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**Petroleum and natural gas industries —
Mooring of mobile offshore drilling units
(MODUS) — Design and analysis**

*Industries du pétrole et du gaz naturel — Amarrage d'unités mobiles de
forage en mer — Conception et analyse*



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Foreword

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ISO/TR 13637, which is a Technical Report of type 2, was prepared by the American Petroleum Institute (API) (as API Recommended Practice 2SK, 2nd edition) and was adopted by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 7, *Offshore structures*.

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This document is being issued in the Technical Report (type 2) series of publications (according to subclause G.3.2.2 of part 1 of the ISO/IEC Directives, 1995) as a “prospective standard for provisional application” in the field of offshore structures for the petroleum and natural gas industries because there is an urgent need for guidance on how standards in this field should be used to meet an identified need.

This document is not to be regarded as an “International Standard”. It is proposed for provisional application so that information and experience of its use in practice may be gathered. Comments on the content of this document should be sent to the ISO Central Secretariat.

A review of this Technical Report (type 2) will be carried out not later than three years after its publication with the options of: extension for another three years; conversion into an International Standard; or withdrawal.

Introduction

For the purposes of providing interim guidance on mooring/stationkeeping design, ISO TC 67/SC 7 has adopted API RP 2SK in recognition that it constitutes one of the most complete documents on the subject. API RP 2SK contains design guidelines which are based on experience in the offshore industry, results of several joint industry projects and many technical publications.

There are several issues that require further consideration and harmonization prior to this Technical Report being progressed further as part of ISO 13819-4. These include:

- environmental criteria in terms of return periods for temporary and permanent moorings;
- factors of safety for tensions, anchor load and fatigue;
- improving the definition and the methodology of the mooring analysis;
- improving the guidelines for thruster-assisted mooring systems;
- providing specific guidance in relation to corrosion protection of mooring lines;
- including IMO DP Guidelines (MSC Circ 645 “Guidance for vessel with dynamic positioning systems”) and relevant industry standards.

Technical Report ISO/TR 13637 reproduces the content of API Recommended Practice 2SK, 2nd edition, 1996. ISO, in endorsing this API document, recognizes that in certain respects the latter does not comply with all current ISO rules on the presentation and content of a Technical Report. Therefore, the relevant technical body, within ISO/TC 67, will review ISO/TR 13637:1997 and reissue it, when practicable, in a form complying with these rules.

This Technical Report is not intended to obviate the need for sound engineering judgement as to when and where this Technical Report should be utilized and users of this document should be aware that additional or differing requirements may be needed to meet the needs for the particular service intended.

Standards referenced herein may be replaced by other international or national standards that can be shown to meet or exceed the requirements of the referenced standards.

Appendices A, B, C and D to this document should not be considered as requirements. They are included only as guidelines or information.

Petroleum and natural gas industries — Mooring of mobile offshore drilling units (MODUS) — Design and analysis

1 Scope

This Technical Report presents a rational method for analysing, designing or evaluating mooring systems used with offshore floating units for the petroleum and natural gas industries.

2 Requirements

Requirements are specified in:

“API Recommended Practice 2SK, 2nd edition, December 1996 — *Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures*”

adopted as ISO/TR 13637.

For the purposes of international standardization, however, modifications shall apply to publication API RP 2SK as outlined below.

- a) Information given in the SPECIAL NOTES and FOREWORD is relevant to the API publication only.
- b) Throughout publication API RP 2SK, the conversion of English units shall be made in accordance with ISO 31. The content shall be replaced by the following.

LENGTH	1 inch (in)	= 25,4 mm (exactly)
	1 foot (ft)	= 304,8 mm
PRESSURE	1 pound-force per square inch (lbf/in ²) or psi	= 6 894,757 Pa
	NOTE 1 bar = 10 ⁵ Pa	
STRENGTH OR STRESS	1 pound-force per square inch (lbf/in ²)	= 6 894,757 Pa
IMPACT ENERGY	1 foot-pound force (ft·lbf)	= 1,355 818 J
TORQUE	1 foot-pound force (ft·lbf)	= 1,355 818 N·m
TEMPERATURE	The following formula was used to convert degrees Fahrenheit (°F) to degrees Celsius (°C): °C = 5/9 (°F – 32)	
VOLUME	1 cubic foot	= 0,028 316 8 m ³ or 28,316 8 dm ³
MASS	1 pound (lb)	= 0,453 592 37 kg (exactly)
FORCE	1 pound-force (lbf)	= 4,448 222 N

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Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures

Exploration and Production Department

API RECOMMENDED PRACTICE 2SK
SECOND EDITION, DECEMBER 1996

EFFECTIVE DATE: MARCH 1, 1997



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FOREWORD

The bar notations identify parts of this recommended practice that have been changed from the previous API edition. Note that all sections, paragraphs, figures, and tables have been renumbered.

This recommended practice is under the jurisdiction of the API Subcommittee on Off-shore Structures.

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Suggested revisions are invited and should be submitted to the director of the Exploration and Production Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

This standard shall become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

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Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures

1 Scope

The purpose of this document is to present a rational method for analyzing, designing or evaluating mooring systems used with floating units. This method provides a uniform analysis tool which, when combined with an understanding of the environment at a particular location, the characteristics of the unit being moored, and other factors, can be used to determine the adequacy and safety of the mooring system. Some design guidelines for dynamic positioning systems are also included.

The technology of mooring floating units is growing rapidly. In those areas where the committee felt that adequate data were available, specific and detailed recommendations are given. In other areas general statements are used to indicate that consideration should be given to those particular points. Designers are encouraged to utilize all research advances available to them. As offshore knowledge continues to grow, this recommended practice will be revised. It is hoped that the general statements contained herein will gradually be replaced by detailed recommendations.

2 Basic Considerations

2.1 INTRODUCTION TO STATIONKEEPING SYSTEMS

The stationkeeping system for a floating structure can be either a single point mooring or a spread mooring. Single point moorings tend to be used more frequently for ship shaped vessels, while spread moorings are used mostly for semisubmersibles. A third type of stationkeeping system is dynamic positioning (DP). Dynamic positioning can be used as the sole source of stationkeeping or used to assist a catenary mooring. Dynamic positioning can be used with either tanker or semisubmersible based systems.

2.1.1 Spread Mooring

Figure 1 is an illustration of a catenary spread moored semisubmersible. This is a conventional mooring technique used in floating drilling operations. For floating production applications, spread moorings are used primarily with semisubmersibles. Since the environmental force on a semisubmersible is relatively insensitive to direction, a spread mooring system can be designed to hold the vessel on location regardless of the direction of the environment. However, this system can also be applied to ship-shaped vessels which are more sensitive to environmental directions. The mooring can be chain, wire rope, fiber rope, or a combination of the three. Either conventional drag anchors or anchor piles can be used to terminate the mooring lines.

A spread mooring offers some advantages to the semisub-

mersible based floating production system. Since it fixes the position of the vessel, drilling and completion operations can be carried out on subsea wells located immediately below the vessel. The same is true for workover operations. On the other hand, a spread mooring system has a fairly large mooring spread (on the order of several thousand feet). Anchors and suspended mooring lines are present within this spread. These must be considered in the installation or maintenance of pipelines, risers, or any other subsea equipment.

The combination of a spread mooring with vertical mooring tendons to restrain a tension leg platform (TLP) on location, as shown in Figure 2 enhances both the operability and reliability of the basic TLP concept. The spread mooring allows for adjustment of the surface vessel in a controlled manner and provides an independent parallel load path to react against the lateral environmental forces. With this concept it is possible to horizontally position drilling tools and production equipment packages to be landed and attached to seafloor structures. Otherwise, these equipment packages would have to be positioned by other means such as guidelines, thrusters, or skidding the derrick on the surface vessel. The configuration and design of this spread mooring will be very similar to a spread mooring system used to moor semisubmersible based floating production systems.

2.1.2 Single Point Mooring

Single point moorings are used primarily for tankers. They allow the vessel to weather vane. This is necessary to minimize environmental loads on the tanker by heading into the prevailing weather. 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 vessel. An introduction to typical single point mooring systems is as follows:

a. Turret mooring. A turret mooring system is defined as any mooring system where a number of catenary mooring legs are attached to a turret that is essentially part of the vessel to be moored. The turret includes bearings to allow the vessel to rotate around the anchor legs.

The turret can be mounted externally from the vessel bow or stern with appropriate reinforcements (see Figure 3—External Turret Mooring System) or internally within the vessel (see Figure 4—Internal Turret Mooring). The chain table can be above or below the waterline. The turret also could be integrated into a vertical riser system that is attached to the bow or stern of the vessel (or internally) through some kind of mechanism that allows articulation (gimballed table, “U” joint or chain connections). The base of the riser is often weighted through additional weight within the riser or suspended beneath the riser (counterweight). These items affect

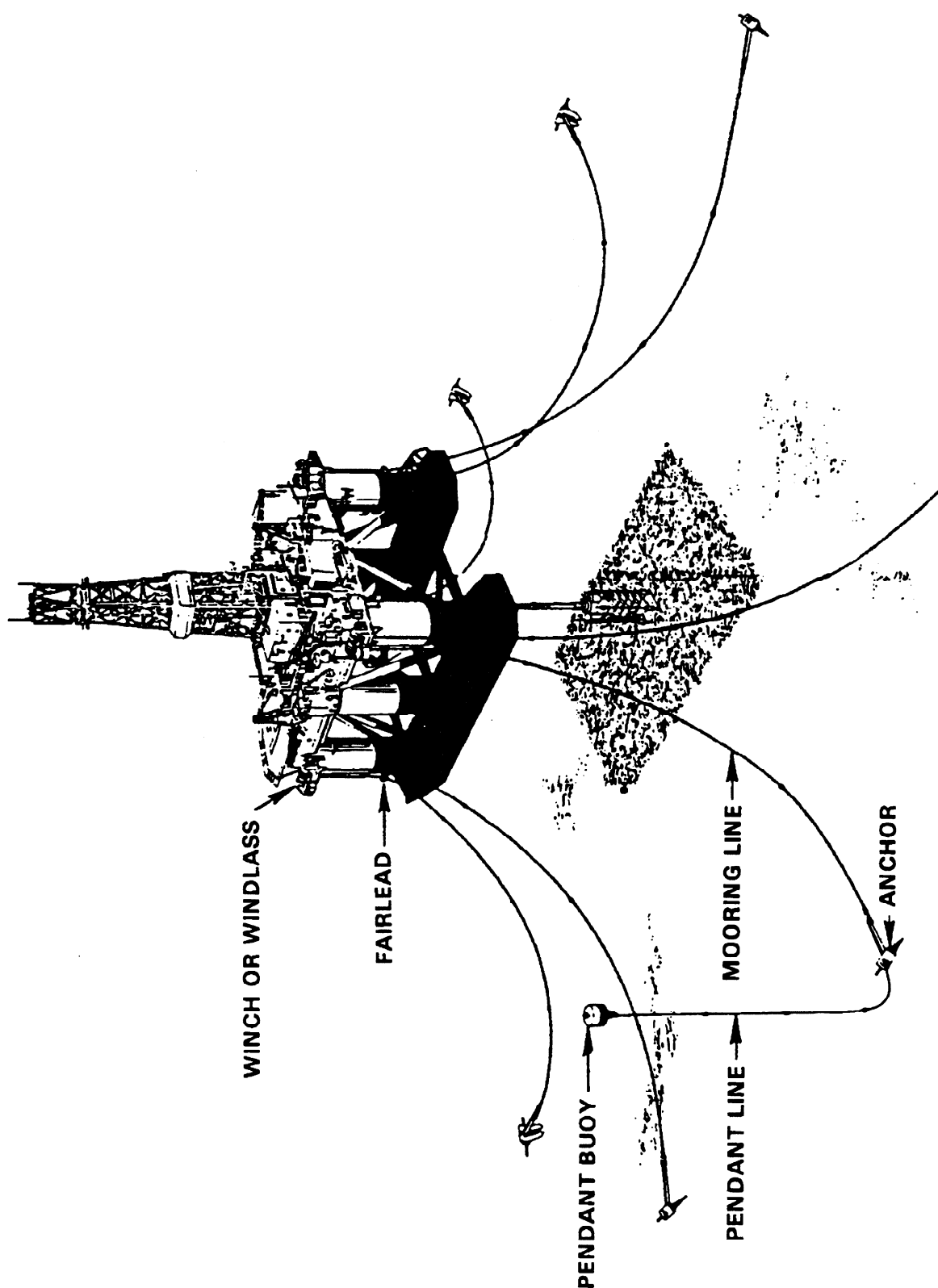


Figure 1—Spread Mooring

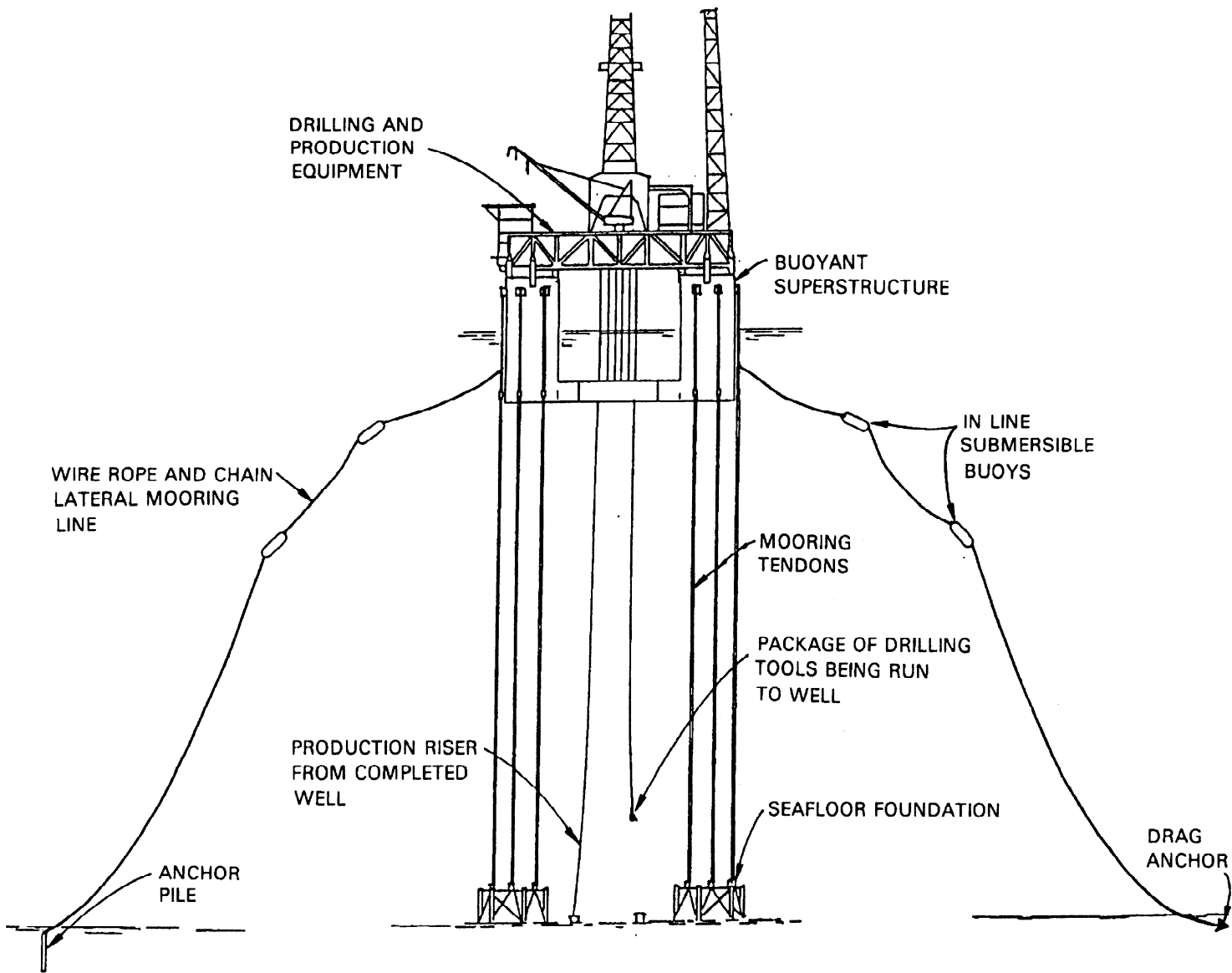


Figure 2—TLP Lateral Mooring System

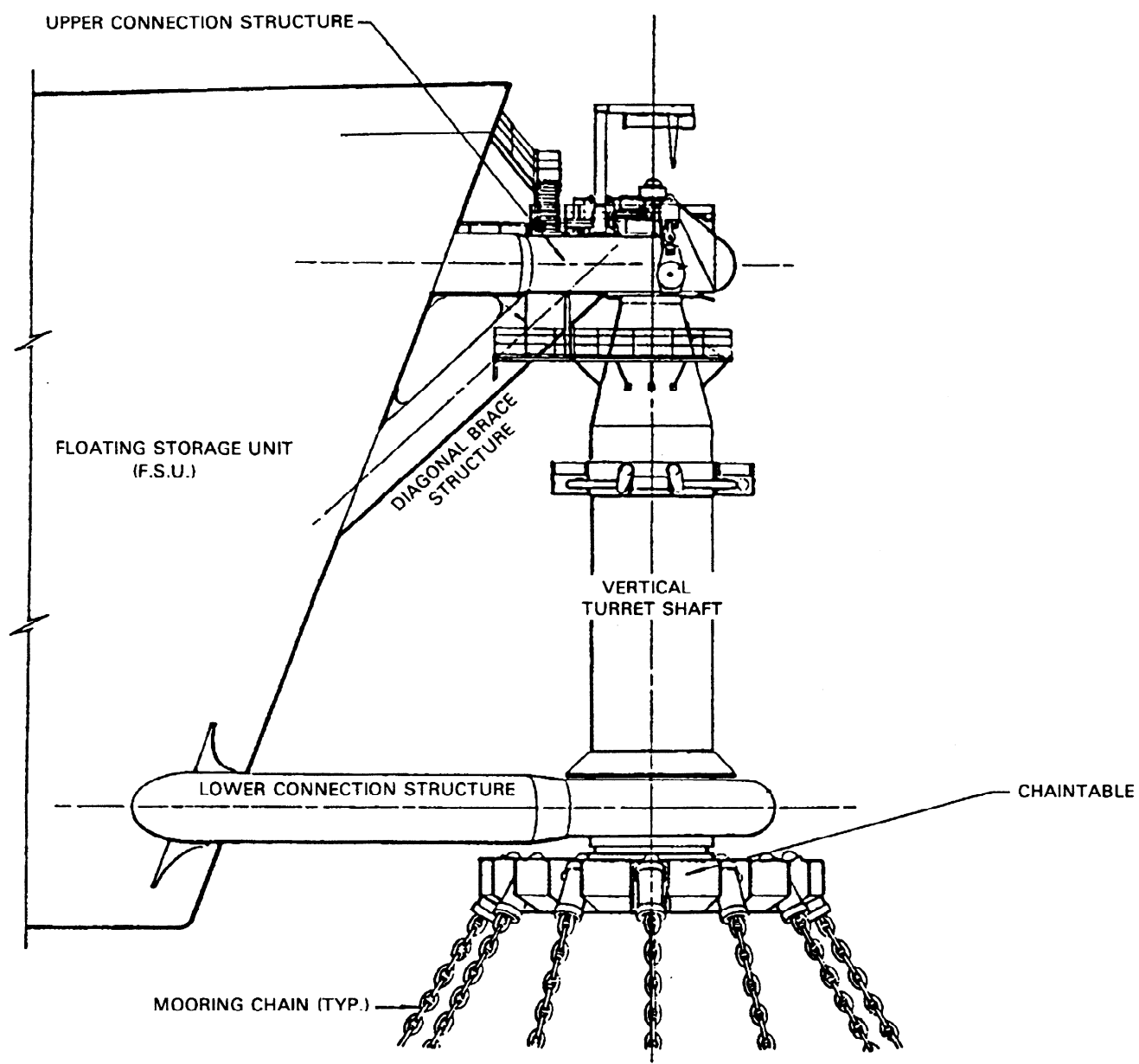


Figure 3—Typical External Turret Mooring Arrangement

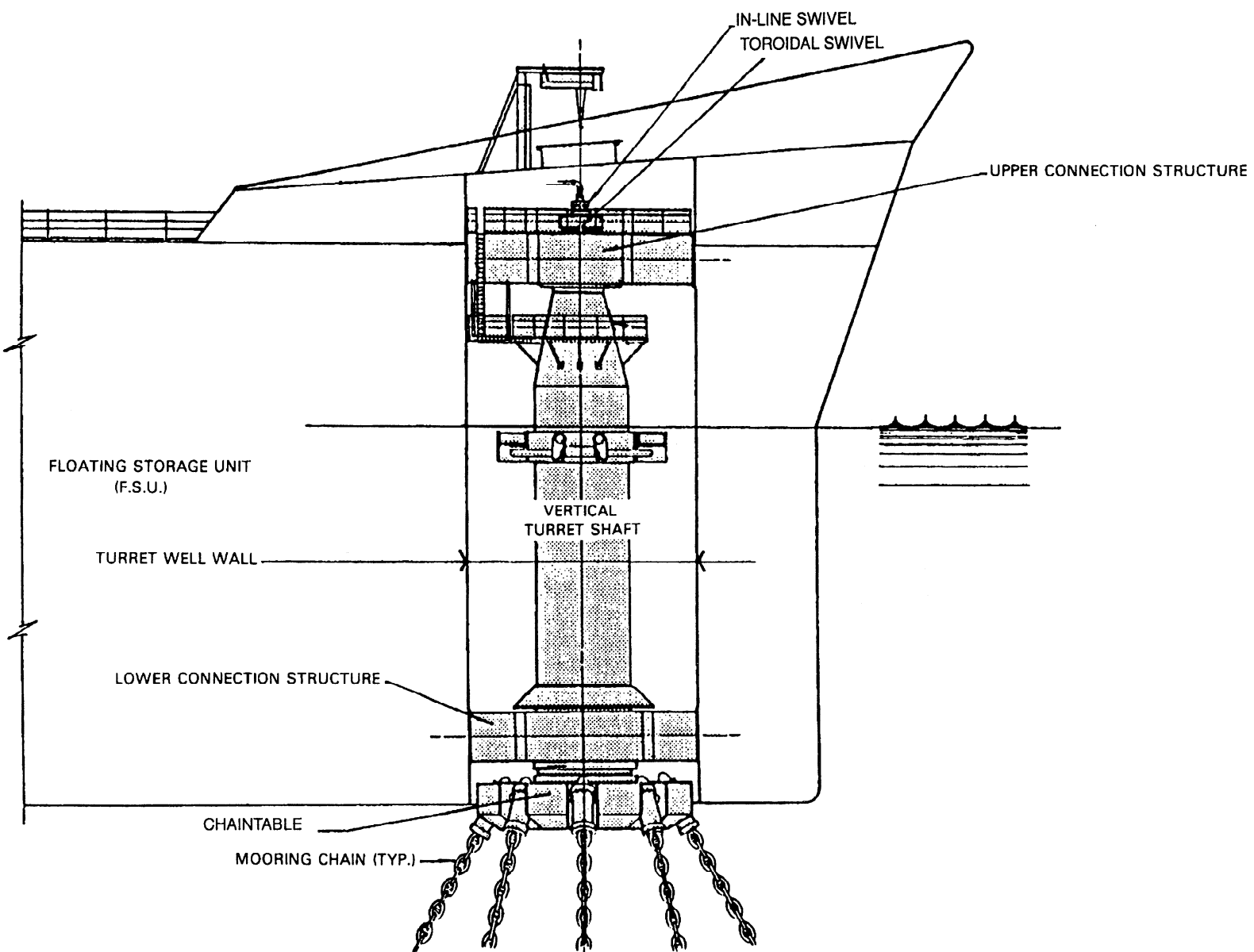


Figure 4—Typical Internal Turret Mooring Arrangement

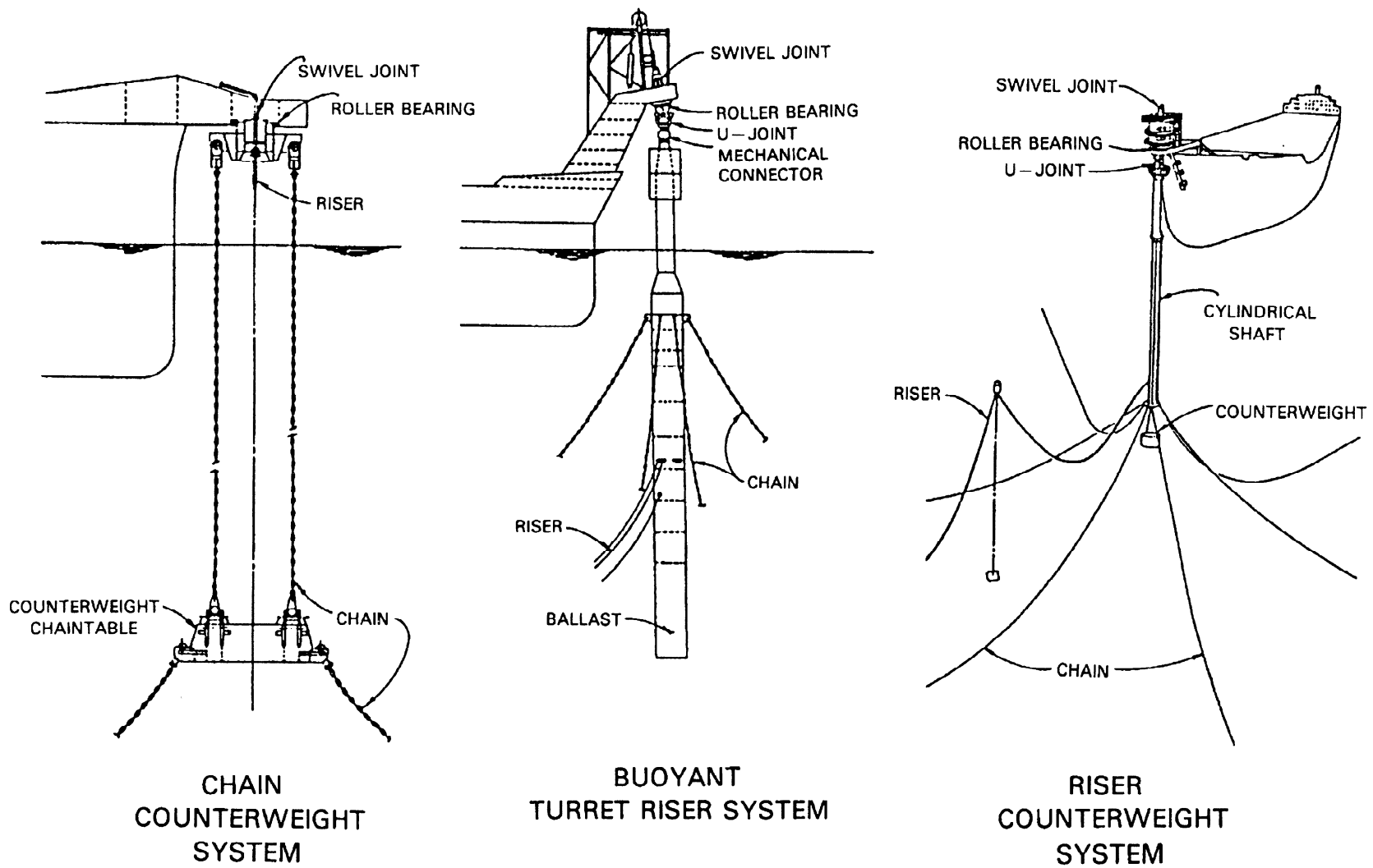


Figure 5—Variations on Turret/Riser Systems

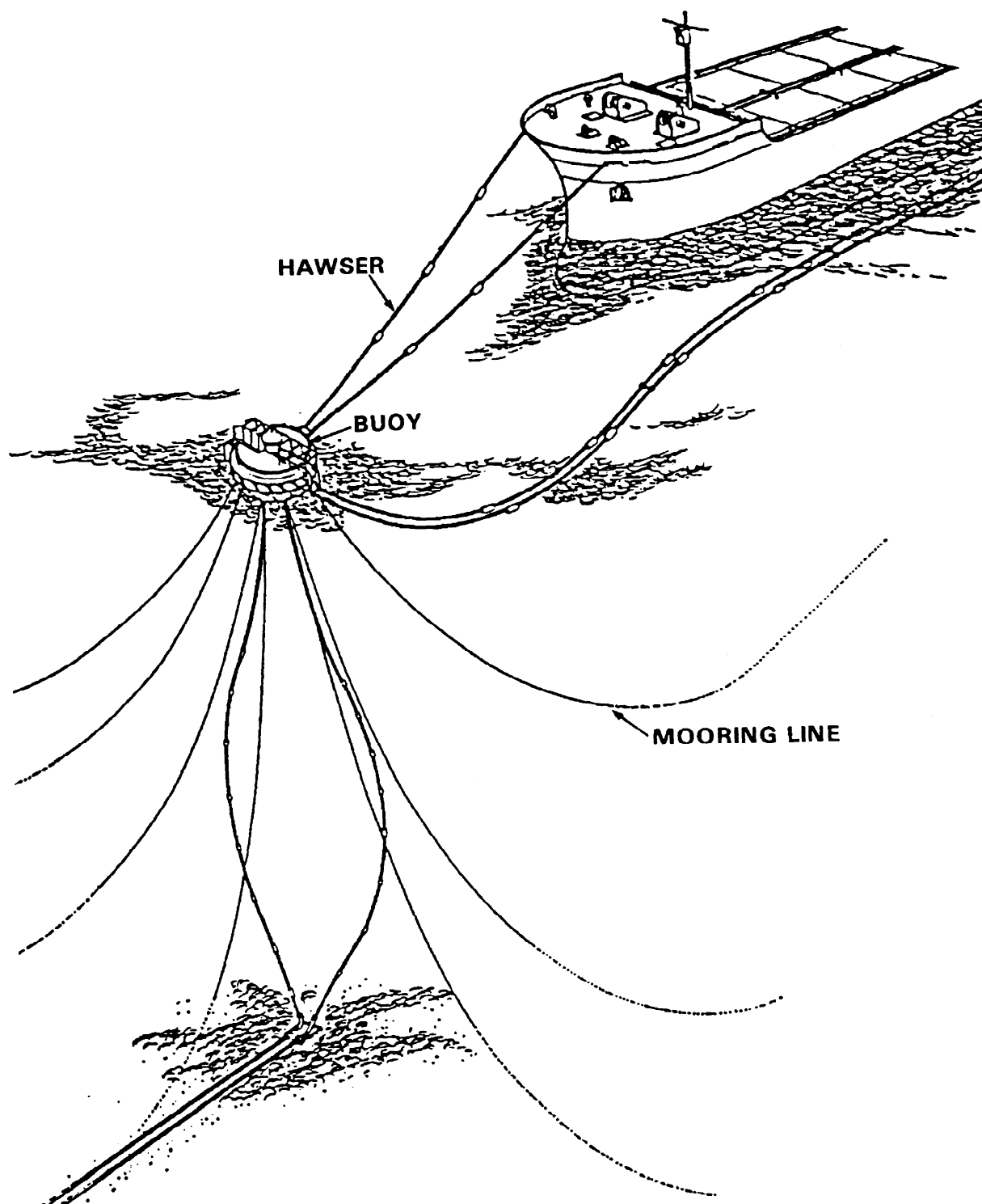


Figure 6—Catenary Anchor Leg Mooring (CALM) with Hawasers

the performance of the mooring system. The configuration of the riser could include steel tubular, chain or wire rope components and can vary considerably in diameter and length. The position of the chain table relative to the riser also can vary according to the design. Figure 5 shows some variations in the turret design offered by industry.

b. CALM (catenary anchor leg mooring). The CALM system consists of a large buoy that supports a number of catenary chain legs anchored to the sea floor (Figure 6). Riser systems or flow lines that emerge from the sea floor are attached to the underside of the CALM buoy. Some of the systems use a hawser, typically a synthetic rope, between the tanker and the buoy. Since the response of the CALM buoy is totally different than that of the tanker under the influence of waves, this system is limited in its ability to withstand environmental conditions. When sea states attain a certain magnitude it is necessary to cast the tanker off.

In order to overcome this limitation, rigid structural yokes with articulations are used in some newer designs to tie the ship to the top of the buoy. An example is shown in Figure 7. This rigid articulation virtually eliminates horizontal motions between the buoy and the tanker. A more recent development, shown in Figure 8, is a buoyant yoke with a soft mooring connection using chains attached to the yoke.

c. SALM (single anchor leg mooring). This system employs a vertical riser system that has a large amount of buoyancy near the surface, and sometimes on the surface, that is held by a pretensioned riser. The system typically employs a tubular, articulated riser with a fixed yoke (Figure 9). It is possible also to use a chain riser with soft mooring connections (Figure 10). The vertical buoyancy force acting on the top of the riser functions as an inverted pendulum. When the system is displaced to the side, the pendular action tends to restore the riser to the vertical position.

The tanker can be secured to the top of this SALM buoy with either a flexible hawser or a rigid yoke as discussed in the CALM description. The base of the riser is usually attached through a U-joint to a piled or deadweight concrete or steel structure on the sea floor. In deep water, the riser system usually has mid-span articulation.

2.1.3 Dynamic Positioning

Dynamic positioning (Figure 11) can be used as the sole source of stationkeeping or used to assist a catenary mooring system. Dynamic positioning consists of a position reference system, usually acoustic, coupled with computer controlled thrusters around the vessel. Dynamic positioning can be used in conjunction with a mooring which is called DP assisted mooring (or thruster assisted mooring if thrusters are manually controlled). Dynamic positioning is particularly well suited for a vessel designed to come onto and leave location frequently, such as an extended well test system.

2.2 DIFFERENCES BETWEEN PERMANENT AND MOBILE MOORING SYSTEMS

Permanent moorings are normally used for production operations with longer design lives. The mooring for a floating production system (FPS), for example, is a permanent mooring since FPSs typically have design lives of over 10 years. Mobile moorings often stay on one location for a short period. Examples of mobile moorings include those for mobile offshore drilling units (MODUs), and for tenders moored next to another platforms such as floatels, drilling tender, and service vessels. The division between mobile and permanent moorings may not be clear for operations with design lives of a few years. In this case, the user should make a judgment based on the risk of exposure to severe environments and the consequence of a mooring failure. Differences between permanent and mobile moorings are significant, as discussed below. The discussion can be used as a guideline to determine the category (permanent or mobile) to which the floating structure belongs.

2.2.1 Type of Mooring

A mobile vessel is normally equipped with a spread mooring, internal turret mooring, or dynamic positioning system. However, a permanent vessel has more choices of mooring design because mobility is normally not required.

2.2.2 Environmental Criteria

The design environments for mobile moorings are lower than those for permanent moorings. The lower design environment for mobile moorings is based on the consideration that the consequence of a mooring failure would generally be less severe. This can be illustrated by comparing a MODU with an FPS. In many instances, a MODU can at least disconnect and may even lay down its drilling riser. In the case of tropical storms, it may be possible to move the vessel before the arrival of a storm. By contrast, an FPS is unlikely to be removable from location, and may not even have quickly-retrievable risers.

2.2.3 Method of Analysis

A quasi-static analysis method is normally used for evaluating the performance of a mobile mooring system, and the effects of line dynamics are accommodated through the use of a relatively conservative safety factor. A more rigorous dynamic analysis is required for the final design of a permanent mooring system, and the factor of safety is relaxed to reflect that some uncertainty in line tension prediction is removed. Dynamic analysis should also be performed for mobile moorings if the consequence of a mooring failure is severe.

Also, a fatigue analysis is not required for mobile mooring systems. Because of abuse from frequent deployment and retrieval, many mooring components of a mobile mooring

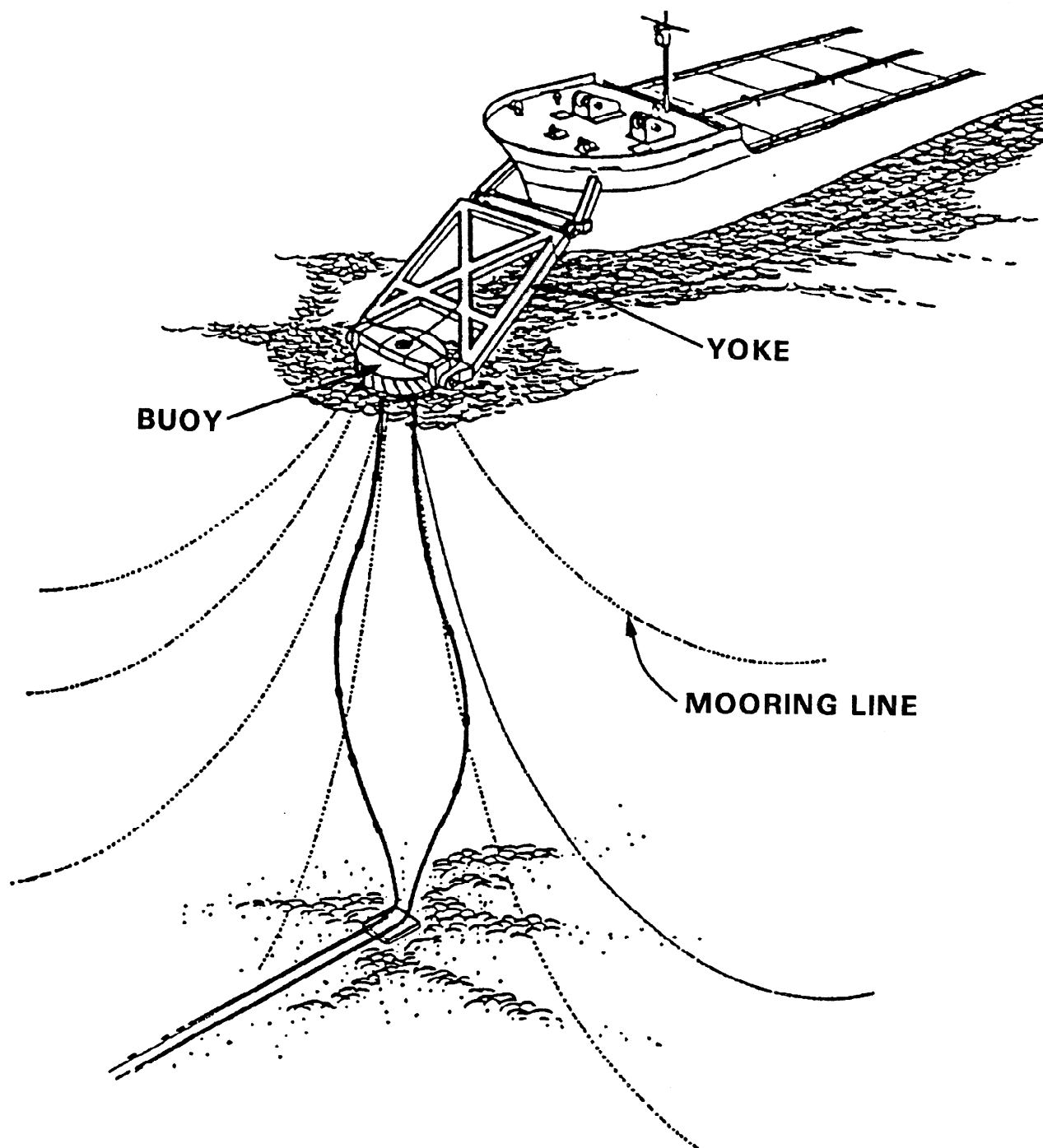


Figure 7—Catenary Anchor Leg Mooring (CALM) System with Fixed Yoke

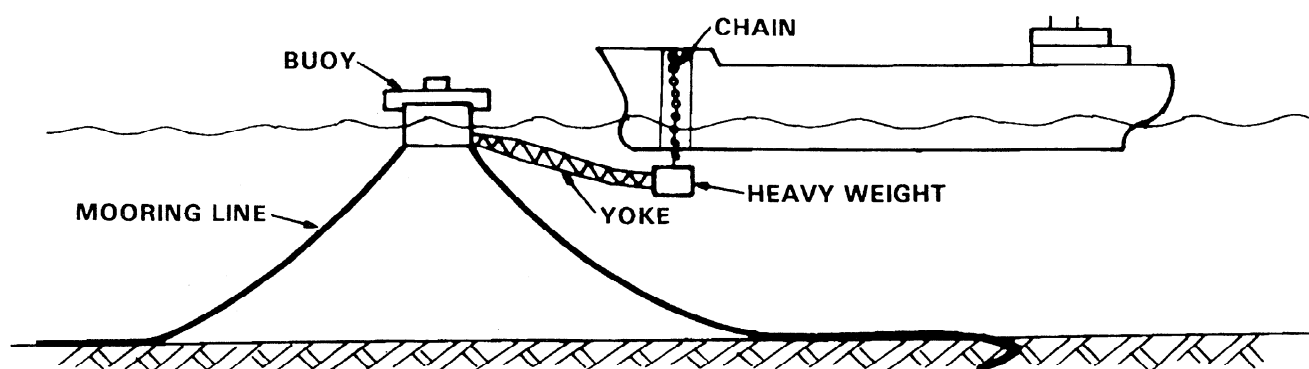


Figure 8—Catenary Anchor Leg Mooring (CALM) System with Soft Yoke

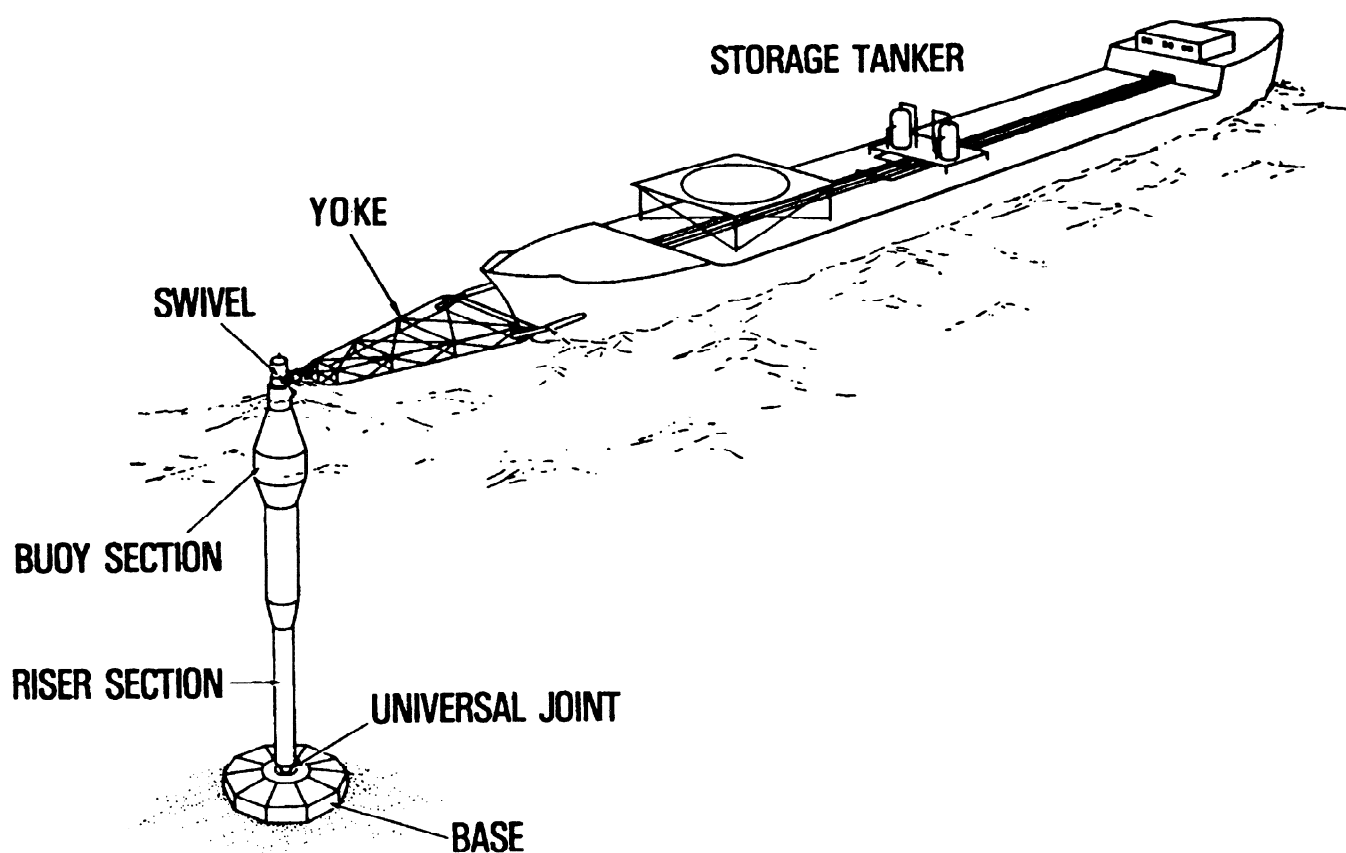


Figure 9—Single Anchor Leg Mooring (SALM) with Tubular Riser and Yoke

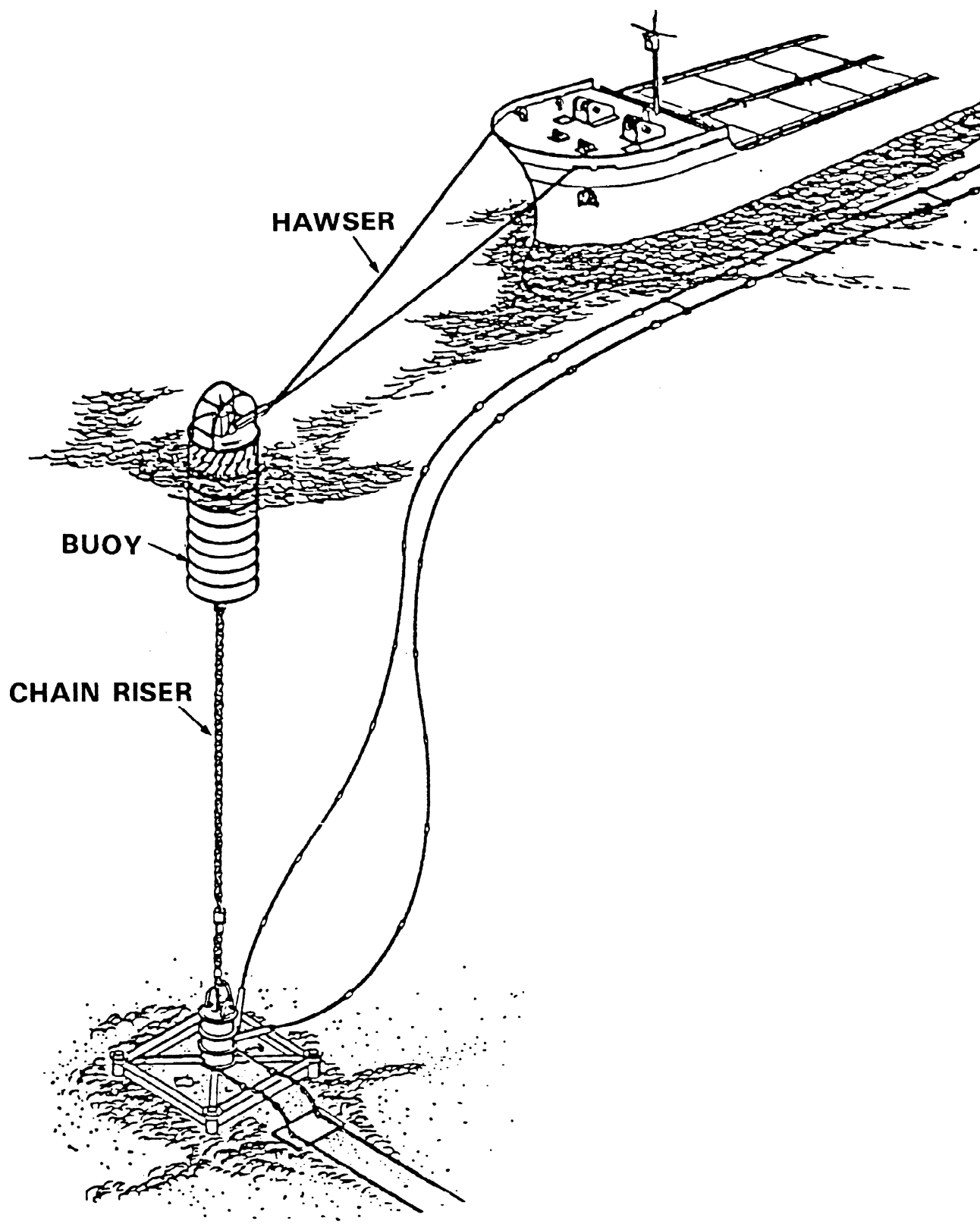


Figure 10—Single Anchor Leg Mooring (SALM) with Chain Riser and Hawser

system are replaced before they reach their fatigue limits. However, for permanent installations such as an FPS, fatigue is an important design factor, and a fatigue analysis should be performed.

2.2.4 Mooring Hardware

Mobile moorings use the mooring hardware that can be rapidly deployed and retrieved. This limitation does not apply to permanent moorings. Many mooring components such as anchor piles, linear winches, buoys, and chain jacks that may not be suitable for mobile moorings can be used in a permanent mooring. Also permanent moorings often require heavier mooring hardware because of the more stringent design requirements.

2.2.5 Installation

The deployment of a mobile mooring is normally carried out with the assistance of work boats. This operation is simple and usually takes no more than a few days. The deployment of an FPS mooring often requires the assistance of much heavier vessels such as a derrick barge or a purposely built work boat. A portion of the mooring is usually preset. Sometimes special design features are incorporated in the mooring design to facilitate deployment.

2.2.6 Inspection and Maintenance

A mobile mooring can often be visually inspected during retrieval or deployment. Retrieving a permanent mooring for inspection can be very expensive. To inspect a permanent mooring, divers or ROVs are often used. Also, replacing faulty mooring components is easier for mobile moorings than for permanent moorings.

2.3 DESIGN CONSIDERATIONS

2.3.1 Primary Design Considerations

The primary design considerations associated with a mooring system are design criteria, design loads, design life, operation and maintenance considerations. These considerations are addressed in detail in the following sections. In addition, a designer must also pay attention to the riser and subsea equipment considerations.

2.3.2 Riser Considerations

Risers transfer fluids between the seabed and the production or drilling vessel, and constitute one of the primary design constraints of the mooring system. The riser system often places limitations on the allowable vessel offset. In the event of excessive vessel offsets, mooring line adjustments such as slackening the leeward lines are sometimes performed to avoid damage to the riser. An equally important consideration is interference between mooring lines and risers, during both operational and extreme weather conditions. The mooring system and riser system must therefore be

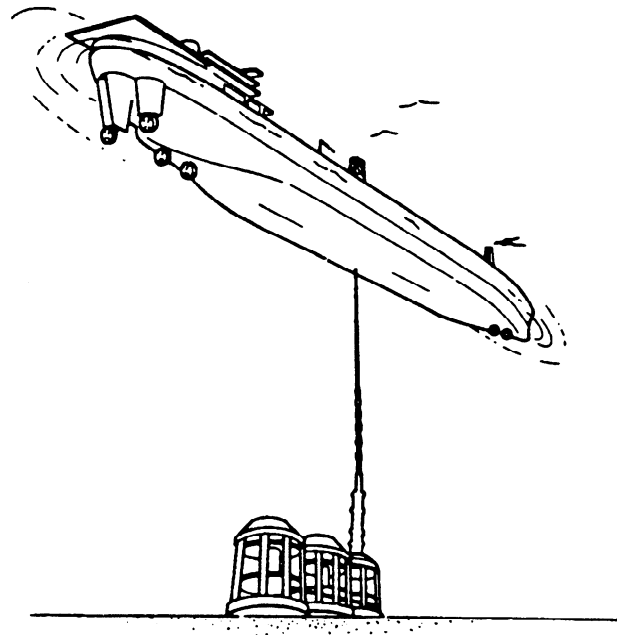


Figure 11—Dynamic Positioning

designed to accommodate each other, and coordination of these two design efforts is essential.

Design guidelines for riser systems can be found in API Recommended Practice 17A [5], API Recommended Practice 17B, [6], and API Recommended Practice 16Q [7].

2.3.3 Subsea Equipment Considerations

Subsea equipment such as templates, riser bases, satellite wells, and flowlines should be located clear of any potential mooring line interference. Any contact between mooring lines and subsea equipment during installation, operation or maintenance presents a high potential of damage to both the equipment and the mooring lines. If interference, or the potential for interference appears unavoidable, it may be possible to alter the layout and design of the mooring system through the use of an asymmetric arrangement of mooring lines, or the use of clump weights or spring buoys. Coordination of the mooring system design with the subsea equipment layout is essential.

Guidelines for the design of subsea equipment are given in API Recommended Practice 17A.

3 Mooring Components

3.1 MOORING LINE

3.1.1 Classification

Mooring lines for moored vessels may be made up of chain, wire rope, synthetic rope, or a combination of them. There are many possible combinations of line type, size, and

location, and size of clump weights or buoys that can be used to achieve given mooring performance requirements. The following are typical systems used by the industry:

3.1.1.1 All-Wire Rope System.

Because wire rope is much lighter than chain, wire rope provides a greater restoring force for a given pretension. This becomes increasingly important as water depth increases. However, to prevent anchor uplift with an all-wire system, much longer line length is required. A disadvantage of an all-wire rope mooring system is wear due to long term abrasion where it contacts the seabed. For these reasons, all-wire rope mooring systems are seldom used for permanent moorings.

3.1.1.2 All-Chain System.

Chain has shown durability in offshore operations. It has better resistance to bottom abrasion and contributes significantly to anchor holding capacity. However, in deep water an all-chain system imposes an increasing weight penalty on the vessel's load carrying capacity by its own self weight and high initial tension requirements.

3.1.1.3 Chain/Wire Rope Combination.

In this system, a length of chain is typically connected to the anchor. This provides good abrasion resistance where the mooring line contacts the seabed and its weight contributes to anchor holding capacity. The choice of chain or wire rope at the vessel end and the type of termination also depend on the requirements for adjustment of line tensions during operations. By proper selection of the lengths of wire rope and chain, a combination system offers the advantages of reduced pretension requirements with higher restoring force, improved anchor holding capacity, and good resistance to bottom abrasion. These advantages make combination systems attractive for deep water mooring.

An alternative to the above system is the wire rope/chain/wire rope combination system where wire rope segments are connected to both the vessel and the anchor. A length of chain is used in the dip zone where the mooring line is in dynamic contact with the seafloor. This minimizes the amount of chain, which is costly and difficult to deploy at deepwater sites.

3.1.2 Chain

The choice of material and fabrication of large diameter chain for a moored vessel 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 connection links and the associated problems with fatigue. Otherwise, connecting links with sufficient fatigue life should be used.

Chain can be obtained in several grades with Grade 4 (K4) being the highest strength. Oil Rig Quality (ORQ) chain has

been sold in large quantities to drilling contractors over the years and has generally performed well. Grade 3 chain has a catalogue break strength of approximately 93 percent of the equivalent ORQ chain, and K4 chain has a catalogue break strength of approximately 130 percent of the equivalent ORQ chain. Grade 2 chain is not recommended for major mooring operations.

A grade of chain somewhere between ORQ and K4, for example "ORQ + 20 percent" (breaking strength 20 percent higher than ORQ), is preferred by some designers since it is easier to manufacture than K4 chain. In any case it is recommended that considerable care is taken in establishing correct chemical composition of the bar stock, manufacturing techniques that incorporate precise quality control, and finally, comprehensive testing of samples of the final manufactured product. Detailed guidance in the specification, inspection, and testing of ORQ chain can be found in API Specification 2F [46].

Protection against chain corrosion and wear is normally provided by increasing chain diameter. The allowance in chain diameter for corrosion and wear is a complicated issue that still requires significant research and service experience to address. Current industry practice is to increase the chain diameter by 0.2 mm to 0.4 mm per service year in the splash zone where oxygenated water tends to accelerate corrosion and in the dip or thrust zone on hard bottom where heavy abrasion takes place. The diameter increase is reduced to 0.1 mm to 0.2 mm per service year in the remaining length. Galvanic protection for chain with anodes has been developed, but they have not been widely used because of their relatively short life (about 5 years), difficulty of attachment, and high cost.

3.1.3 Wire Mooring Line

The wire rope sections of the moorings can be of various constructions as shown in Figure 12. The wire rope construction type includes a number of strands wound in the same rotational direction around a center core to form the rope. The number of strands and wires in each strand (i.e., 6 by 36, 6 by 42, 6 by 54), 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.

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.

For corrosion resistance in permanent moorings, typically a polyethylene or polyurethane jacketing is employed. The jacketing material should be a high density type. Also all wires should be galvanized. Zinc filler wires are sometimes incorporated to provide additional corrosion protection. A filler material is used to block the inside spaces between the

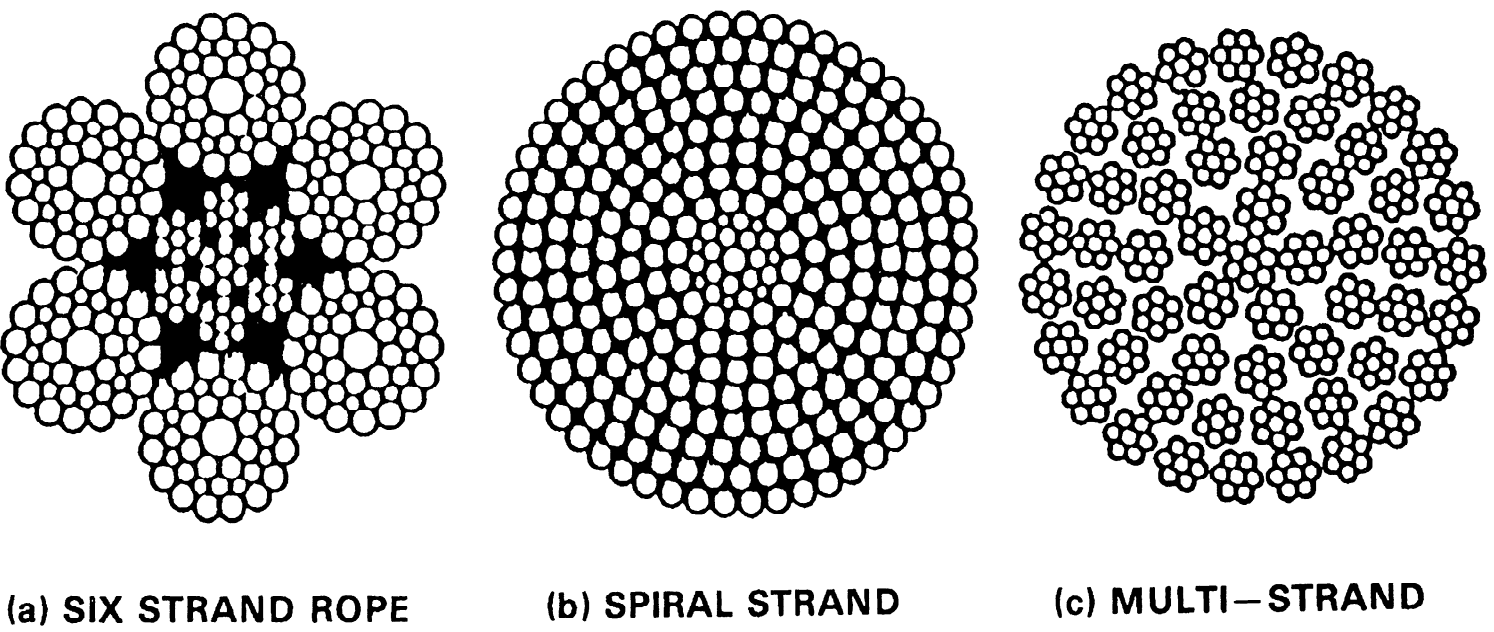


Figure 12—Different Wire Line Constructions

wires to minimize the spread of corrosion with ingress of salt water. It has not been a common practice to increase the diameter of wire mooring lines for corrosion and wear. However, in a few permanent moorings with unjacketed wire mooring lines, the rope diameters have been increased by 0.1 mm to 0.2 mm per service year for protection against corrosion and wear.

The ends of each mooring line section should be terminated with sockets. A resin material is preferred over zinc for pouring the sockets. For permanent moorings, the sockets should be provided with flex relieving boots (bend limiting devices) joined to the socket in a manner to seal out the ingress of water and limit free benching fatigue. Careful quality control and testing should be exercised prior to and during the fabrication of the rope to ensure that the rope meets design specifications and the final product produces guaranteed minimum break strength as specified.

3.1.4 Synthetic Mooring Line

Synthetic materials are generally not used in permanent mooring systems because of a lack of long term service experience. Research is underway to better understand the properties of various ropes made of high-performance synthetic materials, which may be in wide use in the future. An exception is the use of synthetic hawsers in CALM systems where high elasticity is an important property. These hawsers can be inspected frequently and replaced. Also, in very shallow water locations under mild design environment, a length of synthetic rope (typically, nylon rope) is often inserted in the mooring line to absorb the energy from vessel dynamics.

3.1.5 Clump Weight

Clump weights are sometimes incorporated in mooring legs to improve performance or reduce cost. By providing a concentrated weight to the mooring leg at a point close to the seabed, a clump weight can be used to replace a portion of chain and increase the restoring force of a mooring leg. Using clump weights in a mooring line design requires consideration of potentially adverse effects, such as increased use of connecting hardware installation complexity, undesirable dynamic response of the mooring line, and embedment of the clump weight in the seabed.

3.1.6 Spring Buoy

Spring buoys are surface or subsurface buoys that are connected to a catenary mooring line. The benefits of spring buoys are the following:

- Reduced weight of mooring lines that must be supported by the vessel hull; this is particularly advantageous to semisubmersibles moored in deep water.
- Reduced effects of line dynamics in deepwater.
- Reduced vessel offset for a given line size and pretension.

The adverse effects of spring buoys are the following:

- Increased use of connecting hardware, and installation complexity.
- Potential for increased design loads on the mooring lines due to dynamic response of the buoy in heavy seas.

Spring buoys used with permanent moorings could be constructed from steel or a combination of synthetic material surrounding a steel structure. 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 risers and floats for flexible risers. Steel buoys have been found to provide a cost competitive solution. The buoys can be built either spherical in shape, using unstiffened dished ends welded together, or with ring stiffened cylindrical bodies and ends. Buoys can be placed in line with the mooring (with a strength member through the buoy) or attached separately to the mooring through a tri-plate as shown in Figure 13. When using the in-line buoy approach, care must be taken to allow for rotation in the end connections.

The buoys should be designed to have adequate strength for maximum operating depth. During fabrication of the buoys, all welding should be tested with appropriate non-destructive testing. Also, corrosion protection should be adequately provided.

3.1.7 Connecting Hardware

Connecting hardware such as shackles, swivels, fishplates, 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 and corrosion protection become important considerations. The design of all connecting hardware used in permanent mooring lines should be thoroughly evaluated to ensure that stress concentration factors are correctly identified, and that fatigue life and corrosion protection are adequate. Manufacturing of connecting hardware should be subject to an appropriate level of quality assurance.

Connecting links such as Kenter and Baldt links are often used in mobile moorings. They can pass through chain fairleads and windlasses and can be periodically inspected and replaced.

3.2 WINCHING EQUIPMENT

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 the floating vessel itself must initially tension the mooring lines or test-load anchors. A floating vessel usually has the means of adjusting mooring line tension, pretensioning after anchor drag, and disconnecting individual mooring lines. Besides, a floating vessel is often used for combined drilling and production. This will require the capability for finite surface positioning

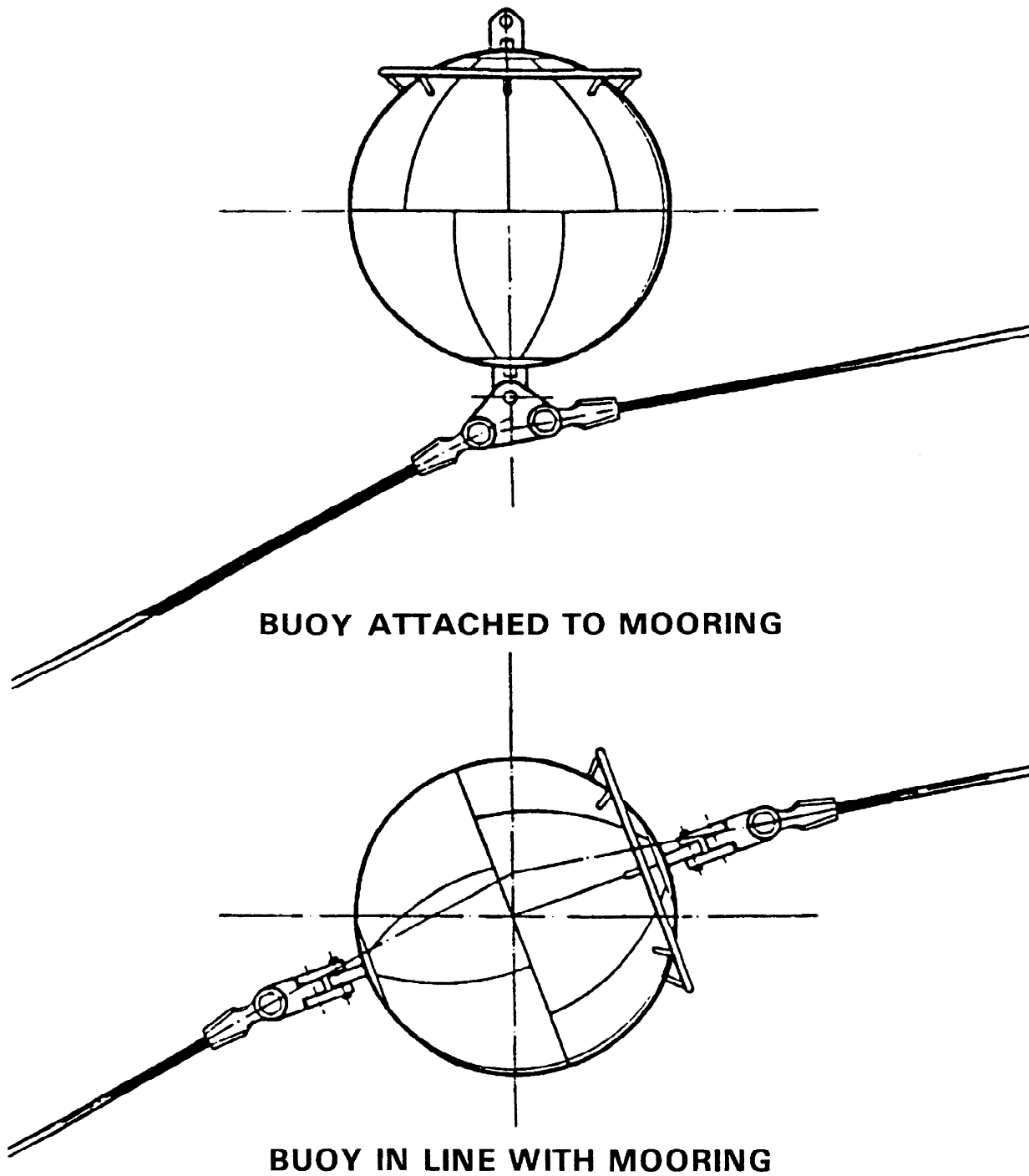


Figure 13—Submersible Buoy Configurations

for maneuvering the risers. This positioning can be achieved by paying-out and heaving-in mooring lines.

3.2.1 Windlass

The most common method of handling and tensioning chain is through the use of a windlass. The windlass consists of a slotted wildcat that 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 then lowered into the chain locker. Once the chain is hauled in and tensioned, a chain stopper is engaged to hold the chain. The windlass has proven to be a fast and reliable method for handling and tensioning chain.

3.2.2 Chain Jack

A chain jack is a device that reciprocates linearly to haul-in and tension chain. Usually powered by one or more hydraulic cylinders, the chain jack engages the chain, pulls in a short amount of the chain, 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 that do not require frequent line manipulation.

3.2.3 Drum-Type Winch

The conventional drum-type winch is the most common method used for handling wire rope. Operation of a drum-type winch is fast and smooth. A drum-type winch consists of a large drum on which wire rope is wrapped. The base of the drum is often fitted with special grooves sized specifically to the size of wire rope being handled. The grooves control the positioning of the bottom layer of wire rope on the drum. For subsequent layers of wire rope, an external guidance mechanism such as a level-wind is often used to control positioning of the wire rope on the drum.

The drum-type winch can be a cumbersome method of handling wire rope for deepwater or high strength mooring systems. As the requirement for line sizes and lengths increases, the size of the winch can become impractical. In addition, when wire rope is under tension at an outer layer on the drum, spreading of preceding layers can occur causing damage to the wire rope.

3.2.4 Linear Winch

A linear winch is similar in principal to the chain jack. Two sets of grippers, one stationary and one translating, are used to haul-in and tension the wire rope. Linear winches are available in a single-acting form where the wire rope moves intermittently as the gripper is retracted to begin another stroke, and in a continuous double-acting form in which case two translating grippers are used alternately for continuous smooth motion of the wire rope. A linear winch is most ap-

plicable in a permanent application when high tension and large-diameter wire rope are required. A take-up reel is necessary in this case to coil the wire rope after it passes through the linear winch. A winching system using linear winches is illustrated in Figure 14.

3.2.5 Traction Winch

Traction winches have been developed for high tension mooring applications, and for handling combination mooring systems. They consist of a powered drum on which the wire rope makes just a few wraps (typically, 7). Tension in the wire rope causes the wire rope to grip the drum. The wire rope is coiled on a take-up reel that is required to maintain a nominal level of tension in the wire rope (typically 3 percent to 5 percent 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 its compact size, capability to provide constant torque, and ability to handle very long wire rope without reduced pull capacity.

3.2.6 Fairlead and Stopper

Mooring lines are subjected to high wear and stress at the fairlead and stopper arrangements. The long term service of a mooring system requires that fairlead and stopper arrangements be carefully designed to minimize wear and fatigue.

Mooring chain and wire rope are often stopped off at the vessel in order to take direct mooring loads off the winch. Chain stoppers and wire rope grips used for permanent mooring systems must be designed to keep the stress concentrations and wear within the chain or wire rope at acceptable levels.

Fairleads should provide sufficient sheave-to-rope diameter ratio to minimize tension-bending fatigue. Typically, 7-pocket wildcat sheaves are used for chain. Sheaves for wire rope have D/d ratios of 16/25 for mobile moorings, and 40/60 for permanent moorings. There are other devices that provide attractive alternatives for fairleading large diameter mooring lines. An example is the underwater swivelling bending shoe shown in Figure 14. This device incorporates a shoe-to-rope 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 material is possible by slacking down the mooring line and removing the bearing material that is bolted to the bearing surface in sections.

3.3 ANCHORING SYSTEM

The options that are available for anchoring floating vessels include the following:

- a. Drag embedment anchors.
- b. Pile anchors (driven, jetted, drilled and grouted).

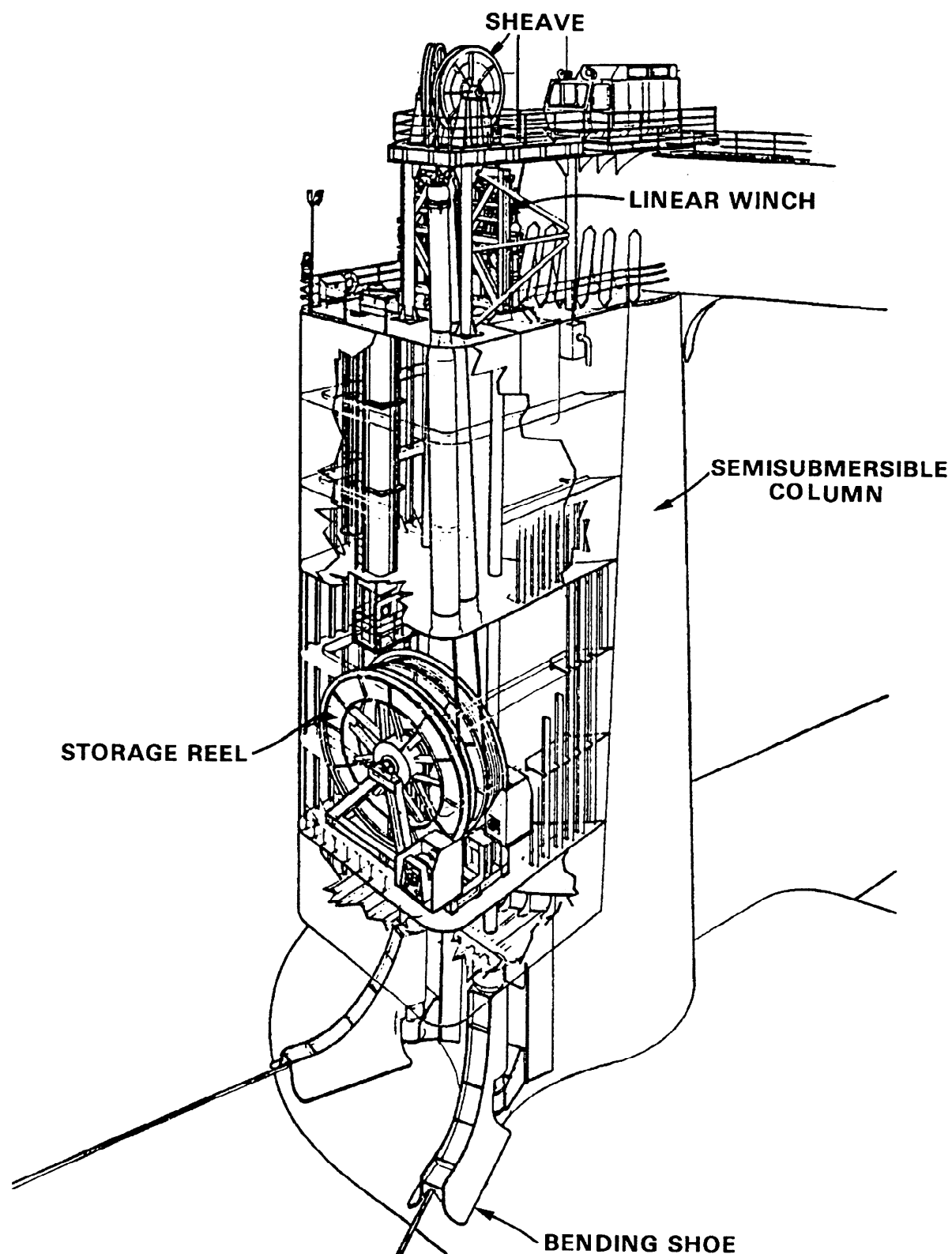


Figure 14—Winching System Using Linear Winch and Bending Shoe

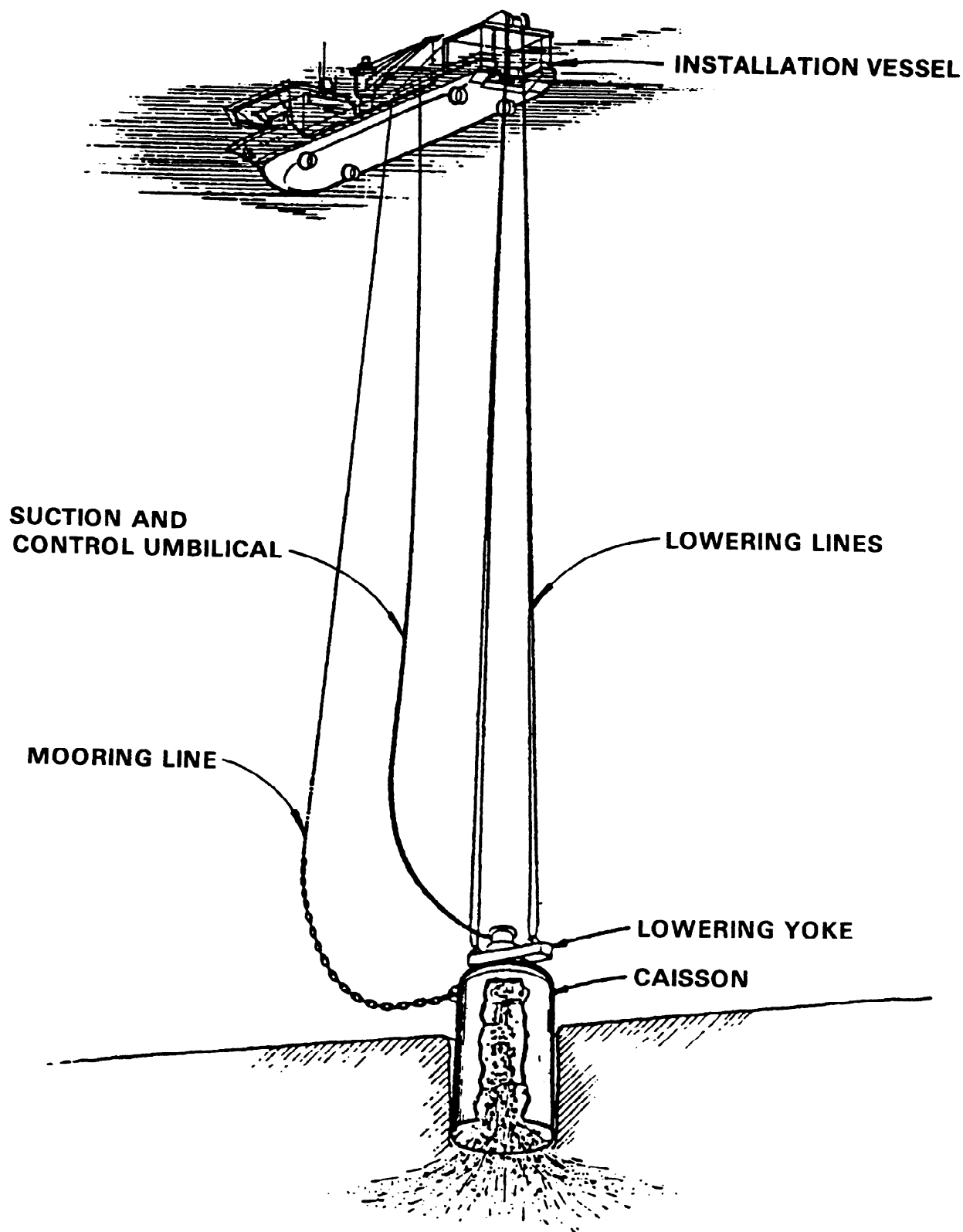


Figure 15—Installation of Caisson Foundation (Suction Anchor)

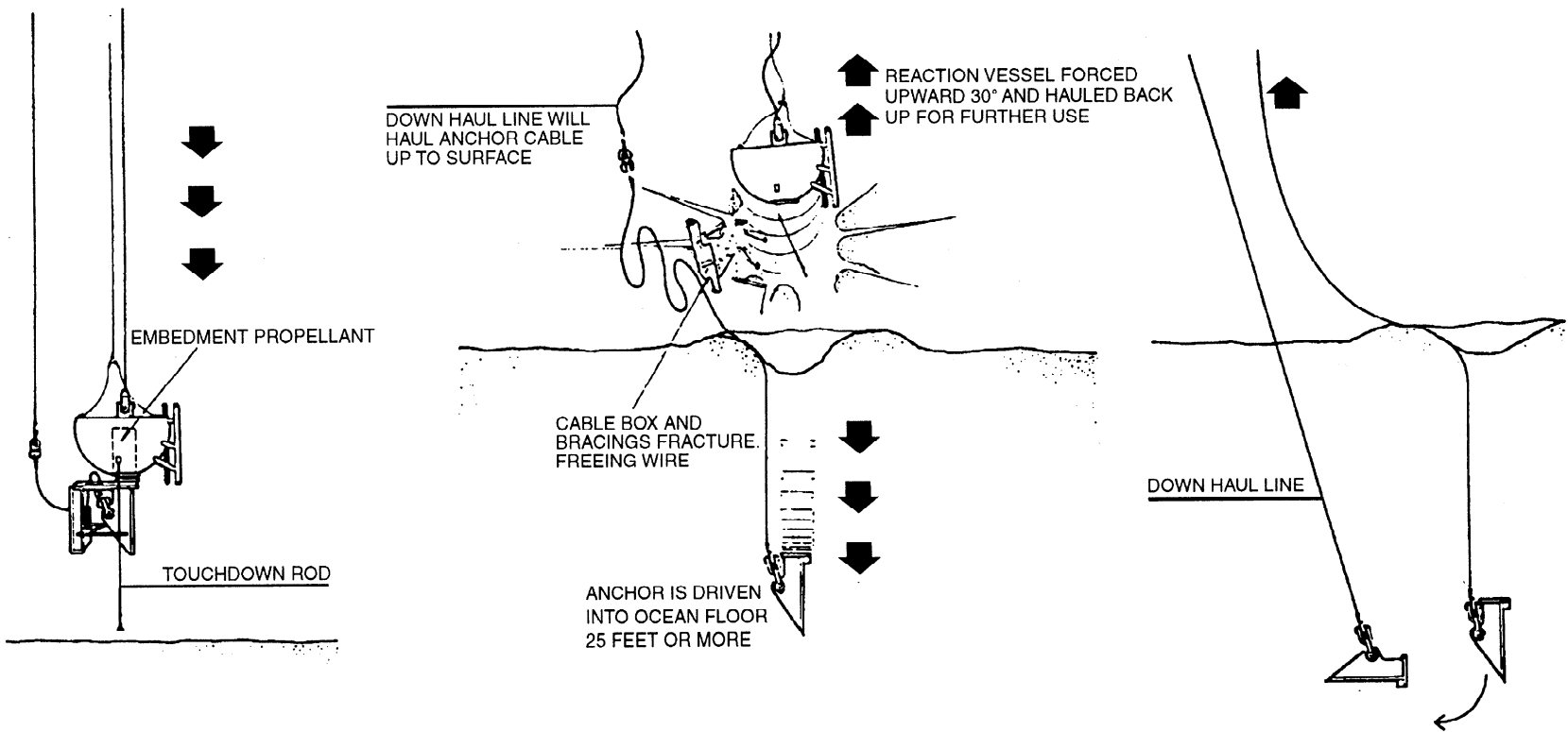


Figure 16—U.S. Navy Propellant Embedment Anchor

- c. Caisson foundations (suction anchors).
- d. Gravity anchors.
- e. Propellant embedment anchors.

In selecting anchor options, considerations must be given to required system performance, soil conditions, reliability, installation, and proof loading.

3.3.1 Drag Embedment Anchor

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 the soft soil conditions. High-efficiency drag embedment anchor is generally considered to be an attractive option for mooring applications because of its easy installation and proven performance. In fact, the majority of the existing permanent and mobile moorings use drag embedment anchors. The anchor section of a mooring line can be preinstalled and test loaded prior to platform installation.

3.3.2 Pile Anchor

A pile anchor's resistance to uplift and lateral loading is primarily a function of pile dimensions, the manner in which the pile is installed and loaded, and the type, stiffness, and strength of the soil adjacent to the pile. Horizontal capacity can be increased considerably by adding special elements such as skirts or wings to the pile top. Pile anchors can be designed to develop high lateral and vertical resistance, and be very stable over time. Piles are generally installed using driving hammers, although other methods such as jetting, and drilling and grouting 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 carefully evaluated. API Recommended Practice 2A [2] provides detailed information on design and installation of driven piles.

3.3.3 Caisson Foundation (Suction Anchor)

A caisson foundation is installed by using a suction embedment technique and therefore is often called a suction anchor. A caisson foundation can take many forms, ranging from a gravity base with skirts to a no-ballast caisson that resists all applied loads by soil friction and lateral resistance.

Generally, a caisson is technically feasible for soft to medium hard soils. For very soft soils such as some Mississippi Delta areas, the caisson must extend so deeply into the soil to reach competent load bearing material that the structure becomes unwieldy and difficult to handle. For very hard soils, it may not be possible for the skirts to penetrate deeply enough to provide adequate in-place strength.

A caisson installation is illustrated in Figure 15. When lowered to the seafloor, the caisson will penetrate to a certain depth by its own weight and create a seal to allow the suction operation to commence. Water is evacuated from inside the caisson with a submersible or surface vacuum pump through an umbilical attached to the top of the caisson. This causes the pile to be anchored into the seabed. Embedment of the caisson is assumed to be completed prior to placing ballast material in the caisson's upper chambers.

3.3.4 Gravity Anchor

Gravity anchors are deadweight anchors that commonly consist of concrete or steel blocks, scrap metal, or other materials of high density. Design uplift capacity is dependent on the submerged weight of the anchor. Horizontal capacity is a function of the friction between the anchor and the soil, and shear strength of the soil beneath the anchor.

3.3.5 Propellant Embedment Anchor

The concept of a propellant embedment anchor was first developed by the U.S. Navy and used for relatively low capacity fleet moorings in shallow water. The system used by the Navy involves a fluke or plate that is lowered to the seabed with a mooring line. An explosive charge is then triggered from the surface forcing the plate a certain distance into the seabed. The mooring line is then pulled—tripping the plate into a horizontal position (Figure 16). This system could be advanced for high capacity mooring applications, and other concepts of propellant embedment anchor have been investigated. However, significant further development is required to advance this technology for high capacity mooring applications.

4 Environmental Criteria

4.1 ENVIRONMENTAL CONDITION

The industry recognizes two classifications of environmental condition when evaluating mooring systems: maximum design condition and maximum operating condition.

4.1.1 Maximum Design Condition

The maximum design condition is defined as that combination of wind, waves, and current for which the mooring system is designed. Selection of the maximum design conditions should be the responsibility of the owner. The design environmental criteria should be developed from the environmental information described in 3.2 and may also include a risk analysis where prior experience is limited. The risk analysis may include: historical experience, the planned life and intended use of the mooring, the consideration of safety of operating personnel, prevention of pollution, the estimated cost of the mooring designed to environmental

conditions for several average expected recurrence intervals, the probability of mooring damage or loss when subjected to environmental conditions with various recurrence intervals, and the financial loss due to mooring failure.

4.1.1.1 Maximum Design Condition for Permanent Moorings

Experience with major fixed platforms in the Gulf of Mexico supports the use of 100-year oceanographic design criteria. In the absence of extended experience with permanent moorings, this criteria can be used for permanent floating operations with design lives comparable to fixed platforms. Risk analysis may justify either longer or shorter recurrence intervals. However, no less than a 100-year oceanographic design criteria should be considered where the design event may occur without warning while the platform is manned, and/or when there are restrictions, such as great flying distances, on the speed of personnel removal.

If the design life of the platform is substantially lower than that of fixed platforms, a shorter recurrence interval may be justified. In this case, the recurrence interval should be determined by a risk analysis taking into account the consequence of failure.

For a permanent operation with a mooring system that permits rapid disconnection of the production vessel from the mooring, the maximum design condition is the maximum environment in which the production vessel remains moored. However, the mooring alone (without the production vessel) should be able to withstand the maximum design environment for permanent moorings.

Mooring systems should be designed for the combination of wind, wave, and current conditions causing the extreme load in the design environment. In practice, this is often approximated by the use of multiple sets of design criteria. For example, in the case of a 100-year design environment, two sets of criteria are investigated: (a) the 100-year waves with associated winds and currents, and (b) the 100-year wind with associated waves and currents. The most severe directional combination of wind, wave, and current forces should be specified for the permanent installation being considered, consistent with the site's environmental conditions.

4.1.1.2 Maximum Design Conditions for Mobile Moorings

Maximum design conditions including the following:

a. Operations away from other structures. In general, moorings for mobile floating units such as MODUs operating away from other structures should use a maximum design environment with a return period of at least 5 years. Special attention should be given to operations in areas of tropical cyclones such as the Gulf of Mexico (hurricane) and the South China Sea (typhoon). These areas are characterized by

a generally mild environment combined with severe storms during the cyclonic storm season. For operations out of the cyclonic storm season, the 5-year environment can be determined using the environmental data excluding tropical cyclones. For operations during the cyclonic storm season, the tropical cyclone data should be included.

On some special occasions, the return period can be reduced for operations during the tropical cyclone season if the following conditions are met:

1. A risk analysis is conducted to evaluate the consequences of a mooring failure. Such an analysis examines various scenarios of mooring failure, probability of occurrence of each scenario, and their impact on safety and the environment.
2. Operational personnel evacuation is planned and executed before the arrival of a tropical cyclone.
3. A weather forecast system with local environment feedback is available to provide accurate forecasting.
4. For drilling operations, the drilling riser is pulled before the arrival of a tropical cyclone.
5. There is no other structure within a few miles of the operation.

The reduced return period should be determined by the risk analysis, but it should not be less than one year.

b. Operations in the vicinity of other structures. The maximum design environment for mobile units operating in the vicinity of other structures should be determined by a risk analysis that evaluates the consequence of a mooring failure. However, it should have a return period of at least 10 years. In an area of tropical cyclones, for operations out of the cyclonic storm season, the 10-year environment can be determined using the environmental data excluding tropical cyclones. For operations during the cyclonic storm season, the tropical data should be included. An example of such an operation is a MODU with mooring lines deployed over a pipeline. Damage to the pipeline may occur if the anchors are dragged into the pipeline. Other examples include a drilling tender, a floater, or a service vessel moored next to a platform.

The 5-year and 10-year return period environments discussed in 4.1.1.2, items a and b should generally be determined by annual statistics. However, if the operating season is well defined and seasonal environmental data are sufficient to provide meaningful statistics, these environments can be determined by seasonal statistics.

4.1.2 Maximum Operating Condition

The maximum operating condition is defined as that combination of maximum wind, waves, and current in which production and/or drilling operations can be conducted. The operating environmental criteria should be known to the people responsible for the drilling or production operations in order that timely plans to suspend operations can be performed.

Generally these criteria are less severe than those for the maximum design conditions. However, in some FPS operations where the system is designed to continue production during a severe storm, the maximum operating condition will be the same as the maximum design condition.

4.2 ENVIRONMENTAL DATA

Collection and selection of environmental data for a floating platform's mooring system is the responsibility of the owner. Experienced specialists should be consulted when defining the pertinent oceanographic and meteorological conditions for a site. The dynamic nature of a floating platform and its mooring system requires that the designer work closely with those specialists to develop the data and interpretations in the form needed for the particular design/ analysis to be used. Effects of directionality should, in particular, be considered.

Statistical models are essential for adequately describing environmental parameters. Recognized statistical methods and models should be applied to the assessment of maximum design and operating conditions. Models leading to the design responses of interest should consider the jointly distributed environmental phenomena. Environmental data, such as wind, wave, current, and tide, have site-specific relationships governing their interaction. The commonly used assumption of taking the combined maximum of each usually produces overly conservative designs. When collecting data, the various relationships should be included, if possible. Of particular importance are the wind/wave, wave height/period, and wave/current relationships and their relative directions. Design levels obtained from joint probability distributions of all relevant phenomena should be based on the design service life and risk analysis as described in 4.1.

The directions of the various environmental phenomena should also be considered. This is especially important at single point moorings. If all the environmental phenomena come from the same direction, and the moored vessel aligns with this direction, then the resulting force on the system is usually minimized. However, when waves act at high angles to winds or currents and the moored vessel is not aligned with the predominant environmental force, the resulting forces are generally higher.

4.3 WIND

Wind is a significant design factor. The wind conditions used in a design should be appropriately determined from collected wind data and should be consistent with other environmental parameters assumed to occur simultaneously.

Two methods are generally used to assess effects of wind for design. These include the following:

- a. Wind forces are treated as constant and calculated on the basis of the 1-minute average velocity.
- b. Fluctuating wind force is calculated on the basis of a steady component, based on the 1-hour average velocity, plus a time-varying component calculated from a suitable empirical

wind gust spectrum.

The choice of the treatment depends on the system parameters and goals of the analysis. Either approach may give more severe loads, depending on the system moored and the wind spectrum used. The time varying component in method b is also known as low-frequency wind force. Although methods for predicting low-frequency wind force have been extensively studied, there is still a substantial degree of uncertainty in the estimation, particularly in the wind energy spectrum that is derived from measured wind data. Therefore, caution should be exercised in selecting the spectrum to ensure that it adequately represents wind energy at the low frequencies typically associated with natural frequencies of moored structures. A more detailed discussion on low-frequency wind forces is presented in A.4.

The design wind speed should refer to an elevation of 33 feet (10 meters) above still water level. Rapid changes in wind direction and the resulting dynamic loads should be considered in the design of single point mooring systems.

4.4 WAVES

Wind-driven waves are a major source of environmental forces on offshore facilities. Such waves are random in nature, vary in height and length, and may approach a platform from more than one direction simultaneously. For these reasons the intensity and distribution of the forces applied by waves are difficult to determine. Because of the complex nature of the technical factors that must be considered in developing wave-dependent criteria for the design of moored installations, specialized knowledge in the fields of meteorology, oceanography, and hydrodynamics should be applied.

Because of the random nature of the sea surface, the sea-state is usually described in terms of a few statistical wave parameters such as significant wave height (average of the highest one third wave heights), spectral peak or significant wave period, spectral shape and directionality. Other parameters of interest can be derived from these. Refer to API Recommended Practice 2A for a more detailed discussion on sea-state representation.

The design significant wave height should be determined based on the design recurrence interval and wave data. The wave data used to determine the design should include available measured data and storm hindcast data as well as ship observations. The wave height versus wave period relationships for the design sea-state should be accurately determined from oceanographic data for the area of operation. The period can significantly affect surge and sway amplitudes and mean drift forces. For cases where measured data are not available, Figure 17 provides significant wave period versus wave height relationships for wind-generated waves and for predominant swell conditions.

4.5 CURRENT

The most common categories of currents are: (a) tidal currents (associated with astronomical tides), (b) circulatory currents

(associated with oceanic-scale circulation patterns), (c) storm-generated currents, (d) loop and eddy currents, and (e) soliton currents. The vector sum of these currents is the total current, and the speed and direction of the current at specified elevations are represented by a current profile. The total current profile associated with the sea-state producing the extreme waves should be specified for mooring design. The frequency of occurrence of total current speed and direction at different depths for each month and/or season may be useful for planning operations. In certain geographic areas, current force can be the governing design load. Consequently, selection of appropriate current profiles requires careful consideration.

4.6 WATER DEPTH AND TIDE

Tidal components for design include astronomical, wind, and pressure-differential tides. Tides and slope and direction of the ocean floor should be included in the determination of the design water depth.

4.7 SOIL CONDITIONS

Bottom soil conditions should be determined for the intended site to provide data for the anchoring system design.

4.8 ATMOSPHERIC ICING

There are several sources of superstructure icing. Sea-spray icing can effect the structure to a height of 50 feet above the waterline. Ice formed from fog or rain can accumulate on any exposed surface. Superstructure icing should be considered in platform wind force calculations.

4.9 MARINE GROWTH

The type and accumulation rate of marine growth at the design site may affect weight, hydrodynamic diameters, and drag coefficients of vessel members. These should be taken into consideration in the design.

5 Environmental Forces and Vessel Motions

5.1 BASIC CONSIDERATIONS

The purpose of this section is to describe methods for calculating forces that act on floating vessel due to environmental effects, such as waves, winds, currents, and so forth. Forces due to platform motion responses are also significant and are discussed herein. Environmental parameters needed

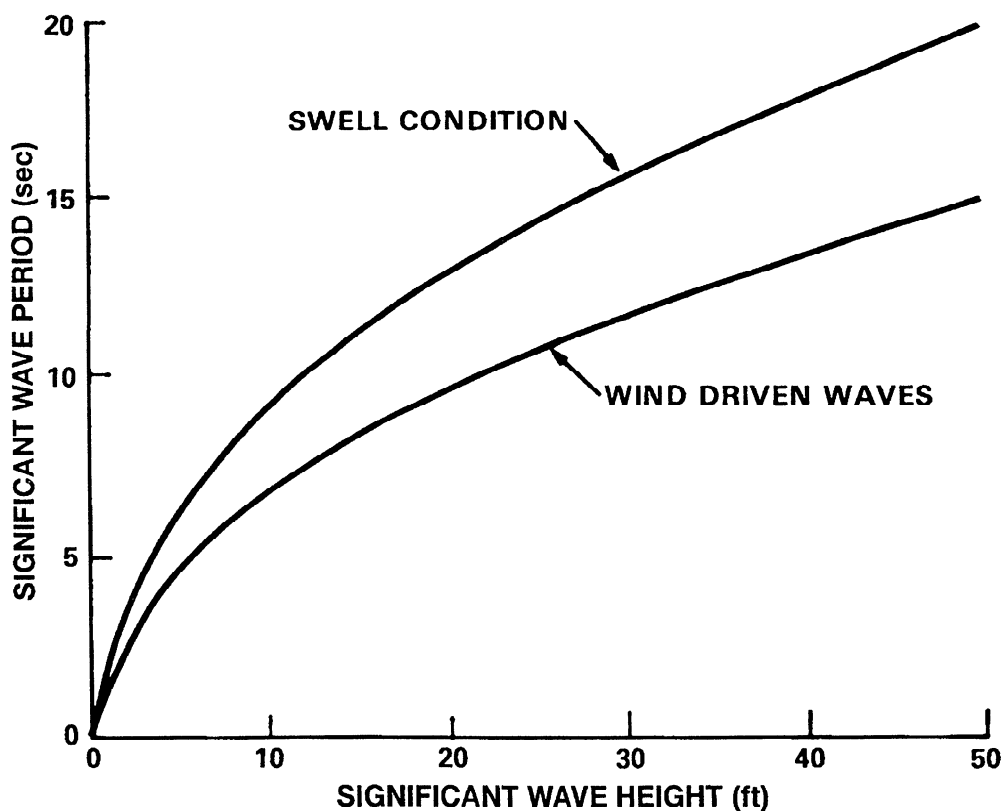


Figure 17—Wave Height/Wave Period Relationship

for these calculations are defined in Section 4. Methods for estimating platform motions and mooring system loads caused by these environmental forces are given in Section 7.

Environmental forces should be calculated at the following three distinct frequency bands to evaluate their effects on the system:

- a. Steady forces such as wind, current, and wave drift are constant in magnitude and direction for the duration of interest.
- b. Low-frequency cyclic loads can excite the platform at its natural periods in surge, sway, and yaw: typical natural periods range from 1 to 3 minutes.
- c. Wave frequency cyclic loads are large in magnitude and are the major contributor to platform member forces and mooring system forces. Typical wave periods range from five to twenty seconds.

5.2 GUIDELINES FOR THE EVALUATION OF ENVIRONMENTAL FORCES AND VESSEL MOTIONS

Environmental forces and vessel motions can be determined either by model testing or calculation. Guidelines for evaluating these values by various approaches are provided in API Recommended Practice 2T [3]. The wind spectrum recommended for the evaluation of low-frequency wind forces can be found in API Recommended Practice 2A [2].

5.3 SIMPLIFIED METHODS

Design equations and curves for a quick evaluation of environmental forces and vessel motions are provided in Appendix A. 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. For the final design of permanent moorings, however, the more rigorous approaches as outlined in 5.2 are recommended. Simplified methods are available for the following force components:

- a. Current forces for ship-shaped and semisubmersible hulls.
- b. Mean wave drift forces and low-frequency motions for ship-shaped and semisubmersible drilling vessels.
- c. Steady wind force.
- d. Wind and current forces for large tankers.
- e. Forces due to oblique environment.

Appendix A also provides some general discussion on the evaluation of environmental forces and vessel motions.

6 Design Criteria

6.1 BASIC CONSIDERATIONS

In this section, design criteria are established for the following conditions:

- a. Intact condition. This is the condition in which all mooring lines are intact.
- b. Damaged condition. This is the condition in which the vessel settles at a new equilibrium position after a mooring line breakage.
- c. Transient condition. This is the condition in which the vessel is subjected to transient motions (overshooting) after a mooring line breakage before it settles at the new equilibrium position.

Also, two mooring analysis methods, dynamic analysis and quasi-static analysis, can be used for mooring design. Different factors of safety were established for the two methods to account for the different levels of uncertainty of two approaches. Section 7 gives a more detailed discussion on the differences between dynamic analysis and quasi-static analysis.

Following are guidelines for the type of analysis to be conducted and conditions to be analyzed for various operations:

Type of Mooring	Analysis Method	Conditions to be Analyzed
Permanent Mooring		
Preliminary design	Quasi-static or dynamic	Intact/damaged
Final design	Dynamic	Intact/damaged/ transient
Fatigue Design	Dynamic	Intact
Mobile Mooring		
Away from other structures	Quasi-static or dynamic	Intact
Mooring lines over pipeline	Quasi-static or dynamic	Intact/damaged
Vessel next to a platform	Quasi-static or dynamic	Intact/damaged/ transient

In some operations, special operation procedures are used to reduce mooring line tensions and vessel offsets. For example, it is a common practice for MODUs to slacken a couple of leeward lines in a storm environment to reduce line tension. Such a practice may also be carried out in an operating environment with high currents to reduce vessel offset. Operational aspects of this nature can be taken into consideration in the analysis if such a practice is well defined in the operation manual and is routinely carried out by trained operation personnel. On the other hand, if the vessel operates in an area where a storm can come without much warning or can change direction suddenly, such a practice is not practical and therefore should not be incorporated into the mooring analysis.

In the areas of hurricanes or tropical cyclones, the drilling

riser of a MODU is often pulled, and all the mooring lines are slackened before arrival of a hurricane or tropical cyclone. This operational practice can also be taken into consideration in the mooring analysis.

Another special operation procedure is to optimize the windward lines such that all the windward lines share approximately the same load. In general, this practice should not be considered in the analysis for several reasons. First, windward lines cannot be optimized in a confused sea as in an analysis. Second, it is dangerous to attempt optimizing windward lines in a severe storm where releasing the winch brakes or the chain stoppers can lead to serious consequences. Third, operation experience indicates that such a practice is seldom carried out even though it is stated in the operation manual. One exception is that for certain operations where storms develop slowly and maintain a fairly constant direction, a well trained crew will have sufficient time to establish favorable moorings for the impending storms. In this case some consideration can be given to windward line optimization in the mooring analysis.

6.2 OFFSET

6.2.1 Definition of Mean Offset

The mean offset is defined as the vessel displacement due to the combination of current, mean wave drift, and mean wind forces.

6.2.2 Definition of Maximum Offset

The maximum offset is the mean offset plus appropriately combined wave frequency and low-frequency vessel motions. Maximum offset can be determined by the following procedure.

Let:

S_{mean} = mean vessel offset.

S_{max} = maximum vessel offset.

S_{wfmax} = maximum wave frequency motion.

S_{wfsig} = significant wave frequency motion.

S_{lffmax} = maximum low-frequency motion.

S_{lfsig} = significant low-frequency motion.

(1) $S_{lffmax} > S_{wfmax}$, then

$$S_{max} = S_{mean} + S_{lffmax} + S_{wfsig} \quad (6.1)$$

(2) $S_{wfsig} > S_{lffmax}$, then

$$S_{max} = S_{mean} + S_{wfsig} + S_{lffmax} \quad (6.2)$$

A parametric study has been performed to assess the risk level associated with this method of combining wave and low-frequency motions [14]. The chance of exceeding the combined motions defined above was estimated using a probabilistic approach for different hull forms, water depths, environments, and types of mooring. The results of the study

indicate that the combined low and wave frequency motions defined in this manner would be exceeded on the average of once in the specified storm duration.

An alternative to this approach is a time domain simulation of vessel motions or model testing for the specified storm duration. If this approach is used, the simulation or model testing should be of sufficient length to establish reasonable confidence bounds for the expected maximum response in the storm duration. Typically specified storm duration should be simulated several times, and statistical fitting techniques should be used to establish the expected maximum response.

The above discussion applies to the intact and damaged conditions. For the transient condition, maximum offset is defined in 7.3.

6.2.3 Offset Limits

The offset of the vessel from the sea floor well location must be controlled to prevent damage to drilling or production risers.

6.2.3.1 Drilling Operation

The mean offset should be controlled under the drilling operating condition because of its direct relevance to the mean ball joint angle of the drilling riser. The allowable mean offset should be determined by a drilling riser analysis, allowable mean offsets depend on many factors such as water depth, environment, and riser system. For the drilling operation to continue, allowable mean offsets normally fall in a range of 2 percent to 4 percent of water depth. Generally the lower bound applies to deepwater (2000-3000 feet) operations, and the upper bound applies to shallow water (below 300 feet) operations.

The maximum offset should be controlled under the maximum storm condition for the drilling operation to prevent damage to the mechanical stop in the ball joint below the drilling riser. The allowable maximum offset should be determined by a drilling riser analysis. Allowable maximum offsets depend on many factors such as water depth, environment, and riser system. They normally fall in a range of 8 percent to 12 percent of water depth. Generally the lower bound applies to deepwater (2000-3000 feet) operations, and the upper bound applies to shallow water (below 300 feet) operations. Analysis of vessel offset for drilling operations is required for the intact condition only. Guidelines for the analysis of marine drilling risers are given in API Recommended Practice 16Q [7].

6.2.3.2 Production Operations

There are basically four types of production risers:

- Rigid riser.
- Flexible riser.
- Hybrid riser.
- Riser integrated with single point mooring.