

Petroleum and natural gas industries — Drilling and production equipment

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

ICS 75.180.10

National foreword

This Published Document is the UK implementation of CEN ISO/TR 13624-2:2013. It is identical to ISO/TR 13624-2:2009. It supersedes PD ISO/TR 13624-2:2009.

The UK participation in its preparation was entrusted to Technical Committee PSE/17, Materials and equipment for petroleum, petrochemical and natural gas industries.

A list of organizations represented on this committee can be obtained on request to its secretary.

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This Published Document was published under the authority of the Standards Policy and Strategy Committee on 31 January 2010

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Published by BSI Standards Limited 2013

ISBN 978 0 580 82649 8

Amendments/corrigenda issued since publication

Date	Comments
30 November 2013	This corrigendum renumbers PD ISO/TR 13624-2:2009 as PD CEN ISO/TR 13624-2:2013.

English Version

Petroleum and natural gas industries - Drilling and production equipment - Part 2: Deepwater drilling riser methodologies, operations, and integrity technical report (ISO/TR 13624-2:2009)

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 (ISO/TR 13624-2:2009)

Erdöl- und Erdgasindustrie - Bohr- und Förderanlagen - Teil 2: Riser für die Tiefsee, Methodik, Betrieb und technische Dokumentation (ISO/TR 13624-2:2009)

This Technical Report was approved by CEN on 24 September 2013. It has been drawn up by the Technical Committee CEN/TC 12.

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Foreword

The text of ISO/TR 13624-2:2009 has been prepared by Technical Committee ISO/TC 67 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” of the International Organization for Standardization (ISO) and has been taken over as CEN ISO/TR 13624-2:2013 by Technical Committee CEN/TC 12 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” the secretariat of which is held by AFNOR.

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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

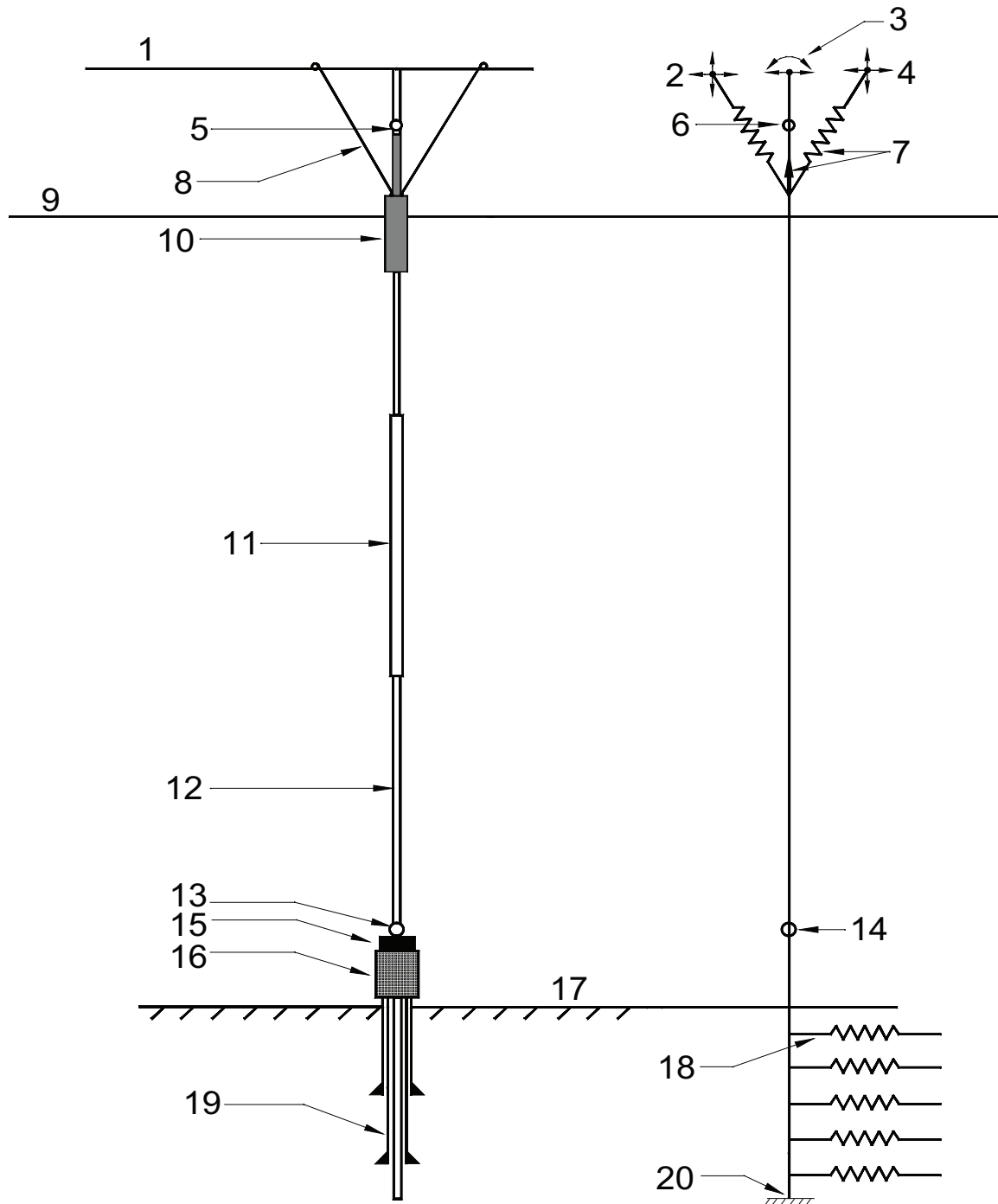
5 Coupled drilling riser/conductor analysis methodology and worked example

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

Figure 1 — Drilling riser system configuration and coupled analysis model

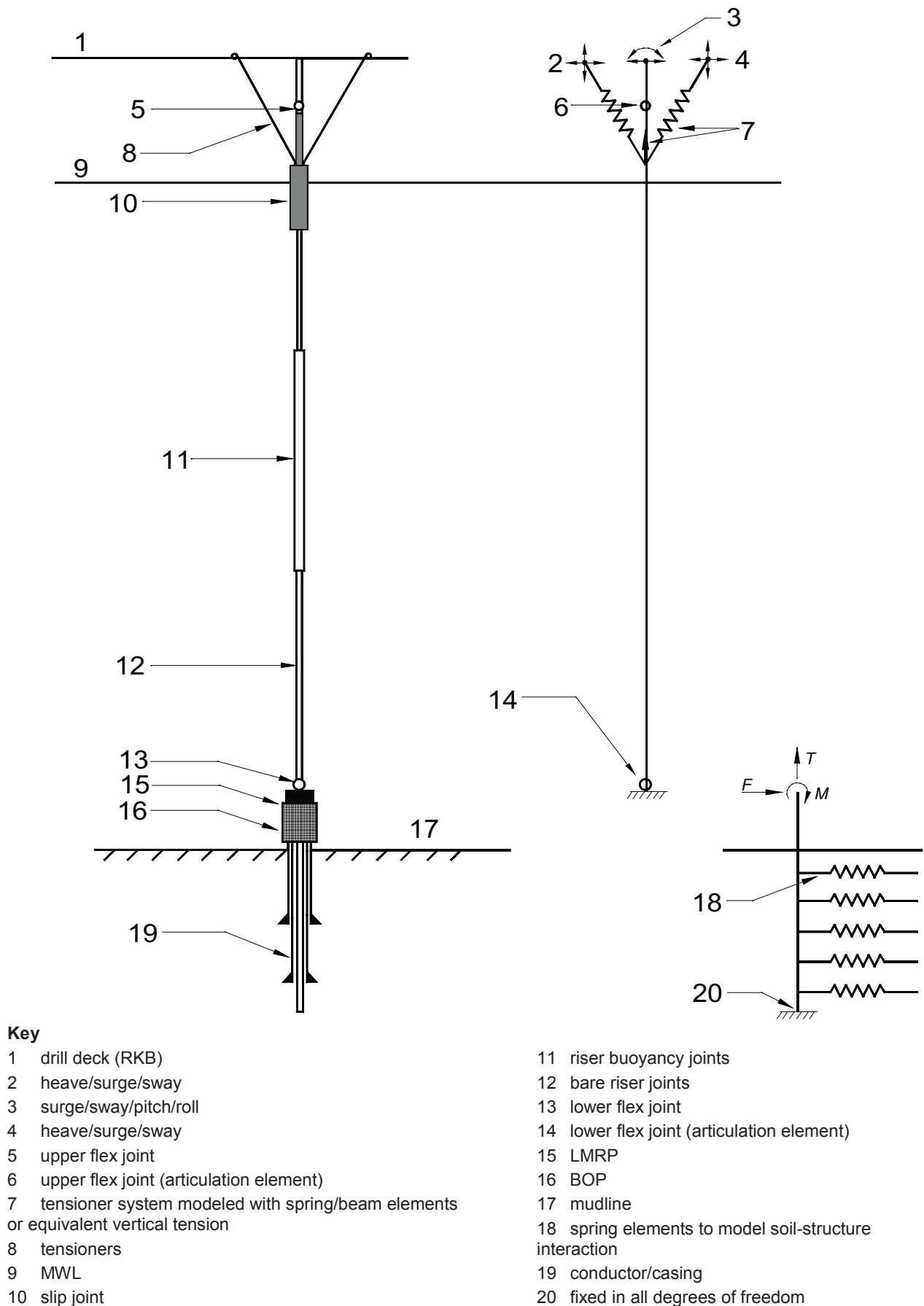


Figure 2 — Drilling riser system configuration and decoupled analysis models

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

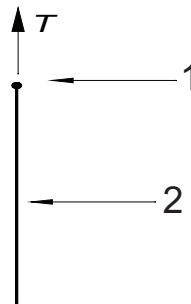
If the tensioner system is modeled explicitly, the heave, surge and sway RAOs should be applied at the top of the tensioner elements and the surge, sway, pitch and roll RAOs applied at the top of the riser, as illustrated in Figure 1.

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.

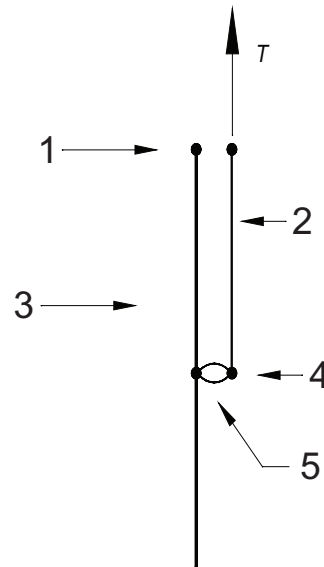


Key

- 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.



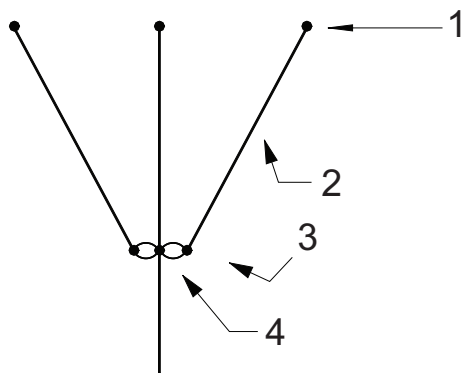
Key

- 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

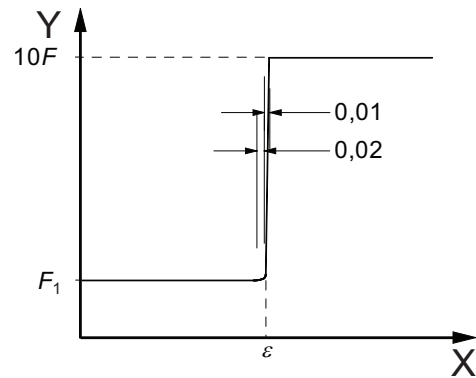
Figure 4 — Simplified tensioner model 2

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

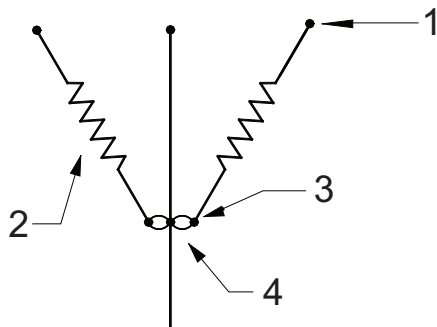
X strain, ϵ

Y force, F (lb)

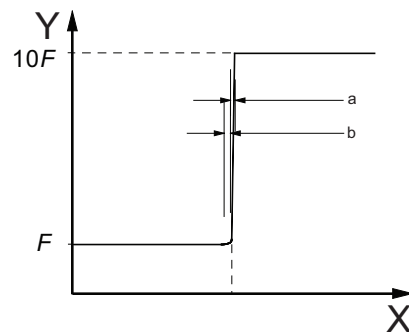
- 1 vessel motions applied to all nodes at this elevation
- 2 tensioners modeled using nonlinear beam elements
- 3 tensioner ring of slip joint
- 4 articulation elements

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):

$$F_r = F_t \times \cos \theta \quad (1)$$

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.

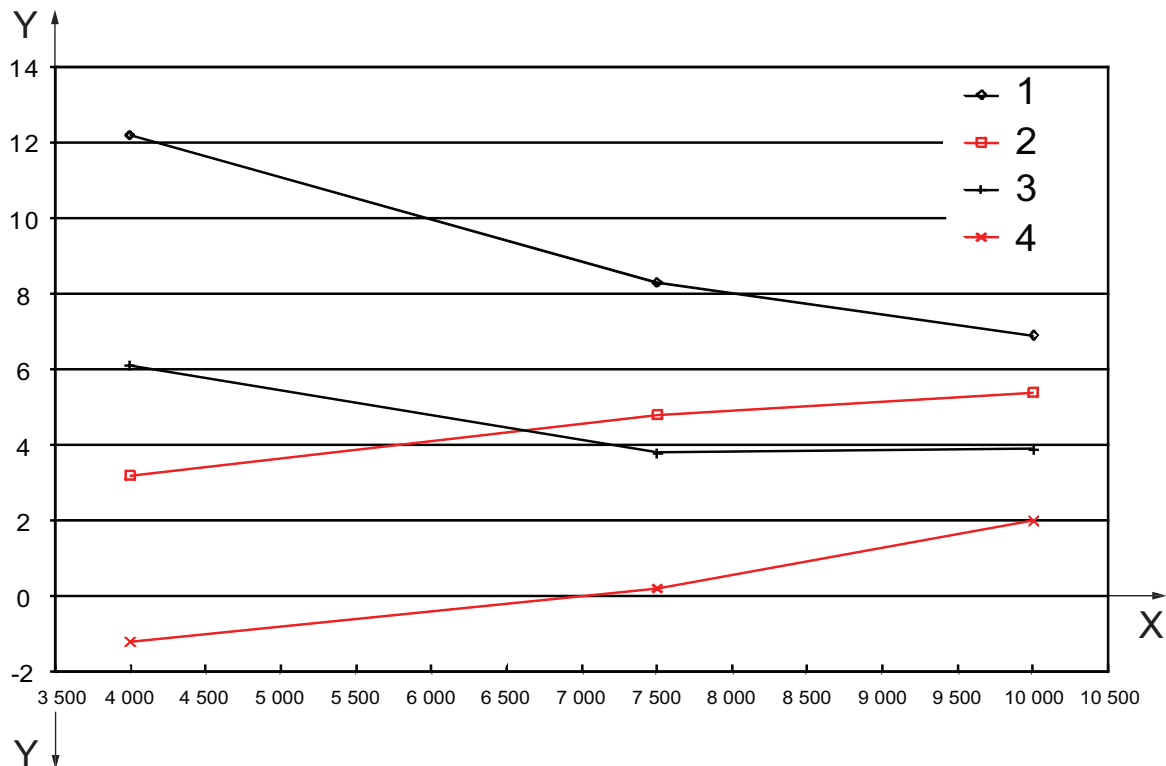
All of the results for the drilling riser system are available from one model. This makes post-processing easier, thus reducing analysis time and reducing the possibility for bookkeeping errors.

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

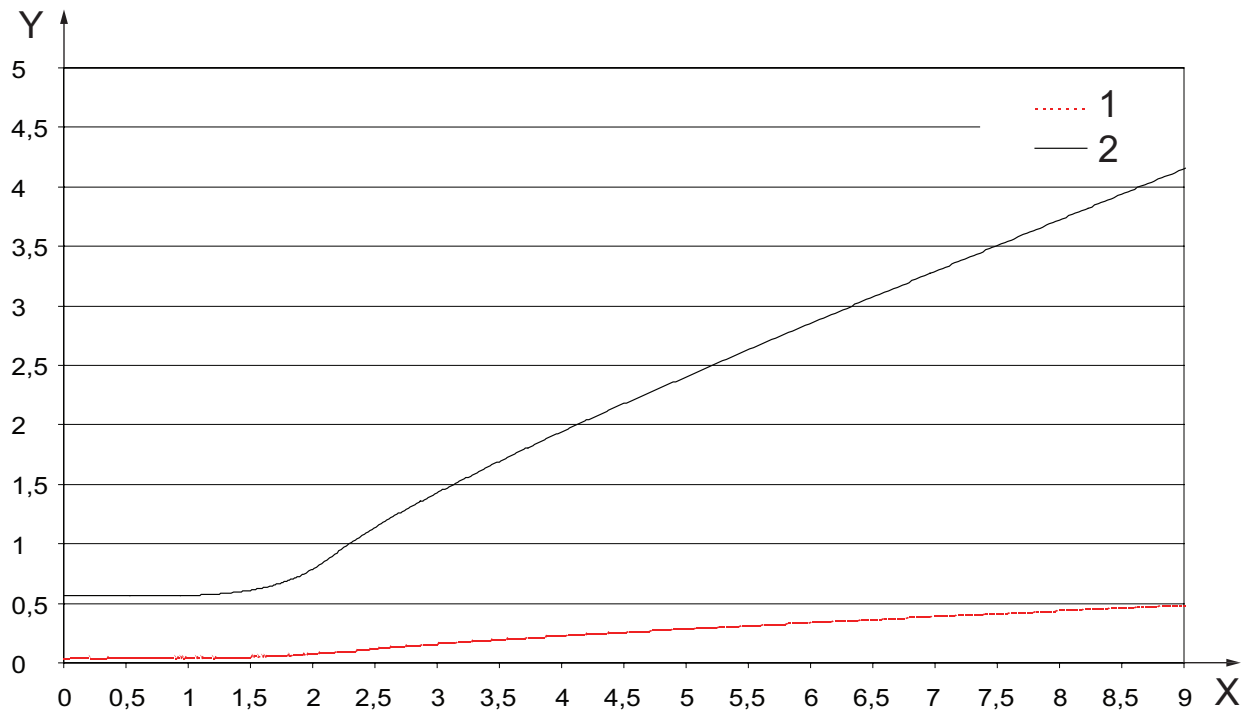
X water depth (ft)
Y percentage by which decoupled maximum bending moment along conductor is greater than coupled maximum bending moment

- 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.	

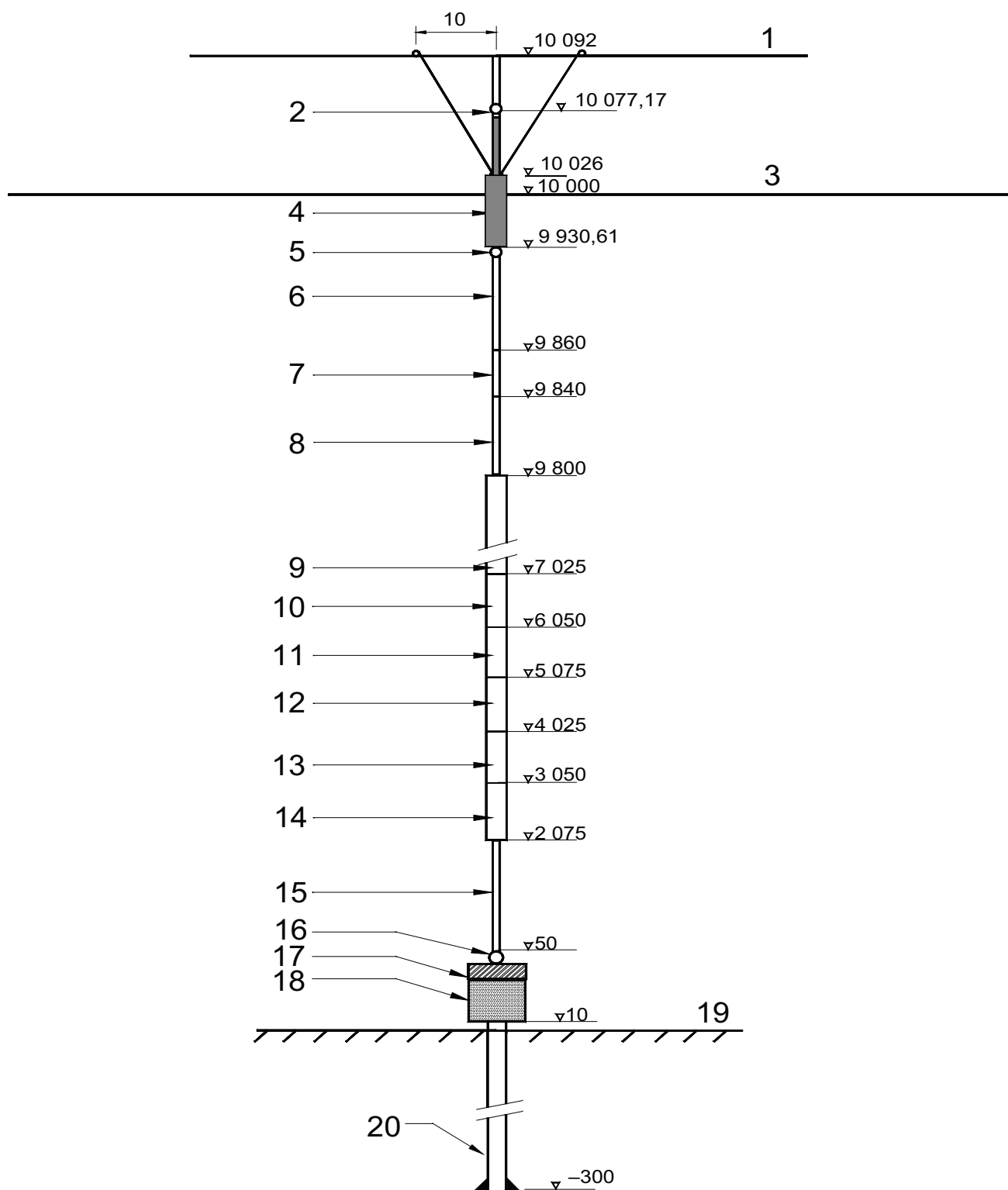
5.8.2 Riser stack-up

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 m (ft)	Bare joint air weight N (lb)	Foam density kg/m ³ (lb/ft ³)	Lift N (lb)	Wet weight		Total dry weight per joint N (lb)	Total wet weight for all joints kN (kips)
						Per joint N (lb)	Per unit length N/m (lb/ft)		
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	1 482,9 (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



Depth	Size
0' – 90'	36" × 2"
90' – 180'	36" × 1.5"
180' – 300'	36" × 1"

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