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Petroleum and natural gas industries — Drilling and production equipment — Offshore conductor design, setting depth and installation

Industries du pétrole et du gaz naturel — Équipements de forage et de production — Conception des tubes conducteurs en mer, profondeur de mise en place et installation

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Contents

Page

Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular, the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation of the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT), see www.iso.org/iso/foreword.html.

This document 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,* in collaboration with the European Committee for Standardization (CEN) Technical Committee CEN/TC 12, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries,* in accordance with the Agreement on technical cooperation between ISO and CEN (Vienna Agreement).

Any feedback or questions on this document should be directed to the user's national standards body. A complete listing of these bodies can be found at www.iso.org/members.html.

Introduction

This document provides requirements and guidance on the design, setting depth, and installation of offshore conductors used by the petroleum and natural gas industries worldwide. Sound engineering judgment is necessary in the use of this document.

Conductor design addresses actions and action combinations, strength and stability checks, and fatigue checks. Setting depth provides calculation methodologies for different installation methods. Installation identifies relevant methods and their applicability together with corresponding procedures as well as documentation and quality control requirements.

Some background to and guidelines on the use of this document is provided in Annex A.

Petroleum and natural gas industries — Drilling and production equipment — Offshore conductor design, setting depth and installation

1 Scope

This document specifies the requirements and recommendations for the design, setting depth and installation of conductors for the offshore petroleum and natural gas industries. This document specifically addresses:

— design of the conductor, i.e. determination of the diameter, wall thickness, and steel grade;

— determination of the setting depth for three installation methods, namely, driving, drilling and cementing, and jetting;

— requirements for the three installation methods, including applicability, procedures, and documentation and quality control.

This document is applicable to:

— platform conductors: installed through a guide hole in the platform drill floor and then through guides attached to the jacket at intervals through the water column to support the conductor, withstand actions, and prevent excessive displacements;

— jack-up supported conductors: a temporary conductor used only during drilling operations, which is installed by a jack-up drilling rig. In some cases, the conductor is tensioned by tensioners attached to the drilling rig;

— free-standing conductors: a self-supporting conductor in cantilever mode installed in shallow water, typically water depths of about 10 m to 20 m. It provides sole support for the well and sometimes supports a small access deck and boat landing;

— subsea wellhead conductors: a fully submerged conductor extending only a few metres above the sea floor to which a BOP and drilling riser are attached. The drilling riser is connected to a floating drilling rig. The BOP, riser and rig are subject to wave and current actions while the riser can also be subject to VIV.

This document is not applicable to the design of drilling risers.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements 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 19900, *Petroleum and natural gas industries — General requirements for offshore structures*

ISO 19901-4, *Petroleum and natural gas industries — Specific requirements for offshore structures — Part 4: Geotechnical and foundation design considerations*

ISO 19901-8, *Petroleum and natural gas industries — Specific requirements for offshore structures — Part 8: Marine soil investigations*

ISO 19902, *Petroleum and natural gas industries — Fixed steel offshore structures*

ISO 19906, *Petroleum and natural gas industries — Arctic offshore structures*

3 Terms and definitions

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

ISO and IEC maintain terminology databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at https://www.electropedia.org/

3.1
axial capacity
ability of conductor to resist vertical actions without soil failure

Note 1 to entry: The axial capacity of a conductor can change with time due to the soil disturbance and recovery.

3.2
conductor
tubular pipe set into the *seabed* (3.11) to provide the initial stable structural foundation for setting the *surface casing* (3.13) and protecting the internal well string from metocean actions

3.3
conductor shoe
short conductor joint whose upper end is connected to a whole conductor while its lower end has an internal chamfer to assist penetration

3.4
design situation
set of actions and combination of actions representing real conditions during a certain time interval, for which the design demonstrates that relevant limit states are not exceeded

3.5
drilling and cementing
method for installing a *conductor* (3.2) where a borehole is drilled, the conductor is lowered into the borehole and cement slurry placed in the annulus

3.6
driving
method for installing a *conductor* (3.2) where a vessel or rig is used to hammer the conductor into place

3.7
effective weight
weight in sea water or drilling fluid

3.8
jetting
method for installing a *conductor* (3.2) where the bottom hole assembly and conductor are combined, the borehole is washed by hydraulic force and the conductor simultaneously lowered into the hole

3.9
metocean action
effect of wind, wave and current on a *conductor* (3.2)

Note 1 to entry: The determination of these effects can include the influence of tide, surge, vortex induced vibrations and related processes.

3.10
sea floor
interface between the sea and the *seabed* (3.11) referring to the upper surface of all unconsolidated material

[SOURCE: ISO 19901-1:2015, 3.30]

3.11
seabed
materials below the sea in which the structure is founded, whether of soils such as sand, silt or clay, cemented material or of rock

Note 1 to entry: The seabed can be considered as the half-space below the *sea floor* (3.10).

[SOURCE: ISO 29400:2020, 3.128]

3.12
setting depth
distance between the depth reference point, usually the *sea floor* (3.10) or sea level, and the *conductor shoe* (3.3)

Note 1 to entry: A minimum setting depth is required to provide adequate axial capacity and formation integrity at the conductor shoe during surface casing drilling and cementing.

3.13
surface casing
casing that is run inside the *conductor* (3.2) to contain pressure in conjunction with the wellhead and blow-out preventer and to protect weak formations

3.14
undrained shear strength
maximum shear stress at yielding or at a specified maximum strain in an undrained condition

4 Symbols and abbreviated terms

4.1 Symbols

4.1.1 Symbols for conductor design

A	accidental actions
A_{cs}	cross-sectional area
C_m	moment reduction factor
D	deformation actions
D_{od}	outer diameter
D_R	Palmgren-Miner's sum or damage ratio during a certain time interval
E	Young's modulus of elasticity
E_e	extreme quasi-static metocean actions due to wind, wave and current
E_o	metocean actions due to owner-specified operating wind, wave and current parameters
F_d	design value of action
f_b	representative bending strength
f_c	representative axial compressive strength
f_e	Euler buckling strength
f_v	representative shear strength

f_y	representative yield strength
G	permanent actions
I	moment of inertia of conductor cross-section
K	effective length factor
K_{LE}	local experience factor
L	unbraced length
L_f	calculated fatigue life
M_E	maximum bending moment on cross-section due to environmental actions and deformation actions
M_I	maximum bending moment on cross-section due to eccentricities of inner strings not being centralized
N_i	number of cycles to failure under constant amplitude stress range
n_i	number of cycles of stress range
Q	variable actions
r	conductor radius of gyration
T	time period over which Palmgren-Miner's sum is determined
t	wall thickness
U_m	utilization of conductor
V	shear due to factored actions
Z_e	elastic section modulus
Z_p	plastic section modulus
$\gamma_{f,E}$	partial action factor for extreme metocean action
γ_{f,E_O}, γ_{f,E_e}	partial action factors applied to the total quasi-static metocean actions plus equivalent quasi-static action representing dynamic response for operating and extreme metocean conditions, respectively, and for which different values can be applicable for different design situations
γ_{FD}	fatigue damage design factor
γ_G, γ_Q, γ_D, γ_A	partial action factors for the various permanent, variable, deformation and accidental actions
$\gamma_{R,b}$	partial resistance factor for bending strength
$\gamma_{R,c}$	partial resistance factor for axial compressive strength
$\gamma_{R,v}$	partial resistance factor for shear strength
λ	column slenderness parameter
σ_b	bending stress due to forces from factored actions

σ_{ce} axial compressive stress due to forces from factored external axial actions of wellhead, BOP, christmas tree, emergency equipment and Workover equipment

σ_{ci} axial compressive stress due to forces from factored internal axial actions of inner casings and tubing

τ_b maximum shear stress due to forces from factored actions

4.1.2 Symbols for setting depth

A_s side surface area

D_{od} outer diameter

ρ_{fluid} fluid density

F_{s1}, F_{s2} partial safety factors

F_{xBOP} axial force applied to the conductor during the BOP installation stage

F_{xcap} axial force applied to the conductor in the extreme design situation

F_{xial} axial force in conductor

F_{xsc} axial force applied to the conductor during the subsequent casings installation stage

F_{xsur} axial force applied to the conductor during the surface casing installation stage

F_{xXt} axial force applied to the conductor during the christmas tree and tubing installation stage

$f(z)$ unit skin friction

g acceleration due to gravity

H jetted conductor setting depth in the seabed

h_{min} minimum setting depth of the conductor

K_{con} axial stiffness of the conductor

K_0 coefficient of lateral earth pressure

K_{cs} axial stiffness of the coupled foundation composed of the surface casing and the conductor

K_{sys} axial stiffness of the wellbore coupled system composed of all casings and the conductor

L_a length of conductor above the sea floor

N_{load} axial force in conductor

P_f soil fracture pressure

P_{fluid} fluid circulation pressures

P_l annular pressure loss of fluid

Q_0 conductor axial capacity immediately after jetting

Q_f skin friction resistance of conductor

Q_r axial capacity of conductor

Q_{setup}	set-up axial capacity of jetted conductor
Q_t	axial capacity of jetted conductor
R	design safety factor of conductor capacity
S	WOB utilization
s_u	soil undrained shear strength
$s_{u,ave}$	mean soil undrained shear strength within the setting depth range
t	time after the completing of jetting
u	pore water pressure
W_{BHA}	effective weight of jetting BHA
W_{BOP}	effective weight of BOP
W_{cap}	effective weight of capping equipment
W_{con}	effective weight of conductor
W_{cs}	weight of cementing string in air
W_{fc}	weight of the fluid inside the cementing string
W_{fdc}	weight of the fluid displaced by the casing assembly
W_{fs}	weight of the fluid inside the surface casing
W_{land}	effective weight of surface casing during cementing
W_{RT}	effective weight of drill-ahead running tool
W_{sc}	weight of surface casing in air
W_{squ}	effective weight of subsequent casings after cementing
W_{sur}	maximum action applied to the conductor from the time the surface casing is landed until the cement is set
W_{tub}	effective weight of production tubing
W_{WH}	effective weight of wellhead housing
$W_{WOB.last}$	last WOB recoded during jetting
W_{XT}	effective weight of christmas tree
α_1	distribution coefficient for the effective weight of the BOP
α_2	distribution coefficient for the effective weight of the subsequent casings
$\Delta\alpha_t$	soil set-up factor
σ_3	minimum principal stress at the calculated depth
$\sigma_h^{'}$	effective horizontal stress

σ'_v effective vertical stress, or overburden pressure

α, β empirical coefficients of soil fracture pressure

4.2 Abbreviated terms

APB annular pressure build-up

BHA bottom hole assembly

BOP blow-out preventer

HFT hydraulic fracture test

LWD logging while drilling

OEM original equipment manufacturer

ROV remote operated vehicle

SCF stress concentration factors

VIV vortex induced vibrations

WOB weight on bit

5 General requirements

5.1 General

A conductor has the following main functions:

a) to stabilize and to protect the near-surface sediments from collapse and fracturing under fluid pressures during surface casing drilling and cementing;

b) to resist the effective weight of the first casing string (surface casing), which is landed shortly after installation of the conductor, or the first two casing strings if a liner is landed before the surface casing;

c) as a composite system with the surface casing, to provide lateral stability for the well system and the BOP against cyclic and tensile loading from direct metocean actions, vessel motions and riser motions including VIV.

The exposure level of the well that a conductor supports shall be specified prior to the start of the design or assessment in accordance with ISO 19900.

5.2 Limit states for conductor design

Conductor design shall determine conductor outer diameter, wall thickness, steel grade and choice of connectors to satisfy design situations through all phases of the conductor's design service life, including the installation method.

The limit state approach shall be used for conductor design and assessment. ISO 19900 outlines the limit state verification requirements. The pertinent limit states are:

a) ultimate limit states (ULS);

b) abnormal/accidental limit states (ALS);

c) serviceability limit states (SLS);

d) fatigue limit states (FLS).

Additional information and guidance are given in Annex A.

5.3 Setting depth requirements

Conductor setting depth shall be determined to address the function requirements outlined in 5.1.

The setting depth shall be designed to resist the actions resulting from the conductor's installation method.

5.4 Installation requirements

The installation method can be affected by the demands of the well as well as related field conditions.

The following installation methods are considered in this document:

— driving;

— drilling and cementing;

— jetting.

In some cases, a combination of driving and drilling and cementing methods can be applied. Installation requirements (see Clause 9) shall be consistent with the chosen installation method.

5.5 Design situations

Conductor design requirements should be determined based on the exposure level, site-specific soil conditions, metocean and ice conditions, and installation method.

Conductor design should consist of the following:

— operational design situations;

— extreme design situations;

— abnormal design situations;

— accidental design situations;

— short duration design situations;

— serviceability design situations.

Design situations are described in ISO 19900.

6 Design parameters

6.1 General

Metocean, ice, soil and engineering design parameters should be collected.

6.2 Metocean parameters

The metocean parameters shall include:

a) water depth;

b) tide and storm surge;

c) significant wave height and spectral peak period;

d) current velocity and profile;

e) wind velocity and profile.

Collection of metocean parameters should be in accordance with the requirements of ISO 19901-1 and consistent with the requirements of ISO 19902. Guidance on wind, wave and current directions is given in Annex A.

Metocean parameters are primarily used to determine actions on the conductor and to calculate corresponding action effects. Action effects are used to check conductor strength, stability and fatigue.

6.3 Ice parameters

Ice parameters should include ice thickness and strength (see ISO 19906).

6.4 Seismic parameters

Seismic parameters should be determined by using either the simplified or the detailed seismic action procedure, as specified in ISO 19901-2.

6.5 Soil parameters

Where site-specific geotechnical data are available or acquired specifically for conductor design, the soil properties and corresponding geotechnical parameters should include:

a) soil profile with classification and index properties for each layer;

b) design profile of submerged unit weight of soil;

c) design profile of undrained shear strength of cohesive soil layers;

d) design profile of effective angle of internal friction of cohesionless soil layers.

Marine soil investigations shall be conducted in accordance with ISO 19901-8. Use of the soil parameters in design and installation shall be in accordance with ISO 19901-4.

Where site-specific geotechnical data are not available, there exists a risk of conductor foundation failure. Mitigation of this risk to acceptable levels may be achieved where there is extensive regional experience, site geologic conditions are consistent with those of past successful installation sites, and bounding values of regional of field geotechnical parameters are considered in the design of setting depth.

6.6 Engineering design parameters

6.6.1 Platform parameters

For fixed platform, the conductor is an auxiliary structure. The parameters required shall include:

a) spacing between well slots;

b) guide hole size, elevation and constraint;

c) corrosion protection;

d) interfaces to facilities such as cellar deck and christmas tree flowlines.

6.6.2 Well operations parameters

6.6.2.1 General

Well operations include drilling, completion, production and Workover phases. The action effects that the conductor resists during design situations depend upon its configuration as described in 5.2 and 5.5. Some of the parameters referred to in 6.6.2.2, 6.6.2.3, 6.6.2.4 and 6.6.2.5 are used for conductor design (see Clause 7) and some are used to determine setting depth (see Clause 8).

6.6.2.2 Platform conductors

For platform conductors, the following parameters shall be collected:

a) wellbore structure and casing configuration;

b) weight of BOP, wellhead, christmas tree and Workover equipment;

c) action effects to which the conductor is subjected during drilling, completion, production and Workover phases;

d) actions due to thermal APB for surface casings that are not fully cemented or poor cemented, if any.

6.6.2.3 Jack-up supported conductors

The parameters for jack-up supported conductors are the same as those for platform conductors in 6.6.2.2. In addition, the following parameters shall be collected:

a) tension at the upper end of the conductor, if any;

b) misalignment between the jack-up platform and the conductor;

c) relative motion that can occur between the jack-up platform and the conductor.

6.6.2.4 Free-standing conductors

The parameters for free-standing conductors are the same as those for platform conductors in 6.6.2.2.

6.6.2.5 Subsea wellhead conductors

For subsea wellhead conductors, the following parameters shall be collected:

a) wellbore structure and casing configuration;

b) weight of BOP, wellhead, christmas tree and Workover equipment;

c) weight of mudmat;

d) weight of low-pressure housing and high-pressure housing;

e) weight of running tool for installation by jetting;

f) weight of capping equipment;

g) bending moments and other action effects transmitted by the drilling riser;

h) interfaces with the template, if any;

i) action effects to which the conductor is subjected during drilling, completion, production and Workover phases;

j) actions due to thermal APB for surface casings that are not fully cemented or are poorly cemented;

k) sediment transport around the template and conductor due to current actions.

7 Conductor design

7.1 General

The conductor shall be designed to resist the design situations outlined in 5.5 and satisfy the limit states defined in 5.2.

Strength, stability and fatigue checks shall be conducted for all design situations. The results of these checks are outer diameter, wall thickness, steel grade, corrosion allowance/corrosion protection philosophy and fatigue life. OEM equipment such as connectors including welds shall also be included in these checks.

A model equivalent to the actual structure should be developed for use in the structure analysis, accounting for interaction between the conductor and the surrounding media, i.e. soil and sea water. For a subsea wellhead conductor, a fully coupled model that includes the vessel response, drilling riser, subsea equipment stack and well foundation should be established.

The conductor outer diameter shall also accommodate the following functional requirements:

a) the outer diameter of the conductor installed below the sea floor shall be kept constant;

b) the outer diameter of the conductor shall consider the inner diameter of the platform guides (if present) and any restraints set after conductor installation;

c) in the case of non-vertical or deviated conductors, the outer diameter of the conductor shall consider the offset between platform guides (if present) and any restraints set after conductor installation;

Further information about conductor analysis based on numerical techniques is described in Annex A.

7.2 Actions

7.2.1 General

Design situations for conductors are described in 5.5 and should distinguish between persistent situations and accidental (including abnormal) situations. The resulting action effects are dominated by axial forces and bending moments. Thermal APB action effects shall also be addressed.

7.2.2 Permanent actions (*G*)

Permanent actions (*G*) imposed on conductor by the self-weight of the conductor and associated equipment include:

— effective weight of the conductor;

— effective weight of the inner casings and tubing mounted on a conductor that do not change with mode of operation. The weight transmitted to the conductor should be calculated in proportion of the conductor stiffness to the coupled wellbore system stiffness;

NOTE The coupled wellbore system stiffness refers to the stiffness of conductor and all inner casings.

— effective weight of external equipment, e.g. wellhead, BOP, christmas tree, emergency equipment and Workover equipment.

7.2.3 Variable actions (Q)

Variable actions (Q) can change in magnitude, position and direction during the time period considered. Q includes:

— thermal APB action;

NOTE For conductor, where the surface casing cement slurry does not reach the mudline (i.e. partial cementation), thermal exchanges during production or injection can cause APB action. APB can be limited by the sealing capacity of the low-pressure housing or the conductor connections. Integrity assessment of the surface casing for partial cementation condition is beyond the scope of this document.

— conductor deformation due to thermal effects during production.

7.2.4 Deformation actions (D)

Certain actions can be treated as resulting from imposed deformations. Drilling unit displacements are normally applied horizontally to the top of the conductor, at the location(s) where the conductor is supported horizontally by the drilling unit. They include static (with time) offsets and time-varying offsets (normally due to the action of waves on the unit).

For platform conductors, horizontal deflections of the platform itself (under the metocean actions) can occur, producing consequential actions on the conductor.

7.2.5 Accidental actions (A)

Accidental actions can occur from abnormal environmental events, malfunction, mal-operation or accident.

Primary sources of accidental actions include:

— abnormal metocean, ice and seismic events;

— collisions from ice actions;

— fires;

— explosions;

— fishing gear.

7.2.6 Environmental actions

7.2.6.1 Metocean actions

Metocean actions (including wind, wave and current) applied to the conductor are:

a) for platform, jack-up supported and free-standing conductors, metocean actions impinging on the conductor;

b) for subsea wellhead conductors, metocean actions impinging on the conductor, riser and BOP system.

Metocean actions should be calculated in accordance with the requirements of ISO 19902.

Metocean actions can be cyclic in nature and cause fatigue stresses in the conductor.

7.2.6.2 Ice actions

In regions with seasonal ice cover, actions due to ice shall be considered.

The computation of ice actions is highly specialized and location-dependent and shall be in accordance with ISO 19906.

7.2.6.3 Seismic actions

Procedures for the determination of seismic actions are provided in ISO 19901-2.

7.3 Partial factors for actions

The design action(s) for a particular design situation comprise one or more combinations of factored actions.

The general formula for determining the design action (F_d) for in-place conductor situations is given by Formula (1), and the recommended partial action factors for each design situation are given in Table 1:

$$F_d = \gamma_G G + \gamma_Q Q + \gamma_{f,E_o} E_o + \gamma_{f,E_e} E_e + \gamma_D D + \gamma_A A \quad (1)$$

where

G	are the permanent actions specified in 7.2.2;
Q	are the variable actions specified in 7.2.3;
E_o	are the metocean actions corresponding to the owner-specified operating wind, wave and current parameters;
E_e	are the extreme quasi-static actions due to wind, wave and current;
D	are the deformation actions specified in 7.2.4;
A	are the accidental actions specified in 7.2.5;
γ_G, γ_Q, γ_D, γ_A	are the partial action factors for the various permanent, variable, deformation and accidental actions discussed in 7.2 and, for which, values for different design situations are given in Table 1;
γ_{f,E_o}, γ_{f,E_e}	are partial action factors applied to the total quasi-static metocean actions plus equivalent quasi-static action representing dynamic response for operating and extreme metocean conditions, respectively, and for which, values for different design situations are given in Table 1.

Table 1 — Partial action factors for design situations

Design situation	Recommended environmental return period	Partial action factors [a]					
		γ_G	γ_Q	γ_{f,E_o}	γ_{f,E_e}	γ_D	γ_A
Permanent and variable actions only	-	1,3	1,3	0,0	0,0	0,0	0,0
Operating situation with corresponding wind, wave, and/or current conditions [b]	1 year	1,3	1,3	$0{,}9\gamma_{f,E}$	0,0	0,0	0,0
Extreme conditions when the action effects due to permanent and variable actions are additive [c]	100 years	1,0	1,0	0,0	$\gamma_{f,E}$ [e]	0,0	0,0
Extreme conditions when the action effects due to permanent and variable actions oppose [d]	100 years	0,9	1,0	0,0	$\gamma_{f,E}$	0,0	0,0
Accidental (and abnormal) situation [f]	10,000 years	1,0	1,0	0,0	1,0	0,0	1,0
Short duration situation	1 year	1,0	0,0	1,0	0,0	1,0	0,0
Serviceability situation	50 years	1,0	1,0	1,0	0,0	0,0	0,0

[a] A value of 0,0 for a partial action factor means that the action is not applicable to the design situation.

[b] *G* shall be the maximum values for each mode of operation.

[c] *G* shall include those parts of each mode of operation that can occur during extreme conditions.

[d] *G* shall exclude any parts associated with the mode of operation that cannot be ensured to occur during extreme conditions.

[e] $\gamma_{f,E}$ is the partial action factor for extreme metocean action (see Annex A).

[f] Abnormal metocean actions and accidental actions are mutually exclusive, i.e. both are treated as independent of each other.

7.4 Boundary restraints

7.4.1 General

Boundary restraints used in the structural analysis shall reflect actual conditions for each conductor type. This information is used to determine the conductor unbraced lengths and the effective length factors when checking column buckling (see 7.5.3.2).

Conductor-soil interaction should be modelled using non-linear springs based on *p-y* curves: *p-y* curves shall be in accordance with the requirements of ISO 19901-4.

7.4.2 Platform conductors

For platform conductors, the following shall apply:

— the upper end may be assumed restrained laterally by the transverse support;

— each guide hole restricts lateral displacement, the value of which is determined by the gap between the inner diameter of the guide hole and the outer diameter of the conductor. If a wedge is placed between the guide hole and the conductor, the lateral displacement is determined by the gap between the wedge and the outer diameter of the conductor;

— the lower end is laterally and flexurally restrained at a depth below the sea floor that is dependent upon the properties of the (shallow) soil. A recommended value for this depth is the depth where the maximum bending moment occurs in the conductor. The designer may also select a suitable depth based on local experience.

7.4.3 Jack-up supported conductors

For jack-up supported conductors, the upper end is restrained by the transverse support or conductor tensioner system. The lower end restraints are the same as those for platform conductors. There are no guide hole restraints.

7.4.4 Free-standing conductors

For free standing conductors, the upper end is free. The lower end restraints are the same as those for platform conductors.

7.4.5 Subsea wellhead conductors

For subsea wellhead conductors, the following apply:

— for drilling design situations, subsea wellhead conductors should be analysed together with the vessel and riser;

— for the in-place condition, the upper end is free;

— conductor-soil interaction over a range of two to three conductor joints lengths below the sea floor should be modelled using non-linear springs (see 7.4.1);

— the lower end is the same as for platform conductors.

7.5 Strength and stability checks

7.5.1 General

The axial actions on conductors can be classified as internal and external axial actions. The significance of the internal and external axial actions is relevant when checking column buckling.

Guidance concerning internal axial actions and external axial actions is given in Annex A.

7.5.2 Design method

Conductor strength and stability verification shall be in accordance with the requirements of ISO 19902.

Conductor axial stress, bending stress, shear stress and combined axial and bending stress shall be calculated separately for each design situation.

7.5.3 Axial compression

7.5.3.1 General

Conductors subjected to axial compression shall satisfy Formula (2):

$$\frac{\sigma_{ci}\gamma_{R,c}}{f_y}+\frac{\sigma_{ce}\gamma_{R,c}}{f_c}\leq 1 \qquad (2)$$

where

σ_{ci} is the axial compressive stress due to forces from factored internal axial actions of inner casings and tubing;

σ_{ce} is the axial compressive stress due to forces from factored external axial actions of wellhead, BOP, christmas tree, emergency equipment and Workover equipment;

f_c is the representative axial compressive strength (see 7.5.3.2);

f_y is the representative yield strength;

$\gamma_{R,c}$ is the partial resistance factor for axial compressive strength, $\gamma_{R,c}$ = 1,10.

NOTE The representative value of yield strength is normally the specified minimum yield strength.

The utilization of a conductor, U_m, under axial compression shall be calculated from Formula (3):

$$U_m = \frac{\sigma_{ci}}{f_y / \gamma_{R,c}} + \frac{\sigma_{ce}}{f_c / \gamma_{R,c}} \quad (3)$$

7.5.3.2 Column buckling

The representative axial compressive strength shall be calculated from Formula (4):

$$\begin{cases} f_c = \left(1{,}0 - 0{,}278\lambda^2\right) f_y & \text{for } \lambda \leq 1{,}34 \\ f_c = \frac{0{,}9}{\lambda^2} f_y & \text{for } \lambda > 1{,}34 \\ \lambda = \sqrt{\frac{f_y}{f_e}} = \frac{KL}{\pi r}\sqrt{\frac{f_y}{E}} & \end{cases} \quad (4)$$

where

λ is the column slenderness parameter;

f_e is the Euler buckling strength, $f_e = \dfrac{\pi^2 E}{(KL/r)^2}$;

E is Young's modulus of elasticity;

K is the effective length factor in accordance with Table 2;

L is the unbraced length of the conductor in accordance with Table 2;

r is the conductor radius of gyration, $r = \sqrt{I / A_{cs}}$;

I is the moment of inertia of the conductor cross-section;

A_{cs} is the cross-sectional area of the conductor.

Table 2 — Conductor unbraced lengths, effective length factors and moment reduction factors

Type of conductor	Unbraced length L	Effective length factor K	Moment reduction factor C_m
Platform conductors	a) distance between transverse support and adjacent guide hole; b) distance between adjacent guide holes; c) distance between adjacent guide holes should be multiplied by the ratio of guide inner diameter to conductor outer diameter, where wedges are not used; d) 0,85 times distance between lower end and adjacent guide hole.	1,0	$1{,}0-0{,}4\frac{\sigma_{ce}}{f_e}$ but $\leq$ 0,85
Jack-up supported conductors	distance between transverse support and lower end	1,0	$1{,}0-0{,}4\frac{\sigma_{ce}}{f_e}$ but $\leq$ 0,85
Free-standing conductors	distance between upper end and lower end	2,0	1,0
Subsea wellhead conductors	distance between upper end and lower end	2,0	1,0

7.5.4 Bending

Conductors subjected to bending moments shall satisfy Formula (5):

$$\sigma_b = \frac{M_I + M_E}{Z_e} \leq \frac{f_b}{\gamma_{R,b}} \tag{5}$$

where

σ_b is the bending stress due to forces from factored actions;

f_b is the representative bending strength, in accordance with Formula (7);

$\gamma_{R,b}$ is the partial resistance factor for bending strength, $\gamma_{R,b}=1{,}05$;

M_I is the maximum bending moment on the cross-section due to the eccentricities of inner strings not being centralized;

M_E is the maximum bending moment on the cross-section due to the environmental actions and deformation actions;

Z_e is the elastic section modulus, $Z_e = \frac{\pi}{64}\left[D_{od}^{\,4} - (D_{od} - 2t)^4\right] / \left(\frac{D_{od}}{2}\right)$;

D_{od} is the outer diameter of the conductor;

t is the wall thickness of the conductor.

The utilization of a conductor, U_m, under bending moments shall be calculated from Formula (6):

$$U_m = \frac{\sigma_b}{f_b / \gamma_{R,b}} = \frac{(M_I + M_E)/Z_e}{f_b / \gamma_{R,b}} \tag{6}$$

The representative bending strength for a conductor shall be calculated from Formula (7):

$$\begin{cases} f_b = \left(\dfrac{Z_p}{Z_e}\right) f_y, & \dfrac{f_y D_{od}}{Et} \leq 0{,}051\ 7 \\ f_b = \left[1{,}13 - 2{,}58\left(\dfrac{f_y D_{od}}{Et}\right)\right]\left(\dfrac{Z_p}{Z_e}\right) f_y, & 0{,}051\ 7 < \dfrac{f_y D_{od}}{Et} \leq 0{,}103\ 4 \\ f_b = \left[0{,}94 - 0{,}76\left(\dfrac{f_y D_{od}}{Et}\right)\right]\left(\dfrac{Z_p}{Z_e}\right) f_y, & 0{,}103\ 4 < \dfrac{f_y D_{od}}{Et} \leq 0{,}2 \end{cases} \tag{7}$$

where, additionally, Z_p is the plastic section modulus, $Z_p = \frac{1}{6}\left[D_{od}^{\,3} - (D_{od} - 2t)^3\right]$.

7.5.5 Shear

Conductors subjected to beam shear forces shall satisfy Formula (8):

$$\tau_b = \frac{2V}{A_{cs}} \leq \frac{f_v}{\gamma_{R,v}} \tag{8}$$

where

τ_b is the maximum shear stress due to forces from factored actions;

f_v is the representative shear strength, $f_v = f_y / \sqrt{3}$;

$\gamma_{R,v}$ is the partial resistance factor for shear strength, $\gamma_{R,v} = 1{,}05$;

V is the shear due to factored actions;

The utilization of a conductor, U_m, under shear shall be calculated from Formula (9):

$$U_m = \frac{\tau_b}{f_v / \gamma_{R,v}} = \frac{2V / A_{cs}}{f_v / \gamma_{R,v}} \tag{9}$$

7.5.6 Combined stress

Conductors subjected to combined axial compression and bending forces shall satisfy Formulae (10) and (11) at all cross-sections along their length:

$$\frac{\gamma_{R,c}\sigma_{ci}}{f_y} + \frac{\gamma_{R,c}\sigma_{ce}}{f_c} + \frac{\gamma_{R,b} C_m \sigma_b}{f_b\left(1 - \gamma_{R,c}\sigma_{ce} / f_e\right)} \leq 1{,}0 \tag{10}$$

and

$$1\text{-}\cos\left[\frac{\gamma_{R,c}\pi}{2}\left(\frac{\sigma_{ci}}{f_y} + \frac{\sigma_{ce}}{f_c}\right)\right] + \frac{\gamma_{R,b}\sigma_b}{f_b} \leq 1{,}0 \tag{11}$$

where, in addition to the definitions given in 7.5.3 and 7.5.4, C_m is the moment reduction factor in accordance with Table 2;

The utilization of a conductor, U_m, under axial compression and bending shall be the larger value calculated from Formulae (12) and (13):

$$U_m = \frac{\sigma_{ci}\gamma_{R,c}}{f_y} + \frac{\sigma_{ce}\gamma_{R,c}}{f_c} + \frac{\gamma_{R,b}C_m\sigma_b}{f_b\left(1-\sigma_{ce}\gamma_{R,c}/f_e\right)} \tag{12}$$

$$U_m = 1\text{-}\cos\left[\frac{\gamma_{R,c}\pi}{2}\left(\frac{\sigma_{ci}}{f_y}+\frac{\sigma_{ce}}{f_c}\right)\right] + \frac{\gamma_{R,b}\sigma_b}{f_b} \tag{13}$$

7.6 Fatigue

Significant fatigue damage is unlikely to occur in the basic conductor pipe. If fatigue damage does occur, it is most likely to be in items supplied by OEM or at welds. This is due to the presence of welds and manufacturing details which contain stress concentrations in such equipment. Fatigue assessment shall be in accordance with the requirements of ISO 19902. Fatigue assessment of driven conductors follows the same guiding rules, particularly for welded sections. If conductor segments are connected by means of mechanical connectors, larger SCF can be applicable.

Cumulative damage shall be calculated using Palmgren-Miner's rule, Formula (14):

$$D_R = K_{LE}\gamma_{FD}\sum_i \frac{n_i}{N_i} \tag{14}$$

where

D_R is the Palmgren-Miner's sum or damage ratio during a certain time interval;

K_{LE} is a local experience factor taken as 1,0 for a conductor;

γ_{FD} is a fatigue damage design factor, $\gamma_{FD} = 5{,}0$ for inspectable locations and $\gamma_{FD} = 10{,}0$ for non-inspectable locations;

Segments of the conductor above the sea floor in locations where the water depth is beyond 200 m shall be taken as non-inspectable.

γ_{FD} may be increased to ensure appropriate reliability for short term drilling operations.

n_i is the number of cycles of the stress range, occurring during time period (see ISO 19902);

N_i is the number of cycles to failure under constant amplitude loading for the stress range, taken from the relevant *S*–*N* curve (see ISO 19902).

In the fatigue assessment procedure, fatigue failure is assumed to occur when $D_R = 1{,}0$.

Formula (14) may be employed for:

a) variable stress ranges associated with a given sea state;

b) multiple sea states and wave directions;

c) multiple sources of cyclic actions;

d) current induced VIV.

Formula (14) may be used to estimate fatigue life. If all damage is due to the same circumstances (e.g. in the in-place situation), fatigue life, L_f, may be calculated using Formula (15):

$$L_f = T / D_R \tag{15}$$

where

L_f is the calculated fatigue life based on the calculated fatigue damage;

T is the time period ($T \geq 1$ year) for which Palmgren-Miner's sum is determined.

8 Setting depth

8.1 General

The following apply to the setting depth:

a) the soil at the conductor shoe shall have sufficient formation strength to withstand fluid pressures applied during the surface casing drilling and cementing phase, to avoid fluid losses and jeopardising the integrity of the foundation;

b) the conductor shall have sufficient axial capacity, derived from external frictional resistance alone to transfer self-weight and all axial forces on the conductor (e.g. BOP, initial casing hung off) to the shallow formation(soil);

c) the conductor shoe should be set in a cohesive layer in order to minimize the potential for excessive washout that can occur in a cohesionless soil.

The minimum setting depth shall be the largest of the setting depths required for each different function.

8.2 Setting depth for fluid circulation channel

As a fluid circulation channel, the conductor is to stabilize and to protect the near-surface sediments from collapse and fracturing under fluid circulation pressures. Thus, the soil fracture pressure at the conductor shoe shall be greater than the fluid circulation pressures as described by Formula (16):

$$P_{\text{fluid}} \leq P_f \tag{16}$$

The minimum setting depth shall be calculated from Formula (17):

$$h_{\min} = \frac{P_f - P_l}{g\rho_{\text{fluid}}} - L_a \tag{17}$$

where

P_{fluid} is the maximum fluid circulation pressure at the conductor shoe during surface casing drilling or cementing;

P_f is the soil fracture pressure at the conductor shoe (see Annex A);

$h_{\min}$ is the minimum setting depth of the conductor;

P_l is the annular pressure loss of fluid;

g is the acceleration due to gravity;

ρ_{fluid} is the surface casing drilling or cementing fluid density;

L_a is the length of conductor above the sea floor.

8.3 Setting depth for wellbore structural foundation

8.3.1 General

The setting depth design shall account for the installation method. The minimum setting depth shall provide capacity to resist the actions described in 7.2.

8.3.2 Installation by driving, drilling and cementing

8.3.2.1 General

For installation by driving and/or drilling and cementing, axial capacity shall satisfy Formula (18):

$$F_{\text{xial}} \le Q_{\text{r}} / R \qquad (18)$$

where

F_{xial} is the axial force in the conductor (see 8.3.2.2);

Q_{r} is the axial capacity of the conductor (see 8.3.2.3);

R is the design safety factor of conductor capacity having a value of 1,3 for operating situations and 1,2 for the extreme situations.

8.3.2.2 Axial forces

As described in 7.2.2, permanent actions are the prime contributors to axial forces in a conductor. These actions are not necessarily applied simultaneously, but at different stages throughout the drilling, completion and production procedures. Typically, the following five stages are distinguished:

a) surface casing installation stage

The most common and critical stage for the conductor is to resist the effective weight of the surface casing during cementing. The axial force for this design situation should be calculated from Formula (19):

$$F_{\text{xsur}} = W_{\text{con}} + W_{\text{sur}} \qquad (19)$$

where

F_{xsur} is the axial force applied to the conductor during the surface casing installation stage;

W_{con} is the effective weight of the conductor;

W_{sur} is the maximum weight applied to the conductor from the time the surface casing is landed, until the cement is set.

NOTE W_{sur} can be: a) the full effective weight of the surface casing and cementing string, b) zero, if the weight of the surface casing is suspended by the rig, c) a fraction of the buoyant weight of the surface casing and cementing string if their weight is partially suspended by the rig.

b) BOP installation stage

After the surface casing is cemented, the effective weight of the BOP is resisted by the foundation composed of the surface casing and the conductor. The axial force for this design situation should be calculated from Formulae (20) and (21):

$$F_{\text{xBOP}} = F_{\text{xsur}} + \alpha_1 W_{\text{BOP}} \qquad (20)$$

$$\alpha_1 = K_{con} / K_{cs} \tag{21}$$

where

F_{xBOP} is the axial force applied to the conductor during the BOP installation stage;

W_{BOP} is the effective weight of the BOP;

α_1 is the distribution coefficient for the effective weight of the BOP;

K_{con} is the axial stiffness of the conductor;

K_{cs} is the axial stiffness of the coupled foundation composed of the surface casing and the conductor.

NOTE When considering the axial stiffness of the coupled foundation composed of the surface casing and the conductor, the connections between the different elements need to be considered when determining the load path of the BOP effective weight actions.

c) subsequent casings installation stage

During this stage, the effective weight of the subsequent casings is resisted by the coupled wellbore system. The axial force for this design situation should be calculated from Formulae (22) and (23):

$$F_{xsc} = F_{xBOP} + \alpha_2 W_{squ} \tag{22}$$

$$\alpha_2 = K_{con} / K_{sys} \tag{23}$$

where

F_{xsc} is the axial force applied to the conductor during the subsequent casings' installation stages;

W_{squ} is the effective weight of the subsequent casings after cementing;

α_2 is the distribution coefficient for the effective weight of the subsequent casings;

K_{sys} is the stiffness of the wellbore coupled system composed of all casings and the conductor.

d) christmas tree and tubing installation stages

During these stages, the effective weights of the christmas tree and tubing hanger are resisted by the coupled wellbore system. The axial force for this design situation should be calculated from Formula (24):

$$F_{xXt} = F_{xsur} + \alpha_2 \left(W_{squ} + W_{XT} + W_{tub} \right) \tag{24}$$

where

F_{xXt} is the axial force applied to the conductor during the christmas tree and tubing installation stages;

W_{XT} is the effective weight of the christmas tree;

W_{tub} is the effective weight of the tubing.

e) emergency capping condition

For subsea wellhead conductors, the effective weight of the emergency capping equipment should be considered as an extreme design situation for which the axial force should be calculated from Formula (25):

$$F_{\text{xcap}} = F_{\text{xXt}} + \alpha_2 W_{\text{cap}} \tag{25}$$

where

F_{xcap} is the axial force applied to the conductor in the extreme design situation;

W_{cap} is the effective weight of the capping equipment.

Design situation a), b), c) and d) should be applied to all conductors. Design situation e) should only be applied as an extreme design situation (survival) for subsea wells.

8.3.2.3 Axial capacity

The axial capacity of the conductor shall be calculated from Formula (26):

$$Q_{\text{r}} = Q_{\text{f}} = f(z) A_{\text{s}} \tag{26}$$

where

Q_{r} is the axial capacity of the conductor;

Q_{f} is the skin friction resistance of the conductor;

$f(z)$ is unit skin friction;

A_{s} is the side surface area of the conductor or the cement annulus in soil.

The relative deformation between the conductor and the soil and the compressibility of the conductor-soil system should be considered in determining the axial capacity. In some cases, it is necessary to more precisely consider the influence of axial performance on capacity, which should be carried out in accordance with the requirements of ISO 19901-4.

For conductors installed by driving, methods for calculating unit skin friction, $f(z)$, are provided in ISO 19901-4. For conductors installed by drilling and cementing, the unit skin friction is usually determined by interface friction between the cement and the soil (see Annex A).

8.3.2.4 Minimum setting depth

As described by Formula (18), when the axial force in the conductor is balanced by the axial capacity, the minimum setting depth is obtained. This depth should be determined as follows:

a) use Formulae (19) to (25) with different setting depths to obtain the relationship between axial force and setting depth;

b) use Formula (26) with different setting depths to obtain the relationship between axial capacity and setting depth;

c) plot the two curves for depths below the sea floor by a) and b) and the first intersection of the curves is the minimum setting depth.

Minimum setting depth should also consider verticality requirements or deviations (see 9.2.6) of trajectory that can have an effect on the structure's foundation integrity.

8.3.2.5 Pile group effect

For conductors installed by driving, pile group effects, i.e. hammer refusal and driving resistance, should be evaluated for conductor spacing less than eight times of conductor outer diameter.

Assessment of the conductor pile group effects should be carried out in accordance with the requirements of ISO 19901-4.

8.3.3 Installation by jetting

8.3.3.1 General

Jetting disturbs soil around the conductor while axial capacity increases with time after jetting. Setting depth satisfies equilibrium between the axial force and the axial capacity.

8.3.3.2 Axial capacity

Axial capacity of a jetted conductor is composed of an initial axial capacity after installation and set-up axial capacity due to soil set-up with time.

The initial axial capacity should be determined by Formula (27):

$$Q_0 = W_{\mathrm{WOB,last}} = S \cdot (W_{\mathrm{con}} + W_{\mathrm{WH}} + W_{\mathrm{BHA}} + W_{\mathrm{RT}}) \tag{27}$$

where:

Q_0 is the conductor axial capacity immediately after jetting, defined at the time t = 0,01 d;

$W_{\mathrm{WOB,last}}$ is the last WOB recorded during jetting;

S is the WOB utilization;

W_{con} is the effective weight of the conductor;

W_{WH} is the effective weight of the wellhead housing;

W_{BHA} is the effective weight of the jetting BHA;

W_{RT} is the effective weight of the drill-ahead running tool.

The value of the WOB utilization, S, should be less than 1,0 to avoid compression or buckling of the drill pipe above the running tool. Typically, the WOB utilization, S, is 0,8.

The increase in capacity due to set-up, Q_{setup}, at any time less than 10 d after jetting may be empirically determined from Formula (28):

$$Q_{\mathrm{setup}} = \Delta\alpha_{\mathrm{t}} \cdot \pi \cdot D_{\mathrm{od}} \cdot H \cdot s_{\mathrm{u,ave}} \tag{28}$$

where

Q_{setup} is the set-up axial capacity of the conductor;

$\Delta\alpha_{\mathrm{t}}$ is the soil set-up factor;

D_{od} is the outer diameter of the conductor;

H is the jetted conductor setting depth in the seabed;

$s_{\mathrm{u,ave}}$ is the mean soil undrained shear strength within the setting depth range.

The determination of $\Delta\alpha_t$ (see Annex A) requires regional experience from back-analysis of installed jetted conductors.

The undrained shear strength is generally obtained from laboratory tests. In the absence of such experiment results, regional empirical data may be adopted.

The axial capacity of a jetted conductor defined at a time less than 10 d (Q_t) should be calculated from Formula (29):

$$Q_t = Q_0 + Q_{setup} \tag{29}$$

8.3.3.3 Axial forces

The axial forces in the jetted conductor are calculated from Formulae (30) and (31):

$$N_{load} = F_{s1} \cdot (W_{con} + W_{WH}) + F_{s2} \cdot W_{land} \tag{30}$$

$$W_{land} = W_{sc} + W_{cs} + W_{fs} + W_{fc} - W_{fdc} \tag{31}$$

where

N_{load}	is the axial force in the conductor;
F_{s1}, F_{s2}	are partial safety factors; the recommended value for F_{s1} is 1,0, the recommended value for F_{s2} is 1,3;
W_{land}	is the effective weight of surface casing during cementing;
W_{sc}	is the weight of the surface casing in air;
W_{cs}	is the weight of the cementing string in air;
W_{fs}	is the weight of the fluid inside the surface casing;
W_{fc}	is the weight of the fluid inside the cementing string;
W_{fdc}	is the weight of the fluid displaced by the casing assembly.

After the surface casing is cemented, the effective weight of the BOP is shared by the conductor and the surface casing. The effective weight of subsequent casings, tubing, christmas tree and capping equipment does not necessarily influence the setting depth of a jetted conductor, which is resisted by the coupled wellbore system.

8.3.3.4 Setting depth

Setting depth is determined when both the conductor axial forces and the axial capacity are in equilibrium as given by Formula (32):

$$Q_t = N_{load} \tag{32}$$

N_{load} may be reduced by the amount of load suspended by the drilling rig when landing and cementing the casing and waiting for the cement to develop sufficient strength to bond the casing to the surrounding formation.

The setting depth is largely determined by the waiting time after jetting. The depth varies with the allowable waiting time, which depends on the operator's specific requirements. Typically, the waiting time is the time it takes to drill the next section of hole and run the casing.

9 Installation

9.1 General

Selection of the installation method is important to efficiently achieve the setting depth while maintaining safety and quality. Construction operations are subject to operator management procedures.

Factors that should be considered in determining the installation method (see 5.4) include the following:

a) the development mode of the target offshore well or field;

b) regional experience;

c) water depth;

d) seabed soils;

e) drilling rig specifications;

f) related equipments.

9.2 Driving

9.2.1 Applicability

Driving is used for a relatively shallow water depth to avoid column buckling of the conductor during driving, typically less than 200 m. Subsea driving is beyond the scope of this document.

The driveability analysis may be used to adapt the driving to the specific soil parameters. Driveability (See 9.2.2) depends on factors such as the soil conditions, conductor specification, hammer parameters, and well slot spacing. In areas where direct driving to the target depth is not possible due to the soil plug, the method of driving-drilling-driving may be used.

9.2.2 Driveability analysis

Driveability analysis shall be carried out in accordance with the requirements of ISO 19901-4.

9.2.3 Installation procedures

A suitably equipped vessel or drilling rig should be used to drive the conductor. If a vessel is used, the installation steps shall follow those undertaken to drive jacket piles. If a drilling rig is used, the following steps should be undertaken:

a) prepare the driving equipment and tools, including the hoisting equipment, pile hammer, centralized fixing block, substitute pipe, cutting machine, connecting equipment, rope, level instrument, flaw detection equipment, elevator, slip and hammer sleeve. The conductor directional drive shoe may be used to avoid collision;

b) measure and number the conductors by marking each conductor every 0,25 m or 1 ft;

c) install the conductor from the driving elevation by adding successive joints until it reaches the sea floor and penetrates the seabed under its own weight but with enough length above the rotary table;

d) install the hammer and hammer sleeve;

e) release the hammer onto the conductor, and use a small amount of power to hammer the conductor, at the conclusion of self-penetration, ensuring it does not slip below the rotary table;

f) add successive joints by thread or welding;

g) drive the conductor to the target depth;

h) use a survey tool, e.g. gyro tool, to measure the trajectory;

i) cut off any excess.

During the beginning of driving, conductor and hammer self-weight penetration and controlling of the hammer energy are critical to ensure the conductor does not experience large rapid penetration due to changes in the soil profile.

9.2.4 Pile group conductor driving sequence

Consideration should be given to the effects of closely spaced adjacent piles on the resistance–displacement characteristics of the pile group. Pile group effects (see 8.3.2.5) should be considered in the hammer driveability analysis (see 9.2.2). The recommendation of driving sequence should be from the middle to the surround.

9.2.5 Data documentation

Throughout driving of the conductor, comprehensive driving and associated data should be documented and reviewed for conformance with the installation plan. If significant deviations are observed, it can be necessary to take appropriate measures. The documented data can include:

— structure and conductor identification, water depth and readings of reference elevations of conductor markings;

— conductor tip penetration;

— relevant information on conductor stabbing;

— penetration of the conductor under its own weight and under the weight of any new add-on;

— additional penetration of the conductor under the weight of the hammer;

— data on followers used (where applicable);

— blow counts throughout driving, with hammer identification and hammer blow rate (blows/minute) after every 0,25 m or 1 ft of penetration;

— cumulative number of blows, at relevant penetrations;

— driving energy observations and hammer monitoring data (if available);

— conductor instrumentation data (if available);

— date and time of starts and stops in driving, including set-up time;

— elapsed time for driving each joint, with actual length of conductor joints and cut-offs;

— unusual behaviour of the hammer or the conductor during driving;

— elevations of soil plug and internal water surface after driving.

9.2.6 Quality

Quality requirements for driven conductors are comparable to those for driven piles. For platform conductors, the tolerance of the centre of each guide and the best-fit line should be less than 10 mm at the top guide and where the vertical spacing between guides is less than 12 m. In other cases, the tolerance at the centre of each guide and the best-fit line should be less than 13 mm.

9.3 Drilling and cementing

9.3.1 Applicability

The drilling and cementing installation method is suitable for almost all situations, especially for complex geological situations, highly variable rock properties, or situations with too many obstacles.

9.3.2 Size match of bit and conductor

The selection of the bit diameter should meet the requirements of the conductor diameter and of the cementing. Common matches are shown in Table 3.

Table 3 — Common size match of bit and conductor

Match	Conductor outer diameter	Bit diameter
1	914,4 mm (36 in)	1 066,8 mm (42 in)
2	762,0 mm (30 in)	914,4 mm (36 in)
3	609,6 mm (24 in)	660,4 mm (26 in)
4	508,0 mm (20 in)	660,4 mm (26 in)
For match 3, the annulus is 25,4 mm (1 in) so cement quality and cementing procedures require more attention.		

9.3.3 Wait on cement

Cement waiting time shall be determined based on cement slurry test results. Before drilling the next section, the conductor shall possess the capacity to hold subsequent weights.

9.3.4 Quality

Centrality and cementing quality should be guaranteed. Centralizers should be attached to the conductor to provide a uniform annulus. The cement slurry should return to the sea floor. A grouting operation should be performed on the top to fill the annulus if the objective was not met on the primary cement job.

9.4 Jetting

9.4.1 Applicability

Jetting is generally used for deep water subsea exploration and development wells which often require a fully cemented surface casing. It is also normally used in slightly over-consolidated marine clays.

9.4.2 Size match of bit and conductor

The following recommendations should be followed when jetting:

a) conductor outer diameters are generally 762,0 mm (30 in) and 914,4 mm (36 in). Jetting bit diameters are generally 660,4 mm (26 in) and 444,5 mm (17,5 in) although 406,4 mm (16 in) in some cases.

b) the amount of bit sticking out of the conductor tip should be determined from the soil properties and the jetting parameters. For standard bit sizes, the bit sticks out (150 ± 75) mm (3 in to 9 in) below the conductor tip while the nozzles are approximately 330 mm (13 in) inside the conductor. Additional recommendations on bit sticking out are given in Annex A.

9.4.3 Jetting bottom hole assembly

Jetting involves fully assembling the entire length of conductor sections, running tool (drill-ahead tool), drill bit and drill pipes, and then setting the conductor into the hole jetted by seawater, and occasionally injecting high-viscosity mud through the drill bit to sweep the cuttings. Multiple reciprocations (raising and lowering the conductor during jetting) are often needed to reach the target depth.

The general jetting BHA is as follows:

Bit + mud motor + stabilizer + jet sub + stabilizer + pony collars (as needed to space out) + running tool (drill-ahead tool) + drill pipe string.

NOTE A LWD tool can be included in the jetting BHA.

9.4.4 Jetting procedure

The jetting process can vary with operator and location. Annex A describes a typical jetting process.

9.4.5 Jetting operating parameters

For jetting, the following operating parameters should be determined:

a) WOB, considering that:

   1) the adopted WOB profile has an impact on the axial capacity, and should be constantly monitored throughout the operation to ensure the drill pipe above the sea floor always remains in tension;

   2) the criteria for the maximum and minimum allowable WOB can vary between operators;

   3) WOB utilizations between 0,8 and 1,0 may be used although typically 0,8 is adopted. WOB utilizations above 1,0 shall be avoided to prevent compression or buckling of the drill pipe above the running tool;

   4) the adopted WOB profile is determined based on the conductor installation satisfying particular criteria and allowing for the reciprocations which are performed, so that the WOB falls between the selected maximum and minimum values;

   5) to minimize damage to the surrounding formation, the WOB should be reduced.

b) flow rate, considering that:

   1) the jetting fluid should return through the annular space between the conductor and the BHA, not between the conductor and the formation; if the latter occurs, the flow rate should be reduced;

   2) during jetting, flow rates and corresponding pressures normally start at a low value and gradually increase to the target value; this target value can vary widely among rig operators.

   Guidance on a calculation method for flow rate is given in Annex A.

9.4.6 Data recording

a) the following data should be recorded prior to the start of jetting operations:

   1) measured weight of the conductor;

   2) measured weight of the jetting BHA;

   3) measured length of the conductor;

   4) hook load when the bit is just above the sea floor;