# Design and Analysis of Stationkeeping Systems for Floating Offshore Structures

API RECOMMENDED PRACTICE 2SK
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**THE *CONTENTS*, *SPECIAL NOTES*, AND *FOREWORD* WILL BE INSERTED BY API DURING THE PAGE PROOFING PROCESS.**

## Introduction

API's standards for the analysis and design of moored vessels have evolved, since the first editions of API 2P, API 2FP1, and API 2SK (published in 1984, 1993, and 1995, respectively), and these codes continue to be applicable to the analysis and design of stationkeeping systems that are normally manned and may be occasionally evacuated. The design of mooring systems described herein assumes redundancy, intact and one-line broken cases satisfying the acceptance criteria are required, and therefore is not applicable to moorings that cannot keep station in one-line broken conditions (such as single-line tethers for buoys, or mooring systems with less than five mooring lines in the intact case). For permanent production systems, operating procedures for stationkeeping systems are intended, as a minimum, to include the ability to shut-in wells and the facility in an emergency (e.g. emergency shut-down valves on the seabed); otherwise the consequence of mooring failure could be very different than inherently assumed.

This edition includes several additions and changes. The most significant changes include:

— Mandatory minimum design requirements are collected in the body of the standard and informative guidance is included in Annex A.

— Gulf of Mexico hurricane season MODU mooring requirements are included in Annex B.

— Guidance based on recent technical advances in the offshore industry is also included throughout.

The 4th edition of API 2SK also represents an umbrella document for stationkeeping system design, which is supported by additional guidance or specifications of stationkeeping system components, such as environmental criteria, anchor design, inspection, and integrity management. These supporting documents include (to address the described interest):

— API 2MET (environmental conditions a moored stationkeeping system is exposed to)

— API 2SM (determination of fiber rope properties for design analysis)

— API 2I (inspection of moored stationkeeping systems and components)

— ISO 19901-4 (geotechnical aspects of anchor designs for stationkeeping systems)

— API 2MIM (integrity management of moored stationkeeping systems)

— API 2F (chain specification for moored stationkeeping systems)

— API 9A (wire rope elements of a moored stationkeeping system)

— API 2S (mooring fairleads or windlasses for a moored stationkeeping system)

The technology of moored floating units continues to develop. In those areas where adequate data is available, specific and detailed recommendations are given. In other areas, general statements are used to indicate where it is intended for consideration to be given to those particular design aspects. Designers are encouraged to utilize research advances available to them.

# Design and Analysis of Stationkeeping Systems for Floating Offshore Structures

## 1 Scope

This standard addresses the design and analysis of stationkeeping systems (mooring systems with or without thruster assistance) in conditions from survival to operational. Different design requirements for mobile and permanent moorings are provided.

The procedures for the design of permanent or site assessment of mobile mooring systems specified in this document are based on a deterministic approach where mooring system responses such as line tensions, vessel offsets, and anchor loads are evaluated for a design environment defined by an annual probability of occurrence or return period. Mooring system responses are then checked against acceptance criteria for mooring strength, offsets and orientation, clearances, anchor capacity, fatigue resistance, and so forth. The minimum acceptance criteria are either defined in this standard or are to be specified by the owner or operator.

For moored vessels, system responses are calculated and compared to acceptance criteria for limit states describing acceptable extreme loads (line tensions), vessel offsets (translation and rotation), clearances (vessel, risers, water surface, seabed, anchors, field infrastructure, etc.), and fatigue (cumulative mooring component fatigue damage). Limit states associated with the extremes of the vessel's first order wave frequency motions (surge, sway, heave, roll, pitch, and yaw at a particular point on the vessel) such as serviceability of machinery, heave compensators, separators, tank sloshing, motion-sickness, etc. exist, however they are not addressed by this standard.

The requirements of this standard mainly address spread and single-point mooring systems with mooring lines composed of chain, wire rope, fiber rope, or a combination of these. This standard is applicable to the following types of stationkeeping systems:

— spread moorings;

— single-point moorings, anchored by spread mooring arrangements;

— thruster-assisted moorings.

NOTE Guidance on the design and operation of dynamically positioned vessels is contained in IMCA M103.

This standard is not applicable to the vertical tendons found on tension leg platforms (TLPs); which are covered by API 2T. Parts of this standard may not be appropriate for stationkeeping systems that are normally un-manned and occasionally manned (such as wind farms) or normally un-manned floating facilities. API 2SM, API 2I, and API 2MIM provide more detailed guidance on fiber ropes, mooring inspection, and integrity management.

## 2 Normative References

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

API Recommended Practice 2SM, *Design, Manufacturing, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring*

API Recommended Practice 2I, *In-Service Inspection of Mooring Hardware for Floating Drilling Units*

ISO 19901-4:2016, *Petroleum and natural gas industries — Specific requirements for offshore structures — Part 4: Geotechnical and foundation design considerations*

API Recommended Practice 2MET, *Derivation of Metocean Design and Operating Conditions*

API Recommended Practice 2A-WSD, *Planning, Designing, and Constructing Fixed Offshore Platforms*

# 3 Terms, Definitions, Symbols, and Abbreviations

## 3.1 Terms and Definitions

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

**3.1.1**
**active stationkeeping system**
Stationkeeping systems that make use of dynamic positioning, thruster assistance, line length or pretension adjustments, planned changes in vessel draft, winching (kedging) off location, disconnection, etc.

**3.1.2**
**catalog break strength (CBS)**
The manufacturer's design or target break strength for fiber rope (including terminations), wire, chain, or connecting hardware used in mooring lines, usually given in kilo-Newtons (kN), metric tons (tonne), or thousands of pounds (kip).

NOTE 1 Adapted from API 2SM.

NOTE 2 The minimum break strength (MBS) of a component is also used.

**3.1.3**
**catenary mooring**
Mooring system where the restoring force is mainly provided by the distributed weight of mooring lines.

NOTE Mooring system restoring forces are due to forces from both catenary and strain deformations of the mooring lines.

**3.1.5**
**damaged condition**
State of the stationkeeping system after a mooring line(s) breakage or a single-point failure of the thruster system or a combination of these.

**3.1.6**
**design criteria**
Specific values or quantitative formulations that describe the conditions to be satisfied for each limit state.

NOTE The design criteria given in this standard are minimum requirements.

**3.1.7**
**design service life**
Duration for which the structure or structural component is intended to be used, with planned maintenance (usually given in years).

**3.1.8**
**design condition**
**design situation**
A set of physical conditions within an annual probability of occurrence, or return period, used in evaluating the relevant limit states, one of the design load cases.

**3.1.9**
**dynamic load**
External load that induces acceleration of a structural component, normally specified by a spectrum, e.g. Wind and wave spectra and associated parameters.

**3.1.10**
**dynamic positioning (DP)**
Stationkeeping technique in which on-board thrusters generate forces that counter vessel offsets and or environmental loads.

**3.1.11**
**expected value**
The expected value of a probability distribution is a predicted value of the variable, calculated as the sum of all possible values each multiplied by the probability of its occurrence, Also known as the expectation, mathematical expectation, mean, average, or first moment of the distribution.

**3.1.12**
**floating structure**
Surface structure where the structure's weight and vertical forces due to mooring lines, risers, umbilicals, etc., are completely supported by its buoyancy.

**3.1.13**
**integrated thruster control system (ITCS)**
The integrated thruster control system (ITCS) consists of the thrusters, and the control, power generation and distribution systems.

**3.1.14**
**limit state**
Limit states define the limiting conditions beyond which the structural system or component is no longer deemed to satisfy the design requirements, consequently, there is a correspondence between limit states and traditional design conditions.

**3.1.15**
**minimum break strength (MBS)**
The minimum break strength is the component's strength as defined by a recognized industry standard.

NOTE It is also called the minimum break load (MBL), break test load (BTL), reference break strength (RBS), and catalogue break strength (CBS).

**3.1.16**
**mobile mooring system**
Mooring system, generally retrievable, intended for deployment at a specific location for a short-term operation, such as those for mobile offshore drilling units (MODUs).

**3.1.17**
**mobile offshore drilling unit (MODU)**
A floating structure that performs drilling operations.

**3.1.18**
**mobile offshore unit (MOU)**
Structure that is frequently relocated to perform a particular function.

EXAMPLE Pipelaying vessel or barge, offshore construction structure, accommodation structure (floating hotel or floatel), service structure, or mobile offshore drilling units.

**3.1.19**
**mooring component**
A component used in mooring or anchoring a floating structure.

EXAMPLE Chain, steel wire rope, fiber rope, clump weight, buoy, winch, windlass, chain jack, stopper, triplate, H Links, shackles, fairlead, anchor, etc.

**3.1.20**
**operator**
Representative of the company or companies which own or operates a development, who can be the operator on behalf of co-licensees.

EXAMPLE The operator owns the development while the MODU is owned by the drilling contractor.

**3.1.21**
**owner**
Representative of the company or companies that own a development or that own the floating structure.

**3.1.22**
**passive mooring**
Passive moorings respond to changes in vessel draft, trim, and environmental loads without any intervention or adjustment of the mooring lines, do not use thrusters, and are not readily dis-connectable.

**3.1.23**
**permanent mooring system**
Mooring system normally used to moor floating structures deployed for long-term operations.

NOTE Such as those for a floating production system (FPS).

**3.1.24**
**probability**
The relative frequency that an event will occur, as expressed by the ratio of the number of occurrences of the event to the total number of possible occurrences.

**3.1.25**
**reliability**
A measure of the probability of an item or system to adequately perform a required function under stated conditions of use and maintenance for a stated period of time.

**3.1.26**
**resistance**
**strength**
Capacity of a structure or component to withstand load effects without failure.

EXAMPLE Component strength (kN, tonne, or kip) or fatigue resistance (component TN fatigue curve).

**3.1.27**
**return period**
The return period, in years, is equal to the reciprocal of the annual probability of occurrence of a single event, or the joint probability of occurrence of multiple events.

**3.1.28**
**riser**
Tubulars used for the transport of fluids between the sea floor and the platform.

NOTE Possible functions include drilling, well intervention, production, injection, subsea systems control, and export of produced fluids.

**3.1.29**
**risk**
The product of the probability of occurrence of a hazardous event and its consequence(s).

**3.1.30**
**semi-submersible**
Floating structure normally consisting of a deck structure with a number of widely spaced, large cross-section, supporting columns connected to submerged pontoons.

NOTE Pontoon and column geometry is usually chosen to minimize global motions in a broad range of wave frequencies.

**3.1.31**
**significant value**
Statistical measure of a zero-mean random variable equal to twice the standard deviation of the variable.

NOTE Has the same dimensional properties as the variable being examined.

**3.1.32**
**single-point mooring**
Mooring system that allows the floating structure to which it is connected to vary its heading.

EXAMPLE One example of a single-point mooring is a turret mooring system where a number of mooring lines are attached to a turret, which includes bearings to allow the structure to rotate.

**3.1.33**
**spar**
Deep-draught, small water-plane area floating structure.

**3.1.34**
**spread mooring**
Mooring system consisting of multiple mooring lines terminated at different locations on a floating structure, extending outwards, and providing an almost constant vessel heading.

**3.1.35**
**stationkeeping system**
System capable of limiting the excursions of a floating structure within prescribed limits.

**3.1.36**
**thruster-assisted mooring (TAM)**
Stationkeeping system consisting of both mooring lines and thrusters.

**3.1.37**
**tropical revolving storm (TRS)**
Collective name for hurricanes, cyclones, and typhoons.

**3.1.38**
**virtual mass and inertia**
The sum of mass and added hydrodynamic mass or inertia and added hydrodynamic inertia.

NOTE Also called effective mass and inertia.

## 3.2 Symbols

| | |
|---|---|
| $D$ | annual fatigue damage, in years$^{-1}$ |
| $d$ | diameter of the mooring line or component, in millimeters (mm) or inches (in.) |
| $K$ | fatigue constant for TN curves, non-dimensional |
| $K_S$ | fatigue constant for SN curves; $K_S$ has dimension of $S^{m_s}$, where $S$ is stress and $m_s$ is the slope of the SN curve |

$L$ design services life, in years (yr)

$m$ slope of the TN fatigue curve

$m_s$ slope of the SN fatigue curve

$N$ number of cycles, non-dimensional

$N_i$ number of cycles to failure at normalized tension range *i* (from appropriate T-N curve)

$n_i$ number of cycles per year within the tension range interval *i*

$P_i$ probability of occurrence of environmental state *i*

$R$ ratio of tension range to reference breaking strength at half of the component's design life, non-dimensional

$T$ specified storm period, in seconds (s)

$T_i$ time spent in environmental state *i* per year, in seconds (s)

$v_i$ zero up-crossing frequency of the tension spectrum in environmental state *i,* in hertz (Hz)

## 3.3 Abbreviations

AHC anchor holding capacity

AJP annual joint probability of occurrence

CALM catenary anchor leg mooring

CBS catalogue break strength

CFD computational fluid dynamics

DP dynamic positioning

ELBS end-of-life break strength

FEA finite element analysis

FLS fatigue limit state

FMEA failure modes and effects analysis

FPS floating production system

FPSO floating production, storage, and offloading structure or system

FSO floating storage and offloading structure or system

HMPE high modulus polyethylene

IMO International Maritime Organization

ITCS integrated thruster control system

MBS minimum break strength

MODU mobile offshore drilling unit

| | |
|---|---|
| MOU | mobile offshore unit |
| NPD | Norwegian Petroleum Directorate |
| OD | owner defined |
| ORQ | oil rig quality |
| RAO | response amplitude operator |
| RBA | response-based analysis |
| RBS | reference break strength |
| RRP | required, recommended, or permitted |
| SCF | stress concentration factor |
| SEPLA | suction embedded plate anchor |
| SLS | serviceability limit state |
| SWF | single worst failure |
| TAM | thruster-assisted mooring |
| TLP | tension-leg platform |
| ULS | ultimate limit state |
| VIM | vortex induced motion |
| VLA | vertically loaded anchors |

# 4 Stationkeeping Systems and Components

## 4.1 Mooring Components

### 4.1.1 General

The mooring components shall be specified or approved by the owner or operator. Manufacturing of mooring line components should be subject to quality assurance standards, as specified by the owner or operator.

Mooring components are used to connect the moored floating structure to the seafloor and can be categorized as tensioning equipment, fairleads and bending shoes, padeyes, mooring line segments including terminations, connecting hardware, buoys, weight chain, clump weights, and anchors.

### 4.1.2 On-vessel tensioning equipment

The strength of tensioning equipment should be greater than the maximum line tension under which it will be operated, with a safety margin. For example, stoppers, fairleads, padeyes, and their structural foundations should be designed to the maximum intact and one-line damaged loads with a safety margin, while winches and chain jacks may be designed to the loads under which they will be operated. The design philosophy is based on mooring line components failing before the foundations fail.

The analysis and design of fairleads, bending shoes, padeyes, and stopper arrangements should include effects in addition to tension-tension loading on the wear and fatigue performance of the mooring line components.

Winches should be designed to ISO 9089. The foundation of the tensioning equipment on the floating structure should be designed to API 2A-WSD or API 2FPS.

Tensioning equipment, such as winches, windlasses, and chain jacks should be maintained according to API 2S or API 2MIM.

#### 4.1.3 Fairleads and bending shoes

For fairleads, chain links are supported in pockets, and wire ropes are supported in a shaped channel. Poor support conditions or poor geometric fit between chain or wire rope and the fairlead may result in a reduction in the strength and fatigue endurance of the component.

Bending shoes may be made of a curved plate or of a number of flat plates with angular discontinuities (knuckles) between the plates. Also, the bending shoe may contain a grove, in which case every other link is horizontal with both side bars resting on the plate and the intermediate links are vertical in the groove. The complex loading of the links on the bending shoe may result in the reduction of their strength and fatigue life.

#### 4.1.4 Off-vessel anchor line components

##### 4.1.4.1 General

Mooring line off-vessel components consist of, but are not limited to, fiber ropes, steel wire ropes, chains, connectors, buoys, clump weights, weight chain, and anchors.

NOTE See Section 7 for anchors; also, recommendations for geotechnical survey's and the design of some types of anchors are provided in ISO 19901-4.

##### 4.1.4.2 Fiber rope

Mooring system requirements, analysis methods, and the acceptance criteria for fiber ropes are the same as for steel components. For fiber rope properties, construction, and testing see API 2SM.

##### 4.1.4.3 Mooring wire rope

Wire ropes and end sockets should be manufactured to meet or exceed the requirements of one of the following specifications:

a) Owner or operator specified manufacturing and testing specifications, or

b) API 9A.

##### 4.1.4.4 Mooring chain

Mooring chain should be manufactured to meet or exceed the requirements of one of the following specifications:

a) Owner or operator specified manufacturing and testing specifications,

b) API 2F, or

c) ISO 20438:2017.

##### 4.1.4.5 Connecting hardware

Connecting hardware consists of standard components (e.g. D-shackles, Kenter links, etc.) or components specially designed for a particular application. Design, manufacturing, and functional requirements shall be specified by the owner or operator. Multi-year drilling campaigns may require fatigue assessment of mooring components, particularly connecting hardware.

Standard connecting links should be made of forged or cast material and should be compatible with the connected chain or terminations of the wires or fiber ropes in terms of strength, fatigue, and corrosion protection requirement. Kenter links should meet the requirements specified in API 2F or ISO 20438:2017 .

Specially designed mooring connectors, such as H-links, subsea mooring line connectors, single or dual-axial hawse pipes, etc., shall satisfy the strength and fatigue requirements in this standard.

#### 4.1.4.6 Buoys

Surface buoys should incorporate measures (such as compartmentalization) in order to minimize the risk of sinking in the event of damage. Subsurface buoys of steel construction shall be designed for external pressure to a pressure containment standard for use at the maximum operational depth identified by the mooring analysis; see 7.3.6.3 for specific information regarding the requirements.

Steel buoys should be provided with a corrosion protection system.

#### 4.1.4.7 Disconnectable turret buoy

Turret buoys are used on FPSOs with disconnectable turrets. The net buoyancy of the buoy should be adequate to support the risers, umbilicals and mooring lines during and after disconnection. The mooring and riser loads and the net buoyancy should be designed so that when released the buoy's motions do not result in clashing of the mooring lines and/or risers or unacceptable seabed contact.

## 4.2 Monitoring Equipment

### 4.2.1 Genera

For regions where vessels are evacuated during extreme environmental conditions, such as for tropical revolving storms, remote monitoring should be implemented with data uploaded in real time. See Annex B and API 2MIM.

### 4.2.2 Line tension, pay-out, and vessel position

If the operation of the floater requires mooring line adjustment, line tensions and line pay-out shall be continuously displayed at the winch and in the control room. Passive mooring systems should be equipped with a monitoring system that at a minimum displays and records vessel position, heading, and draft.

Where vessel position information is critical to operations, the position reference system(s) should provide redundancy.

# 5 Environmental and Site Data

## 5.1 General

Design and site-assessment of station keeping systems shall account for the normal and extreme wind, sea-wave, swell-wave, and current conditions.

For a mooring system subject to ice loading, design recommendations are provided in API 2N.

## 5.2 Site-specific Data Requirements

### 5.2.1 General

The joint probabilities of wind, sea-wave, swell-wave, and current intensities and directions should be evaluated in the development of metocean criteria for normal and extreme conditions.

### 5.2.2 Environmental data

Environmental data shall be collected and analyzed in conformance with API 2MET. The interaction of environmental phenomena, such as wind, waves, current, and tide, is site-specific. The joint probabilities of wind, sea-wave, swell-wave, and current intensities and directions should be considered in the development of metocean criteria for normal and extreme conditions.

Some areas are subject to transient conditions, such as squalls, or to occasional high currents, such as solitons. In these cases, the occurrences should be accounted for in determining the relevant environmental design conditions.

For mobile moorings, if the start and duration of the site-specific operation are defined, seasonal environmental data may be used in developing the site-specific metocean criteria.

For fatigue analyses, weather bins of sea-wave, swell-wave, wind, current intensities, and global directions should be developed to support the mooring analyses. Multi-year hindcasts of wind, sea-wave, swell-wave, and current conditions may be provided for direct use in the fatigue analyses.

### 5.2.3 Seabed map, bathymetry, and soil profile

The field bathymetry map over the extent of the mooring line and riser touchdown points, and anchor locations should be provided. Seabed structures, hazards, or restricted zones, if any, shall be provided on field charts or maps.

Seabed soil conditions shall be investigated for the intended site to provide data for the anchoring system design. The sea floor slope shall be properly accounted for in the mooring analysis, when relevant. For permanent moorings, seabed surveys shall be performed in sufficient detail to obtain data representative of each proposed anchor installation target area. Refer to ISO 19901-4 for more detailed guidance.

### 5.2.4 Wave statistics

Site-specific (hindcast) data requirements for sea and swell-waves should account for:

a) wave height versus wave period,

b) wave height versus wave direction relationships, and

c) wave spectrum and associated parameters.

### 5.2.5 Wind statistics

Site-specific data requirements should account for:

a) wind speed and reference height,

b) wind direction,

c) wind profile, and

d) wind spectrum or time-history for transient winds.

### 5.2.6 Current statistics

Site-specific data requirements should account for:

a) current speed,

b) current direction,

c) current profile, and

d) current spectrum (when applicable).

# 6 Design and Site Assessment of Stationkeeping Systems

## 6.1 General

The purpose of passive or active stationkeeping systems is to restrict the excursion of the floating structure within prescribed limits, and to provide heading control when the structure's orientation is important for operations or safety. Not all system responses can be controlled or restricted by the stationkeeping system; e.g. wave frequency vessel motions are generally insensitive to the stationkeeping system.

Design and site assessment of stationkeeping systems shall account for the type of system, which include:

a) mobile and permanent systems, and

b) passive and active (dis-connectable, TAM, and MOU) systems.

The design or service life of permanently moored facilities is typically in the 15-year to 30-year range. Unless designed for disconnection, permanent stationkeeping systems shall be designed for full year metocean conditions (full populations of all types) without disconnection of risers. Mobile offshore units themselves typically have a design life of 30 or more years; however, they may be on a particular location for only a few weeks or months. Consequently, a MOU site assessment may be based on seasonal metocean conditions, e.g. MOU operations may be planned to avoid the winter storm season or tropical revolving storm season.

For mobile moorings where the consequences of a stationkeeping failure cannot be mitigated by suspending operations and moving to the survival condition (e.g. mooring in close proximity to a permanent facility), a risk assessment should be used to determine the appropriate environmental return period (i.e. inverse of the annual joint probability of occurrence), for the operation.

Mobile and permanent stationkeeping systems may be passive or active, or may occasionally require active intervention, such as line length management of a moorings with fiber rope segments.

Passive mooring systems do not make use of thrusters to assist in keeping station, are not readily dis-connectable, and typically do not adjust outboard mooring line lengths once the lines are deployed and pre-tensioned; that is, passive systems respond to changes in vessel draft, trim, and environmental loads without any intervention or adjustment of the mooring lines. For some permanent mooring systems, outboard line lengths may not be readily adjustable (e.g. where the lines are terminated at pad-eyes).

Active stationkeeping systems make use of some of the following:

— dynamic positioning (DP),

— thruster assisted mooring (TAM),

— line length or pretension adjustments for different operational-modes (e.g. step tensioning to reduce VIM response, or MODUs moving to survival condition, etc.),

— planned changes in vessel draft in preparation for extreme conditions and/or evacuation, and

— disconnection of the mooring lines from the vessel (e.g. for sea-ice or tropical revolving storms).

Mobile mooring or stationkeeping systems are commonly active systems. For example, during drilling operations MODUs typically ballast to a deep draft with high pretensions and may winch off-center to a safe zone while transferring loads, running casing, etc. When preparing for storm conditions, MODUs will typically disconnect and hang-off or retrieve the drilling riser, de-ballast to increase airgap, reduce pretensions, and may or may not evacuate some or all personnel. For MODUs, these two vessel and mooring conditions are referred to as the *operating* and *survival* conditions. For MOUs, the consequences of a stationkeeping failure for *operating, standby,* and *survival* conditions can be very different. Offset limits associated with the *operating* or riser connected conditions are also different from those associated with the storm *survival* condition. Similarly, different acceptance criteria may also apply to MOUs used for tender assistance, accommodation, diving support, construction, pipe-laying, etc., depending upon the proximity to other structures and the operation being performed.

Mobile moorings may be operated in different modes (e.g. operating, standby, or survival) with varying levels of consequences of failure. Typically, operations with high consequences are performed in mild environmental conditions and operations are suspended in severe weather, so that the consequences of a stationkeeping failure are reduced in extreme environmental conditions that result in extreme responses, offsets, tensions, anchor loads, etc.

Line length adjustments during extreme environmental events shall not be considered in the stationkeeping analysis. If operating practice and procedures for improving mooring performance, such as slackening leeward lines or slackening all mooring lines, before severe weather and/or evacuation is established, it can be taken into consideration in the stationkeeping analysis.

The acceptance criteria in this standard assumes that the risers of permanent stationkeeping systems are equipped with emergency shut-in valves that allow the risers to be shut-in and possibly purged (e.g. in advance of disconnection or prior to evacuation).

## 6.2 Design Conditions

### 6.2.1 General

The methodology for the design of permanent or site assessment of mobile mooring systems in this document is based on performing mooring system analyses and comparing specific mooring system responses with acceptance criteria defined in this document or specified by the owner or operator. IMCA M103 and ISO 19905-3 provides design and operational guidance for DP systems.

For moored vessels, system responses are calculated and compared to acceptance criteria for:

- Strength.(ultimate limit state (ULS)): Mooring component strength for intact and damaged conditions. Herein the ULS includes both intact and damaged stationkeeping systems.
- Serviceability (serviceability limit states (SLS)): Vessel offset, orientation, and clearance constraints. For mooring components these constraints include clearances with; the vessel, risers, seabed, water surface, field infrastructure, exclusion zones, etc.
- Fatigue (fatigue limit state (FLS)): Cumulative mooring component fatigue damage.

System properties such as wind, current, and wave forces and moment coefficients, wave motion RAOs, virtual mass and inertia, mooring line pretensions, mooring system stiffness, mean equilibrium position, etc., all depend on the vessel's draft and trim. The range of the vessel's draft, trim, and in some cases heel, shall be accounted for in the stationkeeping analyses. For FPSOs, where the range of operating drafts and trims are significant, the design analysis cases should be performed for minimum, mid, and maximum operating drafts and trims. For MODUs, mooring line pretensions and vessel drafts are often different for operating, standby, and survival conditions. For site assessment of MODU stationkeeping systems, the survival and operating cases shall be analyzed using the appropriate vessel draft, vessel properties, and mooring line pretensions.

NOTE An example of analysis cases and acceptance criteria for a permanent system's mooring line strength and seabed clearance is illustrated in Table A.1, and an example for a site assessment of a mobile mooring is illustrated in Table A.2.

The analysis cases for the design of permanent and site assessment of mobile systems are described and summarized in tables in 6.2.2 through 6.2.5. The acceptance criteria are in Section 7 and methods of analysis and analysis requirements are in Section 8.

For both mobile and permanent stationkeeping systems the environmental parameters describing extreme return period, normal operating, and fatigue conditions shall be developed from site-specific metocean data. Metocean conditions for extreme N-year return period conditions are defined as those combinations of wind, waves, and currents with an annual joint probability of occurrence of 1/N. This is often approximated using multiple sets of conditions, for example:

— N-year wind with associated sea-waves, currents, and swell-waves,

— N-year sea-waves with associated winds, currents, and swell-waves,

— N-year currents with associated wind, sea-waves, and swell-waves, and

— N-year swell-waves with associated winds, sea-waves, and currents.

The most severe directional combination of wind, sea-wave, current, and swell-wave for the response being investigated shall be selected for the design or site assessment of the stationkeeping system, consistent with the site's environmental conditions (see A.6.2). For turret moored vessels in transient wind squall conditions, the directional combinations shall include initial vessel heading and wind squall direction consistent with the site-specific metocean conditions (see 8.6.3).

For some mooring systems or types of system response, the most onerous response(s) may not be associated with the maximum environmental return period; for example:

— mean wave drift forces and low frequency vessel motions increase with decreasing wave period, consequently the N-year return period wave condition may not yield the most onerous responses (maximum tensions, offsets, minimum clearances, etc.) with an annual probability of occurrence of 1/N or greater;

— for spars VIM lock-in, $4 < V_r < 6$, and maximum responses may occur for current speeds below the N-year return period current speed; and

— for an external turret moored vessel, clearances between the mooring lines and vessel are usually smallest in benign metocean conditions; while for MODUs, mooring line contact with the anchor bolster is most critical for slack lines in extreme environments.

In this standard where an N-year return period metocean condition is specified this shall include all metocean conditions up to and including N-year return period conditions (return periods ≤ N-years), or more generally all conditions with an annual joint probability of occurrence greater than or equal to 1/N (annual joint probability (AJP) ≥ 1/N).

NOTE The calculation of the joint annual probability of simultaneous occurrence of two independent events is described in A.6.2.

It is recommended that stationkeeping analyses be performed for metocean conditions with a range of return periods that span the required return period. For example, MOU or permanent mooring's strength analyses may be performed for return period conditions of 1, 5, 10, 25, 100, and 200 years to ensure that the most onerous conditions are identified and to provide a better understanding of system responses and trends.

Where there is a concern that the (deterministic) design approach in this standard is inappropriate for the specific system, a response-based analysis (RBA) may be used. If a RBA is performed, the methodology (development of the metocean dataset used as input and the statistical post-processing of system responses) shall be specified by the owner or operator (see A.8.8). The acceptance criteria for tension, offset, and clearance provided in Section 7 shall still be satisfied.

### 6.2.2 Strength analysis cases

#### 6.2.2.1 Strength analysis cases for permanent systems

Analysis cases for the evaluation of the intact and damaged strength of passive and active permanent stationkeeping systems are listed in Table 1. Analyses shall be performed for vessel drafts and trims that span the operating range of the vessel.

Passive permanent mooring systems (part A of Table 1) shall satisfy the strength criteria of Section 7 for intact and 1-line broken cases, for metocean conditions with return periods up to and including 100-yr.

Thruster-assisted moored (TAM) permanent systems that are not also disconnectable mooring systems (part B of Table 1) shall satisfy the strength criteria, Section 7, for intact and single failure cases for metocean conditions with return periods up to and including 100-years. For TAM systems, definitions of intact and damaged conditions are given in 7.1.1.

Disconnectable permanent mooring systems, with or without thruster assistance, shall be analyzed for two conditions, with the vessel connected, and the vessel disconnected (buoy alone, part C1 of Table 1), respectively. With the vessel connected, the stationkeeping system shall satisfy intact and single failure (mooring line or thruster) strength criteria, Section 7, for metocean conditions up to and including the maximum vessel connected environmental condition. For example, where a permanent mooring system will only disconnect for ice conditions, the maximum connected environment shall include 100-year return period metocean conditions. Where the vessel will disconnect for tropical revolving storms, the maximum connected environment is the 100-year return period environment excluding tropical revolving storm conditions. Where it may not be possible to disconnect for sudden hurricanes, the 100-yr sudden hurricane criteria should be considered. Intact and damaged strength analyses shall also be performed for the buoy alone (vessel disconnected, part C2 of Table 1) for metocean conditions up to and including 100-year return period conditions.

**Table 1 — Strength Analysis Cases: Permanent Systems**

| Permanent Systems - Analysis Cases | Annual Joint Prob. or Return Period | RRP | Comment |
|---|---|---|---|
| **(A) Strength, Passive Mooring** | | | |
| Intact Mooring | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| One-line Broken | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| ***Robustness and system behavior*** | | | |
| Two-lines Broken | OD | Permitted | Weather conditions and risk assessment for producing with one line broken |
| Intact Mooring | OD | Permitted | Change in response (VIM, wave in deck, etc.) risk assessment (e.g. AJP ≥ $10^{-4}$) |
| Hull Compartment Damage | OD | Permitted | Special case as needed (e.g. AJP ≥ $10^{-2}$) |
| **(B) Strength, Thruster Assisted Mooring** | | | |
| Intact System | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| Single Failure (mooring, thruster) | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| ***Robustness and system behavior*** | | | |
| Double Failures (mooring, thruster) | OD | Permitted | Weather conditions and risk assessment for producing with one line broken |
| Intact System | OD | Permitted | Change in response (VIM, wave in deck, etc.), risk assessment (e.g. AJP ≥ $10^{-4}$) |
| Thruster Blackout | OD | Permitted | Risk assessment (e.g. AJP ≥ $10^{-2}$) |
| Hull Compartment Damage | OD | Permitted | Special case as needed (e.g. AJP ≥ $10^{-2}$) |
| **(C1) Strength, Disconnectable Mooring – Vessel Connected** | | | |
| Intact System, vessel connected | Max connected env. | Required | Max connect env., AJP ≥ $10^{-2}$ |
| Single Failure (mooring, thruster), vessel connected | Max connected env. | Required | Max connect env., AJP ≥ $10^{-2}$ |
| ***Robustness and system behavior*** | | | |
| Double Failures (mooring, thruster), vessel connected | OD | Permitted | Weather conditions and risk assessment for producing with one line broken |
| Intact System, Vessel Connected | OD | Permitted | Risk assessment (e.g. AJP ≥ $10^{-4}$) |
| Hull Compartment Damage | OD | Permitted | Special case as needed (e.g. AJP ≥ $10^{-2}$) |
| **(C2) Strength, Disconnectable Mooring – Buoy Alone, Vessel Disconnected** | | | |
| Intact System, Buoy, Vessel Disconnect | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| One-line Broken, Buoy, Vessel Disconnect | $10^{-2}$, 100-yr | Required | Return periods up to and including 100-yrs |
| Transient Analysis, response of buoy on disconnecting | OD | Permitted | Risk assessment, mooring line and riser clashing, etc. (max disconnect env.) |

All load-bearing components of the mooring system shall satisfy the acceptance criteria of Section 7; i.e. at anchors, fairleads, stoppers, end points of each mooring line segment, connectors, buoys, clump weights, etc., where applicable. For mooring lines that include buoys, clump weights, or loop/weight chains the loss due to disconnection from the mooring line without the failure of the line itself, shall be included as a potential damaged mooring line scenario.

To develop a more complete understanding of the performance of the stationkeeping system the owner or operator may perform analyses for some of the additional optional or permitted cases in Table 1. For example, knowledge of the stationkeeping systems' performance with two failures (mooring lines or thrusters) is necessary for evaluating risks associated with re-starting production with one line failed.

#### 6.2.2.2 Strength analysis cases for mobile systems

Analysis cases for the strength of intact and damaged mobile stationkeeping systems are listed in Table 2. Analyses shall be performed for the vessel drafts and pretensions applicable for operating, standby, and survival modes. Site-specific assessment criteria for MODUs operating in the Gulf of Mexico during hurricane season, June 1st to November 30th, shall be as specified in Annex B.

The consequences of a failure to keep station depend upon the proximity of the moored system to other surface and subsea structures, and environmentally sensitive areas such as reefs and seafloor habitats; this is implicit in the types of MOU operations distinguished in Table 2, where:

— Away from other structures, means negligible risk of hitting other structures during progressive failure of the mooring system, nominally greater than 25 miles.

— In vicinity of other structures, means possibility of hitting other structures during progressive failure of the mooring system, nominally greater than 1 mile.

— In close proximity to other structures, means likely to hit other structures during progressive failure of the mooring system (TAD, floatel, gangway connected), nominally less than 1 mile.

Passive and thruster assisted mooring systems shall satisfy the strength criteria, Section 7, for intact and single failure cases (Table 2) for metocean conditions with return periods up to and including 5, 10, and 25 years where they are away from, in the vicinity of, or in close proximity to other structures.

Disconnectable mobile mooring systems, with or without thruster assistance, shall be analyzed with the vessel connected for intact and single failure cases for the maximum connected environmental conditions. For example, where a MOU mooring system will only disconnect for ice conditions, the maximum connected environment shall include 5-, 10-, or 25-year return period conditions, depending on whether or not the mooring is away from, in the vicinity of, or in close proximity to other structures. Where the vessel will disconnect for hurricanes, including sudden hurricanes, the maximum connected environment is the 5-, 10-, or 25-year return period conditions, excluding tropical revolving storm conditions, depending on whether or not the mooring is away from, in the vicinity of, or in close proximity to other structures. See Section 7 for acceptance criteria.

All of the components of the mooring system shall satisfy the acceptance criteria (i.e. tensions or loads at anchors, fairleads, stoppers, end points of each mooring line segment, connectors, buoys or clump weights, etc.), where applicable. For mooring lines that include buoys, clump weights or loop/weight chains, the loss due to disconnection from the mooring line without the failure of the line itself shall be included as a potential damaged mooring line scenario.

**Table 2—Strength Analysis Cases: Mobile Systems**

| Mobile Systems - Analysis Cases | Passive and TAM | Disconnectable | RRP | Comment |
|---|---|---|---|---|
| | Annual Joint Prob. or Return Period | | | |
| **A) Strength, Survival Conditions** | | | | |
| **A1) Away from Other Structures** | | | | |
| Intact System | $2 \times 10^{-1}$, 5-yr | Max Connected Env | Required | — |
| Single Failure (mooring, thruster) | $2 \times 10^{-1}$, 5-yr | Max Connected Env | Required | — |
| **A2) In the Vicinity of Other Structures** | | | | |
| Intact System | $10^{-1}$, 10-yr | Max Connected Env | Required | — |
| Single Failure (mooring, thruster) | $10^{-1}$, 10-yr | Max Connected Env | Required | — |
| **A3) In Close Proximity to Other Structures** | | | | |
| Intact System | $4 \times 10^{-2}$, 25-yr | Max Connected Env | Required | Gangway disconnected in survival or standby mode |
| Single Failure (mooring, thruster) | $4 \times 10^{-2}$, 25-yr | Max Connected Env | Required | Gangway disconnected in survival or standby mode |
| Transient Response after First Failure (mooring, thruster) | OD | OD | Permitted | Special case as needed |
| ***Robustness and system behavior*** | | | | |
| Double Failure (mooring, thruster) | OD | | Permitted | Risk assessment |
| Intact Mooring and Blackout | OD, TAM only | — | Permitted | Informative, system performance, risk assessment |
| Intact System and Failure to Disconnect | — | OD | Permitted | Informative, system performance, risk assessment |
| Intact System | OD, large return periods | — | Permitted | Informative, system performance, risk assessment |
| **B) Strength, Operating Condition** | | | | |
| Intact System | OD. Max Operating Env | OD. Max Operating Env | Required | Required for riser and clearance analyses, etc. |
| Single Failure (mooring, thruster) | OD. Max Operating Env | OD. Max Operating Env | Required | Required for riser and clearance analyses, etc. |

### 6.2.3 Offset analysis cases

Analysis cases for permanent or mobile vessel offsets for intact and damaged stationkeeping systems are listed in Table 3. Analyses shall be performed for vessel drafts and pretensions applicable for the permanent or mobile system as described in 6.2.2.

**Table 3—Offset Analysis Cases: Permanent and Mobile Systems**

| Analysis Case | Permanent Systems | Mobile Drilling (MODU) | Tender Assist or Close Proximity | RRP |
|---|---|---|---|---|
| | Annual Joint Probability or Return Period | | | |
| Intact System | Intact riser offset limits, AJP $10^{-2}$, RP 100-yr | Offset limit for the maximum riser connected drilling (rotating) environment, OD. | Offset limit for the maximum gangway connected environment, vessel to platform clearance, etc., OD. | Required |
| Single Failure (mooring, thruster) | Single failure riser offset limits, AJP $10^{-2}$, RP 100-yr | Offset limit for the maximum riser connected non-drilling (non-rotating) environment, OD. | Offset limit for the maximum gangway connected environment, vessel to platform clearance, etc., OD. | Required |

For MOUs, the serviceability offset limit state is associated with the maximum environmental conditions for which the operations (riser connected, gangway connected, etc.) can be performed. These limiting environmental conditions will control the amount of time that is spent waiting on weather and therefore have a direct impact on the economics of the operation. Vessel offset analysis cases and acceptance criteria applicable for other types of MOU operations, such as diving support, construction, pipe-laying, etc., shall be specified by the owner or operator.

### 6.2.4 Clearance analysis cases

Analysis cases for assessing clearances of intact and damaged permanent and mobile mooring systems are listed in Table 5 and apply to the deployed (installed and pre-tensioned) mooring system, installation criteria and considerations are addressed in 6.3 and 10.2. Analyses shall be performed for vessel drafts and pretensions applicable for permanent and mobile systems as described in 6.2.2.

Fiber and steel wire ropes and their terminations may be damaged by repeated contact with the seabed. The recommended analysis cases to determine minimum clearances between wire and fiber ropes and the seabed (Table 5) apply to the slack mooring lines, in particular the bottom end of the wire or fiber rope segment in the water column. That is, wire or fiber ropes in the water column that are on the slack side of the mooring system which could contact the seabed (be located in the thrash zone). Wire ropes may be in contact with the seabed provided that the contact remains throughout the full range of predicted line tensions (i.e. the wire or fiber rope does not slide on or lift off the seabed). The susceptibility to damage of a fiber rope due to seafloor contact depends on the design of the rope's jacket and filter barrier, and the soil conditions and seafloor characteristics. Also, as fiber ropes are close to neutrally buoyant, or slightly negatively buoyant, they are susceptible to movement and possible damage on the seafloor. Requirements for rope construction, seabed survey, and soil conditions are specified in API 2SM for fiber ropes in contact with the seabed.

For fiber moorings, a suitable length of steel wire or chain should be provided at the top end of the fiber rope mooring leg. The upper steel mooring line segment can be used to adjust the mooring line tension as needed to allow for rope elongation throughout the mooring system's life, or for repositioning of permanent or mobile vessels. It is recommended that the owner or operator establish clearance requirements between the top of the fiber rope and the sea surface (part B of Table 4).

For external turret moored vessels, the clearance between the mooring lines and vessel are usually smallest in benign metocean conditions when the vessel's orientation places it over a line or group of lines, and clearances generally increase with the severity of the environment. For external turret moorings contact of taut lines with the hull shall be avoided in metocean conditions up to and including 1-year return period conditions (part C of Table 7.3). The calculation of the minimum clearance between the hull and mooring line, shall be performed for the most onerous combination of vessel draft and trim and include the effects of low and wave frequency vessel motions.

For other types of permanent moorings and MOUs, clearances between the mooring line and hull or anchor bolster are generally a minimum for slack lines in extreme environmental conditions. For permanent systems, slack side mooring lines shall remain clear of the hull in the intact conditions specified in 6.2.2. For permanent systems, slack mooring lines should remain clear of the hull in the single failure conditions specified in 6.2.2. For MOUs, the owner/operator may define the return period and clearance requirements for slack side mooring lines. Analysis cases for slack lines of permanent and mobile moorings for intact and damaged stationkeeping systems are contained in Table 4.

Mooring lines shall remain clear of risers, mooring lines of other installations, pipelines, seabed infrastructure and exclusion zones (part D of Table 4) in the intact conditions specified in 6.2.2. Mooring lines should remain clear of risers, other mooring lines, pipelines, seabed infrastructure, and exclusion zones in the single failure conditions specified in 6.2.2.

Surface and sub-surface buoys may be used in intact and damaged cases to manage clearances where a mooring line crosses over a pipeline, another installation's mooring line, or to maintain clearance between the line and the hull or anchor bolster. Analyses shall be performed to calculate the maximum submergence of a surface buoy or maximum depth below the water surface of a sub-surface buoy, as specified in part E of Table 4.

The failure of a buoy, clump weight, or loop/weight chain due to disconnection from the mooring line or loss of buoyancy, without the failure of the line itself, will impact clearances and mooring system performance. The owner or operator should evaluate the effects of the loss of a buoy, loop/weight chain, or clump weight on clearances and mooring system performance, and where necessary introduce redundancy or other measures to mitigate the consequences of losing buoyancy, weight chain, or clump weight.

The owner or operator shall assess the impact of trenching on the integrity of the mooring system. The depth, width, and length of trenches created by the mooring line's motion at the line's touchdown point depend on the type of soil and the magnitude of line's motions (kinetic energy) in normal or daily environmental conditions. The degradation rate of the mooring chain (side bar abrasion and interlink wear) also depend on the line's motions and soil conditions. Similarly, other types of mooring components (wire and fiber rope) and risers will be damaged by soil excavation and trenching.

In shallow water, the depth of the trench may significantly increase the mooring system's total vertical load on the vessel. For floating structures with small water-plane areas, such as CALM buoys, the increase in vertical load may in turn result in a significant loss of freeboard. The design should allow for the potential increase in vertical mooring and riser loads due to the formation of trenches over the field life of the system.

Trenches that develop close to the anchor can reduce the anchor's holding capacity (AHC). Design methods and codes for predicting the depth and width of a trench near to the anchor at the end of field life, and for evaluating the anchor's holding capacity in the presence of the trench are not presently available. However, the mooring system may be designed with a length of mooring line adjacent to the anchor in contact with the seabed, so that the distance between the trench and the anchor (proximity) does not reduce the anchor's holding capacity. Analyses for the case where the distance between the trench and the anchor is sufficient to ensure that the AHC is not reduced are specified in part F of Table 4 and discussed in 7.3.7 and 8.6.4.

Clearances between installed anchors and pipelines, other installation's mooring lines, seabed assets, and exclusion zones are specified in Section 7. Anchor clearances are based on two considerations, whether the anchor's holding capacity is greater or less than the mooring line's break strength, and the direction of potential anchor dragging with respect to seabed infrastructure and exclusion zones (part G of Table 4). For MODUs operating in the Gulf of Mexico during hurricane season, anchor clearance requirements are provided in Annex B.

**Table 4—Clearance Analysis Cases: Permanent and Mobile Systems**

| Analysis Case | Type of Clearance and/or Environmental Conditions | Permanent | | Mobile | |
|---|---|---|---|---|---|
| **(A) Clearance, Mooring Line with Seabed (Thrash zone)** | | **RRP** | **Comment** | **RRP** | **Comment** |
| Intact System (mooring, thruster) | Wire rope remains clear of seabed in environments up to intact design return period (see Tables 1 and 2) | Recommended | — | Permitted | Informative |
| Intact System (mooring, thruster) | Fiber rope remains clear of seabed in environments up to intact design return period (see Tables 1 and 2) | Required | — | Recommended | Depends on seabed conditions |
| Single Failure (mooring, thruster) | Limiting environments for wire or fiber rope to remain clear of seabed | Permitted | Informative, producing with single failure | Permitted | Informative |
| Double Failure (mooring, thruster) | Limiting environments for wire or fiber rope to remain clear of seabed | Permitted | Informative | Permitted | Informative |
| **(B) Clearance, Mooring Line with Sea Surface** | | **RRP** | **Comment** | **RRP** | **Comment** |
| Intact System (mooring, thruster) | Fiber rope minimum depth below sea surface at pre-tension | Recommended | — | Permitted | Informative |
| **(C) Clearance, Mooring Line with Hull** | | | | | |
| Intact System (mooring, thruster), External Turret, Taut Lines | Mooring lines remains clear of the hull | Required | Avoid chaffing | — | — |
| Intact System (mooring, thruster), Slack Lines | Mooring line remains clear of the vessel's hull in environments up to the design return period (see Tables 1 and 2) | Required | Avoid rare contact | Permitted | Avoid rare contact |
| Single Failure (mooring, thruster), Slack Lines | Mooring line remains clear of the vessel's hull in environments up to the design return period (see Tables 1 and 2) | Recommended | Avoid rare contact | Permitted | Avoid rare contact |
| Double Failure (mooring, thruster), Slack Lines | Limiting environments for mooring line to remain clear of vessel hull | Permitted | Informative | Permitted | Informative |
| **(D) Clearance, Mooring Line with Risers, Mooring Lines, Pipelines, Seabed Assets, Exclusion Zones** | | **RRP** | **Comment** | **RRP** | **Comment** |
| Intact System (mooring, thruster) | Mooring line remains clear in environments up to the design return period (see Tables 1 and 2) | Required | — | Required | — |
| Single Failure (mooring, thruster) | Mooring line remains clear in environments up to the design return period (see Tables 1 and 2) | Recommended | Risk assessment | Recommended | Risk assessment |
| Double Failure (mooring, thruster) | Limiting environments for mooring line to remain clear | Permitted | Informative | Permitted | Informative |
| **(E) Clearance, Surface, and Sub-surface Buoys** | | **RRP** | **Comment** | **RRP** | **Comment** |
| Intact System (mooring, thruster) | Maximum submergence of surface buoys and maximum depth of sub-surface buoys in environments up to intact design return period (see Tables 1 and 2) | Required | — | Required | — |
| Single Failure (mooring, thruster) | Maximum submergence of surface buoys and maximum depth of sub-surface buoys in environments up to one failure design return period (see Tables 1 and 2) | Required | — | Required | — |
| Double Failure (mooring, thruster) | Limiting environments for submergence of surface buoys and maximum depth of sub-surface buoys | Permitted | Informative | Permitted | Informative |
| **(F) Clearance, Trench with Anchor** | | **RRP** | **Comment** | **RRP** | **Comment** |
| Intact System (mooring, thruster) | Trench (due to mooring line motions at touchdown) far from anchor so that AHC is not affected | Permitted | Special case as needed | Permitted | Special case as needed |
| **(G) Clearance, Anchor with Mooring Line, Pipeline, Seabed Assets, Exclusion Zones** | | **RRP** | **Comment** | **RRP** | **Comment** |
| All, (Intact, One and Two Failures) | Anchors with AHC < mooring line strength and in the drag path | Required | 300 m | Required | 300 m |
| All, (Intact, One and Two Failures) | Anchors with AHC < mooring line strength and NOT in the drag path | Required | 100 m | Required | 100 m |
| All, (Intact, One and Two Failures) | Anchors with AHC > mooring line strength | Required | 100 m | Required | 100 m |

### 6.2.5 Fatigue analysis cases

For permanent systems, the total fatigue damage caused by low and wave frequency motions of the installed system and where applicable by vortex induced motions (VIM) of the floating platform shall be calculated. The fatigue life of all the components of the mooring system (line segments, connectors, anchors, on-vessel line foundations) shall be evaluated. Analysis cases for assessing fatigue damage of permanent systems are listed in Table 5, acceptance criteria and methods for calculating fatigue damage are in Sections 7 and 8, respectively. For driven anchor piles, the dynamic loads due to hammer impact during pile installation shall be calculated and added to the in-place fatigue damage resulting from the dynamic mooring line tensions at the anchor.

Stationkeeping analyses shall be performed for the intact system and for the range of vessel drafts and pretensions applicable to the permanent system. A permanent system may be configured with different numbers of risers, umbilicals, and offloading lines during different phases of its life resulting in different pretensions, dynamic responses, and rates of fatigue damage accumulation for each configuration. The fatigue analysis shall account for the various system configurations and the historic or expected number of years for each system configuration.

The environmental load cases used in the fatigue analysis, the fatigue weather bins shall be based on site-specific long-term distribution of winds, wind-waves, currents, and swell-waves. It is recommended that the multi-year hindcast of daily (normal) wind, wave, and current conditions and their global directions, be used directly in the stationkeeping fatigue analysis. Alternatively, a set of fatigue weather bins may be developed from the site-specific multi-year hindcast that is statistically representative of the long-term distribution of wind, wave, and current conditions and their simultaneous global directions. For some turret moored systems, thrusters are used to control the vessel's heading in daily or normal environmental conditions; for these systems, the effect of the thruster's heading control on the vessel relative environmental directions and total fatigue damage should be included in the fatigue analysis.

For moored systems that are subject to vortex induced motions (VIM) fatigue damage due to the long-term distribution of current conditions shall be added to the fatigue damage resulting from wind and wave conditions. Additionally, the fatigue damage due to the worst single VIM event with a return period of 100-years or less (an annual probability of occurrence of $10^{-2}$ or greater) shall also be calculated.

**Table 5—Fatigue Analysis Cases: Permanent Systems**

| Fatigue Analysis Cases | Fatigue Damage Due To | RRP |
|---|---|---|
| Intact System (mooring, thruster) | Site-specific fatigue weather bins or direct use of hindcast | Required |
| Intact System (mooring, thruster), Single Event | Single event extreme VIM response, e.g. spar and semi VIM | Required |
| Installation, Single Event | Pile driving | Required |

For long-duration MOU operations, a fatigue analysis may be conducted to assess the fatigue performance of the mooring system; particular attention should be given to Kenter links and other components with limited fatigue resistance. When assessing the fatigue performance of MOU mooring, the fatigue damage from previous deployments should also be accounted for.

## 6.3 Installation Considerations at Design Stage

### 6.3.1 Weather windows for installation

The mooring system design and the installation procedures should minimize the time required to install the mooring system. The storm-safe condition is defined as the minimum number of mooring lines that are required to be connected before the floating structure can survive the site-specific seasonal *storm* (e.g. storm, loop, or eddy current, etc.) determined by a risk assessment. The risk assessment should consider the consequences of failure (e.g. nearby facilities, safety of people, etc.).

Where the consequence of failure is entirely financial, the owner or operator shall select: (1) the return period of the storm, (2) the time required to achieve the storm safe condition, and (3) the safety factor. However, to ensure no damage to mooring components, the maximum tension should not exceed 60 % of the component's break strength.

Where the consequence of failure is not purely financial (e.g. impact on safety and/or the environment): (1) the storm shall not be less severe than a 1-year return period site and seasonal specific storm, API 2MOP , (2) the time required to achieve the storm-safe condition shall be specified by the owner or operator, and (3) to ensure no damage to the mooring components, the maximum tension should not exceed 60 % of the component's break strength.

In addition to maximum line tension, other mooring system constraints may apply (e.g. mooring lines crossing over risers, pipelines, or other infrastructure, polyester or wire rope touching the seabed, etc.) and should be assessed in the stationkeeping analysis and included in the risk assessment.

#### 6.3.2 As-installed mooring system and design criteria

The owner or operator shall verify that the as-installed mooring system satisfies the design criteria in Section 7 for the conditions specified in 6.2. If the as-installed mooring system does not meet the design criteria, appropriate plans shall be developed and implemented in a timely fashion to ensure that the design requirements are satisfied.

Installation tolerances (for anchors, installed line segment properties, twist in line segments, pretensions, etc.), procedures, and acceptance criteria shall be developed by the owner or operator to ensure that the installed mooring system satisfies the assumptions made in the design or site assessment. In particular, mooring line pretensions used in the strength and fatigue analysis shall be consistent with the installed pretension; this is especially important for mooring systems with grouped lines. If perfect load sharing between lines within a group is used for the strength and fatigue analysis, the installation procedures and acceptance criteria shall ensure that the installed mooring system also has perfect load sharing. However, if the mooring system strength and fatigue analyses uses a tolerance on line pretensions, the installation procedures and acceptance criteria shall also result in pretensions within that variation; for example, with a ±10 % variation in pretensions, the installation procedures and acceptance criteria shall also result in pretensions within a ±10 % variation.

### 6.4 Corrosion, Wear, and Abrasion Allowance for Chain

Protection against corrosion, abrasion, and interlink wear shall be provided for permanent mooring systems. Because of the lack of proven theoretical models for predicting corrosion, abrasion, and wear rates, the allowances used in design should be based on historical data. Where historical data for moored systems nearby or in the general region of the facility exists, it should be referenced when developing corrosion, abrasion, and wear rates for the permanent mooring system.

It is realized that corrosion, abrasion, and wear originate from different sources. In the absence of separate corrosion, abrasion, and wear data, their design allowances are typically combined into one allowance.

For chains, a corrosion, abrasion, and wear allowance shall be included in the design by an appropriate increase in the link diameter. The increase should be determined by a site-specific assessment dependent upon many parameters; for example, these could include:

— coatings or other forms of protection,

— the locations of the links (in the splash zone, submerged catenary, or touchdown zone),

— level of dissolved nitrogen,

— level of dissolved oxygen,

- water temperature,
- water salinity,
- micro-biological flora and fauna,
- frequency of cleaning,
- characteristics of mooring line motions (at the top of the line, below buoys, or at the touchdown point), and/or
- soil conditions.

If site-specific corrosion, abrasion, and wear data is not available, the range of allowances given in A.6.4 may be considered in the design.

### 6.5 Sheathed and Unsheathed Wire Rope

For permanent moorings, sheathed wire ropes are generally used for wire segments in the water column; while unsheathed wire ropes have been successfully deployed for ground segments that are always in contact with the seabed. Corrosion of wire rope at connections to sockets can be accelerated by the galvanized wire acting as an anode for adjacent components. For permanent systems, the socket should be electrically isolated from the adjacent component. Additional corrosion protection can be achieved using sacrificial anodes to this area.

## 7 Design and Site Assessment Criteria

### 7.1 Safety Factors for Mooring Component Strength

#### 7.1.1 Line tensions

For mooring line components, acceptable tension limits are defined with respect to the component‘s end-of-life break strength. Mooring analyses may be performed in the frequency or time domain. The calculation of line tensions due to wave frequency vessel motions shall include the dynamic effects of the line’s velocity (drag forces) and acceleration (inertial forces), in Table 5 this is referred to as dynamic analysis. The end-of-life break strength (ELBS) shall allow for the reduction in strength by reducing the diameter to account for corrosion, abrasion, and interlink wear. For mobile moorings that satisfy the requirements of API 2I, the ELBS may be taken as equal to the catalog break strength (CBS).

Where mooring components are subject to more complex loading, in sheaves, fairleads, bending shoes, out of plane loading at pile and turret pad-eyes, etc., the strength of the component is likely to be less than the strength in tension loading. The strength of the component (ELBS) used in calculating the strength factor of safety shall allow for the reduction in strength due to complex loading.

Tension limits for intact and damaged conditions of permanent and mobile stationkeeping systems in normal and extreme environmental conditions shall be in accordance with Table 6.

**Table 6—Safety Factors for Tensile Strength of Mooring Line Components**

| System Condition | Safety Factor: End-of-life break strength/max tension, with dynamic analysis | |
|---|---|---|
| | **Permanent Mooring** | **Mobile Mooring** |
| Intact (mooring, thrusters) | 1.67 (60 % of ELBS) | 1.67 (60 % of ELBS) |
| Single Failure (mooring, thrusters) | 1.25 (80 % of ELBS) | 1.25 (80 % of ELBS) |

Safety factors for double failures (lines or thrusters) and thruster blackout cases, and the associated environmental return period or annual joint probability of occurrence may be defined by the owner or operator. The calculation of the annual joint probability of simultaneous occurrence of a thruster blackout and an environmental condition of a particular return period is described in A.6.2. Analysis cases, system conditions, and environmental return periods are specified in 6.2.2.1 and 6.2.2.2.

The criteria in Table 6 applies to all mooring line components (e.g. chain, wire rope, fiber rope, H-links, shackles, Kenters, etc. and applies to both passive and active stationkeeping systems (i.e. passive, thruster assisted moorings, and dis-connectable moorings).

Where mooring lines contain fiber rope segments, tensions are sensitive to the load-elongation properties of the fiber rope segments. The non-linear elastic properties of the fiber rope shall be modelled based on test data for the rope. Differences in fiber rope segment lengths due to permanent elongation can result in unequal load sharing for lines within a group, and thus have an impact on extreme tensions in both intact and one-line damaged conditions.

Strength analyses based on idealized mooring system properties can result in a significant under-estimation of the extreme tensions. It is important to conduct sensitivity checks and allow for the uncertainty in outboard segment lengths, pretensions, load sharing, and stiffness in the strength analysis.

For thruster assisted mooring (TAM) systems single failures include mooring line failure and the single worst failure (SWF) of the integrated thruster control system (ITCS) as identified by the FMEA, the ITCS consists of the thrusters, and the control, power generation and distribution systems. For TAM systems definitions of intact and damaged conditions are given in Table 7.

**Table 7 — Definitions of Intact and Damaged Conditions for Thruster Assisted Mooring**

| Definitions of System Conditions | | Mooring | Thruster |
|---|---|---|---|
| Intact | | Intact | Intact |
| Damaged – Single Failure | Case A | One-line Failed | Intact |
| | Case B | Intact | Single Worst Failure |
| Damaged – Double Failure | Case C | Two-lines Failed | Intact |
| | Case D | One-line Failed | Single Worst Failure |

### 7.1.2 Anchor factors of safety

#### 7.1.2.1 General

Safety factors for conventional drag embedded anchors, plate anchors, gravity anchors, suction piles, and driven piles are specified herein. Other anchor types (e.g. gravity embedded anchors, scoop anchors, etc.) may be used provided they can be documented to achieve similar levels of reliability to the anchors discussed below.

For plate and gravity embedded anchors, where it has been demonstrated by field tests or other methods that the overloading behavior (failure mode) is similar to conventional drag anchors, drag anchor factors of safety may be used.

The anchor's holding capacity (AHC) should be based on site-specific soil properties.

#### 7.1.2.2 Drag embedded anchors

The anchor holding capacity (AHC) of a drag anchor is the horizontal component of the steady pull that can be resisted by the anchor at continuous drag. This includes the soil resistance on the buried portion of the chain or of the wire rope but excludes the friction of the chain or wire rope lying on the sea floor.

Safety factors that shall be used for drag anchors used in permanent and mobile stationkeeping systems are specified in Table 8. Safety factors for vertically loaded plate anchors are in 7.1.2.3.

**Table 8—Safety Factors for Drag Anchor**

| **System Condition** | **Safety Factor: AHC/max load, with dynamic analysis** | | |
|---|---|---|---|
| | **Permanent Mooring** | **Mobile Mooring** | |
| | | In close proximity or with riser connected or anchors in drag path | Away from other structures without riser connected and anchors not in drag path |
| Intact (mooring and thrusters) | 1.5 | 1.0 | 0.8 |
| Single Failure (mooring, thrusters) | 1.0 | OD | OD |

For MOU moorings in the survival condition, anchor slippage can result in redistribution of mooring line loads with the most loaded line shedding load to adjacent lines; therefore increasing the chance of surviving a storm event. However, for close proximity MOU mooring or MODUs in the operating condition, with the drilling riser connected or where subsea infrastructure lies in the drag path of the anchor (e.g. pipeline), anchor movement should be avoided. That is, the safety factor for MOU drag anchors depends on the consequence associated with anchor movement. Also see 6.2.2, 6.2.3, and 6.2.4, , and .

Drag embedded anchors should not be loaded vertically (uplift) in normal operating conditions. This requirement is especially important for anchors in sand and hard soil where anchor penetration is shallow. Vertical loads may be acceptable in survival conditions for certain types of high-efficiency anchors in clay soils with deep penetration for which sufficient research has been conducted and field experience gained to confirm that they can withstand vertical loading.

The following conditions shall apply to vertically loaded high-efficiency drag embedded anchors:

a) Vertical loads are allowed only in extreme (survival) conditions

b) It should be confirmed that the soil conditions and the anchor test load will result in deep penetration (soft clay). No vertical loads should be applied if the soil conditions are not thoroughly investigated or the anchor test load is insufficient to achieve deep penetration.

c) The maximum line angle at the mudline (including the effects of low frequency vessel motions) in extreme (survival) conditions is less than 20 degrees for both the intact and damaged condition. The anchor holding capacity (AHC) shall be reduced by the factors specified in Table 9 based on the calculated maximum line angle at the mudline.

**Table 9—AHC Reduction Factors for Vertically Loaded High-Efficiency Drag Anchors in Soft Clay with Deep Penetration**

| **Mudline Angle** (degrees) | **AHC Reduction Factor** |
|---|---|
| 0 | 1.00 |
| 5 | 0.98 |
| 10 | 0.95 |
| 15 | 0.89 |
| 20 | 0.81 |

The line angle at the mudline should be zero at the early stage of test loading to ensure anchor penetration. When evaluating if vertical loading of a drag anchor is acceptable, the estimated vertical load at the mudline "dip down point" should be calculated and compared to the anchor weight. Vertical loads less than the anchor weight are less likely to unseat the anchor.

#### 7.1.2.3 Vertically loaded plate anchors (VLAs)

Acceptance criteria that shall be used for vertically loaded plate anchors (See Annex A for example VLAs.) used in permanent and mobile systems are given in Table 10. The safety factor is defined as the anchor holding capacity (AHC) divided by the maximum anchor load from a dynamic analysis, where the AHC is for the direction in which the anchor is loaded, i.e. the direction of loading in the failure envelope.

**Table 10—Safety Factors for Vertically Loaded Plate Anchors**

| **System Condition** | **Safety Factor: AHC/max load, with dynamic analysis** | |
|---|---|---|
| | **Permanent Mooring** | **Mobile Mooring** |
| Intact (mooring, thrusters) | 2.0 | 1.5 |
| Single Failure (mooring, thrusters) | 1.5 | 1.2 |

#### 7.1.2.4 Anchor piles and gravity anchors

The vertical and horizontal resistances of anchor piles (gravity, suction, driven, or dynamically embedded) and gravity anchors shall be determined in accordance with ISO 19901-4. The maximum vertical and horizontal components of the extreme mooring line tensions derived from dynamic analysis shall not exceed the vertical and horizontal resistances divided by the safety factors in Table 11.

**Table 11—Safety Factors for Pile Anchors and Gravity Anchors**

| **System Condition** | **Safety Factor: AHC/max load, with dynamic analysis** | | | |
|---|---|---|---|---|
| | **Permanent Mooring** | | **Mobile Mooring** | |
| | Vertical | Horizontal | Vertical | Horizontal |
| Intact (mooring, thrusters) | 2.0 | 1.6 | 1.5 | 1.2 |
| Single Failure (mooring, thrusters) | 1.5 | 1.2 | 1.2 | 1.0 |

## 7.2 Vessel Position, Offsets, and Heading

### 7.2.1 Position limits

Vessel offset, and heading (if applicable), limits for permanent and mobile systems shall be established by the owner or operator.

Offset and heading limits should be based on the requirements of equipment such as drilling or production risers, umbilicals, gangways, etc., as well as the requirement for safe disconnection of dis-connectable systems. Generally, different criteria will apply to operating, standby, and survival conditions and for intact, damaged, and transient cases. For example, MODU offset limits for the riser connected drilling (rotating), riser connected non-drilling (non-rotating), and survival (riser disconnected) cases are usually different, and these should be based on the riser and wellhead mechanical limits. For MOU operations, such as diving support, construction, pipe-laying, etc., offset criteria for operating, standby, and survival conditions shall be specified by the owner or operator.

### 7.2.2 Position monitoring

Permanent and mobile vessels shall be equipped with an offset monitoring system. If the vessel's heading is important for operations or the heading is to be controlled (e.g. thruster assisted turret moored vessels), the vessel shall be equipped with a heading monitoring system.

The redundancy and accuracy requirements of the position monitoring system(s) shall be defined by the owner or operator.

## 7.3 Requirements for Clearances

### 7.3.1 General

Clearances between the vessel, its mooring lines and anchors with other surface, subsurface, or seabed structures shall be calculated for the analysis cases specified in 6.2.4 and shall satisfy the requirements herein. Clearance checks should include design installation tolerances of the mooring system.

### 7.3.2 Mooring line with seabed (thrash zone)

Fiber or steel wire ropes and their terminations can become damaged by repeated contact with the seabed; consequently it is recommended that chain be used at the touchdown, or thrash zone, of the mooring line. Wire ropes may be in contact the seabed provided the contact remains throughout the full range of predicted line tensions.

The clearance requirements that shall be followed between wire or fiber ropes and the seabed in Table 12 apply to the bottom end of wire or fiber rope segments that are in the water column; i.e. to prevent wire or fiber rope of the slack lines repeatedly contacting the seabed (wire or fiber rope in the thrash zone).

**Table 12—Minimum Clearances between Bottom of Suspended Wire or Fiber Rope and Seabed**

| Clearance, Rope with Seabed | Permanent Mooring | | Mobile Mooring | |
|---|---|---|---|---|
| **(A) Steel Wire Rope** | **RRP** | **Minimum Distance** | **RRP** | **Minimum Distance** |
| Intact (mooring, thrusters) | Recommended | > 1 m | Permitted | OD |
| Single Failure (mooring, thrusters) | Permitted | OD | Permitted | OD |
| **(B) Fiber Rope** | **RRP** | **Minimum Distance** | **RRP** | **Minimum Distance** |
| Intact (mooring, thrusters) | Required | > 1 m | Recommended | > 1 m |
| Single Failure (mooring, thrusters) | Recommended | > 1 m | Permitted | OD |

The susceptibility to damage of a fiber rope due to seafloor contact depends on the fiber rope's jacket, design of the filter barrier, the seafloor characteristics, and the line's motions at the touchdown point. Also, because fiber ropes are close to neutrally buoyant, or slightly negatively buoyant, they are susceptible to movement and possible damage on the seafloor. Requirements for rope construction, seabed survey, and soil conditions are specified in API 2SM for fiber ropes that are in contact with the seabed.

### 7.3.3 Mooring line with sea surface

For fiber moorings, a suitable length of steel wire or chain should be provided at the top end of the fiber rope mooring leg. The upper steel segment can be used for adjustments of the mooring leg's tension, to compensate for rope elongation over the life of the mooring, and for repositioning operations. Therefore, suitable equipment for adjusting the length of the upper steel mooring component segment should be provided for each mooring leg. For more information see API 2SM.

For permanent systems, it is recommended that the owner/operator establish clearance requirements between the top of the fiber rope and the sea surface. In the absence of owner/operator defined clearance requirements for permanent systems, a minimum clearance of 100 m for the intact mooring system under design pre-tension is recommended according to Table 13 and Table 4.

**Table 13—Minimum Clearance between Top of the Fiber Rope and Sea Surface**

| Clearance, Fiber Rope with Sea Surface | Permanent Mooring | | Mobile Mooring | |
|---|---|---|---|---|
| | **RRP** | **Minimum Distance** | **RRP** | **Minimum Distance** |
| Intact (Mooring and Thrusters) Under Design Pre-tensions | Recommended | OD | Permitted | OD |

### 7.3.4 Mooring line with hull

For external turret moored vessels, clearances between the mooring lines and vessel are usually smallest in benign metocean conditions; when the vessel's orientation places it over a line or group of lines, clearances generally increase with the severity of the environment. For other types of permanent and mobile moorings, clearances between the mooring line and hull, or anchor bolster, are generally a minimum for slack lines in extreme environmental conditions.

For permanent mooring systems, the owner or operator shall define the minimum allowable clearances for the intact cases defined in part C of Table 4. For permanent systems with a single failure (line or thruster), the owner or operator should also define the minimum allowable clearance for the slack lines.

For MOUs, the clearance requirements and associated vessel drafts, pretensions, and environmental conditions should be established by the owner or operator for the cases in part C of Table 4.

For permanent or mobile systems with two failures (lines or thrusters), analyses may be performed to determine the limiting environmental conditions for which the mooring lines remain clear of the hull.

### 7.3.5 Mooring line with risers, mooring line, pipeline, seabed assets, and exclusion zones

Mooring lines shall remain clear of risers, the mooring lines of other installations, pipelines, seabed infrastructure, and exclusion zones (part D of Table 4) in the conditions specified in 6.2.2. A minimum clearance of 10 m under the intact condition shall be maintained. The clearance requirement of 10 m does not apply to mooring lines and risers close to or at the vessel (e.g. for a turret moored vessel the clearances between lines and risers at or near to the turret may be less than 10 m).

Where a mooring line within the elevated part of its catenary crosses a pipeline on the sea floor, a minimum clearance of 10 m under the intact condition shall be maintained. A mooring line may pass over and be in contact with a protected pipeline, provided this contact remains throughout the full range of predicted intact line tensions (i.e. the contact does not change causing abrasion or damage to the pipeline or the mooring line).

It is recommended that mooring lines remain clear of other mooring lines, pipelines, seabed infrastructure, and exclusion zones in the single failure conditions specified in 6.2.2. Surface or sub-surface buoys and fiber rope line segments may be used to maintain clearances between a failed mooring line and other mooring lines, pipelines, seabed infrastructure, and exclusion zones. A minimum clearance for the single failure condition shall be specified by the owner or operator.

### 7.3.6 Buoys, surface, and submerged buoys

#### 7.3.6.1 General

Surface and sub-surface buoys may be used in intact and damaged cases to manage clearances, where a mooring line crosses over a pipeline or another installation's mooring line or to maintain clearance with anchor bolsters. Analyses shall be performed to calculate the maximum submergence of a surface buoy or maximum depth below the water surface of a sub-surface buoy as specified in part E of Table 4.

The motions of buoys deployed near or on the water surface can cause excessive wear to connecting links resulting in component failure; as a result, buoy motions shall be accounted for in the design of the components connecting the buoy to the mooring line.

Sub-surface buoys can be used to minimize the wave motions of the buoy and the resulting wear and fatigue damage on the hardware connecting the buoy to the mooring line. By placing the buoy away from the surface, the risk of the buoy being damaged from a collision with a surface vessel is also eliminated.

Both above risks have been observed in the field. However, submerged buoys are generally more of an investment than surface buoys and usually require a ROV to retrieve them if connection to the buoy or mooring line is needed. The deployment scheme of the submersible buoy with its mooring line attached should be considered at the design stage, to ensure that the buoy assembly will not be submerged beyond its rated water depth. If the buoy is not an inline component, the hardware required to prevent entanglement of the pennant line around the mooring line, due to torque responses of the system during installation and while in-service, should be part of the buoy's design.

Buoys shall be filled with foam, or incorporate measures such as compartmentalization, to minimize the risk of sinking in the event of damage. Surface and sub-surface buoys should be designed for the maximum buoy submergence depth for the analysis cases in Table 4. The maximum safe working depth for mid-line buoys should be based on analyses and/or testing using applicable design and manufacturing codes.

#### 7.3.6.2 Surface buoys

Surface buoys shall be designed to remain at the surface (i.e. a maximum 67 % submergence) in all intact and single failure conditions, unless specifically designed for submergence (see 7.3.6.3).

#### 7.3.6.3 Subsurface buoys

Subsurface buoys of steel construction, designed for external pressure, shall be designed in accordance with an appropriate recognized pressure containment standard for use at the maximum operational depth identified by the mooring analysis. The design safety factor shall be no less than 1.5 for permanent moorings and 1.2 for mobile moorings. ASME BPVC, Div. 1, Sec. VIII provides detailed engineering requirement for sub-surface buoys of steel construction designed for external pressure.

For foam-type buoys, an allowable hydrostatic pressure shall be determined by dividing the hydrostatic collapse pressure by a design safety factor; where the choice of the design safety factor depends on the design service life and criticality of the buoy. The long-term water absorption rate of the foam material at its service depth shall be determined and included in the design stage of the mooring system.

#### 7.3.6.4 Submerged turret buoy

Submerged turret buoys are typically used on FPSOs with an internal disconnectable turret. The net buoyancy of the buoy should be adequate to support the risers, umbilicals, and mooring lines before, during, and after disconnection. The mooring line pre-tensions and buoyancy should be designed so that upon release of the buoy, the inertial motion does not result in the buoy falling to the seafloor, with the risers and mooring lines. The intent of the design is that the mooring and riser connection point remains a few hundred feet below the waterline, to avoid the bulk of the environmental surface wave and current forces. In the connected mode, the turret buoy should also allow free rotation of the vessel in all loading conditions.

### 7.3.7 Effect of mooring line trenching on anchors

To prevent trenches from degrading the holding capacity of the anchor, the owner or operator may define a minimum allowable distance between the anchor and the mooring line's touchdown point in *representative* return period environmental conditions. Alternatively, the anchor may be designed (sized) so that the anchor's holding capacity, with the (predicted) end of field life trench at the anchor is sufficient to satisfy anchor factors of safety.

Guidance for analyzing where the distance between the trench and the anchor is sufficient to ensure that the AHC is not reduced are specified in part F of Table 4 and described in A.8.6.4.

### 7.3.8 Anchor with mooring line, pipeline, seabed assets, and exclusion zones

#### 7.3.8.1 Clearance between a drag anchor and other installations

If the drag path of a drag anchor is expected to bring it close to another installation, the final anchor position shall allow a margin of at least 300 m of drag distance before contact can occur with the installation. If the anchor's drag direction will not result in contact with the installation, the final anchor position shall be at least 100 m from the installation.

#### 7.3.8.2 Clearance between other types of anchors

Other types of anchors may also have clearance requirements which are unique to their holding capacities and installation method. It is important to understand how the anchor achieves its holding capacity and consider common failure mechanisms, to adequately account for the needed clearance between other types of anchors.

## 7.4 Safety factors for mooring component fatigue resistance

The fatigue endurance of chain, Kenter and Baldt links, and steel wire rope shall be verified with the T-N curves provided in Table 14, using a fatigue factor of safety of 3. Mooring components are considered un-inspectable and this fatigue safety factor of 3 applies to un-inspectable components. The fatigue endurance of well-constructed polyester and HMPE rope, for tension ranges ($T$) of less than 50 % of CBS, is a least six-times that of spiral strand wire rope with a mean load ratio ($Q$) of 0.3, according to API 2SM, API 2FC-2 , and ISO 19901-7:2013.

For moored systems that are subject to vortex induced motions (VIM), fatigue damage due to the long-term distribution of current conditions shall be added to the fatigue damage resulting from wind and wave conditions. In addition, fatigue damage due to the worst single VIM event with a return period of 100-years or less (an annual probability of occurrence of $10^{-2}$ or greater) shall be calculated; the required fatigue safety factor for this event alone is 3.0.

For driven anchor piles, the dynamic loads due to hammer impact during pile installation shall be calculated and added to the in-place fatigue damage resulting from the dynamic mooring line tensions at the anchor.

The T-N fatigue curves used to calculate fatigue lives of mooring components is given by Equation 1.

$$N = \frac{K}{R^m} \tag{1}$$

where

*N* = Number of cycles,

*R* = Ratio of tension range (double amplitude) to reference breaking strength (RBS). For chain, RBS is taken as CBS (catalogue break strength) of ORQ common chain link of the same size for common or connecting links. Guidance on increase of chain diameter for corrosion, wear, and abrasion is contained in 6.4. For wire rope, RBS is the same as CBS.

Values of *m* and *K* for common mooring line components are provided in Table 14.

**Table 14—T-N Fatigue Curve Parameters, m and K, for Use with a Fatigue Safety Factor of 3.0**

| Component | *m* | *K* |
|---|---|---|
| Common stud-link | 3.00 | $1000 = 10^3$ |
| Common studless link | 3.00 | $316 = 10^{2.5}$ |
| Kenter connecting link (for example) | 3.00 | $178 = 10^{2.25}$ |
| Six / multi-strand wire rope (corrosion protected) | 4.09 | $10^{(3.20 - 2.79\,Q)}$, $K = 231$, when $Q = 0.3$ |
| Spiral strand wire rope (corrosion protected) | 5.05 | $10^{(3.25 - 3.43\,Q)}$, $K = 166$, when $Q = 0.3$ |
| Polyester or HMPE rope (6x spiral strand, tension range (*R*) less than 50 % CBS) | 5.05 | $1000 = 10^3$ |
| NOTE *Q* is the ratio of mean tension to CBS of the wire rope. | | |

The reference breaking strength for common chain or connecting links of all grades is equal to the catalogue breaking strength (CBS) of ORQ (oil rig quality) common chain link of the same diameter. CBS for ORQ Grade chain in kN = $0.0211 * d^2 * (44 - 0.08d)$, where *d* is the nominal bar diameter in mm.

NOTE See A.7.4 for additional guidance on use of the above T-N curves.

The T-N curves in Table 14 are based on pure tension-tension loading (i.e. tension loading without bending or torsion). The fatigue life of mooring components (chain, wire rope, connectors, etc.) that are subject to loading that is not pure tension (e.g. chain in the fairlead, on bending shoes, in the thrash zone, at articulations and terminations, out-of-plane bending (OPB), etc.) should be determined using other methods. For those chain links that are subjected to more complex loading, the fatigue damage assessment methodology shall be approved by the owner.

Where mooring lines contain fiber rope segments, the calculated fatigue life of the steel components of the mooring line are sensitive to the load-elongation properties of the fiber rope segments. The non-linear elastic properties of the fiber rope shall be modelled based on test data for the rope. Differences in fiber rope segment lengths due to permanent elongation can result in unequal load sharing for lines within a group; and thus have an impact on mean tensions and tension ranges in the fiber and steel segments.

Fatigue analyses based on idealized mooring system properties can result in a significant under-estimation of the fatigue damage. It is important to conduct sensitivity checks and allow for the uncertainty in the lengths of outboard segments, load sharing, and stiffness in the fatigue analysis (see A.7.4).

To account for the effects of corrosion and wear over the design life, when determining the reference breaking strength of common chain or connecting links, the diameter should be taken equal to the nominal diameter minus half of the corrosion and wear allowance. That is, the mid-life or average diameter of chain links and connectors should be used when calculating fatigue damage.

For complex loading (e.g. tension, bending, and or torsion) or for non-standard mooring line components, where fatigue test data does not exist (e.g. shackles, H-links, tri-plate, and specialty connectors), fatigue resistance shall be demonstrated through the use of S-N curves for the base material with hot spot stresses or stress concentration factor (SCF) derived from FEA. For complex loading or non-standard components, the S-N curves and associated fatigue safety factors shall be specified by the owner or operator.

The T-N curves in Table 14 should be used in conjunction with a fatigue safety factor of 3, and are associated with a probability of fatigue failure of about $10^{-4}$ in 10,000 links, see derivation of fatigue curves contained in API 2FC-1 .

The owner may approve the use of alternative fatigue curves with an associated fatigue safety factor. The derivation of an associated fatigue safety factor for these alternative fatigue curves should follow the methodology in API 2FC-1 , and target the same overall reliability of a probability of fatigue failure of about $10^{-4}$ in 10,000 links. The chain diameter calculated using the alternative fatigue curve and associated safety factor shall not be smaller than the diameter calculated with the fatigue curve and associated safety factor from this standard.

The T-N curves for wire rope are for wire ropes protected from corrosion. Elements for corrosion protection include galvanizing, sheathing, blocking compound, and zinc filler wires. Careful investigation considering the design life, inspection, and change-out strategy should be carried out to determine the combination of these elements needed for a specific project. Mean load has a significant influence on wire rope fatigue life and therefore should be included in the design curve equations. A mean load of 0.3 RBS is considered to be representative for conventional mooring systems.

# 8 Analysis

## 8.1 General

Mooring analysis shall be performed to calculate system responses for the design conditions provided in 6.2 and 6.3. The calculated system responses shall be compared to the acceptance criteria provided in Section 7.

The mooring designer shall confirm that output of the analysis can be used to verify that all components meet their individual design requirements such as strength, fatigue, compression, contact, curvature, torsion, etc.

The mooring analysis shall:

a) cover configurations based on the anticipated installation sequence and planned future installations of:

   1) risers, and

   2) topsides equipment,

b) account for variation in the following:

   1) pretension due to change in vessel draft and trim or pay-out of lines,

   2) vessel properties (virtual mass and inertia, damping coefficients, projected areas, etc.),

3) wind, wave, and current force coefficients,

4) wave motion RAOs due to changes in draft and trim,

5) sea floor slope,

c) include sensitivity analysis to define installation tolerances to ensure that the installed mooring system satisfies the assumptions made in the design or site assessment (also see 7.3.2).

d) take into account the effect of risers on system responses (stiffness, damping, mean load). The influence of the risers on the mooring system response may be ignored if doing so results in a more conservative mooring design.

For permanent systems not subject to any regular marine growth removal, marine growth on the hull, risers and mooring system shall be accounted for in the mooring analysis. Properly accounting for the effect of marine growth on mooring and risers requires a coupled analysis. The more conservative case (i.e. either with or without marine growth) shall be identified and used in the mooring analysis.

The physical properties of the mooring line components, weight, stiffness, diameter, etc. that are used in the mooring analyses shall be the nominal values (i.e. catalogue values with no deduction for corrosion, abrasion or wear).

In the case of fiber rope, load-elongation properties used in the mooring analysis shall be defined based on the mooring system behavior and appropriate test data. A comprehensive discussion on testing and modeling fiber mooring ropes for mooring analysis purposes is provided in API RP 2SM.

It should be understood that, in this section, “risers” includes a single (drilling) riser, multiple risers and umbilicals.

Recommendations for determining the properties and modeling fiber mooring ropes in the mooring analysis can be found in API 2SM.

## 8.2 Analysis Methods

The methods generally used to compute the system responses of a moored floating structure are:

— the frequency-domain approach,

— the time-domain approach, or

— a combination of frequency-domain and time-domain analysis

These methods involve different degrees of approximation and are affected by different limitations, and therefore do not necessarily yield consistent results. Both time domain and frequency domain analysis can include linear or nonlinear approximations. Furthermore, the effect of the vessel heading (mean and low frequency variations) shall be taken into account when calculating the wave frequency responses. This is particularly important for passive turret moored vessels, and more so for transient, e.g. squall, events. If verification of the approach selected for the mooring analysis is required, an alternative approach, model test data or full-scale measurements should be used.

A line-dynamic method of analysis shall be used where the analysis shall account for dynamic loads on the mooring lines and risers associated with mass, drag, and acceleration. Quasi-static methods where dynamic loads are neglected shall not be used for final design of permanent or final site-specific assessment of MOU moorings. When low-frequency damping is added as a user defined input, the amount of damping that is added shall be documented.

## 8.3 Coupling Effects

Interaction or coupling between the floating structure and the mooring and risers in the form of inertia, damping, mean load, and stiffness affects the responses of the floating structure. The impact of the coupling on the resulting system responses will vary depending on the size and type of floating structure, and the response mode being evaluated. The coupling between the floating structure and the mooring and risers can be captured to varying degrees. Both frequency domain and time domain can be coupled or decoupled, and line dynamics can be taken into account in both coupled and decoupled analysis. For decoupled analysis, the mooring designer should evaluate the impact of mooring line and riser damping, and riser stiffness if not included, in the system response. For CALM buoys without an offloading vessel connected, the effects of coupling are significant and should be included when calculating the buoy's wave-frequency motion response.

## 8.4 Environmental loads on the floating structure

### 8.4.1 General

The floating structure offsets and motions to be used in the station keeping system design shall be evaluated for all relevant combinations of wind directions, wave directions, and current directions, consistent with the site-specific metocean characteristics. Both collinear and non-collinear combinations shall be assessed where site-specific information is lacking. Multiple wave trains with different directions (e.g. sea and swell) may be needed to properly describe the total wave environment at the site. The ability of the floating structure to change heading in response to changing environmental conditions may be taken into account.

For passive turret moored vessels in wind-squall events, where the wind speed increases over a short time-period, the vessel heading before the squall arrives at the site (the initial heading) is determined by the non-squall environmental conditions. For turret moored vessels in transient wind squall conditions, the directional distribution shall include all combinations of initial vessel headings and squall directions, consistent with the site-specific metocean conditions. Consequently, a load case shall consist of a vessel initial heading and a wind squall direction (wind direction at the time of maximum wind speed); then different squall time-histories result in different realizations of system responses for each load case.

### 8.4.2 Wave forces

Wave-induced forces (steady, low-frequency, and wave-frequency) shall be determined by analytical methods or empirically based on model testing with consideration of water depth effects. Approximate analytical methods include diffraction and radiation theory and slender member hydrodynamics.

The mean and slowly varying wave force components shall be accounted for in the analysis. In addition, vessel wave-frequency responses shall also be included, by input of wave displacement RAOs or wave force RAOs and hydrodynamic coefficients (mass, added mass, damping).

The sensitivity of the extreme responses to variations of the peak wave period shall be assessed and accounted for where relevant.

The effect of current on wave forces shall be accounted for where relevant. This includes the change in intrinsic wave-frequencies to apparent wave-frequencies (encounter frequency effect), as well as changes in the magnitude of wave-induced forces.

For structures with slender members (semisubmersibles, spars), viscous wave drift forces should be considered as they may be larger than the diffraction-radiation forces.

In shallow water, the effect of water depth on the wave kinematics and forces shall be included.

### 8.4.3 Wind forces

Wind induced forces shall be determined by wind tunnel tests, CFD, or numerical analysis methods.

NOTE See Annex A for more details.

The wind field contains energy near the natural frequency of a floating structure, which can produce a significant dynamic response. The wind dynamics (except for squalls) can be described by a steady component, based on the 1-hour average velocity plus a time varying component calculated from a suitable wind spectrum. The wind spectrum shall be defined over the full range of natural frequencies of the moored structure. The wind spectrum is used directly in frequency-domain analysis. In time domain analysis, the wind spectrum is used to generate a number of different time histories (n-realizations) each depending on a different random seed.

Recommendations for wind profile, gust factors, and wind spectra can be found in API 2MET. For hurricane conditions, the ESDU wind spectrum is recommended; for non-hurricane conditions, the ISO (NPD) spectrum is recommended. For the ISO spectrum, there is a cut-off at 600 seconds. For systems with natural periods longer than 600 seconds, the recommended wind spectrum for non-hurricane conditions is the upper bound API spectrum (alpha = 0.01).

NOTE See Annex A for a more detailed discussion.

For sites affected by wind squalls, the concept of a wind spectrum is not applicable. The analysis of corresponding wind-induced responses should be performed in time domain using time-histories of both wind speed and direction that span the range of return periods required.

### 8.4.4 Current forces and VIM

Current force coefficients on large-body floating structures shall be determined by means of wind tunnel tests, towing tests, CFD, or numerical analysis tools. For coupled analysis, current loads shall be based on vessel-relative current velocities.

Floating structures consisting of large diameter cylindrical components, or columns such as spars and semi-submersibles, can experience low-frequency motions due to vortex shedding in the presence of currents. Vortex induced motions (VIM) and its effects shall be accounted for in the design of the mooring system for both the strength and fatigue limit states.

## 8.5 Loads on mooring lines and risers — Wave and Current Forces

Direct wave loads on mooring lines and risers can typically be neglected for mooring system response.

The effect of current forces, loading, and damping on mooring lines and risers shall be determined. Current loading can be important for locations with high currents and systems in deep water with many mooring lines and risers. Mean current loads on mooring lines and risers shall always be included in the analysis. For coupled analysis, current loads shall be based on the slender body-relative current velocities.

## 8.6 Mooring analysis for strength, offset, and clearance

### 8.6.1 Basic considerations

The mooring analysis shall be set up to produce the following outputs:

a) line tension for each mooring component and at the end points of the mooring line,

b) offsets of floating structure at all locations of interest,

c) clearance between mooring components and the vessel, seabed, sea-surface, field infrastructure, exclusion zones, and

d) extreme values of grounded mooring line length.

In some cases, mooring line tensions are adjusted for operational reasons and/or in advance of foreseeable survival environmental events. For the analysis of strength limit states, the modelling of the stationkeeping system and floating structure configuration shall reflect such adjustments. However, the adjustment of line tensions during a storm shall not be taken into account in the survival analysis.

If the results of the analysis indicate that a mooring line goes completely slack, the behavior should be further investigated.

The end-of-life strength shall be used for calculating safety factors.

### 8.6.2 Extreme value statistics

The acceptance criteria shall be compared to the most probable maximum or minimum value of the system response in the design event duration, consistent with the site-specific metocean conditions. Typically, the design event duration is taken as 3 hours of steady state conditions.

For time domain analyses, characteristic extreme values of system responses may be determined by statistical fitting techniques. The analysis can consist of one long realization or multiple short realizations of the design environment. The total duration shall be long enough to obtain enough response cycles to reach statistical convergence of the predicted extreme responses. In time-domain analyses, care shall be taken to ensure that the input (wind, wave, and current) time-histories are non-repeating within a single realization or across multiple realizations.

For frequency domain analysis, the extreme value distribution for each response shall be selected. Some frequency-domain programs by default assume a Rayleigh distribution; this is not necessarily correct for mooring system responses.

The offset location at which the extreme wave frequency line tension is calculated shall be documented.

NOTE See A.8.6.2, where guidance for frequency domain calculations and a simplified method for combining low-frequency and wave-frequency responses is provided; additional information on time-domain analysis is also provided.

### 8.6.3 Design Values for responses to transient wind squalls

The characteristic design value for line tension shall be taken as the mean or expected value of the peak mooring line tensions from all squall realizations within the governing load case. A load case here is a unique combination of initial vessel heading and squall direction (wind direction at time of peak wind speed).

The characteristic design value for vessel offsets is defined in two-dimensions (Eastings and Northings) and is therefore much more complex than the design value for line tension. Envelopes of vessel offset may be defined with varying levels of conservatism as follows:

— Option 1: circular envelope based on maximum radial ($R_{xy}$) offset from each realization,

— Option 2: contour based on maximum characteristic tension or utilization, or

— Option 3: irregular shaped envelope containing all response trajectories.

### 8.6.4 Mitigating mooring line trenching effects on AHC

The owner or operator shall assess the impact of trenching on the performance of the mooring system. An example of such an assessment is provided in Annex A.

## 8.7 Mooring analysis for fatigue

### 8.7.1 Basic considerations

The fatigue weather bins (load-case matrix) shall be established that describes the long-term environment at the site. The fatigue weather-bins can be constructed from the marginal distributions (e.g. sea and swell wave-scatter diagrams by direction, and wind and current speed and direction-scatter diagrams) each with an annual probability of occurrence or can be made up of a multi-year hindcast of wind, sea, current, and swell conditions. A mooring analysis is then performed for each weather-bin and for a representative combination of vessel drafts and trims, and base case and future risers.

Components that are exposed to low-cycle/high-stress regimes, API 2FC-2 , should be analyzed to assess damage accumulation during rare extreme events that may be of extended duration, such as a rise and fall of the 100-year event. The single 100-year return period event on its own shall not result in a fatigue failure; that is, the damage from the single 100-year return period event is evaluated separately from the long-term damage.

Depending on the mooring system configuration (catenary vs taut), the largest tension ranges are not necessarily found at the top of the mooring line.

The fatigue analysis shall be performed for the intact station keeping system and cover the range of vessel drafts and trims, and base case and future riser configurations. If the mooring system operates in different modes, for example, an FPSO or offloading buoy with and without an offtake tanker in tandem, a separate analysis for each mode shall be performed. For turret moored vessels where thrusters are used to actively control the vessel's heading, the way in which the vessel heading is chosen in each fatigue weather bin should be included in the fatigue analysis. Fatigue-life calculations shall be performed for all components in the mooring line.

### 8.7.2 Analysis Approach

Time-domain or frequency-domain dynamic analyses shall be used to determine load (tension or stress) ranges. When performing frequency-domain analysis, the standard deviations of low-frequency and wave-frequency tension components shall be calculated about the mean floating structure offset position for each fatigue weather bin. When performing time-domain analysis, the time history of the total tension (mean + low-frequency + wave frequency contributions) can be directly derived from the analysis.

The net static-horizontal loads from risers can impact the fatigue performance of mooring lines and shall be included in the analysis. Where applicable, changes to the pre-tension of the mooring lines from the addition of future risers shall be accounted for, and conservative riser configurations shall be used for the fatigue analysis.

Where applicable, a sensitivity analysis should be performed for the range of loading conditions of the floating structure so that a conservative loading condition can be selected for the fatigue analysis.

The annual number of load cycles shall be determined separately for each load case (draft, trim, and riser configuration) and for each mooring line segment.

The T-N curves provided in 7.4 are based on pure tension-tension loading (i.e. tension loading without bending or torsion). The impact on fatigue life of mooring components (chain, wire rope, connectors, etc.) that are subject to loading that is not pure tension, e.g. chain in the fairlead, on bending shoes, in the thrash zone, at articulations and terminations, out of plane bending (OPB), etc., shall be assessed using other methods. For these chain links that are subjected to more complex loading, the fatigue damage assessment methodology shall be approved by the owner. An example of a damage assessment for chain OPB fatigue is provided in A.8.7.2.

### 8.7.3 Fatigue damage calculation methods

#### 8.7.3.1 General

The general principle for fatigue damage calculation is the Palmgren-Miner linear damage hypothesis. That is, the annual fatigue damage accumulated in a mooring line component is the sum of the fatigue damage occurring in each of fatigue weather bins chosen to discretize the long-term environment that the mooring system is subjected to:

$$D = \sum_{i=1}^{n} D_i \tag{2}$$

where

$D$ is the annual fatigue damage in a mooring line component, years$^{-1}$.

$D_i$ is the annual fatigue damage arising in fatigue weather bin $i$, years$^{-1}$.

The calculated fatigue life, $L$, of the mooring system is given by:

$$L = 1/D \text{ (years)} \tag{3}$$

The annual fatigue damage accumulated in an individual bin is given by:

$$D_i = \frac{n_i}{N_i} = \frac{n_i}{K} E[R_i^m] \tag{4}$$

where

$m$ and $K$ are defined in Table 14 and,

$n_i$ is the number of cycles at load range $R_i$ occurring in the $i$'th fatigue weather bin, per year

$N_i$ is the number of cycles to failure at load range $R_i$ from Equation (1), per year

$E[R_i^m]$ is the expected value of the normalized tension range $R_i$ raised to the power $m$, in weather bin i

The discretization into $i = 1, \ldots, n$ environmental states, fatigue weather bins, should be sufficiently detailed to avoid significant errors in the total. Each fatigue weather bin is defined in terms of the wind, sea-wave, swell-wave, and current parameters and directions required to compute mooring system responses. The probability of occurrence, $P_i$, is required for each fatigue weather bin. The number of tension cycles per year in each state can be determined from:

$$n_i = v_i \cdot T_i = v_i \cdot P_i \cdot 3.15576 \times 10^7 \tag{5}$$

where

$v_i$ is the zero up-crossing frequency (hertz) of the tension spectrum in environmental state i,

$T_i$ is the time spent in environmental state i per year,

$P_i$ is the probability of occurrence of environmental state i.

For non-standard mooring line components such as shackles, H-links, tri-plates, and specialty connectors, fatigue damage shall be calculated using an appropriate S-N curve for the base material with hot spot stresses or stress concentration factors (SCF) derived from finite element analysis. When evaluating theses non-standard components using a S-N curve, Equation (4) is replaced by Equation (6).

$$D_i = \frac{n_i}{N_i} = \frac{n_i}{K_S} E[S_i^{m_S}] \tag{6}$$

where

$m_S$ and $K_S$ are the parameters of the SN curve and,

$E[S_i^{m_S}]$ is the expected value of the hot-spot stress range $S_i$ raised to the power $m_S$, in fatigue weather bin $i$

### 8.7.3.2 Combining wave-frequency and low-frequency fatigue damage

The annual fatigue damage can be calculated from a load time-history with a cycle counting method or from a response spectrum with a probabilistic method.

The most widely accepted method of cycle counting is the rainflow cycle counting (RFC) method. Several RFC algorithms can be found in ASTM E1049-85 .

Probabilistic methods make an assumption about the load process. For moored vessels in fatigue environmental conditions the distribution of the tension peaks are described by a Rayleigh distribution. Most response spectra of mooring line tension are bimodal spectra with distinct peaks for low-frequency and wave-frequency tension components. The following section discusses the different methods available for combining low-frequency and wave-frequency fatigue damage.

The following methods may be used for combining the damage due to wave-frequency and low-frequency tension spectra:

a) Simple summation: wave-frequency damage and low-frequency damage are calculated independently, and the total damage is taken as the sum of the two. This method is slightly non-conservative when low- and wave-frequency contributions to the total damage are similar. This method may be used when the total damage is dominated by either the wave- or low-frequency contribution. This method is helpful in understanding mooring system response because it is the only method which provides estimates of the relative contributions from low- and wave-frequency tensions to the total fatigue damage.

b) Combined spectrum: the standard deviations of wave-frequency tension ranges and low-frequency tension ranges are calculated independently based on the separate wave-frequency and low-frequency tension spectra or the separate wave-frequency and low-frequency tension time series; the standard deviation of the combined response is computed as the square root of the sum of the variances. The damage is then calculated using the combined standard deviation. This method is always conservative and may significantly overestimate the actual fatigue damage.

c) Combined spectrum with dual narrow-banded correction factor: a correction factor is applied to the result of the combined spectrum method presented in b). This method is an improvement on method (b), that yields less conservative predictions. It is suitable for cases where low- and wave-frequency contributions to the total damage are similar. However, when the fatigue damage is dominated by low-frequency tensions, this method will overestimate the fatigue damage.

d) Time-domain cycle counting: fatigue damage is calculated from a tension time history using a cycle counting method, such as the rainflow method, to estimate the magnitude and number of tension range cycles. The tension time-history can be determined directly by a time-domain analysis or it can be generated from the combined low- and wave-frequency spectral analyses. Time-domain cycle counting when rigorously performed with a sufficient number of simulations is often considered to be the most accurate method.

Formulae and discussion is contained in A.8.7.2

#### 8.7.3.3 Accounting for mean value of tension in wire rope

Fatigue damage in steel wire rope depends on the mean value of the tension as well as the tension range.

To account for this the mean tension, $Q_i$, shall be determined for each line segment in each fatigue weather bin *i*. The *K* parameter of the wire rope T-N curve shall then be calculated as a function of the mean tension *Q* (see Table 14).

#### 8.7.3.4 Combining wave induced and VIM induced fatigue damage

Fatigue damage from vortex induced motions shall be calculated separately and added to the fatigue damage from wind and wave induced motions.

### 8.8 Response-based Analysis (RBA)

Traditionally, global hydrodynamic or motion responses, which include mooring extreme response for strength design, have relied on deterministic analyses performed for a design environment with an annual joint probability of occurrence of 1/N; that is, an event with a combined return period of N-years (e.g. loss of heading control and winter storm conditions). In this approach, the extreme mooring system response (the N-year response) is implicitly assumed to occur in the extreme N-year return period condition. Floating structures and their station keeping systems are, generally, complex nonlinear systems. Due to the unique characteristics of each response mode, it is possible that N-year extreme responses may not occur in the N-year return period environmental condition.

A response-based analysis (RBA) can overcome this limitation. The target of the RBA approach is to determine the N-year return period extreme responses, rather than the extreme responses due to the N-year return period environment. An RBA is based on the response statistics (e.g., mooring line tension, vessel roll, vessel offset, etc.) using a long-term time series of metocean events instead of metocean statistics. It can be performed to supplement the responses of critical design variables estimated using the design environmental condition analysis. In the context of the mooring system design, critical design variables to be considered in an RBA may include:

— motions,

— offset, and/or

— mooring line tension.

More details on RBA methodology can be found in A.8.8.

## 9 Thruster-assisted Mooring

### 9.1 General

This section provides information and requirements regarding the particular configuration where a single-point mooring system or a spread mooring system is assisted by onboard thrusters. Stationkeeping by dynamic positioning (no mooring lines) is not covered in this section; see Annex A.9 for more information on dynamic positioning. The analysis conditions and acceptance criteria for thruster-assisted mooring (TAM) systems are given in Sections 7 and 8, respectively.

### 9.2 Use of thrusters

Thrusters can be used to provide mean load reduction, heading control, low frequency damping or a combination of these.

For TAM using mean load reduction, the allowable thrust is used to counter only the mean environmental loads. The remainder of the mean load and the low-frequency motions shall be counteracted by the mooring system.

For structures with single-point moorings, typically the main function of the thrusters is heading control. For structures with thruster capacity that significantly exceeds the heading control requirements, the available capacity may be shared between heading control and mean load reduction or the generation of low-frequency damping.

### 9.3 Determination of allowable thrust

The allowable thrust used in the mooring analysis shall be determined as follows.

a) Determine the available effective thrust, accounting for the efficiency of the thrusters and losses due to floating structure motions, current, thruster/hull and thruster/thruster interference effects, and any directional restrictions.

b) Determine the worst thruster system failure. FMEA should be performed to identify the worst single failure of the integrated thruster control system (ITCS). The ITCS consists of the thrusters, and the control, power generation and distribution systems. The definition of the worst single failure should allow for thruster system availability (mean time to failure and mean time to repair) over the design service life of the installation.

c) Determine the allowable thrust:

   1) for automatic thruster control systems, the allowable thrust is either:

      I) for the intact thruster system, equal to the available effective thrust, or

      II) for the damaged thruster system, equal to the available effective thrust after accounting for the worst single component failure as determined by the FMEA;

   2) for manual thruster control systems, the allowable thrust is 0.7 of the value found in 1).

The allowable thrust used in the mooring analysis should be verified by thruster system sea trials.

### 9.4 Failure mode and effects analysis

Failure modes and effects analysis (FMEA) shall be conducted for floating structures with TAM and shall be kept up-to-date during operations. IMCA M103 provides guidance for performing FMEA. The FMEA should include the effect of failures of power generation, power distribution, thrusters, thruster control, and so forth, and identify the single worst failure of the entire thruster system. The FMEA shall include, at a minimum (but not be limited to), the following types of failures:

a) the sudden loss of major items of equipment,

b) the sudden or sequential loss of several items of equipment with a common link,

c) control and monitoring instabilities and failures, and methods of detection and isolation, and

d) faults that can be hidden until another fault occurs.

## 10 Installation, test load and as-installed survey

### 10.1 General

Before a mooring system design is finalized, the designer should conduct a constructability review of the mooring system with the key stakeholders from fabrication, transportation, installation, site geotechnical survey, and project management. This design review cycle allows the mooring designer to gather and verify all construction related restrictions for the mooring system, and to adjust the design to meet the design goals within the site-specific restrictions. The designer and the stakeholders together should also define and agree on the acceptable dimensional tolerances in the mooring component fabrication and system installation. The final design analysis cycle should verify that the cumulative effect of the dimensional tolerance will not cause problems for the system installation or hook-up, or cause the mooring system to fail to meet any design targets such as extreme loading limit, platform offset limit, clearances, or fatigue performance. This section provides information in the following areas:

— mooring system installation considerations during design stage,

— mooring line test loading requirement, and

— post-installation survey and establishment of as-installed (i.e. as-built) capacity.

## 10.2 Installation considerations and storm-safe criteria

### 10.2.1 General

Before the mooring system design is finalized, the requirement for installation of the platform shall be incorporated into the mooring system design. The designer and installation contractor shall: (1) assess the risk of any mooring line component being damaged during offshore installation, and (2) specify the mooring component spare parts needed to ensure the successful completion of the mooring system installation.

### 10.2.2 Mooring line handling and installation procedure

For permanent systems, if part of the mooring line will be pre-installed (either on the seabed or not) with each anchor, the mooring line installation and recovery procedures shall be developed in-advance; to allow adequate time for the mooring design and analysis to properly include installation considerations, as well as the design and fabrication of mooring hardware and installation aids.

If mooring lines need to be pre-laid on the seabed, they shall not be laid on subsea equipment without proper protection of the subsea equipment and mooring lines. Dragging of mooring components during the pre-lay or recovery operations should be avoided, especially for fiber ropes. On-deck mooring lines and jewelry/accessory connections or disconnection, as well as active boat winch payout or haul-in activities and boat-to-boat transfer operations, should not take place while the involved vessels are above subsea equipment or pipelines. Documented procedures shall be in-place to mitigate risks from dropped objects. If an anchor handling vessel is required to transit over subsea infrastructure while installing a mooring line, the anchors should be decked and secured prior to transiting over the infrastructure.

The mooring installation and recovery procedures shall include reference to appropriate *safe-handling* locations, with sufficient clearance from subsea infrastructure, for heavy-lift operations such as offshore vessel-to-vessel transfer of mooring hardware, personnel, and anchor handling.

The mooring installation and recovery procedures shall also include minimum required line tensions, to ensure mooring system components, such as wire rope, fiber rope, and chain/rope connectors, remain clear of the seabed including during kedging to safe handling locations.

If there is a requirement for mooring system components (e.g. wire or fiber rope, chain/rope connectors, etc.) to contact the seabed during pre-lay of mooring hardware in the field, the procedure shall comply with local regulatory and owner or operator specified requirements. Any requirement for mooring system components to contact the seabed, other than those components specifically designed for this purpose (e.g. mooring chain, etc.), should be specified in the mooring system basis of design.

For a MODU which requires mooring lines to be pre-laid, there shall be sufficient chain or wire onboard to allow hook-up operations of the rig components to the pre-laid lines.

NOTE The storm safe condition of a floating platform during mooring line installation is a temporary state when the minimum number of lines are hooked up that enables the platform to survive a site- and seasonal-specific return period "storm" event (storm, loop, or eddy current, etc.); see 6.3.2.

## 10.3 Test loading requirements

### 10.3.1 General

During installation, the mooring shall be test loaded to eliminate slack in the grounded portion of the mooring lines, detect damage to the mooring components during installation, and to ensure that the mooring line's inverse catenary is sufficiently formed to prevent unacceptable mooring line slacking due to cut-in during extreme conditions.

NOTE In some cases, the test load is also used to confirm the holding capacity of the anchoring system.

### 10.3.2 Test load for permanent mooring

For permanent moorings with drag, plate, or torpedo anchors, the mooring lines shall be test loaded to at least 80 % of the maximum load determined by a dynamic mooring analysis for the intact survival condition.

NOTE This is based on experience with drag embedment anchors in soft clay where deep anchor penetration can be achieved.

For drag embedment anchors on hard or sand seafloors, where anchor penetration is typically limited to no more than one fluke length, the test load should be higher. In defining the test load, the designer should consider the uncertainties in the calculated force and the consequences of potential platform displacement resulting from anchor movement.

The duration of the installation test load shall be at least 15 minutes after the anchor stops dragging.

### 10.3.3 Test load for mobile mooring

For mobile moorings with drag anchors, the installation test load should be determined by consideration of a number of factors, including type of anchor, soil conditions, winch pull limit, and anchor retrieval. As a minimum, the following shall be satisfied:

a) The installation test load at the anchor shank is not less than three times the anchor weight;

b) The installation test load at the winch is equal to the maximum intact tension under the operating condition (such as riser or gangway connected)

c) For close proximity moorings, the installation test load is equal to the maximum mean line tensions for an intact mooring in the survival condition.

d) The duration of the installation test load is a minimum of 15 minutes after the anchor stops dragging.

NOTE The required test loads may only be achievable through the cross-tensioning of mooring lines.

## 10.4 As-installed survey and establishment of as-installed capacity

In addition to the guidelines in 6.3.2, an as-installed survey shall be performed as part of the installation to accomplish the following.

a) Assess the quality of the mooring installation (e.g. proper load sharing in mooring line groups, excessive twist) and identify areas that may need immediate attention or remediation.

   NOTE Some remedial measures need to be carried out before or during installation (e.g. anchor position/orientation, chain un-twisting, etc.).

b) For permanent moorings, create baseline data of chain dimensions to which future corrosion and wear inspection data can be compared.

c) For mobile mooring, site-specific soil data may not be available before installation. The post-installation survey should provide anchor locations, embedment depths, orientations, and test loads, which may be used to verify the estimates of soil properties used in the design. For mobile mooring installation, the survey should also record the configuration and properties of the actually deployed mooring hardware in each mooring line and its resultant mean tension, to enable establishing as-installed set-up (such as vessel draft or line payout) in both operational and survival conditions. For MODUs operating in the Gulf of Mexico during hurricane season, see Annex B.

d) Gather data for updating of simulation models with actual anchor placements, as-installed line lengths/properties, and pretensions, as well as vessel draft and trim after mooring line hook-up, to ensure as-installed mooring system is within the design criteria,

e) Document the initial reading of position monitoring devices, load cells, and mooring line inclinometers, which are essential for mooring system integrity management,

f) Provide stakeholders with needed information about the as-installed mooring system to assess risks.

As-installed survey data should be gathered in such a way that it can be used by the mooring designer to define an as-installed mooring model that can be used to assess the capacity for the system. The owner or operator shall re-assess the as-installed mooring system to ensure that the requirements of this standard are satisfied.

NOTE Information and requirements for subsequent mooring inspections is provided in API 2I.

# ANNEX A

(informative)

# Guidance and Commentary

NOTE The clauses in this annex provide additional information and guidance on the clauses in the body of this standard; the same numbering system and heading titles have been used for ease in identifying the subclause in the body of this standard to which it relates; guidance is only offered on the identified clauses.

## A.1 Scope

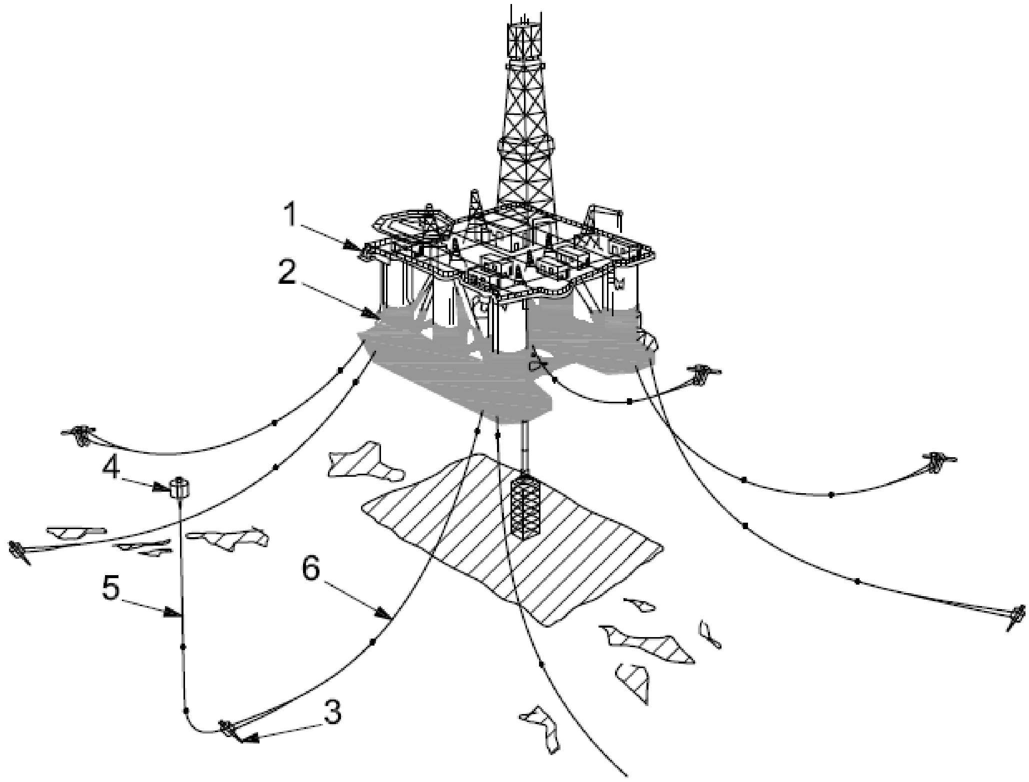
Types of mooring systems

Stationkeeping systems for floating structures used for oil and gas applications can be of many types, depending on the characteristics of the structure and on the environmental conditions. Single-point moorings are frequently used for ship-shaped floating structures and offloading buoys. Spread moorings are used mostly for semi-submersible or other types of structures when maintaining a particular heading is important. Another type of stationkeeping system is dynamic positioning (DP). Thruster-assisted moorings can also be used to reduce mooring line tensions and/or to control heading.

Spread mooring

Figure A.1 is an illustration of a typical catenary spread moored semi-submersible used for drilling operations. For floating production structures, spread moorings are often used with semi-submersibles and vessels with cylindrical-shaped hulls. Since the environmental actions on these types of vessels are relatively insensitive to direction, a spread mooring system can adequately hold the structure on location. When the prevailing weather at the site comes from one direction, spread moorings are sometimes used with ship-shaped structures. In this case, the structure's major axis is aligned with the prevailing environmental direction. Spread moorings can incorporate chain, wire rope, fiber rope, or any combination. Fiber rope generally is not used all the way up to the floater. A variety of connectors and accessories are also used. Drag anchors, vertical load anchors, suction piles, and driven piles are generally used to terminate the mooring lines.

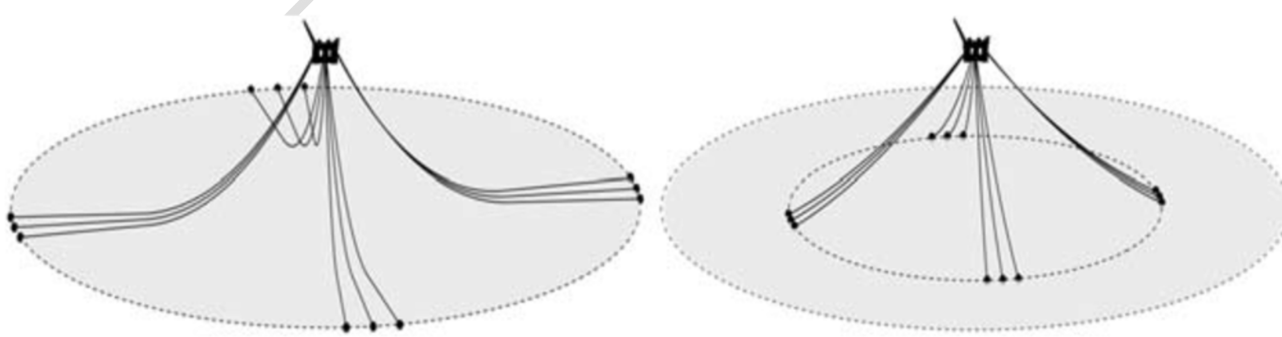
The main advantage of a spread mooring system is that it fixes the orientation of the floating structure so that drilling, completion, and well intervention operations can be carried out from the structure on subsea wells located immediately below the structure. Catenary spread mooring systems have a fairly large mooring spread and seafloor footprint (significantly greater than the water depth). The presence of anchors, mooring lines, and grounding chain should be considered in the installation or maintenance of pipelines, risers, wellheads, or any other subsea equipment. Spread mooring systems also include taut or semi-taut-line systems which have the smallest footprint, higher stiffness than catenary systems, and are typically used in permanent systems installed in deepwater (see Figure A.2).




**Key**

1 winch or windlass
2 fairlead
3 anchor
4 pendant buoy
5 pendant line
6 mooring line

**Figure A.1 – Spread Mooring for a Drilling Semi-submersible**



**(a) Catenary** **(b) Taut**

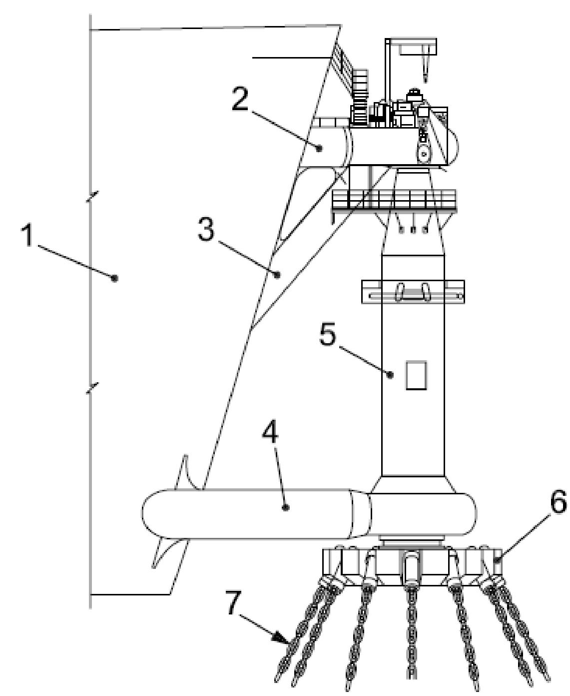
**Figure A.2 – Spread Mooring in Catenary or Taut Configurations**

Single-point Mooring (turret, CALM, SALM)

Single-point moorings are used primarily for ship-shaped floating structures such as FPSOs and FSOs with a turret mooring system. Their main characteristic is that they allow the structure to weathervane. There is wide variety in the design of single point moorings, but they all perform essentially the same function. Single-point moorings interface with the production riser and the structure. A summary of common single-point mooring systems is as follows:

- Turret moored, either external or internal
- Catenary-anchor leg mooring (CALM)
- Single-anchor leg mooring (SALM)

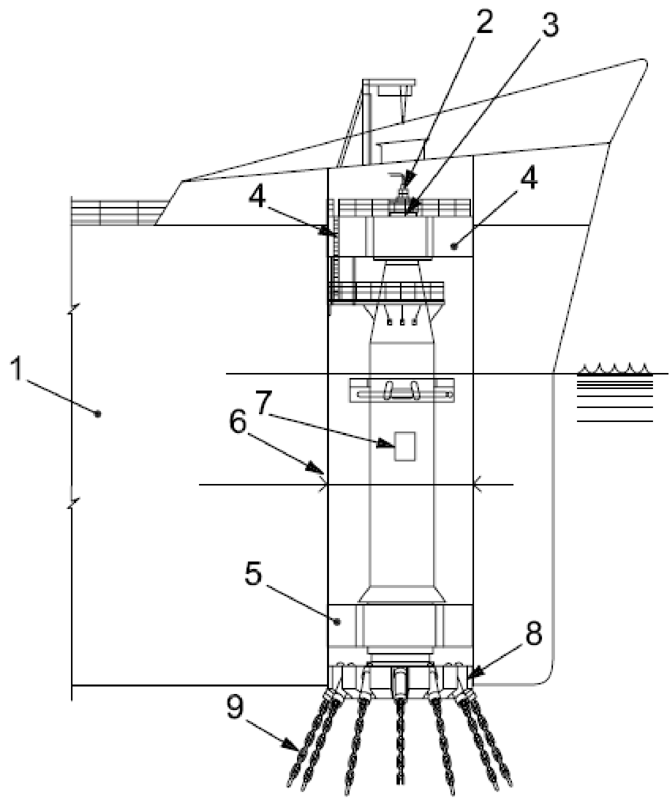
For turret mooring systems, mooring lines are attached to a turret, which is essentially part of the structure to be moored. The turret includes bearings to allow the structure to rotate (yaw) independently of the mooring system. The turret can be mounted externally from the structure's bow or stern with appropriate reinforcements (Figure A.3), or internally (Figure A.4). The chain table can be above or below the waterline. Typically, it is between the process facility and the geostationary part of the turret which runs through a swivel. The swivel also provides an electrical and control link between the vessel and seabed assets. Risers (and umbilicals) connect the seafloor to the bottom of the turret.




**Key**

1 floating storage unit (FSU)
2 upper connection structure
3 diagonal brace structure
4 lower connection structure
5 vertical turret shaft
6 chain table
7 mooring chain (typical)

**Figure A.3 – External Turret Mooring System (Bow-mounted Type)**




**Key**

1 floating storage unit (FSU)
2 in-line swivel
3 toroidal swivel
4 upper connection structure
5 lower connection structure
6 turret well wall
7 vertical turret shaft
8 chain table
9 mooring chain (typical)

**Figure A.4 – Internal Turret Mooring System**

In some cases, the turret is designed as a disconnectable system, as shown in Figure A.5. A turret buoy, which incorporates permanent connecting points for each mooring line, provides means to easily connect to, and disconnect from, the structure of the vessel. The turret buoy assembly also contains the main bearings which allow the vessel to weathervane. The turret buoy can be disconnected to enable the floating structure (usually self-powered) to depart from the location in advance of a foreseeable severe environmental event (e.g. tropical cyclone or approaching iceberg). This system is also used to temporarily moor specially modified export tankers for direct loading of produced oil. After disconnection from the vessel, the turret buoy remains submerged at a pre-set depth range while supporting the risers. The mooring lines maintain the horizontal offsets within acceptable limits for the riser system.

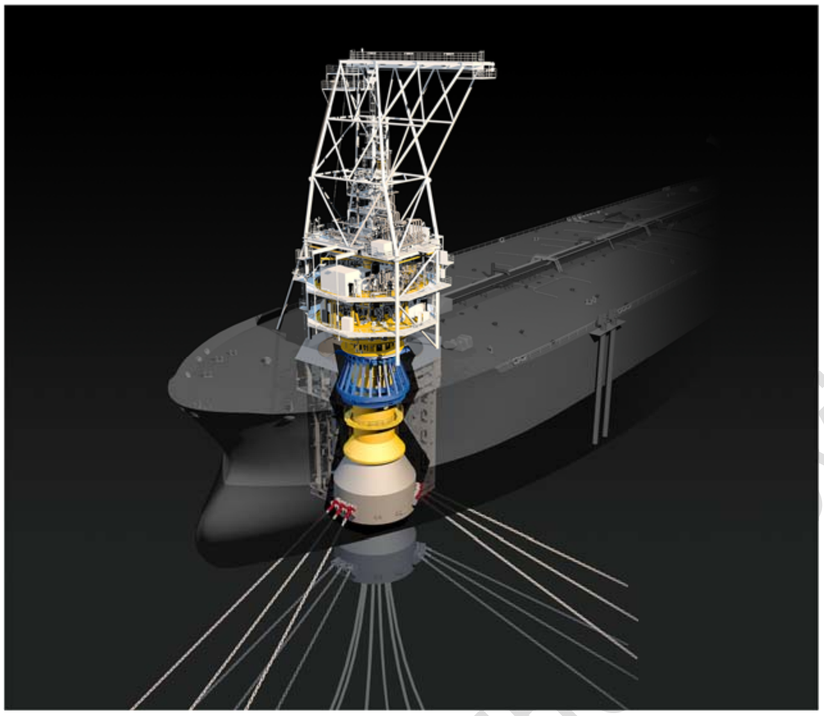
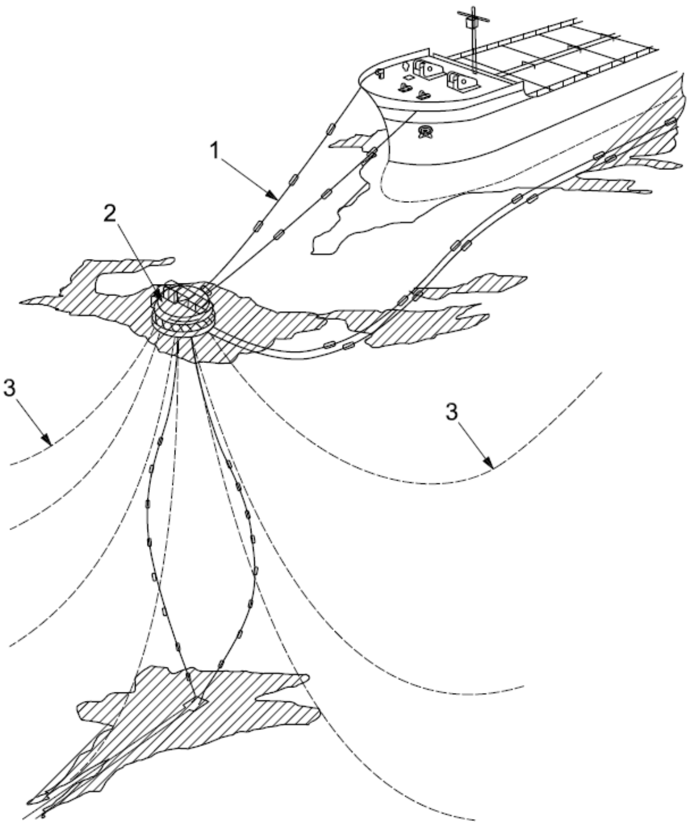


**Figure A.5 – Disconnectable Turret Mooring System**

A CALM system consists of a large buoy that supports a number of mooring legs anchored to the seafloor (Figure A.6). Such systems are typically used as export terminals for direct loading of tankers at the production field. Riser systems or flow lines that emerge from the sea floor or via mid-water flowlines with a nearby FPSO/FSO are attached to the underside of the CALM buoy. A hawser, typically a fiber rope, connects the tanker to the buoy. Since the response of the CALM buoy to environmental actions is decoupled from the tanker, this system is limited in its ability to withstand environmental conditions. When sea states reach a certain magnitude, it is necessary to disconnect the tanker.




**Key**

1 hawser

2 buoy

3 mooring line

**Figure A.6 - Catenary Anchor Leg Mooring (CALM) System with Hawsers**

A SALM employs a vertical chain riser system that is pre-tensioned by a surface piercing buoy. The buoyancy acting on the top of the riser tends to restore the riser to the vertical position (inverted pendulum effect). A tanker can be moored to the top of this SALM buoy with a hawser. The base of the riser is usually attached through a U-joint to a piled or deadweight concrete or steel structure on the seafloor. In deeper water, the chain riser system can be replaced by a tubular riser structure. Variants of this concept have been used to moor a floating structure (FPSO or FSO) using a rigid arm.

Dynamic Positioning and Thruster-assisted Mooring

Dynamic positioning is a technique of automatically maintaining the position of a floating vessel within a specified tolerance by controlling onboard thrusters which generate thrust vectors to counter the wind, wave, and current forces. Dynamic positioning is particularly well suited for a vessel designed to arrive and leave location frequently (i.e. an extended well test system). It is also well suited for ultra-deepwater application of mobile units such as drillships.

Many floating vessels designed to operate with moorings are also equipped with thrusters and thruster control systems. The thrusters can be used to control the vessel heading, reduce mooring load under severe environment, or increase the workability of the floating vessel.

## A.4 Stationkeeping Systems and Components

## A.4.1 Mooring components

### A.4.1.2 On-vessel tensioning equipment

There are a few types of tensioning equipment used in mooring systems, such as traction winch, windlass, chain jack, and others. The type and design of winching equipment required in a particular mooring system depends on the type of mooring line to be handled, and whether (or not) pre-tensioning of mooring lines and test loading of anchors is carried out from the floating structure. A MOU usually has the means of adjusting individual mooring line tension, re-tensioning after anchor drag, and disconnecting individual mooring lines. If a floating structure is used for combined drilling and production, the capability to position the structure over individual well locations can be required. This can be achieved by paying-out and heaving-in mooring lines.

Traction winches have been developed for high-tension mooring applications as well as for handling combination mooring systems. They consist of two closely spaced parallel mounted powered drums, which are typically grooved. The wire rope makes several wraps (typically 6 to 8) around the parallel drum assembly. The friction between the wire rope and the drums provides the gripping force for the wire rope. The wire rope is coiled on a take up reel which is required to maintain a nominal level of tension in the wire rope (typically 3 % - 5 % of working tension) to ensure the proper level of friction is maintained between the wire rope and the traction winch. This system has been favored for use in high-tension applications due to the compact size, capability to provide constant torque, and ability to handle very long wire rope without reduced pull capacity.

A windlass, equipped with a gypsy head or wildcat, is common equipment for handling and tensioning chain, as shown in Figure A.7 (see [18]). The windlass consists of a slotted wildcat which is driven by a power source through a gear reduction system. As the wildcat rotates, the chain meshes with the wildcat, is drawn over the top of the wildcat, and lowered into the chain locker. Once the chain is hauled in and tensioned, a chain stopper or brake is engaged to hold the chain. The windlass has proven to be a fast and reliable method for handling and tensioning chain. Windlass are often found on anchor handlers and occasionally found on MODUs which allows a steady controlled pay-out or haul-in of the chain elements in a mooring system.

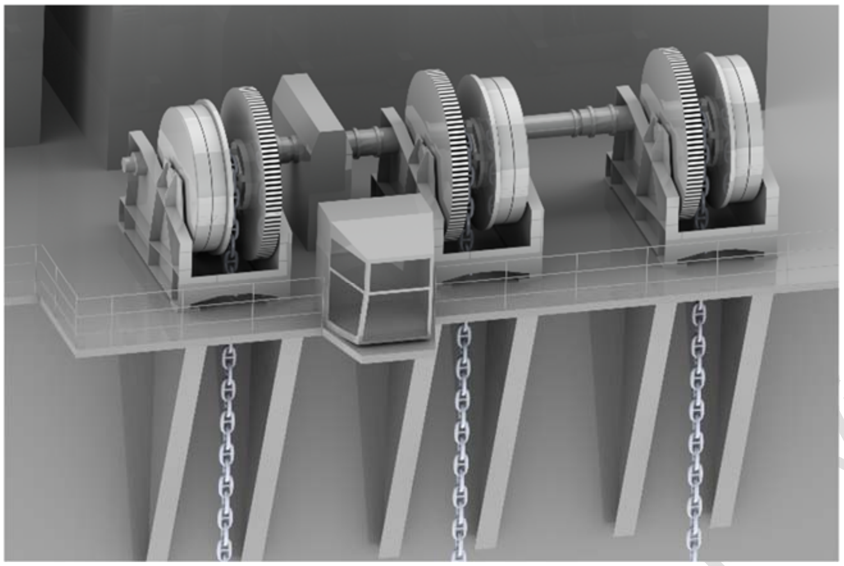
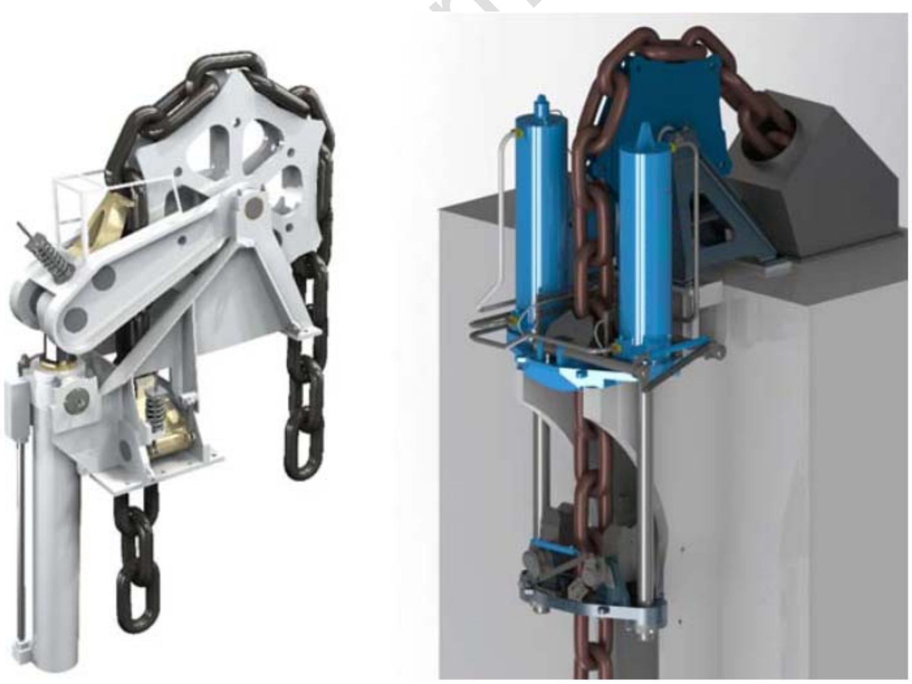


**Figure A.7 – Windlass**

The chain jack is a device which reciprocates linearly to haul in and tension chain, as shown in Figure A.8 (see [18]). Usually powered by one or more hydraulic cylinders, chain jacks engage the chain, pull in a short amount of the chain (i.e. usually two links), engages a stop, retracts, and repeats the process. Although a chain jack can be a powerful means for tensioning chain, it is very slow and is recommended for applications not requiring frequent line manipulation.



**(a)** **(b)**

**Figure A.8 –Examples of Chain Jacks**

Tensioning equipment should be serviced and maintained in working order so that they are ready to install and tension a replacement line in the event of a mooring failure. Otherwise, the time taken to procure or refurbish tensioning equipment should be allowed for in the mooring line replacement plan.

### A.4.1.3 Fairleads and bending shoes

Fairleads (also called “sheave-type fairleads”) and bending shoes (also called “bending-shoe-type fairleads”) are used with both wire rope and chain. Figure A.9 shows an example of a chain fairlead [18].

Sheaves used for chain typically have 7 to 9 pocket wildcats. Sheave-type fairleads have been used more often but bending shoes may provide an alternative for fair-leading large diameter mooring lines. An example is the underwater swiveling bending shoe. This device, which is used initially with wire ropes, incorporates a shoe (D) to rope (d) diameter ratio of more than 70 and a special high-density nylon bearing material secured to the bearing surface on the shoe. Replacement of the polymeric material is possible by slacking down the mooring line and removing the bearing material which is bolted to the bearing surface in sections. Industry experience indicated that this device can also be used for chain. However, operating with high chain tension and frequent vessel movements should be avoided because it can cause serious damage to the bearing material.

Fairleads are fitted with large sheaves to minimize tension bending fatigue on wire ropes. Sheaves for wire rope typically have diameter (D/d) ratios of 16-25 for mobile moorings, and 40-60 for permanent moorings.

**Figure A.9 – Fairleads**

### A.4.1.4 Off-vessel anchor line components

In addition to the information in this section, refer to API 2SM (fiber ropes) and API 2F (mooring chains).

#### A.4.1.4.2 Fiber rope

Fiber ropes may be used as segments in catenary systems, taut, and semi-taut leg systems. The differences from steel wire rope and chain mooring include:

— specific gravity,

— range and the non-linearity of axial stiffness,

— minimum tension requirements (for some ropes),

— position of fiber rope segments to be away from fairlead and seafloor (depending on application),

— failure mechanisms (elongation, creep, wear, cutting, marine growth, or soil infiltration), and/or

— handling procedures.

Fiber ropes have a range of density and can be buoyant in seawater, display non-linear load elongation behavior, and may also undergo permanent elongation during their service-life. For fiber rope moorings, system behavior may be dominated by strain energy rather than potential energy, contrary to steel mooring systems. Consequently, the way in which the non-linear load-elongation behavior of fiber ropes is modelled can have a significant impact on the results of the mooring analyses (offsets, strength, fatigue, etc.)

Polyester (polyethylene terephthalate or PET) ropes have been extensively used in permanent units in water depths exceeding about 1100 ft. The compliance of polyester ropes has allowed the use of taut systems in deep and ultra-deep water without the need of resources for catenary compliance to limit dynamic-tensions, mostly excited by waves. Polyester ropes have also seen significant application in pre-set moorings and in extending the water depth range of MODUs. HMPE (high-modulus polyethylene) ropes have been used extensively in MODU moorings and in a few FPSO moorings. Nylon (polyamide) ropes have been used for hawsers in CALM systems and are currently being considered for shallow water and tender assisted moorings.

Fiber ropes are typically constructed to be torque-neutral (see Figure A.10; also see [18]). Low-twist parallel-laid or long-braid length constructions are typically used in fiber rope for moorings. These constructions confer high-tensile efficiency and endurance to the ropes. There are two classes of constructions: torque-neutral (parallel-strand type) and torque-matched (wire-rope type). A torque-matched rope is used when it is connected with a mooring component that is not torque-free (such as a six-strand wire rope).

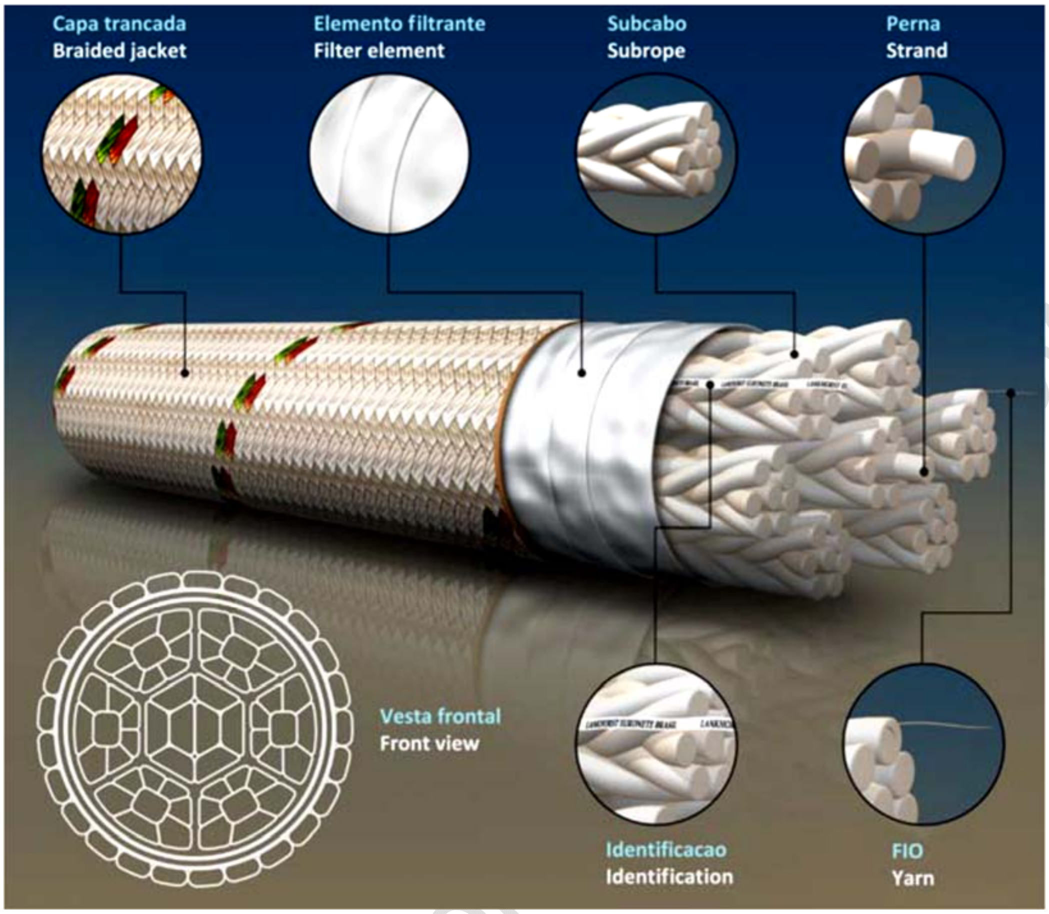
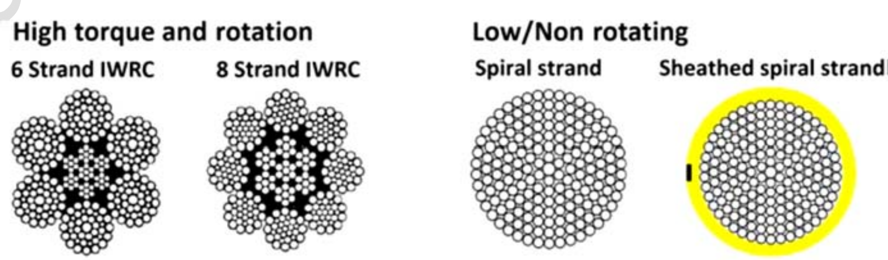



**Figure A.5.10 – Typical Fiber Rope Constructions**

### A.4.1.4.3 Mooring wire rope

The wire rope sections of the moorings can be of various constructions, as shown in Figure A.11. The wire rope construction-type includes several strands wound in the same rotational direction around a center core to form the rope. The number of strands and wires in each strand, core design and lay of strands are governed by required strength and bending fatigue considerations for the rope. This construction generates torque as tension increases. Mooring steel wire rope should not have a fiber core.

The spin-resistant strand-type constructions (spiral strand and multi-strand) are attractive for use with permanent moorings since they do not generate significant torque with tension changes. Both constructions use layers of wires (or bundles of wires) wound in opposing directions to obtain the spin resistance characteristics.




(a) (b)

**Figure A.11 – Typical Wire Rope Constructions**

Wire ropes may be jacketed or unjacketed. For corrosion resistance in permanent moorings, typically a high-density polyethylene jacket is employed. Also, all wires should be galvanized. Zinc-filler wires are sometimes incorporated to provide additional corrosion protection. The space between wires uses a filler material as a lubricant and to block the inside spaces between the wires to minimize the spread of corrosion with ingress of saltwater.

Wire rope used in permanent systems is designed for corrosion resistance according to the location and water depth. Typical life-expectancy, based on corrosion resistance, of different types of wire rope in permanent systems is provided below; designers should use caution if employing these values:

- Galvanized 6 or 8 strand 4-10 years
- Galvanized unjacketed spiral strand 8-12 years
- Galvanized unjacketed spiral strand with zinc filler wires 15-17 years
- Galvanized jacketed spiral strand 20-30 years
- Galvanized jacketed spiral strand with zinc filler wires 20-35 years

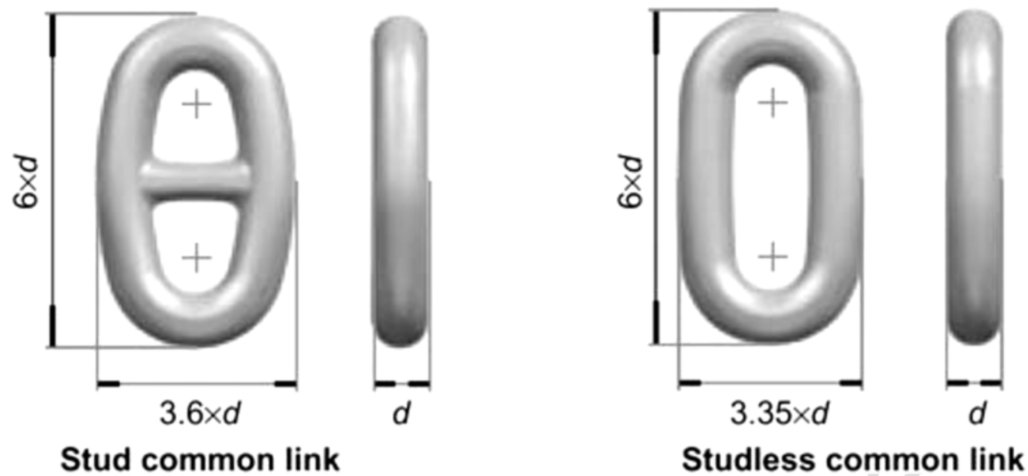
The ends of each wire rope section should be terminated in resin or zinc-poured sockets. A resin material is typically preferred over Zinc for pouring the sockets. The socket should be designed and test-proven not to be the weakest point of the wire rope segment. For permanent moorings, the sockets are typically provided with flex-relieving boots (bend-stiffener) joined to the socket in a manner to seal out the ingress of water and limit free-bending fatigue. Zinc anodes are attached to protect the socket from corrosion, and isolation washers are used to electrically separate the two connected segments. Typically, the socket is electrically isolated from the rope.

#### A.4.1.4.4 Mooring chain

The choice of material and fabrication of large diameter chain for a moored floater requires careful evaluation. It is desirable to have chain used for this application manufactured in continuous lengths for each mooring leg. This eliminates the need for chain connecting links and the associated problems with fatigue. Otherwise, connecting links meeting the specified fatigue-life shall be used.

Chain can be obtained in several grades. Oil rig quality (ORQ), R3, R3S, R4, R4S, and R5 chain has been sold in large quantities over the years. It is important to recognize that there is another category of chain called ship chain (or marine chain); with lower tensile strengths, they are not recommended for offshore mooring operations. The designer should consider the fracture toughness and the likelihood of hydrogen embrittlement when specifying higher grades. Regardless, the designer should use appropriate practices and good judgement in selecting the correct chemical composition of the bar stock, manufacturing techniques (which incorporate precise quality control), and comprehensive sample testing of the final manufactured product.

Stud chain (Figure A.12) has been used by the offshore industry for more than 40 years. For R3 grade, studs are often welded on the side opposite to the flash weld. Studs are normally not welded for higher grades. The industry has experienced significant problems associated with studs, including loose studs, fatigue crack and fracture at the stud weld or stud footprint. In the 1990's, studless chain (Figure A.12), gained wide acceptance in the application of permanent moorings. For the same diameter, studless chain is about 10 % lighter than the stud chain but has the same catalogue breaking-strength. Fatigue-resistance of studless chain is less than that of stud-link chain. Industry experience with studless chain has been favorable so far. In fact, most of the permanent moorings recently installed or designed use studless chain instead of stud chain.




(a) (b)

**Figure A.12 – Stud and Studless Chain**

### A.4.1.4.5 Connecting hardware

Connecting hardware such as shackles, H-links (as shown in Figure A.13[18]), swivels, triangular plates, and detachable links are used to connect the main mooring line components. Inspection and replacement of connecting hardware in a permanent mooring are difficult, therefore, fatigue life, corrosion protection and hardness compatibility become important considerations.

On permanent systems, many have used D-shackles and H-links because these connectors have a fatigue performance that is equal to or better than studless chain while Kenter links (for example) have a worse fatigue performance than studless chain.

(a) (b) (c)

**Figure A.13 – Examples of Shackle and H-links**

Specially designed connectors (subsea mooring connectors) were developed to allow connection and disconnection of two mooring line segments underwater. Some have a male-part and a female-receptacle, which are installed onto two different line segments which will be connected; others rely on improved hooks. The underwater operation of connecting or disconnecting the male- and the female-parts are performed by an ROV.

All connecting hardware to be used in permanent mooring lines should be analyzed to determine stress concentration factors to be used in fatigue analysis.

Connecting hardware should be fully inspected by non-destructive testing (magnetic particle, dye penetrant, eddy current, etc.) according to recognized standards as required to ensure these connectors are fit for purpose. Quality control measures should be in-place and test fit-ups should be carried out to assure the connectors can be assembled in the field.

#### A.4.1.4.6 Buoys

Buoys can be placed in-line with the mooring (with a strength-member passing through the buoy) or attached separately to the mooring through a tri-plate or swiveling connection. When using the in-line buoy approach, care shall be taken to allow for rotation in the end connections. Buoy motions should be considered in the design of connecting links to the buoy and the mooring line's dynamic responses. The motions of buoys can cause interlink rotations resulting in wear and fatigue damage of chain and connecting links, causing the buoy to detach from the mooring line.

Buoys are connected to a mooring line to gain the following benefits:

- Reduced weight of mooring lines that shall be supported by the vessel hull; this is particularly advantageous to floating vessels moored in deep water and/or with disconnectable systems,
- Reduced vessel offset for a given line size and pretension,
- Increased vertical clearance between the mooring line and the equipment below.

Adverse effects of spring buoys are:

- Increased use of connecting hardware and installation complexity,
- Potential increased design loads on the mooring lines due to dynamic response of the buoy in heavy-seas,
- Potential failure points at the connecting padeye, shackle, chain or wire rope termination due to wear or fatigue,
- Potential loss of buoyancy over time.

Buoys used with permanent moorings are typically constructed from steel or synthetic material. Steel buoys can be built in either a cylindrical or spherical shape. Recognized pressure containment standards should be used for designing subsurface buoys of steel construction subject to external pressure. A high-density foam material (glass spheres encased in a high-density foam) has been successfully used to provide buoyancy for deepwater drilling and production riser and mooring operations. For foam buoys the long-term water absorption rate of the foam material at its service depth should be determined and included in the design of the buoy.

A submersible mid-water buoy can be used to reduce the effect of wave motions on mooring components by comparison to a surface buoy, thus reducing wear and fatigue damage. Also, by placing the buoy below the surface, the risk of the buoy being damaged from collision with a surface vessel is reduced or eliminated. The deployment scheme of the submersible buoys with its mooring line attached should be considered at the design stage to ensure that the buoy assembly will not be submerged beyond its rated depth-limit.

#### A.4.1.4.7 Disconnectable turret buoy

Turret buoys are used on FPSOs with disconnectable turrets. The net buoyancy of the buoy should be adequate to support the risers, umbilicals, and mooring lines during and after disconnection. The mooring and riser loads and the net buoyancy should be designed so that when released the mooring line, riser and buoy motions do not result in clashing or unacceptable seabed contact.

The design of submerged turret buoys is a complex undertaking. Design load cases shall include installation, connected, disconnected, disconnection, and reconnection conditions. Typically, the system includes provisions for ballast adjustments, and the floater contains a combination of void tanks and/or floatation modules and ballast tanks. Integrity management of submerged turret buoys is paramount since loss of the buoy by any means would compromise the risers and umbilicals.

### A.4.2 Monitoring equipment

#### A.4.2.1 General

Monitoring systems may provide the operator information regarding metocean conditions, line tensions, line pay-out, vessel position, vessel heading, draft, trim, and so forth. A combination of a calibrated model of the mooring system with measurements of position, displacement, and sea current (if necessary) has successfully been used to “monitor” mooring line tensions.

#### A.4.2.2 Line tension, pay-out, and vessel position

Tension-measurement is typically performed using electrical resistance based on strain-gauged load cells. Depending on the configuration of the system, the load-sensing element may be in or out of the water and the system may or may not have been designed for the sensor to be unloaded during operation. A number of configurations have been used by direct measurement such as: instrumented shear pins on fairleads, turn down sheaves and end connections, instrumented chain stoppers, load cells supporting the winching system, and instrumented links.

The use of sensors based on strain-gauge load cells in permanent systems has historically had poor performance due to zero drift and need for gain adjustments. The strain gauges may have poor long-term reliability and can be costly to replace. If such a system is selected, it is recommended that the operator has means to unload the sensing element to adjust the zero set-point. Systems with provision to allow at least a two-point verification of gain (zero-tension and pre-tension) are preferred.

The easy access from the topside and the fact that it is dry under normal operating conditions make the chain stopper on the topside an ideal location for direct load-measurement of the tension in the mooring line. To be reliable, the load cells should be properly calibrated and compared against another calibrated load monitoring device during commissioning. Many load cell interfaces allow the technician commissioning the unit to adjust the gain on the load cells which can adjust and change the readings through a range of values. Commissioning guidelines for tension monitoring equipment should be well established and agreed upon before the mobilization of the offshore hook-up and commissioning. To perform as desired, they should be designed with suitable primary and secondary support structures. They should also be easily inspected for signs of fatigue and cracking during the regular mooring inspection intervals. The load cells should also be designed with ease of repair and replacement in service to ensure continued monitoring in support of mooring system integrity management.

In catenary and semi-taut moorings without buoys, inclinometers have successfully been used in conjunction with a calibrated mooring model to calculate quasi-static and low-frequency tensions.

One alternative to load cells and inclinometers is the use of a calibrated mooring model in conjunction with measurement of floater position, heading, and draft. The approach has demonstrated adequate performance in calculating line-tension.

## A.5 Environmental and Site Data

#### A.5.2.2 Environmental Data (collection and analysis)

When collecting data where joint probabilities are to be considered, care should be exercised to preserve the appropriate information. Of particular importance are the wind/wave, wave height/wave period, and wave/current relationships, and their absolute- and relative-directionality characteristics.

#### A.5.2.5 Wind statistics

Wind velocity increases with height above the water. In order to account for this change, a wind force height coefficient, $C_h$, is included. The height coefficients, $C_h$, should be calculated based on the wind profile and time-averaged wind speed as specified in API 2MET or a different wind profile as defined by a metocean specialist.

The wind profile for squall events requires special consideration. A metocean specialist should be consulted.

## A.6 Design and Site Assessment of Stationkeeping Systems

### A.6.1 General

Long-duration MOU operations

A MOU may be at a single location or in a field for more than a few weeks or months, for example a multi-year development drilling campaign. If the duration of the operation is sufficiently long and it is not planned to disconnect the mooring for extreme environmental conditions, then all-year full-population metocean conditions are appropriate for survival or standby cases. If the MOU's operations (e.g. drilling, pipe-laying gangway connected, etc.) can be suspended for extreme environments, the stationkeeping analyses performed to determine limiting operating environmental conditions and time spent waiting on weather, may be based on appropriate seasonal metocean conditions. For long-duration MOU operations, a risk assessment can be used to determine the environmental return period appropriate for the extreme survival or standby cases. For multi-year MOU operations in harsh environments without the ability to inspect the mooring system on retrieval and redeployment, a fatigue analysis can provide useful input to the risk assessment.

### A.6.2 Design conditions

Mooring line strength factors of safety

Designing a mooring system to a strength safety factor of 1.0 on ultimate component strength is discussed below and shown to be equivalent to designing for failure and therefore is not recommended.

Stationkeeping codes define mooring line-strength factors of safety with respect to the ultimate strength of the line's components, this is fundamentally different from other structural codes where factors of safety are defined with respect to the nominal yield stress of the component's material. However, the design procedure (recipe) that has evolved over the last 40 years, of analyzing both intact and one-line failed mooring systems for 100-year return period environmental conditions with total line-tension safety factors of 1.67 and 1.25, respectively, has worked well. For permanent systems, the number of mooring line failures due to overload, both expected and unexpected, has been extremely small (see [20]).

Acceptance criteria for mooring systems exposed to return period conditions of 1000 to 10,000 years combined with component-strength factors of safety close to 1.0, require careful and thorough examination. The following topics are considered below,

- Environmental hazard curves; winter storm (e.g. North Sea, Canada, etc.) and tropical revolving storm (Gulf of Mexico, Australia, etc.),
- Mooring component strength; load, load ranges, elasto-plastic stresses, strains, and permanent deformations,
- Fatigue failure; single event fatigue failure due to high-stress range / low-cycle fatigue damage,
- Forensic analyses of mooring line failures due to overload; bias factor determined using deterministic mooring analyses and probabilistic analysis (Bayesian updating).

Design requirements for intact stationkeeping systems in 10,000-year environmental return period conditions with an associated strength safety factor of 1.0 have been introduced (see B.2.3.7 of ISO 19901-7:2013; also see [15]). The risk associated with stationkeeping system failure will depend on the consequences of failure, as well as the probability of failure. In some geographic regions it is standard practice to remain manned in extreme environmental conditions while in other regions personnel are evacuated prior to storm conditions reaching the site. In addition, while a mooring system failure has financial consequences, it does not necessarily have consequences other than financial (e.g. safety or environmental consequences); that is, a mooring system failure can be an initial event in a sequence of events, each with their own conditional probability of occurrence, that shall also take place leading ultimately to the unwanted outcome. The acceptance criteria in this standard apply to permanent stationkeeping systems, where the risers are equipped with emergency shut-in valves that allow them to be shut-in and possibly purged (e.g. in advance of disconnection or prior to evacuation).

The uncertainty (absolute and relative) in 10,000-year return period metocean conditions developed for different regions of the world may vary greatly and should be considered; however, this is beyond the scope of this stationkeeping standard. For regions of the world where the slope of the environmental hazard curve is sufficiently shallow the new 10,000-year return period design condition, with an intact safety factor of 1.0, makes no (or little) difference to the design of the mooring system (i.e. the strength of the mooring system is controlled by the 100-year return period intact and one-line broken design cases with their associated safety factor, or the 10-year return period two-line broken case); however, where the slope of the environmental hazard curve is sufficiently steep (some tropical revolving storm regions), the 10,000-year return period design case with a safety factor of 1.0 can be the controlling case for mooring system strength-design. When mooring system strength is controlled by novel design criteria, such as the 10,000-year return period condition with a safety factor of 1.0 for which there is not a long history of use, the implications of designing to a safety factor of 1.0 based on ultimate component-strength should be carefully and thoroughly examined.

Break-load tests used for qualification or acceptance of mooring components are based on simple single-cycle loading of short-duration, the break test does not represent a realistic dynamic time-history of loading that lasts for the duration of the storm event; that is the break-load test is not representative of the loading that components will be exposed to in extreme design situations, particularly when the safety factor is close to 1.0. In addition, the definition of mooring line ultimate strength does not account for the fact that mooring lines are composed of a series of structural elements (i.e. many break-test lengths connected in series).

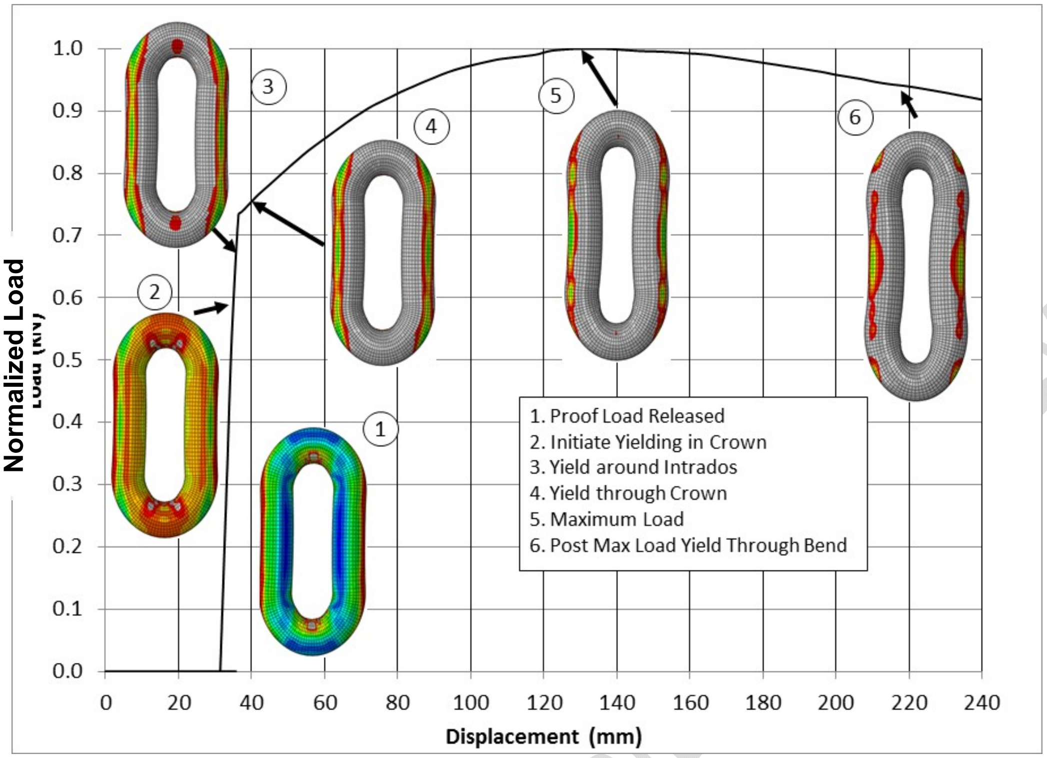
For example, during manufacture, chain links are subject to two load tests: (1) proof-load and (2) break-test load. Formulas giving the required proof and catalogue break-strengths (CBS) for chains of different types (stud and studless), grades, sizes, and acceptance and rejection criteria are contained in IACS W22 [21]. The break-test load is the same as the catalogue break-strength (CBS) published in chain catalogues. The proof load is between 66 % and 79 % of CBS depending on chain type (stud or studless) and chain grade. All (100 %) of the links in a chain order are subject to the proof-load testing, although links have failed below or at the proof-load (which is not a frequent occurrence). Break-test loading is performed on links that are not part of the delivery, as permanent and unacceptable damage is done to the links that are break-test loaded. A break-load test is required approximately once for every 500-link length that is manufactured (e.g., every 1000 feet for 6-inch chain). The break-test loading consists of slowly increasing the load to the CBS value and holding the load for 30 seconds before unloading (see Figure A.14; also see [22]). If the sample does not fail below or at the CBS, the 500-link length is acceptable. If the sample fails below or at the CBS, two additional break-load tests may be performed on links taken from the same length. If the results of two additional tests and the failure investigation are satisfactory, the 500-link length may be accepted.

Consequently, the testing and acceptance criteria for chain links ensures that, for new chain, all links have a “strength” greater than or equal to the proof-load. However, it is possible that the “strength” of a number of the new links supplied is below the CBS. Additionally, in the discussion above, “strength” is associated with a single slowly increasing load that is held for 30 seconds, followed by discarding the links. This type of loading (i.e. break-test loading), that is used to approve the ultimate strength of a chain order, is very different from the loading that mooring chains are exposed to in extreme environmental conditions, particularly when the strength factor of safety is close to 1.0 (i.e. maximum tensions are close to the CBS).

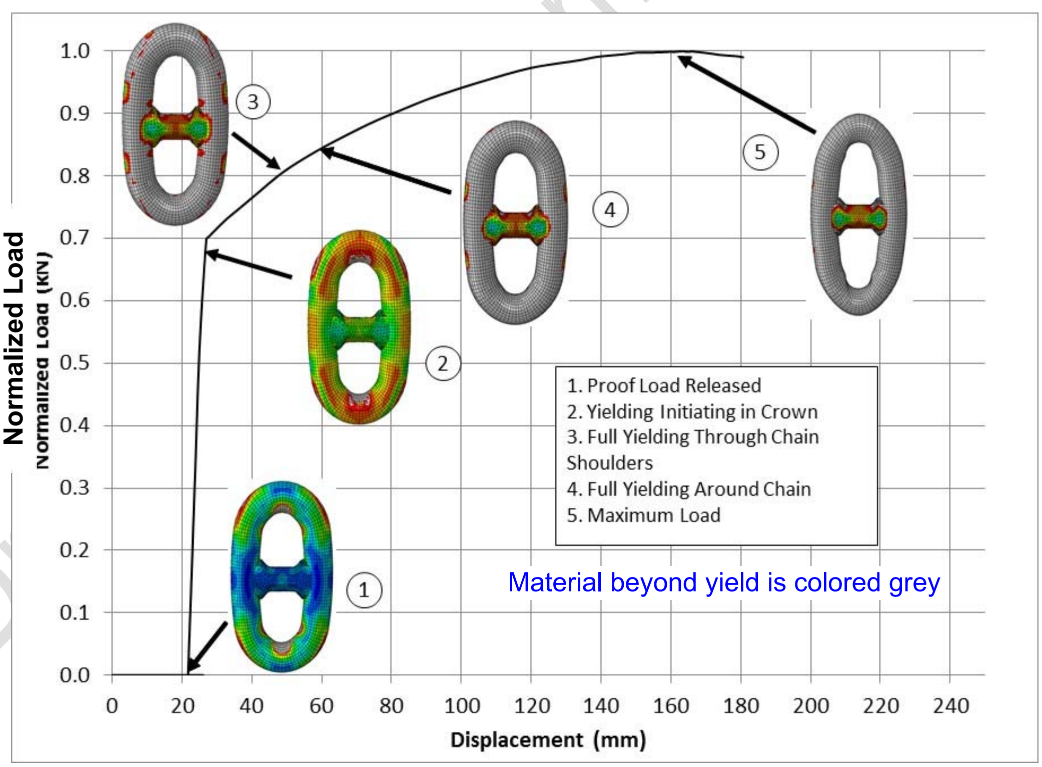
When the tension in a chain is about 60 % or 68 % of CBS for studless- and stud-links respectively, stresses in the crown region of the link are at or above yield (see Figure A.14). Consider an extreme storm event with a duration of 3 hours for which the strength factor of safety is 1.0; that is, the maximum line-tension in three hours is equal to the ultimate break-strength of the mooring line-component. During this single three-hour event, there will be multiple tension cycles with peak tensions above the elastic limit (60 % to 68 % of the CBS). If this storm event were to occur, failure due to high tension range low cycle fatigue damage must be considered as a failure mode. That is, the “strength” analysis shall evaluate component-failure due to both high-tension range low-cycle fatigue damage and simple single-cycle exceedance of the component’s ultimate strength. High-tension range low-cycle fatigue T-N curves for chain, wire, and polyester [14] are reproduced in Figure A.15.

The MODU Mooring Strength and Reliability JIP [23] analyzed seven MODUs that were impacted by hurricanes Katrina and Rita — six that experienced mooring system failures and one that did not. The methodology used to determine the bias factor (bias factor = predicted tension at failure/CBS) followed that used in the study of fixed platforms in the Gulf of Mexico. The biggest difference is that in the analysis of fixed-structures it is not possible to know when the structure failed within the storm-event, and it is assumed that fixed-jacket failures occurred at the peak of the storm. However, all of the MODUs studied were equipped with tracking equipment, so it could be determined when (within about 15 minutes) line failures occurred. A hindcast was used to define the metocean conditions at the location and time of failure. All the first failures occurred at the top of the mooring lines in the wire rope segment. The bias factor was determined using probabilistic analysis (Bayesian updating) and post processing of the results of deterministic mooring analyses. The study concluded that the resulting mean bias was 57 %; that is, conditional on the hindcast and mooring analysis used, mooring line failure occurred at about 60 % of the wire rope's break-strength.

Stationkeeping codes define mooring line-strength factors of safety with respect to the ultimate strength of the line's components; this is fundamentally different from other codes where factors of safety are defined with respect to the nominal yield stress of the component's material. The discussion above demonstrates that designing to a strength safety factor of 1.0 on ultimate component-strength, in associated extreme return period conditions, is equivalent to designing for failure. Also, the design procedures that have evolved over the last 40 years of analyzing both intact and one-line failed mooring systems for 100-year return period environmental conditions with safety factors of 1.67 and 1.25, respectively, have worked well. For permanent systems, the number of mooring line failures due to overload, both expected and unexpected, has been extremely small (see [20]). Additionally, there is no basis for the introduction of design cases for moored systems that use strength factor of safety of 1.0 based on the ultimate strength of mooring components.




**(b)**




**(a)**

**Figure A.14—Stresses and Elongation of Chain Links during Break Test Loading to CBS**

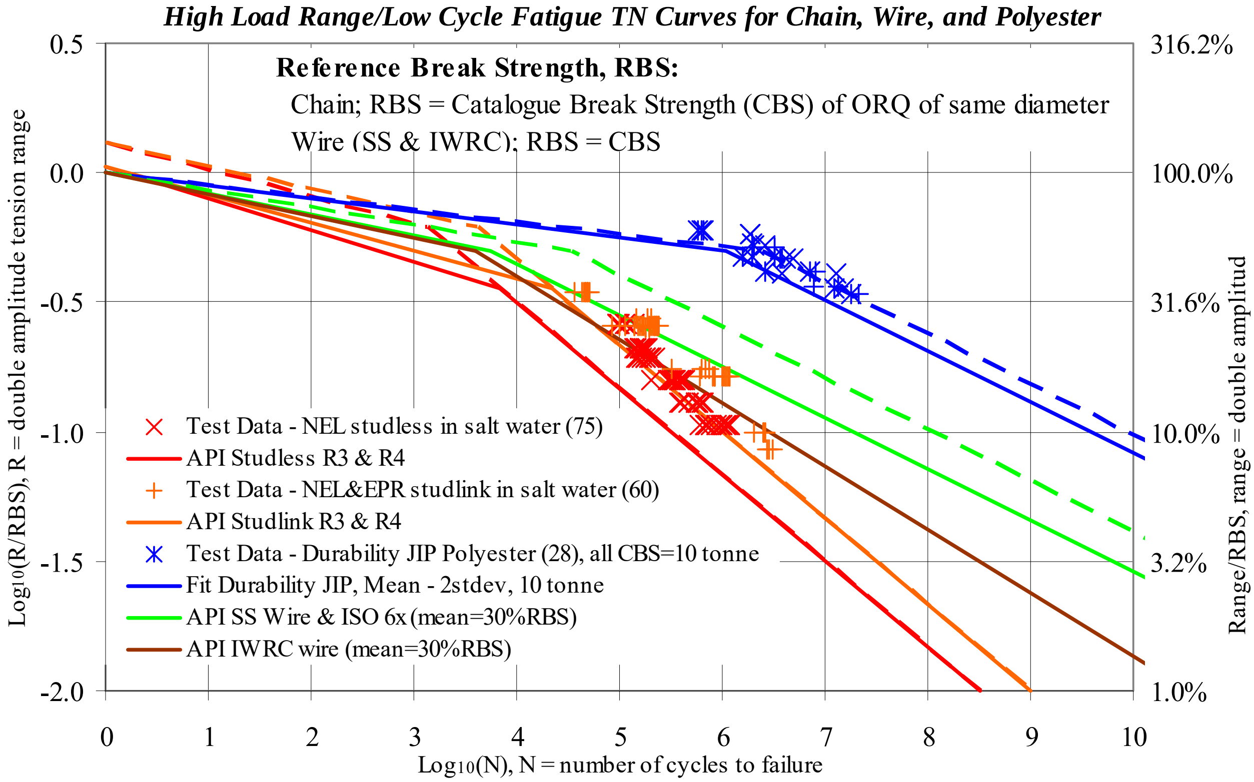



**Figure A.15—High Load Range / Low Cycle Fatigue TN Curves for Chain, Wire, and Polyester [14]**

<u>Example of project specific permanent mooring design criteria</u>

An example of a possible permanent mooring project-specific strength and polyester rope seabed clearance cases and criteria are illustrated in Table A.1.

**Table A.1 —Permanent Mooring: Example of Project Specific Strength and Seabed Clearances**

| Design Condition | Intact | 1-Line Missing | 2-Lines Missing |
|---|---|---|---|
| **Strength (see Table 1)** | | | |
| 100-year return period environmental conditions | 60 % ELBS | 80 % ELBS | Information |
| 10-year (reduced extreme) return period environmental conditions | Information | 60 % ELBS | 80 % ELBS |
| 1000/10,000-year return period environmental conditions | Information | Not Applicable | Not Applicable |
| **Polyester Rope Seabed Clearance (see Table 5)** | | | |
| 100-year return period environmental conditions | > 5 m | None, Information | Not Applicable |
| 10-year (reduced extreme) return period environmental conditions | Information | > 5 m | Information |
| 1000-year return period environmental conditions | Information | Not Applicable | Not Applicable |

Example of project specific MODU mooring design criteria

An example of MODU mooring project specific strength and offset criteria is illustrated in Table A.2.

**Table A.2 —MODU Mooring: Example of Project Specific Strength and Offset**

| Design Condition | Intact | 1-Line Missing | 2-Lines Missing |
|---|---|---|---|
| **Strength, Survival (see Table 3)** | | | |
| Survival, close proximity, 25-year return period environmental conditions | 60 % ELBS | 80 % ELBS | Not Applicable |
| Survival, less than 10,000-year return period environmental conditions | Information | Not Applicable | Not Applicable |
| **Strength Operating (see Table 3)** | | | |
| 95 % non-exceedance environmental conditions | 60 % ELBS | 80 % ELBS | Not Applicable |
| **Offsets, Project Specific (see Table 4)** | | | |
| Offset limit for drilling and non-drilling riser connected | Drilling – mean offset ≤ 2 % WD | Non-drilling, connected – maximum offset ≤ 6 % WD | Not Applicable |

Mooring one- and two-line broken cases

Stationkeeping analyses are always required for intact and 1-line broken mooring system configurations and may be performed for 2-line broken configurations. Additionally, analyses to calculate system transient responses when a line fails may be performed at the owner or operators' discretion.

Where the stationkeeping system is simple or well understood from previous analyses of similar systems (e.g. semisubmersible MODU with a standard mooring pattern) engineering judgement may be used to reduce the number of 1-line broken cases analyzed. For example, breaking the "most loaded" and "second most loaded" lines resulting from the intact analyses will often result in the largest 1-line broken vessel offsets and line tensions, respectively.

For complex systems, where vessel and mooring system properties lack symmetry, the "most loaded" and "second most loaded" lines may not be the critical 1-line broken cases. Examples of more complex systems, where the above approach may be inadequate, include systems where the strength of the mooring lines are not all the same, the water depth at touchdown and anchor locations differ, grouped mooring systems, and so forth. For mooring systems with three or more lines in a group, the central lines are unlikely to be highly loaded, due to the system's high-stiffness for offsets directly away from the group; that is, the outside lines in a group are generally the most highly loaded lines, they "protect" the inner lines which are the least loaded lines. However, breaking a central line in the group increases the exposure of the adjacent outside line because the plan-view angle between the outside line and its nearest (remaining) neighbor is increased.

When calculating transient system responses that follow the sudden failure of a mooring line, both the line that is going to fail and the point in the low-frequency oscillation of the system at which the failure occurs shall be chosen. The selection of which line to fail in a transient analysis is similar to that discussed above for the 1-line broken case. Transient responses can be sensitive to the chosen position of the vessel within its low-frequency oscillations at which the line suddenly fails; consider three cases, for example:

1. Failure occurs at the vessel's extreme low-frequency turnaround-point away from the line's anchor; where the line tension is maximum and the net mooring system restoring force towards the anchor is also maximum, for that cycle, and the velocity away from the anchor is zero, when the line fails.
2. Failure occurs as the vessel passes through the mean position in the low-frequency oscillation while moving away from the chosen line's anchor; where the line tension is the mean tension, the net mooring system force is zero, and the velocity away from the anchor is near maximum for that cycle, when the line fails.

3. Failure occurs at the vessel's extreme low-frequency turnaround point towards, closest to, the line's anchor; where the line tension is minimum and the mooring system net force away from the anchor is a maximum, for that cycle, and the velocity away from the anchor is zero, when the line fails.

The three different times at which the line fails within the low-frequency oscillations will result in different extreme offsets and maximum tensions. In general, the maximum transient response is not associated with line failure at the maximum line tension (i.e. the most likely time step for line failure). When transient analyses are performed, the methodology used should be approved by the owner or operator. It may be of interest to compare maximum transient tensions and vessel offsets with corresponding values from the 1-line broken analysis (i.e. where in the stationkeeping analysis the line is entirely missing, or removed, from the mooring system).

Environmental directions

The number of global environmental directions that need to be analyzed to adequately define extreme (maximum or minimum) system responses will depend on the symmetry of the vessel and mooring system, and on the directional variability of the environment. For each environmental load case (collinear, non-collinear, wind-dominant, wave-dominant, etc.), environmental directional increments of between 10 and 22.5 degrees should be adequate to capture extreme responses.

In some cases where system properties are simple or well understood from previous experience (e.g. semi-submersible MODU with a standard mooring pattern), engineering judgement may be used to reduce the number of directions analyzed; for example, it may only be necessary to analyze "down-line" and "between-line" environmental directions to find the maximum tension and offset cases. The symmetry of the vessel and its mooring system combined with conservative omni-directional environmental criteria may be used to greatly reduce the number of stationkeeping analyses required; for example, the force coefficients and RAOs for a semi-submersible MODU or barge-shaped FPSO can have bow-stern and port-starboard symmetry — most vessels will have port-starboard symmetry. If the mooring system also has bow-stern and port-starboard symmetry (or it is clear which is the most critical quarter) and omni-directional metocean conditions are being used, then stationkeeping analyses performed for environmental directions that span the most critical quadrant of the vessel may be conservatively used to evaluate all quadrants.

For some frequency- and time-domain programs, an individual stationkeeping analysis (simulation) performed in the frequency-domain can be many orders of magnitude faster than an individual time-domain simulation. And many time-domain simulations, with different seeds to generate different realizations of wind, sea-wave, and swell-wave time histories are required for each environmental load case in order that statistical convergence of characteristic design values (particularly extreme values) is achieved. Where time domain analyses are used, it may be necessary to perform screening analyses in the frequency-domain and use these results together with engineering judgement to reduce the number of environmental load cases (wind-, wave-, current-, and swell-dominant cases with associated relative and global directions) analyzed in the time-domain.

For transient environmental conditions (e.g. wind squall time-series) system responses of spread or turret moored vessels can only be fully realized in the time-domain. For passive turret moored vessels, the vessel's initial heading (immediately before squall winds arrive at the site) will be defined by the background non-squall wind, wave, current, and swell conditions. Consequently, for passive turret moored vessels in transient squalls, the directional combinations of initial vessel heading and squall direction (consistent with the site-specific metocean conditions) comprise the directional cases that shall be considered (see 8.6.3 and A.8.6.3). The search of the two-dimensional space (combinations of initial vessel heading and squall direction) required to identify the most critical load case for the number of squall realizations (different time-histories of squall-wind speed and direction) specified by the site-specific metocean criteria requires a large number of time-domain simulations to be performed [22].

Joint annual probability of simultaneous occurrence of independent events

The joint annual probability of simultaneous occurrence of two independent events ($P_J$) (see [24,25,26,28, 29] ) is given by:

$$P_J = \frac{f\left(D_L, D_S\right)}{R_L \cdot R_S \cdot 8766} \tag{A.1}$$

where

- $P_J$ is the joint annual probability of simultaneous occurrence of the two independent events (1/years)
- $D_L$ is the duration of the longer event, $D_L \geq D_S$, (hours)
- $R_L$ is the return period of the longer event, (years)
- $D_S$ is the duration of the shorter event, $D_S \leq D_L$, (hours)
- $R_S$ is the return period of the shorter event, (years)
- 8766 is the number of hours in a year of 365.25 days, (hours/year)
- $f(D_L, D_S)$ is associated with the treatment of partially overlapping events and the expected duration of the joint event.

Equation (A.1) is valid for all cases of $f(D_L, D_S)$ (i.e. Eq. A.2, Eq. A.3, and Eq. A.4 defined below, when $D_L \ll R_L$, and $D_S \ll R_S$).

NOTE When $D_L$ is not $\ll R_L$, or $D_S$ is not $\ll R_S$, Equation (A.1) is not valid for some of the cases of $f(D_L, D_S)$.

Three examples of annual joint probabilities of simultaneous occurrence of independent events calculated using Equation (A.1) are presented in Table A.3.

A) When $f(D_L, D_S) = D_L + D_S$, all completely overlapping and partially overlapping occurrences of long and short events are included, the expected duration of the joint event is given by:

$$Average\left(D_J\right) = \frac{D_L}{D_L + D_S} \cdot D_S \tag{A.2}$$

This definition is appropriate when success or failure does not depend on the duration of the joint event. For example, if 'instantaneous brittle failure' will occur in any joint event regardless of its duration, i.e. when $D_J$ is strictly > 0, then this is the appropriate definition of $f(D_L, D_S)$, and the duration of the joint event is immaterial.

B) When $f(D_L, D_S) = D_L$, all completely overlapping and half of the partially overlapping occurrences of long and short events are included, the expected duration of the joint event is:

$$Average\left(D_J\right) = \frac{D_L + 0.5 \cdot D_S}{D_L} \cdot D_S \tag{A.3}$$

This is the appropriate definition to be used when success or failure depends on the total duration of the joint events. For example, when calculating fatigue damage in joint events, it is appropriate to use $f(D_L, D_S) = D_L$ to define $P_J$ together with a joint event duration of $D_S$.

C) When $f(D_L, D_S) = D_L - D_S$, only completely overlapping (no partially overlapping) occurrences of long and short events are included, the duration of all joint events is $D_S$ and:

$$Average\ (D_J) = D_S \tag{A.4}$$

This is the definition to be used when success or failure depends on a threshold duration of the joint event. For example, consider an engine overheating which for a given power output will only occur if the duration exceeds a threshold, and the engine is undamaged if the threshold duration is not achieved.

**Table A.3 —Examples of Joint Probabilities of Occurrence of Independent Events**

| Joint Probability of: | | Short Duration Event | Long Duration Event |
|---|---|---|---|
| 1 | Independent Thruster Blackout and Metocean Conditions | ***Thruster Blackout*** | ***Metocean Conditions*** |
| | | $D_S$ = 0.5 hours | $D_L$ = 3.0 hours |
| | | $R_S$ = 5 years | $R_L$ = 1 year |
| | | (A) $f(D_L, D_S) = D_L + D_S$ | $P_J = 7.99 \cdot 10^{-05}$ or RP = 12,523 years |
| | | (B) $f(D_L, D_S) = D_L$ | $P_J = 6.84 \cdot 10^{-05}$ or RP = 14,610 years |
| | | (C) $f(D_L, D_S) = D_L - D_S$ | $P_J = 5.70 \cdot 10^{-05}$ or RP = 17,532 years |
| 2 | Independent Earthquake and Metocean Conditions | ***Earthquake*** | ***Metocean Conditions*** |
| | | $D_S$ = 0.1 hours | $D_L$ = 3.0 hours |
| | | $R_S$ = 10 years | $R_L$ = 1 year |
| | | (A) $f(D_L, D_S) = D_L + D_S$ | $P_J = 3.54 \cdot 10^{-05}$ or RP = 28,277 years |
| | | (B) $f(D_L, D_S) = D_L$ | $P_J = 3.42 \cdot 10^{-05}$ or RP = 29,220 years |
| | | (C) $f(D_L, D_S) = D_L - D_S$ | $P_J = 3.31 \cdot 10^{-05}$ or RP = 30,228 years |
| 3 | Independent Wind and Swell Metocean Conditions | ***Wind Event*** | ***Swell Event*** |
| | | $D_S$ = 3.0 hours | $D_L$ = 12.0 hours |
| | | $R_S$ = 1 year | $R_L$ = 1 years |
| | | (A) $f(D_L, D_S) = D_L + D_S$ | $P_J = 1.71 \cdot 10^{-03}$ or RP = 584 years |
| | | (B) $f(D_L, D_S) = D_L$ | $P_J = 1.37 \cdot 10^{-03}$ or RP = 731 years |
| | | (C) $f(D_L, D_S) = D_L - D_S$ | $P_J = 1.03 \cdot 10^{-03}$ or RP = 974 years |

### A.6.2.2 Strength analysis cases

Tables 1 and 3 contain cases that may be included in the design of the permanent or mobile mooring system at the discretion of the owner or operator. For these permitted cases, the associated environmental return period or joint annual probability of occurrence should be defined by the owner or operator: in general, these cases are new to this edition of API 2SK (they were not in the 3rd Edition and may not be applicable for all stationkeeping systems). These cases are included in Tables 1 and 3 since they are sometimes incorporated in design and site assessment of stationkeeping systems, and because they provide additional information on the performance and risks associated with the stationkeeping system and its operation. Also, it is possible that some of these discretionary cases may become recommended cases in future editions of API 2SK.

### A.6.2.3 Offset analysis cases

Offset analysis cases are generally performed to determine limiting metocean conditions for risers, umbilicals, flowlines, transfer hoses, and so forth. The purpose of these analyses is to verify that the station keeping system can restrict vessel offsets such that these systems are not damaged.

### A.6.3 Installation considerations at design stage

### A.6.3.2 Design Driven Installation Criteria

Guidance with respect to defining polyester rope pre-stretching requirements:

When polyester mooring ropes are used in the permanent mooring system, the mooring line's design pretension may decrease over time as the new polyester rope's length increases due to permanent elongation (construction stretch and material creep) under tension. To maintain the line pretension per design, the mooring line tension can be maintained by periodically hauling in a few chain links on the top if the facility is equipped with operational pull-in equipment, such as a chain jack. Alternatively, an in-line tensioner may be installed as part of the mooring line assembly.

Another suggested method to eliminate or to reduce the need to re-tension polyester mooring line periodically is to apply a high enough test tension to the polyester mooring line after it is hooked up, and holding the test tension for approximately 30 minutes, then reduce the line tension to the design pretension. The test tension load needs to be higher than the design pretension and needs to be selected to be within the safe operating load range of the tensioning equipment on the platform, or the construction vessel's capability. Typically, the test tension load level of around 30-40% MBL of the polyester mooring rope is found to be effective in reducing the need to re-tension.

Guidance to polyester stretch and recovery behavior may be taken from API 2SM.

Guidance with respect to defining pre-tension and top angle target values and tolerances:

Pre-tension alone is typically not a complete criterion to define the correct mooring line restoring characteristics. The combination of pre-tension and top angle, and specifying at which draft and facility position this is referenced, will define more accurate characteristics. Differences in these facility conditions during installation (specifically at the time these criteria are evaluated) shall be accounted for in the target values (and tolerances) for pre-tension and top angle.

#### A.6.3.3 As-installed mooring system

In deepwater systems that contain grounding chain and wire rope the mooring system design and the installation procedures should consider the possibility of residual twist being entrapped in the chain or being transferred to the wire or fiber rope, which may cause a reduction in MBL of the chain and/or birdcaging of the wire rope.

### A.6.4 Corrosion, wear, and abrasion allowance for chain

In general, material loss of chain in permanent and mobile mooring systems includes the following types: uniform corrosion, pitting corrosion (microbiologically induced corrosion, or MIC), interlink wear, side bar abrasion, and mechanical damage. It is noted that corrosion and wear on chain links are induced by different mechanisms. Due to lack of precise methods to account for their individual effects, their design allowances in this section are lumped together based on historical data. It should be realized that the corrosion and wear allowance for permanent mooring chain is intended to account for reductions in break-strength and fatigue-resistance due to long-term general corrosion (uniform reduction in bar diameter).

Uniform corrosion rates tend to be highest in the splash zone and decrease with increasing water depth. Pitting corrosion can occur on chain links on the seabed where Sulphur Reducing Becteria (SRB) can cause MIC, and also occur near splash zone in tropical waters. Field evidence suggests that rates of uniform and pitting corrosion are higher for mooring systems in tropical waters than moorings in temperate climates. Interlink wear is caused by relative rotations between adjacent links, interlink sliding, and is highest near to the top or fixed ends of the mooring line, adjacent or near to buoys, clump weights, and weight chain attachments, and in the thrash zone. Because interlink wear is caused by sliding rotations between adjacent links, it is associated with bending and torsional stresses and related fatigue damage (e.g., IPB and OPB fatigue damage). High-rates of side-bar abrasion have been observed for chains in the thrash zone with hard calcareous soil conditions. Side-bar abrasion has also been observed for chains that have excavated large trenches at the touchdown zone.

Guidance on loss of chain strength due to uniform corrosion, pitting corrosion, interlink wear, and side-bar abrasion can be found in [29], [56], [57], [58].

The owner or operator should consider corrosion, abrasion, and wear rates from existing mooring installations in the same geographic region when selecting a corrosion, wear, and abrasion rate for a new development. Table A.4 summarizes the range of corrosion, abrasion, and wear rates that have been historically observed.

**Table A.4 —Historical Range of Chain Corrosion, Abrasion, and Wear Rates**

| Chain Location | Allowance on Chain Diameter for Corrosion, Abrasion, and Wear (mm/year) |
|---|---|
| Splash zone (see NOTE 1) | 0.2 – 2.0 |
| Mid-catenary (see NOTE 2) | 0.2 – 0.8 |
| Touchdown zone (see NOTE 3) | 0.2 – 1.0 |
| Buried below seabed (see NOTE 4) | 0.0 – 0.2 |

NOTE 1 Splash zone: the chain links that are wetted by waves and spray as the vessel changes draft; corrosion rates larger than 2.0 mm/yr have been reported in rare cases in tropical environment.

NOTE 2 Mid-catenary: mooring line below the splash zone and always above the touchdown point.

NOTE 3 Touchdown or thrash zone: chain links that are intermittently in contact with the seabed or excavate trenches.

NOTE 4 This allowance assumes that there is no micro-biological material loss below seabed. If site specific survey indicates the presence of SRB/MIC below seabed, the allowance for Touchdown zone is recommended.

## A.7 Design and site assessment criteria

### A.7.1 Safety factors for mooring component strength

The criteria in Table 7 applies to all mooring line components loaded in tension (e.g. chain, wire rope, fiber rope, H-links, shackles, Kenters, etc.). Where mooring components are subject to more complex loading that include bending and/or torsion, the safety factors on tension in Table 7 may not be applicable. For example, the reduction in strength of wire rope or chain in a sheave, fairlead pockets, or on a bending shoe depends, in-part, on the component-type (six-strand, spiral strand, studless, studlink, etc.) and the geometry, dimensions, and fit of the supporting structure (d/D ratio, fit and support of sheaves, fit between chain links and a 7- or 9-pocket fairlead, grooved or un-grooved bending shoes, etc.). Out-of-plane loading/bending at the padeye of an anchor pile, or the padeye at the vessel or turret, is likely to result in a reduction of the component's strength. Finite element analysis or component testing may be used to determine the structural strength of components subject to complex loading. Guidance on finite element analysis is contained in DNV C208. Determination of structural capacity by non-linear FEA methods (see [30]). For wire ropes, design consideration and guidance for ropes over sheaves, drums, and rollers can be found in [31] .

#### A.7.1.2 Anchor factors of safety

#### A.7.1.2.1 General

In selecting anchor options, the required system performance, soil conditions, reliability, installation, and proof-loading shall be included in the selection process.

Drag Embedment Anchor

Drag embedment anchors, as shown in Figure A.16 (see [18]), were initially used for mobile mooring operations. Drag embedment anchor technology has advanced considerably in recent years. Engineering and testing indicate that the new generation of fixed-fluke drag embedment anchors develop high holding power, even in soft soil conditions. High-efficiency drag embedment anchors are generally considered to be an attractive option for mooring applications because of their easy installation and proven performance. In fact, some existing permanent and many mobile moorings use drag embedment anchors. The anchor section of a mooring line can be pre-installed, and test-loaded prior to platform installation.

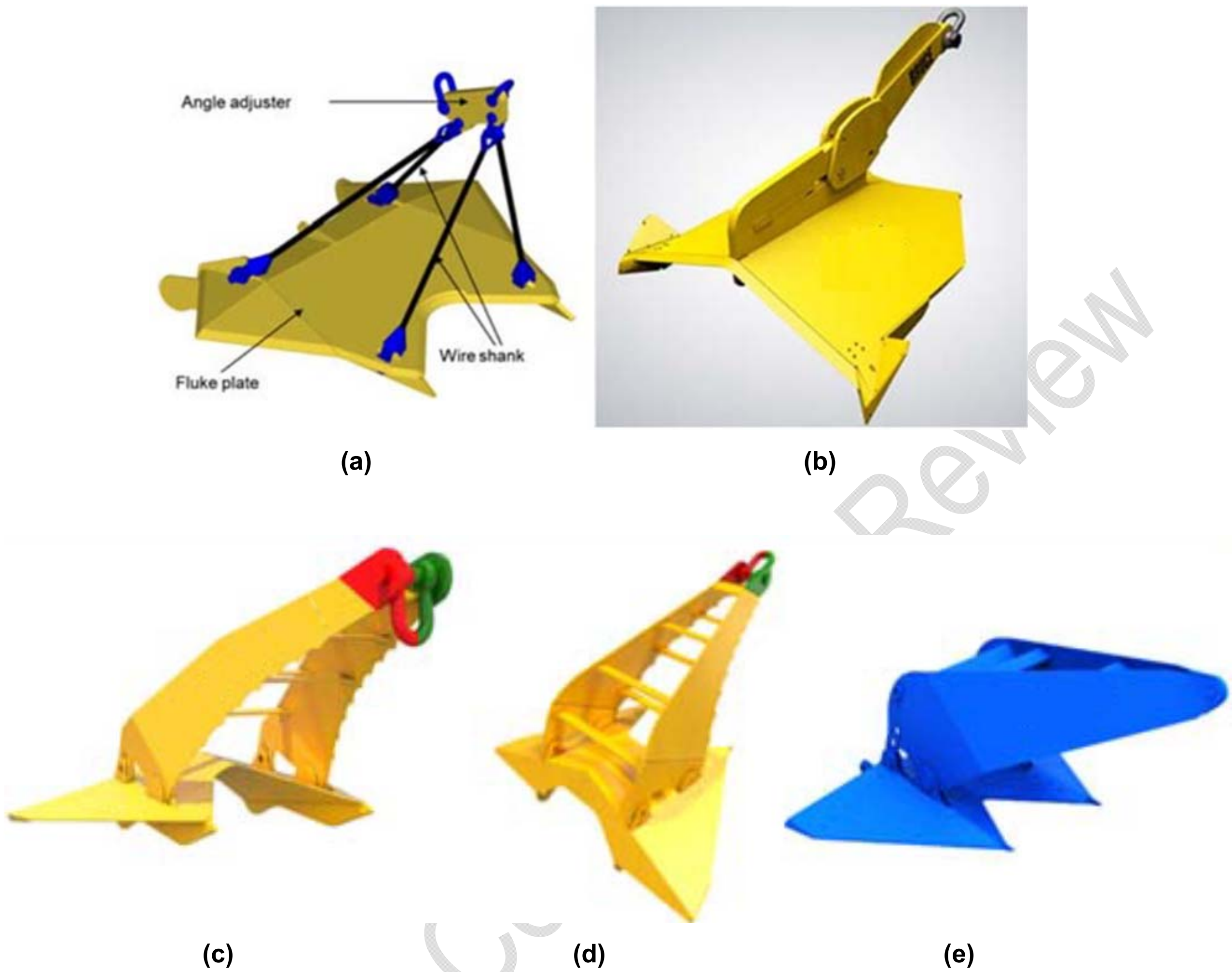



**Figure A.16 – Examples of Drag Embedment Anchors**

<u>Drag Embedded Plate Anchor (Vertically Loaded Anchor)</u>

Drag embedded plate anchors are embedded to a deep penetration in a manner similar to drag anchors. During installation, the anchor is placed on the seafloor and then pulled along the bottom as it penetrates the soil. The anchor dives (more or less) parallel to the fluke as it rotates until the target penetration-depth is achieved. Following the embedment, the shank is released (usually by increasing the uplift angle of the anchor line to break the shear pin) such that the fluke becomes nearly perpendicular to the anchor line to provide high-horizontal and -vertical holding capacity. These drag embedded anchors are often referred to as VLA (vertically loaded anchor), shown as (a) and (b) in Figure A.16 (see [18]).

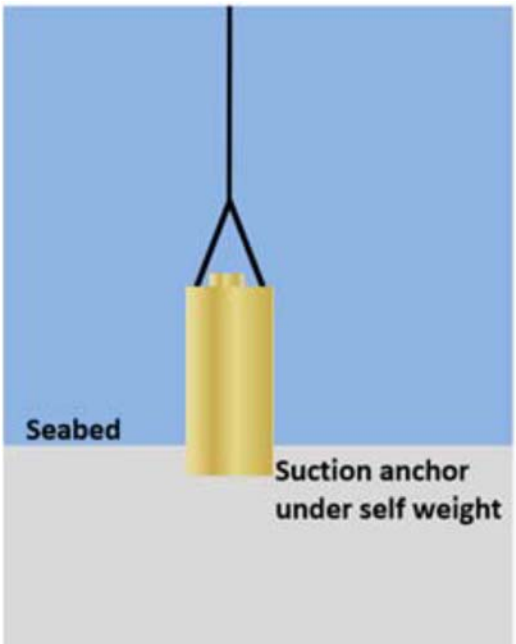
<u>Driven Pile Anchor</u>

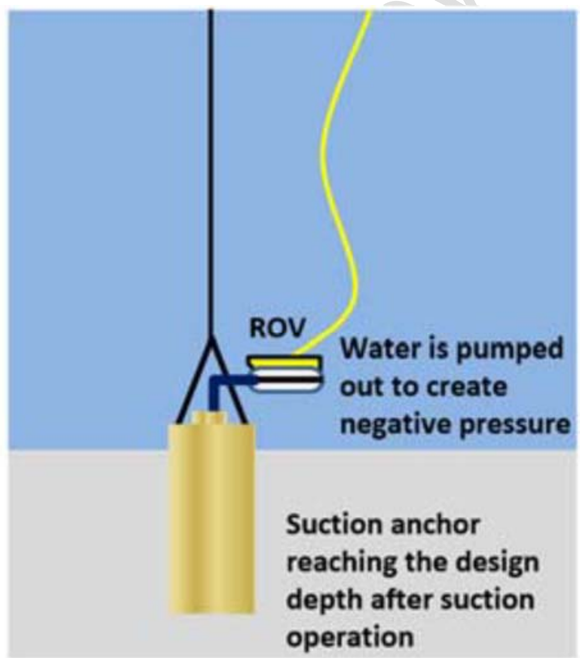
Driven piles can be designed to develop high-lateral and -vertical resistance, and to be very stable over time. Piles are generally installed using driving hammers; although other methods such as jetting or drilling and grouting techniques have been used. Installation of jetted or drilled and grouted piles can be handled by a conventional drilling rig without major modifications. However, disturbance of soil during jetting and drilling operations should be evaluated.

<u>Suction Pile Anchor</u>

Suction piles can be used for large deepwater mooring systems and can be designed for very high mooring line loads. They are typically tall steel cylindrical structures in cohesive soils (or shorter girthier cylinders for sands) generally with internal stiffener systems. The cylinder unit is open at the bottom and normally closed at the top. A suction pile is installed by first lowering it into the soil to self-penetration depth (i.e., penetration due to submerged pile weight). The remainder of the required penetration is then achieved by pumping the trapped water from the inside of the suction pile, as shown in Figure A.17 (see [18]). The pressure differential created will result in an additional driving force on the anchor top, which will further drive the pile into the soil. As the penetration increases, the penetrating force needed normally increases; requiring a gradually increasing differential pressure. Due to the pressure differential, the suction pile will behave structurally like an externally pressurized vessel; internal stiffening is generally required to avoid buckling.

After penetration, the water outlet is normally closed and a suction pile may achieve substantial capacity to resist vertical downward loads, horizontal loads, vertical uplift loads, moments, and combinations of these loads. For suction piles embedded in clay and with a closed outlet, the capacity to resist environmental loads is governed by an undrained shear failure in the soil around and beneath the pile. The capacity depends on depth of skirt penetration, cylinder diameter, shear strength in the clay, shear strength at the clay/wall interface, the load inclination, and the location of the load-attachment point. In the case where the top part is left open or retrieved, or for long-term uplift load components, pull-out of the skirts may also be a possible failure mechanism.




(a) (b)

**Figure A.17 – Suction Pile**

<u>Gravity Installed Anchor</u>

Gravity installed anchors (also known as drop anchors) penetrate the seabed by the kinetic energy obtained from free-fall through the water column by their own weight. Examples of drop anchors include torpedo anchor, deep penetrating anchor, and others. The typical configuration of torpedo anchors is of a closed cylindrical pile, weighted with ballast, with conical tip and lateral fins. These piles are dropped from a pre-determined elevation in relation to the seabed, free-fall and self-embed in the soil. Unlike conventional torpedo anchors, after the  anchor is released via its top attachment, mooring loads are transferred to a swiveling mooring arm, allowing for high-efficiency in load resistance due to lateral loading being near the center of anchor rotation and out-of-plane loading capabilities due to the nature of the swiveling arm (see [19]). This placement and geometry of the loading arm allows the anchor to key, dive, and drag in all directions, increasing geotechnical capacity and promoting line load sharing.

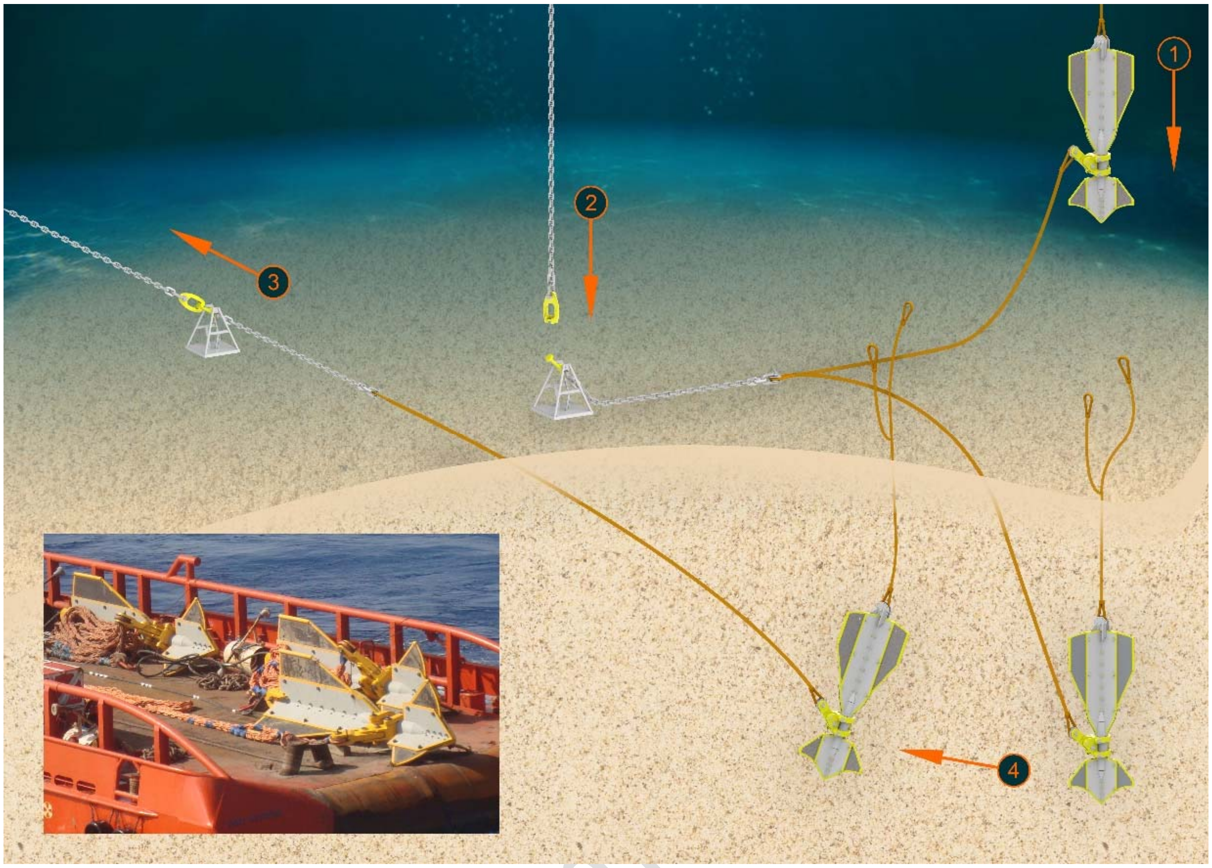



**Figure A.18 – Gravity Installed Anchor**

Direct Embedded Plate Anchor

Direct embedment of plate anchors can be achieved by suction, impact or vibratory hammer, propellant, or hydraulic ram. As an example, the SEPLA (suction embedded plate anchor) uses a suction follower, which is essentially a reusable suction anchor with its tip slotted for insertion of a plate anchor. The suction follower is immediately retracted by reversing the pumping action once the plate anchor is brought to the design depth, and can be used to install additional plate anchors, as shown in Figure A.19 (see [18]). During SEPLA installation, the plate anchor's fluke is embedded in a vertical orientation, and adequate fluke rotation is achieved during a keying process by pulling on the mooring line.

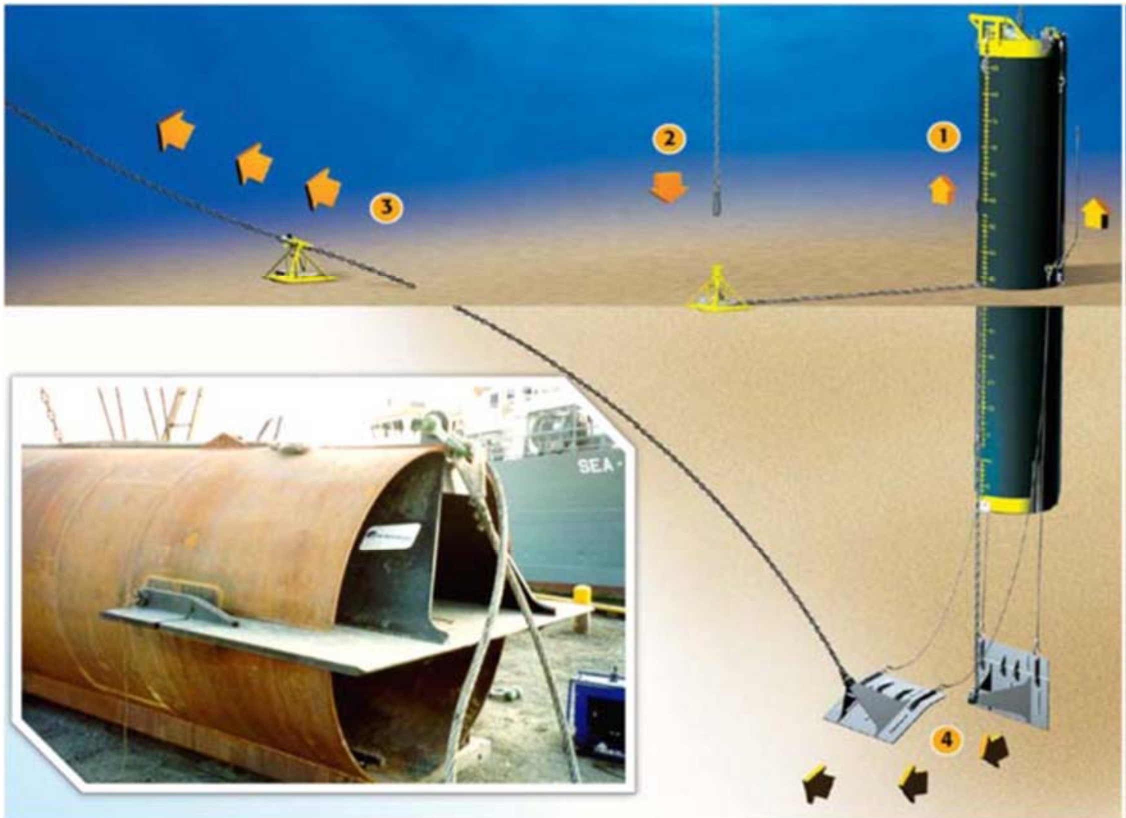



**Figure A.19 – Suction Embedded Plate Anchor**

### A.7.3 Requirements for Clearances

#### A.7.3.2 Mooring line with seabed (thrash zone)

The intent of the clearances specified in Table 12, together with the associated analysis cases described in Section 6, is to ensure that the probability of the bottom-end of wire or fiber rope segment in the water column making contact with the seabed is small. For example, for a permanent mooring system the minimum clearance would be calculated for:

a) the most onerous 100-year return period environmental condition, which includes:

    1) most onerous wind-, wave-, current- or swell-dominant environmental case, with

    2) most onerous relative directions between wind, wave, current, and swell, for

    3) the most onerous global environmental direction (for turret moors in transient wind squall conditions this includes the most onerous initial vessel heading), and

b) assuming the worst-case line failure (i.e. the failed line that results in the minimum clearance), where

c) the minimum clearance is associate with the maximum slack in the mooring line (i.e. the largest mean plus low-frequency vessel offset towards the mooring line's anchor).

Consequently, the calculated minimum clearance is based on layers of conservative assumptions leading to a small probability of occurrence that may be characterized as occurring "once or never" in 100 years. The small clearance values specified in Table 12 reflect the layering of conservative assumptions in the design recipe.

NOTE The user of this standard may exceed the requirements specified herein.

## A.7.3.3 Mooring line with sea surface

Fiber rope mooring lines have been used in shallow water moorings that do not allow for large clearances between the fiber rope and the sea surface due to water depth limit; also, the design of the filter barrier and the rope jacket continue to improve. Consequently, it is not possible to provide a single value for the minimum clearance between the fiber rope and the sea surface.

### A.7.4 Safety factors for mooring component fatigue resistance

The T-N curves in Table 14 are based on pure tension loading. The vast majority of a mooring line is loaded in tension; while more complex loading occurs near to the ends of lines or line segments, close to the stopper, through hawse pipes, on bending shoes and in fairleads, adjacent or near to buoys, clump weights, and loop/weight chain attachments, and in the thrash zone. In general, this loading will consist of tension combined with bending and/or torsion. The stress hot-spots for tension, bending, and torsion will generally occur at different locations on the component, and the occurrence of peak tension, bending, and torsional stresses may not be in-phase.

The chain T-N curves in Table 14 are most applicable to links with uniform corrosion; they may not be conservative for chains with pitting corrosion (e.g. all sizes and locations of pits), mechanical damage (e.g. gouging, missing or loose studs, etc.), interlink wear, side-bar abrasion, and so forth, or combinations of these. Most of the chain fatigue failures that have occurred in the field have been associated with contributing conditions (e.g., installation damage, pitting corrosion, preferential weld corrosion, etc).

Fatigue analyses that are based on ideal mooring system properties (e.g. pretensions that result in perfect load-sharing) can result in a significant under-estimation of fatigue damage. It is important to allow for the uncertainty in outboard segment lengths and properties, pretensions and load-sharing, and line and system stiffnesses in the fatigue analysis.

Fatigue analysis requirements for permanent mooring systems were first introduced in API 2FP1 and the methodology and fatigue curves have continued to evolve. This fatigue analysis methodology has worked remarkably well; for example, there were a number of permanent mooring systems designed in the late 1990’s when studless mooring chain was first introduced into the market, but before fatigue testing of studless chain had been performed and fatigue curves for studless chain developed. At the time, it was (erroneously) thought that studless chain would have a longer fatigue-life than studlink chain. Consequently, there are a number of permanent mooring systems containing studless chain that were designed in the late 1990’s based on fatigue curves for studlink chain (e.g. Balder, Schiehallion, Terra Nova, etc.) — some of which do not satisfy current standards when evaluated using the presently available fatigue curves for studless chain. However, there have not been many fatigue failures of studless chain mooring lines dating from this design period. Fatigue failures of some of these mooring systems designed in the late 1990’s containing studless chain have been attributed, at least in-part, to out-of-plane bending (OPB) (see Table A.24 in A.8.7).

Mooring components (chain, wire rope, connectors, etc.) that are subject to loading that is not pure tension include chain or wire in the fairlead or on bending shoes, at articulations and terminations, or chain subject to out-of-plane bending (OPB) adjacent to terminations or in the thrash zone, and so forth. The fatigue assessment of mooring components, subject to these complex loading conditions, may be based on the following.

1) Finite element analyses to calculate stresses and phasing between tensile, bending, and torsional stresses, stress concentration factors, transfer functions, and so forth, in conjunction with S-N curves for the material and environment and an associated fatigue safety factor.

2) Fatigue curves and associated fatigue safety factor derived from statistical analysis of fatigue test results from tests specifically designed to mimic the load and support conditions of the mooring component.

3) Or combinations of (1) and (2) above; for example, where fatigue testing (2) is used to verify or calibrate analytic methods (1).

Studless chain is commonly used in permanent mooring systems while mobile moorings almost exclusively use studlink chain. The fatigue endurance (i.e. number of cycles to failure) of studless chain is about 31 % of studlink chain and about 78 % greater than Kenter links (see K values in Table 14). Consequently, in the fatigue assessment of permanent systems, the studless chain segments are usually the most critical mooring line component.

The studless chain fatigue test failures from the NEL/ND (National Engineering Laboratory / Noble Denton) JIP [32], [55] and the TWI (The Welding Institute) JIP [33] are plotted in Figure A.20.

The NEL/ND JIP[32], [55] tested R3 and R4 studless chain lengths supplied by three manufactures, all links where 76 mm in diameter and in all cases the mean load was 20 % of the CBS of the chain (i.e. 977 kN for R3 and 1200kN for R4 chains). All tests were performed in oxygenated ASTM-seawater after presoaking; there were a total of 75 failures, with 44 as R3 and 31 as R4. This NEL/ND fatigue test dataset was the dataset used to derive the T-N curve for studless chain in Table 14 (see [16]). The NEL/ND fatigue failures and the mean regression fit to the 75 failures are shown in black in Figure A.20.

The TWI JIP [33] tested R4 and R5 studless chain lengths supplied by two manufactures of two chain sizes with diameters of 76 mm and 127 mm. In all but one case, the mean load was 20 % of the CBS of the chain (i.e., 1200 kN for 76 mm and 2991 kN for 127 mm R4, and 1402 kN for 76 mm and 3493 kN for 127 mm R5 chains). All but one test was performed in oxygenated saltwater after presoaking; there were a total of 69 failures in the saltwater tests, with 19 as R4 (8 of 76mm and 11 of 127mm) and 50 R5 (8 of 76mm and 42 of 127 mm). The TWI fatigue failures are shown in red in Figure A.20. In the TWI test program, there was a single test of 127 mm R5 chain that was performed at a lower mean load of 10 % of CBS (i.e. 1747 kN); this data point is also shown on Figure A.20.

In general, the TWI fatigue test data for studless chain is in good agreement with the older NEL/ND test data. For tension ranges greater than about 15 % of ORQ CBS ($\log_{10} > -0.82$), the TWI fatigue test data is slightly lower than the NEL/ND data. For tension ranges of between about 15 % and 11 % ($-0.82 > \log_{10} > -0.97$), NEL/ND and TWI test data are very similar. For tension ranges less than about 11 % ($\log_{10} < -0.97$), TWI fatigue test endurances are slightly greater than the NEL/ND mean regression curve. However, it should be realized that the smallest tension ranges tested in the NEL/ND JIP were 10.6 % ($\log_{10} = -0.975$) for R3 and 13 % ($\log_{10} = -0.89$) for R4; that is, the low-tension range TWI data lies outside the tension ranges tested in the NEL/ND JIP.

NOTE The above discussion suggests that there is a difference in the slope of the fatigue failures for the two JIPs.

The NEL/ND JIP tested R3 and R4 chain from three manufactures; the failure data does not show a dependence of fatigue-resistance on chain grade (compare black diamonds and circles). The TWI JIP tested R4 and R5 chain from two manufactures; the failure data does not show an obvious dependence of fatigue-resistance on chain grade (compare red triangles and squares) that is, within the TWI dataset there appear to be different trends for “mean” or “central” and lowest fatigue endurances. For tension ranges less than about 15 % of ORQ CBS ($\log_{10} < -0.82$), the “mean” fatigue endurance of R4 and R5 chain appear to be similar. While for tension ranges greater than about 15 % of ORQ CBS ($\log_{10} > -0.82$), the “mean” fatigue endurance of R5 chain appears to be greater than that of R4 chain. However, comparing the lowest fatigue endurances of the TWI R4 and R5 test results (leftmost red triangles and squares) does not show a dependence on chain grade. However, the different numbers of fatigue failures (19 of R4 and 50 of R5) in the TWI dataset are expected to have a larger effect on the extreme (left or right) values than on “mean” or “central” values.

Almost all of TWI fatigue failures (68 of 69) and all 75 of the NEL/ND failures are from tests performed with a mean load of 20 % of the grade dependent CBS; that is, the mean loads for the R4 and R5 tests were effectively 23 % and 43 % higher than the mean load for the R3 tests (see table embedded in Figure A.20). Those 143 fatigue failures do not show an obvious dependence on the mean load for variations in mean load up to 43%. However, a definitive conclusion regarding the effect of mean load on fatigue resistance is not possible due to the single TWI result for the low mean load test (i.e. the TWI, R5, 127 mm, mean = 10 % CBS (R5)) result plotted on Figure A.20. A more definite conclusion regarding mean-load dependence of fatigue-endurance for studless chain requires additional testing and analysis.

The NEL/ND JIP tested only 76 mm diameter chain, while the TWI JIP tested both 76 mm and 127 mm diameter chain. For the TWI tests there were 16 failures of 76 mm chain and 53 failures of 127 mm chain (see the open and filled red triangles and squares in Figure A.20). The TWI fatigue failure data plotted in Figure A.20 appears to indicate that slope of the T-N curve may depend on the diameter; however, there are not very many 76 mm failures.

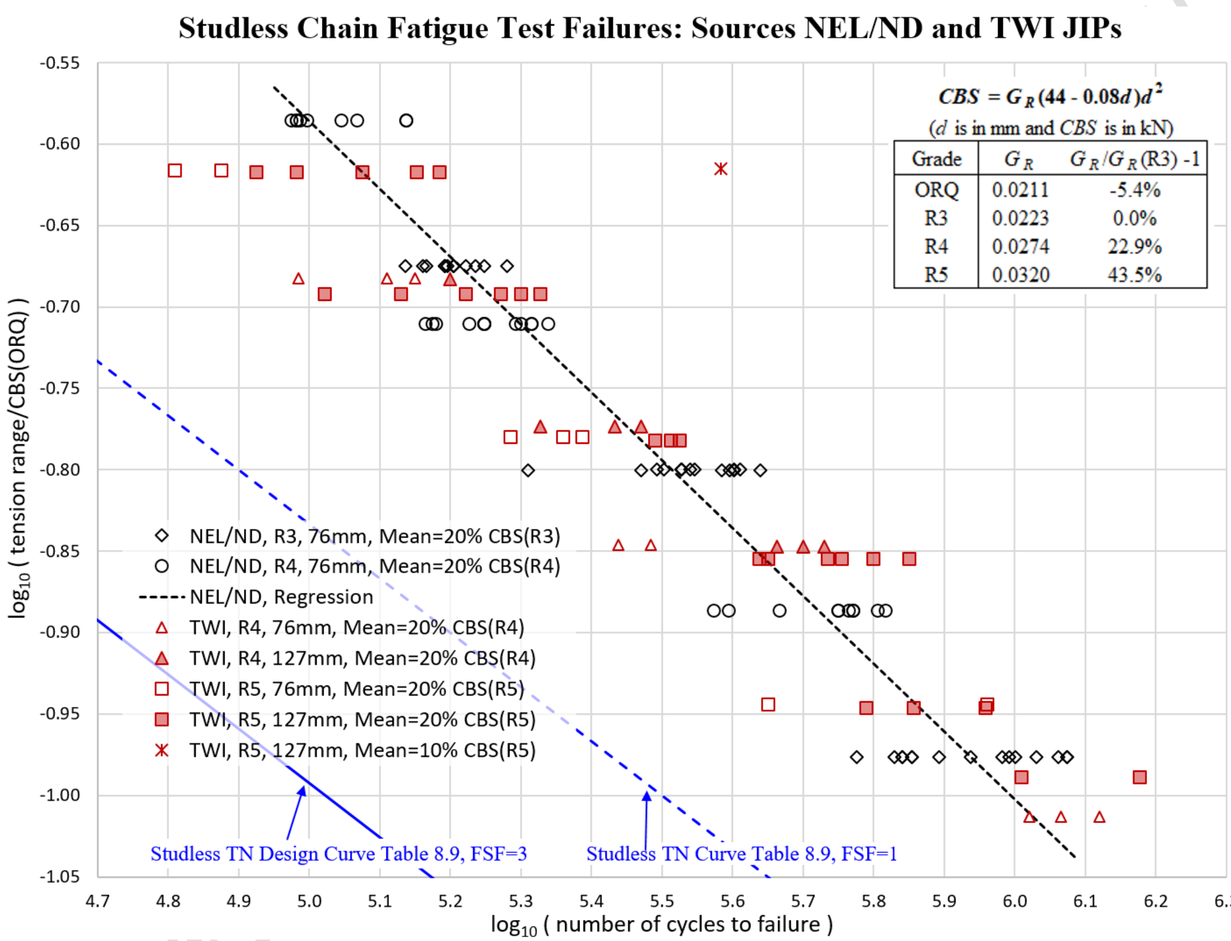



**Figure A.20—Studless Chain Fatigue Test Failures, NEL/ND JIP and TWI JIP**

The fatigue curves in API's stationkeeping practices, API 2FP1 and API 2SK, have always been defined for use with a fatigue safety factor of 3.0. When the present fatigue curves for stud and studless chain were first developed, the intercept of the T-N curves were chosen for use with a fatigue safety factor of 3.0 because that was the fatigue safety factor specified in the 2nd Edition of API 2SK. That is, the choice of the intercepts (the K values) for the chain fatigue T-N curves in Table 14 were based on calibration to the previous fatigue curves with a fatigue safety factor of 3.0 with an individual link probability of failure of $10^{-8}$; that is, the fatigue curves were intended to be used with a safety factor of 3.0.

Fatigue safety factors and the fatigue T-N or S-N curves are intended to work together as a pair. Fatigue curves and associated fatigue safety factors should not be separated without a clear understanding of how they were developed, and probabilities of failure associated with the combination. For example, Figure A.21 shows curves of equal-factored fatigue design-lives for studlink and studless chain based on the API 2SK T-N curves with a fatigue safety factor of 3.0 (see Table 14) and the DNV S-N curves with fatigue safety factors of between 5.0 and 8.0 (see [34]). Because both the API 2SK and DNV chain fatigue curves have the same slope (m=3), there exists a unique chain diameter for which the API and DNV fatigue lives divided by their associated fatigue safety factors, are equal; these curves, for studlink and studless chain, are referred to as “curves of equal-factored fatigue design-lives”. For studless chain with a diameter of about 100 mm, the DNV S-N curve with a fatigue safety factor of 5.0 results in an equivalent design-life as the API T-N curve with a fatigue safety factor of 3.0. However, the DNV S-N curve for studless chain with a safety factor of 8.0 requires a diameter of 165 mm for a design-life equal to the API T-N curve for studless chain with a fatigue safety factor of 3.0.

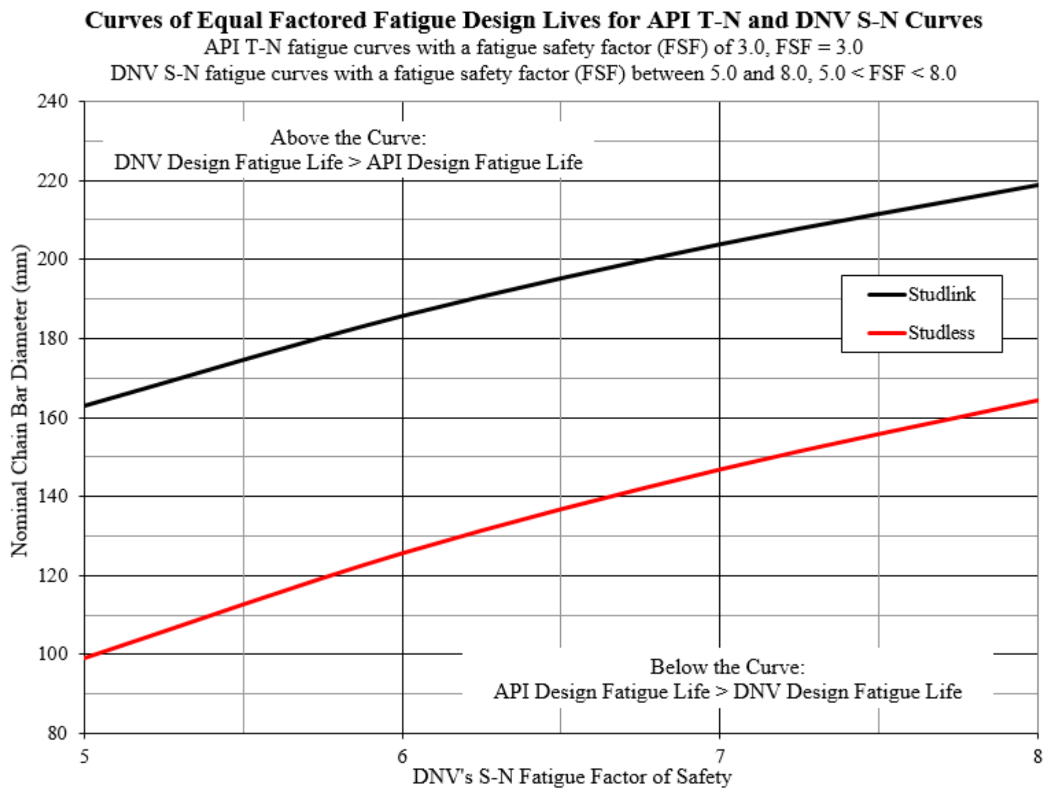



**Figure A.21—Comparison between API T-N and DNV, [34], S-N Fatigue Curves and Fatigue Safety Factors**

Figures A.22 and A.23 provide additional comparisons of API’s TN and DNV’s SN fatigue curves for studlink and studless chain.

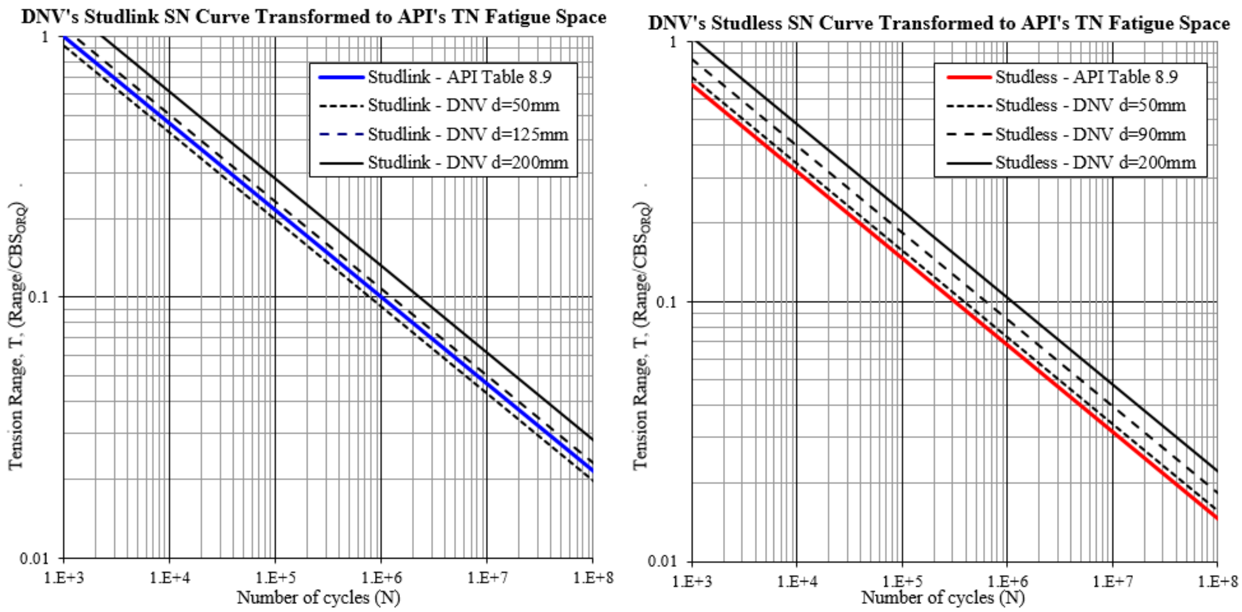



**Figure A.22—Comparison between API TN and DNV SN [34] Fatigue Curves for a Fatigue Factor of Safety of 1.0**

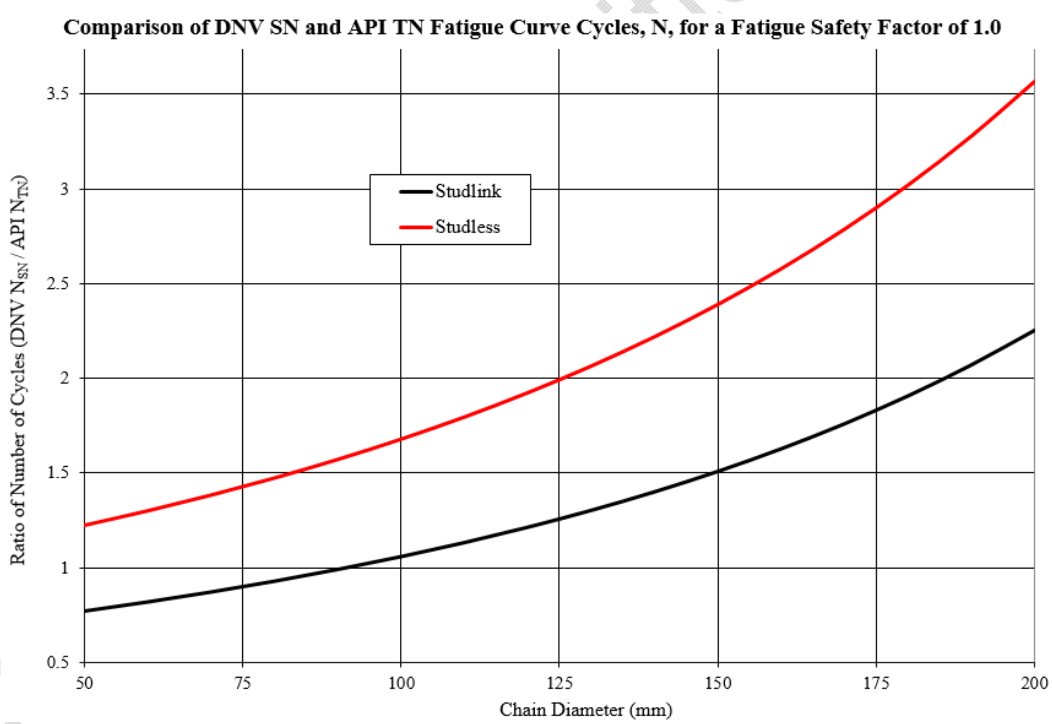



**Figure A.23—Comparison between API TN and DNV SN [34], Fatigue Curve Cycles, N, for a Fatigue Factor of Safety of 1.0**

## A.8 Analysis

### A.8.2 Analysis methods

A series of studies on global performance analysis of floating structures was conducted by the industry from 1999 to 2003. Important findings from these studies on the subject are summarized in API 2SK, 3rd Edition, Appendix I.

### A.8.3 Coupling effects

For systems where the damping contribution from wave frequency line and riser motions is important, the interaction between the wave frequency line dynamics and low-frequency motions of the structure should be calculated consistently.

The riser system, if present, interacts with the floating structure and the stationkeeping system in several ways. Wave and current actions on the risers increase the environmental actions to be resisted by the stationkeeping system, while the stiffness of riser system assists the stationkeeping system. Furthermore, damping from the riser system decreases the low-frequency motions and, in-turn, reduces the mooring tensions. The net result of these effects depends on a number of factors; such as, for example, the type and number of risers and the water depth. Mooring design should take into consideration the riser actions, stiffness, and damping. The effect of the risers on the response of the floating structures may be ignored in the mooring analysis if doing so results in a more conservative mooring design.

### A.8.4 Environmental loads on the floating structure

Environmental loads can be categorized according to the following three distinct frequency bands.

a) Steady load components from wind, current, and wave drift forces which are constant in magnitude and direction for the duration of interest.

– These loads directly impact the mean horizontal offset and mean heading of the floating structure.

b) Low-frequency cyclic loads (often referred to as slow drift) due to wind, wave, current (if applicable), and the interaction between wave and current (if any).

– These loads excite the floating structure at its natural periods in surge, sway, roll, pitch, and yaw, which are typically between 1 minute and 10 minutes. Yaw natural periods of turret moored vessels in mild environments can be longer than 10 minutes. Low-frequency cyclic loads can also induce dynamic excitation at the pitch and roll natural-periods of floaters where the resultant center of the loads is far away from the rotation-center of the floater.

c) Wave-frequency cyclic loads with typical periods ranging from 5-30 seconds.

– If the natural-period of the moored floating structure is close to the wave-periods, the wave-frequency cyclic loads can be dependent on the mooring stiffness; in this case, the effect of the mooring stiffness should be accounted for.

The collinear environment (wind, waves, and current all coming from the same direction) is not always the most critical design situation. For example, the prediction of the mean-heading of a turret-moored FPSO is critical to the prediction of the extreme responses. A shift in the wave-heading from head-on to some oblique-heading angle relative to the wind and current direction can significantly increase the mooring tensions, offsets, and wave-frequency motions.

For guidance on performing mooring analysis of floating systems in squall environments (see [35]).

Design equations and curves for a quick evaluation of environmental forces and vessel motions are provided in API 2SK, 3rd Edition, Appendix C. These simplified analytical tools were developed primarily for the analysis of mobile moorings. They may be used for preliminary designs of permanent moorings if more accurate information is not available at the early stage of the design process, and if the limits for these tools are not exceeded. These simplified methods cover the following force components:

— current forces for ship-shaped and semi-submersible hulls,

— mean-wave drift-forces and low-frequency motions for ship-shaped and semi-submersible drilling vessels,

— steady wind force,

— wind and current forces for large tankers, and

— forces due to oblique-environment.

**A.8.4.2 Wave forces**

For floating structures with slender members such as semi-submersibles, viscous drift-forces can be an important component of the overall wave force. For a detailed discussion and recommendations (see [36]). For a discussion on wave-current interaction and its treatment using potential theory approaches (see [37]).

**A.8.4.3 Wind forces**

The three methods for estimating wind loads (wind tunnel tests, CFD, and empirical 'building block' methods) were the subject of a 2017 comparative wind-load study, organized by the OC-8 Panel of the Society of Naval Architects and Marine Engineers (SNAME). The results of the study are summarized and discussed in [38].

As a result of the comparative wind-load study, the SNAME OC-8 panel is planning to issue a guideline for wind-load estimation for offshore floating systems throughout the engineering design spiral. The intent of the panel is to "synthesize the collective experience of the Panel with respect to empirical 'building block', wind tunnel, and CFD wind-load estimates to provide the industry with a practicable wind load estimation design guideline."

The SNAME OC-8 panel has also been working on a revision of their Technical & Research Bulletin 5-4 (TR 5-4), August 1988. A preview of the upcoming revision can be found in [39].

For ship-shaped structures, wind loads are typically determined as two forces (longitudinal and transverse) and a moment (yaw). For semi-submersibles and spars, wind loads may be sensitive to trim and heel and may have to be calculated for both even-keel and with trim-and-heel.

<u>Wind profile and gust factors</u>

When developing mean-wind load coefficients using wind tunnel testing, CFD, or an empirical "building block" method, the appropriate wind velocity profile should be used. API 2MET, Second Edition, Annex A.7.3 provides separate wind profiles and gust factors for tropical-revolving storms and for extra-tropical storms. For a discussion on wind velocity profile for squall events (see [40]). A comparison of different velocity profiles is shown in Figure A.24.; a comparison of the ISO wind profile for different 1-hourly wind speeds is shown in Figure A.25.

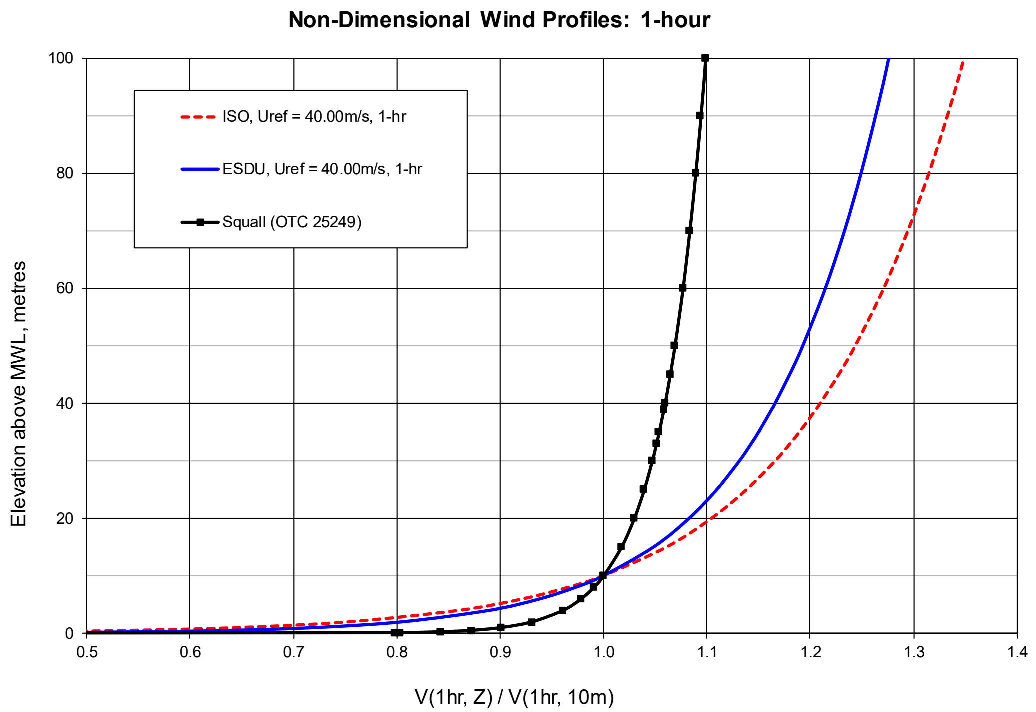



**Figure A.24—Examples of Different Wind Velocity Profiles**

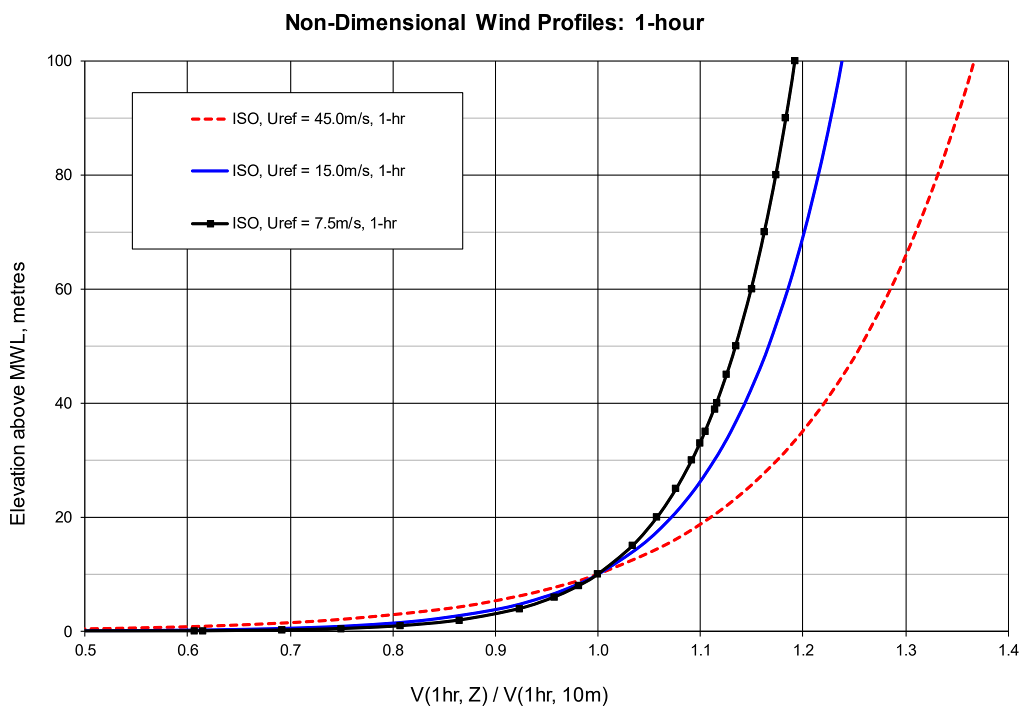



**Figure A.25—Illustration of ISO Wind Velocity Profiles for Different Wind Speeds**

Recommended wind spectrum

For some time, only the API and NPD (now ISO) spectrum were commonly used by the offshore industry. The API spectrum, which was published in editions of API 2A-WSD prior to its 22nd Edition, has much smaller empirical data base than the NPD spectrum. The uncertainty of the API spectrum is addressed through specifying a range instead of a single value for the dimensionless peak frequency. This results in a spectrum defined by upper and lower bound values. In the 22nd Edition of API 2A-WSD, the API spectrum was replaced by the NPD spectrum, which was also adopted by the ISO and API standards for derivation of metocean design and operating conditions. Currently, the NPD spectrum is also referred to as the ISO wind spectrum.

In API 2MET (Second Edition), it is recognized that the spectral-type needs to represent the storm-type associated with the underlying data (tropical-revolving vs extra-tropical). For tropical-revolving storms (hurricanes, typhoons, cyclones) it is recommended to use the ESDU wind spectrum. For extra-tropical storms it is recommended to use the ISO (NPD) spectrum. For more information, see API 2MET, Second Edition, Annex A.7.4. Figure A.26 shows wind spectra using both the recommended forms for extra-tropical storms and tropical cyclones for 1 h sustained wind speeds of 20 m/s, and 40 m/s at elevations of z = 10 m and z = 50 m.

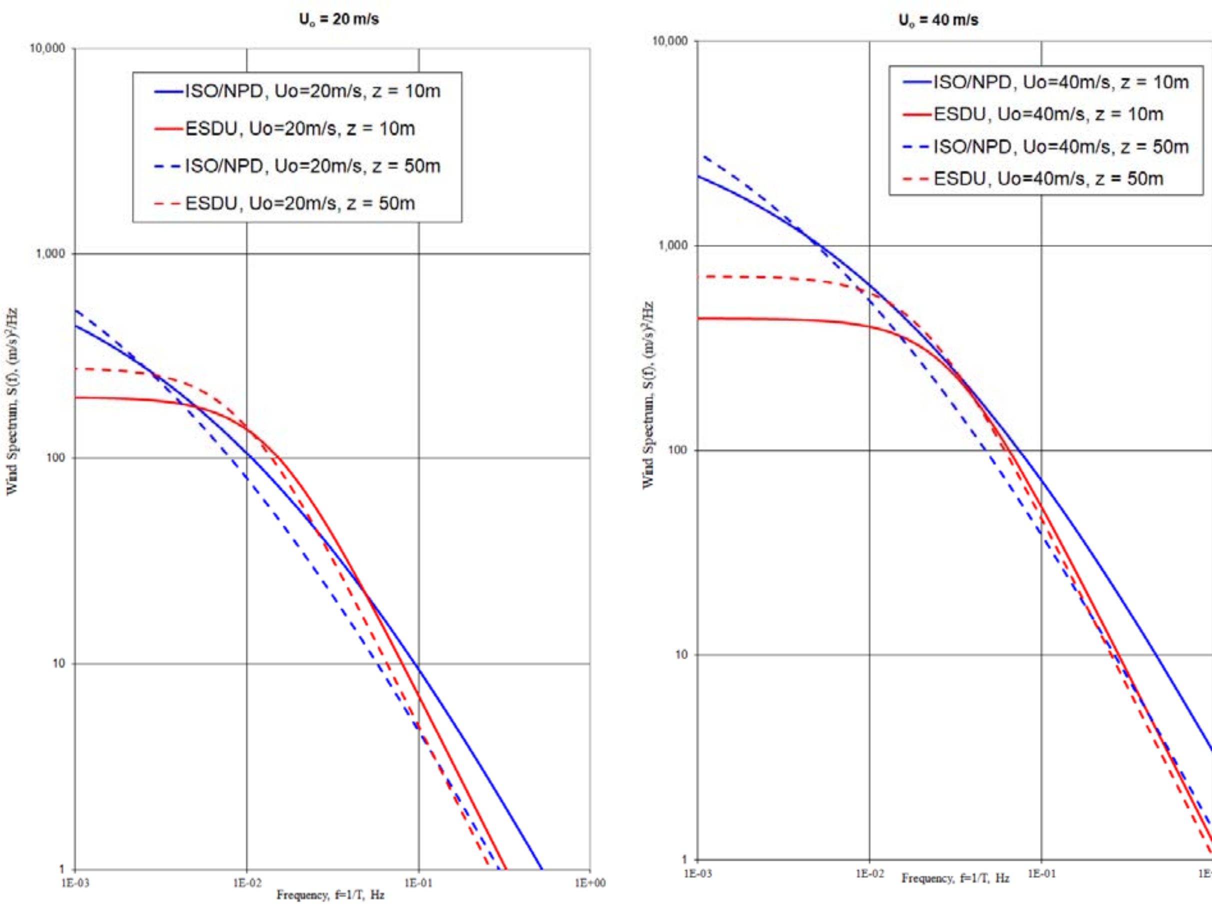



**Figure A.26—Examples of Wind Spectra**

The ISO wind spectrum is defined for periods between 0.5-600 seconds. For responses with natural-periods longer than 600 seconds, the recommended wind spectrum for extra-tropical storm conditions is the upper bound API spectrum (alpha = 0.01). Equations for the API wind spectrum are provided below. Also provided below (Figures A.27-A.29) are plots with comparisons between the ISO (NPD) and API spectrum for various mean-wind speeds.

Equations for API Wind Spectrum

In API 2A-WSD, 21st Edition, wind profiles and gust factors are defined by a single parameter: the 1-hour mean wind speed $U_0$ at 10 m (33 ft) above sea level. However, two parameters are required to define the API wind spectrum: $U_0$ and $I(z)$.

Wind Profiles and Wind Gust Speeds

The average 1-hour wind speed at a height $z$ above sea level (the 1-hour mean-wind profile) is given by:

$$U(z) = U_0 \left( \frac{z}{z_R} \right)^{0.125} \tag{A.5}$$

where

$U(z)$ = 1-hour mean-wind speed at elevation $z$ above sea level, [m/s, ft/s]

$U_0$ = 1-hour mean-wind speed at elevation of 10 m (33 ft) above sea level, [m/s, ft/s]

$z$ = elevation above sea level, [m, ft]

$z_R$ = 10 m (33 ft) = reference elevation above sea level

The wind gust speed averaged over $t$ seconds ($t$ < 60 s) at a height of $z$ meters above sea level is given by,

$$u(z,t) = U(z)\left[1 + g(t)I(z)\right] \tag{A.6}$$

where

$u(z,t)$ = the $t$-second averaged wind gust speed at elevation $z$ above sea level [m/s, ft/s]

$t$ = wind speed averaging time period, $t$ < 60 s

with

$$g(t) = 3 + \ln\left[\left(\frac{3}{t}\right)^{0.6}\right] \quad \text{for } t \le 60 \text{ s} \tag{A.7}$$

and

$$I(z) = \begin{cases} 0.15\left(\dfrac{z}{z_S}\right)^{-0.125} & \text{for } z \le z_S \\ 0.15\left(\dfrac{z}{z_S}\right)^{-0.275} & \text{for } z > z_S \end{cases} \tag{A.8}$$

where

$z_S$ = thickness of the "surface layer" = 20 m (66 ft).

***Wind Spectrum***

The API wind spectrum describes the energy-density of the longitudinal wind speed fluctuations at a point. The 1-point energy-density is given by:

$$S_{API}(f) = \frac{\sigma(z)^2}{f_p\left(1+1.5\dfrac{f}{f_p}\right)^{5/3}} \tag{A.9}$$

where

$S_{API}(f)$ = is the spectral energy-density at frequency, $f$ [(m/s)$^2$/Hz, (ft/s)$^2$/Hz]

$f$ = frequency, [Hz]

with

$$\sigma(z) = I(z)U(z) \tag{A.10}$$

and

$$f_p = \frac{\alpha}{z}U(z) \text{ with } 0.01 \le \alpha \le 0.1 \tag{A.11}$$

For measured wind spectra, the average value of $f_p$ is given by $\alpha$ = 0.025.

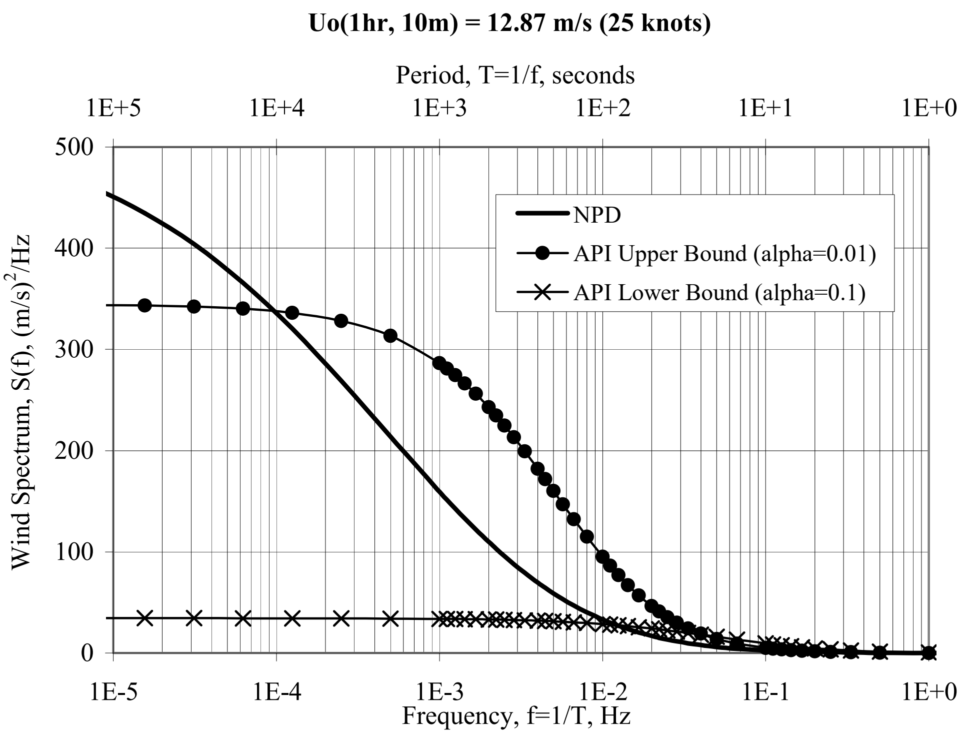



**Figure A.27—Comparison of API and ISO (NPD) Spectrum for 25-knot Wind**

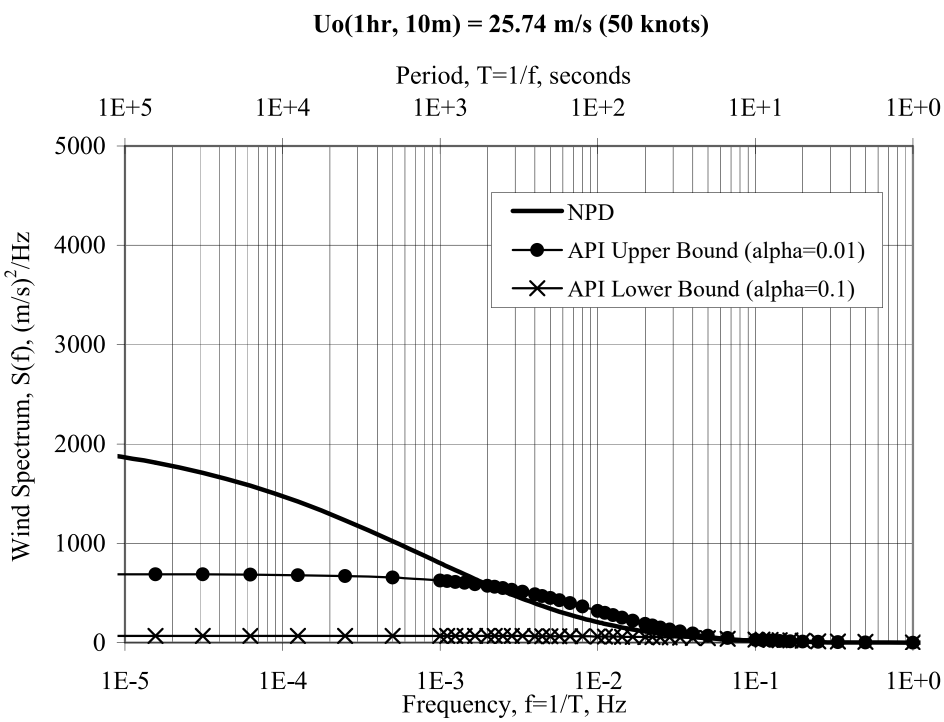



**Figure A.28—Comparison of API and ISP (NPD) Spectrum for 50-knot Wind**

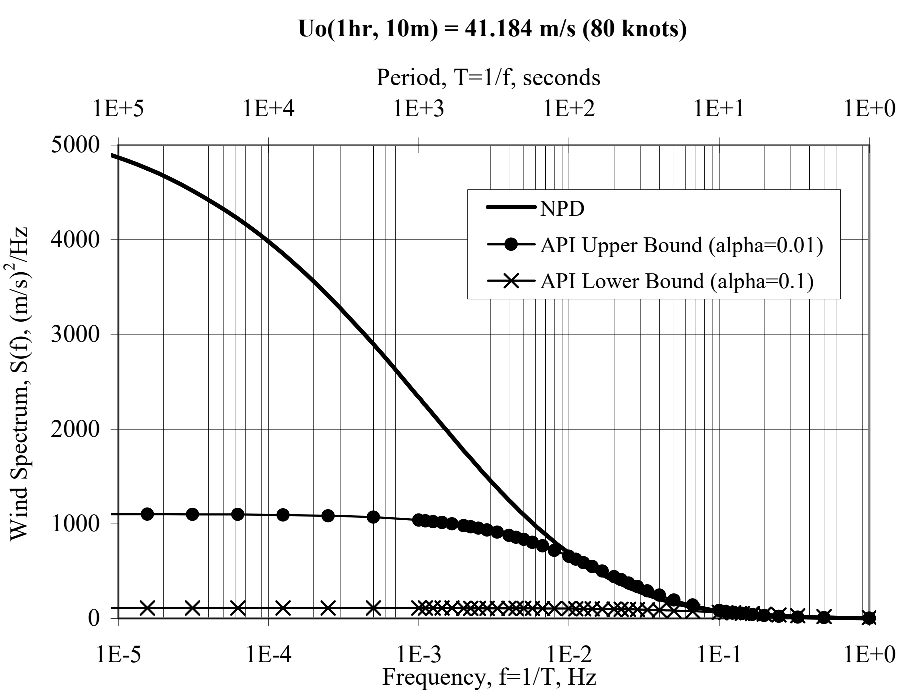



**Figure A.29—Comparison of API and ISO (NPD) Spectrum for 80-knot Wind**

### A.8.4.4 Current forces and VIM

Vortex-induced motions (VIM) are most prominent for spars, where most of the industry experience has been acquired. Multi-column floating structures (such as semi-submersibles) can also experience VIM and this effect should be considered in their design.

Influences of VIM

Fluid flow around a bluff-body results in periodic vortex shedding, leading to an oscillating force on that body. Non-streamlined floating structures (such as SPARs, and multi-column platforms such as semi-submersibles and TLPs) can be susceptible to vortex-induced motion (VIM) when the vortex shedding frequency coincides with a natural-period of the structure. VIM has three primary influences on system responses, as follows:

— The average in-line drag coefficient increases in the presence of VIM.

— Vortex-induced motions produce low-frequency oscillations in mooring line tensions.

— Vortex-induced motions can be significant in terms of the total floating structure offsets.

Because the technology associated with VIM is advancing, designers are encouraged to pay attention to the latest research in this area and incorporate those advances where appropriate. As a starting point, the following general guidance for mooring analysis for VIM is provided

Unlike other resonant responses, the amplitude of VIM is bounded. Transverse motion behavior is usually characterized by the non-dimensional ratio (a/d) of the motion amplitude (a) to a characteristic dimension of the body (d). The largest single-amplitude transverse-motion observed on classical spars is on the order of a/d = 1. Helical strakes are commonly used on spars (and risers) to reduce the motion-amplitude. Strakes can be very effective in eliminating VIM; however, their effectiveness on spars depends on various factors, such as the exact layout and size of the strakes, appurtenances, and current profiles.

Special issues for VIM design and analysis include, but are not limited to, the following scenarios or occurrences.

— It is evident from many publications and several JIPs, that CFD has advanced to a level that it can provide acceptable estimates of VIM responses. A large amount of field data has been collected and published for semi-submersibles and truss spars; indicating the model testing method that had been used for many years was typically too conservative, and that mooring- and riser-induced damping should be included in the model testing and/or CFD simulations to develop the correct VIM design criteria.

— VIM is affected by the natural periods of the combined floating structure and stationkeeping system, current velocity, direction, profile, hull geometry and appurtenances.

— The duration of current resulting in VIM can be much longer than peak storm duration.

— Model tests can only model certain parameters while approximating others; hence care should be exercised in the interpretation and use of model test data.

— Where VIM results in large tension cycles at high-mean load, fatigue life can be short for mooring components with low fatigue-resistance such as chain.

— The calibration of the factors of safety for mooring design does not include the VIM condition nor the uncertainties associated with VIM; consequently, sensitivity checks are recommended.

— Depending on the hull, strake and appurtenance configuration, the presence of waves can further reduce the VIM response.

Because of the above issues, it is important to address VIM conservatively in the mooring design stage. This can be achieved through the following measures:

- establishing design criteria that recognize the uncertainties in VIM behavior; for example, checking sensitivity cases in addition to the base case and checking field measurement data as well as model test data.
- conducting fatigue analysis for the 100-year VIM response condition in addition to long-term fatigue analysis.
- selecting mooring hardware and system design characteristics that can better tolerate or mitigate VIM.

Design parameters for VIM strength analysis

The first step in strength design is to establish suitable VIM design parameters. VIM-related design parameters for mooring strength design include:

- in-line and transverse VIM response amplitude (a/d) as a function of reduced velocity ($V_r$)
- drag coefficient as a function of VIM response amplitude
- definition of ranges for $V_r$
- VIM response trajectory or envelope.

These criteria are generally based on a combination of project-specific model test data and previous VIM design experience. Depending on the approach taken, there can be varying levels of uncertainty in the VIM criteria specified for a particular application. Criteria should be developed for a base-case (the best estimate) and for some sensitivity cases. Tension safety factors for intact and damaged conditions should be met for the base-case. Sensitivity cases should be used to check the robustness of the mooring system design, with the intent of confirming that the risk of mooring failure is at an acceptable level; even in the event that estimates of certain influential parameters such as mooring stiffness, current velocity, drag coefficient, lock-in definition, or VIM amplitude, are inaccurate. One of the important roles of the sensitivity check is to determine if, with some limited changes in critical parameters, the system would enter a VIM lock-in regime that would not be apparent for the base-case design criteria alone.

Basic considerations for VIM strength analysis

Most mooring analysis software is not generally designed to handle VIM analysis; in the past design values have often been obtained from model testing. More recently it has been found that model testing for VIM can result in very conservative response estimates, and that a combination of model testing and CFD is likely to provide more accurate predictions. A simplified analysis procedure for use at the preliminary design stage is described in [41].

Basic considerations for VIM fatigue analysis

VIM-induced mooring tensions are of a cyclic nature and contribute to the mooring system fatigue damage. The following factors should be considered when assessing fatigue due to VIM:

a) For the calculation of the number of tension cycles, use should be made of the VIM period in the offset position, corresponding to the specific current bin under consideration. This period can vary with current direction and magnitude and is generally different from the still-water natural period.

b) In addition to a long-term fatigue damage evaluation, a fatigue analysis for the extreme VIM event is also recommended.

c) Mooring systems experiencing a high mean-tension and large-tension variation can stress the chain beyond the elastic region, where fatigue test data are not available (see [33]). To ensure sufficient fatigue life, mooring systems should be designed to avoid this situation.

d) Fatigue damage of chain at the fairlead requires special attention since additional bending stress is imposed on the chain in this region, and chain typically has the lowest fatigue life of all the components in the mooring system.

e) Sensitivity cases, similar to those used in the strength analysis, should be considered to account for uncertainty in the VIM predictions.

<u>VIM fatigue analysis for long term and single extreme events</u>

For long-term fatigue analysis under VIM conditions, current events can be represented by a number of discrete current bins; with each current bin consisting of a reference direction, a reference current velocity and profile, associated wave and wind conditions, and probability of occurrence. Fatigue damage for each current bin is evaluated, and the fatigue damage due to VIM is combined with the fatigue damage due to wind and waves to yield total fatigue damage.

However, studies indicate that considerable fatigue damage can be caused even by a single extreme VIM event. Consequently, in addition to the long-term fatigue damage evaluation, a fatigue analysis of the 100-year VIM event should be considered. Since VIM response is largely dependent on the reduced velocity, the current associated with the worst-case VIM design situation does not necessarily coincide with the 100-year return period loop or hurricane current. The VIM amplitudes that induce the highest fatigue damage can occur in the presence of currents with lower return periods. The current speed profile and direction used in the single event fatigue assessment should be the most onerous speed profile and direction identified in the strength analysis. However, instead of using a constant current speed profile for the whole extreme event, current variation based on field measurements for strong loop currents can be considered. The duration of this event can be different from that obtained from the long-term current distribution.

**A.8.5 Loads on mooring lines and risers — Wave and Current Forces**

The drag forces on mooring line and risers can provide a significant contribution to the low-frequency damping. The drag force can be calculated with either crossflow or free-stream momentum methods. The range of applicability of each of these approaches depends on the flow regime, which in-turn is affected by diameter, roughness, flow velocity, and angle of incidence. A discussion of both approaches and the effect on estimates of low-frequency damping can be found in [42]. Current forces on risers and mooring lines can be calculated with either crossflow or free-stream momentum methods.

**A.8.6 Mooring analysis for strength, offset, and clearance**

**A.8.6.2 Extreme value statistics**

It has been demonstrated that the responses of moored floating structures, such as mooring line tension and low -frequency platform motions, have non-Gaussian distributions with extreme values that may exceed those that would be predicted by a Rayleigh distribution. This is primarily due to non-linear forcing mechanisms and non-linear stiffness and damping of the mooring system.

For a further discussion of the applicability of different probability distributions for the different global response parameters, see [43].

<u>Frequency Domain Analysis</u>

When using frequency domain analysis, the prediction of extremes from the response spectrum should include consideration of this non-Gaussian behavior through use of appropriate probability distributions for those responses that have non-Gaussian distributions. The appropriate probability distribution of the responses may be determined from model test results, full-scale data, or time-domain calculations.

When using frequency domain analysis, low frequency and wave frequency responses are typically calculated separately and the responses from each need to be combined to arrive at a single design value.

A simplified method for combining low frequency and wave frequency responses based on Turkstra's rule for the combination of load effects is given below. A detailed discussion about the applicability of this procedure can be found in [44].

The maximum response is the mean response plus appropriately combined wave-frequency and low-frequency responses:

$$S_{max} = S_{mean} + \text{Max}\,(S_{dyn1}, S_{dyn2}) \quad \text{(A.12)}$$

$$S_{min} = S_{mean} - \text{Max}\,(S_{dyn1}, S_{dyn2}) \quad \text{(A.13)}$$

$$S_{dyn1} = S_{lfmax} + S_{wfsig} \quad \text{(A.14)}$$

$$S_{dyn2} = S_{wfmax} + S_{lfsig} \quad \text{(A.15)}$$

where

Max is the larger of the absolute values of the terms in parentheses;

$S_{max}$ is the maximum response;

$S_{min}$ is the minimum response;

$S_{mean}$ is the mean response;

$S_{lfmax}$ is the most probable maximum (MPM) value of low frequency response;

$S_{wfsig}$ is the significant value of wave-frequency response = 2 * standard deviation.

$S_{wfmax}$ is the most probable maximum value of wave-frequency response;

$S_{lfsig}$ is the significant value of low-frequency response = 2 * standard deviation.

When using the above algorithm to determine the maximum tension from frequency domain analysis, the wave frequency tension response should be evaluated at several characteristic low frequency offset locations with respect to the that line's anchor to determine the correlation between vessel offset and wave frequency tension response. The significant and MPM wave frequency line tension used to calculate the maximum tension shall be evaluated at the characteristic low frequency offset location that results in the largest maximum total tension.

The most probable (low frequency or wave frequency) maximum response can be calculated from the (low frequency or wave frequency) response spectrum as follows:

If the MPM response is normalized using a peak factor (PF) defined as:

$$PF = MPM/(\text{standard deviation}) \quad \text{(A.16)}$$

then the peak factors for commonly used probability distributions can be calculated as follows:

$$\textit{Rayleigh}: \text{PF} = (2\cdot\ln(N))^{0.5} \quad \text{(A.17)}$$

$$\textit{Exponential}: \text{PF} = \ln(N) \quad \text{(A.18)}$$

where

N = the number of peaks in a 3-hour period.

MPM Peak factors for 100 and 1000 peaks are shown below:

**Table A.5 — MPM Peak Factors Example Calculations**

| N | Rayleigh | Exponential |
|---|---|---|
| 100 | 3.035 | 4.605 |
| 1000 | 3.717 | 6.908 |

Time Domain Analysis

When using time domain analysis, the following can be used to estimate the most probable maximum:

1. Probability Density Function (PDF)—In this approach a PDF for the extreme response is constructed, and the Most Probable Maximum (MPM) is the response where the PDF is maximum. Since construction of a smooth PDF may require a large number (>100), of maximum responses from different time domain realizations, this approach will likely be limited to the governing design load case or be performed as part of an exercise to determine the appropriate extreme value distribution for a particular response parameter.

2. Fitted Probability Distribution Model—In this approach a peak probability distribution model, such as Rayleigh, Weibull, Exponential, is selected and the parameters in the selected model are determined using the available response time histories. Then the expected extreme response can be computed from the fitted model. This approach may require fewer realizations than Method 1. However, in practical applications the fitted parametric model often fails to describe the “true” upper tail behavior, resulting in biased extreme response prediction. Some analysts use special techniques such as fitting the upper tail or taking average of predictions from several realizations to improve accuracy. Nevertheless, this is an approach that requires substantial skill and experience.

3. Average of Maximum Responses—In this approach the average of the maximum responses from a number (20-30) of time domain realizations of different random seeds is taken as design maximum response. The average of the maximum responses does not correspond to the most probably maximum but instead is an estimate of the expected maximum which is a more conservative design value. Because of its relative simplicity and need for fewer realizations, this method may be preferred over the other two.

Note: Mooring design safety factors are typically calibrated for MPM extreme values [54]. Using the expected maximum value as obtained from method 3 above for extreme tension together with the safety factor given in the Normative section of this standard will result in more conservative design.

For each of the three methods described above, each realization should be a 3-hour simulation. See [45] for a comparison of these methods applied to extreme mooring line tension and vessel offset.

### A.8.6.4 Mitigating mooring line trenching effects on AHC

To prevent trenches from degrading the holding capacity of anchors, a minimum distance between the mooring line’s touchdown point and its anchor should be maintained in a *representative* return-period environmental condition. Because trenching requires a long duration of repeated mooring line vertical motions at the seabed, environmental return period conditions that occur, or are exceed, for a few hours a year should be considered as the *representative* conditions. For example, the 6-month and 1-year return period condition will occur (or be exceeded) for about 6 h or 3 h per year, respectively.

The mooring line touchdown point closest to the anchor is calculated in the *representative* environmental conditions based on the following (see Figure A.30),

1) Metocean conditions — Site-specific normal (non-squall) environmental conditions with the representative return period are used to define load cases; somewhere between a 6-month to 1-year return period may be considered.
2) Touchdown point — For each load case, the "taut-side" touchdown location corresponding to the "mean plus maximum low-frequency" vessel/turret offset (or greater) is calculated and used to define the minimum distance between the touchdown point and the anchor.
3) Trench depth — In calculating the touchdown location closest to the anchor, an increase in water depth should be considered (e.g. the nominal seabed bathymetry is increased to allow for the depth of the trench. Increases in water depth of between 10-20 m may be considered, representing a 10-20 m deep trench.

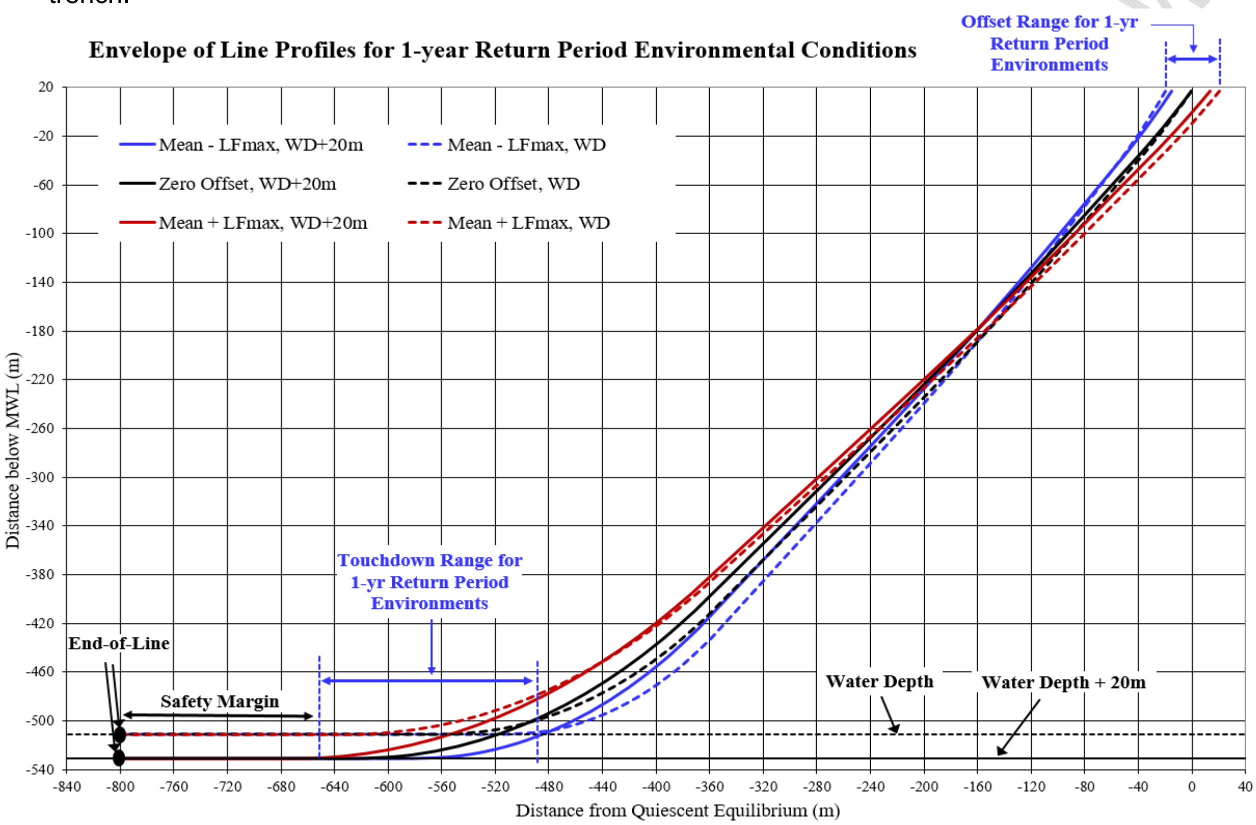



**Figure A.30—Trenching Analysis, Calculation of Distance Between Touchdown and Anchor**

For each mooring line, the minimum distance between the line's *representative* touchdown point closest to the anchor and the anchor should be greater than an owner or operator defined safety margin. In determining the safety margin, the owner or operator should consider the sensitivity of the minimum touchdown to anchor distance to variations in mooring line load sharing, pretensions within a group, vessel draft and trim, seabed bathymetry, and so forth. The owner or operator may want to consider a minimum clearance or safety margin distance on the order of 100 m.

## A.8.7 Mooring Analysis for fatigue

### A.8.7.1 Basic considerations

Use of a hindcast database has the advantage of avoiding the development of tables describing marginal distributions of the metocean parameters that summarize the fatigue weather conditions in the metocean report, and then the approximate reconstructions of fatigue weather bins from these tables by the mooring analyst. This is particularly important for passive turret-moored ships because in each weather bin the vessel's global heading and wind, sea, current, and swell relative directions are all important in determining the fatigue damage.

A large net horizontal load from riser, such as typically encountered on a combination of spread moored FPSO with deepwater offloading buoy, can have a significant effect on the fatigue performance of the mooring lines counteracting that net horizontal load (see [46]).

### A.8.7.2 Analysis approach

No guidance is offered for tension-tension fatigue.

The following is an example of a damage assessment for OPB fatigue.

Background of OPB fatigue

The first fatigue failure identified to be due to OPB happened in mooring legs of the Girassol Loading Buoy in 2001. Since then, OPB fatigue has been recognized as the cause of mooring failure of two other facilities. Information on these mooring systems, taken from [47], [48]. is presented in Table A.6. It is believed that there have been other un-reported OPB fatigue failures. In 2007, a JIP was proposed to the offshore industry with the main objective of implementing a full-scale chain testing program to better assess the OPB fatigue mechanism. The Chain OPB JIP concluded in 2013 and the outcomes are summarized in several papers (see [49]).

**Table A.6—List of Facilities with Chain Failure due to OPB Fatigue**

| **Facility Name** | **Schiehallion** | **Girassol** | **Terra Nova** |
|---|---|---|---|
| **Floater Type** | FPSO internal turret | CALM buoy | FPSO internal turret with thruster assist |
| **Location** | North Sea | West Africa | Eastern Canada |
| **Water Depth** | ~ 395 m | ~ 1400 m | ~ 90 m |
| **Year Installed** | 1998 | 2001 | 2001 |
| **Year in Operation (at time of failure)** | 8 years | 1 to 2 years | 12 years |
| **Chain** | 159 mm R3S studless link | 81 mm R3S stud link | 146 mm R4 studless link |
| **Top chain connection** | Single-axis articulation with short hawse pipe | Single-axis articulation with short hawse pipe | Single-axis articulation with short hawse pipe |

The following is a high-level description of a damage assessment methodology for chain links that are subject to both tension and bending loading. It is a shortened version of [50].

The guidance summarized here is applicable to free-bending fatigue of mooring chain (i.e. out-of-plane bending (OPB) and in-plane bending (IPB)). In theory, OPB fatigue can occur at any location where adjacent chain links undergo relative angular movement. However, the largest relative angles are typically found in the few links at the connection between the chain and the floater.

Physics of OPB

During the chain manufacturing process, chain links are proof-loaded to 70-80 % of their nominal breaking-strength. The proof-loading results in plastic deformation of the chain links, especially the grip area between the links. The change of geometry due to proof-loading is believed to introduce interlink rotational stiffness, and in simple terms causes the links to lock into each other.

To quantify OPB fatigue damage, it is necessary to start with an understanding of the bending moments that result from relative angular motions between adjacent chain links (interlink angular rotations).

The relationship between bending moment and interlink angle can be divided into three distinct phases:

- Locking: The relative motion in the contact area between the two links is zero and the chain links behave as a single-beam element. The bending-moment increases linearly as the interlink angle increases (i.e. the change in relative angle between adjacent chain links). The slope of the bending-moment versus interlink-angle in the locking phase is known as the interlink-stiffness.
- Stick-Sliding: This phase can be considered as a transition-phase between locking and sliding. The relationship between bending-moment and interlink-stiffness decreases in stick-slip phase.
- Sliding: The relative motion between the adjacent links is characterized by sliding at the contact area. The bending-moment remains constant with increase of interlink-angle.

These three phases are schematically shown in Figure A.31. In this figure, the bending-moment generated in the link as a function of interlink-angle (solid line), as well as the relative tangential displacement between the two links as a function of interlink-angle (dotted line), are shown and different phases highlighted. Here, the relative tangential displacement is defined as the distance between two points; one on each link, each one lying on the contact surface and on the centerline of the link, measured tangential to the surface of the contact area. Furthermore, the graphs in Figure A.32 schematically show the effect of friction and proof-loading on interlink-stiffness characteristics. The only difference between in-air and in-water chain links is the coefficient of friction between the links. Since the locking is the result of the geometry, the magnitude of the bending stress during locking is not dependent on the friction between the chain links. During rolling and sliding, the bending-stress does depend on the friction coefficient between the chain links. The theoretical sliding threshold ($M_s$) can be estimated from $M_S = 0.5 \cdot \mu \cdot T \cdot d$; where $\mu$ is the coefficient of friction, T is the tension, and d is the chain bar diameter. An estimate of the coefficient of friction, derived as part of the Chain OPB JIP for links in-air and in-water is 0.5 and 0.3, respectively.

As shown in Figure A.31, in the absence of the plastic deformation in the grip area (i.e. links that are not proof loaded), a relative rotation between chain links will cause rolling and eventually sliding of the two interface surfaces. When considering small interlink angles (<< sliding threshold), the magnitude of the bending stress that develops in a chain link during rolling is significantly lower than the stress that results from locking.

When the applied interlink-angle is reversed, the bending-moment will decrease linearly with interlink-angle, and further changes in the interlink-angle continue the process resulting in a hysteresis loop. The linear portions of the hysteresis loop will not necessarily have identical slopes because of the relative movement of the chain links during sliding.

The interlink-stiffness and the sliding threshold are function of line tension, and both tend to increase with an increase in tension. Similarly, the interlink-stiffness and the sliding threshold are function of chain diameter, and both tend to increase with increases in diameter.

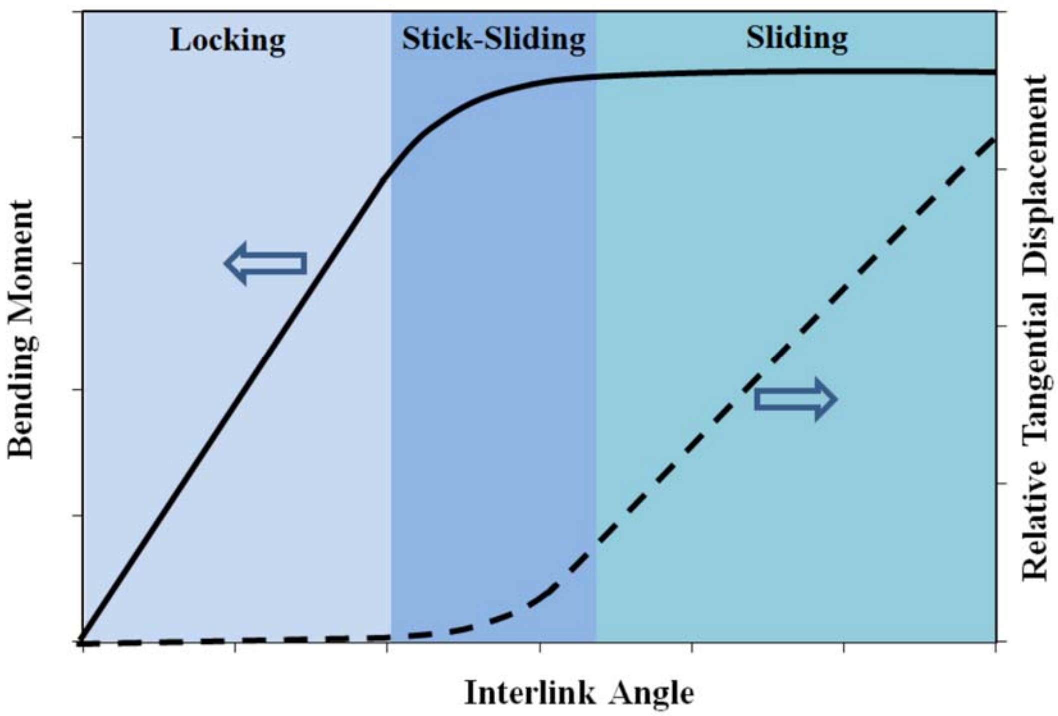



**Figure A.31—Interlink Stiffness Model Showing Three Phases**

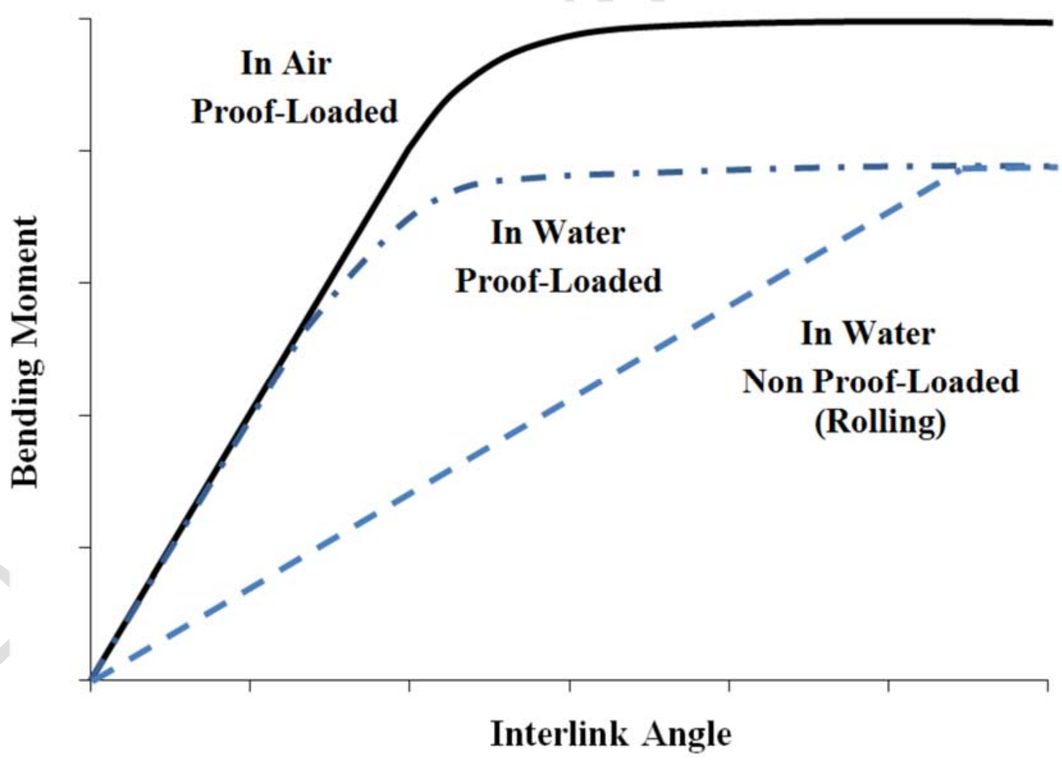



**Figure A.32—Interlink Stiffness Model In-air and In-water**

Since the interlink-stiffness is a function of the geometry of the grip area, the change of geometry during the service-life of the chain (e.g. due to wear) can alter the interlink-stiffness. Evaluating the long-term variation of interlink-geometry requires a detailed understanding of the long-term interlink-wear pattern and the loading history of the chain links. Attention has to be paid to extreme loads experienced by chain links, as high loads can cause plastic deformation in the interlink area and re-establish the locking between the links. In general, the interlink-wear is expected to gradually make the interlink-area more rounded and the interlink-stiffness is consequently expected to decrease towards the interlink-stiffness for a link that has not been proof-loaded. It is also worth realizing that in some systems, excessive interlink-wear can be the governing mode of failure, and the designer should make an assessment whether the mooring system is more likely to fail due to OPB fatigue damage or interlink-wear.

Based on full-scale fatigue test results from the Chain OPB JIP and actual fatigue failures, it can be concluded that the location of OPB fatigue failure and TT fatigue failure on a chain link do not coincide. In the case of pure tensile loading of chain, there are two distinct locations of maximum stress (i.e. hotspots) on the chain link. The two locations are at (1) the transition from the straight legs to inner bend and at (2) the top of the crown. It has been found that the magnitude of the stress concentration factors in the two locations is similar. As a result of symmetry, each chain link contains four TT hotspots at the intrados locations and two hotspots at the top of crown locations. In the case of pure OPB loading, the hotspots are located in the bend region, close to the contact area between the two links. As a result of symmetry, each chain link contains eight potential OPB hot spots (i.e., four on top and another four on bottom) when a single link is laid down flat. In practice, the interlink-angles on both ends of a chain link are different, and only the four hotspot locations on the end with the larger interlink-angles shall be considered.

<u>Methodology for OPB fatigue analysis</u>

The OPB fatigue analysis is performed in the following main steps, with further guidance provided below:

- Step 1 - Development of fatigue sea-states;
- Step 2 - Development of interlink-stiffness and stress concentration factors;
- Step 3 - Global response analysis and local chain link and connection modeling;
- Step 4 - Stress calculation and cycle counting;
- Step 5 - Fatigue damage calculation.

The flowchart in Figure A.33 shows the general workflow of a typical OPB fatigue analysis and clarifies the connection between the steps. It is worth realizing that OPB fatigue analysis (as described here) is similar to the fatigue analysis of other structural details, and involves contributions from mooring, structural, and mechanical engineering disciplines.

<u>Step 1 - Development of fatigue sea states</u>

The process of developing OPB fatigue sea-states is similar to what is typically done for TT fatigue analysis. In general, OPB fatigue damage is more evenly distributed among different environmental combinations as compared to TT fatigue damage. Therefore, a sea-state matrix with larger number of environmental combinations and higher bin resolution is typically required for OPB fatigue analysis. It is also worth realizing that the environmental combinations that generate significant TT fatigue damage may not necessarily be the same combinations that cause significant OPB fatigue damage, and vice versa. For OPB fatigue analysis purposes, attention needs to be paid to sea-states resulting in significant wave frequency motions, especially in rotational degrees of freedom (i.e. roll and pitch).

<u>Step 2 - Interlink bending stiffness and stress concentration factors</u>

The chain interlink-bending characteristics describe the relationship between the interlink-angle and the nominal bending-moment generated between two adjacent links. The relationship (i.e. interlink-stiffness model) can be estimated from full-scale chain testing or FEA. The interlink-stiffness is a function of line tension, and therefore the range of tension that the line will experience in service needs to be defined before starting this step.

Chain OPB fatigue is performed following the hotspot S-N approach. In this approach, the local stress variations at the critical hotspots are estimated using a transfer function between the nominal stresses and the local stresses (i.e. stress concentration factor). FEA has been typically used to estimate the stress concentration factors at OPB hotspots, since measuring stresses at OPB hotspots in chain testing raises practical challenges due to the close proximity of OPB hotspots and the contact zone between the links.

In chain FEA modelling for OPB purposes, attention shall be given to the non-linear material properties and the friction between the adjacent links. The FEA model can take advantage of the symmetry of the chain link in its primary and secondary axes. Therefore, a chain FEA model can be simplified to few (2-3) half-links. A typical FEA for OPB purposes consists of four steps: (1) load the chain links to proof-load level, (2) unload the chain links, (3) apply the mean-tension and maintaining the load, and (4) apply the rotation to the free-end.

In development of the FEA model, attention shall be given to the fact that the chain links do not have a circular cross-section in the bend-area even before proof-loading. A 3-D scan of the link geometry before proof-loading can help the FEA modeling.

As many studies show, material properties play an important role in the interlink stiffness and locking mechanism. It is recommended to use the actual mechanical test data for chain FEA purposes since actual material properties can be significantly higher than the minimum allowable by Class. As a general trend, interlink stiffness tend to increase with decrease in yield strength (i.e. larger plastic deformation in the grip area due to proof-loading).

Interlink stiffness is a function of proof-loading level. Rules and standards define the minimum proof-loading level and allow a 10-15 % increase in the applied load. Chain manufacturers may use high proof-loading levels to achieve the geometry requirements. The FEA should consider the actual load level applied for the proof-loading during manufacturing.

The plastic deformation observed in the FEA should be compared with data from chain manufacturing to verify the robustness of FEA. The sensitivity of the FEA results to the input parameters (i.e. initial geometry, material properties, and proof-loading level) shall be evaluated and included (as needed) in the OPB fatigue analysis and design.

The same FEA model can be used to develop the stress concentration factors. For this purpose, individual OPB, IPB, and TT stress concentration factors at OPB hotspots are derived from the results of FEA under the corresponding loading. When the contribution of TT fatigue is significant, it is recommended to study multiple hotspots with different contributions of OPB and TT in the high OPB stress region. The Chain OPB JIP highlighted the importance of multi-axial stress and the contribution of shear stress to OPB fatigue failure. From physical point-of-view, the importance of shear stress in OPB is expected since the bending along the link's longitudinal axis causes torsion in the bended section of the chain. The Chain OPB JIP concluded that the complex stress distribution in the chain link can impact the location of crack initiation and the fatigue endurance of the chain link. As a solution, the Chain OPB JIP recommended increasing the uniaxial OPB stress concentration factors to account for multi-axial stress phenomena. The topic of multi-axial stress and its impact on the fatigue life of chain components and other structural components is still under investigation and further developments have been made since the conclusion of the Chain OPB JIP. Moreover, the residual stresses and mean stress distribution from the mean load are believed to have an impact on the fatigue endurance of the chain links; these effects are currently under investigation.

In the early design stage, estimates of interlink stiffness and stress concentration factors can be obtained from the results of the Chain OPB JIP (which are included in Appendix 1 of Bureau Veritas Guidance Note NI 604). The interlink stiffness model is derived from full-scale chain tests performed on chains with diameters ranging from 84 mm to 146 mm and grades R3 and R4. The interlink stiffness model should be considered with special care for chain size and grade out of the tested diameter range and grade.

Step 3 - Global response analysis and local chain link and connection modeling

The objective of this step is to estimate the time-series of tension and bending moment components of the chain links in a specific fatigue sea-state. Generally, the analysis comprises two main steps.

— Global vessel-line response analysis: estimates the time-series of line tension and relative line-connection total angles in the line's primary and secondary axes-of-rotation.

— Local chain-connection modeling: transfers the total angles to the local interlink-angles and moments between the chain links.

As a minimum, the global response analysis model should be able to capture the relative angle between the line and the connection in the line's primary and secondary axes-of-rotation. For this purpose, the numerical model should be able to model the floater's dynamic motions in six degrees-of-freedom, line-dynamic response, and the phasing between the vessel's motion and the line's motion. The global response analysis for OPB fatigue purposes is typically done in time-domain, due to the numerical modeling requirements and the complexity of the analysis process. The methodology herein is also based on time-domain simulation results. However, frequency-domain or hybrid frequency-time-domain models may be acceptable if they can be validated.

The local chain-connection modeling considers the bending characteristics of a few chain links, rotational behavior of the connection (if any), and the interaction between the chain links and the connector. The analysis is typically done using a simplified FEA model of the chain segment and top connection; and is performed for the range of global angles observed in global analysis. In case of connections with rotational flexibility, the break-out moment of the connection (i.e. the moment required to rotate the connection) is estimated as a function of the bearing size, coefficient of friction of the bearing, and line tension. For this purpose, a representative estimate of the friction factor obtained from material-specific test data should be used. In some connection types, the interaction between the chain links and connector can play an important role in the moment distribution along the chain links. Possible contact between the moving chain links and the connector may result in change of the center-of-rotation, and may also cause additional friction between the chain and connector.

Depending on the capabilities of the numerical tool used in the analysis, and complexity of the chain-connection interaction, the local chain-connection modeling can be included in the global response model. Otherwise, the global analysis is done assuming a freely rotating connection between the line and vessel, and the local chain-connection modeling is consequently considered on the results of freely rotating model.

Step 4 - Stress calculation and cycle counting

In this step, the time-series of tension and primary- and secondary-moment components are used to calculate the nominal tensile (TT), OPB, and IPB stress components in the affected links using the moments-of-area of the chain link. In the case of free-corrosion, the corroded chain diameter is used for calculation of chain moments-of-area. The total stress at OPB hotspots are then calculated by applying the appropriate stress concentration factors on the nominal stress components. In combining the stress components, attention shall be given to the phasing between the stress components. There are four OPB hotspots on each end of the chain link that have similar OPB and IPB amplitudes, but with different phasing. Specifically, the total stress time-series at each OPB hotspot can be estimated from

$$\sigma_{TOTAL} = SCF_{TT} * \sigma_{TT} \pm SCF_{OPB} * \sigma_{OPB} \pm SCF_{IPB} * \sigma_{IPB} \tag{A.19}$$

Finally, rain-flow cycle counting is applied on the total stress time-series to develop the stress-range histogram of each sea-state. The long-term stress-range histogram is developed from the stress-range histogram of each sea-state and the corresponding probability of occurrence of the sea-state.

Step 5 - Fatigue damage calculation

Once the long-term hotspot stress histogram has been developed, the OPB fatigue damage is calculated based on the S-N curve approach under the assumption of linear cumulative damage (Palmgren-Miner rule). The DNV-RP-C203 B1 curve is recommended here as the basis, and other S-N curves may be used by the designer, provided that the S-N curve is developed using sufficient test data.

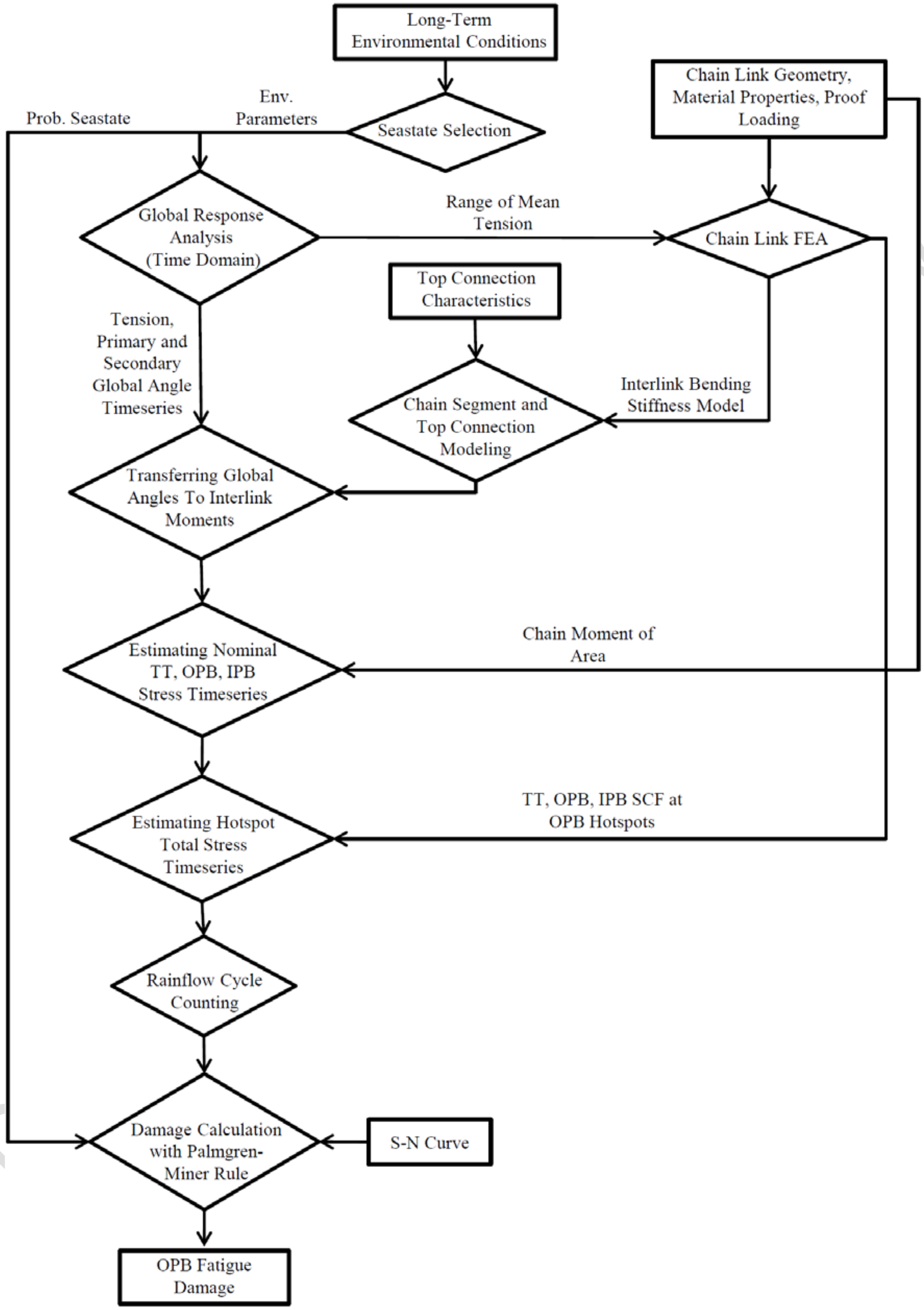



**Figure A.33—Flowchart of a typical OPB Fatigue Analysis**

### A.8.7.3 Fatigue damage calculation methods

#### A.8.7.3.2 Combining wave-frequency and low-frequency fatigue damage

For a comparative study between several spectral based methods and the rainflow cycle counting method see [50].

Equations and guidance is provided below for three different methods of combining low and wave frequency spectral damage to arrive at the total fatigue damage. The equations given herein assume that the distributions of tension peaks are described by a Rayleigh distribution. These methods are (a) simple summation, (b) combined spectrum, and (c) combined spectrum with dual narrow banded correction factor.

When fatigue damage is dominated by either low or wave frequency contributions all methods ought to provide very similar results. However, this is not always the case for method (c). Simple summation (a) will give an acceptable estimate of fatigue life if the ratio of standard deviations of the wave frequency and low frequency tension response satisfies the following condition:

$$\sigma_{wf}/\sigma_{lf} \geq 1.5 \; or \; \sigma_{wf}/\sigma_{lf} \leq 0.05 \qquad \text{(A.20)}$$

Where $\sigma_{wf}$ and $\sigma_{lf}$ are wave frequency and low frequency standard deviations of tension, respectively. However, this method (a) may underestimate fatigue damage compared to RFC if both low and wave frequency tensions contribute significantly to the total fatigue damage.

The simple summation and combined spectrum methods, methods (a) and (b) are *symmetric* in the sense that total fatigue damage is invariant with the naming convention used for the low and wave frequency tension spectra. That is, swapping the parameters of the low and wave frequency spectra does not alter the total fatigue damage calculated by these methods. However, the combined spectrum with dual narrow banded correction factor method, method (c), is not *symmetric*. For method (c) the calculated fatigue damage depends on the naming convention used for the low and wave frequency tension spectra.

Simple summation generally provides a better estimate of fatigue life than either of the other two methods. Simple summation also has the advantage of providing separate estimates of the contributions from low and wave frequency tension variations to the total damage. The combined spectrum method (b) is always conservative and may significantly overestimate the actual fatigue damage, see API 2FP1, and 2SK 3rd edition. The combined spectrum with dual narrow-banded correction factor method (c) is intended to be an improvement on (b), and will generally results in less conservative predictions than method (b). However, when the total fatigue damage includes a significant contribution from low frequency tension variations method (c) will also overestimate the fatigue damage, see API 2SK 3rd edition. Analysis procedures for Methods a, b, and c are presented below.

Simple Summation – Method a

For simple summation the total fatigue damage in the $i^{th}$ weather bin is given by,

$$D_i = \frac{n_{Wi}}{K}(\sqrt{2}R_{W\sigma i})^M \cdot \Gamma(1+M/2) + \frac{n_{Li}}{K}(\sqrt{2}R_{L\sigma i})^M \cdot \Gamma(1+M/2) \qquad \text{(A.21)}$$

where, *K* and *M* are the parameters of the fatigue curves defined in Table 14, and

$D_i$ = annual fatigue damage from wave and low frequency tension variations, in weather bin *i*

$n_{Wi}$ = number of wave frequency tension cycles per year, for weather bin *i*

$R_{W\sigma i}$ = ratio of standard deviation of wave frequency tension range to RBS, equal to twice the standard deviation of wave frequency tension, for weather bin *i*

$n_{Li}$ = number of low frequency tension cycles per year, for weather bin *i*

$R_{L\sigma i}$ = ratio of standard deviation of low frequency tension range to RBS, equal to twice the standard deviation of low frequency tension, for weather bin *i*

$\Gamma$ = Gamma function

Combined Spectrum – Method b

In the combined spectrum method the fatigue damage for the $i^{th}$ weather bin is given by,

$$D_i = \frac{n_i}{K}(\sqrt{2}R_{\sigma i})^M \cdot \Gamma(1+M/2) \tag{A.22}$$

In equation (A.22) the standard deviation of the combined low and wave frequency tension range, $R_{\sigma i}$, is computed from the standard deviations of the low, $R_{L\sigma i}$, and wave, $R_{W\sigma i}$, frequency tension ranges by,

$$R_{\sigma i} = \sqrt{R_{W\sigma i}^2 + R_{L\sigma i}^2} \tag{A.23}$$

The number of tension cycles, $n_i$, in the combined spectrum is calculated using the pseudo zero up-crossing frequency of the combined spectrum, $v_{Ci}$, given by,

$$v_{ci} = \sqrt{\lambda_{Wi} v_{Wi}^2 + \lambda_{Li} v_{Li}^2} \tag{A.24}$$

where,

$v_{Wi}$ = the zero up-crossing frequency (hertz) of the wave frequency tension spectrum in environmental state $i$

$v_{Li}$ = the zero up-crossing frequency (hertz) of the low frequency tension spectrum in environmental state $i$

With $\lambda_{LI}$, and $\lambda_{WI}$ given by,

$$\lambda_{Li} = \frac{R_{Li}^2}{R_{Li}^2 + R_{Wi}^2}, \quad \lambda_{Wi} = \frac{R_{Wi}^2}{R_{Li}^2 + R_{Wi}^2} \tag{A.25}$$

Combined Spectrum with Dual Narrow-Banded Correction Factor – Method c

The combined spectrum with dual narrow-banded correction factor method uses the result of the combined spectrum method and multiplies it by a correction factor, $\rho_i$, based on the low and wave frequency spectra used to define the pseudo total tension spectrum. The fatigue damage for environmental state $i$ is estimated by,

$$D_i = \rho_i \frac{n_i}{K}(\sqrt{2}R_{\sigma i})^M \cdot \Gamma(1+M/2) \tag{A.26}$$

The correction factor is given by,

$$\rho_i = \frac{v_{ei}}{v_{ci}}\left[(\lambda_{Li})^{\frac{M}{2}+2} \cdot \left(1-\sqrt{\frac{\lambda_{Wi}}{\lambda_{Li}}}\right) + \sqrt{\pi\lambda_{Li}\lambda_{Wi}} \cdot \frac{M\Gamma\left(\frac{1+M}{2}\right)}{\Gamma\left(\frac{2+M}{2}\right)}\right] + \frac{v_{wi}}{v_{ci}} \cdot (\lambda_{Wi})^{\frac{M}{2}} \tag{A.27}$$

With the pseudo zero up-crossing frequency of the envelope of the tension process, $v_{ei}$, given by,

$$v_{ei} = \sqrt{\lambda_{Li}^2 v_{Li}^2 + \lambda_{Li}\lambda_{Wi} v_{Wi}^2 \delta_{Wi}^2} \tag{A.28}$$

where,

$\delta_{Wi}$ = the bandwidth parameter of the wave frequency part of the tension process in the $i^{th}$ environmental state. When information to define the bandwidth parameter $\delta_{Wi}$ is not available it may be taken as equal to 0.1. In general, increasing the bandwidth parameter will increase the calculated fatigue damage.

### A.8.8 Response-based Analysis (RBA)

Traditional offshore design practice focuses on the calculation of system loads and responses in the "worst" environments (highest wave heights, highest wind or current speeds) expected in a specified return period. For some offshore systems, the particular response characteristics of the system shall be taken into account in order to determine the metocean conditions that will cause the highest loads; maximum responses and loads may not occur in the highest wave heights, or highest wind or current speeds. An RBA design approach is one that appropriately considers the response characteristics of a system to ensure that the highest loads and responses expected over the system's service-life are considered in design. For example, for a passive turret-moored (weather-vaning) vessel, system loads and responses are dependent not only on the magnitudes of wave, wind, and current, but also on the vessel's heading relative to the environment. Maximum loads and responses may occur in sea-states in which the vessel reaches mean heading equilibrium at an unfavorable heading with respect to wind, wave, or current; even though the wind speeds, current speeds, and wave heights are relatively moderate. Due to this sensitivity to vessel heading, it is possible that load- and response-magnitudes do not necessarily correlate directly with wave-, wind-, and current-magnitudes alone.

The RBA aims to predict the long-term distributions of critical responses such as motions, accelerations, offsets, tensions, and so forth, which have significant impacts on the design of a floating system. As compared with the conventional analysis, which predicts the responses of the facility to the N-year return-period metocean conditions, RBA directly provides the N-year return-period responses by analyzing the statistics of extreme responses of interest. Environment-based and response-based approaches are distinguished as follows:

<u>Deterministic (Environment-based) Analysis</u>

Conventional “deterministic” or environment-based approach assumes that the highest system loads and responses will occur in sea-states that have the highest wave height, wind speed, or current speed, and that responses increase with increasing return-period; this type of analysis is performed based on the premise that the “N-year” environmental conditions will yield the “N-year” responses. Before any system responses are calculated, available metocean data representing extreme conditions are gathered and statistically analyzed to produce estimates of extreme metocean conditions (i.e. those with the highest wave heights, wind speeds, and current speeds that can be expected to occur with an associated return-period (e.g. 100 years)). System responses and design loads are then determined from global analysis for those “worst” return-period metocean conditions, with the expectation that they will produce the most extreme responses. The number of environmental load cases that need to be considered for a global system analysis is typically on the order of $10^3$.

<u>Response-based Analysis (RBA)</u>

In response-based analysis, the analyst does *not* make the assumption that the highest system loads and responses will occur in metocean conditions with the highest wave heights, wind speeds, or current speeds; which for typical metocean criteria increase with increasing return-period. The RBA considers system responses to a broad range of metocean conditions at the site derived directly from a hindcast of metocean conditions. Responses are calculated for all metocean conditions (load cases) derived from the hindcast, and the calculated *responses* are statistically analyzed to produce estimates of the extreme responses for a given return-period. In traditional deterministic analysis, there is a general concern that load cases typically based on intensity of wind speed, wave height, and current speed do not account for factors (such as wave period, length, or steepness, system resonance effects, or relative heading effects of a turret-moored vessel) that may have a significant influence on responses. The RBA addresses this general concern, where the number of metocean conditions (load cases) considered for global system analysis is limited only by the size of the hindcast available to the analyst. For grid-point pooling, the number of load cases will generally be of the order of $10^3$. This is of the same order as the number of 3-hour weather bins in a year (2922) used for hindcast-based fatigue analysis; the most common type of RBA performed for moored systems.

The fundamental differences between the two approaches can be seen by comparing the flowcharts in Figure A.34. The flowchart on the left (Figure A.34 (a)) shows the approach used for traditional design analysis in which 'deterministic' strength analysis is performed using extrapolated metocean extreme values as inputs and 'response-based' fatigue analysis is performed using operational metocean data. The major steps involved in an RBA depicted in the right-hand flow chart (Figure A.34 (b)) are described as follows:

Step 1—Acquire Metocean Data

Acquire a set of seastates that is representative of the variability of metocean conditions of interest at the site. This may consist of a long, continuous or discontinuous (such as episodic storm events), temporal sequence of measured or hindcast wind, wave, and current conditions; or may take the form of tabulated sea-state bins (each bin containing wind, swell, sea and current intensities, global directions, etc., of interest) with associated probabilities of occurrence that have been derived from measured or hindcast data.

Step 2—Perform Global Analyses

Evaluate responses for each of the individual sea-states using the same prediction methods, as used in the deterministic analysis approach.

Step 3—Perform Statistical Analysis of the Responses

Perform separate statistical analysis for each of the responses of interest to determine extreme values for comparison with acceptance criteria. Different environmental load cases (sea-states) may produce the highest values of each of the response parameters of interest. It may be necessary to extrapolate the response distributions to obtain estimates of extreme response for long return-periods.

The term "response-based analysis" does not identify a specific procedure for performing the required global analyses and statistical response analysis; but instead refers generally to approaches that involve statistical analysis (and possibly extrapolation to long return-periods) of *response* data, rather than statistical analysis (and possibly extrapolation to long return-periods) of metocean data. Procedural details for a response-based analysis are typically developed ad-hoc for a specific system; taking into account the physics and response characteristics relevant to that system, the metocean conditions at the site, the amount, type and quality of available metocean data, and the practical computational constraints. Competence in probability theory is critical for development of a sound method. Industry design codes provide little or no guidance on the methods for performing the calculations, but some example applications of response-based analysis techniques have been described in references (see [52], [53] for examples)

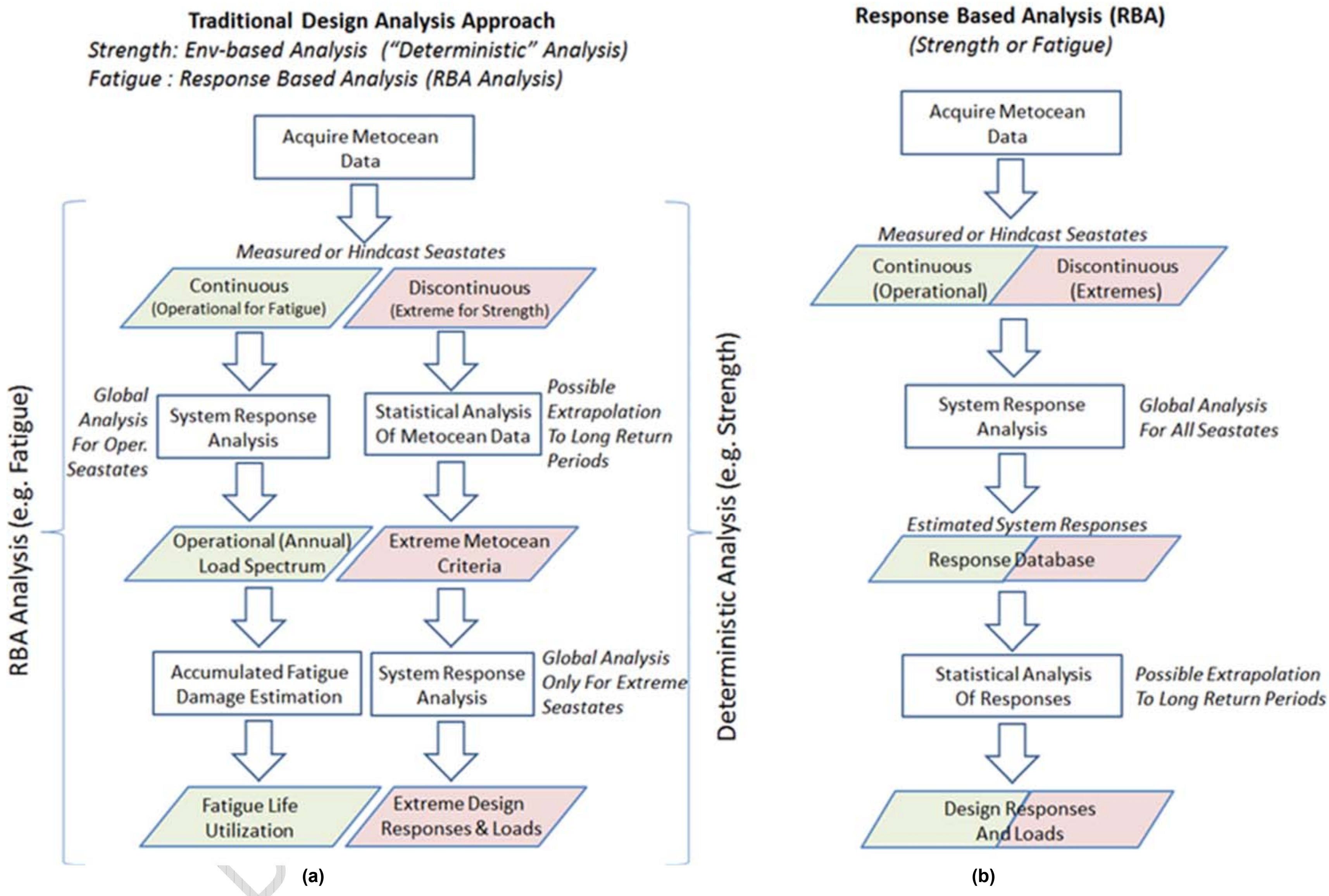



**Figure A.34—Flowcharts for Response-based Analysis**

## A.10 Installation, test load and as-installed survey

### A.10.2 Installation considerations and storm-safe criteria

In cyclonic regions, offshore installation scheduled outside the cyclone season has lower risk; therefore, it should be preferred. If an offshore installation has to be scheduled during the cyclone season, especially the peak of cyclone season, a contingency plan should be developed and implemented to ensure the safety of the installation crew and assets. During the floating platform's mooring line hook-up process, the floating platform is in the most vulnerable phase before the first mooring line in each corner/group is connected to the platform; for a permanent production platform, that phase can be a few days of 24-hour per day operations. The offshore installation faces the greatest risk when a storm is expected to hit the installation site before the completion of connecting the first line in each group of the system. Therefore, the decision tree should be mapped as early as possible after the mooring system design is finalized; based on the available installation vessels' capabilities, on- and off-platform installation aids' strengths, and required factors of safety to guide the installation in terms of when the installation should continue, standby, or reverse the course of hook-up.

A floating platform's storm-safe criteria can vary greatly with project owner/operator's risk tolerance. For example, some operators may consider a floating platform to be storm-safe when it is able to meet the criteria of surviving a 1-year return period storm with maximum tension not exceeding 60 % MBL of line components; while other operators may require the platform to meet different tension criteria in a higher return-period storm. Clearly, the storm-safe criteria will impact not only the mooring system design itself, but also the required on- and off-vessel installation aids; therefore, it should be defined in the project's basis of design.

It should also be realized that the sparing philosophy for the mooring hardware may also impact the time needed to achieve the storm-safe condition. For example, the installation of an asymmetric mooring system, if one mooring line needs a special mooring component (e.g. a segment of wire, rope, or chain) that doesn't have a spare part, the offshore connecting sequence should be arranged to avoid hooking-up that mooring line before the platform achieves storm-safe status. Alternatively, the spare part can be made available for the special mooring component before offshore installation.

#### A.10.2.1 Mooring line handling and installation procedure

For handling of fiber ropes, or wet-storing polyester mooring ropes on the seabed, refer to API 2SM 2$^{nd}$ edition.

#### A.10.2.2 Storm safe condition during mooring installation

As offshore weather can impact installation work significantly, installation weather forecast should be updated at least daily to cover the wind, wave, swell, current that will affect the installation site.

### A.10.3 Test loading requirements

#### A10.3.2 Anchor test load for permanent mooring

When polyester mooring ropes are used in a permanent mooring system, the mooring line's design pretension may decrease over time as the new polyester rope's length increases due to permanent elongation (construction stretch and material creep) under tension. See API 2SM for guideline to load polyester mooring ropes after hook-up to remove part of the construction stretch, thus reducing the frequency to adjust the polyester mooring line's pretension during service.

#### A.10.3.3 Anchor test load for mobile mooring

When new polyester ropes are installed in the mooring lines of a mobile mooring system, the above procedure of applying and holding a test load to remove the rope's construction stretch may not always be necessary because most mobile mooring lines are equipped with line tensioning devices such as a winch, windlass, or chain jacket; which can be easily used to adjust the line tension when the rope's elongation causes a line tension to decrease noticeably. The frequently relocating nature of a mobile mooring system gives the operator enough opportunity to re-tension the polyester mooring lines. However, this increase in polyester rope length (~5% of overall polyester rope length) shall be accounted for in the amount of outboard adjustable MODU line length (e.g., rig wire or rig chain) to prevent connections from approaching the fairlead during retensioning, if required. It is also important to note that polyester ropes that are frequently disconnected and "rested" may require stretching again, as ropes may "relax" under little or no load over time; this is a function of overall time that the rope is under tension and the overall life of the rope.

Test loads should be checked against the tensioning device capacity on the MODU. Procedures for multi-winch cross-tensioning should be developed if test loads exceed the capacity of the tensioning devices.

### A.10.4 As-installed survey and establishment of as-installed capacity

Post installation inspection of permanent mooring systems should be carried out to determine the as-installed length of all mooring lines. The survey should use adequate tools to accurately measure the position of mooring line connectors along each line and touchdown point. This will allow the establishment of a baseline for future assessment of the mooring lines and the detection of any increase in rope length due to creep.

Specific to fibre ropes, the as-Installed survey should report all anomalies identified, such as: seabed contact, sheath damage and repairs, and damages to the polyurethane abrasion layer of the eye splices. Damage reports should include enough information on position and the repair itself to allow comparison with the findings of inspections conducted as a part of the life cycle management of the mooring system. Documentation of any repair, including its location, should be completed.

# ANNEX B
(Normative)

## Regional: Gulf of Mexico MODU Mooring Practice for Hurricane Season

## B.1 General

This annex provides additional requirements, recommendations, and guidance that complement the provisions of this standard, as well as the requirements and recommendations contained in API 2SM and API 2I. The regional guidance in this Annex is the recommended practice in the U.S. waters of the Gulf of Mexico during hurricane season. While this Annex is normative for moored MODUs in the Gulf of Mexico during hurricane season, some of the requirements may be applicable to moored MODUs operating in other regions of the world. This annex is based on Appendix K of the 3rd Edition of API 2SK, which was developed through a cooperative arrangement with an API Subcommittee and the Joint Industry Project entitled "US Gulf of Mexico Mooring Strength Reliability" (MODU JIP).

The information presented herein is premised on the existence of a MODU evacuation plan, the intent of which is to assure timely and safe evacuation of all MODU personnel in anticipation of hurricane conditions.

This annex covers MODU moorings in general, and also applies to MODUs that are "stacked" and not working. MODUs that are not actively working should be moored in accordance with the provisions of this Annex to minimize the likelihood of breaking free and inflicting damage. Alternate methods of stacking MODUs (e.g., setting on bottom for MODUs that can accommodate bottom founding) may be acceptable provided appropriate engineering is performed to assure performance comparable to, or better than, that of moored MODUs.

This annex also supplements the requirements in this standard for Gulf of Mexico MODU mooring design and operating practice during the hurricane season. Topics addressed herein that are part of the overall mooring design and MODU operations include:

— Site- and well-specific data

— Design criteria for the mooring

— Indicative hurricane extreme metocean conditions for Gulf of Mexico

— Mooring analysis

— Site-specific risk assessment and mitigation

— Mooring hardware issues such as anchor system and mooring system upgrade

— Mooring operation issues such as installation, hurricane preparedness, and inspection

— Availability and capability of the on-board tracking system

## B.2 Basic Considerations

### B.2.1 Background

In 2004 and 2005, Hurricanes Ivan, Katrina, and Rita moved through the Gulf of Mexico with extreme winds and waves, causing a number of MODU mooring failures in their paths. Mooring failures have occurred in previous hurricanes, such as Hurricanes Andrew and Lili, but the number of failures was much lower.

The assessment of MODU mooring systems for worldwide operations has frequently been based on API standards. The first API MODU mooring standard (API 2P, published in 1987) specified a design environment lower than the five–ten year return-period required by API 2SK 1st Edition, which was principally driven by the MODU mooring capacities available at that time. Building on the results of a Joint Industry Project focused on MODU mooring code calibration [59], API 2SK 1st Edition incorporated increased MODU mooring design return periods. The criteria in this standard are provided in Table 2, as follows:

- 5-year return period, away from other structures
- 10-year return period, in the vicinity of other structures
- 25-year return period, in close proximity to other structures

There have been significant modifications in the underlying calibration parameters and Gulf of Mexico operations since the 1995 mooring code calibration study, which may influence the applicability to future activities. Differences include:

a) There are more floating and subsea installations and pipelines—This may result in higher risk of property damage or environmental impact, should a MODU break loose or drag its anchors under hurricane conditions.

b) The number of deepwater permanent installations has increased significantly—These are high production rate installations that often share a pipeline to shore. Therefore, the financial consequence for an incident of contact between a drifting MODU dragging its mooring lines and the production infrastructure can be much higher.

### B.2.2 Site- and Well-Specific Information

When planning a MODU mooring operation, the site- and well-specific data should be collected, see B.4.3 for details.

### B.2.3 Exceptional MODU Mooring Operations

It is recognized that a MODU may be required to perform exceptional operations (e.g. to prevent major losses or pollution). Alternately, it may be necessary to relocate a MODU (e.g. to a low-consequence location) with a damaged mooring while it awaits repair. In these cases, a risk assessment should be performed to assess the consequences of not performing the MODU mooring operation and the risks associated with mooring system failure. In these special circumstances, an environmental return period of less than 10 years may be acceptable for the particular (exceptional) operation under consideration.

### B.2.4 Mooring Inspection

Mooring inspection is critical to ensure the integrity of the mooring system and minimize the probability of mooring failure resulting from premature failure of sub-standard components. Guidance for inspection and reuse of MODU mooring components is contained in API 2I, with reference to Annex B .

## B.3 Mooring Analysis

### B.3.1 Mooring Analysis Method

The final mooring analysis, the analysis of record, shall be a dynamic analysis (i.e. includes the effects of line drag and inertia forces, see 7.1.1). Details of the analysis methodology are contained in Section 8.

Wind, wave, and current forces, and vessel motions shall be evaluated using the best available MODU information. Many MODUs have gone through significant modifications, involving additional hull structures and deck equipment, that can change the environmental loads on the vessel. Wind, wave, and current force coefficients and models for hydrodynamic analysis should be adjusted to reflect the changes. The adjustment can be based on new model tests, analysis, or combination thereof.

It is not possible to predict precise wind, wave, and current directions under hurricane conditions; therefore, sufficient environmental directions shall be investigated to capture critical cases for line tensions, anchor load and uplift angle. As a minimum, bow, beam, quarter, down-line, and between-line environmental directions should be analyzed. Analysis for the one-line broken condition should investigate as many cases as necessary to capture the critical cases; including, as a minimum, failure of the most-highly loaded line and adjacent lines. For mooring systems with lines of unequal strength, one-line broken of the most-utilized lines and adjacent lines should also be considered.

### B.3.2 Mooring Strength, Robustness Check and Weak Point Analysis

#### B.3.2.1 General

In addition to the standard safety factor checks specified in Table 2, a mooring robustness or weak-point analysis should be performed. The mooring analysis should include a range of increasing environmental return periods to define limiting environmental conditions for various components of the mooring system (e.g. wire, chain, anchor, connectors, on-vessel hardware, etc). The objective of these analyses is to determine the probable failure mode of the mooring system. Such analyses can provide useful information about the ultimate capacity of the mooring system strength for risk assessment and mitigation strategies; that is, there are no defined acceptance criteria for the mooring analysis results – rather, acceptance is based on the results of a risk assessment.

The mooring analysis should be conducted for both intact and damaged conditions. However, the results of these analyses do not guarantee MODU mooring survival because of other potential failure modes, such as bending over the fairlead, wire fretting, elasto-plastic fatigue damage, and so forth.

For line components such as chain, wire rope, and fiber rope, the capacity of the component is normally taken as the catalog break-strength (CBS), adjusted for the condition of the component; for example, API 2I allows a mooring component to remain in use until its break-strength is reduced to 90 % of its catalog break-strength. In addition, wire rope bending around the fairlead experiences further strength reduction; for example, a D/d (fairlead diameter / wire rope diameter) ratio of 16 may reduce the strength of IWRC wire rope to 90 % of CBS. Strength reduction can also be expected for chains over the fairlead.

#### B.3.2.2 Example of Determining Mooring System Capacity

Following is an example demonstrating how this analysis may be used for risk assessment and mitigation. The mooring is a chain/wire rope combination system with high-efficiency drag anchors. Based on mooring analysis results, plots of FOS versus return period are generated for anchor load and line tension under intact (Figure B.1) and damaged (Figure B.2) conditions. For line tension, the factor of safety is the ratio of the break-strength to the maximum line tension. For anchor load, the factor of safety is the ratio of the anchor holding capacity to the maximum anchor load. These two figures provide the following information.

a) API 2SK's utilization limits are 0.6 (intact line tension), 0.8 (damaged line tension), and 1.25 (MODU intact anchor load for drag anchor) based on dynamic analysis. These utilization limits are satisfied for environmental return periods of 12 years for the intact mooring system and 10 years for the damaged system. Therefore, this mooring system meets the API 2SK line tension safety factor requirements for a 10-year return period hurricane.

b) As an example, consider a wire rope with a reduced break strength of about 80 % CBS (e.g., 10 % strength reduction due to wire condition and 10 % strength reduction due to bending over the fairlead). If there is no faulty component in the windward lines, the intact mooring system may survive a 20–25 year return-period hurricane (see Figure B.1, when line tension FOS = 1.25). However, the anchors of the most loaded lines are expected to move and bury deeper, resulting in redistribution of the load between the highly loaded lines and a reduction in the maximum line tension and anchor load. For hurricane conditions that exceed the 25-year return period, a complete stationkeeping failure – breaking of a number of lines and dragging the anchors of the remaining lines a large distance – is possible if further reduction in mooring line and anchor load cannot be achieved by anchor movement. In this case, with no faulty components, the limiting return period is about 22 years.

c) If anything results in a premature failure (e.g. a faulty component) of a highly loaded mooring line, a complete stationkeeping failure can be expected to occur in about a 10-year return period hurricane, based on Figure B.2. This highlights the importance of keeping the mooring system in good condition through mooring inspection and maintenance. In this case, with a faulty component, the limiting return period is about 10-years.

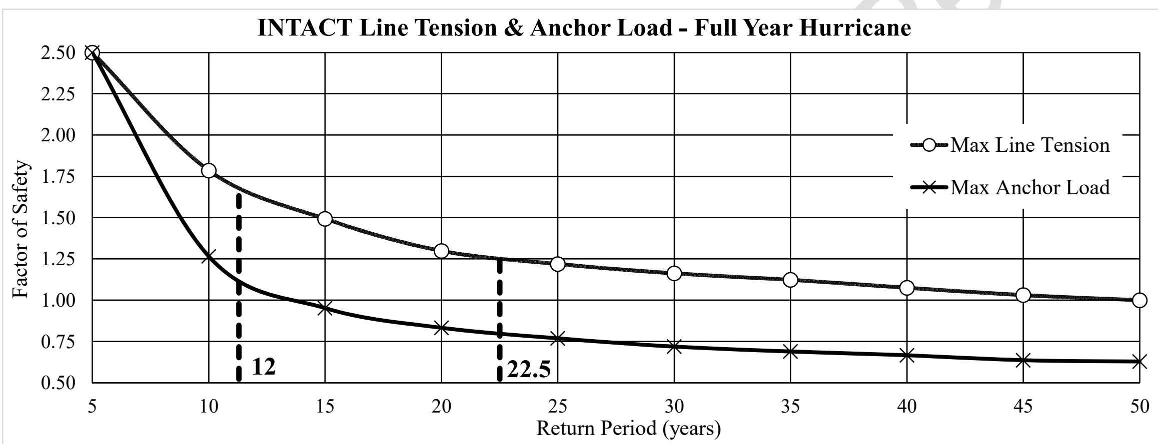



**Figure B.1—Factor of Safety versus Return Period for Intact Condition**

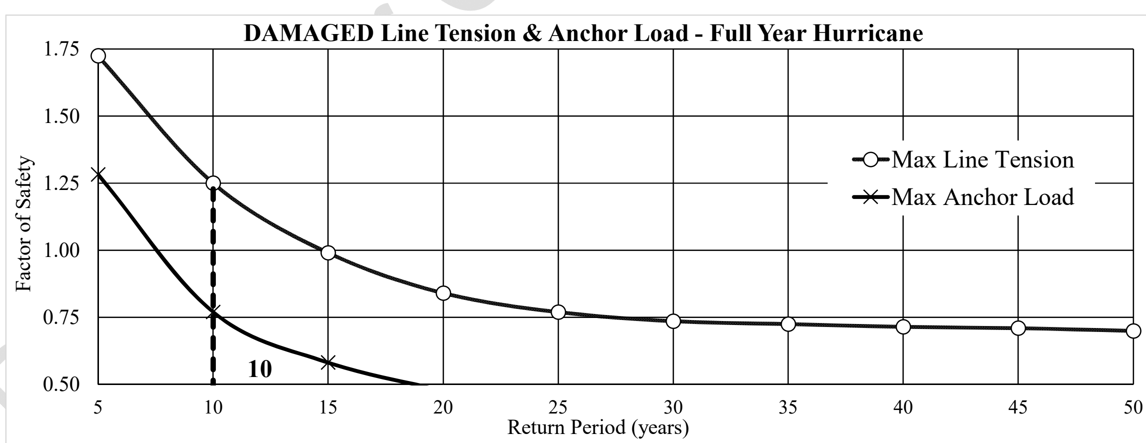



**Figure B.2—Factor of Safety versus Return Period for Damaged Condition**

## B.4 Site Assessment for MODU Mooring

### B.4.1 Existing Criteria

The provisions of this standard provide the basis for mooring analysis for site assessment of MODU moorings.

### B.4.2 Modifications for Site Assessment of Gulf of Mexico MODU Moorings during Hurricane

The 2004 and 2005 Gulf of Mexico hurricanes resulted in a number of total and partial failures of MODU mooring systems; but no failures of permanent mooring systems. As a result of these MODU mooring system failures a risk-based method for site assessment of MODUs operating in the Gulf of Mexico during hurricane season was introduced in API 95F, 1st and 2nd Editions, for use in the 2006 and 2007 hurricane seasons. Subsequently in 2008, the guidance contained in API 95F was modified and added, as Appendix K, to API 2SK 3rd Edition.

The additional criteria in this annex shall be used together with a risk assessment to determine the adequacy of the MODU's mooring system for the planned operation and location. The differences between the MODU site assessment methods recommended in this annex and those in the body of the standard include:

a) Design requirements and recommendations with increased return periods and consequence categories (Section B.6).

b) The metocean conditions used for site assessment of MODUs performing typical or atypical operations shall have a return period of not less than 10 years (Section B.6).

c) For operations within the peak of the hurricane season (as defined in Section B.11), the wind, wave, and current conditions used for site assessment of typical or atypical operations shall not be less than those associated with a threshold Category 1 hurricane. During the pre- and post-peak hurricane seasons, the wind, wave, and current conditions used for site assessment should not be less than those associated with a threshold Category 1 hurricane, unless it can be shown that the overall risk associated with the MODU operations can be significantly reduced with marginally lower metocean criteria.

   NOTE In some cases, mitigation methods (the use of alternative mooring line or anchor types to reduce the consequence of failure) can result in an increase in the probability of system failure (reduction in line or anchor safety factors); in these cases, it can sometimes be shown that despite the increase in probability of mooring system failure, the overall risk of the operation (namely damage to surrounding infrastructure) is substantially reduced.

d) Site and seasonal metocean conditions may be used. Guidance is provided for establishing site and seasonal metocean parameters (Section B.11).

e) For typical MODU operations, guidance is provided for performing a financial risk assessment and decision analysis (Sections B.5, B.6, and B.12).

f) For atypical MODU operations, an appropriate risk assessment is required to evaluate suitability of the operation (Sections B.6 and B.12).

g) Mitigation and prevention strategies for reducing the consequences and likelihood of mooring failure should always be considered when designing the mooring system, as well as planning and scheduling the operation (Sections B.5 through B.10 and B.12).

### B.4.3 Site-specific and Well-specific Mooring Information

The general and local site-specific information to be obtained by the operator should include the following (existing and anticipated during operation):

a) Location Description

   1) Block designation

   2) Location coordinates

   3) Water depth and seafloor bathymetry

   4) Seabed conditions (soil properties) and hazards

   5) Site characteristics (e.g. chemo-synthetics, archeological, etc.)

b) Description of Planned Well Operation

   1) Well-type such as exploratory, development, or workover

   2) Time of year for the planned operations

   3) Expected duration

   4) Confidence in duration and potential overrun

   5) Possible causes of delay

c) Site-specific Metocean Data and Source (See Section B.11)

d) Mooring Installation Hazards

   1) Restrictions to anchor placement and drag

e) Surface and Subsea Infrastructure (See Sections B.6 and B.12)

   1) Distances and directions

   2) Other mooring lines, tendons, etc., within mooring pattern

   3) Mooring lines crossing subsea infrastructure (pipelines, umbilicals, wells, etc.)

The information related to the mooring system that either affects or mitigates the consequences of mooring failure includes:

— Type of anchors: drag embedment, plate, pile, etc.

— Types of mooring components that could damage subsea infrastructure, if dragged.

— Other components used to mitigate the consequences of mooring failure (buoyancy, polyester, etc.)

## B.5 Risk-based Site Assessment for MODU Mooring Operations

### B.5.1 General

The probability and consequences of a MODU losing station shall be assessed. The intent of the risk assessment is to determine the potential consequence of MODU mooring failure to the infrastructure near the drilling operation; and to identify options related to mooring component selection, mooring system design, and mitigation opportunities prior to finalizing the mooring design and installing the mooring system. For the planned MODU operation, the mooring system should be associated with an acceptable risk, either by minimizing potential consequences of a mooring component or system failure (mitigation) or by reducing the probability of a mooring component or system failure (prevention).

### B.5.2 Risk Definition and Consequence-types

Risk is defined as:

Risk = [Probability of an adverse event occurring] x [The consequences associated with that event] (B.1)

The risk can be reduced either by reducing the probability of experiencing an incident (prevention) or by reducing the consequences of that incident if it occurs (mitigation). A fundamental part of reducing the risk associated with MODU operations is to ensure that all parties, including owners, operators, regulators, etc., have a clear understanding of their *risk exposure*.

The different types of consequences that are associated with MODU mooring failures are as follows:

a) Health and Safety

b) Environmental

c) Financial (property and production loss)

d) Corporate Reputation and Image

e) Industry Reputation and Image

f) National Interest

For MODU operations during hurricane season, when the MODU is evacuated and wells and pipelines are shut-in, the health, safety, and environmental consequences associated with a MODU mooring system failing are relatively low. Assessments of consequence-types 4 through 6 will be subject to considerable corporate interpretation, and there will be large variations in risk-tolerance. In the case of industry reputation (e) and national interest (f), the consequences depend on the performance of all MODUs operating in the Gulf of Mexico at any time. The consequences of failure will include public and regulatory perception, which will be influenced by the number of MODUs that fail and the result of those failures on other industry infrastructure in a single hurricane, hurricane season, or few years.

While risk assessments may be performed for all six types of consequences, the one primarily addressed in this annex is financial (c). Other types of risk, namely health and safety and environmental, should be evaluated as required for the operation at hand. For example, if there is a significant risk for an environmental release of hydrocarbons from a drifting MODU colliding with a facility that stores hydrocarbons or dragging an anchor over a pipeline resulting in a release; then such possible environmental hazards should be considered in the assessment process. Additional information on the other types can be found in Section B.12.

### B.5.3 Overview of Risk Assessment

The probability of MODU mooring system failure decreases with increases in the design return period (the return period for which the mooring system satisfies all of the requirements of Sections 7 and 8). Generally, the management of risk to surrounding infrastructure requires that the design return period increases, or that additional mitigation measures be put into place as the consequence of failure increases; but the required return period is independent of the duration of the operation and the season of operation (see example below). However, for a given return period, the intensity of the environmental conditions (wind, wave, and current) is dependent on the particular site and season(s) of operations.

The consequences (to infrastructure) of a MODU mooring failure depend on the density and type of subsea and surface infrastructure that surrounds the location of interest, and to some extent on the type of MODU mooring system (e.g. the consequences of dragging chain over the seabed will be different from those due to dragged polyester). The risk assessment procedures described in this annex address the consequences of damage to surrounding infrastructure. For MODU operations during hurricane season, where the MODU is evacuated, it is the responsibility of the drilling contractor and operator to manage the risk associated with damage to the MODU and its mooring system, and to the operator's drilling program.

The potential consequences to infrastructure from a stationkeeping failure depend on:

a) financial consequence values (including both the cost of replacement and lost production)

b) distances and directions between individual components of infrastructure and the MODU's location

c) mitigation strategies

d) different likelihoods of adverse consequences given a mooring failure

EXAMPLE The following scenario serves to illustrate that the return period is independent of duration; an operator has two wells that need to be drilled near an existing facility with identical consequences; each well will take one month to complete, and they will be drilled consecutively; if two independent Applications for Permit to Drill (APDs) are submitted, each for a drilling program of one month operation, then the design return period for each well should be the same as for a single APD for a MODU operating on the same location for a duration of two months; clearly, different return periods for two one-month APDs compared to a single two-month APD is not a logical solution – the exposure risk for the facility is the same in both cases, so the design return periods should be the same; in effect, the daily risk to the infrastructure should be consistent, so the duration of an operation should not influence the design return period for MODU operations.

Figure B.3 shows the general methodology for carrying out a risk assessment for MODU operations when considering the potential consequences of mooring failure to the surrounding infrastructure.

Recommended assessment criteria and procedures are provided in Section B.6. Additional discussion on details of risk assessment methods is provided in Section B.12.

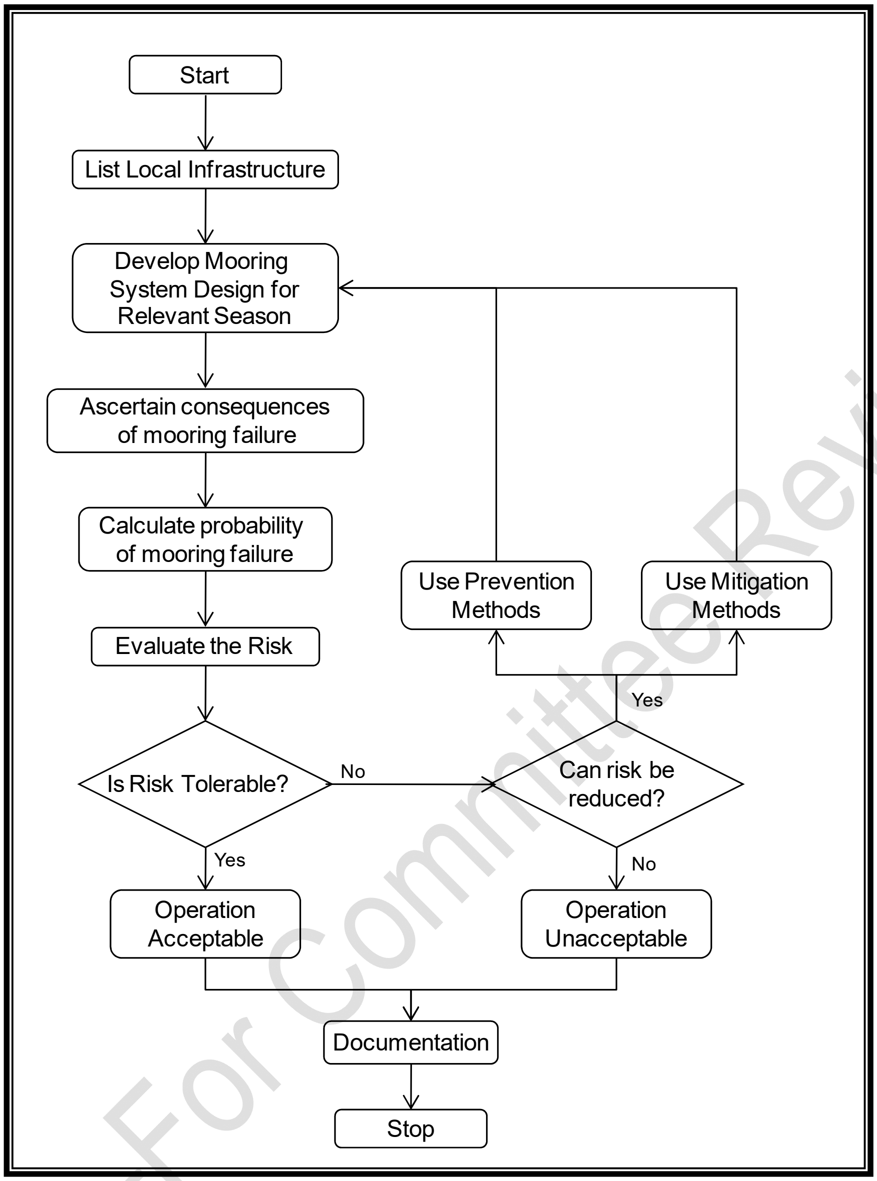



**Figure B.3—Financial Risk Assessment – Overall Process**

## B.6 Assessment Criteria and Procedures

### B.6.1 General

There are two risk categories that depend on the MODU's location:

a) Low Risk, C1: MODU is not moored within 15 nm of any infrastructure or environmentally sensitive area, and

b) Higher Risk, C2 to C4: MODU is moored less than 15 nm of infrastructure or environmentally sensitive area.

For MODU operations in the low risk category (C1), no risk assessment is required and the mooring system should be designed for at least a 10-year return period.

For MODU operations in the higher risk categories (C2 to C4), a risk assessment shall be conducted for all locations with the return period selected as justified by its outcome; however, in no circumstance shall the return period be less than 10 years. The higher risk category includes the exceptional operations as discussed in B.6.2 and atypical as discussed in B.6.3.

For higher risk MODU operations, there are four consequence categories that depend on the MODU operations. These are shown in Table B.1, as along with the associated return periods for each; C4 includes atypical operations, as discussed in B.6.4.

**Table B.1—Unmitigated Consequence Categories for MODU Operations and Associated Return Periods (updated based on [60])**

| Close Proximity Class | BOE/d < 25k | BOE/d 25–75k | BOE/d > 75k |
|---|---|---|---|
| **C1**<br>MODU is in open water or more than 15 nm from surface structures and subsea structures / pipelines | 10-yr Hurricane | 10-yr Hurricane | 10-yr Hurricane |
| **C2**<br>MODU is 5–15 nm from another facility or more than 1 mooring diameter from pipelines | 10-yr Hurricane | 25-yr Hurricane or determined by RA | 25-yr Hurricane or determined by RA |
| **C3**<br>MODU is within either 5 nm to another facility or 1 mooring diameter of pipelines but its mooring lines do not cross pipeline | 10-yr Hurricane | 25-yr Hurricane or determined by RA | Return period determined by RA and not less than 25-yr |
| **C4**<br>MODU is within 1 mooring diameter to another facility or its mooring lines do cross pipeline | Return period determined by RA and not less than 25-yr | Return period determined by RA and not less than 25-yr | Return period determined by RA and not less than 25-yr |

An "active pipeline" is defined as any pipeline located within the OCS that currently has throughput. Pipelines that are abandoned or out-of-service are not active. However, an active pipeline could be temporarily shut-in. Actual throughput should be based on all active pipelines in a corridor. When selecting the initial consequence category, consideration should be given to the number of active pipelines and total throughput.

NOTE Details of active oil and gas pipelines in the Gulf of Mexico may be found online at websites of regulatory agency.

A risk assessment is used to establish the acceptability of risk and design return period. A risk assessment shall consider each of the following elements:

a) Infrastructure and Design Return Period Evaluation: In determining the design return period, the actual infrastructure proximity from a given moored MODU operation is the key design parameter. A detailed evaluation of nearby infrastructure and potential damage to it shall be conducted for all MODU operations. This evaluation includes assessing the MODU mooring system performance and the weak-point analysis in accordance with B.3.2.

b) Operational Planning and Evaluation: Additional issues that affect mooring system reliability and risk exposure should be evaluated. During peak hurricane season, lower risk locations should be given priority in operational planning. If the risk levels during peak hurricane season are not tolerable, adequate contingency plans shall be in place for operations that are planned to end before peak hurricane season.

c) Mitigation Evaluation: As part of the risk evaluation, possible actions should be evaluated that can reduce the potential for mooring failure and consequence of failure. The design criteria in this standard are not intended to preclude reasonable and practical actions that can result in improved mooring systems.

Sections B.5, B.6.2, and B.12 provide more information and guidance for evaluating site-specific consequences associated with MODU mooring failure and for assessing the risk of MODU operations.

### B.6.2 Risk Assessment Procedure for Typical MODU Operations

The purpose of a risk assessment is to facilitate planning and follow-up operations that reduce, as much as practically possible, the risk exposure from MODU mooring systems, as discussed previously. The risk assessment can be conducted utilizing the relevant subject matter experts (SMEs) necessary to perform such a risk assessment or using risk program models explicitly developed for such purposes [60] . When a risk program is used, the results shall be reviewed by SMEs to confirm its validity.

For MODU operations in the higher risk categories (C2 to C4), a risk assessment is required; C2 and C3 can be termed as “typical” MODU operations, while C4 is referred to as “atypical” (see B.6.3).

The risk assessment process contains a series of steps to formally assess the risk at any given location. Consideration should be given to the time required to complete this process. The steps can be summarized as:

— Definition of location and well parameters

— Identification of local and distant infrastructure

— Undertaking a hazard identification (HAZID) study

— Determination of probability of mooring failure (mooring system reliability analysis, anchor holding capacity uncertainty, etc.)

— Quantification of the consequences of failure (e.g., through event tree analysis)

— Risk mitigation

— Documentation

Further information on risk assessment methods is provided in B.12.

NOTE The risk assessment entails a documented and structured identification of options available and their impact, and leads to the selection of the lowest consequence mooring system available while also serving as a valuable tool in designing the mooring system.

A risk assessment should, as a minimum, qualitatively assess and fully document the following:

a) Potential mooring failure modes (see B.12.2),

b) Probability of mooring failure (see B.12.7),

c) Nearby infrastructure and the potential for damage with various types of failure and consequences of damage,

d) Operation plans and impact on analysis' assumptions,

e) Mechanical integrity of systems, and

f) Possible mitigation actions to improve reliability and reduce potential consequences of failure.

A risk assessment may be based on a methodology that determines a mitigated consequence score, which provides a relative basis to allow stakeholders to assess, on a relative basis, the consequences of MODU mooring failure associated with the proposed operations. The intent of this approach is to be more conservative by comparison to a more detailed risk assessment. However, the basic consequence assessment can be completed with the routinely available information, and data that should be available to the operator and drilling contractor.

The consequence assessment should be based on:

1. Consequence values based on location (infrastructure that could be damaged in the event of a mooring failure), and
2. Consequence factors based on mooring components and system details.

Guidance on acceptance criteria for risk assessments (i.e. acceptable return period) is provided in Section B.12.

### B.6.3 Atypical MODU Operations

There may be atypical MODU operations, associated with exceptionally high consequences, that may require very high environmental return periods. MODU operations that may be associated with exceptionally high consequences include, but are not limited to:

— MODU offset drilling,

— Tender-assisted drilling adjacent to a permanent facility, and/or

— MODU operations within a mooring radius of a permanent surface facility.

These operations are categorized under the highest close-proximity class (C4), as defined in B.6.1, and are subject to a risk assessment to determine if the operation is acceptable.

## B.7 Mooring System Improvement

### B.7.1 General

There are various options to improve the survivability of the mooring system and reduce the consequences of a mooring failure under hurricane conditions, such as the use of higher strength components, additional mooring lines, and steel or fiber rope inserts. These options have design and hardware issues that require special attention, as discussed herein.

### B.7.2 Higher Strength Components and Additional Lines

Replacement of existing chain and wire ropes with higher strength components may be considered.

Additional lines may also be placed on a MODU to increase mooring system strength. The additional lines may be terminated in a few ways, such as:

a) Standard fairlead and tensioning equipment with full-tensioning capability,

b) Alternate fairlead and tensioning equipment with limited-tensioning capability, and/or

c) Fixed terminations with no tensioning capability.

NOTE The following items may be affected by the additional lines or the lines with stronger components:

- required anchor holding capacity,
- required stall- and brake-load capacity of winch/windlass,
- global structural strength of the vessel,
- local structural strength of the tensioning equipment frame and foundation,
- local structural strength of the fairlead foundation and support structure,
- vessel variable deck load and loading conditions,
- vessel stability if new down-flooding points are introduced by the mooring modifications, and/or
- available space.

### B.7.3 Fiber Rope Insert

Fiber rope (polyester or HMPE) sections may be inserted in the existing mooring line to improve mooring performance and mitigate the potential for damage due to lines dropped on or dragged over subsea equipment. The selection and design of such systems shall be based on mooring analysis using an appropriate fiber rope stiffness model. The rope should be protected by soil-blocking devices (such as a filter or jacketing) since contact with seafloor is possible under hurricane conditions due to large offsets, anchor drag, or line failure.

### B.7.4 Fiber Rope and Steel Wire Rope Interaction – Strength and Fatigue Considerations

#### B.7.4.1 General

The torque relationship between fiber and steel mooring components requires special consideration to ensure the mooring system performance is not compromised.

#### B.7.4.2 Strength Considerations

For MODU mooring systems, the conclusion of [61] indicates that neither the strength of a fiber rope nor the strength of a 6- or 8-strand wire would be degraded by any noticeable amount when they are connected in the same line for the duration of a severe hurricane when a torque isolation device/design is employed.

#### B.7.4.3 Fatigue Considerations

Typically, no fatigue design analysis is required for a MODU mooring system. However, laboratory testing demonstrates that a 6- or 8-strand wire rope's fatigue performance, when connected with a torque-neutral fiber rope, could be significantly degraded [62]; although the scale effect of such testing is yet to be quantified. Industry experience indicates that there are at least two viable design approaches to address this issue.

a) Torque-matched approach

A steel wire rope's fatigue life is best preserved by connecting to a torque-matched rope. A rope is considered torque-matched if its torsional characteristics over the design load range are essentially the same as that of the connected wire rope. Due to the inherent difference in material properties, a fiber rope typically can only match a wire rope's torsional characteristics at a pre-determined tension level. The difference between the torque of the fiber rope and wire rope increases as the line tension deviates from the match point with changing environmental loading or heading. Other factors that will impact the torque-matched design include torque characteristics, lay direction, presence of swivels in the mooring lines, swivel lock-up load, and the presence and length of chain segments.

b) Non-torque-matched approach

Available torque-neutral fiber ropes can be used for short-term MODU mooring systems if the dynamic torsion of the steel wire could be restrained at the interface between the fiber rope and wire rope [61]; a properly designed submersible buoy could provide such restraint. Available experience shows that wire fatigue damage in such a system is lower than some of the earlier scaled test data suggests [61].

The fatigue damage to wire rope tends to be concentrated near the interface with the fiber rope. The wire rope can be returned to service after the damaged end is re-terminated during a MODU move. It is also possible to insert a short connecting wire rope (200-300 ft) between the MODU mooring wire and the fiber rope to minimize the need for re-socketing wire ropes in the field.

## B.8 Anchor System Considerations

### B.8.1 General

The anchor system plays an important role in hurricane survivability of the mooring system and the consequence of mooring failure. Consideration should be given to alternative anchor types, where necessary, to achieve adequate performance and mitigate consequences of failure. Anchor handling vessel and MODU winch system capabilities should also be considered in selecting the best anchor option.

Drag anchors are commonly used for catenary moorings, while fixed anchors such as suction piles or normally loaded plate anchors (including drag or direct embedded plate anchors) are often used for taut or semi-taut moorings. Drag anchors of the heavily loaded lines may move a short distance (tens to hundreds of feet), causing redistribution of the mooring load among the mooring lines. This redistribution of load may help the mooring system survive. However, for locations where pipelines, subsea trees, manifolds or other subsea infrastructure exist, excessive anchor movement can cause damage to these infrastructure elements.

The use of fixed anchors may increase the likelihood of mooring line failure under similar conditions because redistribution of mooring load cannot be achieved.

For all types of anchors, behavior and performance under severe loading shall be understood to assess and mitigate the risk of moored MODU operations.

### B.8.2 Anchor Holding Capacity, Safety Factors, and Installation Requirements

Anchor installation requirements should be included in anchor type selection consideration, especially when the anchor is to be installed near sea floor infrastructure and where an adequate safety zone should be maintained around the infrastructure during anchor handling. Anchor selection and safety factors should consider capacity, availability, and potential to minimize damage to subsea infrastructure if an anchor failure occurs in conditions such as, but not limited to:

— A marine installation, such as a pipeline that lies in the dragging path of an anchor or in the potential dragging path (i.e., a location such that mooring system failure), could result in an anchor dragging across the installation.

— A mooring line that can cross another mooring line.

— Density or importance of seafloor or water column infrastructure that merits a higher safety factor than specified in Section 8.

Unless site-specific soil data are available, appropriate upper and lower bound soil conditions for the general area of operation shall be used. Any evaluation of anchor holding capacity should take into consideration the uncertainties of the local soil-strength profile and other geotechnical properties.

## B.8.3 Drag Anchor

### B.8.3.1 General

Drag anchors should have a proven performance or be similar to an anchor with proven performance. Performance may be proven through scale-testing, field tests, etc. Drag anchors should be in an undamaged condition to preserve symmetry and holding capacity.

When drag anchors are used for a MODU mooring operation, they should be test loaded (see Section 10) to ensure the anchor is right-side up and sufficient embedment is achieved to produce predictable behavior.

### B.8.3.2 Windward Line Loading

Due to equipment limitations for MODU operations, a drag anchor is typically subjected to a test load below the maximum storm load. When the anchor experiences a load higher than the test load and the uplift angle is within the anchor's design tolerance, a properly set anchor will typically penetrate deeper, developing higher holding capacity. When the storm load exceeds the anchor holding capacity and uplift angles are within the anchor's design tolerance, the anchor will stop penetrating and move horizontally below the seafloor. In this process the mooring line either breaks due to overloading or remains intact due to mooring load redistribution or storm passage. If the uplift angle exceeds the anchor's design tolerance, the anchor may lose penetration and may be dragged to the surface.

NOTE In the 2004 and 2005 hurricane seasons, anchor drag distances for the windward lines were typically less than one mile; however, on some occasions windward anchors dragged over 20 miles off location.

### B.8.3.3 Out-of-plane Loading

When several windward lines fail, resulting in large directional changes of the remaining lines, out of plane loading at the anchor shackle may occur. Although anchor behavior under this loading condition is still a subject of research, there is evidence suggesting that drag anchors will rotate to a new orientation and maintain their holding capacities after greater than normal drag distances. Under this loading condition, a pipeline or subsea equipment that was not originally in the dragging path of an anchor may become in the dragging path due to change of line direction. Consequently, the site-specific assessment should account for the possibility of anchors dragging in directions other than towards the center of the mooring pattern.

When windward lines fail, some drag anchors on the leeward lines may be subject to reverse loading. These anchors may be pulled out and dragged some distance. Some drag anchors may re-embed, limiting the drag distance.

NOTE Industry experience in the 2004 and 2005 hurricane seasons shows that most of the leeward and side anchors stayed in the vicinity of their original locations.

### B.8.3.4 Oversized Anchor

When drag anchors are oversized for a MODU operation to protect the surrounding structures, they should be test loaded to ensure the anchor is right side up and sufficient embedment is achieved. If the anchors are conventionally set, the MODU shall have sufficient winch capacity to apply the required test load.

## B.8.4 Plate Anchor

### B.8.4.1 General

A thorough understanding of the behavior and failure modes of drag embedded and direct embedded plate anchors for MODU operations is necessary to determine suitability of the anchor for the intended operation.

#### B.8.4.2 Fluke Angle Setting

Drag embedment plate anchors may have several options for fluke angle setting: embedment, near normal, and normal. In the embedment or near-normal fluke angle setting, the plate anchor behaves as a drag embedment anchor. The smaller embedment fluke angle is generally used to obtain initial anchor penetration; changing to the larger near-normal fluke angle allows even deeper penetration. In the near normal setting, the anchor may behave as a plate anchor under design loading conditions; but under overload conditions (without changing mooring line loading direction) the anchor can drag, penetrate deeper, and reach a new equilibrium depth with a higher holding capacity. In the normal setting, the anchor ultimately behaves as a fixed plate anchor and overloading will either result in failure of the mooring line or cause the anchor to be pulled out. Selection of these options should be based on evaluation of the specific MODU operation.

Some direct-embedment plate anchors have also demonstrated diving behavior. Diving behavior is a result of an eccentricity between the line of action of the mooring line and the center of soil pressure on the fluke. In an overload condition, plate anchor movement through the soil will cause the fluke to tilt with respect to the mooring line direction developing an effective near-normal shank or fluke angle.

#### B.8.4.3 Triggering the Anchor and Ultimate Holding Capacity

Drag embedment plate anchors typically have two operating modes: (1) an installation mode and a normal or (2) near-normal loading mode. In the installation mode, depending on the consistency of the soil, the load is applied at an angle of 40°–60° to the fluke. After failing a shear pin or triggering the anchor, the load becomes perpendicular (normal) or nearly perpendicular (near normal) to the fluke.

Design holding capacity should be based on rigorous anchor design and installation analysis for a defined set of upper and lower bound soil conditions and installation procedures. Once a normally loaded anchor is triggered, the holding capacity will always be greater than the installation load with relatively small anchor movement. The actual holding capacity will depend on anchor and mooring line dimensions, the sensitivity of the soil, and the change in load-direction. Guidance on installation analysis can be found in [63].

#### B.8.4.4 Out-of-plane and Reverse-loading

Some drag embedment plate anchors for MODU moorings are designed to be retrieved by loading in the reverse direction to operate a release mechanism, permitting low-load recovery by the mooring line. These plate anchors cannot resist reverse-loading, and therefore may also have limited resistance to out-of-plane loading. However, where the risk of damaging pipelines and subsea equipment by anchors needs to be minimized, the reverse retrieval device can be disabled temporarily to provide reverse-loading capability during the hurricane season; with recovery being achieved by means of a drogue tail or submerged buoy attached to the rear of anchor fluke. These anchors may be set from the MODU or preset.

Plate anchors with a normal-loading fluke angle setting that have the retrieval device temporarily disabled or do not incorporate a reverse retrieval device, will therefore have the capability to resist out-of-plane and reverse-loading.

Care should be taken when using drag embedment and direct embedment plate anchors designed with near-normal features; they may lose capacity if rotated approximately 90° in the vertical plane after windward line failure and leeward line direction change as the MODU drifts off location over a leeward anchor.

### B.8.5 Suction Pile

Suction piles have been observed to fail at the padeye due to a combination of tension and excessive out-of-plane bending. The out-of-plane bending occurs due to large vessel offset after first and subsequent line failures. Consideration should be given in the padeye design by applying the breaking load of the mooring line at any angle.

### B.8.6 Soil Conditions

Unless site-specific soil data are available, appropriate upper and lower bound soil conditions for the general area of operation can be considered. However, caution should be exercised at locations where unusual soil conditions beyond the notional bounds may be encountered – e.g., under-consolidated or weak soil, shallow cementation, sand layers and over-consolidated or hard soil. Unusual soil conditions may be identified at specific locations by interpretation of 3-D seismic data, usually analyzed for exploration drilling – see 30 CFR Part 250, Subchapter B [68]. Features that may be interpreted from 3-D seismic data that provide evidence for unusual soil conditions include (but are not limited to):

- Shallow gas
- Erosion features, such as canyons and furrows
- Shallow mass transport deposits
- Seafloor expulsion features
- Seafloor faults

Continental shelf areas, where interpretation of 3-D seismic data for shallow geologic features is extremely limited, may warrant dedicated site-surveys and soil sampling where data for the general area of operation are sparse.

## B.9 Hurricane Preparedness

### B.9.1 Hurricane Preparedness Plan

The overall hurricane preparedness plan should include suitable provisions for other activities, such as personnel evacuation and suspension of drilling activities. The hurricane preparedness plan shall be a written plan and should address as appropriate the following mooring specific items:

a) Ballasting operations
b) Repositioning the vessel to a more favorable storm safe position within the already set anchor positions
c) Mooring line payout and/or tension adjustments to optimize the mooring's storm survivability
d) Engaging storm survival brakes and stoppers or securing and dogging winches
e) Optimum mooring pattern and positions to maximize mooring performance
f) Provision of sufficient battery power, computer disc storage, and so forth, to ensure that critical systems, including MODU trackers, remain operational from the time the crew disembarks until reboarding
g) Confirmation that towing bridles or lines, navigation aids, and position-tracking devices are installed and functional

The hurricane preparedness plan should also include a schedule that reflects the time required to complete necessary mooring activities, operations to secure the well and the MODU, evacuate the crew to a safe location, and allow for some contingency-time.

All units should be prepared to the extent feasible for towing. Each MODU should be equipped with a primary and secondary tow line or bridle.

Contingency plans shall address operations identified as critical to both hurricane survival and resumption of normal activities. The contingency plans shall address the need to have suitable personnel available to respond to the current problem. For example, if a mooring winch is inoperable and cannot be repaired, then it is necessary to have a mooring analyst determine suitable payouts and pretensions on the remaining lines to maximize survivability.

### B.9.2 Loop and Eddy Currents

When a MODU is in a loop or eddy current before a forecasted hurricane, the drilling contractor or operator shall determine the mooring line adjustments required to abandon the MODU in a condition that provides its best chance of riding out the storm and loop/eddy event, considering the anticipated surface current velocity and direction.

The drilling contractor or operator should obtain the following information:

a) Existing line payouts and tensions

b) Stall capacity of the winches

c) Latest measurements of the currents, particularly velocity and direction at the sea surface

d) Forecasts of the loop/eddy current velocity and direction

The drilling contractor or operator should determine the optimum line payouts and pretensions that serve to maximize intact mooring line safety factors without exceeding equipment limits or endangering human life. The environmental conditions used for analysis should include the following weather combinations:

a) Omni-directional hurricane metocean criteria,

b) Hurricane-driven surface currents vectorially added to the local loop or eddy current,

c) The payouts and pretensions updated as surface current velocities or headings change.

### B.9.3 MODU Trackers

Satellite location transponders should be installed and tested onboard all moored MODUs operating in the Gulf of Mexico. These transponder systems should be function tested prior to hurricane season to ensure it is functioning properly. Sufficient care should be given to ensure these systems have adequate battery back-up to enable the transponders to function after the MODU has been abandoned for a minimum period of seven days. Sufficient battery life should allow for reasonable assurance that the system will be operational through a given cyclonic storm-event, and for a time-period after potential passage of the storm, to allow for speedy recovery operations in the event of mooring failure. The tracker system should be fully operational with seven-day capacity within 48 hours of reboarding the MODU.

Redundancy in systems should be considered.

## B.10 Mooring Installation

### B.10.1 Mooring Installation Plan

In addition to the information in Section 10, the following also applies to the mooring installation.

a) An installation plan should be prepared for the mooring system for a specific site, which specifies a number of items related to the mooring design:

    1) MODU heading

    2) Mooring line headings, including installation tolerance

    3) Anchor locations, including installation tolerance

    4) Line segment lengths and composition

    5) Pretensions

    6) Anchor test loads

b) The installation plan should also include information on:

   1) Minimum anchor handling vessel (AHV) specification (bollard pull, winch capacity and pull, and any other equipment requirements)

   2) Maximum sea states for safe operations

   3) Weather window requirements (i.e. duration of installation activities)

   4) Weather forecast requirements

   5) Contingency plan and management of changes to the plan

### B.10.2 As-Installed Information

Once the installation is completed, it is the operator's responsibility to ensure that the information on the as-installed mooring system is recorded and transmitted (as applicable) in a timely fashion. This information should be provided to all relevant parties (including the drilling contractor) for post installation verification, operating the mooring system, and planning for evacuation; completion of the forms in Section B.13 may facilitate recording most of this information. This information can be used to verify that the mooring system is installed within design tolerances and that any deviations from the design tolerances will not have a negative impact on mooring system performance

As a minimum, the as-installed information shall include the following:

a) Global Geometry

   1) MODU heading and global position

   2) Individual line headings

   3) Initial and final anchor locations

b) Mooring Composition

   1) Length, general condition, composition and location of all mooring line sections

   2) Number, location, general condition, and type of connectors (e.g., shackles, connecting links, subsea connectors, etc.)

   3) Anchor type, size, general condition, serial number, and fluke angle, as applicable

c) Anchor Test Load

   1) Test load at fairlead

   2) Estimated test load at anchor shackle

   3) Estimated anchor drag distance

d) Mooring Pretension – Pretension or line angle at fairlead, and estimation of accuracy

### B.10.3 Post-installation Verification

Based on the information specified in sections 10.1 and 10.2, the operator and drilling contractor shall verify that the as-installed mooring system meets the original safety factor requirements. If the as-installed mooring system does not meet the design safety factor requirements, appropriate plans should be developed and implemented in a timely fashion that will provide acceptable mooring safety factors.

## B.11 Hurricane Criteria for Gulf of Mexico

### B.11.1 Selection of Metocean Criteria

Guidance on development of metocean extremes are contained in API 2MET and Annex H of API 2MET 2nd Edition contains hurricane criteria for the Gulf of Mexico.

The consequences to surrounding infrastructure of mooring system failure determine the required minimum design return period. The flowchart shown in Figure B.4 describes a method for selection of metocean criteria. API 2MET provides default metocean criteria that are intended to be conservative for the Gulf of Mexico and may be used instead of site-specific criteria.

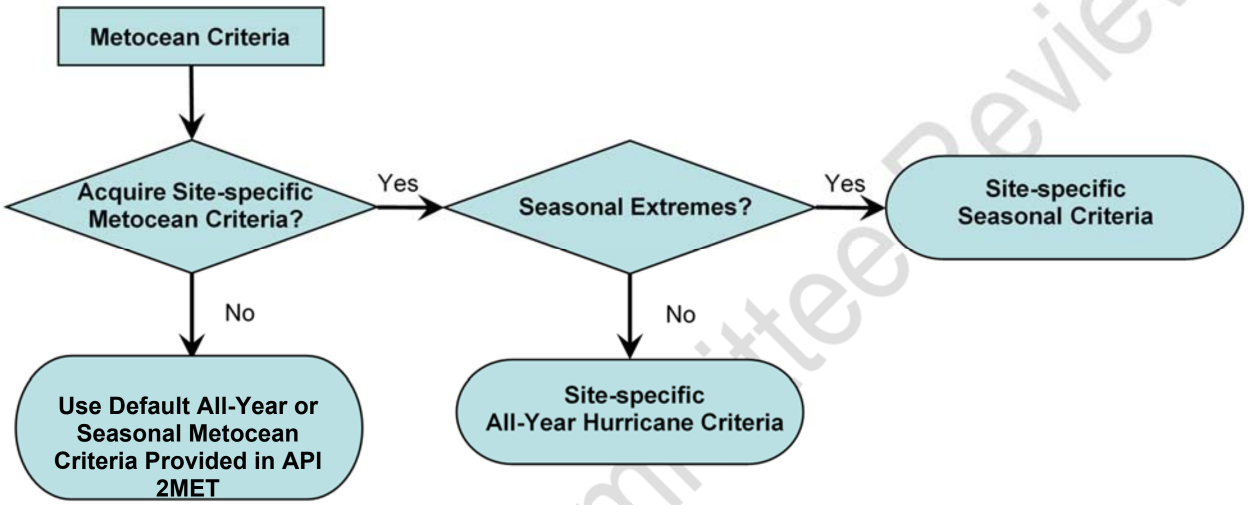



**Figure B.4—Metocean Criteria Flowchart**

For operations during peak hurricane season, the wind, wave, and current conditions used for site assessment of typical or atypical operations shall not be less than those associated with a threshold Category 1 hurricane. This restriction may be eased during the pre- and post-peak seasons, subject to the constraints listed in B.4.2. This minimum Category 1 hurricane condition is not required if the metocean conditions associated with the required return period are more severe.

### B.11.2 Background to Deepwater Gulf of Mexico Hurricane Conditions

Hurricane season in the North Atlantic Basin officially runs from June 1st through November 30th, with the most severe storm activity generally occurring in August, September, and October. The storms which occur during these months effectively control the annual (all-year) hurricane extremes; extremes derived just considering storms which occur during these months will be essentially identical to extremes derived using the full population of storms, regardless of month. Generally, the severe months are preceded by a period of moderate cyclone activity during June and July, and then followed by a period of rapidly decreasing cyclone activity from the end of October through November. While rare, tropical storms have formed or entered in the Gulf of Mexico in both May and December, outside the official hurricane season.

The regional conditions presented in API 2MET have been derived for peak hurricane season (August 14 through October 7) as well as pre-peak (June 1 through August 1) and post-peak (October 21 through November 30) exposure periods. If a facility operates in a manner that restricts its exposure to hurricanes in the Gulf of Mexico (or one of the regions in the Gulf of Mexico) to periods less than one year (i.e. a seasonal operation), it would be reasonable to consider the facility subject to hurricane conditions derived from a limited exposure period.

For MODU operations planned to take place in the pre-peak (ending before August 1st) or post-peak (starting after October 21st) the following should be considered.

a) Planning for operations in the pre-peak hurricane season: the possibility of delayed completion due to late arrival of equipment at the beginning of the operation, delays due to loop current intrusions, and delays due to tropical storm occurrences. Wind, waves, and current corresponding to the latest likely completion date should be used in planning.

b) Planning for operations in the post-peak hurricane season: the possibility of an early start due to early availability of equipment. Wind, waves, and current corresponding to the earliest likely start date should be used in planning, or the operator should be prepared to delay the start until it is clear that no hurricane will approach the Gulf in the next few weeks.

### B.11.3 Summary of API 2MET Hurricane Criteria for Deepwater MODU Site Assessment

API 2MET provides hurricane criteria for three regions with transition zones between the regions. The three regions are defined below:

— Western Gulf, between 92° W and 98° W;

— Central Gulf, between 85° W and 92° W;

— Eastern Gulf, between 82° W and 85° W.

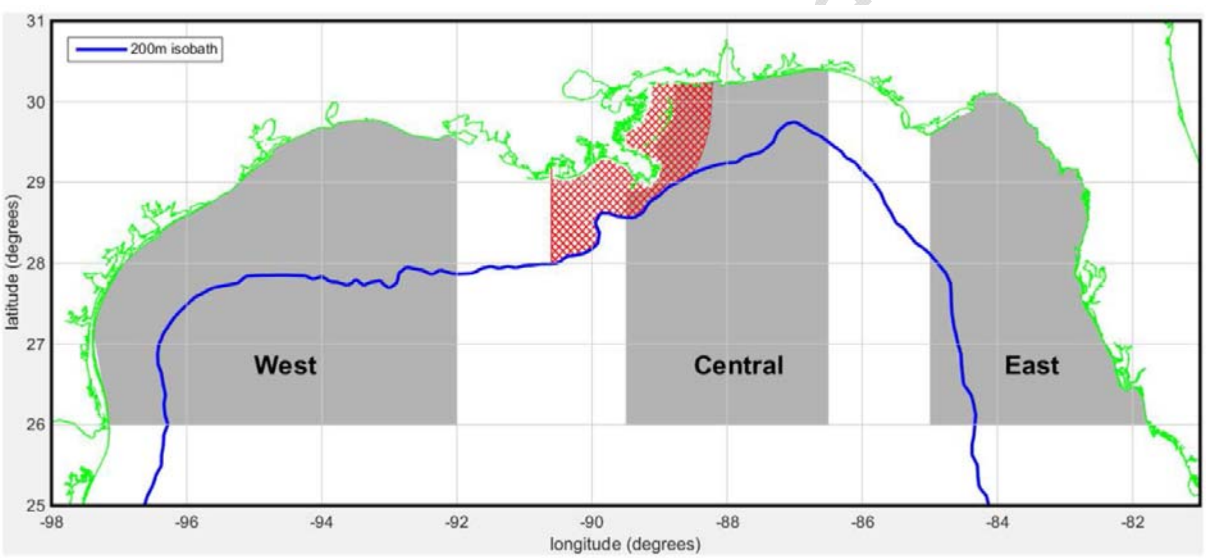



**Figure B.5—Three Gulf of Mexico Regions [API 2MET, 2nd Edition, Figure H.8]**

Between each region are areas of transition (unshaded); criteria for these transition areas should be derived by linearly interpolating between the values of the two adjacent regions across the width of the transition (see API 2MET).

In addition, Annex H of API 2MET 2nd Edition divides the hurricane season into three parts:

— Pre-Peak hurricane season from June 1st to August 1st

— Peak hurricane season from August 14th to October 7th

— Post-Peak hurricane season from October 21st to November 30th

NOTE Two-week transition periods separate the pre-peak, peak, and post-peak parts.

### B.11.4 Minimum Category 1 Hurricane Wind, Wave, and Current Conditions

Site- and seasonal-specific metocean criteria may be used in developing the wave and current conditions associated with a minimum Category 1 hurricane – that is, the wave and current conditions that occur for the same return period as the 64 knot 1-minute wind speed may be determined based on site- and seasonal-specific hurricane criteria. Alternatively, the wind, wave, and current conditions specified in Table B.2 below may be used.

**Table B.2—Minimum Category 1 Hurricane Conditions**

| | | | |
|---|---|---|---|
| ***Wind*** | | | |
| 1-hour mean at 10 m, $V_{1\text{-hr}}$ | 28.0 m/s | 54.5 kts | 91.9 ft/s |
| 1-minute mean at 10 m, $V_{1\text{-min}}$ | 32.9 m/s | 64.0 kts | 107.9 ft/s |
| ***Wave*** | | | |
| Significant Wave Height, $H_s$ | 8.0 m | 26.2 ft | 26.2 ft |
| Peak Period, $T_p$ | 12.2 s | 12.2 s | 12.2 s |
| ***Current*** | | | |
| Surface Speed, $V_{cs}$ | 1.08 m/s | 2.10 kts | 3.5 ft/s |
| Mid-depth Speed, $V_{cm}$ | 0.81 m/s | 1.57 kts | 2.7 ft/s |
| Zero Speed Depth, $D_0$ | 46 m | 151 ft | 151 ft |
| NOTE JONSWAP wave spectrum 2.0 < $\gamma$ < 2.5, and ESDU wind spectrum. | | | |

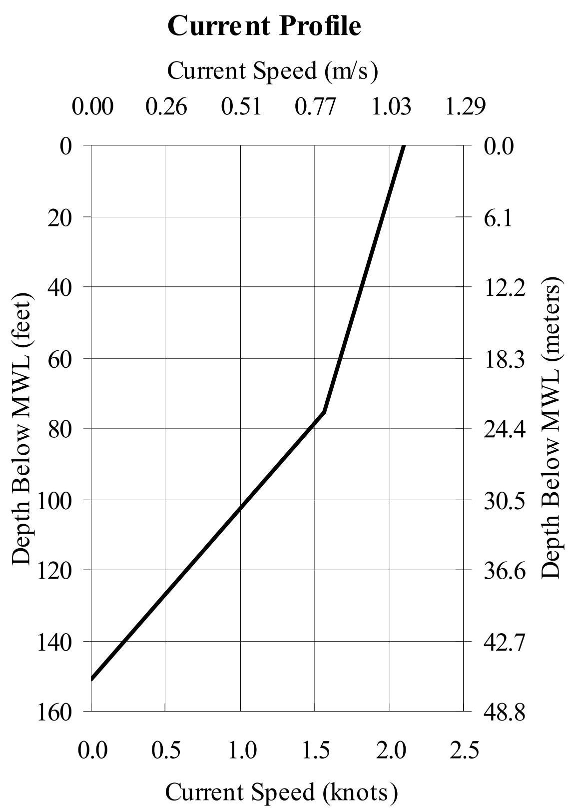



**Figure B.6—Current Profile for Minimum Category 1 Hurricane Conditions**

## B.12 Risk Assessment for MODU Operations

### B.12.1 Risk Assessment—General

The purpose of this section is to describe the basic elements of a risk assessment and to identify the primary drivers of MODU operational risks as they relate to mooring failure. This section does not provide normative guidance on risk assessment methods, only an informative overview related to this specific subject. The information in this section can also apply to conducting a risk assessment of a permanent moored facility.

Risk is defined as:

Risk = [Probability of an adverse event occurring] x [The consequences associated with that event]

Risk assessment is the study of the probability of an adverse event occurring, the potential consequences of that event, and the measures taken to reduce the probability and consequences of such an event. A fundamental part of reducing the risk is to ensure that all parties have a clear understanding of their "Risk Exposure". The risk can be reduced either by reducing the probability of experiencing an incident, prevention, or by reducing the consequences of that incident should it occur, mitigation.

Accidental and extreme environmental events may result in a number of adverse consequences, including:

a) Injury or fatality

b) Environmental damage

c) Property damage (potentially leading to a disruption of production due to GOM infrastructure damage)

d) Damage to corporate image

e) Deterioration in public perception and industry reputation

Risk management can be used to assess and control risks within acceptable levels. Risk assessment techniques can be used to evaluate frequencies and potential consequences of accidents. Risk assessment methods can be used to help evaluate and sort the risks. Further analysis can then be used to help determine and implement mitigation applicable measures. Risk management is also a process that can be effectively integrated into future operations to provide continuous improvement; past experiences can be reviewed with the aim of improving both system reliability and reducing adverse consequences.

A major advantage of undertaking a risk assessment is that it requires the stakeholders to be involved in the process and gives consideration to the issues that make-up the potential risk. This does not require massive attendance at – for example, the HAZID workshops but there is a danger in making any risk assessment process too automated. Risk analysis is an efficient way of helping to comprehend and evaluate issues that cannot be quantified by conventional means or design codes. It is through the process that participants come to understand the risks, which will then help in determining the appropriate acceptance criteria and correct mitigation measures.

### B.12.2 MODU-specific Risk Assessment

The probability and consequences of a specific MODU losing station when operating at any location within the U.S. Gulf of Mexico shall be assessed. The intent of the MODU-specific risk assessment process is to determine the characteristics of the area of operation, and identify options related to mooring component selection, mooring system design, scheduling of operations, mitigation opportunities prior to finalizing the mooring design, and installing the mooring system. For the planned MODU operation, the mooring system should be associated with an acceptable risk, either by minimizing potential consequences of mooring component or system failure or by reducing the probability of mooring component or system failure.

The general definition of risk is composed of the following elements:

a) Probability of a hurricane producing extreme environmental conditions at the site

   1) Hurricane occurring

   2) Distribution of the hurricane's intensity

   3) Distance of the hurricane's track from the MODU location

b) Probability of MODU mooring failure

   1) Strength of mooring line

   2) Holding capacity of anchor

   3) Mooring component resistance (anchor or line) is less than demand

c) Likelihood and consequence

   1) Likelihood of MODU drifting toward surface infrastructure

   2) Likelihood of MODU dragging or slipping anchors toward subsurface infrastructure

   3) Likelihood of damage to infrastructure of differing values (damaged or lost asset or lost production)

The metocean criteria for a specific location reflects the combination in item 1. The probability of suffering a mooring failure reflects the combination in item 2. The likelihood of causing damage, having suffered a mooring failure, is given in item 3. The risk is determined by the product of the probability and suitably summed consequences.

The financial consequences of a MODU mooring failure can be divided into three types:

— consequences of damage to the surrounding subsea and surface infrastructure,

— consequences of damage to the MODU and its mooring system, and

— consequences to operator's drilling program.

The risk assessment described addresses the consequences of damage to surrounding infrastructure. For MODU operations in the hurricane season, where the MODU is evacuated, it is the responsibility of the drilling contractor and operator to manage the risk associated with damage to the MODU and its mooring system.

The probability of mooring failure can be assessed through analysis of the mooring design, and the consequences of failure assessed by giving consideration to the infrastructure local to the proposed drilling location. Figure B.3 shows the general methodology for carrying out a risk assessment of MODU mooring failure, when considering the potential for damage to the surrounding infrastructure.

Each element of this overall process is discussed below.

— List Local Infrastructure: This covers all surface and subsurface infrastructure that can suffer consequences from a MODU mooring failure. The list may be divided up according to infrastructure that is within the mooring pattern, within one mooring diameter to 5 nautical miles, between 5 and 15 nautical miles, and infrastructure beyond 15 nautical miles that may require special consideration depending on size and importance.

  NOTE See NTL 2007-G14 [69].

— Develop Mooring System Design for the Relevant Season: This requires performing a mooring analysis of the proposed mooring system to API 2SK using appropriate metocean design criteria.

NOTE See Section B.11 for additional information.

— Ascertain Consequences of a Mooring Failure: Using an appropriate process (such as hazard identification (HAZID)), where all the potential consequences of a MODU mooring failure are identified.

NOTE Further information can be found in B.12.7.

— Calculate Probability of a Mooring Failure: The probability of MODU mooring system failure decreases with increasing design return period for which the mooring system satisfies all of the requirements of API 2SK.

NOTE Further information can be found in B.12.6.

— Evaluate the Risk: Involves taking information from the probability of mooring failure and consequence of a mooring failure and assessing the risk of the proposed MODU mooring operation.

NOTE See B.12.8 for more information.

— Is (are) the Risk(s) Tolerable? Once the risk is evaluated, the operator's standards shall be used to determine if the risk is tolerable.

NOTE Further information can be found in B.12.9.

— Can the Risk(s) be Reduced? Practical mitigation or prevention measures should be evaluated and implemented as appropriate to reduce the risk.

NOTE See B.12.9 for more details.

— Operation Acceptable or Unacceptable: Using all the information from the risk assessment process, the operator can determine if the location for a given season and MODU mooring system is acceptable or not. If no further mitigation or prevention measures are possible and the risk is deemed high, the operation should be rejected. Usually changing the season of operation, in particular if it is planned for peak of hurricane season and rescheduling to off-peak or non-hurricane season will make the operation acceptable.

NOTE See B.12.9 for additional information.

— Documentation: The risk assessment process shall be formally documented. The documentation should include all information required to support the risk assessment results.

NOTE Further information can be found in B.12.9.

Without participation by personnel experienced in MODU mooring's, their failure modes, and infrastructure sensitivity, the risk assessment process will not be very meaningful.

### B.12.3 Types of Consequences

Most corporate risk assessments include five types of consequence. In this standard, there is an additional consequence-type, national interest, that is specific to offshore operations in the Gulf of Mexico.

This addition is because Gulf of Mexico oil and gas production has a direct influence on the cost and availability of hydrocarbons to the public and the requirements for imports.

NOTE The six consequence types are provided in B.5.2.

In addition to the risk analysis for specific MODUs, there are also considerations for the performance of an entire MODU fleet. There is an expectation that a large hurricane in the Gulf of Mexico may cause multiple

MODUs to be adrift; however, there are limits on the acceptable number of drifting MODUs. Fleet performance is difficult to address through individual MODU risk assessments; it is more driven by overall minimum design return period requirements and fleet distribution throughout the Gulf of Mexico.

## B.12.4 Risk Analysis

### B.12.4.1 General

Risk assessments can be either qualitative or quantitative. The first step for either of these risk assessments is a Hazard Identification (HAZID), resulting in event trees that can be evaluated either qualitatively or quantitatively.

The normal expectation is that the HAZID would be used to assess the broad risks that may be associated with a location, including issues such as:

a) recovery of a drifting rig,

b) personnel evacuation,

c) sudden hurricane survival capability,

d) mooring installation and recovery risks, and

e) additional effects of mitigations that may be required by the main mooring failure risk assessment (e.g. consequences of necessitating additional or stronger mooring equipment).

Direct consequence mooring risk assessment is the main issue addressed in this Annex. This type of assessment may be used to assess the specific probability and consequences of suffering a mooring failure at a particular location (e.g. probability of mooring failure, and the consequences and likelihood of the MODU or its mooring system interacting with both near and far infrastructure). In this assessment, frequency of occurrence of hazardous events, the likelihood of escalation into further accidents, and the magnitude of potential consequences are evaluated. The methods used could be qualitative or quantitative, depending on the system definition and the objectives of the risk assessment. The initiating event-frequencies and the likelihood (conditional probabilities) of the chains-of-events leading to accident scenarios are established using a combination of historical databases, fault-tree, event-tree, and reliability-analysis techniques. Historical data [64, 65, 66 and 67] is available for some failure probabilities, but there is limited experience for the Gulf of Mexico; experience from other areas may not be appropriate due to differences in environmental conditions, water depth, and mooring line components.

Fault-tree analysis can be used to estimate the probability of a mooring failure, but in most cases it will be more accurate (and easier) to use a combination of historical data and structural reliability calculations. Event-trees are often used to estimate the likelihood of an event escalating and its associated consequences.

Consequence-analysis involves analyzing the range of possible outcomes of an accident or initiating event, which can be carried out in either a qualitative or quantitative manner. When undertaking quantitative-analysis, it is important to have sufficient data available to make realistic estimates. Qualitative-consequence-analysis (typical of a HAZID) involves verbal development of an accident scenario and then subjectively evaluating the consequence intensities; it often uses a risk matrix to assess the results.

In most mooring failure risk analyses, it is anticipated that there will be a combination of qualitative and quantitative risk assessments, both using a risk matrix approach (or similar) to assess acceptability.

### B.12.4.2 Levels of Detail

The detail within the risk analysis process should be designed to complement the level of work required to understand the site-specific situation and demonstrate compliance (or lack thereof). There is little point in performing extremely detailed risk analyses if the proposed location is far from any significant infrastructure.

Equally, expect to perform a detailed analysis if the intent is to prove acceptability of a location that is in a highly congested area because of either production infrastructure or multiple MODUs.

A basic risk assessment may entail following a process similar to that contained in B.6.2. A detailed / supplemental risk assessment may include a quantification of the risks, including both the probability of mooring failure and the consequences and likelihood of interacting with surrounding infrastructure.

**B.12.4.3 Data Requirements**

The data required for a risk assessment will depend on the level of analysis being undertaken, as discussed below. The following information is required in order to determine the consequences of a mooring failure. In addition, it will be necessary to determine some measure of the probability of suffering a mooring failure.

As a minimum, the following data will be needed to undertake a MODU mooring failure risk assessment:

a) the global mooring system description and mooring analysis report, including an anchoring system assessment,

b) details on the mooring line components, including jewelry and interconnecting hardware (to help ascertain potential for damaging subsea infrastructure),

c) anchor details including type, weight, capacity, fluke angle (if relevant), and any specific geotechnical limitations,

d) list of all surface and subsurface infrastructure within 15 nautical miles of the wellsite, including:

   1) infrastructure within the mooring pattern,

   2) infrastructure within one mooring radius of any anchor, and

   3) infrastructure within 15 nautical miles of the wellsite.

NOTE One source of infrastructure information is the Gulf of Mexico infrastructure map maintained by the Bureau of Safety and Environmental Enforcement (BSEE).

The mooring system inspection should be current and conforms with API 2I. Although this will not assure the mooring components will not fail at loads significantly below their catalogue values, it should help minimize the probability of such failures.

Infrastructure details should include size and type of any pipeline; if information on flow rate is unavailable conservative estimates should be used.

Information will be required on the physical size of surface facilities. Such information should include both the size of the structure above the waterline and the size of its seabed footprint as well as rated hydrocarbon processing capacity. In the event of a mooring failure, the likelihood of interacting with surface infrastructure will depend on the size and distance of the surface infrastructure from the wellsite. For a TLP, jacket, etc. the surface- and subsurface-footprint will be similar; although export risers may be considered to have the same effect on subsurface-footprint size as mooring lines.

For a spread moored structure, the surface and subsurface-footprint will not be similar in size due to the facility's mooring system. With a spread-moored infrastructure, there is a possibility that broken MODU mooring components will be dragged and damage the moorings of the permanently moored facility. The likelihood and consequences of this interaction will depend on:

- size of the facility's mooring pattern (footprint),
- mooring components used on the facility (chain, wire, polyester, etc.), and
- mooring components likely being dragged by the MODU.

As an example, if a facility's moorings include polyester mooring lines and the MODU mooring lines are steel, it is more likely the facility's moorings will be damaged by the dragged MODU mooring components, assuming there is some interaction. Conversely, if the MODU moorings are largely synthetic and the facility's moorings are steel, the interaction is less likely to cause substantial damage.

### B.12.5 Probability of Mooring System Failure and Failure Location

An integral part of any risk analysis is determining the probability of an initiating event. In the case of a mooring risk assessment, the initiating event is mooring failure. The definition of failure will vary depending on the circumstances, but for the purpose of a risk assessment a failure is any event that could lead to adverse consequences. For some mooring systems deployed over pipelines, that could be as simple as dragging an anchor a short distance (see 3.1.23 for more details and context).

A simple estimate of the probability of a MODUs mooring system failure can be taken as the inverse of the return period corresponding to the load where failure is expected. Common industry practice is to associate a MODUs mooring line failure in hurricane conditions with an intact line strength safety factor of 1.2 [64]; In doing this, consideration should be given to actual anchor capacity and mooring line strength. Mooring line strength may be reduced due to component degradation, bending over the fairlead, wire fretting, elasto-plastic fatigue damage etc., in comparison to catalog values (see B.3.2).

One way to determine the probability of suffering a mooring failure is through the use of reliability analysis; thereby incorporating, to some degree, the uncertainty in the environmental loads and the component strengths. Due to uncertainty in defining basic variables, methods of structural reliability analysis are often best suited to the calculations of comparative system probabilities of failure. Caution should be used with structural reliability methods to calculate absolute probabilities of failure.

The sophistication of the reliability analysis can vary depending on the level of detail required, but in all cases the following factors should be considered.

a) The slope and shape of the metocean extreme curves (parameter vs. return period) This will vary depending on location and season within the Gulf of Mexico.

b) The distribution of mooring component strength. The mean value will vary with age, use, maintenance, etc. A mooring system reliability analysis should not be based on the full CBS of the mooring components, but should reflect the component age, inspection history results, and fairlead bending considerations.

c) Variability in reliability depending on storm approach direction with respect to MODU heading.

d) Different reliability of mooring systems with different redundancy.

The location of the failure along the mooring line affects the possible consequence of mooring failure. The effects of having multiple mooring lines should be considered when determining the likely mooring line location(s). For example, it is reasonable to assume that 80 % of mooring failures occur close to the fairlead; but on an eight-line unit, there is approximately an 85 % chance that at least one line will fail away from the fairlead. Similarly, only approximately 5 % of lines failed at the anchor during the 2005 hurricane season; but that equates to over 33 % probability that on an eight-line unit there will be at least one mooring line failure at the anchor. These factors become very important when determining the likelihood of various components being dragged over the seabed.

### B.12.6 Consequence of Mooring Failure

The greatest concerns for potential asset damage resulting in financial consequence are:

a) Surface facilities – Relatively low likelihood for direct vessel-to-vessel collision unless the MODU is very close, but the cost for a major installation can be well in excess of $1 billion for a major deepwater facility (not accounting for shut-in loss). Such contact likelihoods depend on the "target" size, including any mooring and riser spread. While contact with the surface facility does not necessarily equate to a total loss, the consequence of a collision may depend on the environment when the collision will likely occur during a storm; similarly, consideration should be given to potential damage to the mooring lines or risers. This kind of event has a higher likelihood than the direct vessel-to-vessel collision, but would not be a complete facility loss; it may still result in significant repair costs and lost or deferred production.

b) Pipelines / Flowlines – These become a relatively large "target" if the drifting MODU is dragging an anchor. The cost of possible damage includes the impact on production upstream of the pipeline which will vary depending on if those facilities feeding the pipeline can produce through any alternative route. Repair costs in deepwater can be high and have a long duration. Recent experience is that only approximately one in five MODUs that broke adrift dragged anchors for any significant distance. While dragging an anchor can cause significant damage, it is less clear how much damage can be caused by a dragging a failed wire or chain. The loads imposed by a dragged wire or chain may not be very large; however, damage to the coating or insulation of a pipeline may be sufficient to necessitate costly repairs in the future. There were cases reported from the 2004 and 2005 hurricane seasons where a dragged wire or chain apparently did not damage steel pipelines that they crossed. However, if a groove gets started, a wire or chain will tend to cut into the steel. For flowlines, there is lower likelihood of damage than a pipeline as they tend to be shorter, but conversely may be closer to the MODU operations site; the likelihood of interaction depends on the angle sub-tended. Flowlines being in-field or intra-field (which tend to be smaller and thus lower through-put) gives less consequence if damaged versus pipelines (which are for export to shore).

c) Wellheads – There is a low likelihood of damage by a dragged anchor or broken mooring line(s) due to their small size, however likely to be damaged by a dragged wire or chain. Normally, the consequences would be limited because safety features would prevent flow if the wellhead were pulled off. However, there have been wells where the sub-surface safety valve (SSSV) has been taken out for repair prior to a hurricane's arrival and not enough time to reinstall the SSSV or temporarily plug the well. Damage to the wellhead in these cases could lead to a significant hydrocarbon spill.

d) Umbilicals – A similar likelihood of damage to flowlines, although often less robust, so more prone to damage from dragged mooring components. Normally would not lead to large shut-in production, although there are some umbilicals used for flow assurance for a number of wells. Loss of one of these umbilicals would result in significant shut-in.

There is a high concern for an extended shut-in of production. In most cases, the production of a facility can be reasonably estimated; but there are some facilities (often older ones) that are producing relatively little, but significant quantities of hydrocarbon transit across the facility. These hub-type facilities represent a special risk, as do the main pipelines that feed them. Consideration should be given to some of the massive pipelines that carry crude from hub facilities and the LOOP (Psymwmere$ jjwlsvi$ mpTsvx0. Damage to these could have an impact on oil supplies to the US and therefore should be subject to special assessment.

Determining the impacts of shut-in production is not simple. The production is not normally lost, unless the damage is so great that the economics of replacing the facility are unacceptable but deferred. However, the delay in production leads to significant loss of revenue and may impact the ability to finance further development opportunities.

While the drifting of a MODU into a major surface facility may be a low-likelihood event, it is one of the cases in which the consequences could significantly outweigh the direct financial damage. The perception of such a collision could be detrimental to a company (or companies) and the industry.

### B.12.7 Risk Evaluation – the Risk Matrix

Although risk is defined as the product of the frequency of occurrence of a hazardous event and its consequences, this is sometimes inadequate. In the case of a financial assessment, the result is the "expected loss", in real currency, if the venture is undertaken. A high-probability event of low-consequence can have the same risk as a low-probability event with high-consequences. This is a common definition, but for some very high-consequence events with low-probability of occurrence, this definition can lead to misleading conclusions.

The usual method of presenting results makes use of a risk matrix, whether the mooring failure risk assessment is undertaken at a simplified or detailed level. It is difficult to get a good understanding of what an event with a probability of $10^{-4}$ means when that event is associated with a consequence of $1 billion. In order to put these numbers into perspective, it is best to use a risk matrix; such as shown in Figure B.7, with each cell representing a single combination of probability-range with consequence-range that is assigned either a low, moderate, or high-risk rating.

<table>
<tr><td colspan="2" rowspan="3">Consequences</td><td colspan="4">Probability</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td></tr>
<tr><td>Less Likely</td><td></td><td></td><td>More Likely</td></tr>
<tr><td>IV</td><td>High</td><td colspan="2" rowspan="2"></td><td colspan="2">High Risk</td></tr>
<tr><td>III</td><td></td><td>Moderate Risk</td><td></td></tr>
<tr><td>II</td><td></td><td rowspan="2">Low Risk</td><td colspan="3" rowspan="2"></td></tr>
<tr><td>I</td><td>Low</td></tr>
</table>

**Figure B.7—Typical Risk Matrix Used for MODU Mooring Risk Assessment**

In many cases, particularly when considering mooring failures, the detail of the quantification, magnitude of the numbers, and level-of-accuracy is such that the best way to interpret and present the results is using a risk matrix. The selection of probability and consequence levels depend on the operator, and these shall be defined at the start of the risk analysis. Different matrices may be used at different stages of the analysis.

The risk matrix can be used to assess various type of consequence as discussed in B.12.5. As discussed previously, financial consequence may not be the critical consequence type for some stakeholders, but it is the most easily quantified. Based on position in the matrix, a risk classification such as low, moderate, or high may be used to decide the risk-potential from an individual hazard. Figure B.7 has not been drawn with specific risk categories, but they should be revised to suit the requirements of the stakeholder. An example of three risk levels follows:

— Low Risk (L), the bottom-left of Figure B.7: Severity and likelihood are low. Minimal risks that may be tolerated because it represents low-probability of relatively small-loss and may be addressed as part of normal continuous improvement processes.

— Moderate Risk (M), the middle-area of Figure B.7 from the upper-left to the lower-right: There is either a low-probability of suffering a large-loss (upper-left), or a relatively high-probability of suffering a small-loss (lower-right). Generally, the risks may be within tolerable limits. However, the expected loss is sufficiently high to require best attempts to mitigate the risks. In a more general sense, this risk level requires implementation of reasonable and practicable risk-reducing measures, or more detailed analyses to better define probability and consequences.

— High Risk (H), the top-right of Figure B.7: A high-probability of suffering a large financial loss that is not tolerable without implementation of effective risk-reduction measures. Risk-reduction measures may include reducing the probability of mooring failure or reducing the consequences if one occurs. One way to reduce the probability of failure may be to change the season of operation.

NOTE Possible consequence-reduction measures are provided below.

## B.12.8 Risk Acceptance and Risk Reduction

### B.12.8.1 Risk Acceptance

Risk acceptance involves deciding whether a risk is tolerable, and if risk-reduction measures are needed. Tolerable risk levels should provide a balance between absolute safety requirements, cost, and benefits of proposed risk-reduction measures. Acceptability is generally determined by comparing mooring failure risk against the acceptable risks established for similar or other offshore systems with acceptable operating experience, or with those established by other industries.

Operators, and other stakeholders, may have different risk acceptance criteria driven by different consequence-types. The situation becomes increasingly complex when considering either very high financial losses or the other consequence-types. It may be possible to develop a relatively simple set of criteria for financial loss, but the other consequences of a MODU mooring failure may be difficult to objectively assess.

Other consequences, besides financial (such as corporate image), may be involved; considering only financial risk may mislead the overall assessment conclusions. In addition, when dealing with very low-probability but high-consequence events, the normal approach of cost-benefit analysis can breakdown. Consider the following examples to illustrate the point.

— Example 1: An event with a 0.1 annual probability of occurrence with an associated $100,000 financial consequence produces the same financial risk as an event with a 0.0001 annual probability of occurrence with an associated $100 million financial consequence that is a $10,000 annual risk. However, an event that produced a $100 million loss is likely going to have far greater impact on corporate image than a $100,000 event.

— Example 2: The case where there is a 0.001 probability of doing $2 billion damage. The financial risk can be calculated as $2 billion x 0.001 or $2 million. By implication, it would not be financially advisable to spend more than $2 million (the total financial risk) to reduce the probability to a lower level. However, because the $2 billion loss may be more than the company could tolerate, it would likely be advantageous to attempt reducing the probability to a lower level (even at an expense of over $2 million).

Financial risk may be useful to determine what mitigation or prevention measures are worth investing to reduce risks. The ALARP (as low as reasonably practical) process can also be used to determine if the risk is tolerable, or that the operator has done everything reasonable to reduce the risk.

#### B.12.8.2 ALARP

When evaluating the risk of a mooring failure an operator should make an effort to satisfy themselves that the risk is ALARP. The ALARP-concept is part of the risk decision analysis and goes beyond determining the risk level based on the adequacy of existing mitigation measures by asking: "*What else can be done to further reduce the risk and what is the argument for not doing it*?". The key to the ALARP-concept is that the burden-of-proof is to demonstrate why not to do more to reduce the risks, as opposed to explaining what has or will be done.

Philosophically, all risks should be reduced to a level that is ALARP. The ALARP-concept hinges on what is reasonably practicable in terms of effort and benefit, recognizing that it is not reasonable to expect every possible risk-reduction measure to be implemented. To demonstrate that a risk is ALARP, it is necessary to show that there is a gross disproportion between the benefit (risk reduction) gained and the resources of implementing further risk-reduction measures; gross disproportion implies there is a bias towards risk-reduction. What constitutes gross disproportion will depend to a great extent on the potential consequences associated with the risk – the greater the consequences, more likely the greater the bias towards risk-reduction. The ALARP-concept is consistent with a philosophy of continuing risk-reduction, while recognizing the principle of diminishing returns.

Consider the ALARP-concept as it relates to an example of three possible risk levels − higher, medium, and lower. The suggested response to a higher risk is to reduce it to at least the medium level, which in most cases would generally not be ALARP. Lower risks would be addressed as part of the normal continuous improvement processes; at this lower end of the risk spectrum (where there is little scope for further risk reduction) the ALARP test is typically intuitive. It is at the medium level where there may be less obvious decisions to make about further risk-reduction, which may warrant a more rigorous demonstration of ALARP.

As it applies to evaluating the risk of a MODU mooring failure, the ALARP process requires an operator to evaluate the efforts and benefits associated with alternative mooring system designs (e.g. catenary vs. semi-taut configurations, steel vs. fiber rope, various anchor designs, etc.), and alternative drilling locations and schedules (e.g. can the location be drilled outside of peak hurricane season, or is there a lower risk location in another region of the GOM, or is it feasible to trade MODU slots or share the MODU with another operator, etc.) to demonstrate that the risk of mooring at the location is ALARP.

#### B.12.8.3 Risk Reduction

If a tolerable risk level is not achieved in the risk assessment process, the next step is to identify risk-reducing measures and evaluate their potential to reduce the risks to a tolerable level; risk assessment is an iterative process (i.e. the process is repeated considering the changes in the mooring system until a tolerable risk level is achieved).

Some of the methods that can be used to reduce the risks include, but not limited to:

a) Drilling the well during a more environmentally benign time of the year to reduce probability of mooring failure (prevention)

b) Strengthening the mooring system to reduce the probability of mooring failure (prevention)

c) Using different mooring components to reduce the consequences of mooring failure (mitigation)

The consequential effects of risk-reduction measures should always be considered; there is little point in reducing the risks of one operation only to find that the comparable risks of another have been increased.

### B.12.9 Methodology Outline for Quasi-quantified Mooring Failure Financial Risk Assessment

The following approach assumes that the probability of mooring failure has been determined, and is provided for guidance only and not intended to be all-inclusive.

NOTE When calculating the probability of a mooring failure, it is important to ensure that a suitable factor has been used on the mooring line strength.

a) Obtain a map of area showing all the surface and subsurface infrastructure

b) Divide it into homogenous sectors. A homogenous sector has no changes in infrastructure; the damage caused by a drifting MODU will be independent of the direction it drifts off location within the sector. It may be reasonable to exclude point-sources (e.g. subsea wells or distant surface facilities) if the angle they sub-tend is small; these would then be handled separately.

c) Determine the likelihood that the MODU drifts in the given/expected direction (based on either mooring analysis or metocean extremes, or both).

d) Determine the likelihood of dragging each mooring system component (based on line-break statistics). This will necessitate building a table of components, failure likelihoods, and potential for dragging across the seabed.

e) Determine the likelihood and extent of damage to subsea facilities (based on water depth at subsea infrastructure, dragged components, etc.).

f) Determine the consequences of that associated damage (including direct costs to repair, and delayed or lost production).

g) Develop a weighted sum of the product of consequences and likelihoods for each type of subsea infrastructure that it is desired to keep separate (so they can be plotted on a risk matrix). Alternatively, determine a weighted average of the expected cumulative loss from all subsea equipment.

h) Determine the likelihood that dragged mooring components damage subsurface structures for the following:

   1) All: consider potential for dragged mooring line interaction with SCRs, well risers, subsea tieback flowlines, etc.

   2) TLPs: pile, tendon, porch, and hull

   3) Jackets: structural members

   4) Spread-moored floaters: interaction with mooring system components based on what is dragged, layout of permanent facility mooring, and type of mooring (synthetic or steel); a grouped synthetic mooring system is expected to have the highest likelihood of suffering catastrophic damage due to the potential of damaging an entire group of lines.

i) Determine consequences of drifting into (or otherwise interacting with) surface facility (facilities), including direct repair cost and delayed or lost production.

j) Sum the various types of surface facility consequences so (with the related probabilities) they can be plotted onto a risk matrix.

k) Present the results in both tabular form and plotted on a suitable risk matrix

## B.13 Post-Storm Reporting Sheet

This reporting sheet may be used (as needed or required) for documenting information on the MODU mooring after an event. This form may also be useful documenting the as-installed mooring system information in accordance with B.10.2. This form addresses most cases, however, there will be cases where it does not; thus flexibility should be considered when using it as the intent is to capture the impact of a storm on the MODU and its mooring.

The reporting sheet is divided into four parts (forms), see Figures B.7 to B.10.

a) General Description of the MODU and the Mooring Location

b) As-Installed MODU Mooring Information

c) As-Abandoned MODU Mooring Information

d) Post-Storm MODU Condition

Every reasonable effort should be made to retain, preserve, and label the failure surface of any failed mooring line component for future examination. The labeling should include site name, failure date, MODU name, line number, location along the line, and component serial number (if applicable). Consistent units should be used throughout (either feet and kips or tons and meters, line diameters in inch or mm).

| | | |
|---|---|---|
| Date form completed: | | |
| Contact Information: | | |
| Drilling contractor: | | |
| Contact name: | Telephone: | E-mail: |
| General MODU Characteristics: | | |
| MODU name: | | |
| Designer: | Designer class description: | |
| Classification society and notation: | | |
| MODU modified since delivery? | Yes | No |
| Brief description of modifications: | | |
| Location Description: | | |
| Operator of well: | | |
| Block Name and No. | Latitude: | Longitude: |
| Water depth: | MODU Heading: | |
| Soil data available? | Yes | No |
| If soil data is available, please supply brief description and strength profile. | | |

**Figure B.7—Part 1: General Description of MODU and Mooring Location**

| | | | | |
|---|---|---|---|---|
| General Information: | | | | |
| Was mooring MODU's own system or preset? | | Own | Preset | Both own and preset |
| If preset, whose equipment was used? | | | | |
| Number of mooring lines (details requested below): | | | | |
| What is mooring line 1 (e.g. Starboard; Bow): | | | | |
| What is numbering sequence? (Add drawing if required.) | | Clockwise from above | | Anti-clockwise from above |
| Anchor Information: | | | | |
| Type of anchors: | Drag | Plate Anchor | Pile | Other |
| Anchor description (e.g. weight, size, manufacturer, model, etc.): | | | | |
| For Drag Embedment Anchors: | | | | |
| Manufacturer | | Type | | Weight and Fluke Angle |
| Anchor test load and duration | | | | |
| Were any anchor legs run short? | | Yes | | No |
| If any were run short, why? | | | | |
| Tension and Length Information: | | | | |
| Method of payout measurement during installation: | | | | |
| Method of measuring pretension and operating tension: | | | | |
| Are anchor scopes known or estimated? | | known | | estimated |

**Figure B.8—Part 2: As-installed MODU Mooring Information and Condition**

| | Mooring Line Number | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Line azimuth (True North) | | | | | | | | | | | | |
| Fairlead-Anchor Horizontal Distance | | | | | | | | | | | | |
| Fairlead Component (type, size, outboard length) | | | | | | | | | | | | |
| Component type, size, length | | | | | | | | | | | | |
| Component (type, size, length) | | | | | | | | | | | | |
| Anchor Component (type, size, length) | | | | | | | | | | | | |
| Buoy/Clump (size and location) | | | | | | | | | | | | |
| Type of anchor (size, etc.) | | | | | | | | | | | | |
| Fluke angle or Shear pin size (force to break) | | | | | | | | | | | | |
| Test load at fairlead or AHV stern roller or AHV bollard pull | | | | | | | | | | | | |
| Line arrangement during test load | | | | | | | | | | | | |
| Test load at anchor shackle | | | | | | | | | | | | |
| Anchor test load duration (min) | | | | | | | | | | | | |
| Anchor drag distance during installation | | | | | | | | | | | | |
| Location of MODU during test load | | | | | | | | | | | | |
| Nominal operating pretension | | | | | | | | | | | | |

| Mooring Line Component Information | | | Lines ____ to | | | |
|---|---|---|---|---|---|---|
| | Type | Construction | Diameter | Break Strength | Manufacturer | Age |
| At Fairlead | | | | | | |
| Intermediate Line 1 | | | | | | |
| Intermediate Line 2 | | | | | | |
| At Anchor | | | | | | |
| Mooring Line Component Information | | | Lines ____ to | | | |
| | Type | Construction | Diameter | Break Strength | Manufacturer | Age |
| At Fairlead | | | | | | |
| Intermediate Line 1 | | | | | | |
| Intermediate Line 2 | | | | | | |
| At Anchor | | | | | | |

NOTE If mooring system cannot easily be described through use of this table, attach a separate and full description.

**Figure B.8—Part 2: As-installed MODU Mooring Information and Condition (continued)**

| Mooring System Details: | | |
|---|---|---|
| Was rig position modified for evacuation? | Yes | No |
| How modified? (distance and direction) | | |
| Were line tensions modified prior to evacuation? | Yes | No |
| Was line slackening complicated by high currents, high winds, etc., that made it difficult to accurately establish the line tensions on evacuation? | Yes | No |
| Prevailing weather conditions at the time of mooring adjustment. | | |
| Seas | Height | Direction |
| Wind (One-minute average) | Speed | Direction |
| Current | Speed | Direction |

| | Mooring Line Number | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Line azimuth (True North) | | | | | | | | | | | | |
| Fairlead-Anchor Horizontal Distance | | | | | | | | | | | | |
| Fairlead Component outboard length at evacuation | | | | | | | | | | | | |
| Nominal survival pretension (at zero environment) | | | | | | | | | | | | |
| Evacuation tension (measured) | | | | | | | | | | | | |

NOTE If mooring system cannot easily be described through use of this table, attach a separate and full description.

**Figure B.9—Part 3: As-evacuated MODU Mooring Information and Condition**

| | | |
|---|---|---|
| Storm Name and Date: | | |
| Hull and Structural Condition Summary | | |
| Did the unit suffer any damage during the hurricane? | Yes | No |
| Can repairs be effected on site? | Yes | No |
| Major: Description of hull or structural damage requiring third-party or shipyard repair? | | |
| Significant: Description of hull or structural damage that shall be completed prior to restarting drilling operations: | | |
| Minor: Description of hull or structural damage that can be repaired during normal operations. Include whether there was green water damage. | | |
| What surprised you when you got back on the MODU? (e.g. either damage or indications of things) | | |
| Mooring System Condition Summary | | |
| Did the unit suffer any mooring related failures? | Yes | No |
| Did any anchors drag, and if so, how far? | Yes | No |
| | How far? | |

| | Mooring Line Number | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Failed at fairlead | | | | | | | | | | | | |
| Failed at intermediate | | | | | | | | | | | | |
| Failed at anchor | | | | | | | | | | | | |
| Dragged anchor | | | | | | | | | | | | |
| Other (anchor broke, brake failure, etc.) | | | | | | | | | | | | |
| Component(s) recovered for inspection? | | | | | | | | | | | | |
| Inspection results and availability? | | | | | | | | | | | | |
| Length of any "dangling" mooring component below the keel | | | | | | | | | | | | |

| | |
|---|---|
| MODU Recovery and Re-boarding Operations Summary | |
| How far did unit drift? | |
| Where was the unit after the storm when found? | |

| | | |
|---|---|---|
| Was the unit grounded? | Yes | No |
| Were tugs dispatched to recover the unit? | Yes | No |
| Did the tugs prevent additional drift? | Yes | No |
| Any comments on effectiveness of tugs? | | |
| Is course of unit drift known (e.g. through transponder)? | Yes | No |
| Did the transponder operate properly during the storm, and if not, why (e.g. batteries failed, etc.)? | | |
| Is the plot of location against time (to help with hindcasting and drift prediction) available? | | |
| Other comments on MODU recovery and re-boarding operations: | | |

**Figure B.10—Part 4: Post-storm MODU Condition**

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