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Petroleum and natural gas industries — Drilling and production equipment —

Part 1: Design and operation of marine drilling riser equipment

Industries du pétrole et du gaz naturel — Équipement de forage et de production —

Partie 1: Conception et exploitation des tubes prolongateurs pour les forages en mer

Reference number
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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO 13624-1 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13624 consists of the following parts, under the general title *Petroleum and natural gas industries — Drilling and production equipment*:

— *Part 1: Design and operation of marine drilling riser equipment*

— *Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report* (Technical Report)

Introduction

Since the first edition of API RP 16Q was first issued in November, 1993, hydrocarbon exploration in deep-water environments has increased significantly. As a consequence of this, the need has been identified to update that code of practice to address the issues of deep-water drilling risers in sufficient detail to supplement API RP 16Q for drilling in water depths up to 3 048 m (10 000 ft).

Under the auspices of the DeepStar programme, substantial work was commissioned during 1999 and 2000 by the DeepStar Drilling Committee 4502 and lead to the development by several contractors of *Deep-water Drilling Riser Methodologies, Operations, and Integrity Guidelines* in February 2001. These guidelines were intended to supplement the existing text of API RP 16Q (1993). In a subsequent Joint Industry Project funded by DeepStar 5500 and in collaboration with API, these guidelines were supplemented with other identified revisions to produce a draft update second edition of API RP 16Q and an associated API Technical Report 16TR1, designed to be read in conjunction with the revised API RP 16Q and to supplement its contents, by providing additional guidance on recommended riser analysis methodologies through detailed explanations, step-by-step procedures and worked examples.

API publications can be used by anyone desiring to do so. Every effort has been made to assure the accuracy and reliability of the data contained in them. It is the responsibility of the users of this part of ISO 13624 to ensure that its use does not result in any loss or damage or in the violation of any federal, state, or municipal regulation.

Annex A through Annex E are informative.

Petroleum and natural gas industries — Drilling and production equipment —

Part 1:
Design and operation of marine drilling riser equipment

1 Scope

This part of ISO 13624 pertains to the design, selection, operation and maintenance of marine riser systems for floating drilling operations. Its purpose is to serve as a reference for designers, for those who select system components, and for those who use and maintain this equipment. It relies on basic engineering principles and the accumulated experience of offshore operators, contractors, and manufacturers.

NOTE Technology is advancing in this field and improved methods and equipment are continually evolving. Each owner and operator is encouraged to observe the recommendations outlined herein and to supplement them with other proven technology that can result in more cost effective, safer, and/or more reliable performance.

The marine drilling riser is best viewed as a system. It is necessary that designers, contractors, and operators realize that the individual components are recommended and selected in a manner suited to the overall performance of that system. For the purposes of this part of ISO 13624, a marine drilling riser system includes the tensioner system and all equipment between the top connection of the upper flex/ball joint and the bottom of wellhead conductor outer casing. It specifically excludes the diverter. Also, the applicability of this part of ISO 13624 is limited to operations with a subsea BOP stack deployed at the seafloor.

Clauses 1 through 7 of this part of ISO 13624 are directly applicable to most floating drilling operations. Special situations are addressed in 8.1 and 8.4 dealing with deep-water drilling and collapse. The special considerations required for guidelineless drilling are addressed in 8.2. In addition, 8.3 and 8.5 address operations in cold-weather conditions and H_2S considerations.

It is important that all riser primary-load-path components addressed in this part of ISO 13624 be consistent with the load classifications specified in ISO 13625.

2 Normative references

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

ISO 13625, *Petroleum and natural gas industries — Drilling and production equipment — Marine drilling riser couplings*

BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*

3 Terms, definitions, and abbreviations

3.1 Terms and definitions

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

3.1.1
accumulator
⟨BOP⟩ pressure vessel charged with gas (nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers

3.1.2
accumulator
⟨riser tensioner⟩ pressure vessel charged with gas (generally nitrogen) over liquid that is pressurized on the gas side from the tensioner high-pressure gas supply bottles and supplies high-pressure hydraulic fluid to energize the riser tensioner cylinder

3.1.3
actuator
mechanism for the remote or automatic operation of a valve or choke

3.1.4
air-can buoyancy
tension applied to the riser string by the net buoyancy of an air chamber created by a closed top, open-bottom cylinder forming an air-filled annulus around the outside of the riser pipe

3.1.5
annulus
space between two pipes when one pipe is inside the other

3.1.6
apparent weight
effective weight
submerged weight
weight minus buoyancy

NOTE Apparent weight is commonly referred to as weight in water, wet weight, submerged weight, or effective weight.

3.1.7
auxiliary line
conduit (excluding choke-and-kill lines) attached to the outside of the riser main tube

EXAMPLE Hydraulic supply line, buoyancy-control line, mud-boost line.

3.1.8
back pressure
pressure resulting from restriction of fluid flow downstream

3.1.9
ball joint
ball-and-socket assembly that has a central through-passage equal to or greater than the riser internal diameter and that may be positioned in the riser string to reduce local bending stresses

3.1.10
blowout
uncontrolled flow of well fluids from the wellbore

3.1.11
blowout preventer
BOP
device attached immediately above the casing, which can be closed to shut in the well

3.1.12
blowout preventer
⟨annular type⟩ remotely controlled device which can form a seal in the annular space around any object in the wellbore or upon itself

NOTE Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

3.1.13
BOP stack
assembly of well-control equipment, including BOPs, spools, valves, hydraulic connectors and nipples, that connects to the subsea wellhead

NOTE Common usage of this term sometimes includes the lower marine riser package (LMRP).

3.1.14
bottom-hole assembly
BHA
assembly composed of the bit, stabilizers, reamers, drill collars, various types of subs, etc., that is connected to the bottom of a string of drillpipe

3.1.15
box
female member of a riser coupling, C&K line stab assembly or auxiliary line stab assembly

3.1.16
breech-block coupling
coupling that is engaged by rotation of one member into an interlock with another member by an angle of rotation of 90 ° or less

3.1.17
buoyancy-control line
auxiliary line dedicated to controlling, charging or discharging air-can buoyancy chambers

3.1.18
buoyancy equipment
devices added to riser joints to reduce their apparent weight, thereby reducing riser top tension requirements

NOTE The devices normally used for risers take the form of syntactic foam modules or open-bottom air chambers.

3.1.19
choke-and-kill line
C&K line
kill line
external conduit arranged laterally along the riser pipe and used for circulation of fluids into and out of the wellbore to control well pressure

3.1.20
control pod
assembly of subsea valves and regulators that, when activated from the surface, directs hydraulic fluid through special porting to operate BOP equipment

3.1.21
coupling
mechanical means for joining two sections of riser pipe in an end-to-end engagement

3.1.22
diverter
device attached to the wellhead or marine riser to close the vertical flow path and direct well flow away from the drill-floor and rig

3.1.23
dog-type coupling
coupling having wedges (dogs) that are mechanically driven between the box and pin for engagement

3.1.24
drape hose
flexible line connecting a choke, kill or auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure

NOTE A U-shaped bend or "drape" in this line allows for relative movement between the inner barrel of the telescopic joint and the outer barrel of the telescopic joint as the vessel moves.

3.1.25
drift-off
unintended lateral move of a dynamically positioned vessel off of its intended location relative to the wellhead, generally caused by loss of stationkeeping control or propulsion

3.1.26
drilling fluid
mud
water- or oil-based fluid circulated down the drillpipe into the well and back up to the rig for purposes including containment of formation pressure, the removal of cuttings, bit lubrication and cooling, treating the wall of the well and providing a source for well data

3.1.27
drive-off
unintended move of a dynamically positioned vessel off location driven by the vessel's main propulsion or stationkeeping thrusters

3.1.28
dynamic positioning
automatic stationkeeping
computerized means of maintaining a vessel on location by selectively driving thrusters

3.1.29
dynamic tension limit
maximum allowable pressure multiplied by the effective hydraulic area, divided by the number of line parts

3.1.30
effective hydraulic cylinder area
net area of moving parts exposed to tensioner hydraulic pressure

3.1.31
effective tension
tension that controls the stability of risers

See 5.4.4.

3.1.32
factory acceptance testing
testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings

3.1.33
fail safe
term applied to equipment or a system so designed that, in the event of failure or malfunction of any part of the system, devices are automatically activated to stabilize or secure the safety of the operation

3.1.34
fillup line
line through which fluid is added to the riser annulus

3.1.35
flange-type coupling
coupling having two flanges joined by bolts

3.1.36
fleet angle
angle between the vertical axis and a riser tensioner line at the point where the line connects to the telescopic joint

See Figure 1.

3.1.37
flex joint
steel and elastomer assembly that has a central through-passage equal to or greater in diameter than the riser bore and that may be positioned in the riser string to reduce local bending stresses

3.1.38
gooseneck
type of terminal fitting using a pipe section with a semicircular bend to achieve a nominal 180° change in flow direction

3.1.39
guidelineless re-entry
establishment of pressure-containing connection between the BOP stack and the subsea wellhead or between the LMRP and the BOP stack using a TV image and/or acoustic signals instead of guidelines to guide the orientation and alignment

3.1.40
handling tool
running tool
device that joins to the upper end of a riser joint to permit lifting and lowering of the joint and the assembled riser string in the derrick by the elevators

3.1.41
heave
vessel motion in the vertical direction

3.1.42
hot spot stress
local peak stress
highest stress in the region or component under consideration

NOTE The basic characteristic of a peak stress is that it causes no significant distortion and is principally objectionable as a possible initiation site for a fatigue crack. These stresses are highly localized and occur at geometric discontinuities.

3.1.43
hydraulic connector
mechanical connector that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack

3.1.44
hydraulic supply line
auxiliary line from the vessel to the subsea BOP stack that supplies control system operating fluid to the LMRP and BOP stack

3.1.45
instrumented riser joint
IRJ
riser joint equipped with sensors for monitoring parameters, such as tension in the riser pipe wall, riser angular offset, annulus fluid temperature and pressure, etc.

3.1.46
jumper hose
flexible section of choke, kill or auxiliary line that provides a continuous flow around a flex/ball joint while accommodating the angular motion at the flex/ball joint

3.1.47
key-seating
formation of a longitudinal slot in the bore of a riser system component caused by frictional wear of the rotating drillstring on the riser component

3.1.48
landing joint
riser joint temporarily attached above the telescopic joint used to land the BOP stack on the wellhead when the telescopic joint is collapsed and pinned

3.1.49
landing shoulder
riser support shoulder
shoulder or projection on the external surface of a riser coupling or other riser component for supporting the riser and BOP stack during deployment and retrieval

3.1.50
lower marine riser package
LMRP
upper section of a two-section subsea BOP stack consisting of a hydraulic connector, annular BOP, flex joint, riser adapter, jumper hoses for the choke, kill and auxiliary lines, and subsea control pods

NOTE This interfaces with the lower subsea BOP stack.

3.1.51
made-up length
actual length contributed to a riser string by a made-up riser component (overall component length minus box/pin engagement)

3.1.52
make-up time
riser coupling
time period beginning when the box and pin are stabbed and ending when the coupling is fully preloaded

3.1.53
make-up tool
preload tool
device used to engage and/or preload coupling members

3.1.54
marine drilling riser
tubular conduit serving as an extension of the wellbore from the equipment on the wellhead at the seafloor to a floating drilling rig

3.1.55
maximum tensioner setting
maximum setting that, when added with dynamic variations, is less than the **dynamic tension limit** (3.1.29)

3.1.56
mud-boost line
auxiliary line that provides supplementary drilling fluid from the surface and injects it into the riser at the top of the LMRP to assist in the circulation of drill cuttings up the marine riser, when required

3.1.57
nipple up
assemble a system of fluid handling components

3.1.58
nominal stress
stress calculated using the nominal pipe wall dimensions of the riser at the location of concern

3.1.59
pin
male member of a riser coupling or a choke, kill or auxiliary line stab assembly

3.1.60
preload
compressive bearing load developed between box and pin members at their interface

NOTE This is accomplished by elastic deformation during make-up of the coupling.

3.1.61
protector, box
protector, pin
cap or cover used to protect the box or pin from damage during storage and handling

3.1.62
pup joint
shorter than standard length riser joint

3.1.63
rated load
nominal applied loading condition used during riser design, analysis and testing based on maximum anticipated service loading

See API Spec 16F.

3.1.64
response amplitude operator
RAO
⟨regular waves⟩ ratio of a vessel's motion to the wave amplitude causing that motion and presented over a range of wave periods

3.1.65
riser adapter
crossover between riser and flex/ball joint

3.1.66
riser annulus
space around a pipe (drillpipe, casing or tubing) suspended in a riser

NOTE Its outer boundary is the internal surface of the riser pipe.

3.1.67
riser connector
LMRP connector
hydraulically operated connector that joins the LMRP to the top of the BOP stack

3.1.68
riser disconnect
operation of unlatching of the riser connector to separate the riser and LMRP from the BOP stack

3.1.69
riser hang-off system
means for supporting a disconnected deep-water riser from the drilling vessel during a storm without inducing excessive stresses in the riser

3.1.70
riser hang-off tool
tool used to latch onto an interior profile in the riser and connect it to the motion compensator

3.1.71
riser joint
section of riser main tube having the ends fitted with a box and pin and including choke, kill and (optional) auxiliary lines and their support brackets

3.1.72
riser main tube
riser pipe
seamless or electric-welded pipe that forms the principal conduit of the riser joint

NOTE The riser main tube is the conduit for guiding the drillstring and containing the return fluid flow from the well.

3.1.73
riser recoil system
means of limiting the upward acceleration of the riser when a disconnect is made at the riser connector

3.1.74
riser spider
device having retractable jaws or dogs used to support the riser string on the uppermost coupling support shoulder during deployment and retrieval of the riser

3.1.75
riser string
deployed assembly of riser joints

3.1.76
riser tensioner
means for providing and maintaining top tension on the deployed riser string to prevent buckling

3.1.77
riser tensioner ring
structural interface of the telescopic joint outer barrel and the riser tensioners

3.1.78
rotary kelly bushing
RKB
bushing that sits on top of the rotary table

NOTE It transmits torque from the rotary table to the kelly and is commonly used as a reference for vertical measurements from the drill-floor.

3.1.79
stab
mating box and pin assembly that provides a pressure-tight engagement of two pipe joints

NOTE An external mechanism is usually used to keep the box and pin engaged.

EXAMPLE Riser joint choke and kill stabs are retained in the stab mode by the make-up of the riser coupling.

3.1.80
standard riser joint
joint of typical length for a particular drilling vessel's riser storage racks, the derrick V-door size, riser-handling equipment capacity or a particular riser purchase

3.1.81
storm disconnect
riser disconnect to avoid excessive loading from vessel motions amplified by inclement weather conditions

3.1.82
strakes
helically wound appendages attached to the outside of the riser to suppress vortex induced vibrations

3.1.83
stress amplification factor
SAF
F_{SA}
value equal to the local peak alternating stress in a component (including welds) divided by the nominal alternating stress in the pipe wall at the location of the component

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

3.1.84
thrust collar
device for transmitting the buoyant force of a buoyancy module to the riser joint

3.1.85
subsea fill-up valve
special riser joint having a valve means to allow the riser annulus to be opened to the sea

NOTE To prevent riser pipe collapse, the valve can be opened by an automatic actuator controlled by a differential-pressure sensor.

3.1.86
support bracket
bracket positioned at intervals along a riser joint that provides intermediate radial and lateral support from the riser main tube to the choke, kill and auxiliary lines

3.1.87
surge
vessel motion along the fore/aft axis

3.1.88
sway
vessel motion along the port/starboard axis

3.1.89
syntactic foam
typically, a composite material of spherical fillers in a matrix or binder

3.1.90
telescopic joint
slip joint
riser joint having an inner barrel and an outer barrel with a means of sealing between them

NOTE The inner and outer barrels of the telescopic joint move relative to each other to compensate for the required change in the length of the riser string as the vessel experiences surge, sway, and heave.

3.1.91
telescopic joint packer
means of sealing the annular space between the inner and outer barrels of the telescopic joint

3.1.92
terminal fitting
connection between a rigid choke, kill or auxiliary line on a telescopic joint and its drape hose, effecting a nominal 180° turn in flow direction

3.1.93
threaded-union coupling
coupling having mating threaded members on the pin and box to form the engagement

NOTE The threads on one side of the coupling are free to rotate relative to the riser pipe, so it is not necessary that that the joint rotate to make up the coupling. The threads do not form the seal.

3.1.94
tension ring
support ring around the top of the joint where tensioner lines are attached

3.1.95
type certification testing
testing by a manufacturer of a representative specimen (or prototype) of a product that qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture

3.1.96
vortex induced vibration
in-line and transverse oscillation of a riser in a current induced by the periodic shedding of vortices

3.1.97
wellhead connector
stack connector
hydraulically operated connector that joins the BOP stack to the subsea wellhead

3.2 Abbreviations

BOP blowout preventer

DP dynamic positioning

DTL dynamic tension limit

ID internal diameter

LFJ lower flex joint

LMRP lower marine riser package

OD outside diameter

RAO response amplitude operator

RKB rotary kelly bushing

ROV remotely operated vehicle

SAF stress amplification factor

UFJ upper flex joint

4 Component function and selection

4.1 Introduction

General requirements common to all components are outlined in 4.2 and, where appropriate, individual components are addressed in the rest of Clause 4. The following general format is used:

a) function: the basic function of the component is described;

b) typical designs: examples of typical designs are presented;

c) selection criteria: general performance requirements are outlined.

4.2 Component selection criteria

Design of a riser system begins with an assessment of expected operating conditions and an engineering analysis to establish parameters, such as tensile, bending and combined stresses (maximum and mean), buoyancy requirements, top tension requirements, vessel response amplitude operators (RAOs), etc. Other factors influencing riser system design include riser length (water depth), dimensional requirements (bore, wall thickness, etc.), internal pressure rating, choke/kill, and auxiliary-line specifications, make-up method, storage and handling conditions, operating economy, etc. Once established, these riser-system design criteria should permit the selection of riser components that suit the application.

All riser primary-load-path components addressed in this part of ISO 13624 shall be consistent with the load classifications specified in ISO 13625.

4.3 Marine drilling riser system

The marine riser system forms an extension of the wellbore from the blowout preventer (BOP) stack to the drilling vessel; see Figure 1.

The primary functions of the marine riser system are to

a) provide for fluid communication between the well and the drilling vessel

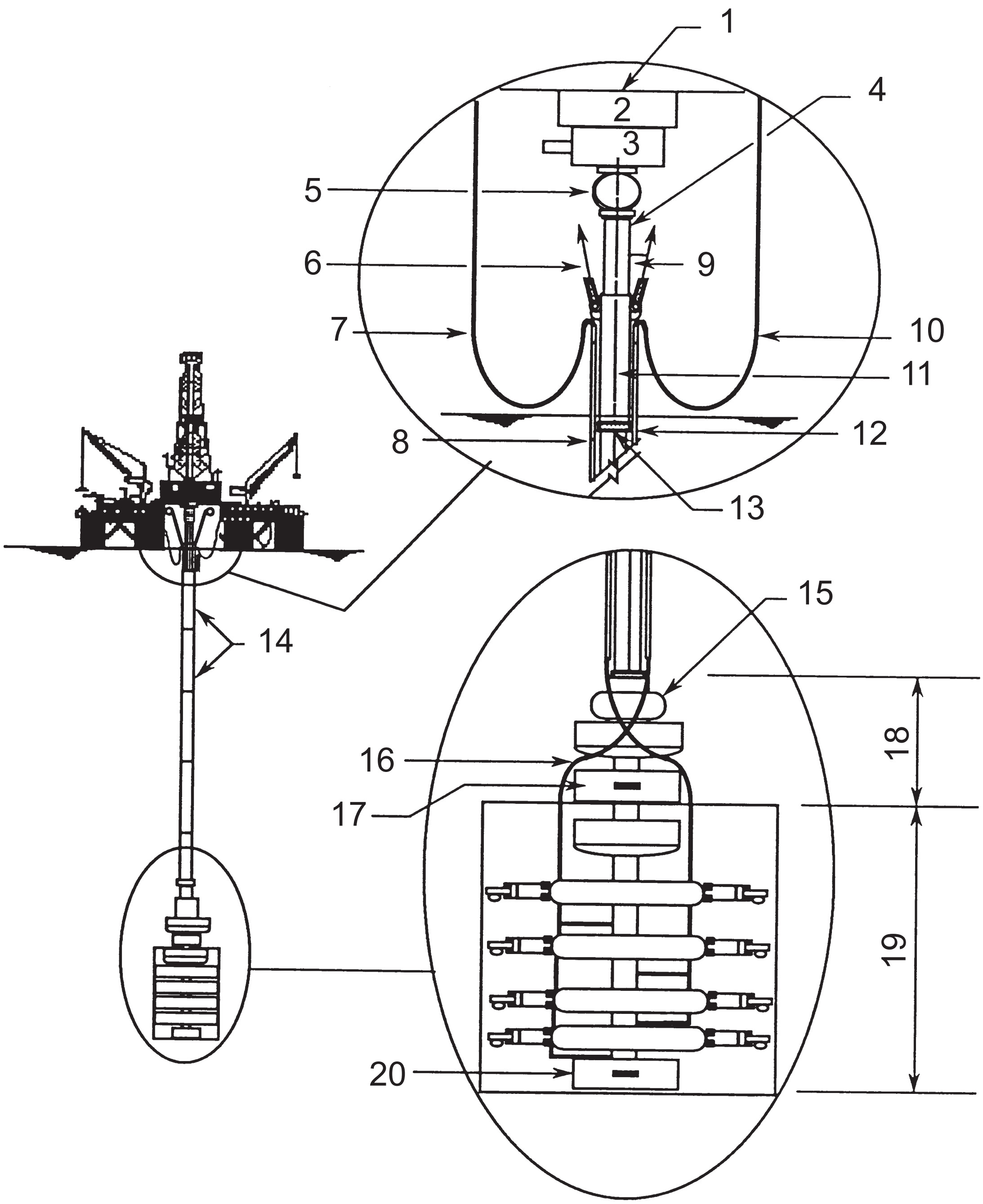
1) in the riser annulus under normal drilling conditions,

2) through the choke-and-kill lines when the BOP stack is being used to control the well;

b) support the choke, kill and auxiliary lines;

c) guide tools into the well;

d) serve as a running and retrieving string for the BOP stack.



Key

1 rotary kelly bushing (RKB)
2 rotary
3 diverter
4 telescopic joint inner barrel
5 diverter flex/ball joint
6 tensioner line
7 choke drape hose
8 choke line
9 fleet angle
10 kill drape hose
11 telescopic joint outer barrel
12 kill line
13 riser coupling
14 marine riser joints
15 flex/ball joint
16 riser/BOP jumper hose
17 LMRP connector
18 lower marine riser package (LMRP)
19 blowout preventer (BOP) stack
20 wellhead connector

Figure 1 — Marine riser system and associated equipment

4.4 Tensioner system

4.4.1 Function

Tensioner units are used to apply vertical force to the top of the marine drilling riser to control its stresses and displacements. The units are normally located on the drilling vessel near the periphery of the drill-floor. They provide a nearly constant axial tension to the riser while the floating drilling vessel moves vertically and laterally in response to the wind, waves and current.

4.4.2 Typical design

A typical tensioner unit uses a hydraulic ram with large-volume, air-filled auxiliary pressure vessels (APV) to maintain a nearly constant pressure/tension on a line (wire rope). One end of the line is attached at the vessel and the other is attached to the outer barrel of the telescopic joint. Typically, a four-part line-reeving system is used so that the piston stroke is equal to one-quarter of the vessel heave. The number and rating of tensioner units used determines the total capacity of the tensioner system. The tension applied by each unit can be varied up to its design capacity by increasing or decreasing the applied air pressure. The tensioner system should be capable of providing sufficient tension based upon the maximum rated water depth, maximum expected mud weight, and other loadings determined from riser analyses.

Direct-acting hydraulic rod-cylinder tensioners are also used on deep-water drilling vessels.

Designs for tensioner systems are described in ISO/TR 13624-2:—, Clause 4.

4.4.3 Selection criteria

Some important considerations for designing an effective tensioner system are as follows.

a) Fleet angle: The idler sheaves should be placed so as to minimize the fleet angle. This maximizes the vertical component of tension, minimizes the horizontal component and increases wireline life.

   Because of the fleet angle, the vertical tension applied to the outer barrel of the telescopic joint is less than the tension supplied by the tensioner system. A reduction factor (see 5.3.2) should be used to reconcile these parameters.

b) Wireline life: Wireline life is a function of many parameters, including wire-rope construction, sheave diameter, applied tension, operating circumstances relating to travel, etc. See API RP 9B.

c) Accumulators and air-pressure vessels: Each tensioner unit should have an accumulator that is large enough to store a volume of hydraulic fluid greater than the cylinder volume. Large air-pressure vessels reduce pressure changes caused by the compression and expansion of the stored air as the tensioner strokes in and out.

d) Fluid and air flow requirements: Properly sized lines reduce tension variations caused by piping-system pressure losses.

   A list of hydraulic fluids compatible with the tensioner units should be specified by the tensioner manufacturer.

e) Friction and inertia losses: Seal friction, sheave friction and inertia of sheaves, wire rope, tensioner rods, and pistons all contribute to variations in the wireline tension.

f) Dynamic tension limit (DTL): Tensioner ratings are defined differently by various manufacturers. This part of ISO 13624 defines a dynamic tension limit, F_{DTL}, as given in Equation (1); see also 3.1.29:

$$F_{\mathrm{DTL}} = P_{\mathrm{A}} \times A_{\mathrm{CYL}} / N_{\mathrm{LP}} \tag{1}$$

where

P_A	is the maximum allowable system operating pressure;
A_{CYL}	is the effective hydraulic area;
N_{LP}	is the number of line parts.

— All components in a riser-system installation, including piping, should be designed for the maximum allowable working pressure. See ASME UG 125-136 for relief-valve-setting criteria.

— The tensioner system should be designed to permit one unit to be out of service for maintenance or repair without jeopardizing the ability of the remaining tensioner units to provide the required tension to the marine drilling riser. A unit may be either a single tensioner or a pair of tensioners, depending on specific design.

g) Maximum tension setting: The maximum tension setting should not exceed 90 % of the F_{DTL} so that the maximum tension, including dynamic variations, is less than the F_{DTL}.

h) Velocity-limiting device: Some type of flow-control device is normally located in the line between the fluid port on each tensioner and its respective air/liquid interface bottle. This device should offer minimal resistance to fluid flow during all anticipated heave velocities. However, if a tensioner wireline should break or other failure occur that allows the tensioner to stroke out at an uncontrolled rate, this flow-control valve should sense the abnormally high fluid flow rate and immediately stop or greatly reduce the fluid flow into the tensioner.

4.5 **Diverter system** (surface)

4.5.1 Function

When drilling a top hole through the structural casing, the riser may be employed enabling the use of weighted mud to provide overbalance, if needed. Blowout preventers (BOPs) are not in place at this stage (see 4.14.1) because the structural casing normally lacks sufficient pressure integrity to allow shut-in. Therefore, if the well flows, the riser directs that flow to the diverter system aboard the rig. Typically, the diverter system includes an annular sealing device, means to both open the vent line and close the mud flowline, and a control system.

4.5.2 Location

Surface diverter systems on floating rigs are usually installed directly below the rotary table. The diverter unit is latched into a built-in housing. The upper flex/ball joint, which is the uppermost component in a marine drilling riser system, is usually mounted to the bottom of the diverter unit.

A subsea diverter stack may be installed on the wellhead to divert subsea.

4.5.3 Operation

API RP 64 provides recommended practices for diverter systems equipment and operations.

4.6 **Telescopic joint** (slip joint)

4.6.1 Function

The basic function of the telescopic joint is to compensate for the relative translational movement between the vessel and the riser. The outer barrel provides structural support for riser tensioner loads.

4.6.2 Typical design

4.6.2.1 General

A telescopic joint has an outer barrel that is connected to the drilling riser, an inner barrel that is connected to an upper flex joint, and a tensioner ring that transmits loads from the tensioner system to the outer barrel of the riser.

4.6.2.2 Riser tensioner attachment

The riser tensioner lines typically attach to the tensioner ring near the top of the telescopic joint outer barrel. This attachment provides the structural interface between the marine riser and the tensioner system. Padeyes on the tensioner ring accommodate pinned connections at the ends of the tensioner lines. The tensile load to support the riser is transmitted through the riser tensioner ring to the pipe wall of the outer barrel and, subsequently, through the couplings and pipe walls of the riser joints.

4.6.2.3 Optional features of the tensioner ring

The following lists optional features of the tensioner ring.

a) For turret-moored and dynamically positioned vessels, a low-friction bearing on the tensioner ring allows the vessel to rotate. Resulting torsional loads on the riser and wellhead should be considered.

b) For guidelineless re-entry, an hydraulic motor drive may be provided on the tensioner ring to orient the LMRP with the BOP stack.

c) For operational convenience, the riser tensioner ring may be detached from the outer barrel and fitted for latching to the bottom of the diverter housing for storage. This arrangement eliminates the time-consuming operations of connecting/disconnecting tensioner lines when deploying/retrieving the riser. Integral stab connectors may also be provided to permit ready connections of the drape hose terminal fittings.

4.6.3 Selection criteria

The selection of a telescopic joint should include consideration and evaluation of the following basic items.

a) Strength: In both its retracted and extended positions, the telescopic joint should support the weight of the riser and BOP stack. The dynamic loads on the telescopic joint should be considered.

b) Stroke length: The maximum stroke length required for the telescopic joint should accommodate the combined expected heave, vessel offset, tidal change and maximum anticipated vessel excursion in the event of a stationkeeping failure.

c) Tensioner ring: Angular orientation on the padeyes on the tensioner ring should accommodate the positions of the tensioner line sheaves. The tensioner ring should be rated for the maximum load capacity of the telescopic joint.

d) Auxiliary lines: The designer of the attachments for auxiliary lines, choke-and-kill lines, and the telescopic joint packing pressure line should consider the layout of the rig and the ease of making and breaking the connections during running and retrieving operations.

e) Packing elements: The packing element that is used to seal between the outside of the inner barrel and the inside of the outer barrel is available as either single-element or double-element units. The advantage of the double-element unit is that when one of the packing elements fails, the second element can be energized, thus maintaining the seal between the drilling fluid and the environment, without having to shut down the drilling operation.

f) Handling and storage: The telescopic joint is typically longer and heavier than the standard riser joint and, therefore, it has special handling and storage requirements.

4.7 Riser joints

4.7.1 Function

A riser joint is a large-diameter, high-strength pipe (riser main tube), either seamless or electric welded, with couplings welded to each end. When the riser system is being deployed, the riser joints are coupled together on the drill-floor and lowered into the water. The string of riser joints represents the principal component of the riser system and is used to perform the riser-system functions listed in 4.3. The box or pin coupling at the upper end of the riser joint usually has a landing shoulder. This landing shoulder, or riser-support shoulder, supports the loads (static and dynamic) of the marine riser and BOP stack when it is suspended from the riser spider (see 4.11.2.2). The coupling may also provide support for choke, kill and auxiliary lines, and load reaction for buoyancy devices.

4.7.2 Typical designs

4.7.2.1 Main tube

Riser main tube and the associated couplings are generally sized to be compatible with a specific BOP stack size. Compatible BOP bore and riser outer diameter combinations are shown in Table 1.

Table 1 — Compatible BOP bore and riser outer diameter combinations

BOP bore mm (in)	**Riser outer diameter** mm (in)
346,1 (13-5/8)	406,4 (16) riser
425,5 (16-3/4)	473,1 (18-5/8) riser
476,3 (18-3/4)	508 (20) riser, or 533,4 (21) riser, or 558,8 (22) riser with thick wall

4.7.2.2 Riser couplings

The four basic riser coupling designs are

a) dog type;

b) flanged;

c) threaded union;

d) breech-block.

Each riser manufacturer usually offers couplings with different strength ratings.

4.7.2.3 Choke/kill and auxiliary lines

Typically, riser joints have choke/kill and auxiliary lines attached to the exterior of the main riser tube by support brackets. On most risers, these lines pass through the riser support shoulder. These riser-mounted choke/kill and auxiliary lines are described in 4.12.

4.7.3 Selection criteria

The following items should be considered when selecting, designing or specifying riser joints.

a) Riser main tube: The riser main tube should have adequate strength to withstand combined loads from waves, current, applied tension, motion of the rig and drilling fluid weight in accordance with Table 2. Collapse pressure and handling loads should also be considered. The strength characteristics of the main tube are dictated by its diameter, wall thickness and grade of steel. Steel grades commonly used in risers are X-52, X-65, and X-80, where the numbers refer to the minimum yield strength, expressed in kilopounds-force per square inch, of each grade.

   — The inside diameter shall provide sufficient annular space to accommodate the desired casing programme.

   — Typically, riser-joint lengths range from 15,2 m to 27,4 m (50 ft to 75 ft). The storage and handling characteristics on the rig shall be considered in the selection of the length.

b) Pup joints: Pup joints are riser joints that are shorter than full-length riser joints. Pup joints of various lengths should be available to accommodate riser spaceout. See 6.4.2.

c) Riser couplings: Coupling selection should be based on

   — strength;

   — load rating of support ring;

   — stress amplification factor (fatigue resistance);

   — reliability;

   — speed of make-up;

   — preload for make-up;

   — maintenance requirements;

   — main tube dimensions;

   — strength-to-weight ratio.

4.8 Lower marine riser package (LMRP)

4.8.1 Function

The lower marine riser package (LMRP) typically includes an assemblage of a riser adapter; a flex/ball joint; one, two, or no annular BOPs; subsea control pods; and an hydraulic connector mating the riser system to the BOP stack. The LMRP provides a releasable interface between the riser and the BOP stack. In addition, it provides hydraulic control of BOP stack functions through the control pods. Jumper hoses provide a flow path around the flex/ball joint for the choke and kill lines.

4.8.2 Typical design

The LMRP can be designed to a variety of configurations depending upon the type, size, ratings and operational water depth of its components. Some design considerations are

a) standard guidepost radius (see API RP 53);

b) minimum bore size and compatible pressure ratings;

c) bending strength;

d) clearance for retrievable control pods;

e) accommodation for subsea accumulators;

f) loads and clearances during an emergency disconnect;

g) available space for storage and handling aboard drilling vessel;

h) emergency recovery system for deep-water BOPs;

i) guidance system for re-entry of guidelineless BOPs;

j) sequenced, retractable control pod stabs and choke/kill stabs on guidelineless systems;

k) flexible lines (see 4.10);

l) guidance structure for BOP handling.

4.8.3 Selection criteria

The selection of LMRP components should be based on the following factors:

a) well-control considerations;

b) BOP pressure rating and bore;

c) guideline or guidelineless operations;

d) overall height and weight limitations;

e) operating environment and design loads;

f) method of BOP control and operational fail-safe design features;

g) operational water depth;

h) method for running/retrieving control pods;

i) methods for re-entry on guidelineless systems;

j) methods for emergency recovery.

4.9 Flex and ball joints

4.9.1 Function

Flex and ball joints are used to allow angular misalignment between the riser and the BOP stack, thereby reducing the bending moment on the riser. They are also used at the top of the riser to allow for the motion of the rig. In some instances, they may also be installed at some intermediate level in the riser string below the telescopic joint to reduce stresses in the riser. The rotational stiffness of flex joints makes them more effective than ball joints in controlling riser angles. Typically, the rotational stiffness of a flex joint is a non-linear function of angle and ranges from 13 600 N·m (10 000 ft-lbf) per degree of rotation to 108 800 N·m (80 000 ft-lbf) per degree of rotation. Rotational stiffness can also vary with temperature.

4.9.2 Typical design

4.9.2.1 Flex joints

The flexure members of a flex joint are typically bonded laminations of elastomer between stacks of spherically shaped steel rings. The elastomer provides flexure and pressure sealing. Some designs provide a landing shoulder for a readily removable wear bushing. Still others provide a wear ring that can be replaced during periodic overhaul of the flex joint. Because of the design of flex joints, repair of major key-seat damage can prove uneconomical. The user should request that the supplier provide a list of facilities with the capabilities to repair key-seat damage.

4.9.2.2 Ball joints

A ball joint is a forged steel ball and socket containing a cylindrical neck extension with a riser adapter attached at the end of the neck. The ball and socket employs a seal that contains the drilling fluids. In most designs, replaceable wear rings or wear bushings are used. Some ball joints require pressure balancing.

4.9.3 Selection criteria

The following items should be considered when selecting, specifying or designing flex joints and ball joints:

a) flex/ball joint function and location in the riser system;

b) maximum angular rotation and maximum rotational stiffness required, which can be determined by a preliminary riser analysis;

c) pressure rating; the flex/ball joint should maintain pressure integrity throughout exposure to wellbore fluids, maximum anticipated temperatures, maximum design mud weight, and maximum design water depth;

d) maximum tensile load being applied;

e) maximum torque being applied.

4.10 Flexible choke-and-kill lines

4.10.1 Function

Flexible choke-and-kill lines allow relative movement at the telescopic joint (drape hose) and at flex/ball joints (jumper hose) in the riser system.

4.10.2 Typical design

Three basic designs are commonly used:

— flexible pipe;

— steel reinforced hoses;

— flow loops with threaded, clamped, or flanged end fittings.

If threaded end fittings are used, they shall contain a means of sealing other than the threads.

4.10.3 Selection criteria

Flexible lines should be compatible with the rest of the choke-and-kill piping system and with the BOP stack, riser and choke-and-kill manifold. Selection of flexible lines should take into account the following considerations:

a) length requirement and tolerance;

b) end fitting compatibility;

c) pressure rating (gas and liquid);

d) collapse rating;

e) temperature rating (maximum, minimum, and ambient conditions);

f) minimum bend radius;

g) fluid compatibility;

h) resistance to wear by abrasive fluids;

i) corrosion resistance;

j) fatigue resistance to bend and pressure cycling.

4.11 Riser running equipment

4.11.1 Function

Riser and diverter handling tools are used for hoisting and lowering the riser and BOP stack. The riser spider is used to support the riser and BOP stack while they are being run or retrieved. When used, guidelines direct the riser and associated subsea equipment to the wellhead.

4.11.2 Typical design

4.11.2.1 Handling tools

Riser handling tools make up to the top of the riser during deployment and retrieval. The top connection is a short length of pipe that is supported by the hoisting equipment.

Another tool of importance is the diverter-handling tool, which may be used to carry the entire riser system load prior to landing the stack on the wellhead. If the diverter-handling tool is used to support the entire riser and BOP stack, it should meet the same standards as the riser-handling tool.

4.11.2.2 Riser spiders

A riser spider provides support for the riser and BOP stack at the drill-floor. Shock-absorbing spiders are designed to reduce impact loads on riser-support shoulders. Gimballing spiders reduce bending moments on the shoulders.

4.11.2.3 Guidelines

Guidelines may be used to direct the riser and associated subsea equipment to their mating connections near the seafloor. Generally, four wire rope guidelines, forming the corners of a square, extend up from the temporary guidebase to the floating drilling vessel where each is tensioned by a guideline tensioner (similar to a riser tensioner). Typically, the guideline attachment points are 2 m (6 ft) from the centre of the wellbore forming a square measuring approximately 2,6 m (8,5 ft) per side.

4.11.3 Selection criteria

The selection, rating and testing of riser running equipment should be based on the following:

a) maximum static loading capacity;

b) dynamic loads induced by vessel motions, waves and currents;

c) bending loads during riser running operations;

d) impact loads.

4.12 Riser-mounted choke/kill and auxiliary lines

4.12.1 Function

These lines carry fluids along the length of the riser. On most risers, they are an integral part of each riser joint and are attached on the outside of the riser main tube by support brackets. Generally, these lines are used for the following purposes.

a) Choke/kill lines are used to provide a controlled flow of oil, gas or drilling fluid from the wellbore to the surface when the blowout preventer stack is closed.

b) Mud-boost lines are used as conduits for drilling fluid that is pumped into the riser just above the blowout preventer stack to increase annular circulating velocities.

c) Air-inject lines are used to supply air to increase riser buoyancy for air-can buoyancy risers.

d) Hydraulic supply lines carry hydraulic operating fluid to the blowout preventer subsea control system. Most blowout preventer systems incorporate a flexible hydraulic-fluid supply line inside the control line hose umbilical.

4.12.2 Typical designs

Typical riser joints have integral choke-and-kill lines. This provides redundancy and also allows for the following well-control operations:

a) circulating down one line and up the other line;

b) circulating down the drillpipe and up one line.

A mud-boost line is incorporated for some risers. Air-inject lines are required for riser systems that use air-chamber buoyancy systems. Hydraulic supply lines can be used as either a primary or secondary supply line.

Generally, choke/kill and auxiliary lines of one riser joint are connected to their counterparts on adjoining riser joints by stab-in couplings. The box contains an elastomeric radial seal that expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized. These stab-in couplings also facilitate fast make-up while deploying the riser.

4.12.3 Selection criteria

The following items should be considered when selecting, designing or specifying choke/kill and auxiliary lines for riser joints.

a) The type of fluid to be carried by the line: Hydraulic supply lines are generally constructed of corrosion-resistant material to prevent rust particles from clogging hydraulic operator ports and damaging seals and sealing surfaces. Choke/kill and mud-boost lines are generally constructed of steel. Care should be taken to ensure that proper galvanic protection is provided between the steel components of the riser joints and the hydraulic supply lines if corrosion-resistant material (e.g. stainless steel) is used.

b) The operating pressures to which the line can be exposed during its lifetime.

   1) Hydraulic supply lines: Working pressure rating should be compatible with the working pressure rating of the BOP control system.

   2) Mud-boost lines: Pressure rating should be suitable for the intended service.

   3) Choke/kill lines: Pressure rating should be the same as that of the BOP stack.

c) The choke/kill and auxiliary line couplings: These couplings shall be able to seal against full pressure while allowing for relative motion between the box and pin caused by:

1) Poisson's effect;

2) structural compression caused by pressure exerted on the ends of the pins;

3) temperature differences between the fluid in the main riser and the fluids in the choke/kill or auxiliary lines;

4) bending loads imposed by deflections of the riser; this relative motion can cause fatigue cracking of the support bracket if an adequate gap is not provided between the support bracket and the coupling.

d) Internal diameter of the line: The ID of the choke/kill lines should be selected to suit well-control operations. The ID of the mud-boost line should be selected to suit drilling fluid requirements. The ID of the hydraulic supply line should be selected to suit control system requirements.

e) Failsafe design and orientation of choke/kill and auxiliary lines: To prevent accidental mismatching of the choke/kill and auxiliary lines when the riser is deployed, the couplings should be oriented asymmetrically around the riser support ring. To prevent accidental over-pressuring of the mud-boost line while testing during deployment, the test caps for the choke/kill lines should be designed so that they cannot be installed on the mud-boost line.

f) Support bracket design: The support brackets attach the lines to the riser and prevent buckling when they are pressurized. The spacing of the support brackets is dependent upon the rated pressure of the choke/kill lines and the buckling characteristics of the pipe.

g) H_2S service requirements: If H_2S can enter the choke and kill lines, material selection should meet the requirements of ANSI/NACE MR0175/ISO 15156.

h) Pressure ratings: All pressure piping should be designed to meet the requirements of API Spec 16C.

i) Corrosion/erosion allowances: The minimum design thickness should include a corrosion/erosion allowance of 1,27 mm (0,05 in) as recommended in API RP 14E.

4.13 Buoyancy equipment

4.13.1 Function

Buoyancy equipment may be attached to riser joints to reduce top tension requirements by decreasing the submerged weight of riser joints.

4.13.2 Typical designs

4.13.2.1 Foam modules

Syntactic foam is typically a composite material of spherical fillers in a matrix or binder. The most common forms of syntactic foam consist of tiny glass microspheres in a matrix of thermo-setting plastic resin, often with larger microspheres of glass-fibre-reinforced plastic.

The diameter of syntactic-foam modules depends primarily on the buoyancy requirements and the foam density. The foam density depends on the design water depth. Denser material is normally used for deeper water to withstand higher collapse pressures. Maximum allowable diameter is determined by the bore of the diverter housing and/or other restrictions through which it is necessary that the riser joint pass. See 5.9 for high-current operations.

Typically, foam modules are installed in pairs around the riser joint, several pairs per joint, and have cut-outs to accommodate choke, kill and auxiliary lines. The modules are held in place by either circumferential straps or other suitable means. Fastener material should be selected to avoid galvanic corrosion.

The vertical lift of the foam module is imparted to the riser by a thrust collar fitted to the riser pipe just below the upper coupling. A matching collar is generally installed at the lower end of the assembled modules to retain them in place during riser handling.

4.13.2.2 Open-bottom air chambers

Open-bottom air cans are typically attached to the riser coupling and provide an annular space around the riser. Air-injection and pilot lines provide the means to inject air at ambient hydrostatic pressure. Air displaces seawater from the annular space to provide buoyancy. A float valve in the injection line near the bottom of the chamber maintains the water at the preset level. Air can be bled from the system through a discharge valve actuated by the pilot line. Valves can be arranged and adjusted to provide the desired buoyancy level. Compressors aboard the drilling vessel are used to supply air through the injection line to the air chambers.

4.13.3 Selection criteria

Foam modules should be selected to provide the required lift and resistance to pressure at the rated service depth. Their design should be such that they do not restrain the bending of the riser tube and can be safely handled and stored. Maintenance and repair procedures should be investigated to ensure that they can be performed on the rig with minimal difficulty. For foam densities and water absorption considerations, see the manufacturer's specifications.

Open-bottom air cans are relatively resistant to handling damage, but they can increase bending stresses at the riser coupling because of the added resistance of the air cans. This should be investigated by the designer to make sure that adequate provision is made for this in the riser operating programme. The systems required to operate and maintain the riser should be evaluated to ensure that adequate redundancy is provided for critical equipment, such as air compressors.

4.14 Speciality equipment

4.14.1 Latch (pin connector), 76,2 cm (30 in)

Under some conditions, it is advantageous to have the riser deployed while drilling the 66,0 cm (26 in) hole. In that event, a 76,2 cm (30 in) latch is used to connect the marine riser to the 76,2 cm (30 in) wellhead housing. A ring-joint pressure seal is effected between the latch assembly and the wellhead housing. Hydraulically operated multiple segments are used to form the mechanical latch engagement; the segments extend radially inward to engage a support shoulder on the wellhead housing OD. The 76,2 cm (30 in) latch is normally controlled by a dedicated hydraulic hose bundle run from the surface diverter/BOP control system. The 76,2 cm (30 in) latch is usually fitted with a flex/ball joint and a riser adapter.

4.14.2 Riser hang-off system

When environmental conditions exceed the limits for safe operation with the riser connected, the riser and LMRP are disconnected from the BOP stack and may be hung-off until weather conditions improve. The disconnected riser may be hung off from the hook, the spider, the diverter housing or specially designed beam structures. This is called the hard hang-off method.

Another method, called a soft hang-off, may be used to hang-off the riser from either the tensioners only or from the tensioners and the motion compensator. A tool called the riser hang-off tool is employed if the motion compensator is used in conjunction with the tensioners to set up a soft hang-off.

The dynamic loads of the riser should be considered to ensure that the hang-off system components provide adequate strength to support the axial and transverse loads imparted by the suspended riser without damage to either the riser or the vessel.

5 Riser response analysis

5.1 General considerations

The drilling riser has very little inherent structural stability. Its ability to resist environmental loading is derived from the applied tension. The marine drilling riser should be designed, and the top tension selected, based on the riser's response to the environmental and hydrostatic loads, as well as the requirement that it properly perform its functions. Among the functional constraints are the angles at both the lower flex/ball joint and the telescopic joint, the mean and alternating stresses, the resistance to column buckling and hydrostatic collapse, the percentage of the DTL applied to the top of the riser and forces and moments transferred to the BOP stack, wellhead and casing.

Specialized computer programs are generally used to predict riser behaviour under the design conditions, and to determine top tension requirements, maximum permissible vessel offsets and maximum loads on riser components.

Because of the manner in which the riser is employed, design of the drilling riser components cannot be separated from operational procedures. For example, when drilling, upper and lower flex/ball joint angles should be maintained within rather low limits. However, in the presence of severe weather, drilling may be suspended and the limitation on flex/ball joint angles relaxed. Limiting criteria for riser design can, then, become maximum stresses. During such a change of operational mode, proper handling of the riser can dictate a change in the top tension. In even more severe conditions, the proper riser handling can dictate disconnecting the bottom of the riser and hanging it off from the rig. Decisions such as when to make such changes are part of the riser-design process and require analysis of the riser in each of the potential operational modes.

This subclause applies equally to the design of a new riser system or the site-specific evaluation of an existing riser system. Riser analyses should be performed for a range of environmental and operational parameters. If the riser is being designed, this requires starting with a proposed design and then iterating until the riser parameters, such as wall thickness and material strength, that satisfy the design objectives are found. For an existing riser system, the options available to the analyst include

a) specifying the appropriate top tension for each combination of environmental and drilling parameters;

b) coordinating the mooring system design to evaluate the position of the top of the riser;

c) specifying the distribution of bare and buoyant riser joints throughout the riser string;

d) selecting the conditions at which the operational mode is changed (from drilling to non-drilling, and when to disconnect).

5.2 Riser analysis procedure

5.2.1 General

Annex A is a data worksheet for recording data prior to performing a riser analysis.

5.2.2 Vessel stationkeeping considerations

The vessel's stationkeeping ability should be determined and used in conjunction with the riser analysis to assess flex/ball joint angles and riser stresses. The mooring and riser analyses are used to define operating limits for the riser. In some cases, mooring lines may be adjusted in response to long-term variations in environmental conditions, such as current and/or wind.

5.2.3 Riser-induced load considerations

The riser introduces shear, bending and tension loads into the LMRP, the BOP stack, the hydraulic connectors, the wellhead and the casing. These loads and moments should be evaluated to ensure that the maximum stresses are within design allowables and the fatigue life is acceptable. The riser also induces loads on the drilling vessel that it can be necessary to consider in the stationkeeping analysis.

5.2.4 Currents

For currents exceeding 1 m/s (~2 kn), see 5.9.

5.2.5 Drilling fluid density

Top tension requirements should be determined for several values of drilling fluid density ranging from that of seawater up to the maximum anticipated density.

5.3 Design

5.3.1 Operating modes

Three operating modes are normally encountered in offshore drilling operations.

a) Drilling mode: The drilling mode is that combination of environmental and well conditions in which all normal drilling activities can be safely conducted, including drilling ahead, tripping, under reaming, circulating, etc. Special operations, such as running casing, cementing, or formation testing, can dictate more restrictive operating limits.

b) Connected non-drilling mode: In this mode, the only drilling operation that should be conducted is circulating. The drillpipe should not be rotated. The riser may be displaced with seawater and preparations made to shut-in the well and disconnect the riser, if necessary.

c) Disconnected mode: If environmental conditions exceed the limits for safe operation in the connected non-drilling mode, the riser should be disconnected to avoid possible damage to surface or subsea equipment.

5.3.2 Recommended guidelines for design

Selection of the appropriate combination of environmental conditions and hydrodynamic coefficients for the analysis involves judgment, experience and an understanding of the type of riser analysis being employed. Design and operating limits for the key riser parameters – upper and lower flex/ball joint angles, mean and alternating stress and the appropriate factor of safety on DTL – are selected based on sound engineering principles and successful operating experience.

Table 2 defines recommended design practices for the three operating modes. It contains two stress criteria methods for the drilling mode, at least one of which should be satisfied. Generally, method A is appropriate for most water depth locations and method B is recommended for deep-water locations. Table 2 addresses riser analysis for exploratory drilling. In cases of extended drilling in a harsh environment, such as on a North Sea template, a fatigue analysis of the riser can be advisable. The mean and maximum flex/ball joint angle limits given for the normal drilling mode are intended to prevent wear and key-seating damage to the riser and flex/ball joint. Prudent operational procedure should strive to maintain these angles as small as possible (e.g. 1° or less), and consider 2,0° (mean) and 5,0° (maximum) as upper bounds. The maximum flex/ball joint angle limits for the connected non-drilling mode and disconnected mode are intended to prevent damage to the riser, flex/ball joint and BOP stack. The upper flex/ball joint angle rarely has a significant effect on riser design; however, this angle should be considered when evaluating clearances in the moonpool area.

Table 2 — Marine drilling risers — Maximum design guidelines

Design parameter	Riser connected		Riser disconnected
	Drilling	Non-drilling	
Mean upper flex/ball jt. angle [a]	1° to 1,5°	N/A	N/A
Max. upper flex/ball jt. angle [a]	5,0°	90 % available (or contact with moonpool structure)	90 % available (or contact with moonpool structure)
Mean lower flex jt. angle [b]	2,0°	N/A	N/A
Max. lower flex jt. angle [b]	5,0°	90 % available	N/A
Stress criteria: [c,d]			
– Method “A” - allowable stress [e]	0,40 σ_y [f]	0,67 σ_y [f]	0,67 σ_y [f]
– Method “B” - allowable stress [e]	0,67 σ_y [f]	0,67 σ_y [f]	0,67 σ_y [f]
– Sign. dyn. stress range [e]			
@ SAF $\leqslant$ 1,5 [g]	69 MPa (10 ksi)	N/A	N/A
@ SAF $>$ 1,5 [g]	$15/F_{SA}$	N/A	N/A
Minimum top tension [h]	T_{min}	T_{min}	N/A
Dynamic tension limit [i]	F_{DTL}	F_{DTL}	N/A
Maximum tension setting	90 % F_{DTL}	90 % F_{DTL}	N/A

NOTE 1 The flex/ball joint angles are differential global angles around the flex or ball joints and, because the wellhead tilt and riser angle (or vessel pitch/roll and riser angle) can be in different planes, they are not easily determined by independent bullseye levels both above and below the flex/ball joint. It is necessary to keep the flex/ball joint angles as small as practicable to avoid wear in the riser system components. The value of 2° in Table 2 is specified to include routine situations with low risk of significant wear, which could not continue with a more restrictive angle. For many drilling operations, mean differential angles are maintained at less than 1°.

NOTE 2 The rate of wear at flex/ball joints between two pieces of metal is dependent on four parameters:

- contact force;
- relative velocity;
- material parameters;
- properties of the surrounding fluid.

For a drillstring in a riser system, the relative velocity is dictated by operations, either rotation rate or running/pulling speed; the material properties are usually specified (steel); and the surrounding fluid is the drilling fluid returns (more of an abrasive than a lubricant). The only parameter subject to control is the contact force.

The contact force is of concern where the drillstring is forced to conform to the bore of the riser system (primarily near the flex/ball joints). The force is amplified when the annulus between the drillstring and the riser bore is small (smaller ID risers, larger OD drillpipe), and when the drill-string tension at the point of contact is high (drill-string is less flexible). Examples of high wear cases include

a) wells deep below the mud line: high tension in the drillstring at the lower flex/ball joint;

b) use of large diameter drillpipe (168 mm [6-5/8 in], for example): smaller annulus, together with higher tension due to a heavier drillstring.

An example of a low wear case is a shallow well drilled with small diameter drillstring. The tool joints are usually responsible for much of the wear.

[a] Upper joint is with respect to vertical and does not include vessel motions.

[b] Lower joint is the differential angle. (See Notes 1 and 2 above.)

[c] These guidelines apply to the global riser response.

[d] All stresses are calculated according to von Mises stress failure criterion, σ_{vm}, as given in Equation (2); see 5.3.2:

$$\sigma_{vm}^2 = \tfrac{1}{2}\left[\left(\sigma_1 - \sigma_2\right)^2 + \left(\sigma_2 - \sigma_3\right)^2 + \left(\sigma_3 - \sigma_1\right)^2\right] \qquad (2)$$

where σ_1, σ_2 and σ_3 are the principal stresses as shown in Figure 2.

The stress criterion is the static stress plus the maximum dynamic stress amplitude.

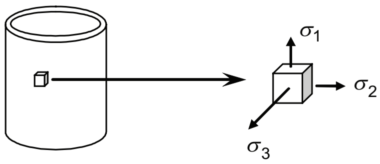
[e] Allowable stress and significant dynamic stress ranges are defined in Figure 3.

[f] σ_y is the minimum yield strength of the material.

[g] See 3.1.83 for definition of stress amplification factor, F_{SA}.

[h] The minimum top tension, T_{min}, required to prevent global buckling of riser is calculated as given in Equation (3).

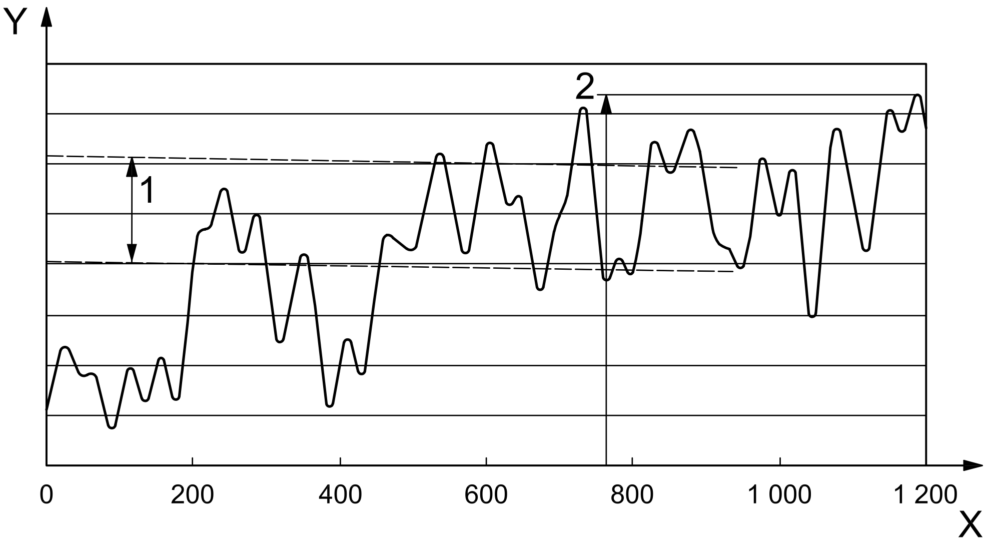
[i] The dynamic tension limit, F_{DTL}, is calculated as given in Equation (1).



Key

σ_1 axial plus/minus the bending stress
σ_2 hoop stress
σ_3 radial stress

Figure 2 — Riser internal stresses



Key

X time, expressed in seconds
Y stress, expressed in megapascals (kilopounds per square inch)

1 significant dynamic stress range
2 allowable stress

Figure 3 — Allowable stress and significant dynamic stress range

The purpose of the maximum stress analysis is to ensure that the riser is strong enough to support the maximum design loads. This is accomplished by requiring the riser to support the maximum design loads while keeping the maximum stresses below the allowable stress. This limit is intended to prevent structural deformation that can lead to failure and includes a margin of safety. All stresses in Table 2 refer to the von Mises stress criterion, σ_{vm}, (see Higdon, *et al.*, 1985). Local peak stresses (3.1.42) are not considered for the maximum load analysis; however, these peak stresses can be of concern for evaluating the fatigue life of the riser. Fatigue analysis is discussed in Annex B.

A minimum tension setting is required to ensure the stability of the riser. The tension setting should be sufficiently high so that the effective tension, as addressed in 5.4.4, is always positive in all parts of the riser even if a tensioner should fail. In most cases, the minimum effective tension is encountered at the bottom of the riser.

The minimum top tension, T_{min}, is determined by Equation (3):

$$T_{min} = T_{Sr\,min} \times N \big/ \left[R_f \left(N - n \right) \right] \tag{3}$$

where

N is the number of tensioners supporting the riser;

n is the number of tensioners subject to sudden failure;

R_f is the reduction factor, relating vertical tension at the slip ring to tensioner setting to account for fleet angle and mechanical efficiency;

$T_{Sr\ min}$ is the minimum tensioner ring tension, as given by Equation (4):

$$T_{Sr\ min} = W_s f_{wt} - B_n f_{bt} + A_i \left[\rho_m H_m - \rho_w H_w \right] \tag{4}$$

where

W_s is the submerged riser weight above the point of consideration;

f_{wt} is the submerged weight tolerance factor (minimum value of 1,05, unless accurately weighed);

B_n is the net lift of buoyancy material above the point of consideration;

f_{Bt} is the buoyancy loss and tolerance factor resulting from elastic compression, long-term water absorption and manufacturing tolerance (maximum value of 0,96, unless accurately known by submerged weighing under compression at rated depth);

A_i is the internal cross sectional area of riser, including choke, kill and auxiliary fluid lines;

ρ_m is the drilling fluid density;

H_m is the height of the drilling fluid column to the point of consideration;

ρ_w is the seawater density;

H_w is the height of the seawater column to the point of consideration, including storm surge and tide.

Note that in Equation (4) for $T_{Sr\ min}$, the exterior pressure, $\rho_w H_w$, is multiplied by the internal cross-sectional area of the riser, A_i, rather than the exterior cross-sectional area, A_o. This is because the buoyancy of the riser pipe walls, $\rho_w H_w$ ($A_o - A_i$), has been included in the submerged riser weight, W_s.

See sample calculation in Clause C.2 for a determination of the minimum top tension setting.

The significant dynamic stress range limit should also be used in conjunction with the maximum load analysis. This limit is intended to provide some control on the fatigue damage accumulated by the riser. Incorporation of this limit in the maximum load analysis eliminates large dynamic stresses that can lead to accelerated fatigue.

Additional operating modes that can influence the design should be considered. Specifically, the disconnected mode, handling-tool interfaces, hang-off on either spider or riser hang-off structure, special handling situations, and emergency conditions should be reviewed for their impact on riser system design.

5.3.3 Riser analysis report

Results of the design analysis should be appended to the riser operations manual (see 6.2). Instructions for determining required top tensions as a function of all the relevant parameters, such as mud density, should be included. The operating tensions provided to the operating personnel should be the tensions that it is necessary to set on the tensioner units. These tensions shall include corrections for tensioner-line fleet angles and losses through the tensioner system. Sufficient tension should be set so as to prevent riser buckling in the event of a tensioner unit failure.

Results of the design analysis are site-dependent and should include recommended tensioner settings versus mud weight. See Figure 8 for an example.

5.4 General riser modelling and analysis approach

5.4.1 General

The mathematical models and the solution techniques that can be used to analyse a drilling riser constitute a highly technical and specialized subject that has been widely treated in the literature. A bibliography is provided for the reader desiring detailed information, and the following text is limited to a general discussion of the pertinent aspects of riser analysis. In particular, reference is made to ANSI/API 16J.

Specific guidance on modelling and analysis is provided in 5.5 through 5.9.

5.4.2 Use of riser analysis

As a general rule, riser analysis has two distinct and different functions.

Prior to ordering a new riser, a set of analyses should be carried out to establish the design specifications. At this time, the environmental conditions are chosen to reflect the maximum operating conditions expected during the design life. Design criteria, such as maximum and alternating stresses, are used in the selection of parameters, such as wall thickness and material properties. The analysis includes the performance of the drilling vessel and should also be used for specifying the vessel's riser-tensioning requirements.

Riser analysis may also be used in preparation for operating with an existing riser and vessel on a new site. In that case, the objective is to establish the top tensioning requirements for the anticipated environmental conditions and drilling fluid densities. Further, the analysis indicates the environmental conditions during which drilling should be stopped and when it is prudent to pull the riser. The analysis also likely includes special conditions, such as hanging-off in a storm or the effect of a broken mooring line. The storm hang-off of the LMRP is one of several considerations that determine the number of bare joints needed.

5.4.3 Structural model

5.4.3.1 General

For purposes of riser response analysis, the drilling riser is a tensioned beam which rarely, if ever, deviates more than 10° from the vertical. For small angles, the fundamental Bernoulli-Euler beam equation adequately describes the response of the riser. The beam equation for the riser is developed by first examining a differential element and the forces that act upon it. Geometric non-linearities should be considered in an analysis if the riser develops an angle greater than approximately 10°.

Figure 4 shows the hydrostatic pressures of seawater and drilling fluid, the tension in the pipe wall and the weight. It also shows the deformation of riser pipe over an elemental length. Finally, the horizontal hydrodynamic forces are indicated. The equations of equilibrium and simple beam theory lead to the equation of motion. The group of terms forming the coefficient of y'' (Figure 4) is commonly called the “effective tension”. This form of the equation governing the behaviour of the riser has been recognized and reported in the literature for years. Riser problems are analysed by modelling the riser as a discretized or lumped-parameter representation. This results in a system of simultaneous equations that allows for variations in riser properties and for the introduction of such other non-uniformities as flex/ball joints and soil restraints.

5.4.3.2 Modelling considerations

In global riser analysis, the riser is modelled as a tensioned beam subjected to loads throughout its length, and with boundary conditions at each end, described as follows.

a) The tensioned beam element descriptions include riser geometry, riser mass and riser material properties. The lengths of the beam elements are important. Elements that are too long do not provide an accurate stress distribution along the riser, while elements that are too short increase run time and cost. Element lengths should be specified with respect to expected riser response along the riser, with shorter elements in areas where either the loading or riser geometry is rapidly changing. Typically, this occurs near the top of the riser in the wave zone and near the bottom of the riser in the vicinity of the lower flex/ball joint. Any intermediate flex/ball joint (see 4.9.1) also represents an area of rapidly changing riser geometry.

b) Loading on the riser includes internal and external pressures, as well as environmental loads caused by waves and currents. Internal and external pressure loads are generally caused by the hydrostatic pressures of the drilling fluid and seawater, respectively. Analyses should be performed for the full range of expected drilling fluid densities, considering that the column of drilling fluid usually has a higher hydrostatic head than that of seawater. The joint is normally modelled using only the dimensions of the main riser tube to calculate the bending rigidity, E_I, of the riser. The dimensions of the choke, kill and auxiliary lines, in addition to the outside diameter of the main riser tube, should be considered when calculating the hydrodynamic forces on bare riser joints. If buoyancy modules are attached to the riser joint, the outside diameter of the buoyancy module should be used to calculate the drag and inertial diameters (see 5.4.4). The model should account for possible shielding of the riser from the motions of the seawater. A riser deployed from a drillship is shielded from waves and currents until it emerges below the keel of the vessel, while a riser deployed from a semi-submersible is exposed to wave and current loads everywhere below the waterline. The weight used in the analysis should equal the weight of the entire riser joint, including choke, kill and auxiliary lines as well as support brackets and coupling.

c) Top boundary conditions generally include top tension, vessel offsets and motions, as well as a description of the rotational stiffness of the upper flex/ball joint. Typically, required top tension depends on the drilling fluid density. It can also vary with the operational and environmental conditions specified for each operational mode (see 5.1). A description of vessel motions is generally available in the form of response amplitude operators (RAOs) and phase relationships. The vessel motions modelled at the top of the riser should result from a wave description (amplitude and phase) identical to that used to model the loads on the riser. Horizontal offset of the vessel should be consistent with the steady wind, wave and current loads used in a stationkeeping analysis. Operational procedures may permit mooring-line manipulations to relocate the vessel in the event of long-term changes in environmental loads.

d) The bottom boundary condition can result from either a connected or disconnected riser (see 5.3.1 for operating modes). In the connected modes, the riser model usually ends at the lower flex/ball joint, in which case the rotational stiffness of that flex/ball joint is a bottom boundary condition and the horizontal and vertical loads, as well as the bottom angle, are outputs on the analysis. Some analysts prefer to choose the structural casing as the lower end of the riser, in which case the lower flex/ball joint is modelled as an intermediate flex/ball joint and the LMRP, BOP, wellhead and structural casing are parts of the riser model. For this situation, the rotational spring constant resulting from the soil interaction with the structural casing should be modelled. The bottom boundary condition of a disconnected riser should include the weight of either the BOP stack or only the LMRP, depending on the situation.

5.4.4 Effective tension

The effective tension controls the stability of risers and, therefore, represents a concept of great importance. It can be defined in several ways.

a) It appears as the coefficient of the y'' term in the basic differential equation describing riser behaviour.

b) It is the axial tension that is calculated at any point along a riser by considering only the top tension and the apparent weight of the riser and its contents (Sparks, 1984, 2007).

Effective tension, T_e, is related to the axial pipe wall tension, T_{real}, (also called real tension or true tension) by Equation (5):

$$T_e = T_{real} - P_i A_i + P_o A_o \tag{5}$$

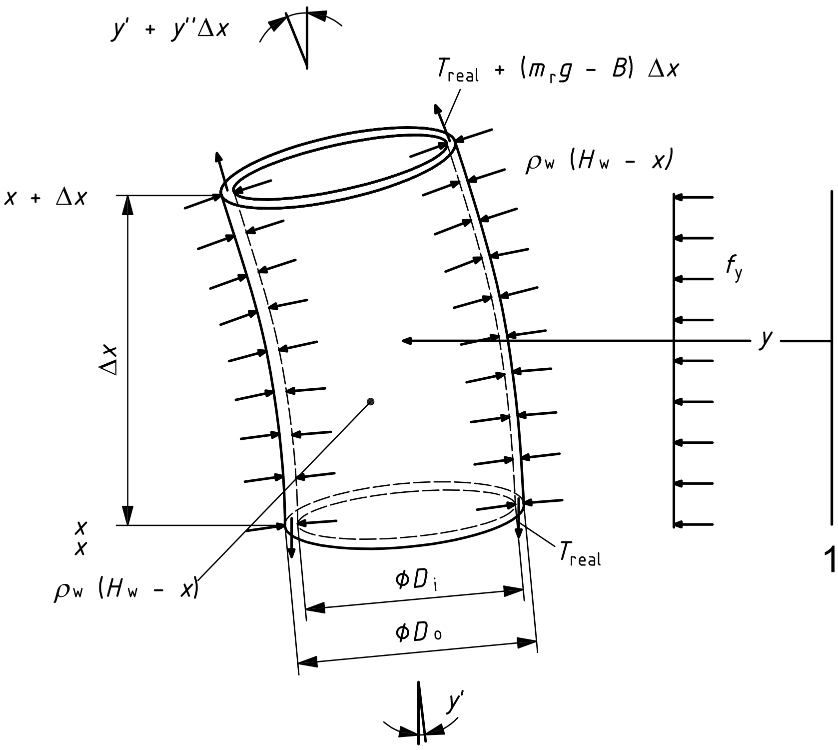
where

P_i, P_o are the internal and external pressures;

A_i, A_o are the internal and external cross-sectional areas;

T_{real} is the axial pipe wall tension derived from free body diagrams of the riser structure.

The riser should be designed so that the effective tension is always positive in all parts of the riser. See the discussion of minimum tension setting in 5.3.2 and Clause C.2.



Key

1 undeformed riser position

Figure 4 — Differential element of the riser

The governing differential equation of motion is given in Equation (6).

$$f_y = M\ddot{y} + EIy'''' - \Delta T y' - T_e y'' \tag{6}$$

where

$$M = m_r + (\pi/4)\left(\rho_m D_{i,riser}{}^2\right)/g$$

$$\Delta T = (\pi/4)\left(\rho_m D_{i,riser}{}^2 - \rho_w D_{o,riser}^2\right) + m_r g - B$$

$$T_e = (\pi/4)\left[\rho_w (H_w - x) D_{o,riser}^2 - \rho_m (H_m - x) D_{i,riser}^2\right] + T_{real}$$

where

B is the buoyant force per unit length;

$D_{o,riser}$ equal to D_h, is the outside diameter, or hydrodynamic diameter, of the riser section;

$D_{i,riser}$ is the inside diameter of the riser section;

ρ_m is the density of the mud;

ρ_w is the density of the seawater;

EI is the product of the modulus of elasticity (Young's modulus), E, and the moment of inertia, I, with respect to the neutral axis;

f_y is the distributed hydrodynamic force acting in the "y" direction;

g is the gravitational acceleration;

H_m is the total height of the mud;

H_w is the total height of the seawater;

M is the total mass (riser and mud) per unit length;

m_r is the mass of the riser (including buoyancy) per unit length;

T_e is the effective tension;

T_{real} is the actual tension in the pipe wall;

ΔT is the variation of the effective tension;

x is the vertical coordinate measured from the bottom of the riser;

y is the horizontal riser translation at x;

$\ddot{y}$ d^2y/dt;

y' $\partial y/\partial x$;

y'' $\partial^2 y/\partial x^2$;

y'''' $(\partial^2/\partial x^2)(\partial^2/\partial x^2)$.

5.4.5 Hydrodynamic model

5.4.5.1 General

There are three different hydrodynamic aspects to consider:

— sea surface: a description of wave height and period variations, either as regular waves or in the form of a wave spectrum;

— wave kinematics: a relationship specifying water velocity caused by wave motion, as a function of distance below the sea surface;

— force algorithm: a relationship specifying the force exerted on the riser from the velocity of the seawater relative to the riser.

All three hydrodynamic aspects depend primarily on empirical evidence. Although extensive data have been gathered in each area, as summarized below, there is as yet no final resolution as to the most accurate general model.

a) Sea surface: It is apparent from observation that, with few exceptions, random, multi-directional processes occur at the surface of the ocean. Nevertheless, most design analyses for offshore structures are based on a periodic, unidirectional wave. There are probably two principal reasons for this. First, the periodic wave is much simpler to deal with and second, in a severe weather design condition, a single-frequency wave often predominates. Nevertheless, the desire of many analysts to use as realistic a model as possible has led to random-wave analysis that requires the use of a wave spectrum such as that of Pierson-Moskowitz, Jonswap, ICSS, etc. (Sarpkaya and Isaacson, 1981; Chakrabarti, 1987). This includes both the linearized frequency-domain method, and the more accurate time-domain solution. (Burke and Tighe, 1971; Hudspeth, 1975; Botke, 1975).

b) Wave kinematics: For a number of years, researchers have worked on models to predict the fluid velocity and acceleration profile beneath the wave surface. In attempting to satisfy the boundary conditions, they have come up with a number of highly non-linear representations, such as Stokes III, Stokes V, Stream Function, etc. (Sarpkaya and Isaacson, 1981). Each of these is rather complicated and, for practical reasons, is generally used only with the single periodic wave model. Environmental data indicate that the easy-to-use linear Airy wave theory is quite adequate for modelling regular wave kinematics for a large number of offshore locations and environmental conditions. It is particularly appropriate for drilling riser analysis, because drilling risers are not normally deployed in shallow waters where the applicability of the Airy wave theory is limited. The linearity of Airy wave theory renders it applicable for combining individual wave kinematics into a spectral representation. However, some limitations remain in all of the wave kinematics theories. None of the theories is accurate near the wave crests or troughs, and the combination of currents with waves is not well understood.

c) Hydrodynamic force algorithm: Hydrodynamic forces are typically evaluated using the Morison equation (Morison, *et al*., 1950). There is, however, extensive debate as to the selection of the drag and mass coefficients, especially in severe sea states. Further complicating the issue for the riser designer is the fact that most of the coefficient data has been acquired from fixed structures. The influence of the riser's relative motion in the waves should be considered.

Drag and mass coefficients, C_d and C_m, vary significantly with cross-section shape, roughness, Reynolds number, Keulegan-Carpenter number and the orientation of auxiliary lines. The correct choice of C_d is a prime factor in determining riser behaviour, because drag controls both hydrodynamic excitation and damping. The selection of an artificially large C_d value is not always conservative.

Commonly used values of C_d and C_m are given in Table 3.

Table 3 — Commonly used values of C_d and C_m

Buoyant riser (based on the diameters of the buoyancy module)			**Bare riser** (based on the diameter of the main tube)		
Reynolds number	C_d	C_m	**Reynolds number**	C_d	C_m
$\mathrm{Re} < 10^5$	1,2	1,5 to 2,0	$\mathrm{Re} < 10^5$	1,2 to 2,0	1,5 to 2,0
$10^5 \leqslant \mathrm{Re} < 10^6$	1,2 to 0,6	1,5 to 2,0	$10^5 \leqslant \mathrm{Re} < 10^6$	2,0 to 1,0	1,5 to 2,0
$\mathrm{Re} \geqslant 10^6$	0,6 to 0,8	1,5 to 2,0	$\mathrm{Re} \geqslant 10^6$	1,0 to 1,5	1,5 to 2,0

An alternative practice is to use an “equivalent diameter” and “equivalent area” (riser main tube plus choke, kill and auxiliary lines) based on the sum of projected diameters and areas with appropriate values of C_d and C_m.

The Morison equation estimates the hydrodynamic force on a body caused by the relative velocity and acceleration of the surrounding fluid. The force is parallel to the flow. In addition, under certain circumstances, there can be a relatively high-frequency oscillating force, predominantly transverse to the flow, caused by the shedding of vortices. When the riser (or an integral line) has natural frequencies of vibration near the shedding frequency, vibrations of substantial amplitude can occur. Although this phenomenon is most likely in high currents and/or in uniform current profiles, it has also been observed in large waves. "Vortex-induced vibration" is accompanied by a large increase in drag. Methods for predicting vortex-induced vibration and drag increase for risers in real environments are not well established, although general guidelines are available (Every, King and Weaver, 1982).

5.4.5.2 Three-dimensional analysis

Thus far in this part of ISO 13624 and in most of the published literature, riser analysis methods have been based on planar motion. The assumptions are that the vessel, the wave, the current and the riser all move in a plane. In reality, waves come from various directions that do not necessarily correspond with the current direction. Also, the vessel responds in some combination of surge and sway. The implication is that, to be totally comprehensive, an analysis method should permit riser motions in three dimensions. This permits the analysis of the riser response in multi-directional, random seas with currents acting at any angle relative to the sea and the vessel motion. The equations of motion remain unchanged, they simply double in number. There is one set of equations for each of the two horizontal, orthogonal directions and the two sets of equations are coupled to each other through any non-linear terms, such as the hydrodynamic forces.

5.4.6 Lumped-parameter model

The partial differential equation that governs riser behaviour is not directly applicable for analysing general problems. It is, therefore, usually converted to a system of finite length elements using either a finite-difference or finite-element technique. The behaviour of the riser can then be described in terms of the nodes at which these elements are joined. The solution involves finding the translations and rotations, bending moments, etc., at each node of the riser. While each of these idealized elements has uniform properties, the non-uniformities of the riser are accounted for by the variation of properties from element to element. This discretization of the riser leads to a series of simultaneous equations that are conveniently and rapidly solved on a computer.

Finite-difference and finite-element techniques are alternative means of formulating simultaneous equations. The finite-difference procedure involves conversion of the continuous derivatives into linear, finite differences. Perhaps the most often referenced illustration of this method for riser analysis is the work done for the Mohole project by NESCO, 1965. Later, Botke, 1975, went through an extensive derivation of the riser equations and finite difference method of solution.

In the finite-element method, it is assumed that the deformation of segments is expressible as the summation of a series of deformation functions related to the deflections of the nodes. This method, as applied to risers, has been described in detail by Gardner and Kotch, 1976.

Both methods are appropriate and can be expected to give accurate and reliable results if used with care and understanding. Perhaps the most critical consideration is the number of elements into which the riser is divided. The spacing of the nodes should be fine in the areas where high bending moments tend to occur. These are always in the wave zone and near the bottom of the riser where the tension is the lowest. Because the finite-element method uses higher-order functions between the nodes than does the finite-difference method, accurate finite-element solutions are generally possible with fewer nodes than from comparable finite-difference solutions. As a general rule, the number of nodes may vary from 30 to 40 for a shallow-water riser when using the finite-element method to several hundred for a deep-water riser using the finite-difference approach.

5.4.7 Solution of the simultaneous equations

The previous section dealt with the mathematical techniques for converting the spatial derivatives into discrete translation coordinates for solution as simultaneous equations. In addition, the governing equation for the riser includes a time derivative in the inertia term. Inclusion of the inertia term yields a mass matrix and the acceleration at each of the nodes. Structural damping, if important, may be added to the equation. When these dynamic terms are included, additional mathematical techniques are required for solution.

For a two-dimensional global riser analysis, it is the wave action and associated vessel motion that provide the dynamic excitation. The waves impose time-varying hydrodynamic forces on the riser, while the vessel drives the top of the riser back and forth, producing additional contributions to the time-varying forces. The applied riser tension also has time-varying components caused by the non-ideal characteristics of the tensioner system and the inertia and geometric effects associated with the vessel, riser-string and slip-joint motions.

There are static, quasi-static and dynamic methods. The static method considers only the riser's response to a constant vessel offset and a current profile, which can change with depth but not with time.

In the quasi-static method, the time-dependent parameters are varied in a series of static solutions. The inertial effects are not included. Also excluded from the hydrodynamic calculation is the relative velocity of the riser passing through the water. The wave and vessel motion are “stepped” past the riser, the static solution is calculated for each step, and the maximum values of the critical parameters are observed over one wave period.

There are two different approaches for solving the equations while including dynamics and relative velocities. A time-domain solution is the more direct and straightforward method and encompasses a direct integration of the equations. Runge-Kutta and Newmark-Beta (see Zienkiewicz, 1977) are two of the well known methods of numerical integration. They permit the inclusion of all non-linearities, such as the non-linear hydrodynamic force, non-linear soil behaviour, non-linear friction characteristics, etc. There is virtually no limitation on the phenomena that may be included. The drawback is cost. The solutions should be carried out over a relatively large number of iterations and each solution represents only one combination of parameters.

Burke, 1974, outlines a frequency-domain technique that, through the use of simplifications, allows a great reduction in cost. All of the input forces and motions are assumed to be sinusoidal, and all the non-linear functions are assumed to be linear about a quasi-steady or mean value. The primary difficulty in this method comes with the non-linear hydrodynamic drag force. An iterative procedure is used whereby the equivalent linear drag is varied in successive solutions until it gives the same amplitude as the non-linear drag. Later, Krolikowski and Gay, 1980, reported a modification to the frequency-domain technique that, for combined current and waves, substantially increases its accuracy with little increase in the solution cost.

5.4.8 Local finite element analysis

Most riser programs use the finite-element method (beam elements) to calculate the global response of the riser structure. The solutions from these global programs do not address the local details of the riser structure. These local details include the connection points (couplings) of two joints a riser, connection of the riser joint to the flex or ball joint and connection of the riser joint to the slip joint.

If the designer has concerns with these connections because of an over-stress situation, high stress-concentration factors (which greatly reduce fatigue life), excessive distortions, etc., a local finite-element analysis should be undertaken to calculate the state of stress and distortion for the connection.

A general-purpose finite-element program is needed to model the connection using either three-dimensional finite elements or axisymmetric elements. If plane stress or plane-strain elements are used (two-dimensional analysis), it is necessary to take considerable care to ensure that the local finite-element model is experiencing plane-stress or plane-strain conditions.

All structural components of the local detail should be modelled to ensure proper interaction of the structural components. Input of loads for the local finite-element model are derived from the global riser analysis for various loading conditions. Depending on the finite-element model, displacements and rotations rather than forces and moments may be used to transfer the loadings from the global model to the local model.

The local finite-element mesh should be created with good modelling practices, paying particular attention to finite-element aspect ratios, finite-element selection (what type of shape function is assumed for the element's derivation), boundary conditions and mesh densities. Mesh densities are especially important in areas where the stress is rapidly changing.

5.5 Coupled/decoupled analysis methodology

Coupled and decoupled analysis of a drilling riser and wellhead conductor/structural casing system for structural integrity and operability evaluations provide understanding of the soil-riser system interaction.

Detailed guidance and a worked example on developing and constructing coupled and decoupled riser models are provided in ISO/TR 13624-2. The report covers the riser system from the structural casing, below the mud line, to the upper flex joint or ball joint inclusive of all components in between. It does not cover the vessel/riser coupling, i.e. the influence that the riser has on the vessel RAOs.

Coupled analysis involves modelling the entire drilling riser system in the same model.

Decoupled analysis involves modelling the drilling riser and BOP/conductor/casing separately. Loads transferred from the base of the drilling riser to the lower flex joint in the drilling riser model are applied to the top of the LMRP in the BOP/conductor/casing model.

5.6 Drift-off/drive-off analysis methodology

5.6.1 Introduction

Drift-off/drive-off analysis of a drilling riser system identifies disconnect limits for dynamically-positioned (DP) vessels. Specifically, this analysis is used to determine yellow-alert and red-alert offsets that alert the crew that the vessel is drifting or driving off.

5.6.2 Overview of drift-off/drive-off analysis

During normal drilling operations, the excursions of a drilling vessel from its mean position are usually restricted to a small percentage of the drilling water depth, typically 1 % to 2 % when the drillpipe is rotating or moving vertically through the riser. This is to ensure that the riser system is protected from wear.

However, if the vessel's DP system fails, the vessel can drift off or drive off. Common practice calls for predetermined offset limits that alert the crew when specific actions are to be taken to ensure that the riser can be disconnected without exceeding its allowable limits. These offset limits are generated in preparation for such an event by performing a drift-off/drive-off analysis of the drilling riser system.

The objectives of a drift-off/drive-off analysis are as follows.

— Determine when to initiate the riser disconnect procedure (red- and yellow-alert offsets).

— Determine the allowable limits for riser response that drive the riser disconnect decision. These include top riser angle, bottom riser angle, slipjoint stroke, tensioner stroke, wellhead bending moment and conductor bending stress.

The drift-off simulation is typically based on a vessel directly over the wellhead that is exposed to the actions of wind, waves and current without the resistance of thrusters. A “black-out” is a typical event that can cause a drift-off. A drive-off simulation is typically based on a vessel directly over the wellhead that is exposed to the actions of thrusters driving the vessel for a specified duration and then drifting under the actions of wind, waves and currents. The drive-off scenario chosen for analysis typically considers advance warning from the DP system and the reaction time of the DP operator (DPO). DPO training is a consideration in assessing the likelihood and severity of the drift-off/drive-off scenarios.

The simulations described above should be done using a transient, time-domain analysis (or equivalent) that includes the effect of riser-restoring force, vessel rotation (moving toward a stable beam seas heading) and the coupled effects of the BOP, conductor pipe and soil resistance.

Historically, the above analysis has been sufficient for industry's purposes. However, special studies have included what is referred to as “weak-point analysis”, which addresses component failure in the unlikely combination of events in which the DP system fails, the riser fails to disconnect from the well and the metocean conditions are severe enough to cause the vessel to drift off far enough to exceed allowable limits. The redundancy in DP systems, the redundancy in riser-disconnect systems and the low frequency of metocean conditions combine to give a very low probability that further reduces the likelihood that drift-off/drive-off, failure to disconnect and severe metocean conditions will occur simultaneously.

5.7 Weak-point analysis methodology

5.7.1 Introduction

"Weak-point analysis" can be performed to predict the most probable point of failure in the riser/wellhead system. This analysis can be used to select structural casing and wellhead equipment in order to ensure wellbore containment in this extreme event.

5.7.2 Overview of weak-point analysis

It should be noted that in order for wellbore containment to be a concern, it is necessary that a sequence of events occur:

a) dynamic-positioning or mooring-system failure;

b) emergency and/or manual disconnect-system failure;

c) environmental conditions severe enough to overcome the restoring force from the riser and thus allow sufficient offset of the vessel to impose the loads required for a component failure;

d) well operation at a critical stage, such that riser disconnect can cause significant environmental damage (i.e. drilling in a hydrocarbon-bearing zone or well testing).

Redundancy in rig position and riser disconnect systems on dynamically positioned rigs, along with the probability of occurrence in the environmental conditions required, result in a very low probability of occurrence for this event. Therefore, this analysis is not normally performed.

Initially, analysis of environmental forces required to impart the necessary loads for failure may be undertaken. This may be used to evaluate risk, based on the probability of occurrence. In some cases, the region's environmental forces might not be sufficient to result in a failure and, therefore, weak-point analysis is not useful, i.e., the riser/wellhead system anchors the rig without failure. This analysis may also be used to define the minimum environmental conditions required and procedures can be developed to prevent the failure from occurring, i.e. planned disconnect of the riser prior to exposure to the environment.

In a weak-point analysis, potential failure points in the system are identified. Typically, this analysis is performed by a finite-element computer program. All components in the system are modelled from the tensioners to the structural casing, including the telescopic joint, riser, flex joints, BOP, wellhead and foundation soils.

The rig is offset, in the computer model, until the first limit in the system is reached and the weak point defined. This type of analysis is referred to as an elastic analysis as it predicts the first component to reach its yield limit. Very often this analysis is a static analysis but can be provided as a dynamic analysis. A dynamic analysis allows coupling of the rig to the riser, includes the environmental forces and accounts for the inertia in the system. However, it is necessary to take care with the selection of environmental forces, as higher environmental forces can result in larger inertial effects, which can result in lower loads on the wellhead than would be predicted with lesser environmental forces. (i.e., higher rig drift speeds result in more lag of the riser in the water column, which would result in lower wellhead loads).

Typically, the two components that reach their yield limit first are the telescopic joint immediately below the tensioner ring and the structural casing. Shortly after the tensioners bottom out, maximum loads are reached. This results in high bending moment and tensions in the telescopic joint and well-containment equipment, while the main loading in the riser is tension. The ideal situation from a weak-point analysis approach is to have the telescopic joint or riser reach its weak point prior to the pressure-containment equipment.

The component that reaches its specified yield limit first might not necessarily be the component that fails first. For instance, if the structural casing reaches its specified yield point first, it can deform and relieve loads on the structural casing, while loads on the telescopic joint continue to increase. Secondly, the telescopic joint is constrained by the tensioner system, while the structural casing is constrained by the soils.

A plastic analysis may be undertaken by using actual material properties of selected components. Stress-strain data may be used in the computer program to analyse the ultimate failure point of the selected components. The rig offset is increased until the ultimate material limit at first fibre of the first component is reached and that component is defined as the failure point. This type of analysis accounts for reduction in loads due to yielding and allows analysis of the components using their actual yield and ultimate strengths.

This failure event is a result of extreme environments and, therefore, dynamic impact occurs as the tensioners bottom-out. This, along with the fact that the loads in the telescopic joint increase rapidly compared to other components, often leads to the telescopic joint as the predicted failure component.

These types of analyses do not include complete separation of components, as they do not include ovaling, local buckling, formation of plastic hinges, ductile elongation, load redistribution or crack propagation to final separation.

5.8 Recoil analysis methodology

5.8.1 Introduction

The purpose of 5.8 is to describe riser recoil analysis.

The intent is to focus on water depths of up to 3 048 m (10 000 ft). It is assumed that the emergency disconnect sequence (EDS) completes and the LMRP connector releases.

5.8.2 Overview

An EDS typically requires 30 s to 60 s to complete. The emergency disconnect system may be equipped with several disconnect sequences to accommodate a variety of circumstances. A substantial change in offset and flex joint angles can occur in this short amount of time. Under these circumstances, there is far too little time to displace the mud in the riser with seawater and reduce top tension to prepare for disconnect.

Disconnect typically occurs in the connector between the LMRP and the top of the BOP stack. This causes a sudden imbalance in tension that accelerates the riser upward, initiating “riser recoil”. Failure to control recoil effectively can cause the riser to impact the vessel substructure with a force that can surpass the structural limits of the components in the load path (e.g., TJ inner barrel, upper flex joint, diverter, rotary table, etc.). Hence, most (if not all) modern drilling vessels are equipped with riser-recoil control systems. The configurations vary significantly from one vessel to another. With appropriate planning, preparation and engineering, safe emergency disconnect is possible whenever the drilling riser is connected to the wellhead. A complete riser-recoil analysis simulates the system's behaviour under various conditions and can provide guidance on TJ spaceout, recoil control system settings, criteria and operating limits (tension, mud weight, and vessel motion). It is necessary that a realistic riser-recoil simulation model the tensioner system in detail, accounting for the kinematics of all moving parts (including the air and oil), forces, pressures and friction. Similar detail is also required in the mud column in order to simulate accurately the load that the mud column imparts on the riser.

Detailed guidance and a worked example are provided in ISO/TR 13624-2.

5.9 High-current environment

5.9.1 Introduction

The use of marine drilling riser systems in currents exceeding 1 m/s (~2 kn) generally causes operational difficulties, but surface currents as low as 0,5 m/s (~1 kn) in certain circumstances have caused difficulties, especially during tripping, running and pulling the riser. Problems arise because of high drag loads on the riser, vessel and mooring system, and because the riser can experience vortex-induced vibrations (VIV) (Gardner and Cole, 1982). High current-induced drag forces result in large riser angles and possibly high bending stresses. Aside from high drag forces, high currents can also cause lateral structural vibrations of the riser which, in turn, further increase drag and fatigue damage.

High current drag loads on the vessel and its mooring system cause high mooring line tensions and corresponding increased vessel offset, with its detrimental effect on riser angle. Mooring capability should include an evaluation of the loads on the riser system (see API RP 2SK for design and analysis of spread mooring systems).

High currents also have a significant impact on open-water operations, which include running the conductor casing strings and the running and retrieval of the riser and BOP.

Where current velocities indicate the potential for vortex-induced vibration of the riser, a VIV analysis is typically performed, which considers both the modal response[1)] of the riser and the hydrodynamic excitation of the current. Where significant VIV is predicted, consideration is typically given to deploying VIV suppression hardware such as fairings.

5.9.2 Mitigation

Lower flex/ball joint angles can be reduced by moving the vessel upstream of the wellhead. For such situations, caution should be exercised to ensure that the upper flex/ball joint angle remains within acceptable limits. Increasing the top tension can further reduce the riser angles, but results in higher axial stresses and increased bottom tension.

Riser fairings have been used successfully (Gardner and Cole, 1982) to cope with the above-described effects. Fairings are streamlined, airfoil-shaped appendages. Usually, they are fabricated from fibreglass and attached to the riser so that they are allowed to weathervane. Depending on design, they can reduce current drag by more than two-thirds, and prevent vortex-induced vibrations. They are very effective but are cumbersome to install and remove. This significantly slows riser deployment and retrieval. Areas prone to tropical storm events are particularly affected by the increased time to prepare for abandonment when fairings are installed on the riser.

Another method to counteract the effects of vortex induced vibrations is the use of strakes (Gardner and Cole, 1982). These devices are clamped onto the riser in a helical pattern. They are effective in suppressing vibrations but, in the absence of vibrations, a straked riser experiences higher drag loads than does an unstraked riser.

The staggering of riser joints, with and without buoyancy, can be effective in reducing the magnitude of vortex-induced vibrations (Brooks, 1987, and Vandiver, 2003).

5.9.3 Analysis

The analytical prediction and description of vortex-induced riser vibration is complex. It depends on the interaction of the current velocity and the lateral vibration modes of the riser. The lateral modes are functions of riser geometry, riser mass, which in turn depends on riser contents, and tension. The excitation of any given mode depends on the current velocity and its distribution along the riser with respect to that mode.

Consequently, it is necessary to select those current profiles for investigation carefully, with particular attention given to occurrence and persistence data. Such data are often difficult to obtain, especially for exploratory well locations.

The maximum current condition, for example, a 10 yr return, might not produce the worst fatigue loading. The velocities or distribution associated with the maximum current can be such that no lateral mode is strongly excited, or its persistence can be such that little fatigue loading is induced. Lower current velocities with more unfavourable uniform distributions and much greater persistence can control fatigue life.

1) The reader is referred to the papers by Allen, D.W.,1995; Furnes, G.K., *et al*., 1998; Hover, F.S., *et al*., 1997, 1998; Huse E., 1998; Techet, A.H., *et al*., 1998; Triantafyllou, G.S., 1998; Triantafyllou, M.S., *et al*., 1994, 1999; Vandiver, J.K., (several).

5.9.4 Riser management

Proper riser management in high-current situations requires continuous information on vessel position, upper and lower flex/ball joint angles and current profiles. Proper instrumentation to measure and display these items should be provided any time high currents are expected.

5.9.5 Open-water operations

5.9.5.1 Open-water operations include drilling the holes for the surface casing strings, running and cementing the surface casing strings and running, landing and retrieving the riser and BOP.

The limiting environmental criteria for running and retrieval operations should be determined. The study should encompass the following as a minimum:

a) vortex-induced vibration (VIV) analysis;

b) lateral deflection analysis;

c) for running, landing, and retrieval of the BOP/LMRP, the axial response of the riser system; the handling tools, travelling equipment and drill line should have loading ratings compatible with the resulting maximum static and dynamic loads.

5.9.5.2 In order to define the limiting current and wave conditions in which the casing strings can be run, the following approach is proposed.

a) Define the minimum fatigue life required to safely conduct the operation.

b) For each of the dominated statistical extreme current profiles (surface-dominated, bottom-dominated or slab), determine the maximum current profile allowed that generates the minimum fatigue life in a) for each of the following deployment depths:

   1) 5 % of water depth, WD,

   2) 15 % WD,

   3) 25 % WD,

   4) 40 % WD,

   5) 60 % WD,

   6) 80 % WD,

   7) 95 % WD.

c) Casing in the hole (rigid bottom connection).

d) For the maximum current profiles determined in b) at each deployment stage, an effective drag coefficient, C_{d}, should be calculated to use in lateral deflection analyses.

Should the fatigue life prove too short for currents expected at the site, then VIV suppression options, such as strakes, should be investigated for casing running operations, or the operations restricted to periods of more favourable current conditions.

The modal response of a suspended riser string differs significantly from that of the connected riser; consequently, a separate analysis of the suspended configuration should be considered for the riser to be deployed in high currents or for the riser to survive disconnected from the LMRP in high currents.

5.10 Hang-off analysis methodology

5.10.1 Purpose

The purpose of 5.10 is to describe the methodology for performing the analysis of a drilling riser when it is supported by the vessel and disconnected from the wellhead. This condition is called hang-off.

5.10.2 General

The analytical methodology described in 5.10 is applicable to riser hang-off from mobile floating drilling vessels.

5.10.3 Overview

Two configurations are used for riser hang-off: running/pulling configuration and storm configuration. In each case, the riser is analysed to demonstrate that during hang-off, all the limits on stress, displacements/clearances and rotations are satisfied for the riser and the other equipment used in implementing hang-off. The end result of hang-off analysis is

a) operating limits for running/pulling of the riser;

b) the feasibility of hard or soft hang-off, typically in a 10 yr storm or in a periodic wave environment;

c) determination of the number of bare riser joints at the bottom of the riser string.

Worked examples for riser hang-off are provided in the papers by Ambrose, *et al*., 2001, and Brekke, *et al*., 1999.

5.10.4 Definitions

The following definitions are used for riser hang-off.

a) Running/pulling configuration: The riser is run or pulled in environmental conditions defined in the rig operations manual as suitable for the operation. The riser can be run with the BOP or just with the LMRP.

b) Storm configuration: The riser is hung off (disconnected) near the wellhead in a severe storm with the LMRP in the riser string.

c) Hard hang-off: The riser is effectively locked to the vessel and moves with it. Hard hang-off is applicable to either the deployment/retrieval configuration or the storm configuration.

d) Soft hang-off: The riser support at the vessel is either through the tensioners only or the tensioners and the motion compensator. This support is generally like a soft spring that results in very little riser vertical motion. The vessel motions are substantially greater than the riser motions, and the riser load variations are substantially lower in this condition than in the hard hang-off condition.

e) Motion compensator: A tool is normally used to support the drillstring. It is also used in conjunction with the tensioning system for soft hang-off.

f) Riser hang-off tool: The tool used to latch onto an interior profile in the riser and connect it to the motion compensator.

5.10.5 Modelling guidelines

At least two riser hang-off configurations should be analysed: running/pulling configuration and storm configuration. Periodic-wave environments such as swell waves can also warrant an evaluation of a special hang-off configuration.

For all models, whether they are used for running/pulling or for storm events, the riser may be assumed to be open at the bottom and filled with seawater, which is free to move in and out of it, unless the riser operating procedure indicates that seawater or drilling fluid can be entrapped in the riser and, therefore, constrained to move with it. In the latter case, the model should include the added mass effect of the entrapped seawater or fluid.

5.10.6 Running/pulling configuration modelling

For the riser running/pulling configuration, the riser is supported by the hard hang-off method, since it is either hung off on the travelling block with no motion compensation or landed in the riser spider. Four models are recommended below for analysis. The near-wellhead model c) is the most important, since the riser has the largest riser mass in the water. Models a) and b) may be omitted if the environment is mild.

a) Wave-zone model: The LMRP and BOP are in the wave zone. This case should be considered because wave-slamming forces on the BOP and LMRP, combined with surface current drag, cause the riser to displace laterally, resulting in bending stresses at the hard hang-off point on the vessel. Displacements and stresses can be significant if the lateral deflection period of the riser is close to the wave period.

b) Intermediate model: The LMRP and BOP are at a point where the current velocity is maximum or at a point where the current normal drag force on them causes maximum bending in the riser. Also, the model can be used to compute maximum lateral displacements that should be checked against moonpool clearance in drilling ships and pontoon clearance in semi-submersible rigs. Furthermore, the model can be used to evaluate diverter-housing clearance if the riser is hung off from the travelling block.

c) Near-wellhead model: The LMRP and/or BOP are just above the wellhead. This case is significant because it can govern the selection of the number of bare joints in the riser. There are two models.

   1) Only the LMRP is in the riser string. In this case, a minimum number of bare joints is needed to add enough weight to prevent compression at the top.

   2) The BOP is in the riser string. In this case, a maximum number of bare joints should not be exceeded for the top tension to be less than the lifting gear capacity.

Stroking of the slip joint should not be considered in these models, since the joint is collapsed and locked. The position of the hard hang-off point relative to the vessel's centre of gravity (CG) should be included in the model so that the vessel RAOs can be properly applied.

5.10.7 Storm-configuration modelling

In a storm configuration, the riser may be supported either by the hard hang-off method or the soft hang-off method. In the following models, the riser bottom is near the wellhead and either the BOP or just the LMRP are in the riser.

a) For the hard hang-off method, the slip joint is collapsed and locked on the vessel.

b) For the soft hang-off method, two methods may be employed:

   — tensioner hang-off method, where the riser weight is supported entirely by the tensioning system;

   — combined tensioner-motion compensator method, where the riser weight is shared by the tensioner and the motion compensator.

The tensioner system may be modelled using springs as described in detail in ISO/TR 13624-2:—, 4.4. Similarly, a spring may be used to model the motion compensator-hang-off tool assembly. The slip joint may be modelled using a beam as described in ISO/TR 13624-2:—, 4.4. These modelling techniques enable the prediction of stroke-out in the tensioner, the slip joint and in the motion compensator. Typically, these components are set at their mean stroke positions to minimize the likelihood of stroke limits being exceeded.

The model should specify the position of the support of each tool (i.e., the springs' upper ends) relative to the CG of the vessel, so that the vessel RAOs can be properly applied.

5.10.8 Analysis guidelines

Because of the axial dynamics encountered in hang-off events, time-domain analysis should be conducted using random-wave analysis and a simulation time of at least 1 000 times the zero up-crossing period of the sea state.

Two sets of metocean conditions are typically used: one for the running/pulling configuration and one for the storm configuration. For running/pulling, metocean conditions consistent with vessel heave, specified in the rig operations manual, are typically used. For the storm configuration, metocean conditions associated with a 10 yr storm are typically used. Bow and quartering (± 20° for a ship-shaped vessel) sea states are generally sufficient for hang-off evaluation.

Sensitivity studies should be performed to evaluate variations in critical analysis parameters, including the following:

a) tangential added mass;

b) wave period.

5.10.9 Evaluation criteria

The evaluation criteria for storm hang-off are as follows:

a) for soft hang-off, the appropriate stroking limits for tensioner, slip joint and motion compensator;

b) contact: no contact between riser and moonpool;

c) maximum top tension: the rating of the lifting gear;

d) minimum top tension: 10 % of the rating of the lifting gear, to avoid uplift on spider or lifting gear;

e) minimum tension along riser: no explicit limit, since momentary compression in the riser does not represent failure (Brekke, *et al.*, 1988); the consequences of compression are covered by motion/stress limits;

f) maximum top tension: rating of substructure, diverter, upper flex joint and other components, such as the hang-off tool;

g) maximum top lateral forces, bending moments: the rating of the lifting gear;

h) riser stress: see 5.3.

5.10.10 Commentary on soft hang-off analysis

The key to minimizing load variations is to open all the APVs and thus minimize the stiffness in the tensioner system so that the riser's first axial period is substantially greater than the vessel heave period.

a) To accurately model the riser response in the soft hang-off mode of operation, the model can include only one tensioner or all of the tensioners. Each tensioner line can be modelled to capture the effect of any asymmetrical loading generated by the vessel wave frequency motions (surge, sway, heave, roll, pitch and yaw). A spring can be used for each tensioner wire. With the location of the riser hang-off points modelled relative to the vessel CG, the vessel motions can be applied properly to the riser.

b) Brekke, *et al.*, 1999, reported that regular wave analysis was found to be too sensitive to riser natural periods and that random-wave analysis is preferable.

6 Riser operations

6.1 Introduction

Efficient deployment and subsequent retrieval of the riser and BOP stack are integral parts of the marine riser design. The designer should consider not only normal procedures, but also emergency disconnect and hang-off procedures, as employed during a storm. These conditions can dominate the design criteria.

Clause 6 presents examples of riser procedures. Operating personnel on each floating drilling vessel should be equipped with a written procedure on how to use the marine riser. These procedures should include operating guidelines for the specific riser equipment, vessel storage and handling equipment.

The care and use of a marine riser system should be supervised by trained and qualified personnel, i.e., designated personnel who, by reason of experience and instruction, are familiar with both the operation being performed and the potential hazards involved.

6.2 Riser operations manual

A comprehensive and up-to-date riser operations manual that includes the following should be maintained on board the vessel at all times to provide information about the marine riser system and the drilling vessel:

a) manufacturer's drawings of the riser-system components outlining critical dimensions, masses and part numbers of the various components;

b) manufacturer's load ratings for the critical components of the riser system;

c) internal and collapse pressure ratings of the riser and integral lines;

d) inspection and maintenance procedures for each component;

e) procedure for running and retrieving the riser;

f) procedure for establishing maximum and minimum tension settings;

g) operating limits and emergency procedures;

h) recommended spare parts inventory list;

i) criteria and procedures for cutting and slipping tensioner lines.

For each new drilling location, it is necessary to update the riser operations to reflect the current configuration of the riser system and site-specific operating envelopes. In practice, a site-specific supplemental report is usually prepared for each new drilling location to supplement the generic, comprehensive riser operations manual. The specific riser stack-up (arrangement of riser joints) and operating envelopes are ordinarily included in the site-specific supplemental report.

6.3 Drilling-riser-operations information systems

6.3.1 Monitoring and forecasting

Riser operating limits are dependent on the following factors:

— top tension and mud density;

— flex joint and ball joint angles;

— vessel position;

— wave height and current velocities.

These parameters should be monitored regularly and recorded in a running log to provide an accurate account of operating history. These records provide a background of experience to apply for future operations and provide a basis for determining the need for riser inspections and maintenance.

In addition to the requirements for riser monitoring, it is necessary to forecast accurately the environmental conditions. Riser operations are more critical in deep-water. Longer risers are inherently more vulnerable to excessive stresses. Deeper water requires more time to run the riser and operations can be limited by the severe currents found in many deep-water provinces. Accurate forecasts of environmental conditions are necessary to ensure that a sufficiently long weather window exists to successfully and safely complete the operations.

6.3.2 Riser operating history

Records of riser usage are necessary to evaluate riser condition and to determine inspection requirements. These data should become a permanent record in the riser operations manual as a reference for future operations and to provide a basis for estimating cumulative riser fatigue damage. The following data shall be recorded:

— operations summary;

— riser stack-ups;

— inspection records.

The operations summary should include sufficient details of environmental conditions and riser-operating parameters to permit analytical estimation of potential riser deterioration, such as wear, corrosion and fatigue.

6.4 Preparing to run riser

6.4.1 General

The preparation required prior to running the riser and landing the BOP stack is described in 6.4. Although there are exceptions, normally the structural and conductor casings have been set and cemented and the wellhead landed before the riser and BOP stack are run.

The preparation involves the steps described in 6.4.2 and 6.4.3.

6.4.2 Site-specific marine riser length determination

The water depth should be measured before operations are begun and the elevation of the wellhead above the mud line should be measured at the time the wellhead is cemented in place. Determining the marine riser length involves choosing the number of riser joints that will properly make up the riser string. A good method to check water depth and determine the required length of the riser string is to measure the actual length of the 508 mm (20 in) landing string. The riser string length is normally planned so that the length of the telescopic joint is near or short of its mid-stroke length when the BOP stack is latched onto the wellhead and the rig is at its normal drilling draft at mean sea level. The actual spaceout is determined using the contractor's operating practices considering that, in the event of a vessel drive-off, it is advantageous to have the riser spaced-out with the telescopic joint less extended to provide greater vessel travel before the telescopic joint bottoms-out. However, a more extended telescopic joint can give the riser-recoil system more time to decelerate the disconnected riser.

Only rarely can an exact mid-stroke position be achieved because of the discrete lengths of available pup joints and the time variance of water depth at a given location.

If a fill-up valve is deployed, it is necessary to include the length of the fill-up joint.

In the mid-stroke position, part of the telescopic joint stroke can accommodate the increased riser length resulting from vessel offset. Rig personnel have a visual warning of excessive vessel heave, because they can see the near-complete retraction of the telescopic joint. If either the extension or retraction limits of the telescopic joint are exceeded, the riser and associated equipment can be damaged. If the telescopic joint extends to its limit, tensile loading dramatically increases, and if it retracts to its limit, the riser can buckle. Both conditions should be avoided.

The following dimensions should be considered when calculating riser length (see Figure 5):

— L_A wellhead height from mud line;

— L_B BOP and LMRP stack-up height;

— L_C required riser length;

— L_D telescopic joint length when set slightly short of mid-stroke (see Clause D.2);

— L_E distance from bottom of diverter to top of rotary kelly bushing (RKB);

— L_F RKB to mud line (mean-tide water depth plus distance from waterline to RKB);

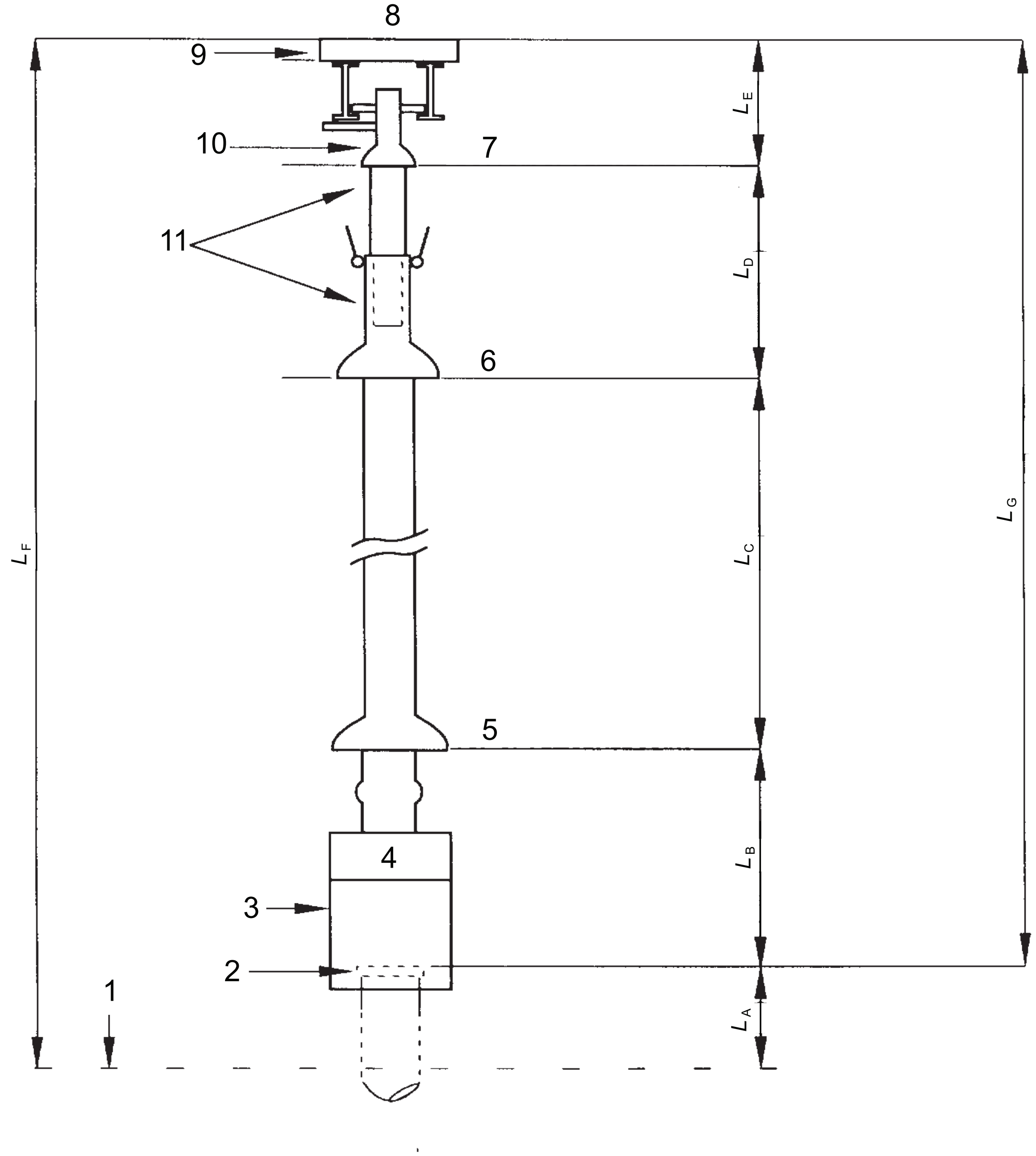
— L_G length of 508 mm (20 in) running (landing) string.

L_B, L_D and L_E are fixed, while L_A, L_F and L_G are measured at the well site.

Thus the riser length, L_C, can be calculated using either Equation (7) or Equation (8), depending on whether the water depth or the length of the 508 mm (20 in) running string is used; see sample calculation in Clause C.1:

$$L_C = L_F - (L_A + L_B + L_D + L_E) \tag{7}$$

$$L_C = L_G - (L_B + L_D + L_E) \tag{8}$$



Key

1	mud line	5	top of the flex/ball joint with riser adapter	9	rotary
2	wellhead	6	bottom of the telescopic joint	10	diverter
3	BOP stack	7	bottom of the flex/ball joint	11	telescopic joint near mid-stroke
4	LMRP	8	rotary kelly bushing (RKB)		

NOTE See preceding text for description of symbols.

Figure 5 — Determination of marine riser length

6.4.3 Riser inspection prior to running

Before running the riser, the following inspections shall occur.

a) Externally inspect the riser pipe, auxiliary lines, and buoyancy equipment (if used) for any damage and ensure that the auxiliary lines are properly clamped.

b) Inspect the coupling locking mechanism for damage and actuate to ensure proper operation.

c) Check that sealing devices are installed.

d) Review the marine-riser manufacturer's care and use instructions for the riser joint to ensure that any special instructions are followed.

e) Remove the box and/or pin protector and inspect the bore of the riser and auxiliary lines for obstructions and wear. Also, clean and inspect the pins of the riser and auxiliary lines. Unless a handling system that protects the box and pin is used, the box and/or pin protectors should be re-installed and not removed until the joint is on the rig floor.

f) Inspect riser-handling tools and treat couplings the same as those on the riser joints.

g) Check riser spider for proper operation.

h) Check inner barrel shoe of telescopic joint for key-seating.

6.5 Riser running and retrieval

6.5.1 General

Each riser system requires unique procedures that should be explained in detail in the riser operations manual to reflect the specific rig equipment and riser components.

An hydraulic-fluid line supplies control fluid to the subsea BOP. A hydrate-injection line may be attached to provide methanol or other inhibitor to the BOP.

An automatic fill-up valve is sometimes installed near the top of the riser and prevents riser collapse by allowing seawater to flow into the riser in the event that lost circulation or a large gas bubble causes the level of the mud column to fall quickly and without forewarning.

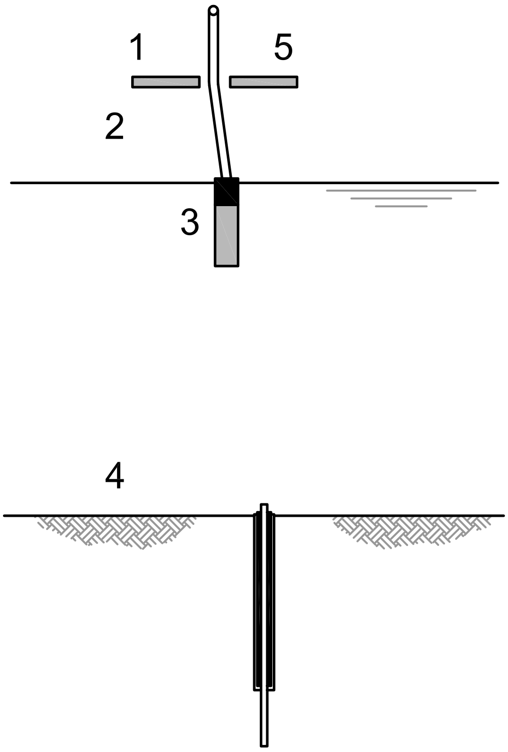
When currents and waves are large, high riser stress can occur when the riser is hanging in the spider. Long periods in this situation should be avoided to minimize fatigue damage.

The riser or BOP can collide with the vessel when surface currents or wave heights are excessive. This risk is greatest where the LMRP or LMRP/BOP stack pass through the air-water interface. When possible, two riser joints should be made-up while the stack is above the water; then lower the assembly as quickly as possible though the air-water interface. Colliding of the riser or BOP is more likely with the more restricted moonpool of a ship-shape vessel than with the pontoons of semi-submersibles. Riser restraint systems are sometimes used to permit riser-running operations in higher surface currents and waves.

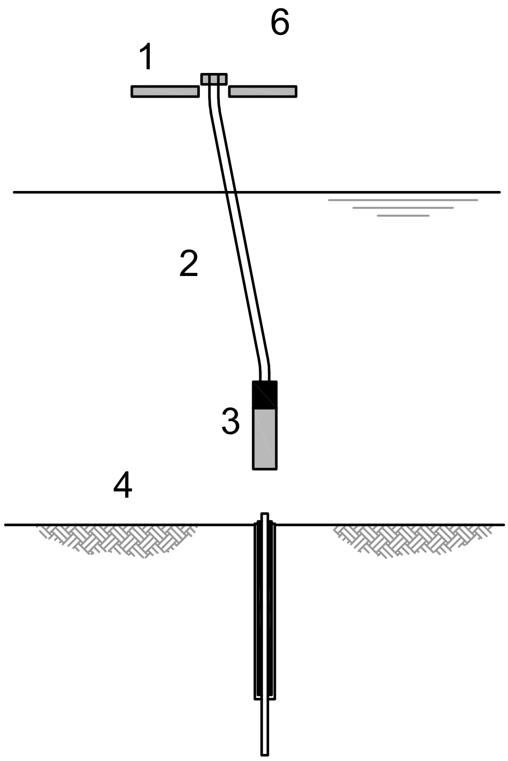
Another critical point during the riser running and retrieval operations is when the subsea BOP stack is landed or disconnected. When landing the BOP stack on the subsea wellhead, the riser load is transferred to the tensioners and/or heave compensator and gently lowered to the wellhead while observing with a remotely operated vehicle (ROV) or other means.

The limiting environmental conditions for safely running the riser are usually determined on-site based on the expert judgment of experienced operational personnel who are familiar with the specific rig and riser system. Alternatively, limiting current and wave may be determined from analyses of specific vessel and riser/BOP arrangements. The analytical results can be shown as an operating envelope that defines maximum wave height and/or current above which the LMRP/BOP can collide with the vessel. On-site current and wave heights can then be measured to provide guidance for operational decisions to run or not to run the riser when environmental conditions are severe.

As an example of how analytical calculations of operating envelopes may be used to assist in operational decisions, the maximum current and wave height that can be tolerated without the riser colliding with the vessel have been determined for the two situations shown in Figure 6. The first situation [Figure 6 a)] is during the most critical time when the LMRP or LMRP/BOP stack is in the wave zone. The second situation [Figure 6 b)] is when the BOP stack is at about 91,4 m (300 ft) below sea level.



a) In the wave zone



b) 91,4 m (300 ft) below sea level

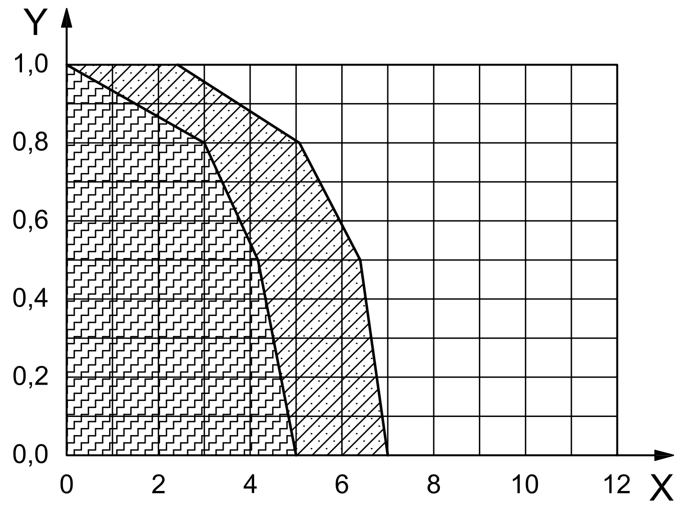
Key

1 drill-floor
2 riser
3 LMRP (and BOP)
4 seabed
5 hook
6 support from spider

Figure 6 — Riser installation and retrieval

Operating envelopes should be based on a physical parameter of the riser system for a specific vessel, e.g. angle at the diverter housing, riser contact with the substructure, etc.

Figure 7 shows one such generic example which was calculated for a specific rig and riser/BOP system. This particular operating envelope graphically shows the maximum current and wave height combinations that can be tolerated without the riser colliding with the vessel. In this example, when the LMRP/BOP is in the wave zone, the maximum significant wave height, with zero current, is 5 m (~16 ft). This is typical of a 1 yr winter storm in the Gulf of Mexico. The maximum current with calm seas is 1 m/s (~2 kn), which is commonly exceeded by surface eddies in the Gulf of Mexico.



Key

X significant wave height, expressed in metres

Y surface current, metres per second

base of LMRP/BOP above mean sea level – 20 m

base of LMRP/BOP at mean sea level – 100 m and below

Figure 7 — Example limiting conditions for riser installation and retrieval

Figure 7 also shows, for this case, that if the LMRP/BOP is out of the wave zone, greater wave heights and currents can be tolerated without the riser colliding with the vessel.

In practice, the decision to run the riser or to wait for improved weather conditions relies on the judgment of experienced operations personnel, based on their past experience and on-site observations. Graphical representations of limiting environmental conditions, such as Figure 7, provide a way to compare and confirm operational experience with analytical predictions.

Currents are usually highest at the ocean surface, riser/BOP collision with the vessel is most likely with the BOP near the surface and VIV is most likely to occur immediately below a surface running current. Allowing a dynamically positioned vessel to drift with the current while deploying a riser has been found to be effective in reducing riser stresses and riser top angles when currents are excessive. Prior to deploying the riser, the vessel is positioned upstream of the desired well location. The vessel is then permitted to drift with the current, in a controlled manner, as the BOP and riser are deployed. Riser stresses and top angles may be predicted in advance for various current profiles, wave heights and vessel drift speeds. These predictions, when compared with on-site measurements of current profiles, wave heights and vessel drift speeds, provide guidance when selecting a drift speed and deciding whether the riser can be safely deployed without exceeding prudent stress and top-angle limits. After the riser is deployed beneath the more critical surface currents, the vessel and riser are positioned over the subsea wellhead to connect the BOP.

6.5.2 Hang-off procedure during running and retrieval operations

A hang-off procedure should be used when environmental conditions preclude pulling the riser and/or there is insufficient time to do so.

Two hang-off procedures are used in the industry: hard hang-off and soft hang-off. With hard hang-off, the riser remains rigidly connected to the vessel; with soft hang-off, the riser is supported on either the tensioners or a combination of the tensioners and the motion compensator. With hard hang-off, the riser is secured to the vessel and moves with it. With soft hang-off, the riser remains relatively stationary as the vessel heaves around it, and has little tension variation.

A typical procedure for implementing soft hang-off from the tensioners and the motion compensator, during riser running/pulling, is as follows.

a) Make up the slip joint in the riser string.

b) Engage the tensioning ring.

c) Make up the hang-off tool, which connects the riser with the travelling block.

d) Reduce the tensioner-system air pressure until the tensioner setting corresponds to half the riser weight for that depth, as per the riser analysis. Lower the riser string until the tensioners support half of the riser string weight, and the tension ring is at mid-stroke.

e) Activate the motion compensator and set it to support the other half of the string weight.

f) Position an observer to monitor/adjust tensioner stroke and set point. It can be necessary to make fine adjustments to the tensioner air pressure to maintain the tension ring at mid-stroke.

This soft hang-off procedure can be done using various procedures. Further operational steps are required, depending on the vessel and the type of equipment being used. Operators should be aware of the time required to reduce the tensioner-system air pressure, which can take more than 1 h. It is also important that the heading for a ship-shaped vessel be maintained to within ± 20° relative to the wave direction during the procedure.

6.6 Installed riser operations

6.6.1 General

Maintaining proper riser tension is of prime importance to prevent riser damage. Recommended maximum and minimum top tension is site-specific and it is necessary that it be determined by analysis of the specific riser stack-up to maintain an optimal condition for the riser. Drilling operations are routinely supplied with a riser-tension-versus-mud-weight operating envelope that is prepared from riser analyses based on available tensioning capacity, riser design, amount and location of buoyancy, water depth and expected environmental parameters.

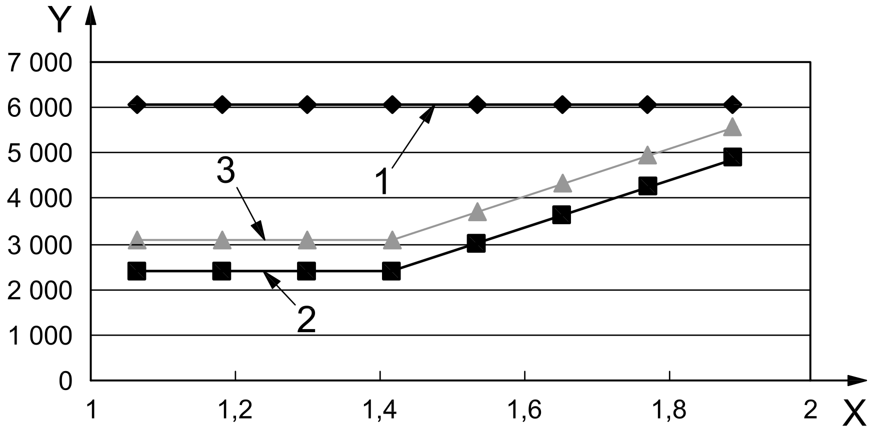
Environmental conditions or equipment failures can require suspension of drilling operations or necessitate disconnecting the riser to prevent riser or well-system damage. The riser operations manual should include well defined procedures and the limiting conditions, such as flex joint angles, under which these procedures should be implemented.

Drillstring rotation should ordinarily be limited to conditions where the mean flex joint angle is less than 2°(see Table 2), depending on well conditions and equipment configurations, as described below. The riser should be disconnected to prevent damage when the flex joint angle is likely to exceed 6° to 10°, depending on the flex joint design, pressure at the flex joint and other equipment limitations. In the event that it is necessary to disconnect the riser, the well should be secured and the riser hung off in a safe manner that minimizes fatigue damage as described in 6.6.2.

6.6.2 Installed riser top tension

The minimum riser tension to prevent riser damage increases as mud weight in the riser is increased because it is necessary that the tensioners support the additional weight of the mud. Any significant changes in mud density should be accommodated by changes in riser tension. The objective of such changes should be to produce the same overpull at the lower flex joint as that obtained with the stack-up and mud density forming the basis of the recommended riser top tension.

Riser-tension operating envelopes provide the basis for riser-tension increases as drilling progresses and mud weight is increased. It can be necessary to adjust the minimum riser tension predictions for on-site observations, such as riser flex joint angle. An example of recommended riser top tension versus mud weight is shown in Figure 8.



Key

X mud density, expressed as specific gravity

Y tensioner setting, expressed in megapascals

1 maximum tension capacity

2 minimum top tension

3 recommended top tension

Figure 8 — Example recommendation — Riser tensioner setting vs. mud weight (density)

Top tension may be expressed as total riser tension pull, as pressure on the tensioner hydraulic system, tension gauge reading or by some other indication of riser tension. The maximum top tension is typically calculated as 90 % of the maximum tension capacity of the tensioning system. Minimum top tension is the API-recommended minimum tension to prevent excessive riser curvature and stresses. This minimum tension is determined from analysis of the stack-up. For normal operations, the top tension should be maintained at a safe level, for example 222,4 kN to 444,8 kN (50 kips to 100 kips), above the API minimum tension to allow for variations in tension that can otherwise allow the riser tension to fall below the minimum top tension.

Since riser curvature increases as vessel offset increases, additional riser tension can be required for increased vessel offset to maintain an acceptable lower flex joint angle.

Higher-than-predicted flex joint angles or other significant deviations from analytical estimations should be promptly reported to the riser analyst who prepared the predictions. Differences in riser stack-up or loss of buoyancy can require changes in the riser-tension-versus-mud-density operating envelope.

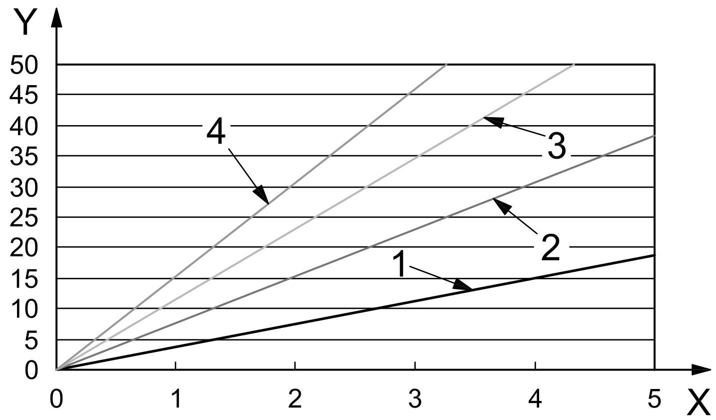
6.6.3 Drilling limits

The differential flex joint angle (relative to the conductor/wellhead, not relative to true vertical) should be minimized by mooring-line or dynamic-positioning adjustments. The differential flex joint angle is a function of both the riser angle and the wellhead/conductor angle. Subsea wellheads/conductors are frequently installed with a small angle from vertical. This angle can either increase or decrease the total angle for the flex joint, depending on the vessel position.

Drillstring rotation should be stopped and other drilling operations curtailed when the mean flex joint angle exceeds 2° (see Table 2), because contact forces between the drillstring and the flex joint/wellhead can cause extreme wear and other damage. The flex joint angle is primarily controlled by adjustments in the vessel position and can also be reduced by increasing the riser tension.

Drillstring wear on the flex joint and subsea equipment is strongly dependent on the differential flex joint angle and the drillstring tension at the flex joint. It is necessary to maintain a smaller flex joint angle to prevent excessive wear when drillstring tension at the flex joint is large, e.g., when the well is deep. For shallow drilling, when only a short length of drillstring hangs beneath the flex joint, a relatively larger flex joint angle can be tolerated. Figure 9 shows the normal force between the drillstring and a flex joint versus drillstring tension at the flex joint. Wear rate is dependent on this normal force, on tool joint abrasiveness, on drilling rate, on drillstring rotary speed and on several other factors.

A normal force less than about 8 896 N (2 000 lbf) between the drillstring and the flex joint is generally acceptable. Normal force in the range of 8 896 N to 35 586 N (2 000 lbf to 8 000 lbf) can cause moderate to severe wear damage, depending on drillpipe tool-joint abrasiveness. In summary, minimizing flex joint angle becomes increasingly important as well depth (and, therefore, drillstring tension at the flex joint) increases.



Key

X flex joint angle, expressed in degrees

Y force between drillstring and flex joint, expressed in kilonewtons

drillstring tension:

1 222,4 kN (50 kips)

2 444,8 kN (100 kips)

3 667,2 kN (150 kips)

4 889,6 kN (200 kips)

Figure 9 — Normal force vs. flex joint angle with various drillstring tensions

The differential flex joint angle limitations on drilling operations should be made based on the specific operation in progress, on well depth, on drillstring configuration and on other factors. A differential flex joint angle of 1° or less is typically maintained for normal drilling operations.

6.6.4 Standby or non-drilling limits

Survival limits define the limiting conditions beyond which the riser or related equipment can be damaged unless the riser is disconnected. Riser survival limits are usually expressed as the maximum flex joint angles beyond which damage occurs.

The lower flex joint angle limit corresponds to the point beyond which the BOP or wellhead can suffer damage or connectors can lose sealing integrity; this is not the limit of flex joint rotation, which is typically 10°. Higher differential pressure between a mud column inside and seawater outside the flex joint also reduces this angle limit. It is necessary that the upper ball joint angle limit not be exceeded to avoid possible damage to the inner barrel of the slip joint, ball joint and/or diverter assembly. It is necessary that the manufacturer's specification be consulted to determine limits for specific equipment.

For planning purposes, the survival limits may be expressed in terms of the wave height, current speed and vessel offset limits that cause the flex joint angles to exceed safe values. Riser analyses based on assumptions of wave height and period and current profile, combined with forecasted environmental conditions, provide predictions of the time necessary to disconnect a riser to prevent damage at a given location.

6.6.5 Riser disconnected

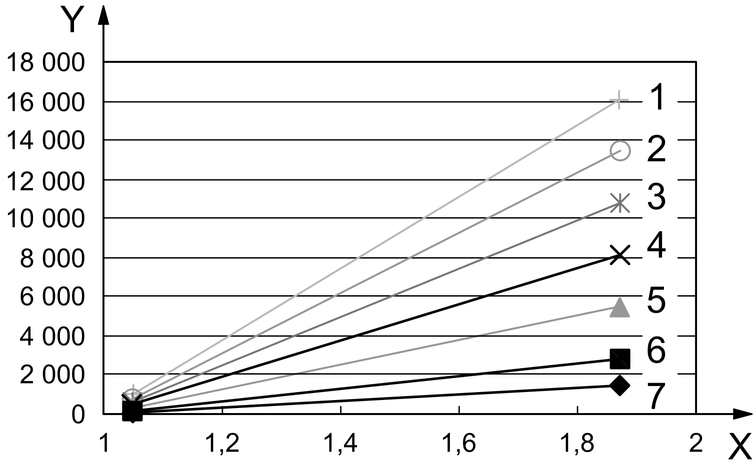
A riser should be disconnected only after thorough evaluation of all alternatives, because of the potential consequences. For example, a dynamically positioned (DP) vessel can experience a drive-off when the riser is disconnected because the riser load can overcome the DP thruster capability. When the riser is disconnected, it is necessary to position the vessel so that the riser and LMRP are moved a safe distance to prevent collision with the subsea wellhead and BOP. Also, a well is more vulnerable to an uncontrolled release of formation fluids when the wellbore is not properly secured prior to the riser disconnect.

Except in emergencies, many hours of tripping operations can be required to secure and prepare a well before disconnecting the riser, as described further in 6.6.6. When environmental conditions are deteriorating, the appropriate steps should be implemented to prepare the well in anticipation of a possible riser disconnect.

For a planned riser disconnect, an additional well-control barrier, such as a mechanical or cement plug, should be installed to replace the well-control barrier that is afforded by the mud hydrostatic column in the riser. However, for an emergency or unplanned disconnect, time constraints do not allow for the installation of a secondary well-control barrier plug and the BOP serves as the well-control barrier. In the drilling mode, drilling-mud hydrostatic pressure provides the primary well control to prevent the uncontrolled release of formation fluids. Subsea BOPs provide an additional (secondary) well-control barrier in the event of a kick, i.e., the formation pressure exceeds the mud-column pressure.

When the riser is disconnected, the mud hydrostatic pressure in the riser is replaced with seawater pressure. In shallow water, it is sometimes possible to maintain a sufficiently high mud weight so that formation pressures are overbalanced with the combination of seawater pressure at the seafloor and the mud-column pressure in the wellbore. However, in deeper water or when high mud weights are required, this seawater and mud-column combination is insufficient to control the formation pressure, making the well vulnerable to a blowout if the BOP fails to close or leaks.

Figure 10 shows the loss in mud-column pressure, riser loss, as a function of mud weight for various water depths. Mud-column pressure is typically 2,07 MPa to 4,82 MPa (300 psi to 700 psi) higher than formation pressure for drilling operations. A “riser loss” of more than this amount eliminates the mud column as a well-control barrier. An emergency disconnect, then, leaves the well with a single well-control barrier, the BOP.



Key

X mud weight, expressed as specific gravity

Y riser loss, expressed in kilopascals

water depth:

1 1 829 m (6 000 ft)
2 1 524 m (5 000 ft)
3 1 219 m (4 000 ft)
4 914 m (3 000 ft)
5 610 m (2 000 ft)
6 305 m (1 000 ft)
7 152 m (500 ft)

Figure 10 — Riser loss vs. mud weight for various water depths

6.6.6 Riser hang-off operations

Soft or hard hang-off (see 6.5.2) can be used after riser disconnect. It has been shown that a soft hang-off can significantly reduce riser motions, peak hang-off loads and riser stress variations as compared with a hard hang-off. Compression in the riser is also avoided with the soft hang-off (Brekke, *et al*., 1999).

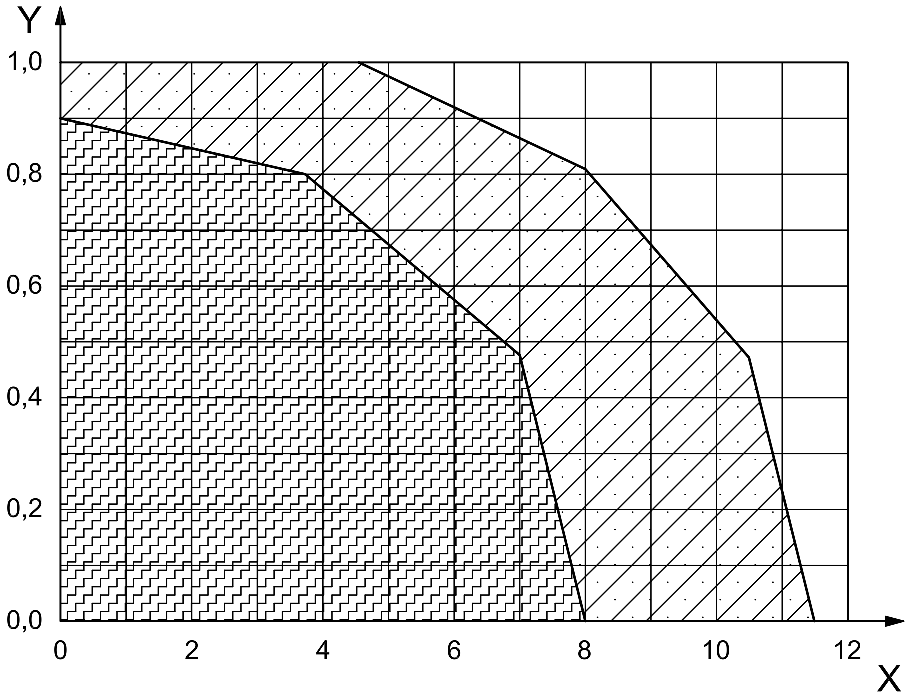
It is necessary to make site-specific analyses of the particular riser configuration to ensure that the tension system provides adequately soft spring stiffness. The spring stiffness afforded by the tension system determines whether the soft hang-off reduces riser motion, load and stress variation or, perhaps, causes increases in these values due to resonance effects. Further limitations of the soft hang-off are that vessel heave motion does not exceed stroke limits and that on-board personnel are available to monitor/adjust the tensioner set point.

An operating envelope (see Figure 11) can be determined by analysis for establishing the maximum current and wave height that can be tolerated for a specific example vessel and riser

— without the riser colliding with the vessel;

— without exceeding 90 % of upper ball joint angle limit (see Table 2);

— without overstressing the slip joint or the joint immediately below.



Key

X significant wave height, expressed in metres

Y surface current, metres per second

slip joint held at maximum up-stroke or riser suspended inside

slip joint allowed to stroke

Figure 11 — Example hang-off envelope

The maximum current and wave height conditions in Figure 11 are extreme for the Gulf of Mexico, except in severe storms. However, this figure demonstrates how the analysis results can be presented to show the limiting conditions.

Riser retrieval is not an option in the event that the limiting conditions are exceeded, i.e., the environmental conditions cause prudent limits for riser retrieval to be exceeded.

In the event that severe weather is encountered, a typical, planned disconnect procedure for unlatching the LMRP and going into soft hang-off, on tensioners only, is as follows.

a) Prepare the riser for disconnect, close the BOP and circulate the mud out, replacing it with seawater. Reduce riser-tensioner air pressure to have some nominal amount of tension [e.g., 222,4 kN (50 kips)] on the LMRP connector; this is done over several steps.

b) Move the rig to the centre of the watch circles, and with the anti-recoil system active, disconnect the LMRP, making certain that the annular preventer is open so that seawater is not trapped to move with the riser.

c) Move the rig a safe distance towards deeper water.

d) De-activate the riser anti-recoil system and open all tensioner APVs.

e) Set the tensioner-system air pressure to support the riser and LMRP weight.

f) Adjust tensioner ring to mid-stroke.

g) Position an observer to monitor/adjust tensioner stroke and set point. It can be necessary to make fine adjustments to the tensioner air pressure to maintain the tensioner ring at mid-stroke.

This soft hang-off procedure can be done using various procedures. Further operational steps are required depending on the vessel and the type of equipment being used. Operators should be aware of the time required to reduce the tensioner-system air pressure, which can take more than 1 h. It is also important that vessel heading be maintained to within ± 20° relative to the waves during the procedure.

Procedures for emergency disconnect vary depending on the operation being conducted on the vessel. Assuming that an emergency disconnect is executed, after all personnel have cleared the moonpool, and the vessel is moved off a safe distance, the above steps f) and g) (plus a step to balance the pressure and open the APVs) can be taken to place the riser in soft hang-off. If, however, environmental conditions are favourable, a hard hang-off involving collapsing the slip joint and hanging the riser under the rig floor is also an option.

6.7 Emergency disconnect — Sudden storm, drive-/drift-off

If a vessel moves off location to the extent that the tensioners run out of stroke, the telescopic joint extends to its maximum limit and/or the flex joint is flexed beyond its maximum limit, extreme stresses can be created that can cause serious damage to the vessel, riser and well-control system.

Each rig should be equipped with written emergency disconnect procedures that account for various tubulars being in the BOP bore, peculiarities in the BOP and control equipment and characteristics of position-keeping or mooring equipment. Multiple procedures are required to provide for these different situations.

An emergency disconnect is usually necessary because of the loss of the ability to control/maintain position. Extreme environmental conditions can also require an emergency disconnect.

When an emergency disconnect is required, it is necessary to perform it fast enough to prevent serious damage to the vessel, riser or well system and to reduce the risk to personnel onboard. When drilling from a dynamically positioned vessel, a loss of station can occur because of a failure in the vessel's control or power systems that results in a drive-off or drift-off. When drilling from a moored vessel, a failure of multiple mooring lines can require an emergency disconnect, but a single failure generally warrants further evaluation before initiation of an emergency disconnect.

The emergency release of the riser from the BOP stack requires special procedures and equipment. The riser tensioning system should be equipped with an anti-recoil system. The tensioning system should continue to apply force to the riser for a short time after the riser is disconnected to ensure the riser lifts clear of the BOP stack. However, this tension should be carefully attenuated, otherwise too much momentum, or riser recoil, can be imparted to the riser. This can result in large impact loads as the telescopic joint is retracted and the riser is propelled upward, with great hazard to the riser, the vessel and human life.

An automatic disconnect system secures and/or shears the drillstring in the BOP, disconnects the riser and activates the anti-recoil system.

The same preparation should be made for a riser disconnect, whether releasing the riser at the LMRP in deteriorating weather conditions or retrieving the BOP. The following should be considered.

— The vessel should be positioned such that the lower flex joint angle is small, typically less than 2°, to ensure that the LMRP connector can release without snagging on the lower mating hub (for an emergency disconnect, this may be impractical).

— It is necessary to set the riser tension, tensioner air-pressure vessels and recoil-system valve closure timings in accordance with the procedures derived from the tensioner-system operations manual and/or results of riser analysis.

A vessel's desired location over a well is normally the position where the differential lower flex joint angle is a minimum. The differential lower flex joint angle is the net differential angle between the BOP stack and the riser adapter. This vessel “set point” position is the centre of imaginary circles, usually referred to as “watch circles.” The largest watch circle defines a limit of vessel excursion, beyond which damage can be expected to occur requiring an emergency disconnect. This may be termed the “red-alert” watch circle. The smallest watch circle, which may be termed the “blue-alert” watch circle, indicates the vessel excursion where normal operations may be performed. An intermediate “yellow-alert” watch circle is typically defined between the red-alert watch circle and the blue-alert watch circle. These watch circles are well-defined limits that are an important part of the emergency disconnect procedures.

The red-alert watch circle is defined by a radius from the vessel set point where the riser tensioners or telescopic joint approach(es) its/their limiting extension or where the differential lower flex joint angle is at its design limit. It is necessary that this calculated red-alert watch circle radius consider water depth, amount of tensioner or telescopic joint extension, tidal changes since the riser was installed, vessel heave and current effects on the riser. The red-alert watch circle radius is decreased by vessel heave motions.

Pre-planned procedures should be followed when the vessel excursion exceeds the various pre-determined watch circles. For example, when a vessel excursion beyond the blue-alert watch circle is imminent or accomplished, normal operations may be terminated and preparation may be made to hang-off the drillstring (if applicable). When the vessel excursion beyond the yellow-alert watch circle is imminent or accomplished, the driller immediately proceeds with hanging-off the drillstring and preparing for an emergency disconnect. Specific pre-planned procedures other than these examples depend on specific vessel configurations, the operation in progress (drilling, tripping, running casing, testing, logging, etc.), company policy and many other factors. However, each vessel requires several specific procedures that differ according to the type of operation in progress and the tubulars that it is necessary to shear (drillpipe, drill collars, large casing, small casing, etc.).

The alarm situations described above may be summarized as follows.

— Blue (advisory situation): Evaluate the operation being carried out and plan the actions that are required for disconnecting, e.g., consider what pipe is across the BOPs.

— Yellow: Prepare to disconnect.

— Red: Activate emergency disconnect sequence.

7 Riser integrity

7.1 Basis of inspection requirements

7.1.1 Overview

Inspection is required at various times during the life of a drilling riser (schematically shown in Figure 12), as defined in Table 4. Following the post-fabrication and commissioning inspection, it is necessary to undertake in-service inspection to detect and quantify deterioration in riser integrity. It is necessary to that the intervals between inspection be short enough such that the rate of equipment deterioration does not result in loss of structural or functional integrity from one inspection to the next.

Deterioration of drilling riser integrity can result from the following causes:

— fatigue damage accumulation;

— wear from drillstring rotation (key-seating);

— impact loads during handling, running and retrieval;

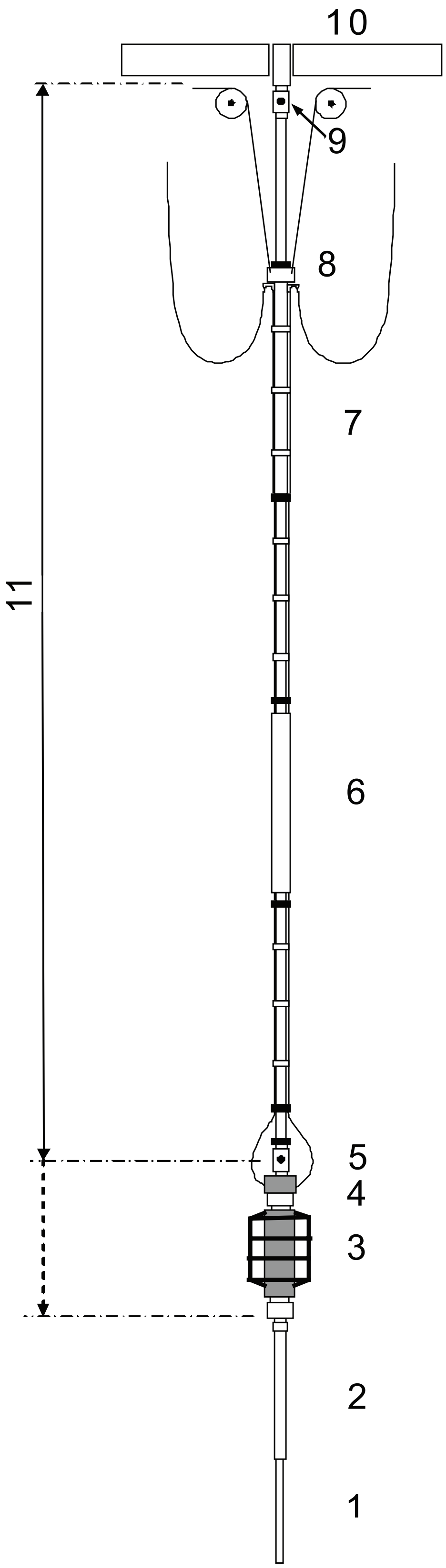
— corrosion.

The contribution of each factor to the deterioration of riser integrity varies from one application to the next. In the absence of riser failures over the long history of drilling riser operation in shallow water, existing inspection programmes may be considered adequate to ensure that the gradual loss of integrity is detected. Where the contribution of any of the parameters identified above becomes more significant, it is necessary to call into question the validity of normal inspection practices and to evaluate alternatives. This is the case for deep-water applications, as described below.

In water depths less than 350 m (1 000 ft) and where 1 yr return current speeds are less than 1 m/s (2 kn), the guidance for conducting inspection (see 7.5) is considered sufficient. For deep-water drilling, a preliminary evaluation of conditions and response should be conducted and a strategy for in-service inspection should be developed, taking into account each well that will be drilled.

Table 4 — Drilling riser inspection requirements

Inspection stage	Requirements	Coverage
Post-fabrication	Through thickness crack detection Surface crack detection Thickness measurement Ovality	All joints
First use	Commissioning inspection, as recommended by manufacturer	All joints
Installation/retrieval	Visual to detect for internal wear, corrosion, obvious signs of cracking in main tube and choke-and-kill line welds, dogs and load shoulders in couplings, gross deformation, loose or damaged attachments, such as choke and kill lines or buoyancy modules	All joints
Periodic	Surface crack detection Wall thickness reduction Surface crack detection from both inside and outside, or through thickness crack detection Ovality, for collapse critical applications	To suit operating conditions



Key

1 casing
2 conductor
3 BOP
4 LMRP
5 lower flex joint
6 slick and buoyant joints
7 telescopic joint
8 tension ring
9 upper flex joint
10 drill floor
11 extent of integrity guidelines

Figure 12 — Schematic illustration of riser system

7.1.2 Implications of deep-water

The characteristics of deep-water drilling riser systems that influence integrity requirements and loss of integrity are as follows:

- higher tensions, that can accelerate fatigue crack growth in the riser and place increased importance on riser pipe integrity;
- larger curvatures, promoting the possibility of wear from drillstring rotation;
- vortex-induced vibrations due to severe currents, which can generate high levels of fatigue damage in short periods of time;
- longer drillstrings having increased tension, increasing wear at the top of the riser;
- longer and heavier riser joints, more difficult to handle with increased scope for damage during riser running and retrieval;
- greater internal pressures from mud head, placing increased importance on wall thickness for hoop load resistance;
- greater external pressures from water column, placing increased importance on wall thickness and dimensional tolerances for collapse resistance;
- load sharing between riser tube and choke-and-kill lines, placing increased importance on the integrity of the choke-and-kill lines for overall structural integrity.

The potentially greater rates of wear and fatigue-damage accumulation and increased importance of wall thickness integrity for deep-water identified above indicate that it is necessary to reassess traditional inspection practices used for shallow-water operations for long-term deep-water drilling. When initiating a drilling programme in deep water or harsh environments, it is necessary, therefore, that the riser-inspection strategy be re-evaluated to take account of the severity of the operating conditions.

7.1.3 Preliminary evaluation

A preliminary evaluation of inspection requirements should be conducted that encompasses the following:

- examination of existing riser-inspection information and historical operating data;
- gathering site-specific, current data prior to well operations;
- fatigue analysis of the rise that spans the range of conditions associated with each well that will be drilled.

Depending on the availability of historical operating data and the interval since the last inspection, a screening inspection of the riser can be warranted (specific inspection of a representative population of riser joints).

7.1.4 Inspection procedures

Procedures that encompass the following should be developed for conducting the inspection of a drilling riser in the course of normal drilling operations:

- inspection during running and retrieval;
- periodic detailed inspection including
  - post-incident inspection,
  - record keeping to ensure inspection schedules can be monitored,
  - maintenance of inspection records.

The issues to address when developing the necessary inspection procedures are discussed in 7.3 to 7.6.

7.2 Maintenance after riser retrieval

After retrieval, the riser should be rinsed with fresh water, visually inspected, serviced and stored in accordance with the manufacturer's recommendations.

7.3 Other riser system maintenance

7.3.1 Riser tensioners

The tensioner piping should be checked for leaks before putting the system into operation. Visual checks of the system for hydraulic leaks and for the correct fluid level should be made periodically. Consult the manufacturer's operation and maintenance guide for procedure and fluid type. Lubricate tensioner rods and determine a specific schedule to keep the exposed rods lubricated. Check sheave groove for wear, lubricate the idler sheave bearings and inspect bearing seals for damage. For wire rope systems, inspect the wireline for broken strands and correct type, as per the manufacturer's recommendation.

Take particular note of the wire condition at points of contact with the sheaves during low-heave operating conditions. When the limit of wireline life is approached, the line should be either cut and slipped to change the wear points or replaced to prevent wireline failure. When slipping the wireline, be certain that the lengths of line that were working over the sheaves before are not working over sheaves after slippage. Also, be certain that the tensioner ring-clamp line attachments are secure and properly installed. A qualified re-termination procedure and personnel qualified for that procedure should be used. All the air-pressure vessels should be regularly drained of any liquids, as specified by the manufacturer.

7.3.2 Telescopic joint

The inner barrel telescopes into the outer barrel and should be bolted or pinned to the outer barrel when handling.

Maintaining minimum pressure to affect a pack-off prolongs the life of the packing element.

The telescopic joint should be inspected and serviced in accordance with the manufacturer's recommendations.

7.3.3 Flex/ball joints

Flex/ball joints should have a protective cover at the upper neck to prevent the entry of cuttings and debris. The boot should be inspected prior to running and replaced when necessary. Flex joints should be inspected to ensure the bore protectors and retaining studs and nuts are intact. After retrieval, wash all exposed surfaces with fresh water and inspect for both internal and external wear. A pressure-balanced ball joint should be tested in accordance with the manufacturer's recommendations to verify pressure integrity.

7.4 Transportation, handling, and storage

7.4.1 General handling and storage

In general, marine riser components are made with precision parts that require careful handling. Protectors should be provided for the pin-end (and box-end, if specified by the manufacturer) couplings of each riser joint. The couplings should be lubricated according to the manufacturer's recommendations. The joints should always be handled individually and with the protectors in place. Foam buoyancy material on risers is especially vulnerable to damage. If it is necessary to pick up and move the riser joints with a crane when automatic handling equipment is not available, a properly designed sling should be utilized. Handling slings should be designed to support the fully assembled riser joint. Telescopic joints typically weigh substantially more than riser joints and slings should be designed accordingly. Most riser joints are provided with lifting eyes located near the box- and pin-ends for the sling attachments. Riser joints should not be lifted by choke, kill or auxiliary lines or their brackets.

Caution should be exercised when stacking riser joints. When bare joints are stacked for shipping or storage, support shims should be provided under the bottom layer and between successive layers. The shims should be designed to prevent contact between adjacent joints. The weight of the joint should not be carried by unsupported sections of the choke or kill lines. Riser joints equipped with syntactic foam buoyancy may be stacked on top of each other without shims in accordance with the buoyancy manufacturer's recommendations.

7.4.2 Rig storage racks

To provide for adequate restraint and support for the riser during stored periods, riser storage racks or cradles should be used.

The design of the racks or cradles varies with the specific constraints of the vessel and riser design; however, the following guidelines can be stated.

a) Cradles should be designed for supporting the weight of the riser, including all dynamic and environmental loadings.

b) Support of buoyed riser joints should be made in accordance with the buoyancy manufacturer's specifications.

c) No portion of the riser should be supported by the choke, kill or auxiliary lines or their brackets.

d) The racks should not hinder access to the pin and/or box protectors or covers for maintenance and inspection.

e) The racks should be able to support the riser and prevent load shifting for any expected list of the rig.

7.4.3 Land base storage

Riser joints should be stored with support shims under the bottom layer and between successive layers. The first tier of joints should be off the ground to keep moisture and dirt away from the joints. The support shims should be spaced to prevent bending of the pipe and damage to the coupling. Joints should be stacked at a safe and accessible height, slightly inclined to assure proper drainage of water. Joints should be cleaned internally and externally and protective coatings should be applied or touched up as necessary before storing. Riser couplings and all mating surfaces should be maintained according to the manufacturer's specifications.

7.4.4 Transportation

When riser-system components are transported, supervision should be provided at the time of loading to ensure that

— the load is tied down securely to prevent shifting;

— painted or coated surfaces are protected from tie-down chains or straps;

— guidelines for handling and storage are followed;

— the components do not come in contact with chemicals, corrosives, bilge water or other damaging substances;

— other materials are not loaded on top of or inside the riser;

— all relevant regulations are satisfied.

7.5 Scheduled field inspection and maintenance

7.5.1 General

Regularly scheduled inspection and maintenance should be performed on all riser system components. Detailed procedures should be developed for the performance of the inspection and maintenance tasks described in 7.5.2 to 7.5.6 and should be contained in the rise operations manual.

7.5.2 Visual inspection for corrosion, cracks and wear

After each retrieval, the marine riser joints and bolting should be visually inspected for corrosion, cracks and wear. The box and pin of the riser connector should be cleaned thoroughly before inspection. Other critical areas, as specified by the manufacturer, should be more thoroughly checked and remedial action taken as needed.

7.5.3 Non-destructive inspection

Liquid-penetrant or magnetic-particle inspection methods should be used to investigate critical areas for cracks. Ultrasonic or other suitable means should be used to check the main tube wall thickness. Acceptance criteria should be agreed upon between operator and drilling contractor. These inspections should be conducted at least once a year, unless results of previous inspections warrant a longer inspection interval. An inspection is recommended after abnormal conditions, such as over-tensioning, under-tensioning or shock loads during running or retrieving the riser. Inspection and remedial action should be in accordance with the manufacturer's recommendations.

7.5.4 Corrosion protection

The riser should be checked for areas of cracked or flaking paint. These areas should be thoroughly cleaned and repainted according to the user's or manufacturer's specifications.

7.5.5 Parts replacement

When the replacement of moving parts in the riser system is required, it should be done in accordance with the manufacturer's recommendations. These instructions should be included in the operations manual and outlined with sufficient clarity for use by rig supervisory personnel. Reliable records of inventory and replacement requirements should be kept.

Replacement of parts should be accompanied by special attention given to the cleanliness of parts, inspection for damage, assurance of correct items by part numbers, lubrication (if required), correct assembly and proper installation.

7.5.6 Welding

No welding should be performed on any riser component without first consulting the manufacturer. Field welding should not be performed without explicit authorization from the manufacturer, accompanied by approved procedures and performed by welders qualified for those procedures.

7.6 In-service inspection

7.6.1 Visual inspection

Visual inspection should be conducted each time the riser is installed or retrieved. The scope of inspection is defined in Table 4. Records should be kept of any adverse findings and the appropriate actions taken, as described in 7.9. Visual inspection should also encompass the recording of any mishaps that are observed during handling, running and retrieval.

7.6.2 Periodic, detailed inspection

7.6.2.1 General considerations

7.6.2.1.1 When determining a strategy for periodic, detailed inspection of deep-water drilling riser joints, four key parameters should be considered:

— severity of operating conditions;

— inspection detail;

— inspection frequency;

— inspection coverage.

7.6.2.1.2 As a general guide, the parameters listed in 7.6.2.1.1 interact to require more frequent inspection:

— more severe operating conditions;

— less detailed inspection;

— less coverage.

However, operational practices may be varied such that the requirement for more frequent inspection with more severe operating conditions is minimized and reduced coverage might not warrant more frequent inspection, provided the joints being inspected are carefully selected.

7.6.2.2 Inspection frequency and coverage

The current approach of inspecting drilling riser joints according to time in service may be adopted for deep-water drilling risers. The time between periodic inspections may be varied to reflect the service conditions to which a riser is exposed. The greater the water depth or the more severe the environmental conditions, the more frequently the inspection should be conducted.

As a minimum, a target frequency for inspection of all the joints in the riser string should be defined and a shorter interval specified for those joints subject to the highest levels of fatigue damage, as identified by riser analysis, and for those joints near the top and base of the riser that are subject to the greatest levels of wear.

The greatest levels of VIV fatigue damage are incurred in the joints above the lower flex joint. Similarly, the greatest levels of fatigue from wave action are expected to occur in the joints in the wave zone. Hence, by conducting the appropriate fatigue analyses, inspection coverage for fatigue damage can be focused on the critical joints. Using such an approach, it is necessary to take due account of the variation in riser configurations and operating conditions in which the riser is used.

7.6.2.3 Inspection methods and detail

In deep-water, the need to inspect a larger number of joints and the difficulties of handling longer and heavier joints while maintaining a sufficient inventory for continued drilling has resulted in considerable ongoing work to find the optimum approach to riser-integrity assessment. Conducting detailed joint inspection offshore can appear to offer some advantages, but lack of space, specialist equipment, personnel and a controlled environment are expected to make application of conventional inspection methods offshore impractical. Amongst alternative methods considered are the following:

— calipers: to detect wear and corrosion, run with the riser *in-situ* while waiting on cement to minimize downtime;

— intelligent pigging: to detect cracks, conducted with the riser *in-situ* while waiting on cement;

— reflected-wave-type methods: conducted on the deck with the riser in storage to detect wear and cracks;

— fatigue fuses: bonded to the riser joints to detect fatigue-damage accumulation.

None of these inspection techniques is expected to offer alternatives to the conventional methods for detailed inspection that are used onshore. However, they may be used as an inspection screening tool, by which joints that require more detailed inspection can be identified and laid aside for return to shore for detailed inspection. This can offer a more rational approach to the scheduling of joint inspection than an approach based simply on time in service.

Different methods of inspection offer differing levels of defect detection. When defining inspection requirements, it may, therefore, be considered preferable to restrict inspection to the use of the most sophisticated methods. However, in view of the potential variability in defect shape, it is recommended that a combination of inspection methods be employed in order to improve the scope for identifying defects. More specific guidance on the methods for consideration is given in 7.8.

When deterioration of integrity is dominated by fatigue-damage accumulation, fracture mechanics analysis provides a basis for rationalizing inspection requirements. The combination of inspection detail, that is, the smallness of flaws that should be detected, and frequency of inspection can be defined through use of the fatigue-crack growth curve, as determined by fracture analysis. The more refined the inspection, the greater the interval that may be allowed between inspections. Hence, a balance can be struck between the level of detail and frequency.

7.6.2.4 Application of fracture analysis

Fracture analysis should be conducted in accordance with BS 7910. The basis of such an assessment is to determine the period over which an undetectable defect in the riser pipe can grow to a size that results in an unstable fracture under maximum expected loading. Application of a safety factor to the period thus determined gives the maximum interval between detailed inspections.

Guidance on the parameters governing fracture response and residual stress distributions that may be used in such an assessment is given in BS 7910, but materials testing is required for reliable crack-growth and unstable-fracture predictions. Testing should be conducted for both pipe-to-pipe welds, as found at joint mid-length, and pipe-to-coupling welds, where different material types may be used.

Fracture analysis is not sufficient in itself for defining inspection detail and frequency. A limitation of using fracture mechanics is that any impacts that occur during handling, running or retrieval of the riser can result in accelerated growth of defects. It is necessary, therefore, to make due allowance for such effects in the selection of safety factors for defining inspection intervals. In addition, records should be kept of any potential damage to a riser joint that can affect the integrity of the riser, and should be properly considered when reviewing inspection schedules.

7.6.2.5 Influence of operational practices

Variations in operational practices can lead to the need for the adoption of inspection practices that differ from one drilling contractor to the next and from one vessel to the next. The types of differences that may be found and their implications are as follows.

a) Tension: Different top tensions can result in different levels of VIV fatigue damage accumulation.

b) Joint rotation: Implementation of joint-rotation programmes can reduce the rate of fatigue damage accumulation.

c) Flex joint angle limits: Use of smaller flex joint angle limits at which drilling may be conducted can reduce the rate of wear from drillstring rotation.

d) Riser configuration: Different levels of buoyancy and different arrangements of slick and buoyant joints can produce different static configurations and different VIV response during service and hang-off or installation.

As a result of these differences, and the variation in inspection interval with water depth and environmental conditions, it is not feasible to define rigid guidelines for maximum inspection intervals. It is necessary that these be determined by individual drilling contractors and reviewed and adjusted as increased experience of deep-water operations is gained and inspection findings are processed.

7.6.3 Incidents

Thorough inspection can be warranted in the event of incidents resulting in abnormal conditions, such as the following:

- under tensioning: loss of tension in a wire, loss of pressure in a tensioner cylinder;
- over-tensioning;
- extended periods of hang-off;
- large vessel offset through impact with another vessel, mooring-line failure, drift-off or drive-off;
- shock loads during running or retrieval.

Inspection should be conducted at the first convenient time following an incident. The nature and extent of inspection depends on the incident.

If tension loss has occurred for a period of time, the riser should be retrieved at the earliest opportunity and inspected for signs of damage. Reduction in tension can lead to over-rotation of the riser, particularly at the lower flex joint, with the possibility of overstressing the flex joint nipple or the joint above. Reduction in tension can also increase the rate of fatigue-life accumulation due to current-induced VIV. Similar effects can occur if large offsets are experienced.

Over-tensioning can affect both the riser and conductor. The most highly tensioned joints near the top of the riser should be inspected if load ratings have been exceeded and the verticality of the wellhead should be re-assessed following such a situation in order for any permanent deformation to be accounted for in future drilling or completion operations.

Extended periods of hang-off can result in rates of fatigue-damage accumulation and impact loads and localized damage to joints near the top of the riser. The joints require the appropriate level of inspection when returned to the vessel. This inspection philosophy is also applicable to any instance of known excessive shock loads during running or retrieval.

7.6.4 Provision for inspection

It is unlikely that periodic inspections will coincide with periods of idle rig activity and careful planning is needed to ensure that the work can be carried out with the minimum of disruption to operations. It is necessary to give consideration to the following:

- recording and regular review of riser usage data; see 7.9;
- laying joints aside during retrieval;
- scheduling of joint transportation to shore;
- spare joints, to enable inspection to continue without disrupting riser operations and to account for adverse findings requiring that joints be laid aside;
- filing of inspection records.

7.7 Guidance on components for inspection

7.7.1 General

The increased rates of fatigue-damage accumulation and wear that can be incurred in deep-water require increased focus on detection of fatigue cracking and wall-thickness reduction during inspection. The locations along the riser system where the effects of wear and fatigue due to deep-water operation can be the most pronounced, and hence where inspection procedures should be focused, are identified in 7.7.2 to 7.7.4.

7.7.2 Riser joints

7.7.2.1 Main pipe

Welds are used to connect the riser couplings to the main riser pipe and mid-length welds may be used for longer riser joints. The main pipe carries the greatest loading and can, therefore, be expected to exhibit the least fatigue resistance.

On risers with joints less than 15,24 m (50 ft) long, it is not expected that mid-joint welds are present, unless integral choke-and-kill line clamps are used. However, it is necessary to establish the presence or absence of mid-joint welds prior to conducting the inspection of a riser joint. The latest generation of drilling vessels being used for oil exploration in water depths greater than 1 828,8 m (6 000 ft) can carry riser joints 22,86 m to 27,43 m (75 ft to 90 ft) long. These riser joints are expected to have mid-joint welds and require the appropriate level of inspection.

All welded connections on standard riser joints and pup joints should be examined during detailed periodic inspection for signs of cracking due to fatigue damage. Wear can also occur in any of these joints, and wall-thickness measurements should be conducted to determine the extent of wear or corrosion.

7.7.2.2 Choke-and-kill lines

Local wave and current loading on choke-and-kill lines can generate significant stresses adjacent to the stab connections between adjacent joints where welds are present and the lines can be subject to vortex-induced vibrations. In addition, in some newer deep-water risers, tension is accommodated by load-sharing between the main riser pipe and choke-and-kill lines and these lines are, therefore, subject to fatigue damage from global loads and motions. In view of the criticality of these lines for maintaining well control, the choke-and-kill lines warrant high priority in terms of inspection requirements, with focus on fatigue cracking at all welded connections.

7.7.3 Slip joint

The base of the slip joint has the same fatigue critical hotspots as a standard riser joint. In addition, fatigue critical hotspots can be found at the upper end of the lower barrel where choke-and-kill line off-takes are mounted and at the interface with the tension ring. Gusset plates may be welded to the outer pipe to provide support for the choke-and-kill line jumpers or support for the tension ring. There may be some redundancy in these components, which should be assessed in order to determine the extent and detail of inspection required.

The inner barrel of the slip joint is susceptible to wear, particularly adjacent to the flex joint where relative rotation between the riser and vessel takes place. While this part of the riser is subject to relatively small axial and pressure loads, the slip joint upper barrel should, nonetheless, be subject to regular checks for wear.

7.7.4 LMRP and BOP

The main location at which wear occurs in the BOP stack is in the region of the flex joint. The flex joint itself can be protected to some extent by integral wear bushings and adjacent components can, therefore, be more prone to wear-induced damage. In all detailed inspections, measurements should be taken to ensure that the levels of wear in and adjacent to the LMRP are acceptable.

All main components of the BOP stack, including rams, annular preventers and connectors, are generally forged components. In most applications, at normal operating pressures, the BOP stack is subject to low levels of tension or compression and accumulated fatigue damage can be negligible. Sundry structural components, such as the frame, may be subject to fluctuating loads but, as the frame is not critical to the structural integrity of the stack, rigorous inspection of the frame is not warranted. However, it is necessary to conduct regular checks to ensure that the clamps and flanges are correctly preloaded.

Modifications to BOPs are occasionally made in order to raise the stack height to accommodate completion tools. These may consist of the use of extended spools or spacer flanges. Where such modifications have been implemented, welding may have been employed. The introduction of residual stresses in this way can produce severely reduced fatigue resistance and thorough inspection is warranted when using such components in deep-water.

7.8 Inspection objectives and acceptance criteria

7.8.1 Visual examination

Signs of riser deterioration identified during visual examination following riser retrieval should be dealt with as follows.

— Wear or corrosion on riser pipe: Conduct thickness inspection of identified location. If any measurements of thickness are less than minimum wall thickness, lay joint aside until a detailed examination can be conducted.

— Obvious signs of cracking: Lay the joint aside for more detailed examination.

— Loose attachments: Secure or replace fixings.

— Damaged buoyancy modules: Remove buoyancy from affected joints if there is any danger of loss during riser operation and adjust riser tension to compensate for buoyancy loss.

7.8.2 Periodic detailed inspection

7.8.2.1 General

Wall thickness measurements, dimensional tolerances and fatigue defects identified during periodic detailed inspections should comply with the fabrication criteria of the riser system. The likely sources of deterioration in integrity and the associated requirements and limitations of the applied inspection techniques are described in 7.8.2.2 to 7.8.2.4. In addition, the possible implications of non-compliance, such as requirements for repair or de-rating of the tension capacity or pressure (depth) resistance of joints, are described.

7.8.2.2 Wall-thickness reduction

Prior to fabrication of a drilling riser, quality control checks are conducted to ensure that the pipe wall complies with specified tolerances. Reduction in wall thickness occurs in service due to drillstring wear and corrosion. Thickness reduction can be evenly distributed around the riser wall due to corrosion in service, or localized, due to storage, drillstring wear or pitting corrosion. Wear on the external pipe surface from handling can also result in corrosion and is likely to occur near critical welds. The procedures used for inspecting wall thickness shall be capable of identifying both global and localized thickness reductions. Inspection acceptance criteria shall account for a wide range of global and local forms of wall thickness reduction. The implications of deterioration in condition are as follows:

a) Localized loss: Local reduction in wall thickness might not significantly affect global bending or tensile strength, but pressure resistance can be impaired. Consequently, the pressure resistance of a riser pipe should be re-assessed where localized wall thickness is less than the minimum expected wall thickness.

b) Longitudinal loss: Longitudinal loss of wall thickness over a small circumferential length can be caused by key-seating from drillstring rotation. Localized circumferential wear might not have much effect on bending and tensile strength of the riser pipe, but internal and external pressure resistance and collapse resistance are reduced. Where thicker-walled joints are used to compensate for wear, it might not be necessary to assess fitness-for-purpose on the basis of nominal thickness less manufacturing tolerance. Alternatively, less stringent dimensional criteria may be devised in conjunction with the equipment manufacturer.

c) Circumferential loss: Circumferential loss of wall thickness can result in reduction in bending, tensile and pressure resistance. In addition, curvature due to bending can become localized, giving an increase in the rate of fatigue-damage accumulation. Hence, the minimum average circumferential wall thickness should not be less than the nominal pipe size less the manufacturing tolerance used for riser design.

Where dimensional measurements fall outside of tolerance limits, it is probable that a joint can be de-rated (in terms of tension and/or pressure resistance) and its use limited to the middle section of a riser string where design pressures and tensions are lower than at the top or bottom.

7.8.2.3 Fatigue cracks

Methods of crack detection can be broadly classified into two categories: surface-flaw detection methods, such as dye-penetrant and magnetic-particle (though magnetic-particle also detects near-surface flaws), and volumetric methods, which detect through-thickness flaws, such as ultrasonic and radiographic testing. The methods required for application depend on the area in question.

Fatigue cracks are most likely to develop in the region of couplings where stress concentrations are found and welding is used. In coupling-load shoulders where no welding is present, cracks are most likely to form on the surface at points of highest stress concentration. In such locations, surface-crack detection methods are sufficient to confidently predict the presence of cracks.

Drilling-riser coupling welds may be single-sided, made from the outside of the pipe, or double-sided, made from both the inside and outside. In single-sided welds, the most likely location of imperfections is at the weld root from incomplete penetration or inclusions and there is an increased probability of cracks developing on the inside of the pipe. Surface-crack detection methods applied to the outside of the pipe are incapable of detecting flaws on the inside. Consequently, either internal inspection or a suitable volumetric method applied from the outside that can reliably detect root imperfections is required.

While the inspection methods referred to above are capable of measuring small flaws, for the purpose of fracture mechanics, it is necessary to consider how large a flaw can be missed. Based on the discussion given by Dickerson, *et al*., 1997, there can be a 50 % chance of missing a flaw 2 mm (0,079 in) deep by 12 mm (0,47 in) long in the root of a single-sided weld using ultrasonic testing. Better results may be expected for defects at or near the weld cap and smaller surface defects can be identified using dye penetrant.

Where fatigue cracks are found, it can be feasible to conduct repairs by grinding and re-welding. However, the crack can be symptomatic of the fact that the joint has used much of its fatigue life and re-use requires the removal of all welds and heat-affected zones in the joint and complete re-fabrication.

7.8.2.4 Ovality and collapse

Pipe ovality can impair the passage of tools inside the riser and reduce collapse resistance. In terms of the drift requirements, any denting damage sustained through mishaps during handling should be measured and the limitations assessed. Though dented, a joint can prove serviceable in shallow-water applications where collapse resistance is not a dominating design requirement. In deeper water, collapse can become the criterion that determines the serviceability of a riser joint. As collapse resistance is affected by both wear and ovality, it is necessary to pay greater attention to the global shape of the riser pipe. The limitations for ovality vary from application to application, but it is necessary that the criteria for each application be developed based on the following:

- functional performance: passage of tools inside the riser limited by ovality;
- ovality/wall thickness: combined limits on wall thickness and ovality or denting that produce unacceptably low resistance to withstand external hydrostatic pressure.

Where section imperfections are judged as being due to ovality, external pressure resistance may be assessed using collapse criteria.

7.9 Operational records for riser components

7.9.1 Introduction

Records of riser usage shall be kept in order that inspection can be conducted at the required intervals and to the appropriate level of detail. The ability to rationalize inspection also depends on the data that are recorded to monitor riser usage.

The more data that are recorded, the more scope there is for rationalizing inspection intervals and scope of inspection, as illustrated in Table 5. However, in extreme cases, more effort can be applied to recording riser data than the benefits gained from reduced inspection requirements. A staged approach to riser usage monitoring and inspection scheduling which enables differing degrees of rationalization according to the variety of recorded data is, therefore, proposed . A two-level approach is outlined in 7.9.2 and 7.9.3.

7.9.2 Usage-only logging

7.9.2.1 The usage-only logging approach requires a relatively small data-collection effort. The objectives of the approach are to enable inspection that is based on the following:

— total time in service of each riser joint: allowing the inspection interval to change with actual time in service;

— joint position: enabling inspection to be focused on critical regions, primarily the riser base and near the top of the riser and enabling the monitoring of joint-rotation programmes;

— riser configuration: primarily required to track long periods of hang-off (typically associated with difficult environmental conditions) where fatigue loading in the upper riser can be severe in order to focus inspection attention in this area.

7.9.2.2 In order that these objectives can be achieved, a riser-usage logging and monitoring system that makes provision for recording the following should be adopted:

— unique joint identifier to enable tracking of usage of each joint;

— riser stack-ups showing the position of each joint within the riser string each time the riser is run;

— water depth;

— riser configuration: installation, connected, hung-off, retrieval;

— start and end dates of each configuration;

— inspection dates.

7.9.2.3 Calculations should be performed using the date information to enable a determination of time in service since last inspection and service time available until next inspection.

Table 5 — Data required for rationalizing inspection

Basis for inspection	Data required	Consequence
Riser age	Date of first implementation	Most simplistic approach that can be taken and which probably results in excessive inspection and unnecessary cost
Riser time in service	Start and end dates of riser operations	Increases intervals between inspections by eliminating the time the riser is in storage
Joint time in service	Joints used each time the riser is run	Reduces the need to inspect joints that have been used less frequently; important for long riser strings where perhaps only half to two-thirds of the string is in regular service
Joint position	Riser stack-up	Focuses inspection attention on joints in critical regions in terms of wear and fatigue damage, primarily the base of the riser and secondly near the top; also enables the monitoring of joint rotation programmes
Riser configuration	In-place/hang-off Configuration	Primarily required to track long periods of hang-off (typically associated with difficult environmental conditions) where fatigue loading in the upper riser can be severe and impact with the hull can take place in order to focus inspection attention in this area
Severity of operating conditions (1)	Tensions, mud weight	Tension in the drilling riser and drillstring, and mud weight can affect wear and fatigue in the riser. Recording actual tensions and mud weights enables making comparisons with predicted data and where differences are found, a review of inspection schedules.
Severity of operating conditions (2)	Current and wave conditions	Higher rates of fatigue damage can be incurred near the riser ends from greater current speeds (VIV) and in the upper riser from more severe wave loading. Inspection schedules based on fatigue or fracture response of the riser can be reviewed by comparing actual conditions to predicted conditions forming the basis of fatigue and fracture analysis.
Incidents	Tension variation/hang-off	Changes in tension, be it loss of tension or over-tensioning, require the selective inspection of riser joints and some components at the earliest opportunity. Hang-off inspection requirements are detailed above.

7.9.3 Usage-and-conditions logging

The usage-and-conditions logging approach incorporates all the requirements of usage-only logging and, in addition, enables basing the inspection on the severity of riser operating conditions. When using this approach to define inspection intervals for deep-water drilling risers prior to active service, it is necessary to make assumptions regarding operating conditions. The more severe the operating conditions, the more frequently inspection should be conducted.

Operating-condition severity typically depends on water depth, riser tension, mud weight, drillstring tension, current and wave loading. Each of these parameters can influence the levels of wear and fatigue damage accumulated in a drilling riser system. By recording each of these parameters, comparisons can be made with the assumed values used to define inspection requirements prior to service, and adjustments made to inspection interval or detail as considered appropriate.

Riser tension, mud weight and drillstring tension can remain relatively unchanged over many hours and daily mean values should provide adequate data for inspection monitoring purposes. Wave and current data can vary considerably throughout each day. However, it is the extremes that have greatest influence on riser behaviour and hence it is recommended that extreme values of current speed and significant wave height be recorded at least daily.

The recording of wave and current data as described above provides a very simplistic summary of environmental conditions. More detailed recording of environmental conditions may be considered necessary in order to further rationalize inspection frequency and methods. In such cases, suitable approaches to defining inspection requirements can be developed by individual drilling contractors along similar lines to the two methods described in 7.9.2 and 7.9.3.

7.9.4 Logging systems and responsibilities

The responsibility for ensuring that the necessary data are recorded and for the maintenance of the logging system should lie with a single individual, nominated by the offshore installation manager. Most, if not all, of the data identified within the usage-only logging approach is routinely available. A relatively small amount of effort is needed to obtain and collate these data, the largest part of which deals with the riser stack-ups that are recorded as the riser is run.

Current practice for measuring the data required for the usage-and-operating-condition logging approach varies considerably from one drilling vessel to the next. Many people can be involved in monitoring these data, which can be collected in different parts of the drilling vessel. Measurements of riser tension and mud weight can be taken a number of times during each shift and recorded in the daily International Association of Drilling Contractors (IADC) drilling report. Drillstring tension is continuously monitored and also recorded in the IADC report. In severe environments, environmental data can be regularly monitored and recorded in a daily marine report. However, most of the operating condition data is not generally recorded with a view to assessing inspection requirements. Additional work is, therefore, necessary by the person responsible for maintenance of the riser-usage logging system, to liaise with the relevant rig personnel and to incorporate the data into the riser logging system on a daily basis.

7.9.5 Inspection records

Records of riser inspection detailing the types of inspection carried out, results obtained and any recommended remedial action for each joint in the riser inventory should be maintained. Details of inspection methods, quantitative findings and any remedial action should be recorded.

8 Special situations

8.1 Deep-water drilling

8.1.1 General

The technical development of risers and control systems has progressively extended water depth capabilities.

Drilling in deeper water imposes greater physical and functional demands on the marine drilling riser system. These additional requirements can include the following:

- higher load rating: stronger couplings, thicker walled pipe and/or higher-strength steel, higher hoop stresses at the bottom;
- mass/weight control: removal of unnecessary metal from couplings and support brackets, use of longer standard joints [reduces overall weight per metre (foot)], use of rolled and welded pipe (rather than seamless pipe) for the riser main tube;
- streamlined deployment and retrieval: use of semi-automated methods for storage, handling and pressure testing, use of quick makeup/breakout couplings, use of longer standard joints;

— emergency disconnect capability: automatic LMRP release capability and anti-recoil system;

— augmented riser lift: syntactic foam and/or air-can buoyancy, increased riser tensioner capacity aboard the rig;

— instrumentation: extra instrumentation to permit closer monitoring of critical parameters, such as applied tension, riser angle and pipe wall tension at the bottom of the riser and current profile;

— annulus pressure control: an automatic fill-up valve to prevent collapse, an annulus closing device positioned below the telescopic joint to control internal pressure in the event of gas influx;

— extra auxiliary lines: a rigid conduit hydraulic supply line for delivery of power fluid to the BOP stack control valves, a mud-boost line to assist return of cuttings up the riser annulus;

— storm hang-off system: special apparatus to permit suspension of a long riser as the vessel rides out a storm;

— interface with a multiplex control system: non-retrievable control pods on the LMRP, clamps on each riser joint for MUX umbilical cables;

— re-entry system: ROV, acoustic, and/or video guided apparatus for guidelineless wellhead or BOP stack orientation and re-entry operations.

8.1.2 Weight control

8.1.2.1 General

The deck weight and storage requirements of a deep-water drilling riser can be several times greater than that of a conventional riser. The large deck weights and space requirements of these risers, as well as their overall cost, often represent a significant percentage of both the variable deck load and the cost of the drilling vessel. Consequently, a cost and weight control programme should be used throughout the design and manufacturing of the deep-water riser.

The large weight of the riser results not only from the extra length of riser required in deep-water, but also from requirements for increased pipe wall thickness, stronger couplings, additional auxiliary lines and increased buoyancy requirements. While the contribution to the overall riser joint weight of such items as auxiliary line support brackets can be small, their effect is often magnified by the necessity to offset this weight with additional buoyancy material. Buoyancy materials and associated components should be optimized for high lift efficiency and reliability.

8.1.2.2 Pipe wall and buoyancy tolerances

The large wall thickness tolerances permitted by ANSI/API Spec 5L/ISO 3183 are inappropriate for deep-water riser main tube applications, because significant weight and buoyancy penalties can be incurred. Consideration should be given to rolled and welded pipe with tighter thickness tolerances. Riser pipe and coupling dimensions should be engineered and selected to meet practical requirements. Material tolerances should be specified and negotiated with the steel mills. Likewise, tolerances for attached buoyancy modules are equally important and should be held within practical limits.

8.1.2.3 Tensioner systems

Current technologies aim to reduce cost and weight of tensioner systems, while maintaining suitable performance (see ISO/TR 13624-2:—, Clause 8).

8.1.2.4 Alternative materials

8.1.2.4.1 General

In ultra-deep-water, it is necessary to carefully weigh the cost and efficiency of buoyancy against the weight and cost of the riser itself. Increased depth demands increased riser strength (and consequently weight), but buoyancy becomes less efficient as water depth increases. There is a point at which non-traditional approaches can be more cost-effective.

Inherently, materials used in deep-water should enhance the strength/weight ratio of the riser joint, thereby creating fewer demands on buoyancy. Emerging technologies aim at substituting lighter-weight high-strength fibre composites or titanium for high-tensile steel. When considering alternative materials in the design of an ultra-deep drilling riser, it is necessary to assess the material's characteristics in an overall integrated system approach, including considerations for cost and performance of the riser string, buoyancy, tensioners, dynamics/fatigue, weight/space and handling systems.

8.1.2.4.2 Fibre composites

Progress has been made in the design and experimental deployment of composite choke-and-kill lines attached to large-bore steel risers. These are small-diameter, thin-wall, steel tubes that are filament wound with a light-weight, high-strength, pre-tensioned synthetic fibre (aramid), embedded in a thermoplastic resin matrix (Tamarelle and Sparks, 1987; Guesnon, 1989; Sweeney and Fawley, 1989). This composite construction permits a significant reduction in mass for auxiliary high-pressure lines attached to the riser.

Designs are emerging that apply this same technology to the riser tube itself. Steel riser tubes can be wound with an aramid fibre. Axial-strength requirements are retained within the steel tube and coupling, while largely relying on the winding to resist hoop stresses caused by pressure from the column of drilling fluid.

Similar to filament winding for steel tubes, all-fibre composites, such as spirally wound graphite and S-glass epoxy matrixes, are currently being developed for use as production risers. Such designs may eventually find a role in high-tech drilling risers, provided that coupling designs and drillpipe wear concerns can be satisfied.

8.1.2.4.3 Titanium

Titanium alloys are very light, very strong and resistant to both the marine environment and fatigue. The material can be formed, forged, welded and machined.

Typical alloys to be considered in riser designs exhibit yield strengths from 830 MPa to 1 100 MPa (120 ksi to 160 ksi), having densities of approximately 60 % of steel, i.e., the weight/strength advantage is on the order of 2,5 to 3,3 when compared with 550 MPa (80 ksi) yield steel.

The principal drawback to using titanium has been its cost. Another disadvantage arises from the low modulus of elasticity of titanium (about half that of steel), which can cause a suspended ultra-deep titanium riser to exhibit high axial dynamic responses. To date, titanium has been utilized successfully in special applications, such as a riser stress joint in a production riser.

8.1.3 Gas influx

Formation gas that can enter the riser before a BOP is closed expands as it ascends in the riser annulus. In a long riser, the consequent volumetric rate of flow at the surface can be hazardous and loss of the mud column can result in riser collapse.

A proposed method of controlling this flow incorporates an annulus-closing device (such as an annular BOP) positioned in the riser string just below the telescopic joint. Beneath this device is a side outlet with a valve connected by means of a drape hose to a choke. With this arrangement, the riser can be shut in when gas is detected at the bottom of the riser. The gas can thereby be circulated out by pumping down the mud-boost line and up the riser annulus to the choke. See Hall, Roche and Boulet, 1986.

8.2 Guidelineless systems

Guidelineless systems may be used for the deployment of drillstrings, casing strings, the drilling riser and the 0,762 m (30 in) latch, or the drilling riser and subsea BOP stack or LMRP. They were developed for use with dynamically positioned drilling units, but can also be used with moored vessels.

Guidelineless re-entry essentially encompasses the following:

a) some means of locating the position of the equipment being run relative to the wellhead, typically an acoustic positioning system for course alignment and a television for fine alignment and observation;

b) some means, such as either a dynamic positioning system or a mooring system, to manoeuvre the drill vessel until the equipment being run and the wellhead are aligned to within a few feet;

c) final mechanical alignment and guidance into the hole or onto the wellhead (usually with a funnel structure).

Typically, a guidelineless well is started by jetting or drilling-in structural casing that has a guidelineless re-entry guide base and a 0,762 m (30 in) wellhead housing attached to the top. An acoustic beacon is mounted on the guidebase so that the drilling vessel can use an acoustic positioning system to monitor the position of the guide base.

During the deployment of the riser and BOP stack, for example, an acoustic beacon is either attached to the BOP stack or lowered on the wireline down the outside of the riser to enable the vessel to monitor the approximate position of the stack with respect to the guide base. Once the stack is near the seafloor, a television camera is lowered through the riser on an armoured cable to visually observe the re-entry operation. The vessel is manoeuvred using the thrusters or the mooring system until the BOP stack can be stabbed into a guide funnel on the guide base. Alternatively, a remotely operated vehicle (ROV) or stack-mounted camera can provide the visual observation of this final stabbing operation.

8.3 Cold weather considerations

8.3.1 General

Low air temperature and sea ice affect riser operations. Steel components exposed to temperatures below −20 °C (−4 °F) should be qualified for cold-temperature applications. Such qualification can require material testing at low temperatures. Testing should be performed in accordance with ASTM A370 and ASTM E23. The operating range of elastomeric materials should also be consistent with cold-weather operations.

8.3.2 Ice formation

Operation of a marine riser in sub-freezing temperatures can lead to problems, including

a) ice formation inside the exposed choke-and-kill lines, terminal fittings, drape hoses and surface piping;

b) ice formation inside the control hoses for functions, such as energizing the telescopic joint packer;

c) freezing of the telescopic joint-packer lubricating fluid.

These problems can be avoided by

— using ethylene glycol solutions for pressure testing, hydraulic control and lubrication;

— enclosing the moonpool and cellar deck space below the drill-floor with windwalls and sealable access doors, as permitted;

— introducing heated air into the enclosed spaces;

— allowing a small amount of drilling mud to flow past the telescopic joint packer.

8.3.3 Ice at sea

Ice at sea can be of either land (glacier) or sea origin. Generally, land-origin ice is composed of floating chunks of ice, while sea-origin ice exists as floating sheets of ice. Except in a very thin or small broken form, ice poses a significant and possibly severe hazard to the drilling vessel, its mooring or thruster system and the riser itself.

Generally, ice is classified by size (thickness, elevation above water, surface area) and by age (Bowditch, 1977).

If at all possible, operations in ice-infested waters should be avoided. A moving ice sheet places severe loadings on the drilling vessel and its positioning system. Floating chunks of ice that are too low in the water to be detected by radar are particularly hazardous, because they can get close to the vessel without detection.

A ship's hull tends to protect the riser from smaller, broken-up sheet ice. With sufficient current or wind, ice can be pushed under the vessel. An “ice lip” around the moonpool can deflect ice from entering the moonpool and impacting the riser.

Semi-submersibles generally offer less protection to the riser. Special skirts or doughnut-shaped columns that extend below the ice zone can be effective in protecting the riser.

8.4 Riser collapse considerations

8.4.1 When a marine riser is partially evacuated (well-control situations, emergency disconnect), it is subject to differential pressures that can cause the riser tube to collapse. The following are design collapse loading cases for consideration:

a) riser partially emptied by gas from below the BOP which migrates and expands: assume riser is 50 % evacuated [but maximum evacuation of 457,2 m (1 500 ft)] with riser-fluid density of 1,02 kg/L (8,55 lb/gal) below[2] the assumed depth of evacuation;

b) hole at riser bottom allowing mud from the U-tube into the sea: assume riser is evacuated to the depth as calculated in Equation (9).

$$L_\mathrm{e} = L_\mathrm{h}\left(1 - \rho_\mathrm{w}/\rho_\mathrm{m}\right) \qquad (9)$$

where

L_e is depth of evacuation;

L_h is depth of hole in riser;

ρ_w is the density of seawater;

ρ_m is the density of the mud.

If the riser collapse strength does not meet these criteria, consider putting an automatic fill-up valve in the riser.

2) Field tests show that gas-bubble migration in deep-water drilling risers filled with water-base mud is dominated by dispersion rather than slug-type, large bubble behaviour (Gonzalez, *et al*., 2000). For non-aqueous drilling fluids, there is the added effect of the gas dissolving into fluid, then evolving the dissolved gas near the surface. This effect also tends to prevent the gas from migrating as a discrete bubble.

8.4.2 Factors that affect the depth at which a tensioned pipe collapses include

a) the diameter to thickness ratio, D/b;

b) the yield strength;

c) dimensions and tolerances (OD, wall thickness, eccentricity, out of roundness);

d) corrosion, key-seat wear, local damage;

e) axial tension;

f) bending stress in riser;

g) density of internal fluid.

8.4.3 Typically, risers can collapse from external pressure by two mechanisms:

— purely elastic collapse failures;

— combination of elastic and plastic deformation, called the transition collapse mode.

The mechanism of failure can be determined from the D/b ratio, the yield strength, and the axial stress of the riser pipe according to the tension collapse formulas in ANSI/API Bull 5C3. Other recognized methods may also be considered. Generally, the higher the D/b ratio, the more likely elastic behaviour of the pipe is. However, smaller-diameter or thicker-walled riser tubulars should be checked for transition mode collapse, since it can occur at lower external pressure.

For drilling risers, collapse is more likely to occur in the elastic region than in the transition mode. Increased axial tension contributes to the probability of occurrence of failure in the transition mode.

8.5 H_2S considerations

Factors required for H_2S cracking to occur are

a) an H_2S-cracking-susceptible material;

b) an environment which promotes H_2S cracking (H_2S and water);

c) stress on the susceptible material; the stress may be external (mechanical loading or pressure) or internal (residual stress from high-strength material and/or welding).

The usual method of controlling the material's H_2S stress cracking susceptibility is to control the drilling environment by methods such as

— inhibitors;

— use of oil-based drilling fluid;

— controlled pH (minimum pH = 10).

If the environment cannot be reliably controlled, it becomes necessary to specify H_2S resistant materials. Users are encouraged to clearly specify quality assurance and product testing for critical equipment. Refer to ANSI/NACE MR0175/ISO 15156.

Annex A
(informative)

Riser analysis data worksheet

Table A.1 — Riser analysis data worksheet

Location	
Water depth/reference	
Vessel name	
Vessel type	
Vessel draft	
Drill-floor to WL	
Moonpool dimensions	

Tensioner system			
Number of tensioners		DTL rating ea. [kN (kip)]	
No. tens./accumul.		Ten. RF: rot./non-rot.	
Tens. line fleet ang.		Tens. line dia. [mm (in)]	
Tens. line B.S. [kN (kip)]		Termination type	
Wire wt. @ tens. [kN (kip)]		Termin. efficiency	

Telescoping joint			
Collapsed length [m (ft)]		Fully ext. length [m (ft)]	
Space-out to UFJ [m (ft)]		Mud ret. bel. DF [m (ft)]	
Outer BBL dia. [cm (in)]		O.B. wall thickn. [cm (in)]	
O.B. air mass [kg (lbm)]		O.B. subm. mass [kg (lbm)]	
Load rating [kN (kip)]		O.B. yield point [MPa (ksi)]	
Drag diameter [cm (in)]		CD1/CD2 (lo/hi Re)	
Mass diameter [cm (in)]		Mass coefficient, C_m	

Table A.1 (*continued*)

Riser joints	Type 1	Type 2	Type 3
No. joints			
Buoyancy			
M.U. length of jt. [m (ft)]			
Coupling type			
Cplg. load rtg. [kN (kip)]			
Cplg. yield [MPa (ksi)]			
Cplg. stress ampl. F.			
Cplg. mass [kg (lbm)]			
Main tube OD [cm (in)]			
Main tube wall th. [cm (in)]			
Main tube yield [MPa (ksi)]			
Tube stress amplif. F.			
C+K line OD/ID [cm (in)]			
Mud B. L. OD/ID [cm (in)]			
Hydraulic L. ID [cm (in)]			
Bare R. air mass [kg (lbm)]			
Submerged mass [kg (lbm)]			
Steel wt. toler. (%)			
Buoyancy type			
Foam density [kg/m^3 (lb/ft^3)]			
Buoy. dia. [cm (in)]			
Buoy. length [m/Jt.(ft/Jt.)]			
Buoy. air mass [kg/Jt. (lbm/Jt.)]			
Net pos. buoy. [kg/Jt. (lbm/Jt.)]			
Buoy. mass to 1 (mean %)			
Buoy. loss (E+T) (%)			
Drag diameter [cm (in)]			
Mass diameter [cm (in)]			
CD1/CD2 (lo/hi Re)			
Mass coeff. C_m			

Pup jt. M.U. leng. [m (ft)]			
Main tube OD [cm (in)]			
Main tube wall th. [cm (in)]			
Air mass [kg (lbm)]			
Subm. mass [kg (lbm)]			

Table A.1 (*continued*)

Flex/ball jts.+adapt.	Upper	Lower	Intermed.
Rating [kN (kip)]			
Rot. ctr. abv. seafloor			
UFJ top. bel. drill Fl.			
Ctr. - top [m (ft)]			
Ctr. - btm. [m (ft)]			
Effect. air mass [kg (lbm)]			
Effect. subm. mass [kg (lbm)]			
Axial stiffn. [kN/cm (kip/in)]			
Rot. stiff. [kN·m/deg (lb-ft/deg.)]			
Max. rotation (deg.)			
Drag dia. [mm (in)]			
CD1/CD2 (lo/hi Re)			
Mass coeff. C_m			

Stack/wellhead	LMRP	Lower stack	Wellhead
Height [m (ft)]			
Air mass [kg (lbm)]			
Subm. mass [kg (lbm)]			
Drag diameter [cm (in)]			
Hydrod. vol. (m^3/m [ft^3/ft])			
Max. tension [kN (kip)]			
Max. bend. mom. [kN·m (lb-ft)]			

Drilling parameters	Drilling	Non-drilling	Disconnected
D.F. weights [kg/L (lb/gal)]			
Vessel offsets (% WD)			
Top tensions (% DTL)			

Environmental conditions			
Operating mode	**Drilling**	**Non-drilling**	**Disconnected**
Design wave ht. [m (ft)]			
Wave period (s)			
Sign. wave ht. [m (ft)]			
Mean per. tz. (s)			
Peak period (s)			
Spectrum type			

Table A.1 (*continued*)

Current profile	**WD** m (ft)	**Velocity** m/s (knot)	**WD** m (ft)	**Velocity** m/s (knot)	**WD** m (ft)	**Velocity** m/s (knot)
Max. storm surge+tide						

Vessel motion response								
Surge/sway			**Heave** m/m (ft/ft)			**Roll/pitch** deg/m (deg/ft)		
t s	**RAO** ft/ft (m/m)	**Phase angle** deg.	*t* s	**RAO** ft/ft (m/m)	**Phase angle** deg.	*t* s	**RAO** ft/ft (m/m)	**Phase angle** deg.

Annex B
(informative)

Fatigue

Fatigue damage in drilling risers arises from two primary sources of fatigue: wave-induced fatigue and VIV fatigue.

There are two fundamental approaches to a fatigue analysis. The first approach is based on fatigue tests and S-N (stress range versus number of cycles) curves and can take the form of either deterministic or stochastic (spectral method) calculations. The second approach is based on fracture mechanics principles. For a drilling riser, both approaches require knowledge of the magnitude and probability of occurrence of the expected sea states during either the riser's life or recommended inspection interval. These expected sea states form the “fatigue weather spectrum” used in the fatigue analysis. The fatigue life of the riser is defined as the total life to riser failure, i.e., the life until the riser fails (“critical failure”).

In the S-N approach, “peak” stress ranges are calculated for each sea state in the fatigue weather spectrum. These “peak” stress ranges are equal to the product of the dynamic “pipe wall” stresses obtained from the riser analysis and the SAFs (stress amplification factors) calculated for the riser components. The dynamic “pipe wall” stresses are calculated from the dynamic bending moments and the dynamic tension variations. The SAFs are derived by local finite-element analysis of a structural component. The SAFs represent the increased stress caused by geometry, three-dimensional effects and load paths through the structural component.

Fatigue curves specifically for risers have not yet been adopted. However, fatigue curves published for offshore structures have been used to assess riser fatigue (see API RP 2A; UK DEN, 1990; DNV, 1984; NPD, 1982). A difficulty in assessing fatigue for a drilling riser arises from the mobility of the floating drilling vessel. Over the life of a drilling riser, it is employed at a variety of locations with differing environmental conditions, whereas an offshore production structure occupies a single location throughout its lifetime.

For deterministic and stochastic fatigue analysis methodologies, see the procedures in API RP 2A.

It is important to understand that the concern in the fatigue analysis is cyclic stress or stress range, rather than the mean stress itself. Tension-tension, tension-compression and compression-compression regimes receive equal consideration in the fatigue analysis. If the stress in a structural component remains constant, that component has a fatigue life of infinity and cannot fail because of fatigue.

It is necessary to take care in calculating the stresses and SAFs used in the fatigue analysis. Relatively small changes in the stresses and SAFs can result in large differences in the resulting fatigue life. Since fatigue life is proportional to the stress ranges and SAFs, each raised to the power of the inverse slope of the S-N curve (which ranges from 3 to 5), it can be demonstrated that, for an S-N slope of 5, doubling of either stress range, SAF, or any product of these, decreases the fatigue life of a structural component by a factor of 32. For example, if the structural component had a fatigue life of 100 yr, doubling of the product of stress range and SAF would reduce it to 3 yr.

In the fracture-mechanics approach, a structure is assumed to have small defects inherent in the parent material and/or weld material. These defects can propagate in the material once a cyclic loading is applied to the zone containing the defect, and the life of the structure is determined by the time these propagating defects take to cause the structure to fail. Once a defect has reached a critical size, brittle fracture can be the controlling failure mechanism. The fracture-mechanics method is based on six parameters:

— defect assessment, based on the size of the initial defect and location in the material;

— propagation parameters, based on material constants and stress ratios;

— stress-intensity factor, the influence of geometry on the crack tip as well as the long-term distribution of stress range; this term should not be confused with stress amplification factors;

— fracture criteria, evaluates the mode of fatigue failure by incorporating brittle fracture;

— boundary conditions;

— residual stresses, stresses inherent in the material due to the method of fabrication or welding (see BS 7910).

The S-N approach is a good method to estimate the initial fatigue life of a riser for assumed environmental conditions. The fracture-mechanics method, when coupled with an inspection programme, is appropriate for estimating the remaining fatigue life of a riser after use.

Annex C
(informative)

Sample riser calculations

C.1 Riser length determination

C.1.1 Problem

A semi-submersible is drilling a well at a 609,6 m (2 000 ft) (mean water level) water depth location. The wellhead has been cemented in place and its elevation above the mud line measured. Equipment, environmental, and operational data have been input into the accompanying riser analysis data worksheet. Determine the riser length using appropriate pup joints.

C.1.2 Solution

The riser length, L_C, is calculated as given in Equation (C.1); see 6.4.2 and Figure C.1:

NOTE 1 The data are summarized in Table C.1.

NOTE 2 All lengths and heights in this example are based on made-up dimensions.

$$L_C = L_F - (L_A + L_B + L_D + L_E) \tag{C.1}$$

where

L_F is equal to the MLW plus the mean tidal change plus the distance from waterline to RKB;

(in SI units)
$L_F = 609{,}6 \text{ m} + 0{,}762 \text{ m} + 26 \text{ m}$
$= 636{,}4 \text{ m}$

(in USC units)
$L_F = 2\,000 \text{ ft} + 2{,}5 \text{ ft} + 85{,}5 \text{ ft}$
$= 2\,088 \text{ ft}$

L_A is equal to the wellhead height above mud line;

(in SI units)
$L_A = 1{,}46 \text{ m}$

(in USC units)
$L_A = 4{,}8 \text{ ft}$

L_B is equal to the lower stack height plus the LMRP height;

(in SI units)
$L_B = 6{,}92 \text{ m} + 6{,}1 \text{ m}$
$= 13{,}02 \text{ m}$

(in USC units)
$L_B = 22{,}7 \text{ ft} + 20{,}0 \text{ ft}$
$= 42{,}7 \text{ ft}$

L_D is equal to the collapsed length plus one-half of the stroke;

(in SI units)
$L_D = 18{,}65 \text{ m} + 1/2(33{,}89 - 18{,}65) \text{ m}$
$= 26{,}27 \text{ m}$

(in USC units)
$L_D = 61{,}2 \text{ ft} + 1/2\,(111{,}2 - 61{,}2) \text{ ft}$
$= 86{,}2 \text{ ft}$

L_E is equal to the top of flex/ball joint below RKB (drill-floor) plus the made-up length of flex/ball joint.

(in SI units)
$L_E = 3{,}08 \text{ m} + (0{,}3 + 1) \text{ m}$
$= 4{,}4 \text{ m}$

(in USC units)
$L_E = 10{,}1 \text{ ft} + (1{,}0 + 3{,}3) \text{ ft}$
$= 14{,}4 \text{ ft}$

Thus

(in SI units)
L_C = 636,4 m − (1,46 + 13,02 + 26,27 + 4,4) m
= 591,2 m

(in USC units)
L_C = 2 088 ft − (4,8 + 42,7 + 86,2 + 14,4) ft
= 1 939,9 ft

Use 11,73 m (38,50 ft) riser joints plus 7,6 m (25 ft) and 4,6 m (15 ft) pup joints. This makes the telescopic joint slightly short of mid-stroke position as recommended in 6.4.2.

C.2 Minimum top tension determination

C.2.1 Problem

Using the riser analysis data worksheet and riser length determination from the previous example, the accompanying riser diagram has been drawn for this location. Determine the minimum top tension for the following cases:

a) drilling with 1,7 kg/L (14,0 lb/gal) drilling fluid;

b) non-drilling with 1,7 kg/L (14,0 lb/gal) drilling fluid;

c) drilling with 1,4 kg/L (12,0 lb/gal) drilling fluid;

d) non-drilling with 1,4 kg/L (12,0 lb/gal) drilling fluid;

e) drilling with 1,025 kg/L (8,555 lb/gal) drilling fluid (seawater);

f) non-drilling with 1,025 kg/L (8,555 lb/gal) drilling fluid (seawater).

Assume that the minimum effective tension is at the bottom of the riser.

C.2.2 Solution

C.2.2.1 Top tension determination

As per Table 2, the minimum top tension, T_{min}, is determined by Equation (C.2).

$$T_{min} = T_{Sr\,min} \times N / \left[R_f \left(N - n \right) \right] \tag{C.2}$$

where

$T_{Sr\,min}$ is the minimum slip ring tension, as given by Equation (C.3):

$$T_{Sr\,min} = W_s f_{wt} - B_n f_{Bt} + A_i \left[\rho_m H_m - \rho_w H_w \right] \tag{C.3}$$

where

W_s is the submerged riser weight, expressed in kilonewtons (kips);

f_{wt} is the submerged-weight tolerance factor;

B_n is the net lift of buoyancy material, expressed in kilonewtons (kips);

f_{Bt} is the buoyancy loss and tolerance factor resulting from elastic compression, long-term water absorption and manufacturing tolerance;

A_i is the internal cross sectional area of riser tubes, expressed in square metres (square feet);

ρ_m is the drilling-fluid density [0,896 kg/L (7,48 lb/gal or lb/ft^3)];

H_m is the height of the drilling fluid column, expressed in metres (feet);

ρ_w is the seawater density [1 025 kg/L (64 lb/ft^3)];

H_w is the height of the seawater column, including storm surge and tide, expressed in metres (feet).

Table C.1 — Sample calculation riser analysis data worksheet

Location	US East Coast
Water depth/reference	609,6 m (2 000 ft) mean low water
Vessel name	"SPICED JAR"
Vessel type	Semisubmersible
Vessel draft	19,8 m (65 ft)
Drill-floor to WL	26,06 m (85,5 ft)
Moonpool dimensions	—

Tensioner system			
No. tensioners	12	DTL rating ea. [kN (kip)]	356 (80)
No. tens./accumul.	2/ (1)	Ten. RF: rot./non-rot.	0,95/0,90
Tens. line fleet ang.	3°	Tens. line dia. [cm (in)]	5,08 (2,0)
Tens. line B.S. [kN (kip)]	1 761 (396)	Termination type	Wdg. sckt.
Wire wt. @ tens. [kN (kip)]	2,45 (0,55)	Termin. efficiency	0,65

Telescoping joint			
Collapsed length [m (ft)]	18,65 (61,2)	Fully ext. length [m (ft)]	34,08 (111,2)
Space-out to UFJ [m (ft)]	1,3 (4,3)	Mud ret. bel. DF [m (ft)]	1,95 (6,4)
Outer BBL dia. [cm (in)]	61 (24)	O.B. wall thickn. [cm (in)]	1,3 (0,5)
O.B. air mass [kg (lbm)]	5 069,8 (11 177)	O.B. subm. mass [kg (lbm)]	4 406 (9 713)
Load rating [kN (kip)]	4 448 (1 000)	O.B. yield point [MPa (ksi)]	379 (55)
Drag diameter [cm (in)]	82,6 (32,5)	CD1/CD2 (lo/hi Re)	1,2/0,9
Mass diameter [cm (in)]	63,7 (25,1)	Mass coefficient, C_m	2,0

Table C.1 (*continued*)

Riser joints	Type 1	Type 2	Type 3
No. joints	26	2	12
Buoyancy	No	No	Yes
M.U. length of jt. [m (ft)]	15,2 (50)	15,2 (50)	15,2 (50)
Coupling type	Brand x	Brand x	Brand x
Cplg. load rtg. [kN (kip)]	5 560 (1 250)	5 560 (1 250)	5 560 (1 250)
Cplg. yield [MPa (ksi)]	—	—	—
Cplg. stress ampl. F.	—	—	—
Cplg. mass [kg (lbm)]	1 090 (2 400)	1 090 (2 400)	1 090 (2 400)
Main tube OD [cm (in)]	53,3 (21)	53,3 (21)	53,3 (21)
Main tube wall th. [cm (in)]	1,3 (0,5)	1,6 (0,625)	1,6 (0,625)
Mn. tube yield [MPa (ksi)]	448 (65)	448 (65)	448 (65)
Tube stress amplif. F.	1,5	1,5	1,5
C+K line OD/ID [cm (in)]	10,2/6,667 (4,0/2,625)	10,2/6,667 (4,0/2,625)	10,2/6,667 (4,0/2,625)
Mud B. L. OD/ID [cm (in)]	10,2/8,573 (4,0/3,375)	10,2/8,573 (4,0/3,375)	10,2/8,573 (4,0/3,375)
Hydraulic L. ID [cm (in)]	—	—	—
Bare r. air mass [kg (lb)]	4 921 (10 850)	5 694 (12 553)	6 079 (13 403)
Submerged mass [kg (lb)]	4 277 (9 429)	4 948 (10 909)	5 283 (11 647)
Steel wt. toler. (%)	± 5	± 5	± 5
Buoyancy type	—	—	Synt. foam
Foam density [kg/m^3 (lb/ft^3)]	—	—	25
Buoy. dia. [cm (in)]	—	—	101,6 (40)
Buoy. length [m/Jt. (ft/Jt.)	—	—	13,7 (45)
Buoy. air mass [kg/Jt. (lb/Jt.)]	—	—	2 735 (6 030)
Net pos. buoy. [kN/Jt. (lbm/Jt.)]	—	—	4 191 (9 240)
Buoy. wt. to 1 (mean %)	—	—	± 0,91 (± 2)
Buoy. loss (E+T) (%)	—	—	2
Drag diameter [cm (in)]	73,7 (29,0)	73,7 (29,0)	101,6 (40,0)
Mass diameter [cm (in)]	56,1 (22,1)	56,1 (22,1)	101,6 (40,0)
CD1/CD2 (lo/hi Re)	1,2/0,9	1,2/0,9	1,2/0,8
Mass coefficient, C_m	2	2	2

Pup jt. M.U. Leng. [m (ft)]	1,82 (5)	3,64 (10)	5,46 (15)	9,11 (25)
Main tube OD [cm (in)]	53,3 (21)	53,3 (21)	53,3 (21)	53,3 (21)
Main tube wall ht. [cm (in)]	1,3 (0,5)	1,3 (0,5)	1,3 (0,5)	1,3 (0,5)
Air mass [kg (lbm)]	1 113 (2 453)	1 525 (3 361)	1 973 (4 349)	2 796 (6 165)
Subm. mass [kg (lbm)]	967 (2 132)	1 325 (2 921)	1 714 (3 779)	2 430 (5 357)

Table C.1 (*continued*)

Flex/ball jts.+adapt.	Upper	Lower	Intermediate
Rating [kN (kip))	—	3 695 (830,7)	—
Rot. ctr. abv. seafloor	—	39,8	—
UFJ top. bel. drill fl.	10,1	—	—
Ctr. - top [m (ft)]	0,305 (1,0)	2,35 (7,7)	—
Ctr. - btm. [m (ft)]	1, 01 (3,3)	1, 01 (3,3)	—
Effect. air mass [kg (lb)]	—	5 332 (11 754)	—
Effect. subm. mass [kg (lbm)]	—	4 633 (10 214)	—
Axial stiffn. [kN/cm (kip/in)]	—	7 706 (4 400)	—
Rot. stiff. [kN-m/deg (lb-ft/deg)]	0	0,027 (20,0)	—
Max. rotation (deg.)	10	10	—
Drag dia. [cm (in)]	45	32,5	—
CD1/CD2 (lo/hi Re)	1,5/1,5	1,5/1,5	—
Mass coefficient, C_m	2	2	—

Stack/wellhead	LMRP	Lower stack	Wellhead
Height [m (ft)]	6,01 (20,0)	6,92 (22,7)	1,5 (4,8)
Air mass [kg (lbm)]	31 751 (70 000)	118 000 (260 000)	—
Subm. mass [kg (lbm)]	27 590 (60 830)	102 485 (225 940)	—
Drag diameter [cm (in)]	167,6 (66)	304,8 (120)	—
Hydrod. vol. (m^3/m [ft^3/ft])	1,86 (20)	4,65 (50)	—
Max. tension [kN (kip)]	8 896 (2 000)	8 896 (2 000)	8 896 (2 000)
Max. bend. mom. [kN-m (lb-ft)]	2,71 (2 000)	2,71 (2 000)	2,71 (2 000)

Drilling parameters	Drilling	Non-drilling	Disconnected
D.F. weights [kg/L (lb/gal)]	1,44 & 1,66 (12 & 14)	1,03; 1,44 & 1,66 (8,56; 12 & 14)	1,03 (8,56)
Vessel offsets (% WD)	0 & 2	2 & 4	6
Top tensions (% DTL)	50 to 90	50 to 90	—

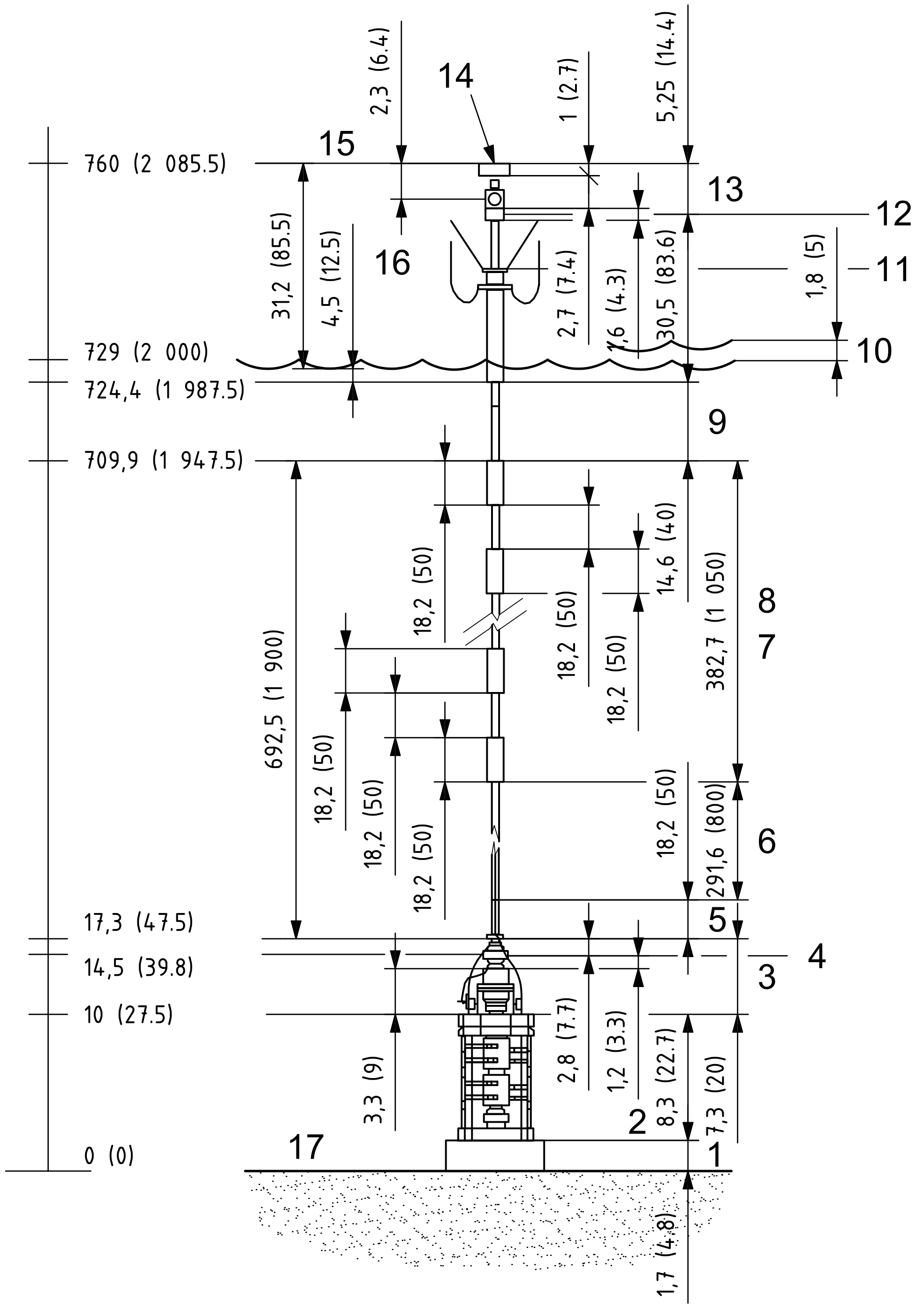
Environmental conditions			
Operating mode	**Drilling**	**Non-drilling**	**Disconnected**
Design wave ht. [m (ft)]	—	—	—
Wave period (s)	—	—	—
Sign. wave ht. [m (ft)]	4,88 (16,0)	6,52 (21,4)	8,2 (26,9)
Mean per. tz. (s)	8,80	9,20	9,70
Peak period (s)	9,94	10,93	13,90
Spectrum type	Jonswap	Jonswap	Jonswap

Table C.1 (*continued*)

Current profile	**WD** m (ft)	**Velocity** m/s (knot)	**WD** m (ft)	**Velocity** m/s (knot)	**WD** m (ft)	**Velocity** m/s (knot)
	0 (0)	0,90 (1,75)	0 (0)	1,03 (2,00)	0 (0)	1,16 (2,25)
	10,06 (33)	0,90 (1,75)	10,06 (33)	1,03 (2,00)	10,06 (33)	1,16 (2,25)
	115 (377)	0,30 (0,58)	115 (377)	0,34 (0,66)	115 (377)	0,36 (0,75)
	226 (873)	0,27 (0,52)	226 (873)	0,30 (0,59)	226 (873)	0,34 (0,67)
	460 (1 509)	0,18 (0,35)	460 (1 509)	0,21 (0,40)	460 (1 509)	0,23 (0,45)
	609,6 (2 000)	0,11 (0,22)	609,6 (2 000)	0,13 (0,25)	609,6 (2 000)	0,14 (0,28)
Max. storm surge + tide	5		5		10	

Vessel motion response								
Surge/sway			**Heave** m/m (ft/ft)			**Roll/pitch** deg/m (deg/ft)		
t s	**RAO** ft/ft (m/m)	**Phase angle** deg.	*t* s	**RAO** ft/ft (m/m)	**Phase angle** deg.	*t* s	**RAO** ft/ft (m/m)	**Phase angle** deg.
0	0,0	0	5,66	0,030	123	0	0,0	0
3	0,039	27	6,01	0,030	150	3	0,016 (0,005)	270
4	0,091	90	6,37	0,020	165	4	0,039 (0,012)	90
5	0,150	270	6,76	0,010	164	5	0,062 (0,019)	90
6	0,234	270	7,18	0,001	58	6	0,134 (0,041)	270
7	0,133	270	7,62	0,026	1	7	0,400 (0,122)	270
8	0,024	90	8,08	0,058	–11	8	0,587 (0,179)	270
9	0,179	90	8,58	0,106	–16	9	0,676 (0,206)	270
10	0,310	90	9,10	0,169	–16	10	0,696 (0,212)	270
11	0,417	90	9,66	0,240	–13	11	0,679 (0,207)	270
12	0,503	90	10,25	0,306	–9	12	0,636 (0,1940	270
13	0,575	90	10,88	0,361	–6	13	0,590 (0,180)	270
14	0,633	90	11,55	0,405	–3	14	0,535 (0,163)	270
15	0,682	90	12,25	0,438	–2	15	0,482 (0,147)	270
16	0,723	90	13,01	0,462	–1	16	0,436 (0,133)	270
17	0,761	90	13,82	0,476	0	17	0,390 (0,119)	270
18	0,799	90	14,69	0,477	0	18	0,348 (0,106)	270
19	0,833	90	15,64	0,459	0	19	0,312 (0,095)	270
20	0,870	90	16,68	0,406	0	20	0,276 (0,084)	270
—	—	—	17,84	0,267	–1	—	—	—
—	—	—	19,14	0,206	–173	—	—	—
—	—	—	20,60	3,000	–75	—	—	—
—	—	—	22,28	1,799	–1	—	—	—
—	—	—	24,19	1,330	0	—	—	—
—	—	—	26,39	1,181	0	—	—	—
—	—	—	28,91	1,112	0	—	—	—

Dimensions in metres (feet) unless otherwise indicated



Key

1 top guide base
2 BOP
3 LMRP
4 centre of lower flex/ball joint
5 riser joint w/o buoyancy [15,9 mm × 18,2 m (5/8 in × 50 ft)]
6 16 riser joints w/o buoyancy [12,7 mm × 18,2 m (1/2 in × 50 ft)]
7 10 riser joints w/o buoyancy [12,7 mm × 18,2 m (1/2 in × 50 ft)]
8 11 riser joints w/o buoyancy [15,9 mm × 18,2 m (5/8 in × 50 ft)]
9 pup joint [5,5 and 9,1 (15 and 25)]
10 storm surge plus tide
11 tensioner ring
12 centre of upper flex/ball joint
13 rotary diverter and UFJ (top part)
14 rotary kelly bushing (RKB)
15 drill-floor
16 centre of mud O.F.
17 mud line

Figure C.1 — Sample calculation — Riser diagram

C.2.2.2 Riser submerged mass, W_s, times the tolerance factor, f_{wt}

The total toleranced submerged mass, $W_{s,Tot}f_{wt}$, is calculated as given in Table C.2.

Table C.2 — Total toleranced submerged weight

Riser joints	Submerged weight per joint $W_{s,J}$ [kN (lb)]	Total submerged weight per joint type $W_{s,Tot}$ [kN (lb)]	Weight tolerance factor f_{wt}	Total toleranced submerged weight $W_{s,Tot}f_{wt}$ [kN (lb)]
26 @ type 1	41,94 (9 429)	1 090 (245 154)	1,05	1 145 (257 412)
1 @ type 2	48,53(10 909)	48,53 (10 909)	1,05	50,95 (11 454)
11 @ type 3	51,36 (11 547)	56,99 (128 117)	1,05	598,4 (134 523)
pup joint, 5,5 m (15 ft)	16.81 (3 779)	16,81 (3 779)	1,05	17,65 (3 968)
pup joint, 9,1 m (25 ft)	23,83 (5 357)	23,83 (5 357)	1,05	25,02(5 625)
slip joint (abv. WL)	49,72 (11 177)	49,72 (11 177)	1,05	52,20 (11 736)
$\sum W_{s,Tot}f_{wt}$	—	1 799 (404 493)	—	1 889 (424 718)

C.2.2.3 Riser net buoyancy, B_n, times the buoyancy tolerance factor, f_{Bt}

The total toleranced buoyancy, $B_{n,Tot}f_{Bt}$, is calculated as given in Table C.3.

Table C.3 — Total toleranced buoyancy

Riser joints	Net buoyancy per joint $B_{n,J}$ [kN (lbf)]	Total buoyancy per joint type $B_{n,Tot}$ [kN (lbf)]	Buoyancy tolerance factor f_{Bt}	Total toleranced buoyancy $B_{n,Tot}f_{Bt}$ [kN (lbf)]
11 @ type 3	41,10 (9 240)	452,1 (101 640)	0,96	434,0 (97 574)
$\sum B_{n,Tot}f_{Bt}$	—	452,1 (101 640)	—	434,0 (97 574)

C.2.2.4 Drilling fluid riser cross sections

The internal drilling-fluid cross-sectional area, A_i, of a riser, (including auxiliary lines) at the bottom of a type 2 riser is calculated as follows:

(in SI units)

$$A_i = \pi/4\ [50{,}165^2 + (2 \times 6{,}668^2) + 8{,}573^2]/100^2 = 0{,}210\ 4\ \text{m}^2$$

(in USC units)

$$A_i = \pi/4\ [19{,}750^2 + (2 \times 2{,}625^2) + 3{,}375^2]/144^2 = 2{,}2647\ \text{ft}^2$$

C.2.2.5 Drilling fluid pressure column, $\rho_m H_m$

The following is a sample calculation to determine the drilling fluid pressure column:

a) drilling fluid density, ρ_m:

(in SI units)

$$\rho_m = 1{,}03\ \text{kg/L} \times 1\ 000\ \text{L/m}^3 = 1\ 025\ \text{kg/m}^3$$

(in USC units)

$$\rho_m = 8{,}555\ \text{lb/gal} \times 7{,}48\ \text{gal/ft}^3 = 64{,}00\ \text{lb/ft}^3$$

ρ_m = 1,44 kg/L × 1 000 L/m^3
= 1 437,8 kg/m^3

ρ_m = 12 lb/gal × 7,48 gal/ft^3
= 89,76 lb/ft^3

ρ_m = 1,68 kg/L × 1 000 L/m^3
= 1 677,4 kg/m^3

ρ_m = 14 lb/gal × 7,48 gal/ft^3
= 104,72 lb/ft^3

b) drilling fluid column height to overflow, including storm surge, H_m:

(in SI units)
H_m = 15,24 + 243,84 + 320,04 + 12,19 +...
... + 25,48 + 4,39 − 1,95 + 1,52
= 620,76 m

(in USC units)
H_m = 50 + 800 + 1 050 + 40 + 83,6 + ...
... + 14,4 − 6,4 +5
= 2 036,6 ft

c) drilling fluid pressure column, $\rho_m H_m$:

1) with seawater:

(in SI units)
$\rho_m H_m$ = 620,76 × 1 025
= 636 387 kg/m^2

(in USC units)
$\rho_m H_m$ = 2 036,6 × 64
= 130 342 lb/ft^2

2) with 1,44 kg/L (12 lb/gal) drilling fluid:

(in SI units)
$\rho_m H_m$ = 620,76 × 1 437,8
= 892 533 kg/m^2

(in USC units)
$\rho_m H_m$ = 2 036,6 × 89,76
= 182 805 lb/ft^2

3) with 1,68 kg/L (14 lb/gal) drilling fluid:

(in SI units)
$\rho_m H_m$ = 620,76 × 1 677,4
= 1 041 289 kg/m^2

(in USC units)
$\rho_m H_m$ = 2 036,6 × 104,72
= 213 273 lb/ft^2

C.2.2.6 Seawater pressure column, $\rho_w H_w$

The following is a sample calculation to determine the seawater pressure column.

a) seawater column density, ρ_w:

(in SI units)
ρ_w = 1 025 kg/m^3

(in USC units)
ρ_w = 64 lb/ft^3

b) seawater column height to centre LFJ, including storm surge, H_w:

(in SI units)
H_w = 609,60 − 1,46 − 6,92 − 6,096 + 1,52
= 596,65 m

(in USC units)
H_w = 2 000 − 4,8 − 22,7 − 20 + 5
= 1 957,5 ft

c) seawater pressure column, $\rho_w H_w$:

(in SI units)
$\rho_w H_w$ = 596,65 × 1 025
= 611 670 kg/m^2

(in USC units)
$\rho_w H_w$ = 1 957,5 × 64
= 125 280 lb/ft^2

C.2.2.7 Internal cross-sectional area times the pressure differential

The following is a sample calculation of the internal cross-sectional area times the pressure differential for various fluids in the riser.

a) with seawater in the riser:

(in SI units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 0{,}210\ (636\ 387 - 611\ 670)$
$= 5\ 200$ kg

(in USC units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 2{,}264\ 7\ (130\ 342 - 125\ 280)$
$= 11\ 464$ lb

b) with 1,44 kg/L (12 lb/gal) drilling fluid:

(in SI units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 0{,}210\ (892\ 533 - 611\ 670$
$= 59\ 093$ kg

(in USC units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 2{,}264\ 7\ (182\ 805 - 125\ 280)$
$= 130\ 277$ lb

c) with 1,68 kg/L (14 lb/gal) drilling fluid:

(in SI units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 0{,}210\ (1\ 041\ 289 - 611\ 671)$
$= 90\ 391$ kg

(in USC units)
$A_i\,(\rho_m H_m - \rho_w H_w) = 2{,}264\ 7\ (213\ 273 - 125\ 280)$
$= 199\ 278$ lb

C.2.2.8 Minimum slip-ring tension, $T_{\text{Sr min}}$

The minimum slip-ring tension, $T_{\text{Sr min}}$, is calculated as given in Equation (C.4):

$$T_{\text{Sr min}} = W_{\text{s,Tot}} f_{\text{wt}} - B_{\text{n,Tot}} f_{\text{Bt}} + A_i \left[\rho_m H_m - \rho_w H_w \right] \quad \text{(C.4)}$$

a) with seawater in the riser:

(in SI units)
$T_{\text{Sr min}} = 192\ 649 - 44\ 259 + 5\ 200$
$= 153\ 590$ kg

(in USC units)
$T_{\text{Sr min}} = 424\ 718 - 97\ 574 + 11\ 464$
$= 338\ 608$ lb

b) with 1,44 kg/L (12 lb/gal) drilling fluid:

(in SI units)
$T_{\text{Sr min}} = 192\ 649 - 44\ 259 + 59\ 093$
$= 207\ 483$ kg

(in USC units)
$T_{\text{Sr min}} = 424\ 718 - 97\ 574 + 130\ 277$
$= 457\ 421$ lb

c) with 1,68 kg/L (14 lb/gal) drilling fluid:

(in SI units)
$T_{\text{Sr min}} = 192\ 649 - 44\ 259 + 90\ 391$
$= 238\ 781$ kg

(in USC units)
$T_{\text{Sr min}} = 424\ 718 - 97\ 574 + 199\ 278$
$= 526\ 422$ lb

C.2.2.9 Minimum required top tension, $T_{\min}$

The minimum required top tension, $T_{\min}$, is calculated as given in Equation (C.5):

$$T_{\min} = T_{\text{Sr min}} \times N \big/ \left[R_f \left(N - n \right) \right] \quad \text{(C.5)}$$

where

N is the number of tensioners supporting the riser, equal to 12;

n is the number of tensioners subject to sudden failure, equal to 2;

R_f is the reduction factor for the vertical tension at the slip-ring tensioner setting, for example to account for line angle and mechanical efficiency, equal to

— 0,95 (drilling),

— 0,90 (non-drilling).

The following is a sample calculation of the minimum required top tension.

a) drilling with 1,68 kg/L (14 lb/gal) drilling fluid:

(in SI units)
$T_{min} = 238\ 781 \times 12/(0,95 \times 10)$
$= 301\ 618$ kg

(in USC units)
$T_{min} = 526\ 422 \times 12/(0,95 \times 10)$
$= 664\ 954$ lb

b) non-drilling with 1,68 kg/L (14 lb/gal) drilling fluid:

(in SI units)
$T_{min} = 238\ 781 \times 12/(0,90 \times 10)$
$= 318\ 375$ kg

(in USC units)
$T_{min} = 526\ 422 \times 12/(0,90 \times 10)$
$= 701\ 896$ lb

c) drilling with 12 lb/gal drilling fluid:

(in SI units)
$T_{min} = 207\ 483 \times 12/(0,95 \times 10)$
$= 262\ 083$ kg

(in USC units)
$T_{min} = 457\ 421 \times 12/(0,95 \times 10)$
$= 577\ 795$ lb

d) non-drilling with 12 lb/gal drilling fluid:

(in SI units)
$T_{min} = 26\ 046 \times 12/(0,90 \times 10)$
$= 276\ 644$ kg

(in USC units)
$T_{min} = 57\ 421 \times 12/(0,90 \times 10)$
$= 609\ 895$ lb

e) drilling with 1,025 kg/L (8,555 lb/gal) drilling fluid (seawater):

(in SI units)
$T_{min} = 153\ 590 \times 12/(0,95 \times 10)$
$= 194\ 008$ kg

(in USC units)
$T_{min} = 338\ 608 \times 12/(0,95 \times 10)$
$= 427\ 715$ lb

f) non-drilling with 1,025 kg/L (8,555 lb/gal) drilling fluid (seawater):

(in SI units)
$T_{min} = 153\ 590 \times 12/(0,90 \times 10)$
$= 204\ 787$ kg

(in USC units)
$T_{min} = 338\ 608 \times 12/(0,90 \times 10)$
$= 451\ 477$ lb

Annex D
(informative)

Example riser running procedure

D.1 Moving stack into running position

Safe handling of the BOP stack depends on the magnitude of vessel motions and the nature of the handling equipment on the particular rig. Some rigs are equipped with special transfer and guidance equipment to guide the BOP stack through the moonpool and the splash zone.

If the vessel motion characteristics permit, the stack can be moved into the running position. On most floating rigs, a set of spider beams is set across the moonpool, either on the rig floor or cellar deck level. The stack is moved and positioned on top of the spider beams, either by overhead trolleys or a bottom-supporting cart or skid. The BOP stack components should be function tested and pressure tested, as required, using the BOP control system for functioning. This testing can be done either before or after the stack is positioned on the spider beams. After successful testing, the BOP stack is ready for running.

D.2 Running the riser and BOP stack

For a typical running procedure, the following steps include the most critical running operations.

a) Prior to lifting the BOP off the spider beams, the BOP controls should be set in the running position and the riser connector should be verified for latching. The controls should not be operated again until the stack is landed.

b) The first riser section (usually two joints) above the BOP stack should be long enough to allow running the BOP stack into the water without stopping. When the BOP stack is in the water, its motions are damped.

c) The riser couplings should be made up in accordance with the manufacturer's recommended procedures. Correct make-up and preload of each coupling should be verified prior to its use as a tensile member. The make-up and break-out tools should be calibrated frequently and set to impart the proper preload to the riser coupling (see API RP 2R for a further discussion of preload).

d) Ensure that the riser spider is properly engaged and supporting the riser before removing the handling tool. A gimballed spider should be considered when vessel pitch or roll motions cause large bending moments on the coupling.

e) As riser joints are added to the string, the choke and kill lines and appropriate auxiliary lines should be pressure tested at regular intervals (usually every fifth joint). The choke-and-kill lines should be filled with water and control-system supply lines should be filled with control fluid.

f) The correct number and length of riser pup joints should be run so that, at mean sea level with the BOP stack latched to the wellhead, the outer barrel of the telescopic joint is sufficiently above mid-stroke to accommodate stroke-out caused by vessel offset.

g) The collapsed and pinned telescopic joint should be made up to the uppermost joint in the riser string and the outer barrel should be hung-off in the spider. On most rigs, the BOP stack is landed with the telescopic joint collapsed and pinned, the additional string length provided by the temporary installation of an extra riser joint (referred to as a landing joint) above the telescopic joint. On some rigs, however, the diverter is made up at this point so that the telescopic joint can be unpinned and fully extended to prepare for landing the BOP stack. The shoe on the inner barrel and the pins joining the inner and outer barrels should each be designed to support the combined submerged weight of the BOP stack and riser, as well as loads from dynamic effects. To avoid confusion, only the collapsed and pinned case is further considered in this part of ISO 13624.

h) The riser, supported by the hook attached to the landing joint, should be lowered sufficiently to allow attaching the riser tensioner lines to the outer barrel of the telescopic joint. The riser tensioners should be adjusted to reduce the hook load while the telescopic joint is supported on the hook. At this point, the BOP stack is in position for landing.

D.3 Landing the stack

The BOP stack landing operation can be monitored using the underwater television system, divers or a remotely operated vehicle (ROV).

Caution should be exercised during the landing operation to avoid putting the riser in compression. Therefore, the BOP stack should be landed with the tensioners supporting more than the weight of the telescopic and riser joints, and the hook or heave compensator supporting the balance of the total weight.

Annex E
(informative)

Sample calculation of maximum and minimum TJ stroke arising from spaceout tolerance, riser stretch, draft, tide, heave and offset

E.1 General information for sample calculation

The information below will be used for the sample calculation of maximum and minimum TJ stroke arising from spaceout tolerance, riser stretch, draft, tide, heave and offset, using the following values:

— height of the riser, H_{riser}, equal to 3 048 m (10 000 ft);

— maximum mud weight (density), $\rho_{\text{m,max}}$, equal to 1,68 kg/L (14 lb/gal);

— outside diameter of the riser, $D_{\text{o,riser}}$, equal to 533,4 mm or 0,533 m (21 in, 1,75 ft);

— inside diameter of the riser, $D_{\text{i,riser}}$, equal to 492,125 mm or 0,492 m (19,375 in, 1,61 ft);

— dry mass of the BOP, $W_{\text{BOP,dry}}$, equal to 158 757 kg (350 000 lbm);

— dry mass of the LMRP, $W_{\text{LMRP,dry}}$, equal to 136 078 kg (300 000 lbm).

The wet mass , W_{wet}, is calculated from Equation (E.1):

$$W_{\text{wet}}(x) = x \cdot \frac{(\rho_{\text{steel}} - \rho_{\text{sw}})}{\rho_{\text{steel}}} \tag{E.1}$$

where

ρ_{steel} is the density of steel, equal to 7 849 kg/m^3 (490 lb/ft^3);

ρ_{sw} is the density of seawater, equal to 1 025 kg/m^3 (64 lb/ft^3).

The wet mass for the BOP and LMRP, $W_{\text{BOP,wet}}$ and $W_{\text{LMRP,wet}}$, respectively, are calculated from Equations (E.2) and (E.3):

$$\begin{aligned} W_{\text{BOP,wet}} &= W_{\text{wet}} \times W_{\text{BOP,dry}} \\ &= 138\ 022 \text{ kg } (304\ 286 \text{ lbm}) \end{aligned} \tag{E.2}$$

$$\begin{aligned} W_{\text{LMRP,wet}} &= W_{\text{wet}} \times W_{\text{LMRP,dry}} \\ &= 118\ 304 \text{ kg } (260\ 618 \text{ lbm}) \end{aligned} \tag{E.3}$$

E.2 Target value for TJ stroke

The target value for TJ stroke is the desired TJ stroke with seawater and the minimum tension setting. Operating procedures may call for an adjustment for stretch. Thus the value of $L_{\text{TJ,target}}$, as determined in

Equation (E.4), may be slightly larger than the actual target value used by rig personnel in determining the spaceout and may be adjusted, if necessary, to achieve the desired maximum and minimum TJ stroke:

$$L_{\text{TJ,target}} = 8{,}946 \text{ m } (29{,}35 \text{ ft}) \tag{E.4}$$

E.3 Stretch calculation

The stretch calculation accounts for the change in TJ stroke that occurs due to changes in tension. When the riser is spaced out, tension is determined by the hanging weight, W_{hang}, of the riser, LMRP and BOP, as given in Equation (E.5). In service, particularly in deep-water and with a heavy mud weight, the operating tension can be significantly higher, thus stretching the riser and shortening TJ stroke.

$$\begin{aligned} W_{\text{hang}} &= W_{\text{riser,wet}} + W_{\text{LMRP,wet}} + W_{\text{BOP,wet}} \\ &= 679\ 978 \text{ kg } (1\ 499\ 095 \text{ lbm}) \end{aligned} \tag{E.5}$$

The cross-sectional area, A_{riser}, of the load-bearing part of the riser is calculated from Equation (E.6):

$$\begin{aligned} A_{\text{riser}} &= \frac{\pi}{4}\left(D_{\text{o,riser}}{}^2 - D_{\text{i,riser}}{}^2\right) \\ &= 33\ 245 \text{ mm}^2 \ (51{,}53 \text{ in}^2) \end{aligned} \tag{E.6}$$

The spring constant of the riser, k_{riser}, can be calculated from Equation (E.7):

$$\begin{aligned} k_{\text{riser}} &= \frac{A_{\text{riser}} E_{\text{riser}}}{H_{\text{riser}}} \\ &= 226\ 219 \text{ kg/m } (152\ 012 \text{ lbf/ft}) \end{aligned} \tag{E.7}$$

where the flexure rigidity of the steel, E_{steel}, is equal to 203 395 MPa (29 500 000 lbm/in^2).

The minimum and maximum TJ stretch, $\Delta L_{\text{TJst,min}}$ and $\Delta L_{\text{TJst,max}}$, respectively, are given by Equations (E.8) and (E.9). The tensions below are given only for illustrative purposes. The actual tensions used for the stretch calculation should come from a connected riser analysis.

$$\begin{aligned} \Delta L_{\text{TJst,min}} &= \frac{\left(W_{\text{hang}} - T_{\text{st,min}}\right)}{k_{\text{riser}}} \\ &= 0{,}31 \text{ m } (1{,}01 \text{ ft}) \end{aligned} \tag{E.8}$$

where $T_{\text{st,min}}$ is estimated as 610 082 kg (1 345 000 lb).

$$\begin{aligned} \Delta L_{\text{TJst,max}} &= \frac{\left(W_{\text{hang}} - T_{\text{st,max}}\right)}{k_{\text{riser}}} \\ &= -2{,}17 \text{ m } (-7{,}11 \text{ ft}) \end{aligned} \tag{E.9}$$

where $T_{\text{st,max}}$ is estimated as 1 170 268 kg (2 580 000 lb).

E.4 Stroke due to offset

This calculation accounts for the change in TJ stroke (extension) that occurs due to the vessel moving off location. Note that this calculation is included only for illustration purposes. A more complete analysis of drive-off/drift-off is likely to predict a somewhat larger change in stroke.

The change in TJ stroke, $\Delta L_{\text{TJ,off}}$, for an offset, L_{off}, of 5,0 % is calculated as given in Equation (E.10):

$$\begin{aligned}\Delta L_{\text{TJ,off}} &= H_{\text{riser}} \cdot \left(\sqrt{1+L_{\text{off}}^2}-1\right) \\ &= 3{,}81\ \text{m}\ (12{,}49\ \text{ft})\end{aligned} \tag{E.10}$$

E.5 Heave, tide, draft

Heave and tide require site-specific data and calculation. Draft changes depend on vessel and operational details. These parameters are defined as ranges (i.e. double amplitudes). The values below appear for illustration purposes only and are not meant to apply to any riser recoil analysis. They assume that the normal condition is midway between the high and low values.

$$\Delta L_{\text{TJ,heave}} = 3{,}96\ \text{m}\ (13{,}0\ \text{ft})$$
$$\Delta L_{\text{TJ,tide}} = 0{,}61\ \text{m}\ (2{,}0\ \text{ft})$$
$$\Delta L_{\text{TJ,draft}} = 0{,}61\ \text{m}\ (2{,}0\ \text{ft})$$

E.6 Spaceout

The spaceout tolerance is determined by the inventory of pup joints. This illustration assumes that the available pup joints allow a spaceout to within 1,52 m, i.e. ± 0,76 m (5 ft, i.e. ± 2,5 ft). This value assumes that the procedure attempts to space out the riser as close as possible to the target stroke and can be either above or below by half the range.

$$\Delta L_{\text{TJ,spaceout}} = 1{,}52\ \text{m}\ (5{,}0\ \text{ft})$$

E.7 Maximum and minimum stroke for TJ spaceout

Assuming the target TJ stroke, the tolerances, $\Delta L_{\text{tol,Tmin}}$ and $\Delta L_{\text{tol,Tmax}}$, to determine maximum and minimum strokes are calculated as given in Equations (E.11) and (E.12), respectively:

$$\begin{aligned}\Delta L_{\text{tol,Tmin}} &= L_{\text{TJ,target}} + \Delta L_{\text{TJst,max}} - \frac{\Delta L_{\text{TJ,heave}}}{2} - \frac{\Delta L_{\text{TJ,tide}}}{2} - \frac{\Delta L_{\text{TJ,draft}}}{2} - \frac{\Delta L_{\text{TJ,spaceout}}}{2} \\ &= 3{,}4\ \text{m}\ (11{,}2\ \text{ft})\end{aligned} \tag{E.11}$$

$$\begin{aligned}\Delta L_{\text{tol,Tmax}} &= L_{\text{TJ,target}} + \Delta L_{\text{TJst,min}} + \Delta L_{\text{TJ,off}} + \frac{\Delta L_{\text{TJ,heave}}}{2} + \frac{\Delta L_{\text{TJ,tide}}}{2} + \frac{\Delta L_{\text{TJ,draft}}}{2} + \frac{\Delta L_{\text{TJ,spaceout}}}{2} \\ &= 16{,}4\ \text{m}\ (53{,}8\ \text{ft})\end{aligned} \tag{E.12}$$

E.8 Maximum and minimum stroke for recoil analysis

For the disconnect analysis, heave is accounted for separately in the calculation of the maximum and minimum recoil, $\Delta L_{\text{TJrecoil,min}}$ and $\Delta L_{\text{TJrecoil,max}}$, respectively, as given in Equations (E.13) and (E.14):

$$\begin{aligned}\Delta L_{\text{TJrecoil,min}} &= \Delta L_{\text{tol,Tmin}} + \frac{\Delta L_{\text{TJ,heave}}}{2} \\ &= 5{,}4\ \text{m}\ (17{,}7\ \text{ft})\end{aligned} \tag{E.13}$$

$$\Delta L_{\text{TJrecoil,max}} = \Delta L_{\text{tol,Tmax}} + \frac{\Delta L_{\text{TJ,heave}}}{2} = 14{,}4 \text{ m } (47{,}3 \text{ ft}) \tag{E.14}$$

If necessary, stretch can be calculated for each tension setting. This makes the maximum and minimum TJ strokes functions of the tension. This increases the minimum stroke for cases with less than the maximum tension and decreases the maximum stroke for cases with more than the minimum tension, as given in the following calculation for an intermediate mud weight of 1,318 kg/L (11 lb/gal) and a tension setting of 8 274 kN (1 860 kips).

For the intermediate case, the tension, T_{int}, is equal to 843 682 N (1 827 000 lbf), and $\Delta L_{\text{TJst,min}}$, $\Delta L_{\text{TJint,min}}$ and $\Delta L_{\text{TJint,max}}$ are calculated as given in Equations (E.15), (E.16) and (E.17), respectively.

$$\Delta L_{\text{TJst,int}} = \frac{\left(W_{\text{hang}} - T_{\text{st,int}}\right)}{k_{\text{riser}}} = \text{- } 0{,}73 \text{ m (- } 2{,}4 \text{ ft)} \tag{E.15}$$

$$\Delta L_{\text{TJint,min}} = L_{\text{TJ,target}} + \Delta L_{\text{TJst,int}} - \frac{\Delta L_{\text{TJ,heave}}}{2} - \frac{\Delta L_{\text{TJ,tide}}}{2} - \frac{\Delta L_{\text{TJ,draft}}}{2} - \frac{\Delta L_{\text{TJ,spaceout}}}{2} = 6{,}83 \text{ m } (22{,}4 \text{ ft}) \tag{E.16}$$

$$\Delta L_{\text{TJint,max}} = L_{\text{TJ,target}} + \Delta L_{\text{TJst,int}} + \Delta L_{\text{TJ,off}} + \frac{\Delta L_{\text{TJ,heave}}}{2} + \frac{\Delta L_{\text{TJ,tide}}}{2} + \frac{\Delta L_{\text{TJ,draft}}}{2} + \frac{\Delta L_{\text{TJ,spaceout}}}{2} = 13{,}4 \text{ m } (43{,}9 \text{ ft}) \tag{E.17}$$

Again, this calculation makes assumptions about tension, offset, tide, spaceout, draft, heave, etc., that it is necessary to determine for each actual analysis. The assumptions used in this example are not intended to be used for actual analysis.

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