TECHNICAL REPORT

ISO/TR 13624-2

First edition
2009-12-01

Petroleum and natural gas industries — Drilling and production equipment —

Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report

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

Partie 2: Méthodologies, opérations et rapport technique d'intégrité relatifs aux tubes prolongateurs pour forages en eaux profondes

Reference number
ISO/TR 13624-2:2009(E)

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Published in Switzerland

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Foreword

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ISO/TR 13624-2 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/TR 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*

Introduction

Since API RP 16Q was issued in 1993, hydrocarbon exploration in 1 200+ m (4 000+ ft) water depths has increased significantly. As a consequence, the need was identified to update that code of practice to address the issues particular to deepwater operations.

Under the auspices of the DeepStar programme, substantial work was commissioned during 1999 and 2000 by the DeepStar Drilling Committee 4502 and led to the development of *Deepwater Drilling Riser Methodologies, Operations, and Integrity Guidelines* in February 2001. Several contractors participated in these efforts. These guidelines were intended to supplement and update the existing API RP 16Q:1993 for deepwater application. In a subsequent joint industry project and in collaboration with DeepStar and the API, these guidelines were later supplemented with other identified revisions and technically edited by an API task group to produce the revision of API RP 16Q:1993 as ISO 13624-1 and the API Technical Report TR1.

This Technical Report is a supplement to the revised API RP 16Q and provides guidance on various analysis methodologies and operating practices.

NOTE The figures have been reproduced as provided by the Technical Committee and, in some cases, contain only USC units.

Petroleum and natural gas industries — Drilling and production equipment —

Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report

1 Scope

This part of ISO 13624 pertains to mobile offshore drilling units that employ a subsea BOP stack deployed at the seafloor. It is intended that the drilling riser analysis methodologies discussed in this part of ISO 13624 be used and interpreted in the context of ISO 13624-1.

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 13624-1:2009, *Petroleum and natural gas industries — Drilling and production equipment — Part 1: Design and operation of marine drilling riser equipment*

API RP 16Q:1993, *Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*

3 Terms and definitions

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

3.1
accumulator
⟨BOP⟩ pressure vessel charged with gas (e.g. nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers

3.2
accumulator
riser tensioner
pressure vessel charged with gas (e.g. 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

3.3
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

3.4
annulus
space between two pipes, when one pipe is positioned inside the other

3.5
apparent weight
effective weight
submerged weight
riser weight in air minus buoyancy

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

3.6
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.

3.7
ball joint
ball-and-socket assembly having a central through passage that has an internal diameter equal to or greater than that of the riser and that may be positioned in the riser string to reduce local bending stresses

3.8
blowout
uncontrolled flow of well fluids from the well bore

3.9
blowout preventer
BOP
device attached immediately above the casing, which can be closed to shut in the well

3.10
blowout preventer
⟨annular type⟩ remotely controlled device that can form a seal in the annular space around any object in the well bore or upon itself

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

3.11
BOP stack
assemblage 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).

3.12
box
female member of a riser coupling, C&K line stab assembly or auxiliary line stab assembly

3.13
buoyancy-control line
auxiliary line dedicated to controlling, charging or discharging air-can buoyancy chambers

3.14
buoyancy modules
devices added to riser joints to reduce their apparent weight, thereby reducing riser top tension requirements

3.15
choke-and-kill lines
C&K lines
kill line
external conduits arranged laterally along the riser pipe and used for circulation of fluids into and out of the well bore to control well pressure

3.16
control pod
assembly of subsea valves and regulators that, when activated from the surface, directs hydraulic fluid through special porting to operate BOP equipment

3.17
coupling
mechanical means of joining two sections of riser pipe in an end-to-end engagement

3.18
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

3.19
drift-off
unplanned lateral move of a dynamically positioned vessel off its intended location relative to the wellhead, generally caused by loss of either stationkeeping control or propulsion

3.20
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 transmission medium for well data

3.21
drive-off
unplanned move of a dynamically positioned vessel off location driven by the vessel's main propulsion or stationkeeping thrusters

3.22
dynamic positioning
⟨automatic stationkeeping⟩ computerized means of maintaining a vessel on location by selectively driving and/or directing thrusters

3.23
effective tension
axial tension that is calculated at any point along a riser in water considering only the top tension and the apparent weight of the riser and its contents

NOTE See ISO 13624-1:2009, 5.4.3, and Sparks, 1984.

3.24
factory acceptance testing
FAT
testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings

3.25
fill valve
valve used to fill the riser with seawater to prevent riser collapse

3.26
fleet angle
⟨marine riser⟩ angle between the vertical axis and a riser tensioner line at the point where the line connects to the telescopic joint

NOTE This angle changes with change in elevation of the vessel.

3.27
flex joint
steel and elastomer assembly having a central through-passage area equal to or greater than the riser bore

NOTE Flex joints are commonly placed at the bottom of the riser to reduce local bending stresses at the transition from riser to lower marine riser package.

3.28
heave
vessel motion in the vertical direction

3.29
hot-spot stress
local peak stress
highest stress in the region or component under consideration, which causes no significant distortion and is principally objectionable as a possible initiation site for a fatigue crack

NOTE These stresses are highly localized and occur at geometric discontinuities.

3.30
hydraulic connector
a mechanical device that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack

3.31
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

3.32
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

3.33
lower marine riser package
LMRP
upper section of a two-section subsea BOP stack consisting of a hydraulic connector, annular BOP, ball/flex joint, riser adapter, jumper hoses for the choke, kill and auxiliary lines, and subsea control pods

NOTE The LMRP lands in the top of the lower subsea BOP stack.

3.34
mud-boost line
auxiliary line that provides a supplementary fluid supply from the surface and injects it into the riser at the LMRP to assist in the circulation of drill cuttings up the marine riser, when required

3.35
pin
male member of a riser coupling or a choke, kill or auxiliary line stab assembly

3.36
pup joint
shorter-than-standard length riser joint

3.37
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

3.38
riser adapter
crossover between riser and flex/ball joint

3.39
riser disconnect
operation of unlatching of the riser connector to separate the riser and LMRP from the BOP stack

3.40
riser joint
section of the riser main tube having ends fitted with a box and pin and including choke, kill and (optional) auxiliary lines and their support brackets

3.41
riser main tube
riser pipe
seamless or electric welded pipe that forms the principal conduit of the riser joint that guides the drill string and contains the return fluid flow from the well

3.42
riser string
deployed assembly of riser joints

3.43
riser tensioner
means for providing and maintaining top tension on the deployed riser string to prevent buckling

3.44
riser tensioner ring
structural interface of the telescopic joint outer barrel and the riser tensioners

3.45
rotary kelly bushing
RKB
commonly used vertical reference from the drillfloor

3.46
slip joint
telescopic joint
riser joint having an inner barrel and an outer barrel with means of sealing in between

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.

3.47
stab
mating box and pin assembly that provides pressure-tight engagement of two pipe joints

NOTE 1 An external mechanism is usually used to keep the box and pin engaged.

NOTE 2 Riser joint choke-and-kill stabs are retained in the stab mode by the make-up of the riser coupling.

3.48
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

3.49
strakes
helically wound appendages attached to the outside of the riser to suppress vortex-induced vibrations

3.50
stress amplification factor
SAF
ratio of the local peak alternating stress in a component (including welds) to 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.

3.51
surge
vessel motion along the fore/aft axis

3.52
sway
vessel motion along the port/starboard axis

3.53
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

3.54
vortex-induced vibration
VIV
in-line and transverse oscillation of a riser in a current induced by the periodic shedding of vortices

3.55
wellhead connector
stack connector
hydraulically operated connector that joins the BOP stack to the subsea wellhead

4 Abbreviated terms

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
RAOs	response amplitude operators
RKB	rotary kelly bushing
ROV	remotely operated vehicle
SAF	stress amplification factor
TJ	telescopic joint
UFJ	upper flex joint
WSD	working stress design

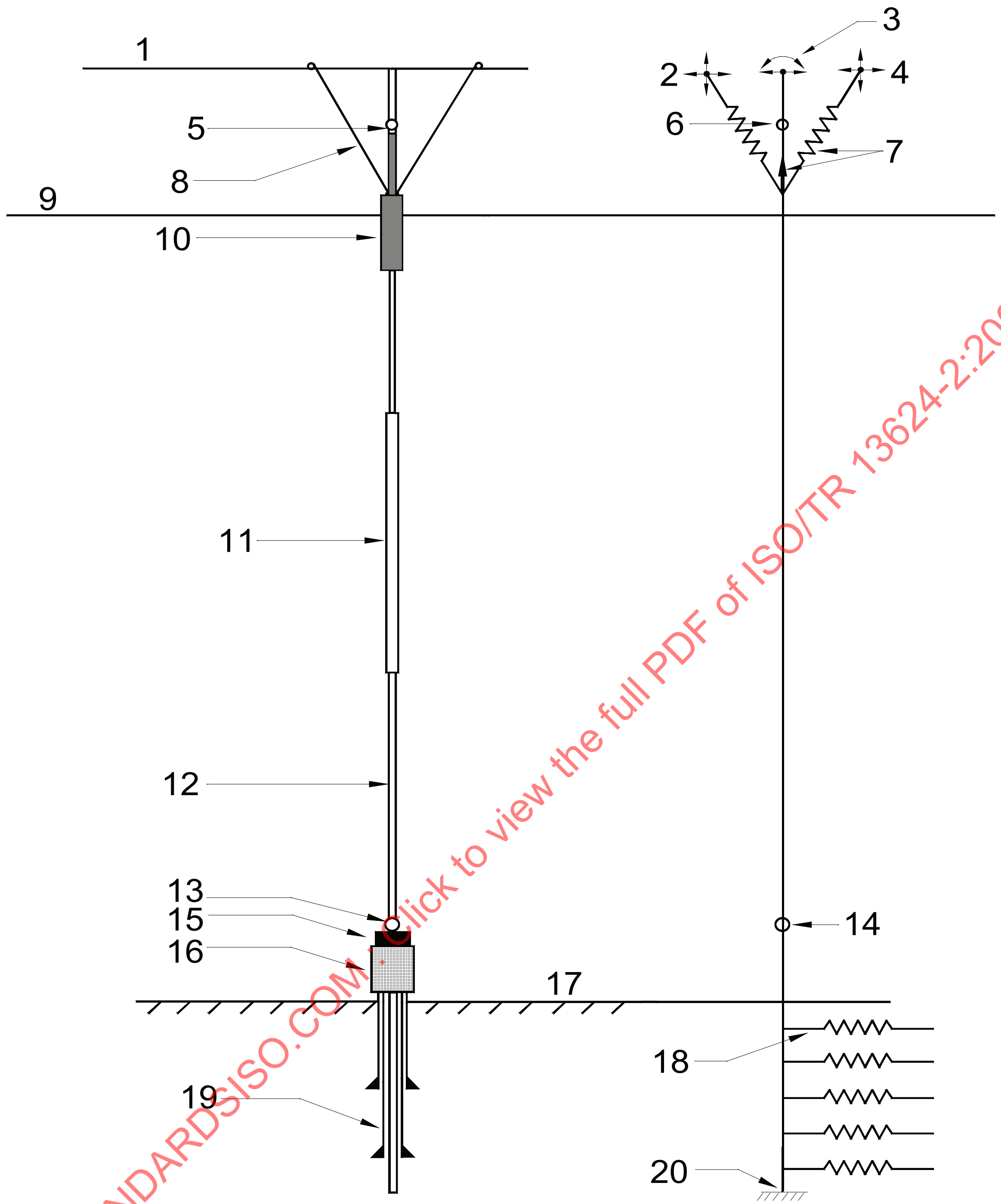
5 Coupled drilling riser/conductor analysis methodology and worked example

5.1 Coupled methodology

In a coupled analysis, the riser system analysed extends from the conductor up to the upper flex joint or ball joint. Therefore, the vessel motions applied at the upper flex joint or ball joint along with the wave and current loading can be used to predict the behaviour of the riser down to the displacements of the conductor in the soil structure. This is a single-stage procedure. Figure 1 shows a schematic of a coupled model.

5.2 Decoupled methodology

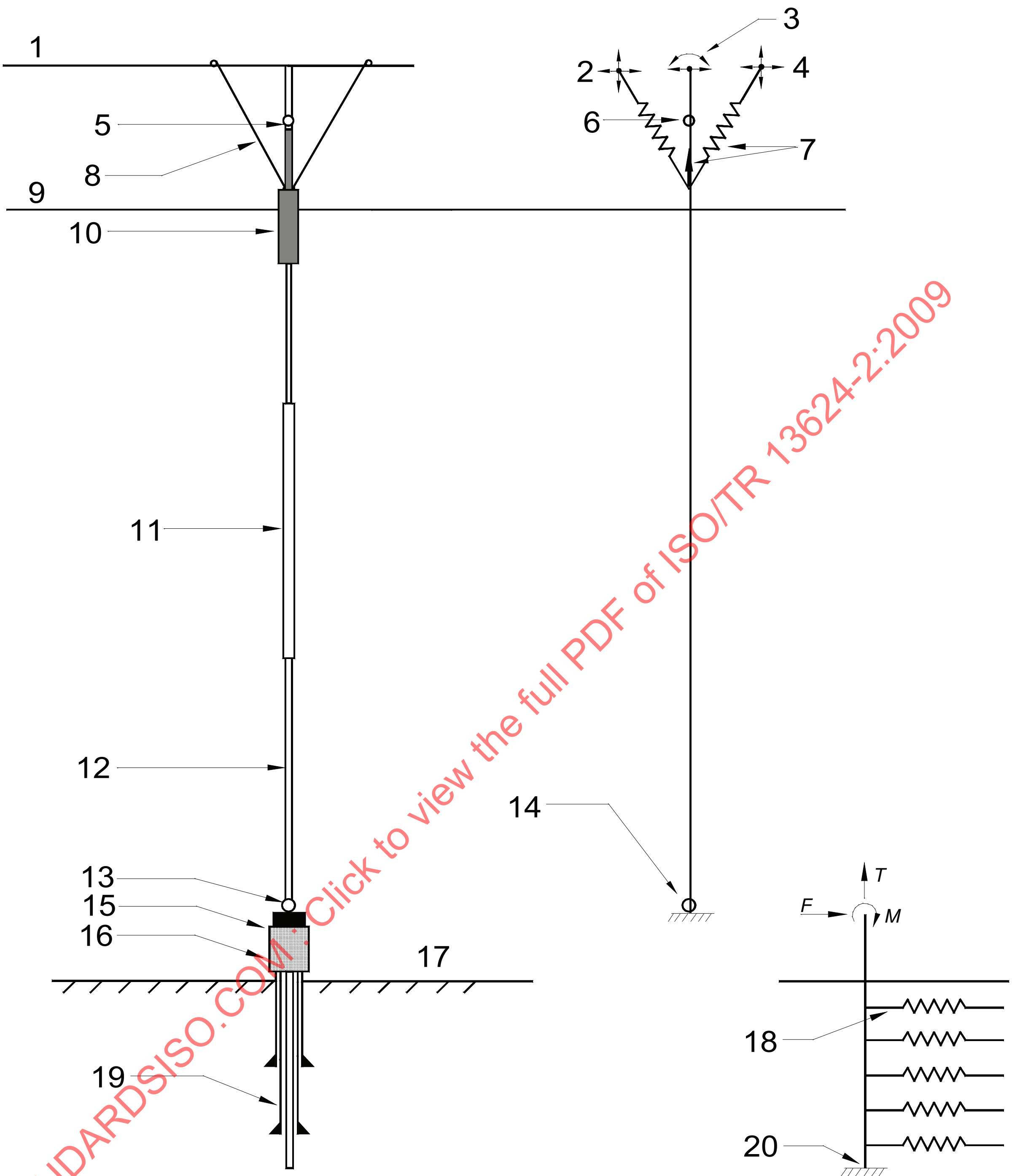
The decoupled methodology is a two-stage procedure where two separate models are used to predict the behaviour in the full riser system. The first model represents the riser system from the top of the subsea BOP/LMRP to the upper flex joint or ball joint. The second model represents the riser from the conductor up to the BOP/LMRP. The loads at the base of the first model (top of BOP/LMRP to upper flex joint or ball joint) are then applied to the top of the second model to evaluate the behaviour of the conductor and riser at the mudline. Figure 2 shows a schematic of a decoupled model.



Key

1 drill deck (RKB)
2 heave/surge/sway
3 surge/sway/pitch/roll
4 heave/surge/sway
5 upper flex joint
6 upper flex joint (articulation element)
7 tensioner system modeled with spring/beam elements or equivalent vertical tension
8 tensioners
9 MWL
10 slip joint
11 riser buoyancy joints
12 bare riser joints
13 lower flex joint
14 lower flex joint (articulation element)
15 LMRP
16 BOP
17 mudline
18 spring elements to model soil-structure interaction
19 conductor/casing
20 fixed in all degrees of freedom

Figure 1 — Drilling riser system configuration and coupled analysis model



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15 LMRP
16 BOP
17 mudline
18 spring elements to model soil-structure interaction
19 conductor/casing
20 fixed in all degrees of freedom

Figure 2 — Drilling riser system configuration and decoupled analysis models

5.3 Analysis considerations

API RP 2RD, Section 6, and API RP 17B, Section 8, discuss in detail the analysis considerations relevant to riser systems, which are also appropriate to drilling risers. The two key issues of relevance to this technical note are as follows:

a) solution of equations of motion (frequency-domain or time-domain solution);

b) dynamic response evaluation (design-wave or design-storm methodology).

Frequency-domain analysis is appropriate when it is known that the effects of tension coupling are small and that there are no other nonlinearities significantly affecting the riser response. It is often used for fatigue analysis where the loads are less extreme and response is nearly linear. Time-domain analysis is used when more accurate representation of nonlinear behaviour is important. This applies particularly to the analysis of nonlinear conductor/soil interaction behaviour, but also to weak-point and disconnect analyses, where nonlinearities are important.

The objective in performing dynamic analyses is to predict the maximum or extreme response of the riser system. The two approaches commonly used for this purpose are design-wave and design-storm analyses. The design-wave (or regular-wave) approach is based on a deterministic sea state description of the wave environment using a single wave height and period to model the sea state. These parameters are derived using wave statistics or simple physical considerations. The advantage of the approach is that the response calculation is straightforward, periodic input generally giving periodic output with no further requirement for statistical post-processing. The limitation of the design-wave approach is that its use is uncertain in systems whose response is strongly dependent on frequency. In such situations, the design-storm approach can be necessary.

The design-storm or irregular-sea approach is based on a stochastic description of the wave environment. The sea state is modeled as a wave spectrum with energy distributed over a range of frequencies. The most common spectra used are the Pierson-Moskowitz (fully developed sea) and the JONSWAP (developing sea) spectra; see Chakrabarti, 1987. The response, in this case, is also stochastic, and statistical post-processing is necessary to identify the design value of the response. Normally, a 3 h design-storm duration should be considered. The extreme response for the design storm should be found by using a recognized most-probable-maximum extrapolation technique.

All dynamic-analysis results presented in this part of ISO 13624 were generated from time-domain solutions of regular-wave analyses.

5.4 Model development

5.4.1 Overview

A schematic configuration of a typical drilling riser system is presented in Figure 1 along with a coupled riser/BOP/conductor/casing tensioned beam model, which is used to analyse the system. A drilling riser system can be typically broken down into the following components:

a) drilling system;

b) tensioner system;

c) slip joint;

d) upper and lower flex joint;

e) drilling riser;

f) LMRP/BOP stack;

g) conductor/casing.

Table 1 presents a list of important parameters associated with each of the components a) to g) above. These parameters represent the basic building blocks from which the drilling riser model is constructed.

The methods for modeling the components of each drilling riser system are discussed in 5.4.2 to 5.4.8.

Table 1 — Input parameters for a drilling riser analysis model

System component	Input parameter
Drilling vessel	Location of vessel centre of gravity
	Vessel response amplitude operators (RAOs)
	Vessel draft
	Vertical distance from upper flex joint to drill floor
	Vertical distance from keel to the drill floor
Tensioner system	Number of tensioners
	Maximum available tension per tensioner
	Tensioner fleet angle and efficiency
	Tensioner length and stiffness
Slip joint	Collapsed length
	Fully extended length
	Outer and inner barrel outer diameter and wall thickness
	Outer and inner barrel air weight and submerged weight
Flex joints	Rotational stiffness of the flex joint as a function of cocking angle subtended
Bare riser joints	Outer diameter and wall thickness of the joint and any choke-and-kill lines and/or auxiliary lines attached to the riser joint
	Weight in air and weight in water of the joint and any choke-and-kill lines and/or auxiliary lines attached to the riser joint
	Length of the riser joint
	Yield strength of the material
	Failure capacity of riser joint bolted flange/screwed connector
Buoyancy riser joints	Weight in air of the buoyancy joints for relevant water depths
	Upthrust of the buoyancy joints for relevant water depths
Internal fluid	Density of the drilling mud
LMRP/BOP stack	Equivalent outer and inner diameters of LMRP/BOP that simulate the bending stiffness and axial stiffness of these components
	Weight in air and weight in water of LMRP/BOP
	Failure capacities of the LMRP/BOP bolted flanges and hydraulic connectors
Conductor/casing	Outer and inner diameters of the conductor pipe and casing sections
	Lengths of the conductor pipe and casing sections
	Height of conductor/casing above seabed
	Assumed level of scour below the seabed
	Yield strength of the conductor/casing pipe material
	Structural properties of the conductor/casing pipe and casing materials
	Variation of soil undrained shear strength and soil unit weight with depth below the mudline (P vs. y curves)

5.4.2 Drilling vessel

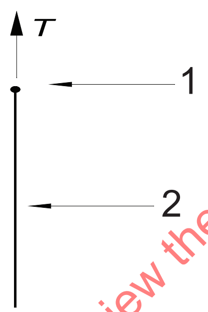
If the tensioner system is modeled explicitly, the heave, surge and sway RAOs should be applied at the top of the tensioner elements and the surge, sway, pitch and roll RAOs applied at the top of the riser, as illustrated in Figure 1.

Alternatively, if the tensioner system is not explicitly modeled, but simulated using a vertical force applied to the top of the riser, then surge, sway, pitch and roll RAOs should be applied to the top of the drilling riser.

The portion of the vessel structure in the vicinity of the drilling riser can be incorporated into the model in order to determine if there is any collision between the vessel structure and the drilling riser under vessel excursions (i.e. the moonpool of a drillship or the pontoons of a semi-submersible).

5.4.3 Tensioner system

The first approach for modeling the tensioner system, which is the most basic method, is to simulate the tensioner system by applying a vertical tension at the top of the riser as shown in Figure 3. One disadvantage with this approach is that the tension always acts in the vertical direction, rather than along the riser axis.



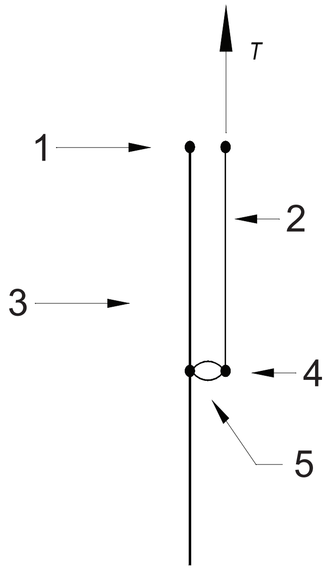
Key

1 vessel motions applied to this node

2 top of the drilling riser (to upper flex joint)

Figure 3 — Simplified tensioner model 1

To overcome this disadvantage, a second approach can be used, as illustrated in Figure 4. Using this method, the riser tension is applied using a parallel, massless, rigid element that is attached to the tensioner ring of the slip joint using an articulation element. The rigid element deflects with the drilling riser and hence the tension applied to the riser always acts along the longitudinal axis of the riser.



Key

1 vessel motions applied to both nodes

2 rigid beam element

3 top of the drilling riser (to upper flex joint)

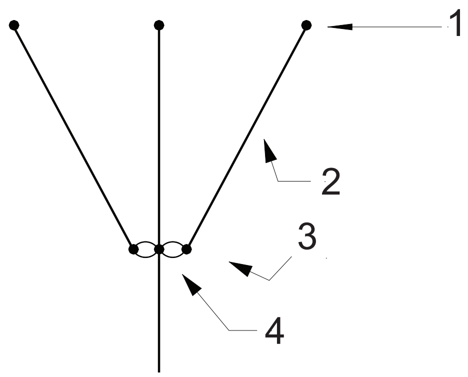
4 tensioner ring of slip joint

5 articulation element

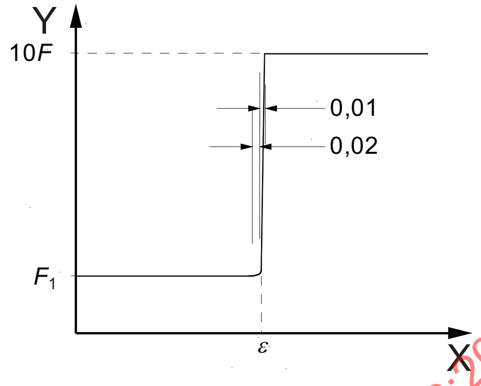
Figure 4 — Simplified tensioner model 2

The two methods illustrated in Figures 3 and 4 implicitly simulate the effect of the tensioner system by applying a constant tension. The other two available methods are more complicated in that they explicitly model the tensioners of the tensioner system and, inherently, the nonlinear behaviour of the system. This is done using nonlinear beam elements as illustrated in Figure 5 or nonlinear spring elements as illustrated in Figure 6. A tensioner system typically consists of four or more tensioners. In general, only two tensioners are modeled for simplicity. The tensioners are modeled inclined at the fleet angle of the tensioner system.

With a nonlinear beam-element model, the tension is applied to the riser using a nonlinear axial stiffness. The nonlinear force/strain (or deflection) relationship is specified as shown in Figure 5, where F is the force in the tensioner element and ε is the strain of the tensioner element.



a) Model



b) Non-linear force/strain relationship

Key

X strain, ε

Y force, F (lb)

1 vessel motions applied to all nodes at this elevation

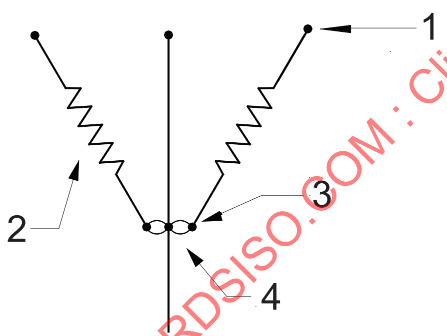
2 tensioners modeled using nonlinear beam elements

3 tensioner ring of slip joint

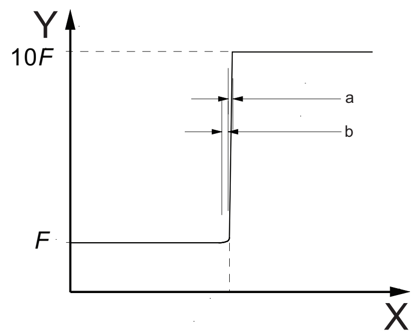
4 articulation elements

Figure 5 — Nonlinear beam tensioner model

Using nonlinear spring elements, the tension is typically applied to the riser using a nonlinear force versus deflection (F vs. deflection) curve, as shown in Figure 6.



a) Model



b) Nonlinear spring tensioner relationship

Key

X deflection (ft)

Y force, F (lb)

1 vessel motions applied to all nodes at this elevation

2 tensioners modeled using spring elements

3 tensioner ring of slip joint

4 articulation elements

[a] Deflection equivalent to 1 % strain.

[b] Deflection equivalent to 2 % strain.

Figure 6 — Nonlinear spring tensioner model

The contribution to the total tension, F_r, applied to the drilling riser from each tensioner is determined as given in Equation (1):

$$F_r = F_t \times \cos\theta \tag{1}$$

where

F_r is the force on the riser from the tensioner;

F_t is the force in the tensioner;

θ is the angle of the tensioner with respect to the vertical, i.e. fleet angle.

The sum of each F_r from each of the tensioner elements should equal the required top tension which is being applied to the riser.

Stroke-out of the tensioner is modeled by incorporating a ramp in the axial/spring stiffness of each tensioner element at the strain/deflection corresponding to the stroke-out of the tensioner. This is illustrated in Figures 5 and 6. The force in the element can be ramped up gradually over a strain of typically 2 % prior to stroke-out. At stroke-out, the force can be further ramped up rapidly over a strain of typically 1 %. This procedure can be necessary to prevent any numerical instability in analysis software due to the rapid change in axial/spring stiffness at stroke-out.

Using approaches in Figures 5 and 6, the heave motion of the vessel is absorbed by the tensioner elements.

The minimum tension required to maintain a positive effective tension throughout the length of the riser should be calculated in accordance with ISO 13624-1:2009, 5.3.2.

5.4.4 Telescope joint

The slip joint is generally modeled at mid-stroke length or with the slip joint partially collapsed [e.g. by 1,52 m (5 ft)] to increase the downward stroke capacity of the slip joint during large offset occurrences. When the tension is applied to the model, the slip joint also partially collapses by the amount of upward motion of the riser due to the applied tension. This should be accounted for in the modeling of the system.

In order to simulate the relative motion between the inner and outer barrel of the slip joint, the inner barrel may be modeled as a massless element with a low axial stiffness. This technique can be used to determine when stroke-out of the slip joint occurs in a vessel drift-off analysis. Stroke-out of the slip joint can be modeled in a similar way to tensioner stroke-out, previously described in 5.4.3. A nonlinear beam element may be used to model the inner barrel, which incorporates a large ramp in the axial stiffness at the element length which corresponds to stroke-out.

After stroke-out, this model induces a large additional force in the riser from the vertical restraint at the RKB. When the system is designed such that stroke-out of the tensioners occurs before stroke-out of the slip joint, then it might not be necessary to model slip-joint stroke-out.

5.4.5 Flex joints

5.4.5.1 General

In a drilling riser, a flex joint may be modeled using an articulation element with an associated rotational stiffness. The rotational behaviour of a flex joint is nonlinear in reality, i.e. the rotational stiffness as a function of flex-joint rotation is non-uniform. As many analysis software packages do not have a facility for modeling this nonlinear rotational stiffness relationship, a method that maintains a reasonable level of accuracy is required to model the relationship. Two methodologies are now described. The rotational stiffness of the articulation element can either be linear (see 5.4.5.3) or nonlinear (see 5.4.5.2). The methodology for modeling flex joints using both element types is now outlined.

5.4.5.2 Nonlinear rotational stiffness

There is a nonlinear relationship between flex-joint rotational stiffness and the angle subtended by the flex joint. Therefore, using an articulation element with a nonlinear rotational stiffness represents the most accurate way to model a flex joint on a drilling riser. The rotational tangent stiffness versus alternating angle (K_a vs. $\Delta\theta$) curve is used as input to the nonlinear articulation element. This curve can be obtained by differentiating the resultant bending moment versus alternating angle curve of the flex joint. This curve is typically supplied by the flex-joint manufacturer.

5.4.5.3 Linear rotational stiffness

If the analysis software being used is capable of modeling articulation elements with only a linear rotational stiffness, then it is necessary to assume that the work done by a flex joint represented by an articulation with a linear stiffness equals the work done by a flex joint represented by an articulation with a nonlinear stiffness in subtending a representative angle, θ, and that the angle, θ, is the typical angle subtended by the flex joint for the particular analysis under study.

Using this assumption, the methodology for modeling a flex joint using a linear articulation element is as follows.

a) Obtain the rotational stiffness versus alternating angle (K_a vs. $\Delta\theta$) curve for the flex joint.

b) Assume the maximum angle subtended by the flex joint under environmental loading is $\Delta\tilde{\theta}$.

c) Read off the rotational stiffness, K, from the nonlinear K_a vs. $\Delta\theta$ curve at the assumed maximum rotation.

d) Run the analysis using this linear rotational stiffness and determine the actual maximum angle, $\Delta\theta$, subtended by the flex joint from the results.

e) Obtain the associated linear rotational stiffness for the new $\Delta\theta$ and rerun the analysis.

f) This iterative process continues until the difference between the chosen maximum rotation and the maximum angle from the analysis is under a specified acceptable level.

For a regular-wave dynamic, the flex-joint rotation used in determining the rotational stiffness should be the maximum rotation, whereas for an irregular sea analysis the value of the standard deviation may be used.

5.4.6 Drilling riser

5.4.6.1 General

Prior to performing an analysis of a drilling riser, it is necessary that some preliminary calculations be carried out to determine the basic equipment design requirements and to develop a riser configuration. The work required is as follows.

— Specify the drilling mud.

— Check the burst resistance of the riser joints.

— Check the collapse resistance of the riser joints.

— Check the depth rating of the buoyancy modules.

— Develop the riser joint arrangement/stack-up.

— Calculate the suspended weight and estimate the minimum top tension.

— Calculate the associated riser properties for incorporation into the drilling riser analysis model.

5.4.6.2 Collapse

Design guidance for checking collapse resistance is given in API RP 2RD. Two key factors affecting riser collapse resistance are wall thickness and ovality. Drilling riser usage can adversely affect both these parameters due to handling affecting ovality and wear of the riser affecting riser wall thickness. It is necessary that allowance be made for these factors when checking collapse resistance.

The riser joints are typically designed to prevent collapse of an empty riser. However, with modern drilling operations, the likelihood of a riser collapse is diminished because standard operating procedure is to shut in at the BOP when dealing with a kick. Therefore, a partially empty riser may be considered for collapse calculations. For example, a half-empty riser may be considered in an emergency disconnect case where the mud flows out. Similarly, collapse calculations in a deepwater case can be based on an estimated length of riser, for example 1 524 m (5 000 ft), being empty. A well reasoned basis for the estimate should be developed before it is used.

Where the collapse resistance of standard riser joints is inadequate, it can be necessary to selectively use thicker-walled or higher-grade joints in the lower riser section or to use a fill valve.

5.4.6.3 Buoyancy rating

The density of buoyancy required for riser joints in deep water is greater than that in shallower water. Increased buoyancy volumes are, therefore, required to provide the same level of upthrust. The depth rating of the buoyancy for a given application should be confirmed. Depth ratings and expected levels of seawater absorption should be specified by the buoyancy manufacturer for each module type.

5.4.6.4 Riser joint arrangement

The arrangement of buoyant and slick riser joints can be varied to improve many aspects of riser response. The key issues for consideration when developing the riser arrangement are as follows.

- Riser curvature: By avoiding use of buoyant joints in regions of greatest current and wave loading, riser curvature and hence flex-joint angles can be reduced.
- VIV: Staggering buoyant and slick joints can reduce the levels of fatigue damage induced by the vortex-induced vibrations.
- Hang-off: Keeping the buoyant joints below the wave zone minimizes the lateral loading on the riser and use of slick joints at the riser base increases tension, both of which can improve limiting hang-off conditions.
- Installation and retrieval: Keeping buoyancy off the lower joints reduces lateral loading as the riser enters the wave zone.

On the basis of the above considerations, the use of two or three slick joints immediately below the slip joint can offer a balanced solution. Below this point, it is necessary to assess the arrangement of buoyant and slick joints and potential benefits of staggering to reduce VIV through riser analysis.

5.4.6.5 Weight and tension

Guidance on specification of riser top tension, accounting for vessel tension capacity, tensioner system malfunction and the requirement to account for losses from fleet angle and friction, is given in API RP 16Q.

5.4.6.6 Riser properties for analysis model

Modeling of the riser is typically achieved using beam elements. The structural and hydrodynamic properties and the methods for calculating these are as follows.

- Bending stiffness: The stiffness of the main riser tube is calculated as the modulus of the steel multiplied by the moment of inertia of the main tube cross-section. The stiffness contribution of auxiliary lines and other components is assumed small.
- Axial stiffness: The stiffness of the main riser tube is calculated as the modulus of the steel multiplied by the cross-sectional area of the main tube. The stiffness contribution of auxiliary lines is assumed small.
- Mass per unit length: The mass of riser joint and all auxiliary lines in air, plus the mass of operational fluids contained in auxiliary lines, plus the mass of buoyancy modules, is divided by the length of the riser joint.
- Drag diameter: This is considered as the distance between the choke-and-kill lines plus the diameter of a choke-and-kill line for slick joints or the buoyancy outer diameter where buoyancy is present.
- Buoyancy diameter: This is considered as the diameter that gives the correct buoyancy load, accounting for all relevant components, including riser joint, auxiliary lines and buoyancy modules.
- Drag coefficients: These are calculated for slick joints and buoyancy modules in accordance with API RP 16Q. The drag coefficients used for in-plane analyses should account for the effects of vortex-induced vibrations, especially in deep water.

The above properties assume that riser internal fluid is specified independently of structural and hydrodynamic properties. If this is not the case, it is necessary to adjust the properties to account for the mass of the internal fluid.

A high level of element discretization is required where either the loading or riser geometry changes rapidly. Typically, this occurs in the wave zone at the top of the riser and at the bottom of the riser near the lower flex joint.

5.4.7 LMRP/BOP

The weight of the lower marine riser package, LMRP, and blowout preventer, BOP, should be obtained from the manufacturer. An equivalent pipe cross-section that simulates the bending stiffness of the LMRP and BOP stack should be estimated. The equivalent cross-sectional properties can be used in the analysis model.

5.4.8 Conductor/casing

The soil-structure interaction may be modeled using nonlinear springs positioned at various depths below the mudline, as shown in Figure 1. The spring stiffness is derived from P vs. y curves, which plot the relationship between soil resistance, P, and lateral deflection, y. P vs. y curves should be developed for the soil conditions on site at various depths below the mudline. Guidance on the development of P vs. y curves is provided in 6.2. The conductor/casing model should typically extend to about 60 m (200 ft) below the mudline, depending on the proposed casing programmes and soil conditions. Significant horizontal deflections can occur at the top of the conductor/casing under extreme environmental loading and vessel drift-off conditions, resulting in conductor/casing motions well below the mudline. A suitable level of element discretization should be used for the conductor/casing elements, particularly near the mudline where the conductor/casing experiences the largest loading. The cement in the annulus may be ignored, since its contribution to the bending stiffness is small.

This type of detailed analysis is recommended in situations where one is trying to determine the strength integrity of the casing and where a more accurate lower flex-joint angle is desired.

5.5 Coupled riser analysis

5.5.1 Overview

Coupled analysis involves modeling the entire drilling riser system in the same analysis model. This encompasses the drilling riser, BOP stack and appropriate section of conductor/casing, as illustrated in Figure 1.

5.5.2 Analysis strategy

Vessel offset, current and wave loading can be applied directly to the entire drilling riser system using coupled analysis. This allows for direct dynamic analysis of the conductor/casing system, which can prove significant in the design of a conductor/casing system.

A small time step should be used in a time-domain dynamic analysis of a coupled model to obtain accurate soil-structure interaction. In general, the more nonlinear the soil characteristics, the smaller the time step required to model the soil behaviour.

For regular-wave-dynamic analysis of a deepwater drilling riser system, the wave should be applied to the riser for 10 or more wave periods. In a deepwater analysis, it typically takes this amount of time to generate a steady state response below the seabed.

5.5.3 Observations on coupled analysis

The following observations have been made regarding coupled analysis.

— In general, results along the conductor/casing from a coupled analysis are less conservative than those from a decoupled analysis, under static and dynamic loading. This is illustrated in Figure 7, which plots the bending moment along a representative conductor/casing system that was analysed using both a coupled and decoupled approach.

— It has been found that for statically applied offset and current loads in soft and stiff clays, the percentage by which the decoupled maximum bending moment in the conductor exceeds that of the coupled model decreases with increasing water depth, as shown in Figure 8. This figure is from a specific example and might not be representative of all cases. The addition of dynamic loads reverses this trend for both soft and stiff clays, i.e. the percentage by which the decoupled maximum bending moment in the casing exceeds that of the coupled model increases with increasing water depth.

— For stiff clays in shallow water depths of 1 219,2 m (4 000 ft) or less, decoupled analysis has been seen as less conservative than coupled analysis. This is shown in Figure 7 by the negative percentage on the plot.

— Coupled analysis allows for full interaction between applied vessel motions, hydrodynamics and soil behaviour. With decoupled analysis, dynamic loads cannot be applied directly to the BOP/conductor/casing model, but alternatively are applied as static extreme loads.

— Coupled analysis is easier and faster to perform since the drilling riser system is contained within the one model. With decoupled analysis, it is necessary that the loading at the LMRP be obtained from the drilling riser model and applied to the conductor/casing model. This can prove to be more time-consuming.

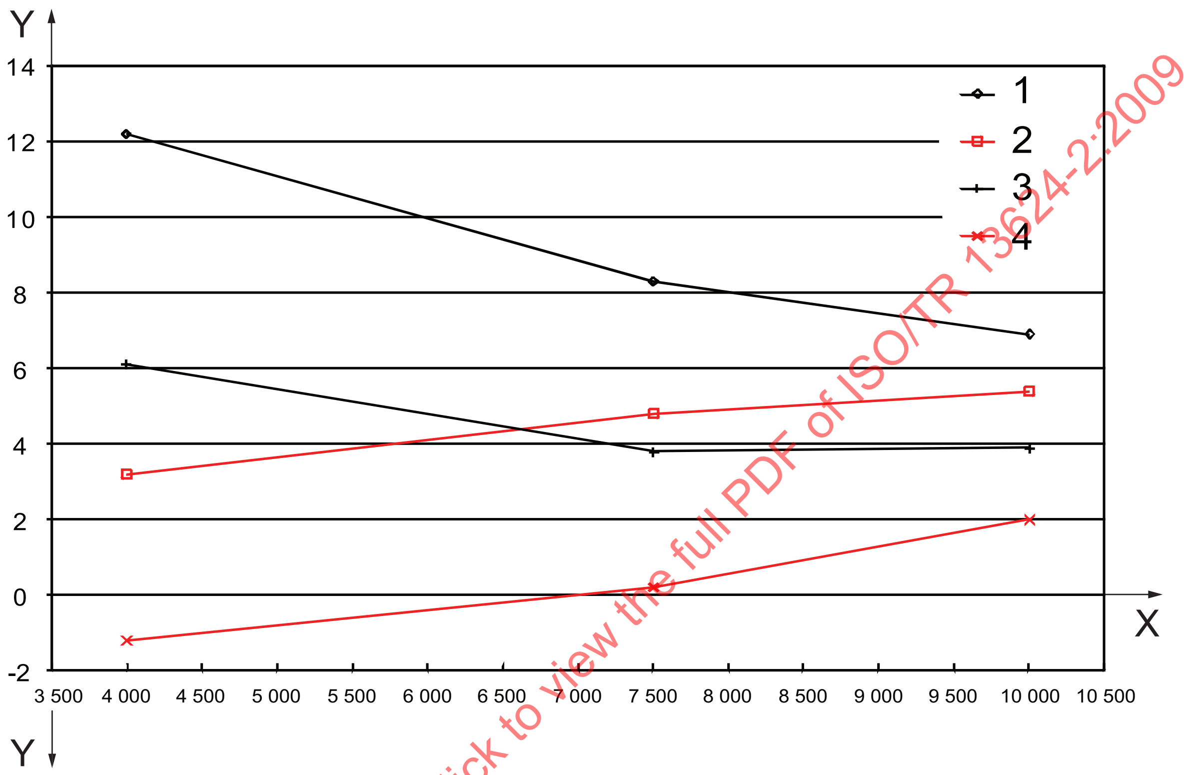
All of the results for the drilling riser system are available from one model. This makes post-processing easier, thus reducing analysis time and reducing the possibility for bookkeeping errors.

5.5.4 Applications of coupled analysis

Guidelines are given in 5.5.4 on the conditions for which a coupled analysis model of a drilling riser is a more appropriate model to use than a decoupled model.

A coupled analysis is a more appropriate method to use when the response of the conductor/casing is a key output from the analysis, for example in the design of the conductor/casing system.

Figure 7 illustrates the percentage by which the decoupled maximum bending moment is greater than the coupled maximum bending moment for identical loading conditions. For these particular conditions, the coupled model is shown as less conservative than the decoupled model for stiff clays in water depths less than approximately 2 133 m (7 000 ft).



Key

X water depth (ft)

Y percentage by which decoupled maximum bending moment along conductor is greater than coupled maximum bending moment

1 static loads – soft clay

2 dynamic loads – soft clay

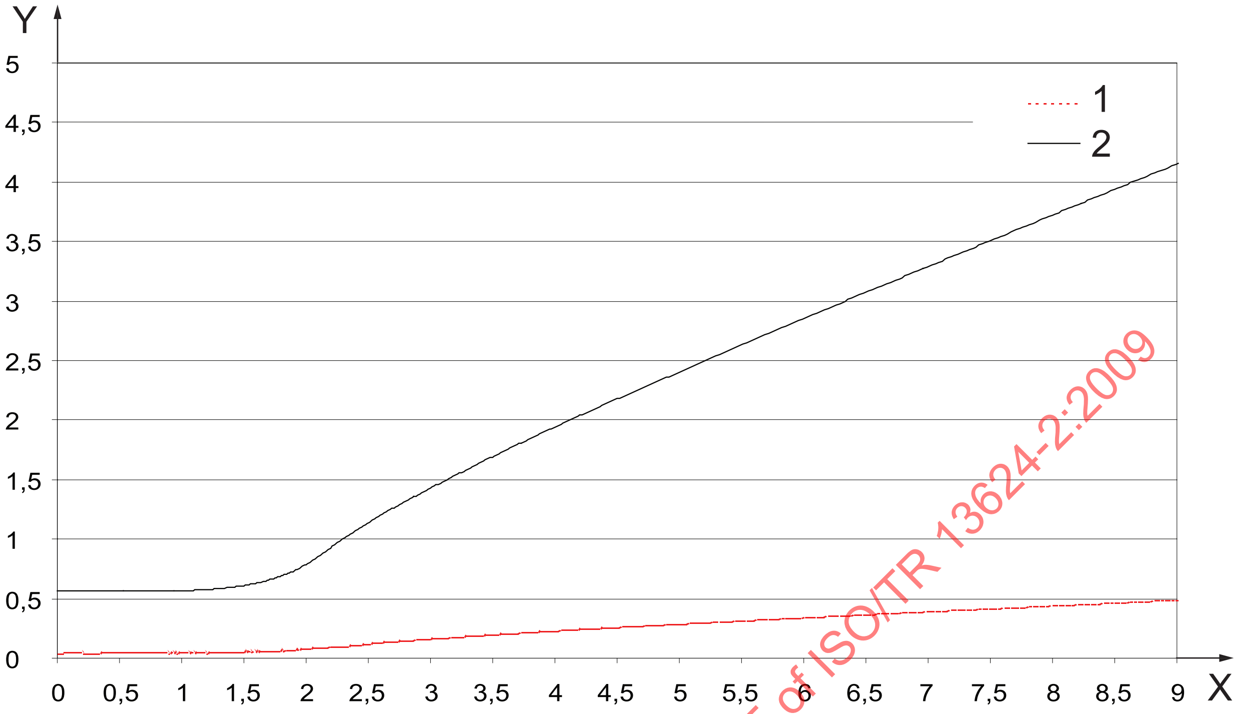
3 static loads – stiff clay

4 dynamic loads – stiff clay

Figure 7 — Percentage by which decoupled analysis is more conservative than coupled analysis as a function of water depth

For the condition analysed, the decoupled method is only slightly more conservative for stiff clays in water depths greater than approximately 2 133 m (7 000 ft).

The coupled analysis method is considered more appropriate for use in a drift-off analysis and weak-point analysis. This is due to the fact that in the coupled method, the BOP stack deflects with the riser, whereas in the decoupled method, the base of the riser model (LMRP/flex joint interface) is restrained from translational motion. This results in greater rotations at the lower flex joint in the decoupled case. In coupled analysis, the ability of the stack to displace laterally introduces more compliancy and, hence, reduces the flex-joint angle. This is illustrated in Figure 8, which plots the lower flex-joint rotation as a function of vessel offset for both the coupled and decoupled methods for identical loading conditions.



Key

X vessel offset (% water depth)

Y rotation of lower flex joint (degrees)

1 coupled model

2 decoupled model

Figure 8 — Comparison of lower flex-joint rotation as a function of vessel offset for a specific coupled and decoupled analysis

An intermediate method between the coupled and decoupled methodologies is possible. This method involves placing a horizontal spring at the base of the upper part of the decoupled model (i.e. top of the LMRP stack) to model the lateral stiffness afforded by the continuous riser system down to the soil stratum. The stiffness of this spring may be linear or nonlinear depending on whether frequency- or time-domain analysis procedures are being employed and/or whether the analysis software employed has the facility to model nonlinear springs. The stiffness relationship for use with the linear or nonlinear springs may be determined by using the lower part of the decoupled model (i.e. from top of BOP stack to conductor/casing), applying a lateral force to the top of the model and measuring the deflection. A linear spring stiffness may be determined by dividing the force applied by the deflection measured. The force applied should be representative of the expected shear in the model at this point. In the case of nonlinear springs, a series of forces and measured deflections may be used to arrive at the nonlinear force-deflection curve to use.

5.6 Decoupled riser analysis

5.6.1 Overview

Decoupled analysis involves modeling the drilling riser and BOP/conductor/casing separately, as shown in Figure 2.

In this method, the drilling riser is modeled from the upper flex joint to the lower flex joint and incorporates the drilling vessel, tensioner system and slip joint, as shown in Figure 2. The second part of the decoupled model consists of the LMRP, BOP stack and conductor/casing system.

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. In general, the loads applied are the effective tension, shear force and bending moment.

5.6.2 Analysis strategy

The vessel offset, current and wave loading are applied only to the drilling riser model. Following each analysis, the effective tension, shear force and bending moment at the lower flex joint are determined from the results. Static analysis of the BOP/conductor/casing model is then performed to determine the tension and bending moment distribution throughout the conductor/casing system resulting from these loads.

As a result of this approach, the effect of dynamic loads cannot be directly applied to the BOP/conductor/casing model. Instead, the maximum dynamic bending moment and associated shear force and effective tension are determined from the results of a dynamic analysis of the drilling riser and are applied as static loads to the BOP and conductor/casing.

5.6.3 Observations on decoupled analysis

The following observations have been made on decoupled analysis based on a specific set of water depth and loading conditions.

— In general, decoupled analysis gives more conservative results along the conductor/casing than coupled analysis. This is illustrated in Figure 7. However, for water depths less than 2 100 m (7 000 ft) and for stiff clay, the two models give similar maximum loads.

— Decoupled analysis enables modeling the drilling riser without incorporating soil behaviour. This is useful when little soil information is available or where the interest is only in the response of the drilling riser to environmental loading.

— Decoupled analysis is more tedious and time-consuming to perform than coupled analysis. This is due to the fact that it is necessary that the loads at the lower flex joint be post-processed following each drilling riser analysis and then applied to the BOP/conductor/casing through a further analysis.

5.6.4 Applications of decoupled analysis

For initial design, the decoupled model can be used for most applications as it gives conservative results, although the coupled model is required for a more refined design of the conductor/casing system. However, it should be noted that for shallow water/stiff clay applications, the decoupled model can give slightly unconservative results.

5.7 Worked example

The example in 5.8 illustrates the process involved in evaluating the response of a coupled riser to a regular-wave and vessel-offset condition. To perform this task, a time-domain approach has been selected. Generally, this type of analysis is performed by frequency-domain methods but in this case the use of the time domain ensures that the full nonlinearity of the springs is used to model the soil-structure interaction.

The analysis basis is described and a description provided of the modeling techniques used for key areas of the analysis model such as the tensioners and the soil-structure interaction.

5.8 Basis of analysis

5.8.1 Vessel dimension

The key vessel dimensions for the analysis are given in Table 2.

Table 2 — Vessel dimensions

Parameter	Value
Draft	13 m (42,65 ft)
Moonpool width (at keel)	9,25 m (30,35 ft)
Moonpool centre forward of LPP/2	0 m (0 ft)
Rotary kelly bushing (RKB)[a] to UFJ[b] centre	4,52 m (14,83 ft)
Rotary kelly bushing (RKB)[a] to keel	40,00 m (131,24 ft)

[a] RKB located at top of drill floor.
[b] Riser upper flex joint.

5.8.2 Riser stack-up

Table 3 presents the stack-up dimension and weights for a drilling riser in 3 048 m (10 000 ft) water depth. The stack-up is presented schematically in Figure 9. API Spec 5L X-80 steel is used for the example.

Table 3 — Riser stack-up for 3 048 m (10 000 ft) **water depth**

Joint description	Number of joints	Depth	Bare joint air weight	Foam density	Lift	Wet weight		Total dry weight per joint	Total wet weight for all joints
						Per joint	Per unit length		
		m (ft)	N (lb)	kg/m^3 (lb/ft^3)	N (lb)	N (lb)	N/m (lb/ft)	N (lb)	kN (kips)
Termination joint	1	42,7 (140)	155 690 (35 000)	0,0 (0,0)	0 (0)	13 802 (30 429)	5 920 (405,7)	155 690 (35 000)	133,4 (30)
W/914 m (3 000 ft) foam	37	888,5 (2 915)	58 190 (27 343)	423 (26,4)	102 840 (23 121)	295,3 (651)	126,7 (8,68)	193 934 (43 598)	106,8 (24)
W/1 219 m (4 000 ft) foam	13	1 185,7 (3 890)	121 630 (27 343)	456 (28,5)	100 260 (22 540)	558,8 (1 232)	239,8 (16,43)	202 955 (45 626)	71,2 (16)
W/1 524 m (5 000 ft) foam	13	1482,9 (4 865)	121 630 (27 343)	484 (30,2)	104 315 (23 451)	145,6 (321)	62,5 (4,28)	214 556 (48 234)	17,8 (4)
W/1 829 m (6 000 ft) foam	13	1 802,9 (5 915)	121 630 (27 343)	506 (31,6)	100 618 (23 165)	275,3 (607)	118,1 (8,09)	227 171 (51 070)	35,6 (8)
W/2 134 m (7 000 ft) foam	13	2 100,1 (6 890)	121 630 (27 343)	516 (32,2)	98 750 (22 735)	470,4 (1 037)	201,8 (13,83)	234 754 (52 775)	57,8 (13)
W/2 438 m (8 000 ft) foam	13	3 567,5 (7 865)	121 630 (27 343)	551 (34,4)	97 165 (22 370)	635,9 (1 402)	272,7 (18,69)	242 050 (54 415)	80,1 (18)
Bare joints	27	3 014,5 (9 890)	124 710 (28 035)	0,0 (0,0)	0 (0)	11 055,4 (24 373)	4 742,6 (324,97)	124 706 (28 035)	2 927 (658)
								Subtotal:	3 430 (771)
								Slip joint:	444,8 (100)
								Pups:	102,3 (23)
								Mux cable:	129 (29)
								Total wet weight kN (kips):	4 106 (923)

NOTE 1 Length of all joints: 22,86 m (75 ft); outer diameter of main tube: 53,34 cm (21 in); normal wall thickness of main tube: 2,06 cm (0,813 in); minimum yield strength of main tube: 80 ksi; connector: 21-inch API class “F”.

NOTE 2 Outer diameter of foam joints: 914 m (3 000 ft), foam: 128,27 cm (50,5 in); 1 219 m (4 000 ft), 130,8 cm (51,5 in); 1 524 m (5 000 ft), foam: 133,3 cm (52,5 in); 1 829 m (6 000 ft), 135,9 cm (53,5 in); 2 134 m (7 000 ft), 141,0 cm (55,5 in); 2 438 m (8 000 ft), 143,5 cm (56,5 in).

NOTE 3 Ancillary lines: choke-and-kill: 16,51 cm × 2,54 cm (6,5 in × 1,0 in), 103,4 MPa (15 000 psi); boost line: 11,43 cm × 0,972 cm (4,5 in × 0,383 in), 41,4 MPa (6 000 psi); supply line: 8,89 cm × 6,670 cm (3,5 in × 2,626 in), ID, 34,5 MPa (5 000 psi); Mux cable: 3,4 kg/m (2,3 lb/ft) weight in air; 2,4 kg/m (1,6 lb/ft) weight in seawater.

Dimensions in feet

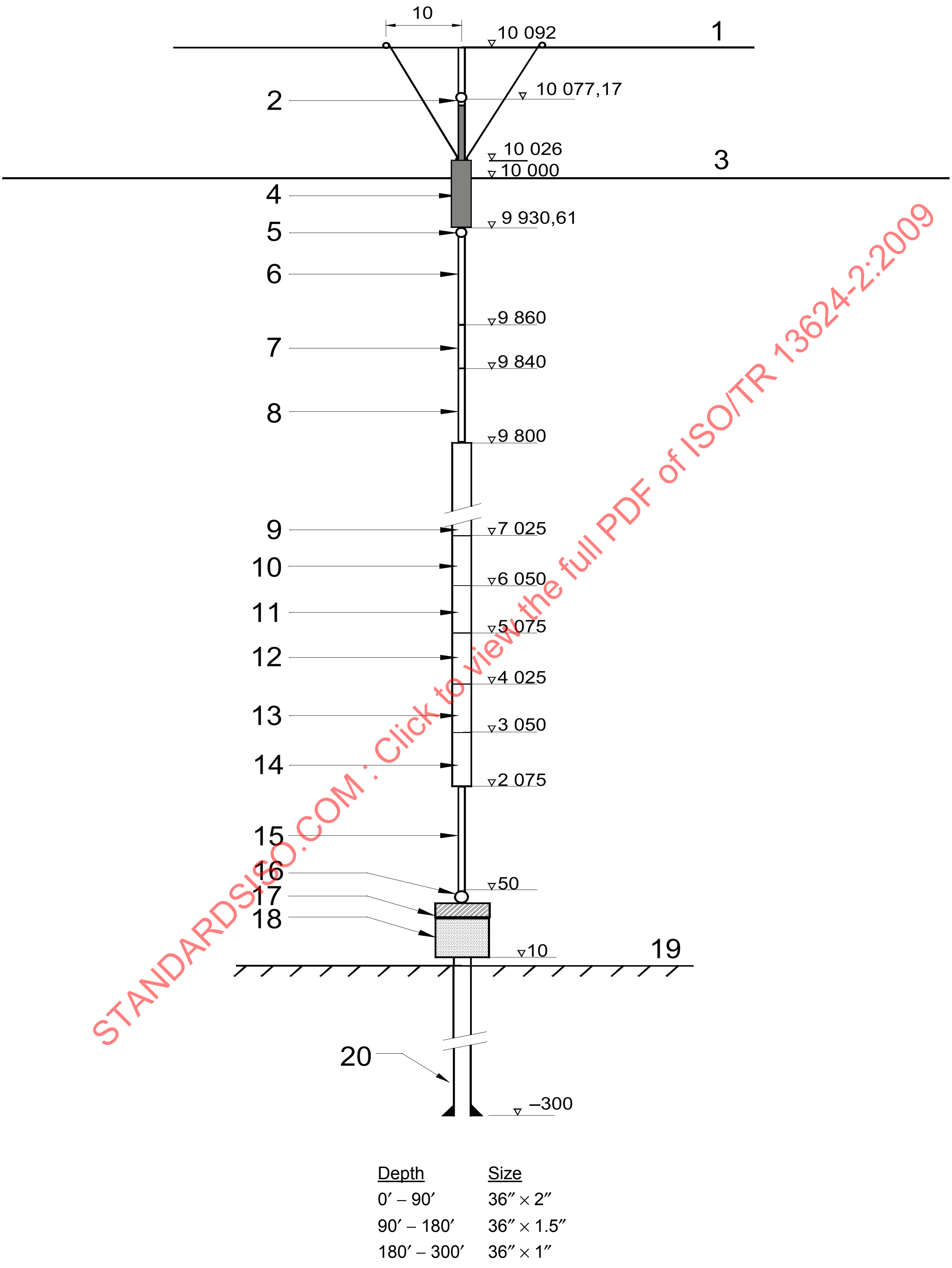


Figure 9 — Riser stack-up schematic for 3 048 m (10 000 ft) **water depth**

Key

1 drill deck (RKB)
2 upper flex joint
3 mean water level, MWL
4 slip joint
5 intermediate flex joint
6 65,83 ft termination joint
7 20 ft pup joint
8 40 ft pup joint
9 37 × 75 ft 3K buoyancy joints
10 13 × 75 ft 4K buoyancy joints
11 13 × 75 ft 5K buoyancy joints
12 14 × 75 ft 6K buoyancy joints
13 13 × 75 ft 7K buoyancy joints
14 13 × 75 ft 8K buoyancy joints
15 27 × 75 ft bare joints
16 lower flex joint
17 LMRP
18 BOP
19 mudline
20 36″ casing

Figure 9 (*continued*)

5.8.3 Flex joints

The riser system employs three flex joints: the upper flex joint (UFJ), intermediate flex joint (IFJ), located under the vessel keel, and lower flex joint (LFJ) have been modeled using articulation elements with a constant rotational stiffness. The following linear rotational stiffnesses have been used for the three flex joints:

— rotational stiffness of UFJ equal to 27,83 kN·m/deg (20 528 ft.lb/deg);

— rotational stiffness of IFJ equal to 18,98 kN·m/deg (14 000 ft.lb/deg);

— rotational stiffness of LFJ equal to 113.89 kN·m/deg (84 005 ft.lb/deg).

5.8.4 Slip joints

The slip joint is modeled at mid-stroke length, with the properties presented in Table 4.

Table 4 — Slip-joint properties

Parameter	Units	Value
Slip-joint mid-stroke length	m (ft)	48,27 (158,36)
Slip-joint stroke length	m (ft)	15,24 (50,00)
Slip-joint retracted length	m (ft)	40,65 (133,36)
Slip-joint extended length	m (ft)	55,89 (183,36)
Weight in water	kN (kips)	444,8 (100)
Inner barrel internal diameter	cm (in)	51,17 (19,75)
Inner barrel external diameter	cm (in)	53,34 (21,00)
Outer barrel internal diameter	cm (in)	58,42 (23,00)
Outer barrel external diameter	cm (in)	66,04 (26,00)

5.8.5 Tensioner system

The tensioner details are summarized in Table 5. The applied top tension is 10 440 kN (2 347 kips), corresponding to the tension applied during drilling operation.

Table 5 — Tensioner system details

Parameter	Units	Value
Number of tensioners	—	6
Max. available tension per tensioner	kN (kips)	1 912,7 (430)
Stroke range	m (ft)	15,2 (50)
Fleet angle	°	9,9
Efficiency	%	95
Weight of tensioner ring	kN (kips)	66,7 (15)
NOTE See API RP 16Q.		

5.8.6 LMR and BOP

Weights and dimensions of the BOP and LMRP are presented in Table 6. The wellhead connects with the BOP 3,05 m (10 ft) above the mudline. The equivalent section properties presented in Table 6 are used to model the BOP and LMRP.

Table 6 — Equipment weights and dimensions

Parameter	BOP	LMRP
Length, metres (feet)	8,53 (28)	3,66 (12)
Weight in water, kilonewtons (pounds)	1 642 (369 000)	1 094 (246 000)
Outer diameter, centimetres (inches)	103,5 (40,75)	103,5 (40,75)
Inner diameter, centimetres (inches)	47,6 (18,75)	47,6 (18,75)
Wall thickness, centimetres (inches)	27,8 (11)	27,8 (11)
Bending stiffness, kilonewton·square metres (pound-square feet)	1,11E+7 (2,69E+10)	1,11E+7 (2,69E+10)
NOTE The diameters, wall thickness and stiffness are equivalent properties.		

5.8.7 Conductor/casing

The properties of the conductor/casing are presented in Table 7. The material grade of the casing is API Spec 5L X-60 steel.

Table 7 — Properties of conductor/casing

Depth below mudline m (ft)	Outer diameter cm (in)	Wall thickness cm (in)
0 to 27,4 (0 to 90)	91,44 (36)	5,08 (2,0)
27,4 to 54,9 (90 to 180)	91,44 (36)	3,81 (1,5)
54,9 to 91,4 (180 to 300)	91,44 (36)	2,54 (1,0)

5.8.8 Internal fluid data

The riser internal fluid is drilling mud with a density of 0,1 kg/L (13 lb/gal). The internal fluid free surface elevation is taken to be at the drilling deck. Internal pressure in the riser is due to static head only.

5.8.9 Drag coefficients

The drag coefficients used for both bare and buoyancy joint sections have been calculated as a function of Reynolds number in accordance with API RP 16Q and are presented in Table 8. These coefficients are a function of the applied current environment.

Table 8 — Drag coefficients along riser

Riser section	Number of 22,86 m (75 ft) joint lengths	Drag coefficient
Bare	27	1,93
2 438,4 m (8 000 ft) rated buoyancy	13	1,09
2 133,6 m (7 000 ft) rated buoyancy	13	1,04
1 828,8 m (6 000 ft) rated buoyancy	14	1,00
1 524 m (5 000 ft) rated buoyancy	13	0,96
1 219,2 m (4 000 ft) rated buoyancy	13	0,89
914,4 m (3 000 ft) rated buoyancy	14	0,81
914,4 m (3 000 ft) rated buoyancy	2	0,75
914,4 m (3 000 ft) rated buoyancy	2	0,73
914,4 m (3 000 ft) rated buoyancy	2	0,71
914,4 m (3 000 ft) rated buoyancy	2	0,69
914,4 m (3 000 ft) rated buoyancy	1	0,68
914,4 m (3 000 ft) rated buoyancy	1	0,67
914,4 m (3 000 ft) rated buoyancy	1	0,66
914,4 m (3 000 ft) rated buoyancy	1	0,66
914,4 m (3 000 ft) rated buoyancy	1	0,65
914,4 m (3 000 ft) rated buoyancy	1	0,64
914,4 m (3 000 ft) rated buoyancy	1	0,63
914,4 m (3 000 ft) rated buoyancy	2	0,62
914,4 m (3 000 ft) rated buoyancy	3	0,61
914,4 m (3 000 ft) rated buoyancy	3	0,61
Pup joints	—	1,24
Termination joint	—	1,15
Slip-joint outer barrel	—	1,04

5.8.10 Water depth and density

Water depth is 3 048 m (10 000 ft). The density of seawater is 1 025,2 kg/m^3 (64 lb/ft^3).

5.8.11 Current data

The applied current profile is presented in Table 9.

Table 9 — Current profile

Depth below surface m (ft)	Velocity m/s (ft/s)
0 (0)	1,8 (5,91)
30,48 (100)	2,36 (5,74)
60,96 (200)	1,23 (4,05)
121,92 (400)	1,03 (3,38)
304,8 (1 000)	0,52 (1,69)
609,6 (2 000)	0,26 (0,84)
Seabed	0,5 (0,17)

5.8.12 Vessel offset data

A maximum vessel offset of 36,6 m (120 ft) is used in this example.

5.8.13 Soil data

The soil used in this example is soft clay. The shear strength is 2,39 kN/m^2 (50 lb/ft^2) at the mudline and increases linearly with depth according to the profile in Table 10.

Table 10 — Soil data

Depth below mudline m (ft)	Shear strength N/m^2 (lb/ft^2)
0 to 9,144 (0 to 30)	239 (5)
9,144 to 91,44 (30 to 300)	407 (8,5)

A strain of 2 % at 50 % of the shear strength of the soil has been used. The effective unit weight of soil is 3,12 kN/m^3 (20 lb/ft^3) near the mudline and increases linearly to 5,34 kN/m^3 (34 lb/ft^3) at approximately 91,44 m (300 ft).

5.8.14 Wave data

The omnidirectional wave data are given in Table 11.

Table 11 — Wave data

Parameter/symbol/unit	Value
Significant wave height, H_s, metres (feet)	7,0 (23,0)
Mean zero crossing period, T_z, seconds	9,1
Maximum wave height, H_{max}, metres (feet)	13,0 (42,8)
Period for H_{max}, seconds	11,5

5.8.15 Drillship response amplitude operators

The drillship response amplitude operators, RAOs, for the wave frequency of 0,087 2 Hz are given in Table 12.

Table 12 — Drillship RAOs for period at 11,47 s

Parameter	RAO	Phase
Heave	—	—
Surge	0,325	90
Sway	0	0
Yaw	0	0
Roll	0	0
Pitch	0,261	97
NOTE Riser is isolated from heave motion by a slip joint.		

5.9 Model description and analysis procedure

5.9.1 Drilling riser

The drilling riser was modeled using beam elements with structural properties assigned to elements according to the riser stack-up data in Table 3. Two elements were used per 22,86 m (75 ft) joint. At the bottom and top of the drilling riser, element lengths of 3,05 m (10 ft) were used approaching the lower and intermediate flex joints.

5.9.2 Soil-structure interaction

The soil-structure interaction was modeled using nonlinear springs positioned every 3,05 m (10 ft) below the mudline. Using the soil data previously presented in 5.8.13, P vs. y curves for each spring element depth were generated according to the methodology presented in API RP 2A. For the nonlinear spring elements used in this case, the spring stiffness is specified by a force-deflection (F vs. y) curve. Therefore, for each depth the P vs. y curve was converted to an F vs. y curve according to Equation (2):

$$F = P \times S \qquad (2)$$

where

F is the axial force in the spring, expressed in newtons (pounds);

P is the soil resistance, expressed in newtons per metre (pounds per foot);

S is the soil spring spacing, expressed in metres (feet).

5.9.3 Slip joint

In order to accurately simulate the actuating motion of the slip joint, the inner barrel was modeled as a massless beam element with a low linear axial stiffness. The mass of the inner barrel was applied at the UFJ. Therefore, the inner barrel element deforms axially in a manner similar to that of the actual slip joint.

In this model, the stroke-out of the slip joint is not modeled explicitly, though this can be achieved using nonlinear axial stiffness properties for the inner barrel. Slip-joint stroke-out in this example is modeled through the tensioner system model.

5.9.4 Tensioner system

For the purpose of this example, the tensioner system is modeled using two rigid elements connected at one end to the tensioner ring and to which an upward force is applied at the other end. This force, applied to each tensioner element, is equal to the total top tension divided by two. Alternatively, one preloaded spring, with stiffness equivalent to all lines, can be used to capture the response of the upper riser at large offsets.

5.9.5 Procedure

The modeling procedure for this example commences with a static analysis of the coupled riser system with the top tension applied. At this stage, it is prudent to check the model against calculations for wet weight and tension at the LMRP, and to check the extension of the riser due to tension.

In this case, the wet weight predicted by the analysis software was 7 612,7 kN (1 711,4 kips) while calculations in accordance with API RP 16Q give a wet weight of 7 552,6 kN (1 697,7 kips). Similarly, for the tension at the LMRP, the analysis software gives a value of 2 827,3 kN (635,6 kips) while the calculation in accordance with API RP 16Q gives 2 888,2 kN (649,3 kips). These values represent good agreement.

The next step in the modeling procedure is to apply the current and vessel offset, in that order. Two separate static analyses are used to apply these loads. Following this, the regular-wave loads are applied in the time domain.

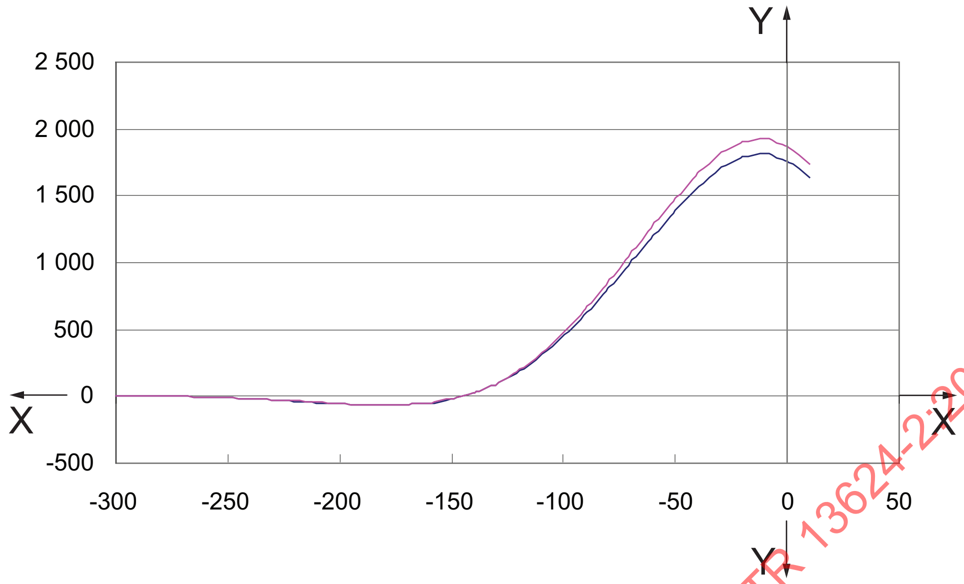
5.10 Results

The primary parameters of interest in this example are the distribution of bending moment and lateral deflection along the conductor/casing. Figures 10 and 11 give maximum/minimum envelopes of these parameters. The envelopes are given from the base of the conductor/casing up to the bottom of the LMRP/BOP. Figures 12 and 13 include decoupled models superimposed on Figures 10 and 11, respectively.

In addition to the analysis of the riser system using a coupled methodology, a decoupled model was built and analysed. The same dynamic loading conditions were used for the riser part of the decoupled model (upper flex joint to top of LMRP/BOP stack). The maximum bending moment and associated shear and tension from this analysis are given in Table 13.

Table 13 — Results from decoupled riser model

Parameter	Value
Maximum bending moment, kilonewtons per metre (kilopounds-force per foot)	2 540,8 (174,1)
Associated shear, kilonewtons (kilopounds-force)	131,7 (29,60
Associated tension, kilonewtons (kilopounds-force)	2 834 (637,1)

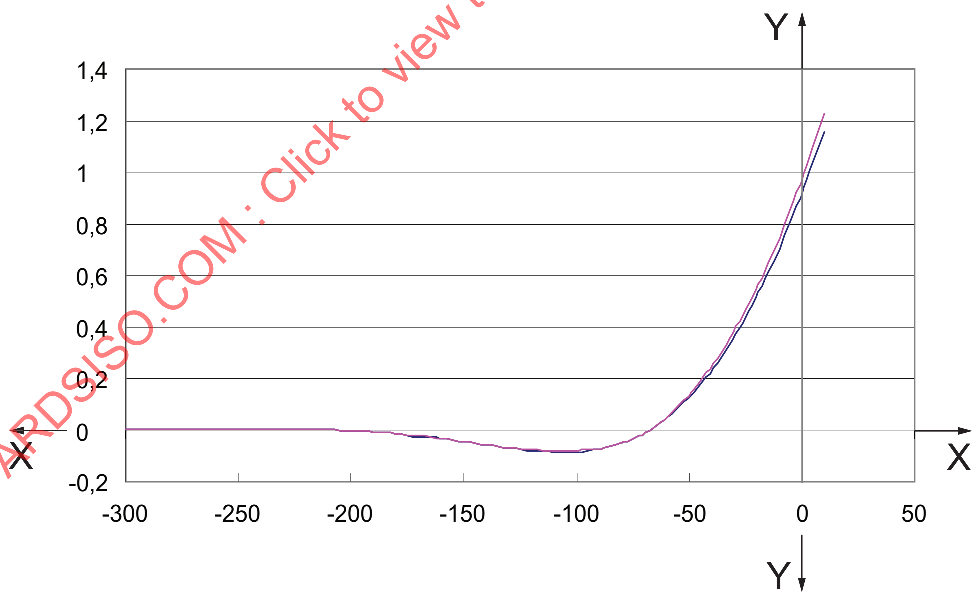


Key

X depth (ft)

Y bending moment (kips.ft)

Figure 10 — Envelope of bending moment for coupled model

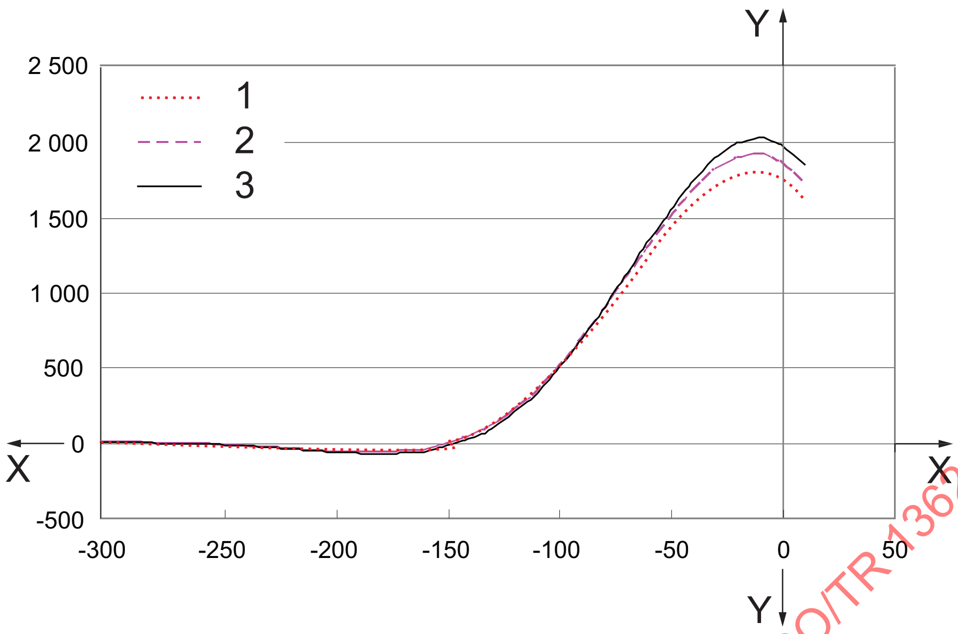


Key

X depth (ft)

Y lateral deflection (ft)

Figure 11 — Envelope of lateral deflection for coupled model



Key

X depth (ft)

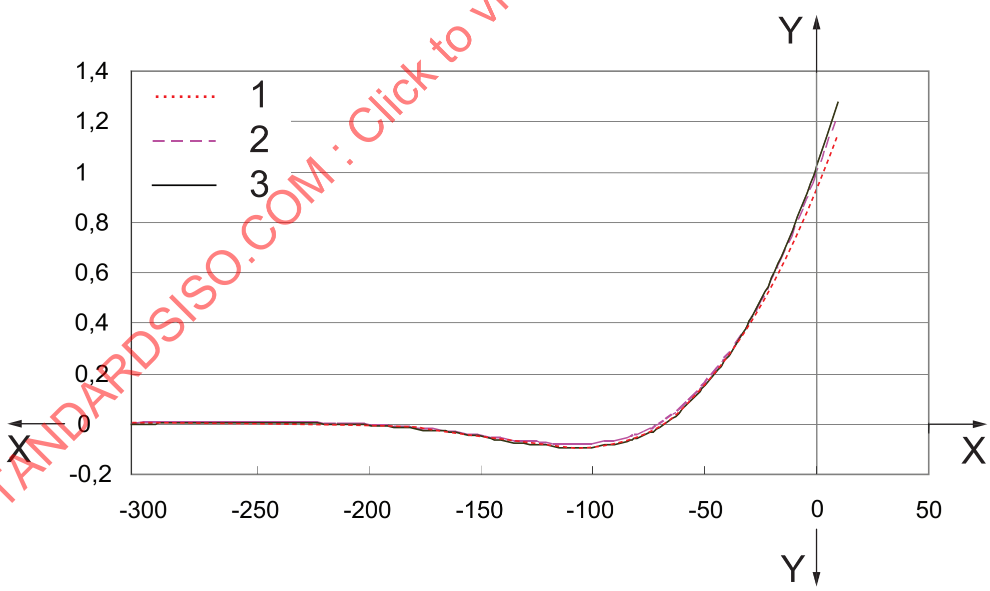
Y bending moment (kips.ft)

1 coupled minimum

2 coupled maximum

3 decoupled

Figure 12 — Envelope of bending moment for coupled model with bending moment from decoupled model superimposed



Key

X depth (ft)

Y lateral deflection (ft)

1 coupled minimum

2 coupled maximum

3 decoupled

Figure 13 — Envelope of lateral deflection for coupled model with lateral deflection from decoupled model superimposed

6 Drift-off/drive-off analysis methodology and worked example

6.1 Drift-off analysis methodology

6.1.1 Overview

Drift-off analysis should form part of the design process of a dynamically positioned, DP, drilling riser system. The objective of a drift-off analysis is to determine when to initiate disconnect procedures under extreme environmental conditions or drift-off/drive-off conditions.

Clause 6 focuses mainly on the procedures for drift-off analysis. Procedures for drive-off analysis are similar. However, the potential range of drive-off scenarios is very extensive and can include a range of DP failure scenarios combined with various environmental conditions. Selection of load cases and associated drive-off curves, therefore, requires careful consideration. In addition, in a DP drive-off occurrence, it is likely that the power to the thrusters will be cut, changing the drive-off scenario to a drift-off scenario.

The steps involved in a drift-off analysis are illustrated in the flowchart of Figure 14. The individual analysis steps associated with drift-off analysis are discussed in 6.1.2 to 6.2.5.

6.1.2 Evaluation criteria

The first task in a drift-off analysis is to determine the evaluation criteria by which the disconnect point is designed/identified. The areas of potential concern in a drilling riser system are typically

— collision between the drilling riser and the vessel structure;

— stroke-out of the tensioner;

— exceedence of top and bottom flex joint limits;

— overloading of the wellhead;

— overloading of the conductor/casing.

The objective in the disconnection analysis is to ensure that the design criteria are not exceeded, thereby ensuring a safe disconnect operation. Therefore, the evaluation criteria for a disconnect analysis are based on allowable loads or allowable stress in the components of the drilling riser system. For the drilling riser itself, the allowable stress is, typically, the material yield stress multiplied by a utilization factor (e.g. 0,67).

For components such as BOP connectors, the allowable loads should be derived in consultation with the manufacturer.

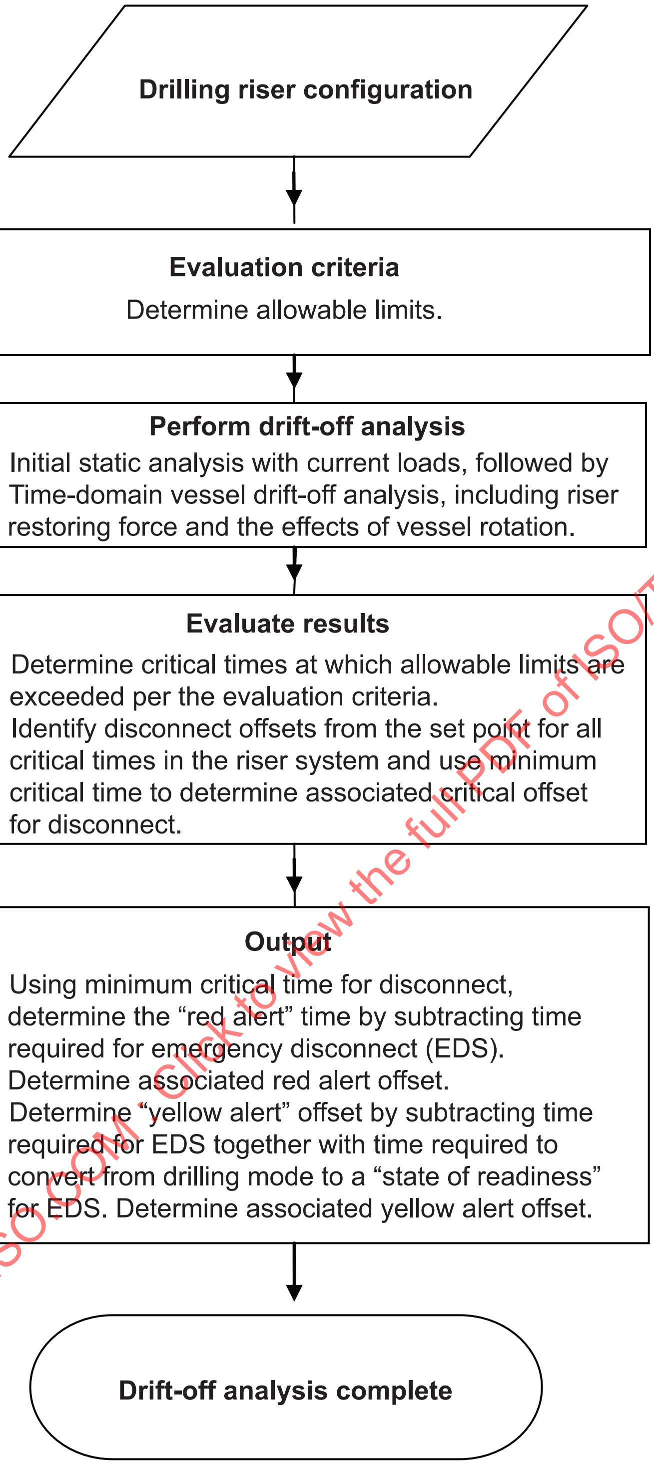


Figure 14 — Drift-off analysis flowchart

6.1.3 Analysis methodology

The analysis methodology is selected to closely represent the expected drift-off conditions. Critical combinations of environmental combinations (wind, wave and current) and vessel drift conditions should be identified. The vessel drift conditions are typically specified as a time history of vessel offset, which is then a direct input into the analysis. In some cases, the riser analysis software can calculate the time history of vessel motion. In such cases, wind, current and second-order wave-force coefficients of the vessel along with thruster-force description should be available.

There are the following two analysis options for combining the environmental conditions and drift-off conditions.

a) First perform drift-off analysis without dynamic wave-induced loads. From this, identify critical offsets at which disconnect load criteria are exceeded. Then perform dynamic analyses with appropriate wave conditions at this offset position to estimate the dynamic load range. These two sets of results can then be used to determine the disconnect point.

b) Perform drift-off analysis with all relevant loads and motions accounted for, including vessel drift-off time history, current conditions and wave conditions. Care should be taken to ensure the phasing between the vessel motion time history and wave forces is accounted for. This may be achieved by obtaining a time history of wave elevation from the vessel motion analyses and comparing this with a time history of wave elevation from the riser analysis software.

In both cases, the approximate current loads are applied in initial static analyses. To accurately assess the transient conditions inherent in a drift-off, a time-domain dynamic analysis procedure should be used.

The environmental load cases for use should be based on a comprehensive evaluation of all conditions that can result in a drift-off occurring. The following environments are, typically, recommended for drift-off analysis:

— maximum connected;

— maximum drilling.

A longer lead-time is required for the drilling conditions.

Consideration should also be given to the tensioner setting and mud weights that are accounted for in the analysis. It can be necessary to include a range of conditions in the load case matrix.

6.1.4 Determination of disconnect point

Following the static and dynamic analyses of the drilling riser system, the disconnect point of the system can be identified using the following procedure.

a) The vessel offset, for the specified environmental load conditions that generate a stress or load equal to the disconnect criteria of the component, is the allowable disconnect offset for that particular component.

b) The allowable disconnect offset should be determined for each of the key components along the drilling riser system.

c) Then the overall disconnect point corresponds to the smallest allowable disconnect offset for all critical components along the drilling riser system.

d) Once the vessel offset at which it is necessary to disconnect the riser is determined, the offset at which it is necessary to initiate the disconnect procedure can be determined. This allows for the time lag between the initiation of the disconnect and the actual disconnect. This time lag can be dependent on drilling conditions and is specific to each vessel. A duration in order of 30 s to 60 s is a typical estimate.

e) The disconnect initiation offset is then determined from the excursion time history of the vessel.

The results from the weak-point analysis, particularly for normal environmental conditions, can then be used to identify alarm limits for the drilling operators. Typically, two alarm conditions are identified, namely a red alarm and a yellow alarm, defined as follows:

— red alarm: point where it is necessary for the operator to hit the disconnect button, i.e. to initiate disconnect;

— yellow alarm: point set to alert the operator that drift-off is beginning to occur.

The time lag between the yellow and the red alarms is selected to give sufficient time for the operator to attempt to rectify the drift-off or to perform any operations necessary before disconnect is initiated.

6.2 Example

6.2.1 General description

The following example illustrates how to perform a drift-off analysis, to determine the excursion at which to initiate disconnect under vessel drift-off conditions. A coupled model of the drilling riser/wellhead/conductor/casing is used for the analysis. The water depth considered is 3 048 m (10 000 ft) and the vessel is a drillship.

The following sections describe the analysis basis and provide a description of the modeling techniques used for key areas of the analysis model, such as the tensioners and the soil-structure interaction. Finally the results of the disconnect analyses are presented and discussed.

6.2.2 Basis of analysis

6.2.2.1 Vessel dimensions

The key vessel dimensions required for the analysis are presented in Table 14.

Table 14 — Vessel dimensions

Parameter	Value
Draft	12 m (39,37 ft)
Moonpool width (at keel)	15,24 m (50,00 ft)
Moonpool centre forward of LPP/2	0 m (0 ft)
Rotary kelly bushing, RKB[a], to UFJ[b] centre	4,52 m (14,83 ft)
Rotary kelly bushing, RKB[a], to keel	40,04 m (131,37 ft)

[a] RKB located at top of drill floor.

[b] Riser upper flex joint.

6.2.2.2 Riser stack-up

Table 15 presents the stack-up weights and dimensions for the drilling riser in 3 048 m (10 000 ft) water depth. The stack-up is presented schematically in Figure 15. The grade of steel used for the drilling riser is API Spec 5L X-80 steel.

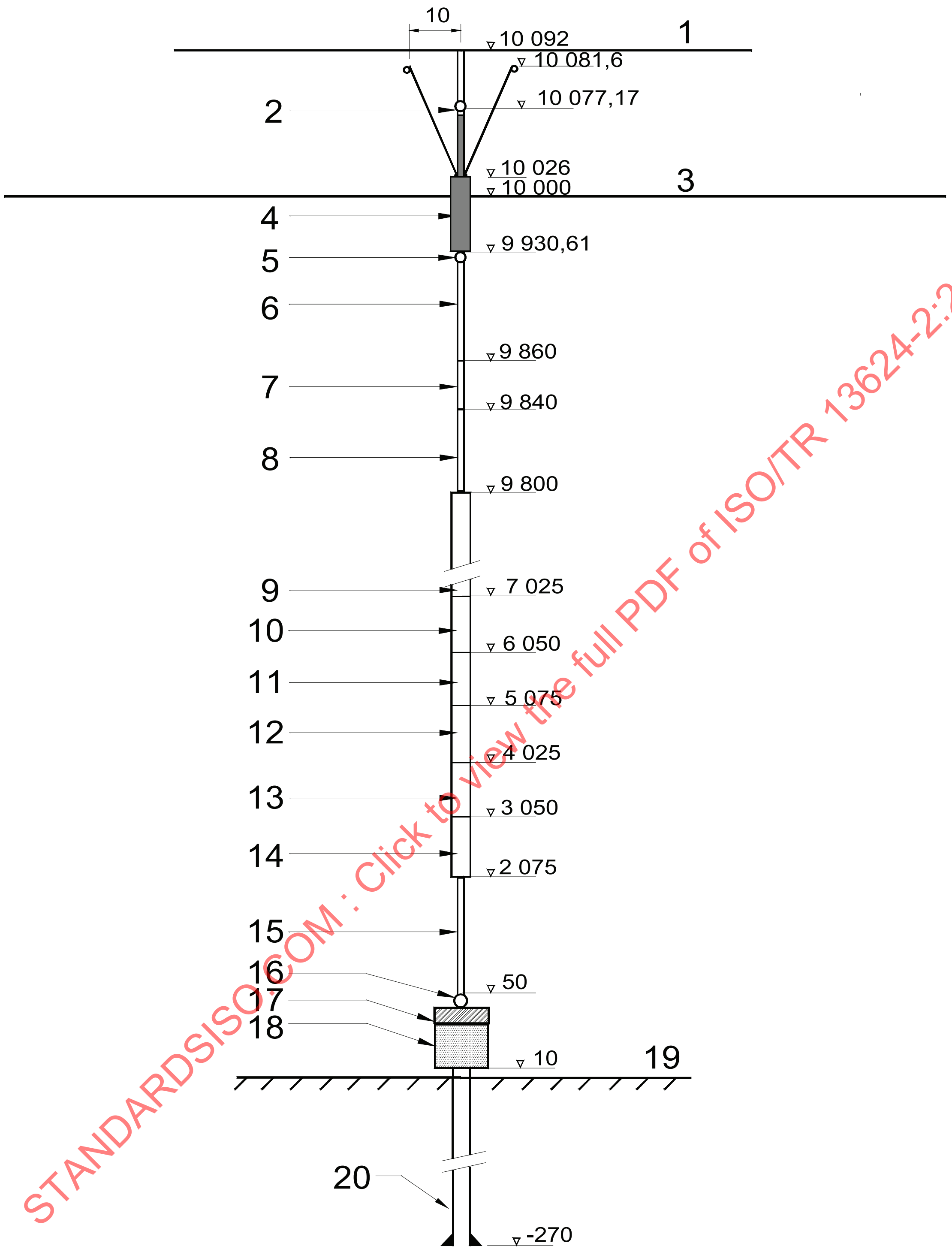
Table 15 — Riser stack-up for worked example

Joint description	Number of joints	OD	Depth	Bare joint weight in air	Foam density	Lift	Wet weight		Total dry weight per joint	Total wet weight for all joints
							Per joint	Per unit length		
		cm (in)	m (ft)	N (lb)	kg/m^3 (lb/ft^3)	N (lb)	N (lb)	N/m (lb/ft)	N (lb)	kN (kips)
Termination joint	1	53,34 (21)	42,67 (140)	155 700 (35 000)	0 (0)	0 (0)	135 355 (30 429)	5 920 (405,72)	155 700 (35 000)	133 (30)
Pup joints	1	53,34 (21)	60,96 (200)	58 190 (13 083)	0 (0)	0 (0)	50 594 (11 374)	2 213 (151,65)	58 190 (13 083)	48,9 (11)
Joints w/ 914,4 m (3 000 ft) foam	37	128,27 (50,5)	906,78 (2 975)	121 620 (27 343)	422,9 (26,4)	102 840 (23 121)	2 900 (651)	126,7 (8,68)	193 930 (43 598)	106,8 (24)
Joints w/ 1 219,2 m (4 000 ft) foam	13	130,81 (51,5)	1 203,96 (3 950)	121 620 (27 343)	456,5 (28,5)	100 260 (22 540)	5 480 (1 232)	239,8 (16,43)	202 955 (45 626)	71,2 (16)
Joints w/ 1 524 m (5 000 ft) foam	13	133,35 (52,5)	1 501,14 (4 925)	121 620 (27 343)	483,8 (30,2)	104 315 (23 451)	1 427 (321)	62,5 (4,28)	214 556 (48 234)	17,8 (4)
Joints w/ 1 828,8 m (6 000 ft) foam	14	135,89 (53,5)	1 821,18 (5 975)	121 620 (27 343)	522,2 (32,6)	100 618 (22 620)	5 124 (1 152)	224,2 (15,36)	226 134 (50 827)	71,2 (16)
Joints w/ 2 133,6 (7 000 ft) foam	13	140,97 (55,5)	2 118,38 (6 950)	121 620 (27 343)	557,4 (34,8)	103 977 (23 375)	1 766 (397)	77,2 (5,29)	245 623 (55 200)	22,2 (5)
Joints w/ 2 438,4 m (8 000 ft) foam	13	143,51 (56,5)	2 415,24 (7 925)	121 620 (27 343)	608,7 (38,0)	82 292 (18 500)	23 451 (5 272)	1 025,8 (70,29)	247 130 (54 415)	306,9 (69)
Bare joints	27	53,34 (21)	3 032,76 (9 950)	124 710 (28 035)	0 (0)	0 (0)	121 630 (27 343)	4 742,6 (324,97)	124 747 (28 035)	2 927 (658)
Total std joints	130								Subtotal:	3 710 (834)
									Slip joint:	445 (100)
									Total wet weight kN (kips):	4 155 (934)

NOTE 1 Joint details: length, 22,86 m (75 ft); nominal wall thickness, 2,063 7 cm (0,812 5 in); minimum yield strength, 5 516 MPa (80 ksi).

NOTE 2 Auxiliary lines: choke-and-kill: 16,51 cm × 2,54 cm (6,5 in × 1 in), 103,5 MPa (15 000 psi); boost line: 11,43 cm × 0,9718 cm, (4,5 in × 0,3826 in), 41,4 MPa (6 000 psi); supply line: 8,89 cm × 6,670 cm (3,5 in × 2,626 in) ID.

Dimensions in feet



Depth	Size
0′ – 90′	36″ × 2″
90′ – 180′	36″ × 1.5″
180′ – 270′	36″ × 1″

Figure 15 — Schematic of riser stack-up for the 3 048 m (10 000 ft) **water depth worked example**

Key

1 drill deck (RKB)
2 upper flex joint
3 MWL
4 slip joint
5 intermediate flex joint
6 65,83 ft termination joint
7 20 ft pup joint
8 40 ft pup joint
9 37 × 75 ft 3K buoyancy joints
10 13 × 75 ft 4K buoyancy joints
11 13 × 75 ft 5K buoyancy joints
12 14 × 75 ft 6K buoyancy joints
13 13 × 75 ft 7K buoyancy joints
14 13 × 75 ft 8K buoyancy joints
15 27 × 75 ft bare joints
16 lower flex joint
17 LMRP
18 BOP
19 mudline
20 36″ casing

Figure 15 (*continued*)

6.2.2.3 Flex joints

The riser system employs three flex joints. The upper flex joint, UFJ, the intermediate flex joint, IFJ, located under the vessel keel, and the lower flex joint, LFJ, are modeled using articulation elements with a constant rotational stiffness. The following linear rotational stiffnesses are used for the three flex joints:

— rotational stiffness of UFJ: 26 809 N·m/deg (19 773 ft-lb/deg);

— rotational stiffness of IFJ: 18 980 N·m/deg (14 000 ft-lb/deg);

— rotational stiffness of LFJ: 120 980 N·m/deg (89 188 ft-lb/deg).

6.2.2.4 Slip joints

The slip joint is modeled at approximately 1,524 m (5 ft) from the mid-stroke length, with the properties presented in Table 16.

Table 16 — Slip-joint properties

Parameter	Units	Value
Slip-joint mid-stroke length	metres (feet)	47,72 (156,56)
Slip-joint stroke	metres (feet)	15,24 (50,00)
Slip-joint retracted length	metres (feet)	38,58 (126,56)
Slip-joint extended length	metres (feet)	52,82 (176,56)
Weight in water	kilonewtons (kilopounds-force)	444,8 (100)
Inner barrel internal diameter	centimetres (inches)	50,17 (19,75)
Inner barrel external diameter	centimetres (inches)	53,34 (21,00)
Outer barrel internal diameter	centimetres (inches)	58,42 (23,00)
Outer barrel external diameter	centimetres (inches)	66,04 (26,00)

6.2.2.5 Tensioner system

The tensioner details are summarized in Table 17. The applied top tension is 11 476 kN (2 580 kips), corresponding to the tension applied during drilling operations. In this example, the stroke-out of the slip joint and of the tensioners is assumed to occur concurrently.

Table 17 — Tensioner system

Parameter	Units	Value
Number of direct-acting tensioners	—	6
Max. available tension per tensioner[a]	kilonewtons (kilopounds-force)	3 558,6 (800)
Fleet angle	degree	9,9
Efficiency	percent	95
[a] Failure tension is assumed to be at the maximum tension of the system, i.e. 21 351,5 kN (4 800 kips).		

6.2.2.6 LMRP and BOP

Weights and dimensions of the BOP and LMRP are presented in Table 18. The wellhead connects with the BOP at a distance of 5,18 m (17 ft) above the mudline. The equivalent section properties presented in Table 18 are used to model the BOP and LMRP. These equivalent properties are based on the overall stiffness of the structure along with dimensions which would provide similar stresses under identical loading in the actual structure.

Table 18 — Equipment weights and dimensions

Parameters	BOP	LMRP
Length, metres (feet)	10,06 (33)	10,06 (33)
Weight in water, kilonewtons (pounds)	164,1 (36 900)	109,4 (24 600)
Outer diameter, centimetres (inches)	103,51 (40,75)	103,51 (40,75)
Inner diameter, centimetres (inches)	47,63 (18,75)	47,63 (18,75)
Wall thickness, centimetres (inches)	27,94 (11)	27,94 (11)
Bending stiffness, kilonewton·square metres (pound-square feet)	1,11E+7 (2,69E+10)	1,11E+7 (2,69E+10)

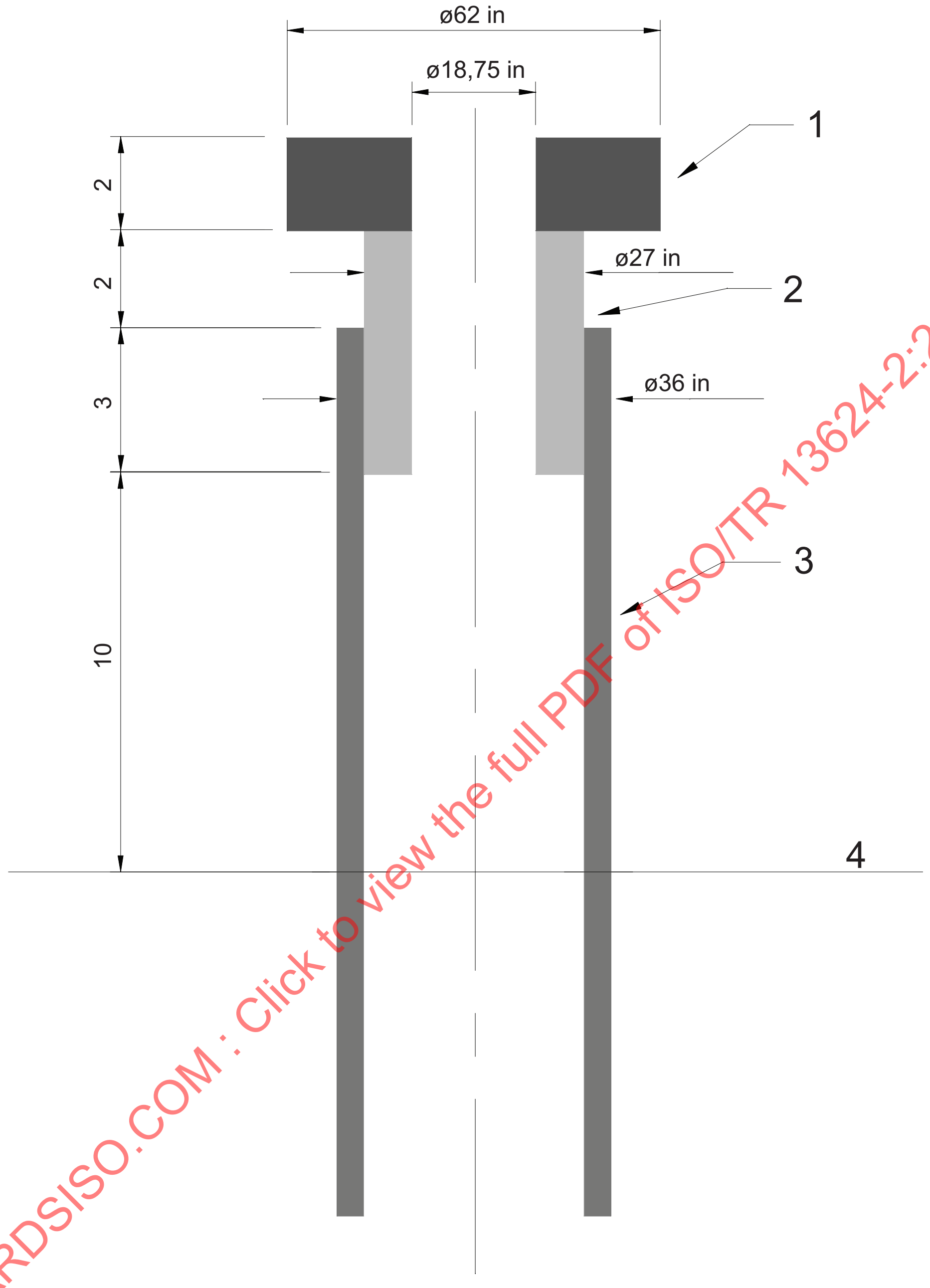
6.2.2.7 Conductor/casing

The properties of the conductor/casing are presented in Table 19. The dimensions and elevations of the casing and wellhead connector above the mudline are illustrated in Figure 16. The material grade of the casing is API Spec 5L X-60 steel.

Table 19 — Conductor/casing

Depth below mudline m (ft)	Outer diameter cm (in)	Wall thickness cm (in)
0 to 27,43 (0 to 90)	91,44 (36)	5,08 (2,0)
27,43 to 54,86 (90 to 180)	91,44 (36)	3,81 (1,5)
54,86 to 82,29 (180 to 270)	91,44 (36)	2,54 (1,0)

Dimensions in feet, unless otherwise indicated



Conductor size

Depth	Size
0′ – 90′	36″ × 2″
90′ – 180′	36″ × 1.5″
180′ – 270′	36″ × 1″

Key

1 wellhead connector
2 high-pressure wellhead housing
3 low-pressure housing
4 mudline

Figure 16 — Schematic illustrating wellhead/conductor/casing layout

6.2.2.8 Internal fluid data

The riser internal fluid is drilling mud with a density of 0,1 kg/L (13 lb/gal). The internal fluid free surface elevation is taken to be at the drilling deck. The effect of the presence of the drill string is neglected. Internal pressure in the riser is due to static head only.

6.2.2.9 Drag coefficients

The drag coefficients used for both bare and buoyancy joint sections are calculated as a function of Reynolds number in accordance with API RP 16Q and are presented in Table 20. These coefficients are a function of the applied current environment.

For simplicity of the worked example, drag enhancement due to the influence of vortex-induced vibration, VIV, is not being considered. The influence of VIV should, however, generally be considered for evaluation of a riser system.

Table 20 — Drag coefficients along riser

Riser section	Number of 22,86 m (75 ft) joint lengths	Drag coefficient
Bare	27	1,93
2 438,4 m (8 000 ft) rated buoyancy	13	1,09
2 133,6 m (7 000 ft) rated buoyancy	13	1,04
1 828,8 m (6 000 ft) rated buoyancy	14	1,00
1 524 m (5 000 ft) rated buoyancy	13	0,96
1 219,2 m (4 000 ft) rated buoyancy	13	0,89
914,14 m (3 000 ft) rated buoyancy	14	0,81
914,14 m (3 000 ft) rated buoyancy	2	0,75
914,14 m (3 000 ft) rated buoyancy	2	0,73
914,14 m (3 000 ft) rated buoyancy	2	0,71
914,14 m (3 000 ft) rated buoyancy	2	0,69
914,14 m (3 000 ft) rated buoyancy	1	0,68
914,14 m (3 000 ft) rated buoyancy	1	0,67
914,14 m (3 000 ft) rated buoyancy	1	0,66
914,14 m (3 000 ft) rated buoyancy	1	0,66
914,14 m (3 000 ft) rated buoyancy	1	0,65
914,14 m (3 000 ft) rated buoyancy	1	0,64
914,14 m (3 000 ft) rated buoyancy	1	0,63
914,14 m (3 000 ft) rated buoyancy	2	0,62
914,14 m (3 000 ft) rated buoyancy	3	0,61
914,14 m (3 000 ft) rated buoyancy	3	0,61
Pup joints	—	1,24
Termination joint	—	1,15
Slip-joint outer barrel	—	1,04

6.2.2.10 Water depth and density

The water depth is 3 048 m (10 000 ft). The density of seawater is 1 025 kg/m^3 (64 lb/ft^3).

6.2.2.11 Current data

The applied current profile is presented in Table 21.

Table 21 — Current profile

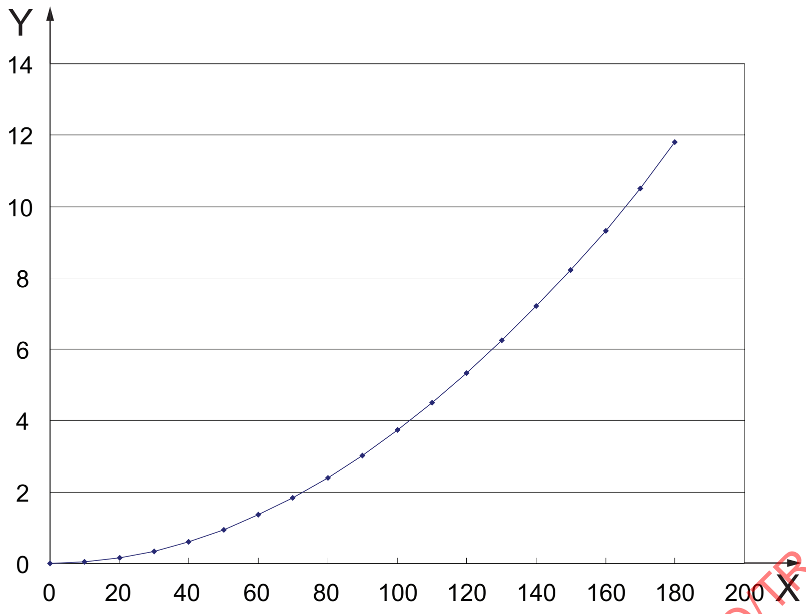
Depth below surface m (ft)	Velocity m/s (ft/s)
0 (0)	1,8 (5,91)
30,48 (100)	1,75 (5,74)
60,96 (200)	1,23 (4,05)
121,92 (400)	1,03 (3,38)
304,8 (1 000)	0,52 (1,69)
609,6 (2 000)	0,26 (0,84)
914,4 (3 000)	0,05 (0,17)

6.2.2.12 Offset data

A time history of the vessel drift-off excursion is presented in tabular form in Table 22, and graphical form in Figure 17.

Table 22 — Time history of offset applied to vessel

Time s	Vessel offset m (ft)
0	0 (0)
10	1,23 (4)
20	4,57 (15)
30	10,36 (34)
40	18,29 (60)
50	28,65 (94)
60	41,45 (136)
70	56,08 (184)
80	73,15 (240)
90	92,35 (303)
100	133,69 (373)
110	137,16 (450)
120	162,76 (534)
130	190,2 (624)
140	219,76 (721)
150	250,85 (823)
160	284,07 (932)
NOTE The drift-off curves for drillships and semi-subs are different and can require different analysis methodologies. In the case of the drillship, after power loss, the ship eventually turns from its head sea position to a beam sea position. It is necessary, if appropriate, to account for this rotation in the analysis.	



Key

X time (s)

Y vessel offset (% water depth)

Figure 17 — Plot of vessel offset as a function of time

6.2.2.13 Soil data

The soil used in this example is soft clay. The shear strength is 2 394 N/m^2 (50 lb/ft^2) at the mudline and increases linearly with depth according to the profile in Table 23.

Table 23 — Soil data

Depth below mudline m (ft)	Rate of increase of shear strength N/m^2 (lb/ft^2)
0 to 9,14 (0 to 30)	239 (5)
9,14 to 91,44 (30 to 300)	407 (8,5)

A strain of 2 % at 50 % of the shear strength of the soil is used. The effective unit weight of soil is 320,4 kg/m^3 (20 lb/ft^3) near the mudline and increases linearly to 720,8 kg/m^3 (45 lb/ft^3) at 91,44 m (300 ft) below the mudline.

6.2.3 Evaluation criteria

To determine when to initiate the disconnect for the riser in a drift-off scenario, the evaluation criteria presented in Table 24 are used.

Table 24 — Disconnect conditions evaluation criteria

Location	Parameter	Value
UFJ	Max. angle, degrees	9,0
IFJ	Max. angle, degrees	9,0
LFJ	Max. angle, degrees	9,0
Slip joint[c]	Stroke length from mean, metres (feet)	4,97 (16,3)
Wellhead connector	Bending moment, metre·kilonewtons (foot-kilopounds-force)	12 202,4 (9 000)
Riser	$\sigma_{vm(max)}/\sigma_{v}$ Max. von Mises stress, megapascals (kilo-pound-force per square inch)[a]	4,62 (0,67) 369,6 (53,6)
Conductor/casing	$\sigma_{vm(max)}/\sigma_{v}$ Max. von Mises stress, megapascals (kilo-pound-force per square inch)[b]	4,62 (0,67) 277,2 (40,2)[d]

[a] Minimum yield strength of riser is 551,6 MPa (80 ksi).

[b] Minimum yield strength of conductor/casing is 413,7 MPa (60 ksi).

[c] The disconnection criteria for the stroke length of the slip joint are determined by subtracting the API margin (10 %) value of 0,76 m (2,5 ft), the heave allowance value of 1,58 m (5,2 ft), the tidal effects value of 0,30 m (1 ft), and the spaceout value of 1,52 m (5 ft) from the mid-length stroke value of 9,14 m (30 ft) for a total of 4,97 m (16,3 ft).

[d] The strength or fatigue of the first conductor connector below the wellhead can be weaker than the conductor.

6.2.4 Model description

6.2.4.1 Drilling riser

The drilling riser is modeled using beam elements with structural properties assigned to elements according to the riser stack-up data in Table 15. Two elements are used per 22,86 m (75 ft) joint. At the bottom and top of the drilling riser, element lengths of 3,05 m (10 ft) are used approaching the lower and intermediate flex joints.

6.2.4.2 Soil-structure interaction

The soil-structure interaction is modeled using nonlinear springs positioned every 3,05 m (10 ft) below the mudline. Using the soil data previously presented in 6.2.2.13, P vs. y curves for each spring element depth are generated according to the methodology presented in the Soil Structure Modeling Report of Clause 6 for soft clay. For the nonlinear spring elements used in this case, the spring stiffness is specified by a force-deflection, F vs. y, curve. Therefore, for each depth, the P vs. y curve is converted to an F vs. y curve according to Equation (3):

$$F = P \times y \quad (3)$$

where

F is the axial force in the spring, expressed in newtons (pounds);

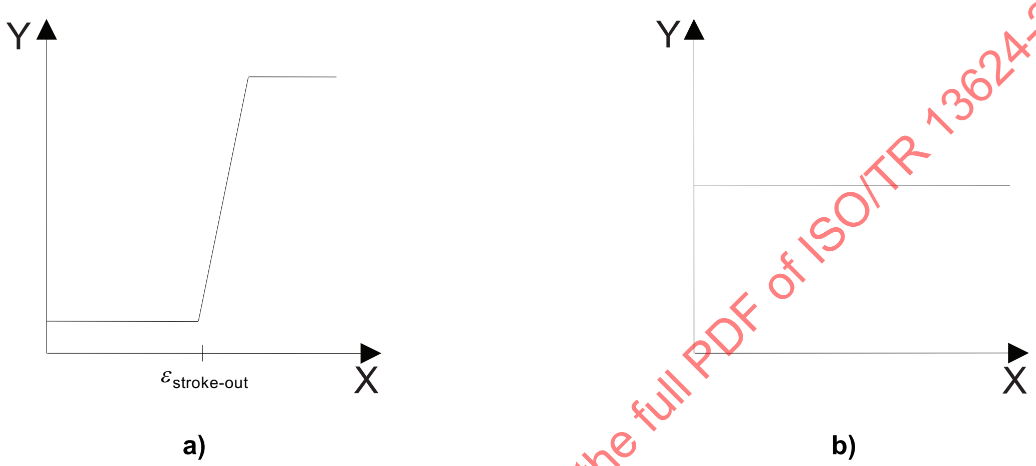
P is the soil resistance, expressed in newtons per metre (pounds per foot);

y is the deflection, expressed in metres (feet).

6.2.4.3 Slip joint

In this model, the stroke-out of the slip joint is modeled explicitly. In order to accurately simulate the actuating motion and stroke-out of the slip joint, the inner barrel is modeled as a massless beam element with a nonlinear axial stiffness. The nonlinear axial stiffness is applied to the element using a stress-strain (σ vs. ε) curve, as illustrated in Figure 18 a). The mass of the inner barrel is applied at the UFJ.

While the slip joint is within its stroke limit, the slip-joint system applies no tension to the riser. Stroke-out of the slip joint is simulated in the model by incorporating a sudden increase in the axial stiffness of the inner barrel element into the stress-strain curve, as illustrated in Figure 18 a). At stroke-out, therefore, the tension applied to the riser through the slip joint increases rapidly. It is necessary to know the length of the inner barrel at stroke-out in order to model in this way.



Key

X strain, ε

Y stress, σ (lb/ft^2)

Figure 18 — Schematic of stress-strain curves for a) inner barrel element and b) tensioner elements

6.2.4.4 Tensioner system

The six direct-acting tensioner system is modeled using two beam elements (whose properties model the effect of the six tensioners) attached to the slip joint at the interface between the inner and outer barrels using articulation elements. The beam elements used to model the tensioners maintain a constant tension during the analyses through the nonlinear axial stiffness capability.

The riser top tension, T_{Top}, applied to the drilling riser is calculated as given in Equation (4):

$$T_{\text{Top}} = F_1 \times \cos\theta_1 + F_2 \times \cos\theta_2 \tag{4}$$

where

F_1, F_2 is the force in tensioners 1 and 2;

θ_1, θ_2 is the fleet angle of tensioners.

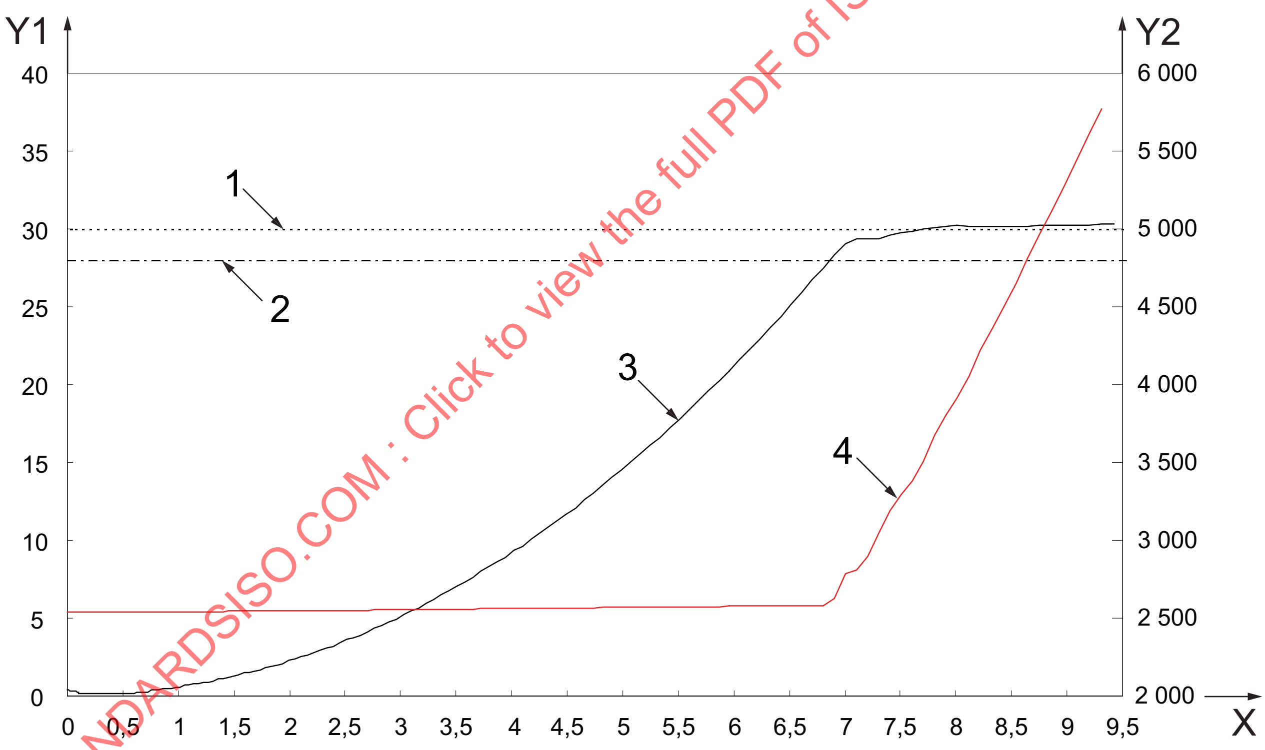
In the initial static analysis, a constant tension of 5 827,2 kN (1 310 kips) is applied to each tensioner to provide the required tension at the riser tensioner ring. This tension remains constant throughout the complete drift-off analysis. Following the initial static analysis, the current specified in Table 21 is applied statically to the coupled riser/conductor model. Finally, the time history of the vessel offset, specified in Table 22, is applied in a dynamic analysis of the riser model.

6.2.5 Analysis results

The key parameters which are monitored for the drift-off analysis are as follows:

- rotation of upper, intermediate and lower flex joints;
- stroke of the slip joint;
- von Mises stress at the top and bottom of the drilling riser;
- von Mises stress in the conductor/casing;
- bending moment at the wellhead connector.

Figures 19 to 21 show the results of the analysis. The length of the slip joint increases with offset. As seen from the curve in Figure 19, when the slip joint reaches its maximum extension at stroke-out, at an offset of approximately 7 % of the water depth, the length of the slip joint remains constant, illustrating correct modeling of the slip-joint stroke-out.



Key

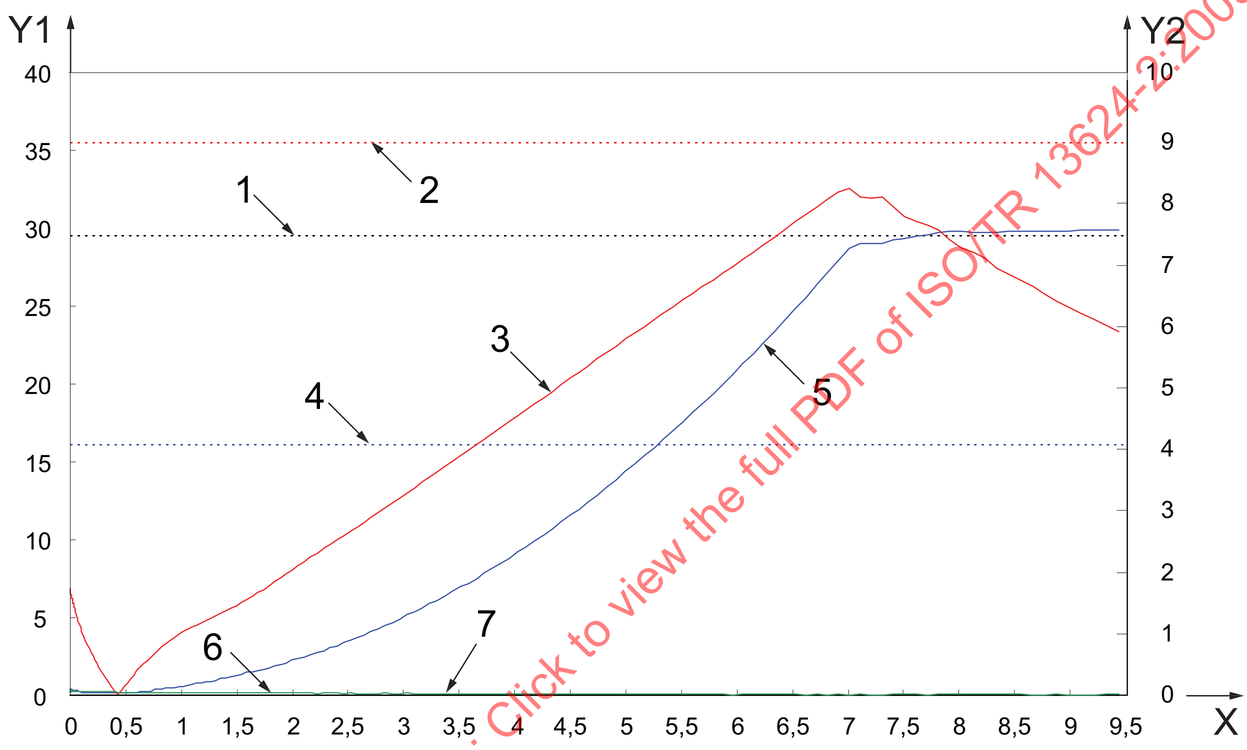
X offset (% water depth)
Y1 stroke length from mean (ft)
Y2 top tension (kips)

1 slip-joint stroke-out
2 tension limit
3 stroke length
4 top tension

Figure 19 — Stroke length from mean and top tension as a function of offset

The effective tension at the top of the riser is also plotted in Figure 19. As the offset increases, the top tension remains constant due to the slip-joint stroking. However, at stroke-out, the slip joint does not extend any farther, resulting in a large increase in top tension with increasing offset. This illustrates the effects of stroke-out on the drilling riser.

Further results are plotted in Figures 20 and 21, together with the evaluation criteria for the riser disconnect previously presented in Table 24. Figure 20 shows that the lower and intermediate flex joints do not rotate significantly with vessel offset, while, the upper flex-joint rotation increases steadily with vessel offset, as does the length of the slip joint. At the slip-joint stroke-out, the rotation of the upper flex joint decreases steadily with further vessel offset and the slip-joint stroke length remains constant.



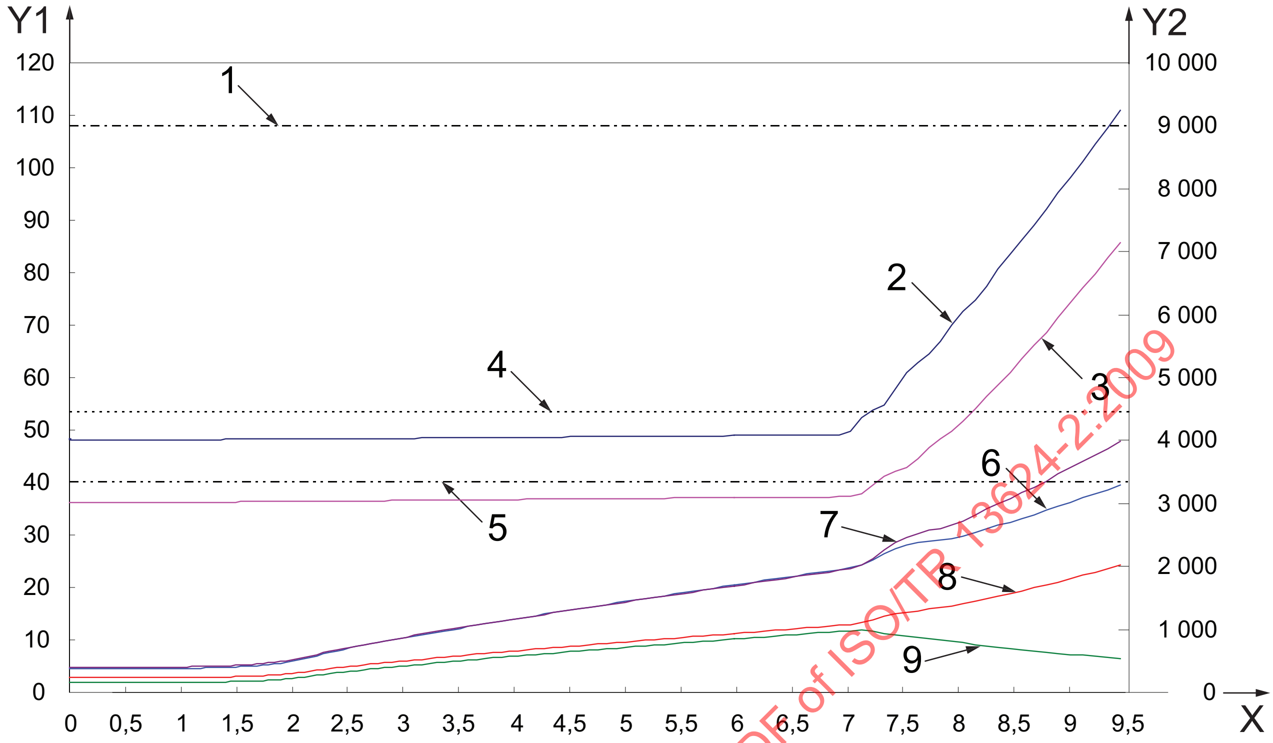
Key

X offset (% water depth)
Y1 stroke length from mean (ft)
Y2 rotation of flex joints (degrees)

1 slip-joint stroke-out
2 flex-joint disconnect limit
3 UFJ rotation
4 slip-joint disconnect limit
5 stroke length
6 IFJ rotation
7 LFJ rotation

Figure 20 — Slip-joint stroke and rotation of flex joints as a function of offset

Figure 21 shows that the von Mises stress at the top and bottom of the drilling riser remains constant with increasing vessel offset until slip-joint stroke-out. At stroke-out, the stress in the riser increases rapidly with increasing offset due to the increase in top tension. A similar trend is seen along the conductor/casing. The von Mises stress in the conductor/casing increases gradually with offset until stroke-out, when the stress increases rapidly.



Key

X offset (% water depth)

Y1 von Mises stress (ksi)

Y2 bending moment at wellhead connector (ft.kips)

1 wellhead moment limit
2 top of riser stress
3 bottom of riser stress
4 riser stress limit
5 casing stress limit
6 stress-casing 60 ft below mudline
7 stress-casing 90 ft below mudline
8 casing at mudline stress
9 moment-wellhead connector

Figure 21 — Riser/casing von Mises stress and wellhead bending moment as a function of offset

Table 25 presents the vessel offset at which the disconnect criteria are exceeded at key points along the riser system.

From Table 25, it is clearly necessary that the riser be disconnected at a maximum vessel offset of 5,3 % due to the slip joint reaching its design stroke length at this offset.

This worked example presents results from a single set of simplified loading conditions. A complete drift-off analysis requires that the analysis be rerun for a matrix of load cases that represent all potential drift-off/drive-off conditions. In addition, the disconnect limit should address any additional allowances required to account for wave-induced dynamic effects.

Table 25 — Disconnect criteria

Location	Disconnect criteria	Offset exceeded
UFJ	Max. angle of 9,0°	—
IFJ	Max. angle of 9,0°	—
LFJ	Max. angle of 9,0°	—
Slip joint	Stroke length from mean of 4,97 m (16,3 ft)	5,3 % of water depth
Top of riser	Von Mises stress of 369,6 MPa (53,6 ksi)	7,2 % of water depth
Bottom of riser	Von Mises stress of 369,6 MPa (53,6 ksi)	8,1 % of water depth
Wellhead connector	Bending moment of 12 202,4 m-kN (9 000 ft-kips)	—
Casing at mudline	Von Mises stress of 277,2 MPa (40,2 ksi)	—
Casing 18,29 m (60 ft) below mudline[a]	Von Mises stress of 277,2 MPa (40,2 ksi)	9,5 % of water depth
Casing 27,43 m (90 ft) below mudline[b]	Von Mises stress of 277,2 MPa (40,2 ksi)	8,7 % of water depth

[a] Location of maximum bending moment below mudline.

[b] Location of maximum von Mises stress below mudline.

7 Recoil analysis methodology and worked example

7.1 Introduction

The purpose of Clause 7 is to illustrate an analysis procedure and set of performance criteria that can be applied to most, if not all, DP drilling vessels. The intent of this clause is to focus on water depths of 2 133,6 m to 3 048 m (7 000 ft to 10 000 ft).

7.2 Background

7.2.1 Riser tensioner configurations

Drilling riser tensioners are designed to apply nearly constant tension to the riser even when the vessel is heaving. The configurations vary significantly, particularly among manufacturers. The following characteristics are common to most, if not all, offshore drilling rigs.

a) The vessel has multiple riser tensioners distributed about the moonpool to provide redundancy (in the event of tensioner or wire-rope failure) and the necessary tension and stroke capabilities.

b) Drilling riser tensioner systems provide heave compensation that is typically passive, not active, in nature. The tensioners use a large volume of air or nitrogen to form a relatively soft spring. This creates a system that provides nearly constant tension.

NOTE Truly constant tension is not practical due to mechanical and hydraulic losses.

c) Tension is adjusted by increasing or decreasing air or nitrogen pressure. Adjusting tension is a manual process that occurs in response to a change in tension requirement.

EXAMPLE Due to a change in mud weight, to modify upper and/or lower flex-joint angles, or to reduce VIV-induced excitation.

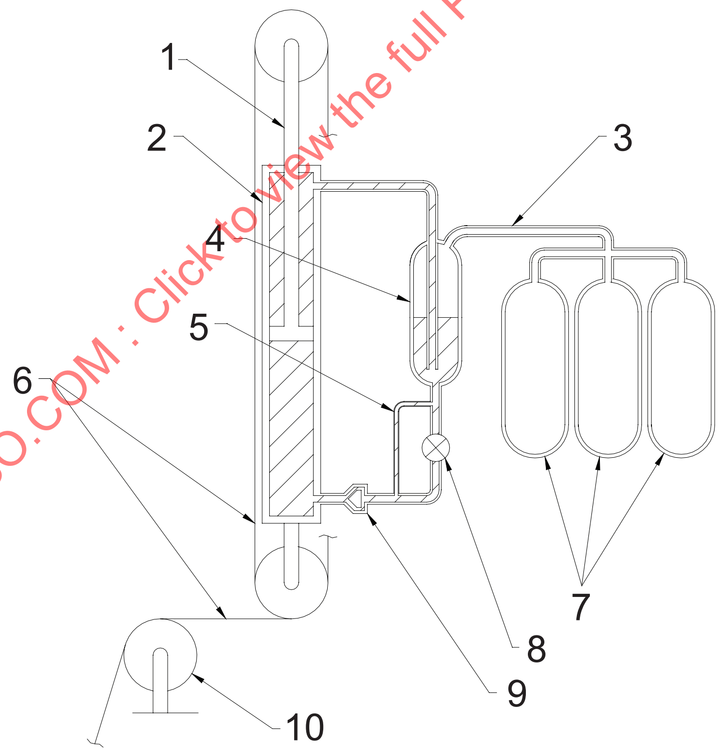
d) The tensioners usually have a “fluid cushion” to soften the impact in the event of a wire-rope break or some other mechanical failure that can cause the tensioner rod and piston to extend at high velocity and impact the top of the cylinder. Usually, this function is implemented by trapping a small amount of fluid above the piston and forcing the fluid through a small opening as the tensioner approaches full extension. This reduces the effective stroke of the tensioners.

Wire-rope tensioners are normally configured with a 4:1 ratio of wire-rope travel to cylinder travel. There is no requirement for a 4:1 ratio, but many, if not all, manufacturers have found 4:1 to be the most appropriate stroke ratio for drilling riser tensioners. Most existing vessels have tensioners with 3,81 m (12,5 ft) of stroke. With a 4:1 ratio, this provides 15,24 m (50 ft) of wire-rope travel. At least two manufacturers have manufactured wire-rope tensioners with 4,95 m (16,25 ft) of stroke, to provide 19,81 m (65 ft) of wire-rope travel. Others are sure to follow if market demand calls for it.

Typical load ratings for individual wire-rope tensioners range from 355,9 kN to 1 112,1 kN (80 000 lb_f to 250 000 lb_f), after accounting for the stroke ratio. A typical vessel has an even number of wire-rope tensioners (typically 8 to 16) distributed about the moonpool. They may be plumbed individually or in opposite pairs.

Figures 22 through 24 show the general arrangements of some wire-rope tensioner systems. Figure 25 shows a direct-acting tensioner system. Drilling riser tensioners with other arrangements are also being used on many drilling vessels. The purpose in showing Figures 22 to 25 is to point out the degree to which the configurations vary from one manufacturer to another, even though all four satisfy the same functional requirement.

Figure 22 shows a tensioner that has both the rod end and blind end of the cylinder plumbed to the same accumulator. Thus, under static conditions both the rod end and blind end are at the same pressure. The tensioner relies on the difference in area between the blind end and rod end (i.e. the area of the rod) and the tensioner pressure to develop force. In an emergency disconnect, this system closes the “anti-recoil valve” when the telescopic joint, TJ, reaches a predetermined stroke. This system has other features for recoil control, which Hock and Young (1992a, 1992b, 1993), Young, Hock, Karlsen and Miller (1992) and Young, Hock, Karlsen and Albert (1992) describe in more detail.



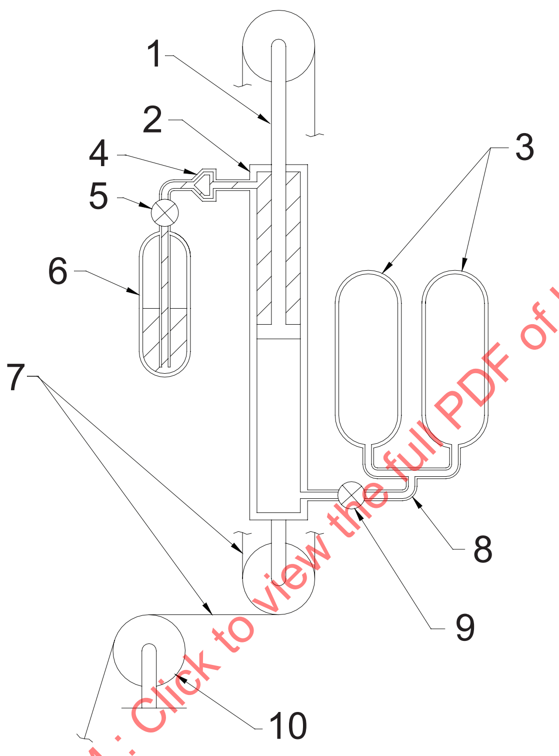
Key

1	rod and piston	6	wire rope
2	cylinder	7	air pressure vessels
3	air line	8	anti-recoil valve
4	air/oil accumulator	9	speed-limiting valve
5	bypass line	10	idler sheave

Figure 22 — Wire-rope tensioner with a high-pressure air/oil accumulator
[adapted from Young *et al* (1992a)]

This system also contains a speed-limiting valve to protect the tensioner in the event of a wire line break. The speed-limiting valve is locked open during an emergency disconnect to avoid rope slack and to make the lift more predictable.

The system in Figure 23 has a low-pressure accumulator on the rod side. It derives tension from pressure acting on the entire blind-side area, with a minimal reduction in tension arising from the relatively low pressure on the rod side. This system uses only air (i.e. no tensioner fluid) on the high-pressure side, thus eliminating the requirement for an air/oil accumulator on the high-pressure side. During a riser-recoil scenario, this system uses computer control to modulate the two valves. A speed-limiting valve on the rod side also activates in high-tension disconnects.

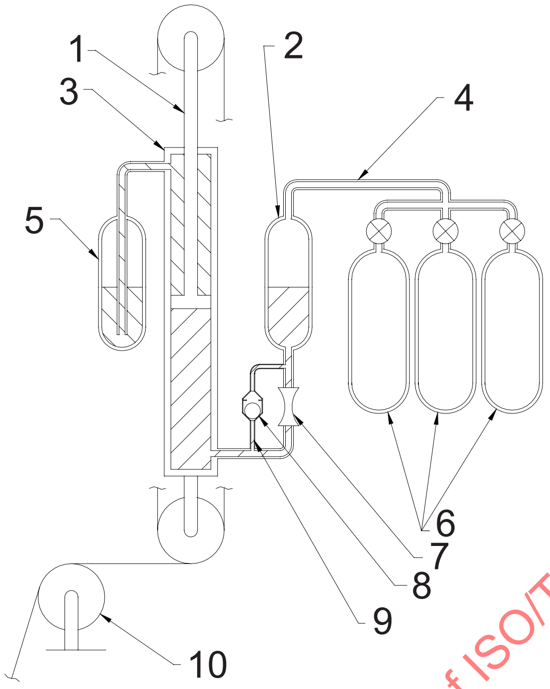


Key

1 rod and piston
2 cylinder
3 air pressure vessels
4 speed-limiting valve
5 recoil-control valve
6 air/oil accumulator
7 wire rope
8 air line
9 isolation valve
10 idler sheave

Figure 23 — Wire-rope tensioner with air on the high-pressure side
(used with permission of Retsco International)

Figure 24 shows a system that has two air/oil accumulators. This system develops force in the same manner as the system in Figure 23. This system closes the recoil-control valve to create a restrictive orifice that slows the riser's ascent. The check valve allows flow to bypass the restriction when the direction of flow is in the opposite direction. The system can also close one or more air pressure vessel, APV, isolation valves as required for recoil-control purposes. This system does not have a speed-limiting valve but it does have a fixed orifice in the rod end piping to limit piston velocity in the event of a rope break.

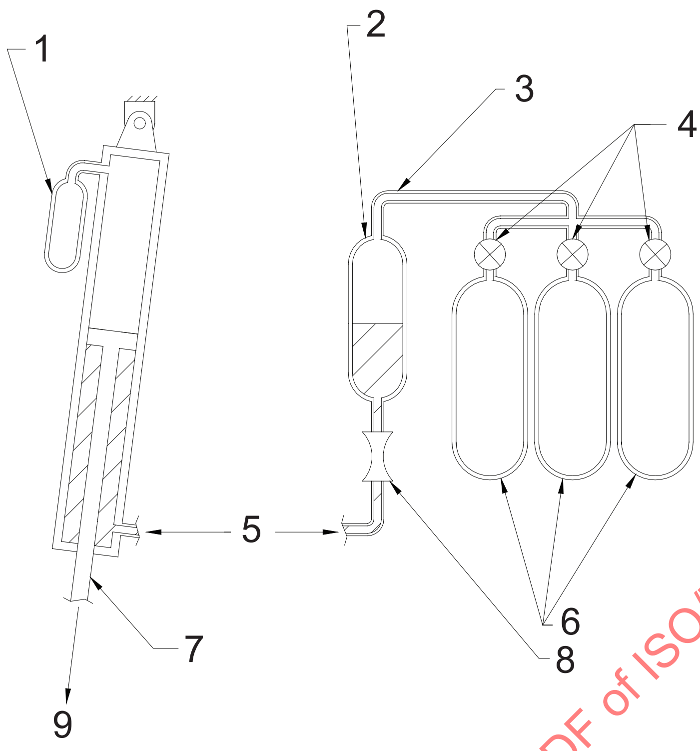


Key

1 rod and piston
2 high-pressure air/oil accumulator
3 cylinder
4 air line
5 low-pressure air/oil accumulator
6 air pressure vessels
7 recoil-control valve
8 check valve
9 bypass flowpath
10 idler sheave

Figure 24 — Wire-rope tensioner with high- and low-pressure accumulators
[adapted from Puccio and Nuttall (1998), and Stahl and Abbassian (2000)]

Figure 25 shows a direct-acting tensioner. This arrangement uses long-stroke cylinders to obtain the necessary stroke capability without using the wire rope and sheaves that appear in Figures 22 to 24. Because these tensioners have a stroke ratio of 1:1 rather than the more common 4:1, each tensioner can apply much more tension to the riser than a typical wire-rope tensioner. Since this is a “rod down” configuration, the cylinders develop tension from pressure acting on the rod side of the piston. The blind side of the piston is normally at low pressure. In other respects, the plumbing is similar to the tensioner arrangements in Figures 22 and 24, with fluid on the rod side and an air-oil accumulator between the cylinder and the APVs. The figure shows a single proportional valve for recoil-control purposes; however, multiple-valve systems have also been developed [Stahl and Hock (2000)]. The figure also shows APV isolation valves, which are optional. Although no speed-limiting valve is shown, this system can include one.



Key

1 low pressure bottle with relief
2 high-pressure air/oil accumulator
3 air line
4 isolation valves
5 flexible piping
6 air pressure vessels
7 rod and piston
8 recoil-control valve
9 to load ring

Figure 25 — Direct-acting tensioner system
(used with permission of Hydralift, Inc.)

These four systems are examples of units currently in service. Other arrangements used on offshore drilling vessels may include a mixture of the features shown in Figures 22 to 25 as well as others that these examples do not show. An accurate riser-recoil analysis cannot proceed without a thorough understanding of the tensioners, plumbing, recoil-control valves and the control system.

Some existing recoil-control systems have been tested by instrumenting key components and collecting data from planned riser disconnects. This demonstrates the effectiveness of the control system and provides valuable data to calibrate recoil simulations. Hock and Young (1992a, 1992b, 1993), Young, Hock, Karlsen and Miller (1992) and Young, Hock, Karlsen and Albert (1992) document one example. Puccio and Nuttall (1998), Stahl (2000), and Stahl and Abbassian (2000) document another. Stahl and Hock (2000) documents a third example. Other test results are undocumented. Usually, a recoil analysis is conducted and results of that analysis confirm the actual behaviour. Recoil analysis of other systems can benefit from similar calibration efforts. Lacking test data, it can be necessary to apply tolerances to key parameters. Thus, test data can make the recoil analysis more reliable, thereby establishing more confidence in the control system and expanding the range of allowable operating conditions.

7.2.2 The need for emergency disconnect capability

A dynamically positioned drilling vessel uses satellite and acoustic navigation equipment to hold a position within an operating “watch circle” and maintain upper and lower flex-joint angles within the limits required for various drilling operations. For various reasons (environment, drift-off, drive-off, mooring failure, etc.) the vessel can move away from the desired position. Operating procedures vary, but a typical disconnect occurs as follows.

— If the vessel violates a "yellow watch circle" (typically 2 % to 3 % of water depth), preparation for emergency disconnect begins.

— If the vessel continues to move farther off location, thereby violating a "red watch circle" (typically 5 % to 6 % of water depth), the driller initiates an emergency disconnect sequence, EDS.

— To avoid damage to the lower portion of the riser or to the wellhead, it is necessary that the disconnect occur before the lower flex-joint angle exceeds a tolerable level (typically 5° to 6°).[1)]

— To avoid damage to the lower portion of the riser, the upper section of the BOP and/or the wellhead, it is necessary that the lower flex-joint angle never reach its maximum "stop" angle (typically 10°).

The 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.

The disconnect typically occurs in the connector between the lower marine riser package, LMRP, and the top of the blowout preventer, BOP, stack. This causes a sudden imbalance in tension that accelerates the riser upward, initiating "riser recoil". Failure to control the recoil effectively can cause the riser to impact the vessel substructure with 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, a 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 accurately simulate the load that the mud column imparts on the riser.

7.2.3 Physics of riser recoil

Riser disconnect initiates a dynamic process that is usually too complex for simple calculations to describe. A typical riser disconnect including intervention by a recoil-control system is described as follows [Stahl (2000)]. In this example, the mud is allowed to escape from the riser.[2)] Several tensioner system configurations are described in 7.2.1. This example refers to the configuration in Figure 24, although the principles are the same regardless of configuration.

a) The EDS completes and the LMRP connector releases.

b) The LMRP, which was in equilibrium before disconnect, suddenly experiences an imbalance in tension, causing it to accelerate upward.

c) If the annular blowout preventer in the LMRP is open, the mud column (also in equilibrium before release) suddenly becomes unconfined at the bottom as the LMRP lifts past it. This produces a sudden drop in pressure at the base of the mud column, causing mud to burst out the bottom of the LMRP.

1) Operating procedures can also account for real-time monitoring of lower flex-joint angle, LFJA, in addition to offset. In that case, violating either threshold (offset or LFJA) can cause a yellow or red alert, as appropriate.

2) If the mud is held in the riser (by closure of an annular BOP in the LMRP), the weight of the mud acts immediately on the bottom of the riser. In addition, the mud behaves like an elastic column. Keeping mud in the riser after an emergency disconnect tends to reduce the severity of riser recoil but it can lead to other problems, including sluggish lift of the LMRP away from the BOP stack and dramatically increased axial dynamic response during storm hang-off, as discussed by Puccio and Nuttall (1998).

d) A tension wave travels up the riser. Above the wave, the riser is relatively still (aside from vessel motion effects), nearly in static equilibrium. As the wave passes, tension decreases by an amount roughly equal to the tension that was in the connector when it released, causing that portion of the riser to accelerate upward. The tensioners and TJ are still as they were just prior to disconnect. In a typical riser, this wave speed is about 3 048 m/s (10 000 ft/s), slower than the wave travel speed for pure steel because of the additional mass of buoyancy modules, auxiliary lines, and so on.

e) Another wave travels up the mud column. Above the wave, the mud is stationary. As the wave passes, the pressure decreases by an amount equal to the pressure difference between the inside and outside of the riser at the LMRP connector just prior to disconnect. The mud accelerates downward. The top of the mud column remains stationary. The wave speed of the mud column is slower, roughly 914 m/s (3 000 ft/s), depending on the mud's density and bulk modulus. This pressure-wave effect is like “fast opening” water hammer.[3)]

f) The tension wave in the riser reaches the TJ outer barrel. This causes the outer barrel to accelerate upward and wire-rope (or rod) tension decreases rapidly.

g) Pressure decreases on the high-pressure (blind) side of the tensioner piston and increases on the low-pressure (rod) side.

h) The difference in pressure between the cylinder and the accumulators causes flow to accelerate from the high-pressure, HP, air/oil accumulator towards the blind side and from the rod side to the low-pressure, LP, air/oil accumulator.

i) If the riser outruns the flow to the tensioners, the tensioner lines will go slack, temporarily decoupling the riser from the tensioners.

j) The pressures in the air/oil bottles respond to the flow exiting or entering them.

k) The difference in pressure between the high-pressure air/oil accumulator and the APVs causes the air in the air line to accelerate towards the air/oil accumulator.

l) APV pressure drops.

m) The mud pressure wave reaches the top of the mud column. The top of the mud column starts flowing. Thus, the entire mud column eventually starts moving, but this does not occur until well after the riser starts to move.

These transient effects continue in various ways depending on the details of the particular scenario. Once the process described above gets under way, the following effects occur in parallel.

— The tension wave reflects up and down the riser but rapidly dissipates.

— The mud column experiences similar reflections but quickly accelerates towards terminal velocity, where the drag load between it and the riser is equal to the effective weight of the mud column. Later flow either slowly diminishes (with a fill valve) or the mud column “U-tubes” (without a fill valve).

— The tensioners either accelerate the riser or reduce tension sufficiently to let gravity decelerate the riser. This depends on the natural pressure drops in the system and the effectiveness of whatever recoil-control measures are built into the tensioner system.

Simple calculations cannot adequately characterize this complex dynamic process, particularly where elaborate control systems and high overpulls are involved. Reliable simulation requires analytical tools that have been developed (or adapted) specifically for this purpose and have been calibrated either to test data or other benchmarked software [Hock and Young (1992), Stahl and Hock (2000), Young, Hock, Karlsen and Miller (1992) and Young, Hock, Karlsen and Albert (1992)].

3) This water-hammer effect can produce a potential collapse condition in the riser even if the riser has a fill valve. This is documented by Miller *et al* (1998), which includes a simple calculation. The condition has a very short duration, so it is not known if this effect can actually collapse the riser.

7.3 Required information

7.3.1 Riser configuration

7.3.1.1 A riser-recoil analysis usually follows a connected-riser analysis and, in some cases, an analysis of the riser in the hung-off condition.[4] The connected-riser analysis, in accordance with API RP 16Q and possibly other procedures, determines the minimum tension requirements for riser stability, upper and lower flex-joint angles, stress, and (in some cases) a minimum overpull to overcome friction in the LMRP connector. Most of the information about the riser system that is required for a riser-recoil analysis will have already been obtained for the connected-riser analyses. In short, this information provides

a) the arrangement of riser joints by elevation (usually by type, i.e. "bare joints", "joints with 610 m (2 000 ft) rated buoyancy", "joints with 914 m (3 000 ft) rated buoyancy", etc.);

b) the structural dimensions of the part of the riser carrying the axial load, to define its axial stiffness, typically the OD and ID of the riser main tube and, if applicable, axial load sharing with the external lines;

c) the ID of external lines (choke, kill, boost, etc.) carrying mud or other relatively heavyweight fluids;

d) the dry weight of each type of joint, both as a complete joint and excluding the weight of buoyancy modules, i.e. known as "total dry weight per joint" and "dry weight per joint excluding buoyancy";

e) the submerged weight of the portion of the joint excluding buoyancy foam (roughly 87 % of the "bare joint dry weight" for steel submerged in seawater);

f) the net lift provided by the buoyancy foam per joint, which is a function of buoyancy foam volume and density);

g) the corresponding structural and weight definition of all other components supported by the tensioners (e.g. the tension ring, TJ outer barrel, intermediate flex joint, termination joint, fill valve, pup joints, etc.) in sufficient detail to determine the distribution of wet weight, dry weight, and stiffness along the length of the riser.

7.3.1.2 Riser-recoil analysis requires additional information, some of which might have been provided for a storm hang-off analysis. Because a typical emergency disconnect occurs in the connector between the LMRP and the BOP, it is necessary that the LMRP become part of the system that is simulated. The following information about the LMRP is required:

a) dry weight;

b) wet weight;

c) gross overall dimensions sufficient to estimate the axial drag on the LMRP and added mass of water entrapped in and/or carried alongside the LMRP;

d) the vertical distance required to lift the LMRP clear of the BOP stack ("swallow"). Although this information is not required for a connected analysis, it is required for a riser-recoil analysis.

4) Cordeiro *et al* (1996) and Puccio and Nuttall (1998) discuss the axial dynamic response experienced by drilling risers during storm hang-off. Historically, storm hang-off has received less attention than the connected condition, because most drilling activity was in relatively shallow water depths. However, storm hang-off analysis has become increasingly relevant now that most drilling activity has moved to deeper water.

7.3.1.3 There is a small amount of added mass and drag area distributed along the riser. Axial frontal drag occurs on the upward-facing surfaces of buoyancy modules and flanges. Added mass is due to the water trapped in cavities between modules and that displaced by frontal drag. There is also a small amount of skin friction on the cylindrical surfaces of the riser. Drag and added mass can be estimated from gross overall dimensions of the riser joints and buoyancy modules. Drawings showing the following dimensions normally suffice:

a) buoyancy foam OD;

b) axial separation (if any) between foam modules on the same joint;

c) cavities between each module and the rest of the riser;

d) gross dimension of flange connections;

e) portion of riser joint not covered by buoyancy modules.

7.3.1.4 Riser disconnect behaviour is sensitive to the riser's actual submerged weight. Unlike riser stability, which concentrates on the heaviest possible weight, it is necessary that riser-recoil analysis account for the extremes of both the heaviest and lightest wet weight. Larger-than-expected weight can cause the LMRP to lift sluggishly (or not at all) from the BOP stack. Smaller-than-expected weight can lead to a rapid lift that can cause the TJ to stroke closed rapidly, producing severe impact loads that are passed to the inner barrel, upper flex joint, diverter, rotary table and the rig floor substructure. Some recoil-control solutions are very sensitive to small changes in overpull. In those cases, this uncertainty can produce wide fluctuations in behaviour in the event of a riser disconnect.

The total submerged weight is equal to the riser's submerged weight excluding buoyancy modules less the lift provided by the buoyancy modules. The submerged weight is usually a small fraction of the other two quantities. Small percentage deviations in either the steel weight or the lift can produce large percentage changes in the resulting submerged weight.

EXAMPLE Suppose a riser's dry weight excluding buoyancy modules is believed to be 13 345 kN (3 000 000 lb_f) and the lift expected from buoyancy modules is 9 786 kN (2 200 000 lb_f). The expected submerged weight would be 1 824 kN (13 345 kN $\times$ 0,87 – 9 786 kN) [410 000 lb_f (3 000 000 $\times$ 0,87 – 2 200 000)]. A deviation of +2 % in the bare dry weight and –2 % on lift would produce a submerged weight of 2 252 kN (506 200 lb_f), an increase in wet weight of 23 %.

Thus, another piece of information required for a riser-recoil analysis is the accuracy of the weights and lifts provided for the riser analysis, or a reliable tolerance on the total wet weight.[5)] Lacking reliable submerged weights, this procedure adopts the recommendations of the existing API RP 16Q of ±5 % on steel weight and ±4 % on lift. One can see from the example above that these tolerances can produce a very large range of possible wet weights, particularly for risers that rely heavily on foam buoyancy. Ranges on steel weight and lift smaller than those mentioned above may be used, provided that the responsible parties are aware of that and the documentation of the recoil analysis clearly states the assumptions and the basis for them. Thus, effort to verify joint weights submerged under realistic pressures is warranted as it can drastically reduce the range of wet weights for which it is necessary to account. For systems that are sensitive to this, accurate weight and lift information can expand the operating envelope significantly by removing this source of great uncertainty.

Riser weights that have been obtained from the vessel's weight indicator are acceptable, provided that inaccuracies in the weight indicator have been accounted for. One method of doing this is to determine, by reliable means, the submerged weight of the BOP, LMRP and bare joints at the bottom of the riser and use that portion of the riser to calibrate the weight indicator. This should provide reliable weight indicator readings that can serve as the final check on the riser's wet weight. Weights measured on this basis can be used for analysis supporting subsequent deployments, provided that the same riser joints are used and the effectiveness of the buoyancy foam has not deteriorated significantly.

5) If the riser has been run previously, a log of hook load and deployed length as the riser is run can be helpful in determining the source of any discrepancies that can exist in the submerged weight.

7.3.2 Operating plan

A connected-riser analysis determines the minimum tension requirements based on riser stability, stress considerations, and the limits on the upper and lower flex-joint angles. Other constraints can require higher minimum tensions. One example is a minimum tension required to overcome any resistance to disconnection (friction, etc.) that exists in the LMRP connector. This can be a simple lower limit on actual tension in the connector or it can be a function of rotation and/or bending moment. In addition, there can be a limit on the lower flex-joint angle or bending moment at which the LMRP connector cannot be expected to release reliably.[6] These various conditions provide a minimum tension requirement as determined by the riser analysis. This minimum tension required to meet stability and flex-joint angle requirements (a function of mud weight and water depth) as well as the minimum tension required to release the LMRP connector is required to complete a riser-recoil analysis.

With that as input, the riser-recoil analysis as described herein can determine that even higher minimum tensions are necessary in order to assure that the LMRP lifts clear of the BOP stack without contacting it. Vessel heave can make the possibility of LMRP contact with the BOP the governing condition for minimum riser tension, especially when low mud weights reduce the tension required to meet other criteria (stability, etc.).

The operating plan may call for higher tensions under certain conditions. For example, high currents can require higher tensions to maintain appropriate flex-joint angles. There can be other operating requirements or preferences that also call for tensions in excess of the minimum tension in accordance with API RP 16Q. API RP 16Q defines a “dynamic tension limit”, DTL, and limits the tension setting to 90 % of DTL. Combined, these requirements define an upper limit that normally is a function of water depth and mud weight. If tensions higher than the minimum described above are anticipated, it is also necessary to define the maximum tension (as a function of water depth, mud weight and tensioner limits).

Another important influence on riser disconnect behaviour is the TJ stroke at the moment the LMRP disconnects from the BOP. This is determined by the stroke prior to the occurrence of any offset and the increase in stroke caused by the offset. The following information is required:

a) desired TJ stroke when the riser is spaced out (may be a maximum, minimum or mean value as long as it is made clear which of these is defined);

b) the smallest increment of spaceout that can be achieved with the available pup joints;

c) operating vessel draft and maximum variations in draft (shallower and deeper) while connected to the wellhead;

d) the range of variation in tide due to astronomical effects and storm surge;

e) the riser configuration and tensions (both of which are called for above);

f) the change in stroke due to vessel offset (a function of water depth, mud weight and top tension that is determined from a drive-off/drift-off analysis).

The worked example contains a calculation that shows how maximum and minimum TJ strokes can be calculated for spaceout purposes. It also illustrates how these are modified for a riser-recoil analysis. In many places, the calculation assumes example values for heave, offset, spaceout, spaceout tolerance, tide, stretch and draft. For an actual drilling riser deployment, it is necessary to use values that are appropriate for the specific vessel, riser and location.

6) The influence of an angle or moment limitation on the recoil analysis would be increased tension requirements or tighter watch circles. These would normally be determined by connected and/or drive-off/drift-off analyses. Although they could theoretically be accounted for in the recoil analysis, modeling the LMRP connector and riser in that level of detail would add unnecessary complexity to most recoil analyses.

7.3.3 Tensioners and plumbing

In 7.2 is discussed the variety of configurations that an analyst can encounter when performing a riser-recoil analysis. It is necessary that the analyst have detailed information about the tensioners, the arrangement of wire ropes and sheaves about the moonpool and the plumbing that interfaces with the tensioners. This requires a schematic showing the general layout of the tensioners and plumbing similar to Figures 22 to 25, as well as plan and elevation views of the moonpool area showing the arrangement of the tensioners and wire ropes.

An appropriate schematic defines the various components in the system and their relationship to one another. A detailed list of specifications varies from one installation to another but it is necessary that the details be sufficient to characterize the following information:

a) air or nitrogen volume as a function of stroke (on both sides, if applicable) sufficient to define the stiffness of the system;

b) weight of the moving (i.e. suspended) portion of the tensioner, including piston, rod and, if applicable, the rod end sheave and wire rope;

c) stroke ratio between the TJ and the tensioners;

d) seal friction, which may have a constant component and a component that is proportional to cylinder pressure;

e) friction losses in the sheaves, if applicable, which is usually a linear function of tension known as “sheave efficiency”;

f) cylinder dimensions, i.e. bore, rod diameter and stroke;

g) fluid cushion detail, if applicable;

h) tensioner stroke at some reference TJ stroke without load;

i) arrangement of idler sheaves or other applicable dimensions to determine “fleet angle”, i.e. the relationship between line tension and vertical tension, as a function of TJ stroke;

j) number of tensioners in the system that are active in any particular set of circumstances;

k) wire-rope specification sufficient to determine its axial stiffness and weight.

The tensioners apply tension to the TJ outer barrel at the tension ring. Thus, the weight of the tension ring and outer barrel should be accounted for in both the connected-riser analysis and in the recoil analysis. In addition, the recoil analysis requires the distance from the riser centreline to the attachment points as part of the fleet angle calculation mentioned above. In some installations, specifically with direct-acting tensioners, the tension ring may have a shouldered connection that, under extreme conditions, allows the riser to lift out of the tension ring rather than loading the rods in compression. It is necessary that this detail be modeled unless the recoil analysis can demonstrate that the riser will remain in tension at all times.

As the tensioners are plumbed to air pressure vessels and one or more air/oil accumulators, the recoil analysis requires sufficient detail to characterize the air volume and hydraulic losses in the plumbing, including

— APV volume and number of APVs per tensioner, or tensioner pair if plumbed in pairs;

— accumulator volumes as appropriate;

— details of the air line piping from the APVs to accumulators or tensioners (i.e. lengths, inner diameters, elbows, fittings, orifices, etc.); and

— details of fluid piping on the rod and blind sides as appropriate (lengths, inner diameters, elbows, orifices, etc.).

7.3.4 Recoil-control system

Many, but not all, systems include a “speed-limiting valve” on each tensioner intended to protect the tensioner in the event of a wire-rope break. Typically, this is a passive device that is held open by a spring. When the tensioner reaches a critical velocity, this produces a sufficient pressure drop across the valve spool to overcome the spring force. Once this occurs, the flow area through the valve is either reduced or closed completely.

Normally, the speed-limiting valve acts only in the direction that the tensioner would move in the event of a wire-rope or rod break. For a typical wire-rope tensioner, a wire line break causes the tensioner to extend. For a direct-acting tensioner, as currently used, a rod break causes the tensioner to retract.

Although speed-limiting valves are not usually intended for recoil control, disconnects under conditions of high tension and/or severe heave trigger them in some systems. This influences the riser disconnect performance. In many cases, this increases the likelihood of slack in the wire ropes and/or interferes with the tensioners' ability to lift the LMRP clear of the BOP stack. For analysis of tensioners with speed-limiting valves, it is necessary to provide the critical flow velocity along with an indication of pressure drop versus flow rate with the valve open and an indication of where the speed-limiting valve is in the system. Unless the recoil analysis can show that the speed-limiting valves will remain open, the recoil analysis also requires an indication of pressure drop versus flow rate with the valve closed and the flow rate at which the valve will reopen.

If there is a recoil-control system on the vessel, a detailed description of its operating principles is required. These systems vary widely from one manufacturer to another. In most systems, recoil control includes a restriction in a fluid line, from either the blind or rod side. This can take many forms. The following examples describe fluid restrictions on many existing recoil-control systems:

a) two-position spool valves that are normally open but close at some point in the disconnect sequence (i.e. shortly before disconnect);

b) ball valves (normally open) that, when closed, force flow through a smaller bypass line;

c) proportional valves that can provide a variable amount of restriction as circumstances require.

Regardless of the type of valve, it is necessary to define its flow characteristics (i.e. pressure drop as a function of flow rate and valve position).

Some systems also isolate some of the APVs during the disconnect sequence to reduce the energy imparted to the riser. Normally, these valves close rapidly and completely. Under these circumstances, all that is required is the location of each valve to determine how much gas volume is trapped behind it when it closes.

These valves are triggered by a control algorithm. A simple valve may be closed as part of the disconnect sequence (timed) or activated by some other event such as the TJ or tensioners reaching a specified stroke. More complex systems also exist. These systems may rely on stroke and accelerometer measurements to modulate the control valves. Regardless, it is necessary that the analysis account for the control algorithm for it to be valid. Accounting properly for the plumbing, control valves and control algorithm (including realistic delays and response rates) can be a significant portion of the entire analysis effort. It is necessary that this be completed before the first valid simulation can be carried out.

7.3.5 Vessel motion

For riser-recoil analyses, the vertical component of vessel motion is the most important. This requires a heave RAO, translated to the upper flex joint if the upper flex joint is not coincident with the centre of pitch and roll.[7] The analyst should decide on a case-by-case basis, but in most cases, other components of vessel motion (i.e. roll, pitch, surge, sway and yaw) may be neglected.

7) The combination of the upper flex joint and the TJ allows the riser to move relative to the vessel. Thus, it is the vessel motion at the upper flex joint that is relevant to riser-recoil analysis.

The heading for which the vessel heave is determined is a function of the type of vessel involved and the circumstances that can cause an emergency disconnect. For example, a dynamically positioned drillship can operate within 30° of a head sea in a severe storm. However, a loss of power causes the vessel to offset and turn slowly so that the seas eventually strike the vessel on the beam. Disconnect can occur before the vessel turns completely. A beam sea produces much more heave than a head sea for a drillship. For a semi-submersible, the heave response is influenced less by heading. It is necessary that documentation of the recoil analysis state the heading assumed and the basis for it.

It is acceptable to apply heave as a simple harmonic function (i.e. regular wave). An irregular heave function determined from a spectral analysis is also acceptable but is usually unnecessary. Using a heave RAO (determined for the heading discussed above and translated to the upper flex joint), a wave spectrum, a significant wave height and a peak period, the analyst can calculate extreme vertical displacements for a particular exceedence threshold. All but the exceedence criterion are required for the connected-riser analysis.

The heave period is also important because a shorter period produces higher velocity and acceleration for the same heave displacement. In many cases, it is possible to find a single heave and period that produce a close match to the maximum displacement, velocity and acceleration. This is not universally true, so it is necessary that it be evaluated on a case-by-case basis. The worked example is a case where a single heave and period characterize extreme vessel motion satisfactorily.

API RP 16Q refers to a “drilling mode”, a “connected non-drilling mode” and a “disconnected mode”. Only the first two modes are relevant to riser-recoil analysis, because a disconnect can be required in either mode. These two modes normally have different tension requirements as a function of mud weight, caused by the different allowable flex-joint angles. In addition, there is usually a more severe environment associated with the connected non-drilling mode, introducing the possibility of more heave. The operating plan may call for circulating the mud from the riser in the connected non-drilling mode, thereby reducing the tension requirements. Operating policies and other details can cause other differences between “drilling” and “connected non-drilling” that influence the riser-recoil analysis as well.

The recoil analysis should account for these two modes as well as any other extreme operating conditions, such as high currents, that produce other combinations of tension requirement, heave and TJ stroke while the riser is connected. In many cases, it can be appropriate to define a “maximum operating condition” and a “maximum connected condition” for the recoil analysis, to reduce the number of recoil simulations and simplify the resulting recommendations. The maximum operating condition is the most severe environment in which the riser may contain drilling fluid. The maximum connected condition is a more severe environmental condition in which the riser is still connected but all drilling fluid has been circulated from the riser. The worked example is created on that basis. It can also be appropriate to define other conditions. One example is a “maximum current condition”, which may have a less severe sea state than the maximum connected condition but higher tension requirements while the riser is connected.

The exceedence criterion on heave is a matter of judgment and it is necessary that it be discussed by the affected parties. A lower bound on the acceptable range of exceedence threshold is the significant heave (i.e. the average of the 1/3 largest heaves). A higher limit of the most probable maximum in 1 000 heaves is used for many types of riser analysis. The value of 1 000 heaves corresponds to a storm approximately 3 h long. Since a disconnect transient usually lasts 30 s or less, one can see that the most probable maximum in 1 000 heaves is a very severe criterion for riser-recoil analysis. In order to experience this heave, it is necessary that the following two uncommon events coincide with an emergency disconnect:

a) a severe storm, typically a 1 year to 50 year event;

b) the most severe heave likely to occur in 3 h.

A more severe exceedence criterion than this is not realistic regardless of the duration of the storm, because it would be necessary for such a large heave to coincide with the disconnect. Both the sea state and the occurrence of an emergency disconnect are rare events. Adding the simultaneous occurrence of the most probable maximum in 1 000 heaves is very conservative.

Using the most probable maximum in 1 000 heaves as the exceedence criterion may place intolerable restrictions on the drilling operation. In that event, it can be appropriate to relax the exceedence criterion. Regardless, the analysis report should clearly state how heave is accounted for and include the following for all scenarios, such as maximum operating condition and maximum connected condition mentioned earlier in this section:

a) significant wave height;

b) peak period;

c) wave spectrum (ISSC, JONSWAP, Bretschneider, etc.);

d) heading;

e) exceedence threshold;

f) resulting heave amplitude and period calculated from these criteria.

By stating this information, the analyst permits the other responsible parties to make informed decisions about risk assessment.

7.3.6 Disconnect scenarios including a drive-off/drift-off analysis

7.3.6.1 The operational plan defines the maximum and minimum for the following:

a) mud weights;

b) tensions for each mud weight;

c) TJ stroke (accounting for draft, spaceout, stretch, offset and tide).

7.3.6.2 Heave should be accounted for in the simulations, so heave should not be included in the maximum and minimum stroke except in determining the appropriate spaceout. In 7.3.2 are mentioned TJ spaceout criteria and the worked example includes a sample calculation. A drive-off/drift-off analysis is required to determine the amount of stroke increase that occurs in the event of a drive-off or drift-off. Although this is outside the scope of the recoil analysis, a drive-off/drift-off analysis is the best way to determine how much the TJ stroke can increase during a typical emergency disconnect scenario. A complete drive-off/drift-off analysis can provide the following:

— minimum and maximum TJ stroke at disconnect;

— increase in tension that occurs due to gas compression and flow restriction in the tensioner system.

7.3.6.3 The degree and way in which these factors influence the recoil analysis can vary from one vessel to the next due to the details of how the tensioners and recoil-control system function. The following generalizations apply to all recoil analyses.

— The minimum stroke at disconnect determines the minimum distance over which it is necessary that the tensioner system be able to control recoil and bring the riser to rest. The minimum stroke occurs at a small (or zero) offset condition, if realistic operating scenarios include that possibility[8]. In many cases, this minimum stroke scenario is the most difficult for the control system to handle effectively.

8) One such scenario is a power failure or some other malfunction that can bring about an immediate disconnect. Because there can be little or no offset associated with this event, it is necessary that the system be able to bring the riser under control in a short distance. Another scenario is a malfunction in the positioning system (either drive-off or drift-off) that requires an EDS to be initiated, followed by the restoration of proper stationkeeping ability, which brings the vessel back over the well prior to disconnect.

— The maximum stroke-out condition influences the recoil analysis in two ways. First, some recoil-control scenarios rely at least in part on a stroke measurement to determine the system's response to recoil. In that case, the maximum stroke can allow the riser to build up considerable velocity before the control system responds. Second, because the stroke in the TJ has increased significantly from the operating TJ stroke, riser tension at disconnect is higher than the tension at the operating condition. Furthermore, vessels with recoil-control systems that rely on isolating some or all air volume prior to disconnect experience a greater increase in tension due to this than those systems that do not. The reduced volume (due to APV isolation) makes the tensioner system much stiffer, so each increment of stroke increase produces a larger increase in tension than would occur without APV isolation.

7.3.6.4 If information from a drive-off/drift-off analysis is not available, an alternative method may be used to determine the maximum stroke condition. This method assumes that the watch circles are set so that disconnect occurs just in time to avoid bottoming the tensioners or TJ. The maximum TJ stroke by this method is the stroke limit based on bottoming either the tensioners or the TJ (whichever would happen first) and subtracting the heave amplitude (i.e. half the total heave assumed in accordance with 7.3.5). Since heave is accounted for in the simulations, the simulations show the system nearly reaching the stroke limit at the crest of each heave prior to disconnect.

Whether the maximum stroke is determined from a drive-off/drift-off analysis or the alternative method mentioned above, the simulations should account for the increase in tension caused by the change in stroke from the operating condition. As described above, this occurs due to the increase in pressure caused by compressing the gas in the APVs as the TJ stroke increases.

7.3.7 Impact tolerance (if applicable)

In the event that the TJ strokes completely closed (i.e. no exposed inner barrel), there is an impact load transferred through the TJ to the diverter and everything else in the load path. The resulting impact load can easily exceed 4 448 kN (1×10^6 lb_f). Without adequate structure, this can exceed the structural limits of components in the load path (i.e. diverter, upper flex joint, etc).

If impact loads are anticipated, it is necessary that the structural limits of the components in the load path be defined in sufficient detail to allow a meaningful assessment of the predicted impact loads. The analysis also requires enough data to define the structure's axial stiffness with reasonable accuracy. Impact-load prediction is only somewhat sensitive to this, because most of the deflection after impact occurs in the riser. If the structural stiffness is not available, a sensitivity study is appropriate and can show that a reasonable approximation of the structural stiffness is sufficient.

7.3.8 Minimum lift from BOP stack

Once the LMRP connector releases, it is possible that the LMRP will lift slightly, then fall back on top of the BOP. This is most likely a problem for cases with low initial tension and substantial heave. In some cases, the drag load produced by drilling mud flowing downward can also cause this to occur. There can be a minimum distance that it is necessary for the LMRP connector to lift in order to clear any guide funnels, posts or other parts of the BOP stack. It is necessary that this be specified.

7.4 Performance criteria

7.4.1 Impact

7.4.1.1 Impacts (indicated by zero TJ stroke) can be quite severe if they occur due to a lack of effective recoil control. In that event, the resulting impact load is highly sensitive to vessel motion at the moment of impact. Many factors influence the impact load, including suspended weight, mass, tension, mud weight, stroke, vessel motion, hydraulic losses and air volume in the tensioner system.

On some vessels, the tensioners can lift the riser enough to stroke the TJ completely closed. This arrangement produces an impact after a high-tension disconnect. Under certain conditions, these impact loads can be quantified with reasonable accuracy. The following conditions control the relative velocity between the riser and the vessel by reducing the sensitivity to small changes in operating conditions, such as vessel motion, stroke at disconnect, tension setting, weight, etc.

— The tensioner system or the recoil-control system introduces and maintains a well defined, consistent restriction in the piping-carrying tensioner fluid (not air).

— The riser stays in tension so that the tensioners maintain control of the riser as the TJ strokes closed. Slack temporarily decouples the motion of the riser from the vessel so that small changes in assumptions about vessel motion, tension, stroke, etc., can bring about large changes in impact-load.

7.4.1.2 If impact-load prediction is desired, it is necessary for the analyst to determine whether an accurate prediction is possible. Some examples of circumstances that prohibit accurate impact-load prediction by making the results highly sensitive to operating conditions and assumptions are

— impacts that occur due to slack in wire rope or the riser lifting off of the tension ring;

— insufficient restriction in the tensioner-fluid piping, which makes the solution highly sensitive to vessel motion;

— uncertainty in tensioner-fluid restriction due to active control-valve modulation.

If relative velocity can be predicted with reasonable accuracy, impact-load prediction is possible. This requires simulations with the riser divided into increasing numbers of elements to demonstrate that a sufficient number of elements was used in the final load prediction. The analyst can expect that several hundred riser elements are required to produce an accurate result.

Simulations with a sufficient number of elements and sufficiently small time increments produce a smooth trace of reaction load versus time. A typical simulation of this sort shows a compressive impact load lasting 1 s to 2 s before the load changes to tension (in the case of a locking TJ) or the TJ strokes out and the reaction load disappears. An impact-load analysis requires that the weakest member be identified along with its load capacity. This can be based on yield or ultimate strength and might or might not include a safety factor. It is necessary that the resulting load capacities and the basis for them be reported in sufficient detail (i.e. calculations, yield versus ultimate strengths, design factors, etc.) to allow the affected parties to make informed decisions about the risk of impact loading.

It can be possible to take credit for the short duration of the load. In that event, the analyst should show data for yield or ultimate strength (as appropriate) for high-strain-rate loading (where strain rate is expressed in terms of strain/time, such as in/in-s). For typical materials and impact loading rates characteristic of this type of problem, the benefit is likely to be modest, probably less than 10 %. It is necessary that any benefit taken for high-strain-rate loading be documented along with the information regarding load capacities.

Although the duration of loading is short, it can be necessary to consider buckling in some instances. Here again, it is necessary that the analyst determine whether such analysis is required. Some components, such as flex joints, might not be designed for compressive loading. It can be that compressive loads well below the ultimate capacity of the component produce other consequences, such as the destruction of the flex element in the upper flex joint. These should be identified and documented.

7.4.1.3 If the TJ has a latch mechanism that prevents the TJ from stroking out once it strokes closed, the structure experiences tensile loads shortly after impact that should be analysed and documented by a similar approach. Without a latch mechanism, there exists the possibility of secondary impacts. It is necessary that the analysis demonstrate that secondary impacts are either

— less severe than primary impact; or

— predictable and within allowable structural limits.

7.4.1.4 While some vessels have their tensioners and TJ spaced out so that the tensioners can lift the riser completely, as described in 7.4.1.1, other vessels leave a substantial amount of “dead stroke”, typically 1,2 m to 2,4 m (4 ft to 8 ft) in the TJ when the tensioners reach their maximum upward position. This provides substantial protection against impact, even if the recoil-control system is offline or ineffective.

With dead stroke, impacts are possible only if the riser lifts so fast (relative to the vessel) that it overcomes all of the dead stroke in the TJ without any lift being provided by the tensioners. This requires an adverse combination of high riser velocity, low riser submerged weight and vessel motion. Impact-load predictions in such cases are highly sensitive to assumptions, such as initial tension, stroke, hydraulic losses and especially vessel motion. With dead stroke, these sensitivities eliminate the practical benefit of impact-load prediction.

Instead, the riser-recoil analysis should identify conditions where the riser can outrun the tensioners. The responsible parties might or might not consider the possibility of such occurrences acceptable, because they produce substantial rope slack, as discussed in 7.4.3. Even if slack is tolerated, the criteria should always provide a substantial safety margin based on remaining TJ stroke, even under the most extreme circumstances. At least 50 % of the “dead stroke” is recommended, since small changes in operating conditions can bring about severe impact[9]. Furthermore, documentation of the riser-recoil analysis should clearly indicate any reasonable scenarios under which this type of event can occur.

7.4.2 Clearance from the BOP stack

In 7.3.8 is described the need for lifting clear of the BOP stack. There may be a fixed distance that it is necessary for the LMRP to lift before it can move laterally away from the BOP. Additional margin should be provided to allow for vessel heave and/or uncertainties in the analysis assumptions. It is necessary that this clearance margin be added to any fixed requirement. These margins may be set to accommodate specific circumstances. Regardless, the analysis documentation should clearly state both the clearance margin and the fixed clearance requirement.

In the event that this criterion cannot be met, the analysis may take credit for the lateral displacement that occurs due to offset, provided that the riser is run without guidelines or other equipment that restricts lateral displacement. Drill pipe in the riser can also prevent lateral displacement, even after it has been sheared by the BOP rams. It is necessary to bear in mind the fact that the riser is submerged, which limits the speed at which the riser can move laterally. This is true even in the presence of substantial top currents. A time-domain, lateral analysis is recommended to demonstrate that the LMRP does not contact the BOP in such instances. It is necessary that this account for the overall dimensions of the BOP and LMRP so that a clearance envelope can be defined. Because most riser-recoil analysis does not consider lateral displacement, it is acceptable to use a separate model to predict the LMRP/BOP interaction, provided that the top boundary condition models the TJ stroke as a function of time with reasonable accuracy. It is necessary that the work consider a range of conditions (drift speed and direction, current profiles, etc.) as well as lateral drag and added mass. It is necessary that the analysis account for all appropriate conditions and document the work in sufficient detail to allow meaningful review by the responsible parties.

7.4.3 Rope slack, jumpout and compression

High-tension disconnects can cause the riser to outrun the tensioners, especially if the recoil-control system puts a restriction in the fluid piping before or immediately after disconnect. Risers that have a low ratio of submerged weight to dry weight (especially those less than 10 %) are particularly susceptible to this. Disconnect during large heave also makes this more likely.

9) For example, if there is 1,22 m (4 ft) of dead stroke but some extreme condition avoids impact by only a few inches, small changes in assumptions about heave, tension, weight or valve response can produce intolerably large impacts. Clearly, this sort of “near miss” is unacceptable and a displacement criterion is more appropriate.

In a wire-rope system, the consequence is a period of slack in the wire ropes. This can lead to any or all of the following.

a) A short but severe spike in riser tension, wire-rope tension and/or cylinder pressure can occur as the tensioners reload. For conventional wire-rope systems, it is possible for this high tension to be carried by a small number of tensioners, thus increasing the risk of parting some of the ropes or experiencing excessive cylinder pressure.

b) Upon reloading, unequal load sharing can impart a very large bending moment on the outer barrel of the TJ.

c) It can be possible for a slack line to jump off of a sheave, thus damaging the wire rope and compromising the ability of the tensioner to function properly.

d) A slack wire rope can “hockle”, “birdcage” or jam in a sheave guard.

In general, it is desirable to avoid slack loading. However, it is not the intent of this part of ISO 13624 to state that a small amount of rope slack is intolerable in all cases. Some systems have features that reduce their vulnerability to these phenomena. It is necessary to evaluate the significance of slack loading on a case-by-case basis, with due consideration to the issues mentioned above.

For example, the system shown in Figure 23 cannot produce a rapid build-up in pressure because air, rather than fluid, is on the high-pressure side. This makes the tensioner inherently soft in this mode of reloading. Hence, overloading one tensioner or the riser after the lines go slack is difficult, if not impossible, with that type of tensioner.

Tensioners such as those shown in Figure 25 may have a check valve that allows flow to bypass the recoil-control orifice, thus reducing the build-up of pressure in the tensioner cylinders.

Most tensioners have guards that prevent the rope from jumping off of a sheave. Thus, with adequate protection, slack cannot force the wire rope off. On the other hand, slack can conceivably cause a wire rope to jam in its sheave guard. Few, if any, existing vessels have sheave guards on the turn-down sheaves (where the wire rope turns nearly vertical to approach the tension ring). Thus, slack can cause the wire rope to jump off of the turn-down sheave, in many cases.

A rope’s tendency to “hockle” or “birdcage” is a characteristic of the wire-rope construction. If significant slack loading is anticipated, the manufacturer of the wire rope should be consulted.

Existing installations with direct-acting tensioners use a tension ring that can pass only tension to the riser. To avoid compressive loading, this arrangement allows the riser to lift out of the tension ring. This “jumpout” is analogous to wire-rope slack for the purposes of riser-recoil analysis. In a severe case, where jumpout lifts the riser clear of the tension ring, it is difficult to predict the consequences of reloading. It is reasonable to expect some misalignment to develop between the tension ring and the TJ outer barrel, so there can be damage to one or both components when they reestablish contact. This is difficult, if not impossible, to model mathematically. From a practical viewpoint, it is more appropriate to avoid jumpout altogether or limit the displacement to just a few centimetres (inches) under the most extreme circumstances, for example by setting operating limits or making adjustments to the recoil-control system.

Direct-acting tensioners that support a tension ring rigidly (as opposed to the tension-only configuration described above) can, theoretically, be loaded in compression. Direct-acting tensioners in existing installations are not intended to support compressive loading. Unless analysis shows that compression is tolerable, it is necessary that it be avoided under all conditions after which the tensioners are expected to remain functional. This can require consultation with the tensioner manufacturer.

7.4.4 Sensitivity to phase angle

Because emergency disconnects occur under adverse circumstances and the disconnect sequence requires a significant amount of time to complete, the operator has no control over the vessel's position, i.e. "phase angle", in the heave cycle when the LMRP connector separates. It is necessary that the riser-recoil analysis account for the influence of phase angle by running multiple simulations of the same load case, changing only the phase angle at which disconnect occurs. At least eight points spaced equally in the heave cycle, i.e. every 45°, are recommended for most recoil analyses. The system's behaviour is normally too complex to allow the analyst to predict in advance the worst-case phase angle. In fact, it is common for the worst phase angle for one criterion, such as slack, to be different from the worst phase angle for another criterion, such as LMRP clearance. Also, the worst-case phase angles can vary from one operating condition to another. Specific circumstances can allow the simulation of fewer phase angles. It is the analyst's responsibility to determine this.

7.4.5 Other criteria

Tensioner systems, riser-recoil-control systems and other equipment vary significantly from one vessel to another. For specific analyses, there can be other criteria that it is necessary to consider, due to unusual characteristics of the vessel and/or the recoil-control system. It is necessary that the responsible parties determine if other criteria apply and, if necessary, modify the criteria presented here to accommodate them[10].

7.5 Worked example applicability

7.5.1 General

The worked example in 7.5 makes assumptions (documented in 7.5.2 through 7.5.6) for purposes of illustration. Although these assumptions are realistic, it is necessary that they not be construed as being applicable to any particular vessel or drilling location. This example merely poses a realistic set of conditions for a hypothetical vessel and drilling operation and applies riser-recoil analysis to those conditions, thereby illustrating the method and addressing the concerns described in 7.1 through 7.4.

7.5.2 Vessel motion

This example presumes that the riser is deployed from a large dynamically positioned drillship, designed for work in 3 048 m (10 000 ft) water depths. Emergency disconnect occurs if the vessel loses its ability to control its heading and/or offset. It is presumed that the vessel can rotate up to 60° from a head sea before the LMRP connector releases the riser from the BOP stack. Table 26 shows the vessel's heave RAO for this condition.

10) For example, the relationship between the tensioner and the TJ stroke can permit the TJ to reach zero stroke with the tensioners still pulling. Any tension greater than the tension required to support the riser and LMRP produces compressive loading in the TJ and upper flex joint, even without considering any dynamic effects. There can be a limit on the amount of compressive loading that the flex joint can endure without damage to the flex element. This can form the basis for a limit on tension or guidelines for stroke and/or APV isolation. This is just one example and there can be other issues that arise from equipment details or operating procedures that call for criteria in addition to those mentioned in 7.4.

Table 26 — Drillship heave RAO for 60° heading

Period	Freq.	RAO
s	rad/s	ampl/ampl
125,66	0,050	1,000
62,83	0,100	1,000
41,89	0,150	1,000
31,42	0,200	0,990
25,13	0,250	0,970
20,94	0,300	0,950
17,95	0,350	0,920
15,71	0,400	0,870
13,96	0,450	0,800
12,57	0,500	0,680
11,42	0,550	0,540
10,47	0,600	0,340
9,67	0,650	0,090
9,31	0,700	0,070
8,98	0,750	0,075
8,50	0,800	0,140
8,15	0,850	0,150
7,80	0,900	0,130
7,39	0,950	0,070
6,98	1,000	0,040
6,61	1,050	0,020
6,28	1,100	0,020
5,98	1,150	0,010
5,71	1,200	0,010
5,46	1,250	0,000
5,24	1,200	0,000
5,03	1,250	0,000

Sea states are presumed to correspond to the ISSC wave spectrum and Table 27. The “maximum operating condition” is the most severe sea state in which the vessel is expected to operate with the riser connected and mud in the riser. It is presumed that if environmental conditions worsen, the well will be secured and the mud will be circulated out of the riser, thereby reducing the top tension requirement. The “maximum connected condition” is the most severe sea state in which the riser may remain connected without mud in the riser.

Table 27 — Presumed environmental conditions

Condition	Significant wave height m (ft)	Peak period s
Maximum connected	7,32 (24,0)	11,0
Maximum operating	6,09 (20,0)	10,0
Mild	4,57 (15,0)	9,3

There can also be circumstances or environmental conditions that can be “severe operating conditions” but the parameters associated with recoil are less stringent than for the maximum operating condition. These conditions may be defined as appropriate. For example, Tables 27 and 28 and 7.5.7 discuss a “mild” operating condition that allows the use of lower riser tensions under normal circumstances.

It is desired to have the recoil analysis account for heave amplitude, velocity and acceleration using the most probable maximum for each value in 50 heaves. Past experience has shown that analysis using a single amplitude and period (as opposed to an irregular heave assumption) is sufficient for this analysis. Calculations using standard methods show that the heave ranges and periods in Table 28 approximate the most probable maximum (in 50) heave displacement, velocity and acceleration for each sea state.

Table 28 — Characteristic heaves and periods

Condition	Significant heave m (ft)	Peak period s
Maximum connected	3,96 (13,0)	12,1
Maximum operating	2,5 (8,2)	11,4
Mild	1,1 (3,6)	10,2

7.5.3 Riser configuration

The riser is configured for 3 048 m (10 000 ft). Table 29 shows the riser configuration[11]. In this example, the total submerged weight of the riser and the LMRP is considered accurate to within ± 178 kN (± 40 kips). Because the vessel has sufficient tensioner capacity, the riser has been configured with a relatively large number of bare joints at the bottom.

This enables the riser to tolerate being hung off from a hard point after disconnecting in a harsh environment, thereby avoiding compression (induced by axial dynamics) and other problems associated with hang-off. In 7.5.9, it is shown that this heavy riser configuration also benefits riser-recoil performance by comparing recoil using this riser to a riser configured with more buoyancy.

11) Observe that this riser configuration is the same as the riser configuration for the portions of this document on weak-point analysis and drive-off/drift-off analysis. It was selected for the riser-recoil worked example for consistency.

