameters by which the operating limits are defined shall be possible to monitor during operations. This will change depending on the vessel and specific operation. For example, the ability to monitor current is very vessel and operation dependent.

Operating limits shall be based on worst case combination of structural loads and environmental load effects.

In general, the validity of operating limits shall be specified in terms of:

— water depth range;

— surface vessel and surface vessel interfaces;

— surface vessel motions and station keeping method;

— subsea vessel interfaces;

— tension range and tensioning method;

— range of functional operating parameters;

— range of environmental operating parameters;

— equipment configuration and space-out;

— well locations within field of operation.

Assumptions and conditions inherent in the analysis method applicable for operating limits shall be clearly stated. For example, if the operating limits are based on structural analysis of a TBIRS only (i.e., limits to flex-joint angles), additional (separate) analyses of the marine riser, BOP, and wellhead system will be required to define the limitations for the total system (i.e., limits to vessel offset, etc.). When defining operating limits, it should be made clear what is limiting the envelope.

Operating limitations shall be used as input to operating procedures and vessel operating watch circle limits Operating limits diagrams should provide the operational parameters, which should be monitored and be kept within specified limits, for continued operation of the system. Operating limits and decision criteria should be based on analyses, suitable for that purpose.

All failure modes should be taken into account with the design factors relevant for the operating mode. In general, there will be more than one operating limits diagram. For example, the “normal connected, pressurized riser,” presumes that the system is operated within the limits defined by the relevant failure modes (represented by design equations) and with the safety margins given by the design factors for normal operating.

The final presented operating limits should be rationalized down to the fewest number of variables possible when defining operability and the most limiting factor must govern operability. For example, it is possible that normal strength limits for connected operations for a OWIRS system would allow for operations beyond the angle at which the EDP can disconnect. In this event the presented operating limits must be limited such that the EDP can always disconnect accounting for accidental vessel offsets. In this case if the EDP disconnect limits are presented separately to the final normal strength limits the possibility of confusion during operations occurs. Another common example seen would be for a DP vessel drift off in which the normal structural limits of the riser system are close to the accidental structural limits. In this case it is very unlikely that the system could disconnect before the accidental structural limits are exceeded in the event of a DP failure. Therefore, the final presented normal and extreme operating envelopes should be restricted such that the emergency disconnect can always be carried out before the accidental structural limits are exceeded.

Once operability has been reported comment should be made on the suitability of the determined limits in which to carry out the operation. This is often best addressed by providing the percentage of the year, or target time frame, in which operations could take place. For example; the percentage operability for the system is 50% however this increases to 85% between June and July. If any of the operability limits are determined to be overly restrictive or the percentage operability is low then this should be highlighted and possible mitigations suggested. Determining what is considered restrictive or low in this instance will

11.4.3 Operability Envelopes for Different Intervention/Workover Riser Systems

Operability envelopes can be given in terms of:

— sea state sensitive limits (for OWIRS, TBIRS, and RSWIS);

— heave sensitive limits (for OWIRS, TBIRS, SPWIS, and RSWIS);

— current sensitive limits (for OWIRS, TBIRS, SPWIS, and RSWIS);

— period sensitive limits (for OWIRS, TBIRS);

— angle limits (for TBIRS, where flex joint angle is likely of importance).

While most operability analysis can be readily expressed based on sea state, current or heave sensitive limits, there might be conditions in which system specific approaches may need to be considered for individual systems.

- For example, TBIRS often have a stuck pipe condition where large overpulls are required to retrieve a string, while this condition is retrieval it is likely critical when compared to other retrieval conditions. Therefore, stuck pipe conditions are often best provided with their own operating envelope.
- As the marine riser will be present for running and retrieval of TBIRS, vessel offset and/or flexjoint angle will likely be a major component of loading in the system and therefore operating envelopes will likely be very similar in design to those presented for connected operations. This is compared to OWIRS in which vessel offset has no direct impact on system loads until land out.
- TBIRS have a range of disconnect conditions in the event of a storm or an emergency disconnect two of which are discussed here:

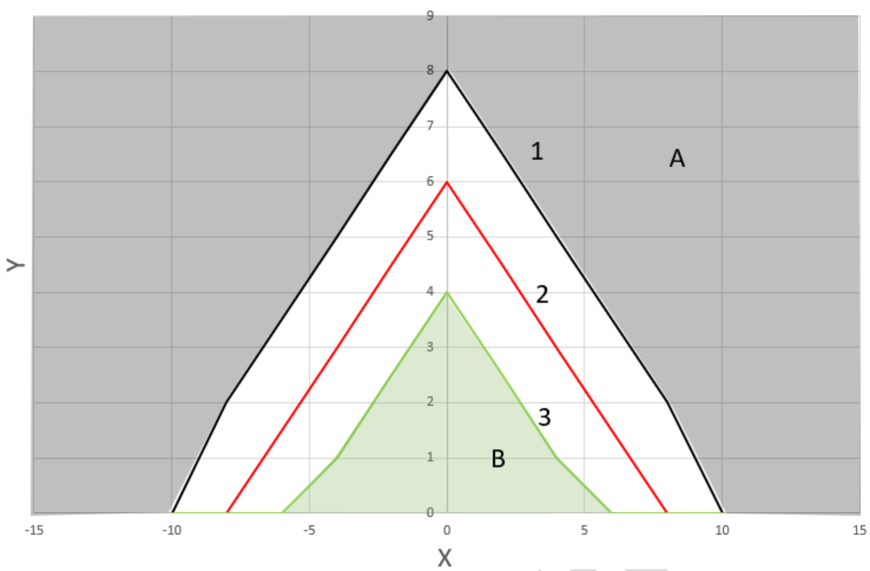
- The first in which the latch is disconnected, or the string is sheared by the BOP and pulled above the lower flex joint with the marine riser remaining connected.
- The second condition is the same as the first however the marine riser will also disconnect.

Each of these disconnect conditions will need a separate operating limit. For conditions in which the marine riser remains connected operating limits are likely best presented in the same format as the connected operations. Once the marine riser has been disconnected at the LMRP vessel offset is no longer a concern. When vessel offset is not a concern and system response is highly dependent on wave period then operability is best presented as shown in figure 11-1.

- For TBIRS, it is important to remember that the intervention system limits do not represent the full limits of the system. The marine riser and wellhead system will have its own limitations and while this is not within the scope of the analysis of the intervention system it should be made clear in the reporting that these other limitations exist and must be accounted for during operations. It is possible to perform analysis to cover the entire system in a single report easing understanding for operations however that would require the combination of a range of standards and is beyond the scope of this document.
- SPWIS are generally most sensitive to current which can cause contact between downlines. Furthermore, SPWIS often use “lazy s” arrangements to compensate for vessel heave on down lines, which are held in place with a clump weight. High current profiles can deflect the clump weight and flatten the “lazy S”, reducing allowable vessel heave and possibly overloading any break away connectors.
- SPWIS/RSWIS often have separately run and retrieved down lines (for e.g. umbilicals connected to mudline control systems) and equipment packages that are run separately, each of which should be treated as a separate operation to be governed by its own operating limits. Additionally, each of these individual operations may have differing limits depending on the sage of running/retrieval. In this case separate operating envelopes will be required for each running operation that the system requires. This can result in significant numbers of operating envelopes and changing between them frequently. Therefore, it is recommended that each individual operation during running/retrieval uses a rationalized operating envelope based on the worst-case stage in the operation. This reduces the complexity of the reporting and eases the understanding for operations. However certain stages of the operation may be excessively limiting, for example in the splash zone, in this case the critical stage should have separate operating envelopes. It should also be noted there is often additional limits limit placed on the vessel during running due to limits on the equipment make up or ROV capability. While the analysis does not necessarily need to account for these limits and they can be imposed by the operator separately, if they are known they should be incorporated into the reporting. The layout of operating envelopes for running and retrieval are likely similar to those for connected operations and the same considerations listed above should be taken into account. However, for running and retrieval sea state and current are likely to become the critical considerations.
- For SPWIS/RSWIS which have been abandoned wet stored either due to an emergency disconnect or a storm condition the limitation envelopes are likely best presented as a table listing maximum current velocities and sea states. As it is not possible to retrieve the system during a storm condition the limitations should be based on return current and waves, (for e.g., 1-year storm, 100-year storm). This is likely not a concern in deep water; however, in shallow water, wave loading can act directly on the structure.

11.4.4 Typical Operability Envelopes for Sea State Sensitive Limits

A typical operating envelope diagram for a connected subsea well intervention system for OWIRS/TBIRS is shown in Figure 11-1 and for RSWIS is shown in Figure 11-2 This shows the range of acceptable vessel offsets for a set of operating conditions. Values below the curve represent safe operation; i.e., the design factors are met. Outside the curve, the load effect acting on the riser may exceed limits on strength and stroke clearance and consideration of remedial action or disconnect operation is necessary. The curve provides a range of significant wave heights, and vessel-offset conditions. Absolute maximum values for other loading considerations have also been provided, including vessel heave, working pressure and tidal amplitude. This design of envelope is best used when vessel offsets and sea state are the governing loads for the operating condition being reported.



Location: Field ....
Vessel: Vessel name ....
Riser: Designation ....
Mode: OWIRS/TBIRS
Top configuration: Tension frame.
Top tension:
Motion compensator: ..kN (lbf)
Tension ring: ....kN (lbf)
Vessel Heave Range limit:.................ft(m)
Bottom tension:
Bottom of EDP/Latch: ...kN (lbf)
Pressure: .... MPa (psi)
Fluid density: .... s.g.
Wave direction: Head ....
T_p range: 90 % confidence interval
Current: .... year return period
Current direction: Head ....
Wellhead inclination: .... °

Key

X vessel static offset, L_{SO}, from wellhead extension, measured as percentage of water depth, positive in direction of current

Y significant wave height, H_S

1 strength limit: survival

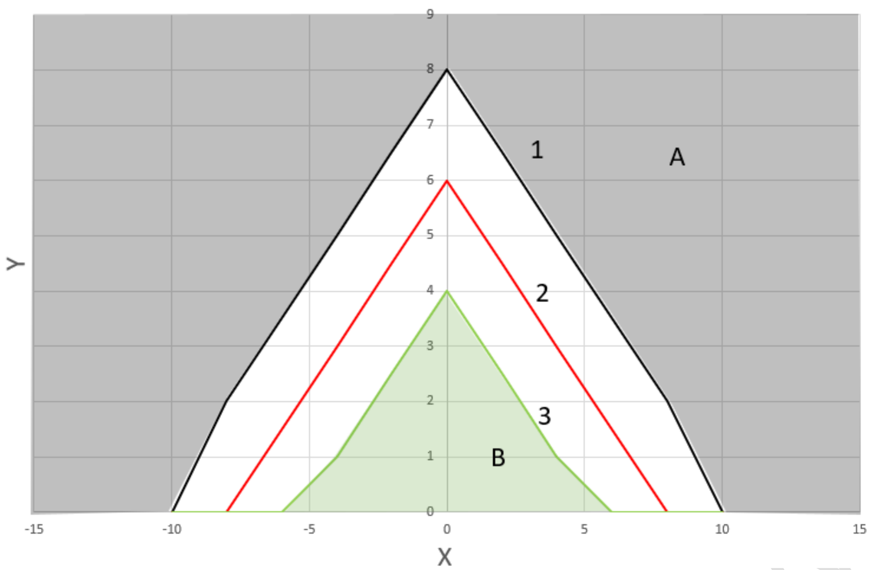
2 strength limit: extreme

3 strength limit: normal

A Unsafe operating area.

B Safe operating area.

Figure 11-1—Typical Operating Envelope for Sea State sensitive limits — OWIRS/TBIRS



Location: Field ....
Vessel: Vessel name ....
Riser: Designation ....
Top tension:
Top of Line X ....kN (lbf)
Bottom tension:
Bottom of Line X: ....kN (lbf)
Pressure: .... MPa (psi)
Fluid density: .... s.g.
Wave direction: Head ....
T_p range: 90 % confidence interval
Current: .... year return period
Current direction: Head ....
Wellhead inclination: .... °

Key

X vessel static offset, L_{SO}, from wellhead extension, measured as percentage of water depth, positive in direction of current

Y significant wave height, H_S

1 strength limit: survival

2 strength limit: extreme

3 strength limit: normal

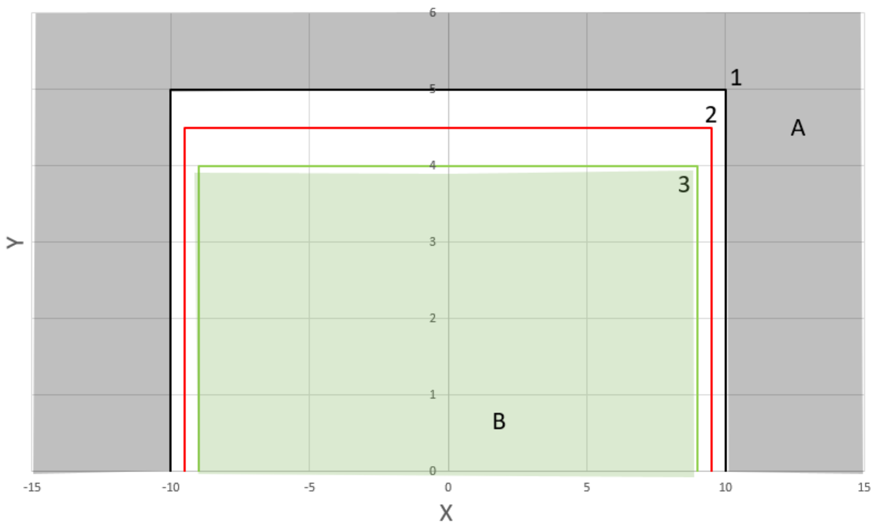
A Unsafe operating area.

B Safe operating area.

Figure 11-2—Typical Operating Envelope for Sea state sensitive limits— RSWIS

11.4.5 Typical Operability Envelopes for Heave/Current Sensitive Limits

The envelopes shown in Figure 11-3 (for OWIRS and TBIRS) and Figure 11-4 (for RSWIS) are similar to Figure 11-1, however, these envelopes place emphasis on vessel heave (or) current rather than placing the emphasis on sea state.



Location: Field ....
Vessel: Vessel name ....
Riser: Designation ....
Mode: OWIRS/TBIRS
Top configuration: Tension frame.
Top tension:
Motion compensator: ..kN (lbf)
Tension ring: ....kN (lbf)
Bottom tension:
Bottom of EDP/Latch: ...kN (lbf)
Pressure: .... MPa (psi)
Fluid density: .... s.g.
Wave direction: Head ....
Maximum Sea State:........................ft(m)
T_p range: 90 % confidence interval
Current: .... year return period
Current direction: Head ....
Wellhead inclination: .... °

Key

X vessel static offset, L_{SO}, from wellhead extension, measured as percentage of water depth, positive in direction of current

Y Vessel Heave Range

1 Heave limit: survival

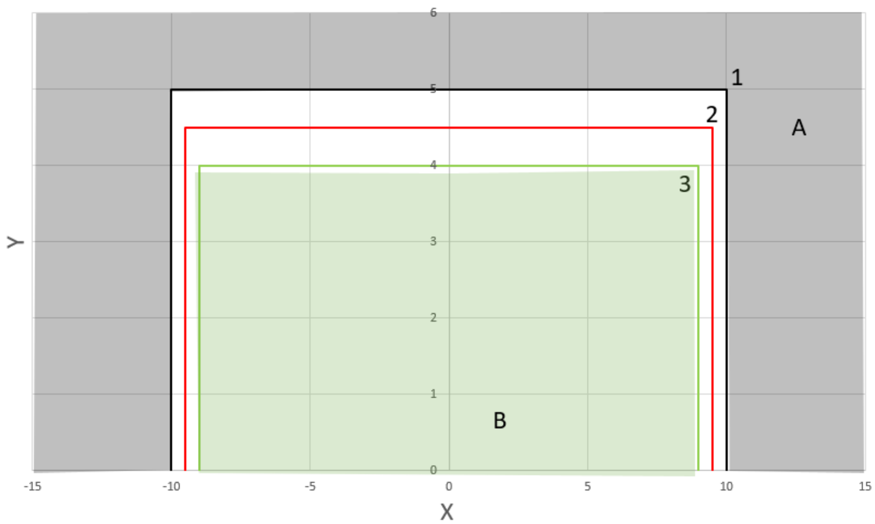
2 Heave limit: extreme

3 Heave limit: normal

A Unsafe operating area.

B Safe operating area.

Figure 11-3—Typical Operating Envelope for Heave sensitive limits—OWIRS/TBIRS



Location: Field ....
Vessel: Vessel name ....
Riser: Designation ....
Mode: Subsea Pumping
Top tension:
Top of Line X
..........................kN (lbf)
Maximum Sea State:........................ft(m)
Bottom tension:
Bottom of Line X: ....kN (lbf)
Pressure: .... MPa (psi)
Fluid density: .... s.g.
Wave direction: Head ....
T_p range: 90 % confidence interval
Current: .... year return period
Current direction: Head ....
Wellhead inclination: .... °

Key

X vessel static offset, L_{SO}, from wellhead extension, measured as percentage of water depth, positive in direction of current

Y Vessel Heave Range (OR) Current Velocity at Xft (Xm) below MSL as measured by ADCP

1 Heave limit: survival

2 Heave limit: extreme

3 Heave limit: normal

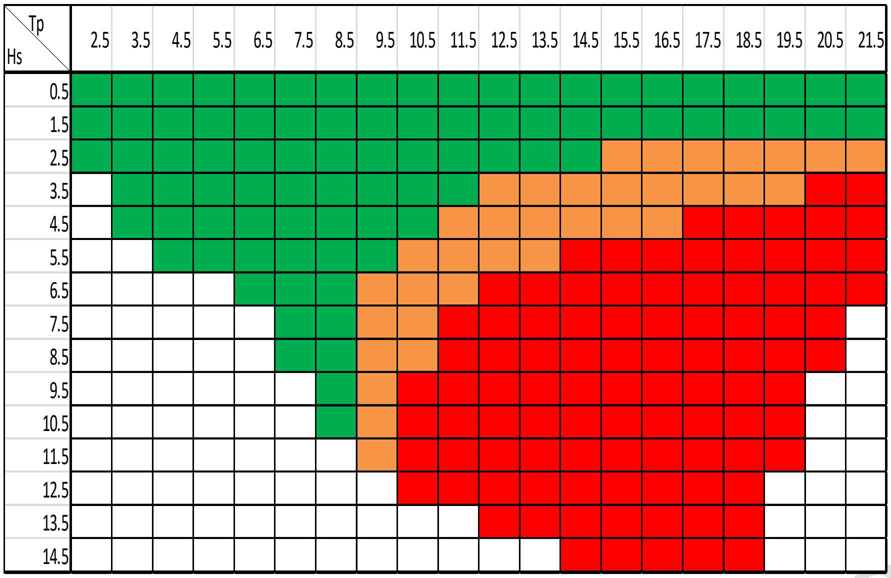
A Unsafe operating area.

B Safe operating area.

Figure 11-4—Typical Operating Envelope for Heave/Current sensitive limits— SPWIS/RSWIS

11.4.6 Typical Operability Envelopes for Period Sensitive Limits

Presenting the limits by wave height only will yield very limited operating envelopes for operating limits that are sensitive to wave period (e.g., stroke-out, and structural loads). As the wave period information is lost and the wave height where the component utilization (or stroke) is acceptable for all wave periods is the limiting condition. An example of this is shown in Figure 13-5, where is no period information is offered the allowable normal operating sea state would be 1.5 m. But if period information is offered some sea states up to 10.5m can be operated in. This type of envelope is best used when vessel offset is not a critical factor in operability or when specific vessel maximum offsets are an input to the analysis (moored vessels).



Location: Field ....
Vessel: Vessel name ....
Riser: Designation ....
Mode: OWIRS/TBIRS
Top configuration: Tension frame.
Top tension:
Motion compensator: ....kN (lbf)
Tension ring: ....kN (lbf)
Maximum Vessel offset..................%
Bottom tension:
Bottom of EDP/Latch: .kN (lbf)
Pressure: .... MPa (psi)
Fluid density: .... s.g.
Wave direction: Head ....
T_p range: 90 % confidence interval
Current: ...... year return period
Current direction: Head ....
Wellhead inclination: .... °

Key

X Sea State Period (Tp (s))

Y significant wave height, H_S

1 strength limit: survival

2 strength limit: extreme

3 strength limit: normal

Figure 11-5—Typical Operating Envelope for Period Sensitive Limits—OWIRS/TBIRS

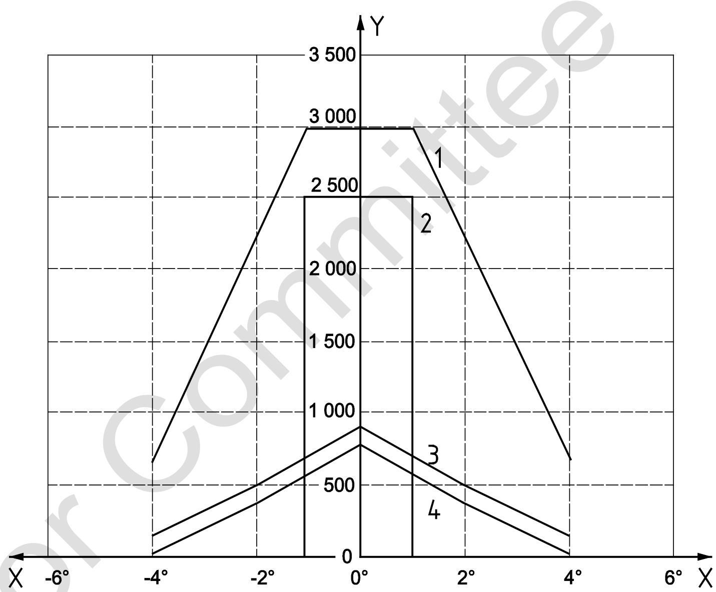
11.4.7 Typical Operability Envelopes Defined by Angle Limits

For TBIRS operations it may be possible to define operability based on the marine risers upper and lower flex joint angles. This is more common for running and retrieval operations but is a possibility for connected operations. Operating limits set by flex joint angles can be seen in Table 11-6 and Figure 11-7.

Table 11-6— Example Operating Envelope Table Defined by Angle Limits— TBIRS

Load Condition	Marine riser flex-joint angle Limits (degrees)	
	Lower	Upper
Normal		
Extreme		
Over-pull to retrieve stuck tubing		

a) The angle should allow for passage of tubing hanger, tubing hanger running tool, subsea test tree, retainer valve, lubricator valve, and deployment string. It is the angle value that should be maintained and not exceeded just prior to running in/pulling out with the tool string. During passage of large diameter/stiff sections, the actual angle is expected to be reduced somewhat.



Location:
Field.........................

Vessel:
Vessel name ....

Riser:
Designation ....

Mode:
TBIRS

Marine riser ID:
.... m (in)

BOP ID:
.... m (in)

Wellhead inclination:
...............................°

Key

X lower flex joint angle q_F, expressed in degrees

Y C/WO riser effective tension, T_e, relative to tubing hanger, expressed in kilonewtons

1. over-pull to release stuck tubing
2. running/retrieval
3. subsea shut-in
4. normal operation

Figure 11-7—Typical Operating Envelope Defined by Angle Limits — TBIRS

11.4.8 Loss of Position (or Weak Point) Assessment

The weak point assessment will vary depending on the type of operation in question however in all cases the aim it to demonstrate that the systems weak point is above the critical barriers.

There are two likely overload conditions for most intervention systems, tension/compression and bending. For each weak point assessment, it should be determined which of the overload conditions can occur together and or singularly. For example, for a DP vessel tension overload can occur with and without bending, due to either a compensator lock-up due to failure or a vessel drift off in which the compensator strokes out. Weak point assessment should be presented for each of the possible overload conditions combined with the best- and worst-case nominal loads. For example, for a tension overload due to compensator lock up the system should be analyzed with zero bending and minimum pressure as well as the worst case bending, and pressure configuration seen during operations.

Reporting for each weak point assessment will likely be very similar. The load condition analyzed the reasoning for its selection should be reported and, at a minimum the structural utilization factors at the critical location above and below the barriers as well as the percentage difference between these. It may also be useful to include the structural utilization off all components in the system. How the failure at a weak point above the barriers reduces loading on the system should also be described. If the weak point is determined to be below the barriers this should be highlighted, and possible mitigations discussed. An example results table for weak point assessment can be seen below along with an example results figure.

Table 11-8 Example Weak Point Assessment Results Table for Bending overload

Component	Pressure	Tension	Bending Utilization
X	….	….	….
Y	…		…
Z	….	….	….

Annex A
(Informative)
Mitigations and Improved Operability

A.1. General

This annex provides guidelines for each type of system with relation to mitigations for conditions in order to improve the operability of the equipment.

For each one of the system exist two conditions, one is the planned EQD, the other is the unplanned EQD. The watch circle is driven by the timing to complete the planned EQD and the vessel drift rate as predicted by the DPO (adjusted for weather/current conditions). The planned EQD does not sever a weak link and assumes there is time to initiate the sequence prior to exceeding the limitations defined in the watch circle. The unplanned EQD is what occurs when there is a drive off or no one notices the loss of position. In this event, there is no time to intervene and/or it happens without the personnel knowing that intervention is required. When the vessel moves past the watch circle, weak points in the system fail. Engineered weak links are a way at preventing other weak points in the system from being damaged.

Subsea well intervention systems may include a purpose-built “weak link” (or safety joint) component as a mitigation for loads induced by this failure to release scenario. This component is intended to fail/rupture at a pre-determined load (or release at a pre-determined angle), thereby limiting the amount of load experienced by the subsea well and therefore maintaining its integrity. Site-specific GRA should demonstrate that the weak link component accomplishes this purpose, i.e., fails as intended (i.e., prior to other system components), based on details for each location/well (e.g., water depth, soil properties). Design of a weak link component is as per 17G.

A.2. Open Water Intervention Riser System

Running and retrieval - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the running/retrieval operational stage:

— find means of restraining motions of the stack when at the first hang-off depths;
— running two or more previously made-up riser joints to get the subsea package through the splash zone as quickly as possible;
— drift (or transit) a DP surface vessel to reduce drag loading experienced during strong currents.

Landing - A possible mitigation for landing operations during strong currents is to offset the surface vessel upstream of the dominant current direction. Doing so can reduce the relative angle between the deployed riser and the wellhead, thereby assisting in connection.

Connected - The following are examples of possible mitigations to consider as means of improving operability limits during connected operations:

— optimize the mean applied tension(s);
— optimize the mean position (also referred to as or mean offset) of the vessel, especially during strong currents;
— optimize the vessel trim, especially during strong currents.

Planned disconnect - A possible mitigation for a planned disconnect during strong current is to offset the surface vessel upstream of the dominant current direction. Doing so can reduce the maximum bending moment at the WCP connector, thereby assisting in release.

Emergency Disconnect - The operability of the OWIRS and the size of the watch circle is heavily dependent on the timing of the EQD sequence. The shorter the sequence, the bigger the watch circle. It is difficult to mitigate unfavorable responses for emergency disconnect at the time it is required; instead, any mitigation options must be investigated and implemented beforehand. A few mitigation options for an open-water intervention system exist when the "tension share" method is used (see appendix A). These include maximizing the amount of tension supplied by the riser tensioning system or optimizing settings within its anti-recoil control system for this application.

Storm Hang-off - The following are examples of possible mitigations to consider as means of improving operability limits during storm hang-off operations:

- drift (or transit) a DP surface vessel to reduce drag loading experienced during strong currents;
- lower the traveling block as close to the drill floor elevation as possible to reduce the possibility of interference with vessel obstructions;
- use of tensioned guide wires to restrict lateral displacements and reduce relative top angles (typically only applicable in shallow water);
- Hang off the riser in the elevators as opposed to setting the slips, if possible;
- If hanging off in the elevators is not possible, consider developing a thick- walled storm hang-off joint to set in the slips in place of a standard riser joint.

A.3. Through-BOP Intervention Riser System

General- If operability limits for TBIRS operations are too restrictive, the following are examples of possible mitigations to consider for reducing mean flexjoint angles:

- minimize the number of buoyed joints used within stack-up of the marine drilling riser;
- increase the mean tension applied to the marine drilling riser;
- optimize the mean position (also referred to as or mean offset) of the vessel, especially during strong currents;
- optimize the vessel trim, especially during strong currents.

Running and retrieval - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the running/retrieval operational stage:

- reduce the diameter and/or length of the component;
- reduce mean flexjoint angles of the marine drilling riser, utilisation of real time monitoring (e.g., riser deflections or through depth ADCP current monitoring);
- optimize the stack-up length such that the SSTTA (or other large/stiff members within the bottom assembly) is not across a flexjoint elevation when top of the deployed riser is supported by the slips.

Landing out - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the landing out operational stage with a TBIRS:

- reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1;
- maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel.

Connected - The following are examples of possible mitigations to consider as means of improving operability limits during connected operations:

- reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1;
- re-visit design of TBIRS components. Generally, each SSTTA is optimized for a specific combination of THS, subsea tree, and BOP Stack, meaning it is intended for use at a specific well from a specific

vessel. Moreover, upper components of the TBIRS (e.g., RSM) are optimized to the UFJ elevation for a specific vessel.

Planned disconnect – The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the planned disconnect operational stage with a TBIRS:

— reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1;
— maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel.

Emergency disconnect - It is difficult to mitigate unfavorable responses for emergency disconnect at the time it is required; instead, any mitigation options must be investigated and implemented beforehand. As further discussed in appendix A, this is exacerbated by systems used to support TBIRS typically not including functionality to control recoil. TBIRS systems have two recoil systems to consider – the marine riser and the TBIRS. The marine riser recoil after the EDS will dictate the watch circle, however, this EDS sequence may change when it's in Upper Completion Mode. This change in sequence and/or timing of the sequence needs to be accounted for in the watch circles

Storm Hang-off - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the storm hang-off operational stage with a TBIRS:

— reduce mean flexjoint angles of the marine drilling riser, as discussed further in Section 5.2.1;
— optimize mean space-out of the upper riser such that the RSM (or other large/stiff members) is not across the UFJ elevation;
— maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Hang off the riser in the elevators as opposed to setting the slips, if possible;
— If hanging off in the elevators is not possible, consider developing an application specific storm hang-off joint to set in the slips in place of a standard riser joint.

A.4. Subsea Pumping Well Intervention Systems

General- If operability limits for the Subsea Pumping Well Intervention system are too restrictive, the following are examples of possible mitigations to consider:

— Increase the mean tension in the line by adding additional weight (should be checked in the GRA)
— Optimize the mean position (also referred to as or mean offset) of the vessel, especially during strong currents;
— Optimize the vessel trim, especially during strong currents.

Running and Retrieval - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the running/retrieval operational stage:

— Alter the vessel heading so that the deployment/recovery occurs on the leeward side of the vessel
— Increase the weight of the clump weight and/or make the clump weight subsea retrievable
— Reduce the outside diameter of the system to decrease drag (remove buoyancy modules for example)
— Drift the vessel during deployment in strong currents

Landing Out - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for landing out the Subsea Pumping Well Intervention System:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel.

— Have two ROVs available to assist with the landing operation
— Use ROV-installed buoyancy modules

Connected - The following are examples of possible mitigations to consider as means of improving operability limits during connected operations:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Re-visit watch circle calculations every shift or as weather/current patterns change
— Adjust tension according to the weather/current conditions;
— Monitor the main pumping line for fatigue (either by sensor or calculation) and move the main pumping line in or out every few hours to avoid creating a fatigue hot spot.

Planned Disconnect – The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the planned disconnect of the Subsea Pumping Well Intervention System:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Alter the vessel heading so that the deployment/recovery occurs on the leeward side of the vessel;
— Have two ROVs available to assist with the landing operation;
— Adjust tension to allow proper set down weight prior to disconnect.

Emergency Disconnect - It is difficult to mitigate unfavorable responses for emergency disconnect at the time it is required; instead, any mitigation options must be investigated and implemented beforehand. For Subsea Pumping Well Intervention Systems deployed from a DP vessel, the watch circle should be dictated by the time required to complete the Planned Emergency Disconnect sequence. To increase the size of the watch circle, the mean time from initiation to disconnect must be shortened.

A.5. Riserless Subsea Well Interventions Systems

General- If operability limits for the Riserless Subsea Well Intervention System are too restrictive, the following are examples of possible mitigations to consider:

— Optimize the mean position (also referred to as or mean offset) of the vessel, especially during strong currents;
— Optimize the vessel trim, especially during strong currents.

Running and Retrieval - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the running/retrieval operational stage:

— A DP vessel with a cursor system can be used to aid in deployment/recovery through the splash zone;
— Alter the vessel heading so that the deployment/recovery occurs on the leeward side of the vessel or through the moonpool where the vessel achieves the least amount of heave;
— Drift the vessel during deployment in strong currents.

Landing Out - The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for landing out the Subsea Pumping Well Intervention System:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Have two ROVs available to assist with the landing operation;
— Use ROV to achieve the required headings prior to landout.

Connected - The following are examples of possible mitigations to consider as means of improving operability limits during connected operations:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Re-visit watch circle calculations every shift or as weather/current patterns change;
— Adjust tension according to the weather/current conditions;
— Monitor the downlines for fatigue (either by sensor or calculation) and move the lines in or out every few hours to avoid creating a fatigue hot spot.

Planned Disconnect – The following are examples of possible mitigations to consider as means of improving operability limits (e.g., weather windows) for the planned disconnect of the Subsea Pumping Well Intervention System:

— Maintain a more favorable vessel heading (relative to the direction of waves) to reduce pitch/roll motions of the surface vessel;
— Alter the vessel heading so that the deployment/recovery occurs on the leeward side of the vessel;
— Have two ROVs available to assist with the landing operation;
— Adjust tension to allow proper set down weight on downlines prior to disconnect.

Emergency Disconnect - It is difficult to mitigate unfavorable responses for emergency disconnect at the time it is required; instead, any mitigation options must be investigated and implemented beforehand. For Subsea Riserless Well Intervention Systems deployed from a DP vessel, the watch circle should be dictated by the time required to complete the Planned Emergency Disconnect sequence. To increase the size of the watch circle, the mean time from initiation to disconnect must be shortened.