Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems

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SECTION 1
GENERAL

1.1 PURPOSE. This recommended practice pertains to the design, selection, operation, and maintenance of marine riser systems for floating drilling operations. Its purpose is to serve as a reference for designers, for those who select system components, and for those who use and maintain this equipment. It relies on basic engineering principles and the accumulated experience of offshore operators, contractors, and manufacturers.

It should be noted that technology is advancing in this field and that improved methods and equipment are continually evolving. Each owner and operator is encouraged to observe the recommendations outlined herein and to supplement them with other proven technology which may result in more cost effective, safer, and/or more reliable performance.

1.2 ORGANIZATION. This recommended practice is organized for ready reference. Section 2 contains a comprehensive description of riser system components including function, typical designs, and selection criteria. Section 3 contains the recommended riser design procedure and recommended design and operating limits for critical parameters. Section 4 contains recommended procedures for operations and maintenance. Section 5 addresses special situations. The appendices contain a glossary of terms used throughout this RP, sample riser analysis data sheets, a presentation of associated topics, sample procedures and calculations, and a section containing both references and a bibliography.

1.3 SCOPE. The marine drilling riser is best viewed as a system. Designers, contractors, and operators should be cognizant that the individual components should be designed and selected so as to suit the overall performance of that system. For the purposes of this Recommended Practice, a marine drilling riser system includes the tensioner system and all equipment between the top connection of the upper flex/ball joint and the bottom connection of the lower flex/hall joint. It specifically excludes the diverter, LMRP, BOP stack, and hydraulic connectors.

Sections 1 through 4 of this RP are directly applicable to most floating drilling operations. For deepwater locations (exceeding 2000 feet for the purposes of this document), refer to the paragraphs in Section 5 dealing with Deepwater Drilling and Collapse. The special considerations required for Guidelineless Drilling are also addressed in Section 5. In addition, Section 5 addresses precautions when drilling in High Currents, in Cold Weather Areas, or when H_2S is present.

All riser primary load path components addressed in this RP should be consistent with the load classifications specified in API RP 2R (Design, Rating, and Testing of Marine Drilling Riser Couplings).

SECTION 2
COMPONENT FUNCTION AND SELECTION

2.1 INTRODUCTION. General requirements common to all components are outlined in Paragraph 2.2 and, where appropriate, individual components are addressed in subsequent paragraphs. The following general format is used:

a. Function — the basic function of the component is described.

b. Typical Designs — examples of typical designs are presented.

c. Selection Criteria general performance requirements are outlined.

2.2 COMPONENT SELECTION CRITERIA. Design of a riser system begins with an assessment of expected operating conditions and an engineering analysis to establish parameters such as tensile, bending, and combined stresses (maximum and mean), buoyancy requirements, top tension requirements, vessel RAOs (Response Amplitude Operators), etc. Other factors influencing riser system design include riser length (water depth), dimensional requirements (bore, wall thickness, etc.), internal pressure rating, choke/kill, and auxiliary line specifications, makeup method, storage and handling conditions, operating economy, etc. Once established, these riser system design criteria should permit the selection of riser components that suit the application.

2.3 MARINE DRILLING RISER SYSTEM. The marine riser system forms an extension of the well bore from the Blowout Preventer (BOP) stack to the drilling vessel (Figure 1.1).

The primacy functions of the marine riser system are to:

a. Provide for fluid communication between the well and the drilling vessel:

1. In the riser annulus under normal drilling conditions.
2. Through the choke and kill lines when the BOP stack is being used to control the well,

b. Support the choke, kill, and auxiliary lines,

c. Guide tools into the well,

d. Serve as **a** running and retrieving string for the BOP stack.

2.4 TENSIONER SYSTEM.

2.4.1 **Function.** Tensioner units are used to apply vertical force to the top of the marine drilling riser to control its stresses and displacements. The units are normally located on the drilling vessel near the periphery of the drillfloor. They provide nearly constant axial tension to the riser while the floating drilling vessel moves vertically and laterally in response to the wind, waves and current.

2.4.2 **Typical Design.** Tensioner units use a hydraulic ram with a large volume, air-filled accumulator to maintain near constant pressure/tension on the line. One end of the line, which may **be** wire rope or chain, is attached at the tensioner and the other is attached to the outer barrel of the telescopic joint. Typically, a four-part line reeving system is used so that the piston stroke is equal to ¼ of the vessel heave. The number and rating of tensioner units used will determine the total capacity of the tensioner system. The tension applied by each unit can be varied up to its design capacity by increasing or decreasing the applied air pressure. The tensioner system should be capable of providing sufficient tension based upon the maximum rated water depth, maximum expected mud weight, and other loadings determined from riser analyses.

Emerging designs for tensioner systems are described in Appendix C, Section C.l.

2.4.3 Selection Criteria. Some important considerations for designing an effective tensioner system are:

a. The **fleet angle.** The idler sheaves should be placed so as to minimize the fleet angle. This maximizes the vertical component of tension, minimizes the horizontal component, and increases wireline life.

Because of the fleet angle, the vertical tension applied to the outer barrel of the telescopic joint is less than the tension supplied by the tensioner system. A reduction factor (see Section 3.3.2) should be used to reconcile these parameters.

b. Wireline life. Wireline life is a function of many parameters including wire rope construction, sheave diameter, applied tension, operating circumstances relating to travel, etc. See API BP 9B.

c. Accumulators and Air Pressure **Vessels,** Each tensioner unit should have an accumulator that is **large** enough to store a volume of hydraulic fluid **greater** than the cylinder volume. Large air pressure vessels will reduce pressure changes caused by the compression and expansion of the stored air as the tensioner strokes in and out.

d. Fluid and air flow requirements. Properly sized lines will reduce tension variations caused by piping system pressure losses.

A list of hydraulic fluids compatible with the tensioner units should be specified **by** the tensioner manufacturer.

e. Friction and Inertia losses. Seal friction, sheave friction, and inertia of sheaves, wire rope, tensioner rods, and pistons all contribute to variations in the wireline tension.

f. Dynamic Tension Limit (DTL). Tensioner ratings are defined differently by various manufacturers. This document defines a dynamic tension limit as the maximum allowable pressure multiplied by the effective hydraulic area, divided by the number of line parts:

$$DTL = P_A \times A_{CYL} / N_{LP}$$

where P_A = maximum allowable **system** operating pressure

A_{CYL} = effective hydraulic area

N_{LP} = number of line parts

All components in a riser system installation, including piping, should be designed for the maximum allowable working pressure. See ASME UG 125-136 for relief valve setting criteria.

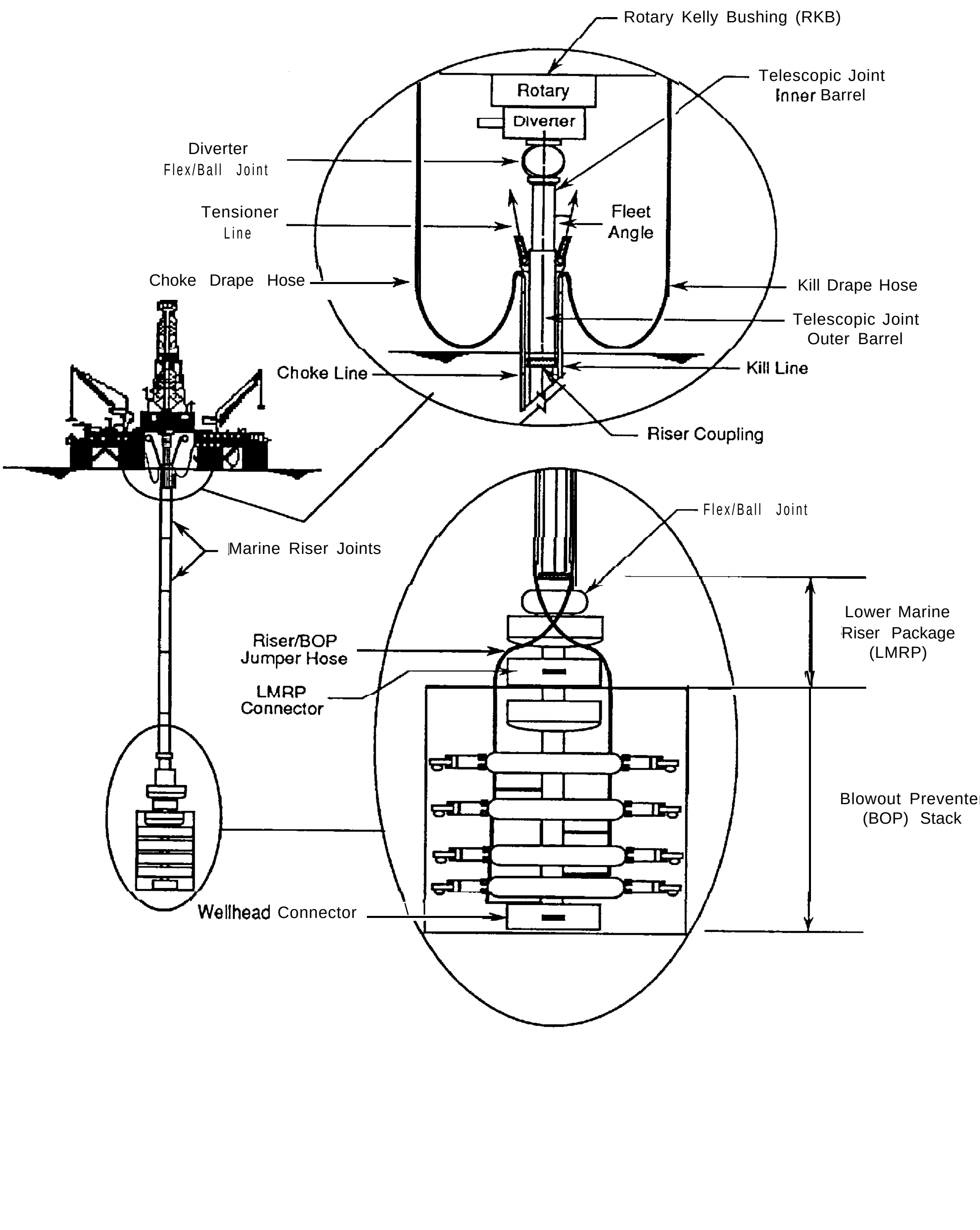


FIGURE 1.1
MARINE RISER SYSTEM AND ASSOCIATED EQUIPMENT

The tensioner system should be designed to permit one unit to be out of service for maintenance or repair without jeopardizing the ability of the remaining tensioner units to provide the required tension to the marine drilling riser. A unit may be either a single tensioner or a pair of tensioners, depending on specific design.

g. Maximum Tension Setting. The maximum tension setting should not exceed 90% of DTL so that the maximum tension, including dynamic variations, will be less than the DTL.

h. Velocity Limiting Device. Some type of flow control device is normally located in the line between the fluid port on each tensioner and its respective air/oil interface bottle. This device should offer minimal resistance to fluid flow during all anticipated heave velocities. However, if a tensioner wireline should break or other failure occur which would allow the tensioner to stroke out at an uncontrolled rate, this flow control valve should sense the abnormally high fluid flowrate and immediately stop or greatly reduce the fluid flow into the tensioner.

2.5 DIVERTER SYSTEM (SURFACE).

2.5.1 Function. When drilling top hole through the 30-inch casing, the riser may be employed enabling the use of weighted mud to provide overbalance if needed. Blowout preventers (BOPs) are not in place at this stage (see Section 2.14.1) because the 30-inch casing normally lacks sufficient pressure integrity to allow shut in. Therefore, if the well flows, the riser will direct that flow to the diverter system aboard the rig. Typically the diverter system includes an annular sealing device, means to both open the vent line and close the mud flowline, and a control system.

2.5.2. Location. Surface diverter systems on floating rigs are usually installed directly below the rotary table. The diverter unit is latched into a built-in housing. The upper flex/ball joint, which is the uppermost component in a marine drilling riser system, is usually mounted to the bottom of the diverter unit.

A subsea diverter stack may be installed on the wellhead to divert subsea.

2.5.3 Operation. API RP 64 provides Recommended Practices for Diverter Systems Equipment and Operations.

2.6 TELESCOPIC JOINT (SLIP JOINT).

2.6.1 Function. The basic function of the telescopic joint is to compensate for the relative translational movement between the vessel and the riser. The outer barrel provides structural support for riser tensioner loads.

2.6.2 **Typical Design.** A telescopic joint has an outer barrel which is connected to the drilling riser, an inner barrel which is connected to the drilling vessel, and a tensioner ring which transmits loads from the tensioner system to the outer barrel of the riser.

2.6.2.1 Riser Tensioner Attachment. The riser tensioner lines typically attach to the tensioner ring near the top of the telescopic joint outer barrel. This attachment provides the structural interface between the marine riser and the tensioner system. Padeyes on the tensioner ring accommodate pinned connections at the ends of the tensioner lines. The tensile load to support the riser is transmitted through the riser tensioner ring to the pipe wall of the outer barrel and subsequently through the couplings and pipe walls of the riser joints.

2.6.2.2 Optional Features of the Tensioner Ring

a. For turret moored and dynamically positioned vessels, a low friction bearing on the tensioner ring allows the vessel to rotate. Resulting torsional loads on the riser and wellhead should be considered.

b. For guidelineless reentry, hydraulic motor drive may be provided on the tensioner ring to orient the LMRP with the BOP stack.

c. For operational convenience, the riser tensioner ring may be detached from the outer barrel and fitted for latching to the bottom of the diverter housing for storage. This arrangement eliminates the time consuming operations of connecting/disconnecting tensioner lines when deploying/retrieving the riser. Integral stab connectors may also be provided to permit ready connections of the drape hose terminal fittings.

2.6.3 Selection Criteria. The selection of a telescopic joint should include consideration and evaluation of the following basic items.

a. Strength. In both its retracted and extended positions, the telescopic joint should support the weight of the riser and BOP stack. The dynamic loads on the telescopic joint should be considered.

b. Stroke length. The maximum stroke length required for the telescopic joint should accommodate the combined expected heave, vessel offset, tidal change, and maximum anticipated vessel excursion in the event of a station-keeping failure.

c. Tensioner ring. Angular orientation on the padeyes on the tensioner ring should accommodate the positions of the tensioner line sheaves. The tensioner ring should be rated for the maximum load capacity of the telescopic joint.

d. Auxiliary lines. The designer of the attachments for auxiliary lines, choke and kill lines, and the telescopic joint packing pressure line should consider the layout of the rig and the ease of making and breaking the connections during running and retrieving operations.

e. Packing elements. The packing element that is used to seal between the outside of the inner barrel and the inside of the outer barrel is available in either single element units or double element units. The advantage of the double element units is that when one of the packing elements fails, the second element can be energized, thus maintaining the seal between the drilling fluid and the environment, without having to shut down the drilling operation.

f. **Handling and Storage.** The telescopic joint is typically longer and heavier than standard riser joints and, therefore, it has special handling and storage requirements.

2.7 RISER JOINTS.

2.7.1 Function. A riser joint is a large diameter, high-strength pipe (riser main tube), either seamless or electric welded, with couplings welded to each end. When the riser system is being deployed, the riser joints are coupled together on the drill floor and lowered into the water. The string of riser joints represents the principal component of the riser system and is used to perform the riser system functions listed in Section 2.3. The box or pin coupling at the upper end of the riser joint usually has a landing shoulder. This landing shoulder, or riser support shoulder, supports the loads (static and dynamic) of the marine riser and BOP stack when it is suspended from the riser spider. (See Section 2.11.2.2.) The coupling may also provide support for choke, kill, and auxiliary lines, and load reaction for buoyancy devices.

2.7.2 Typical Designs

2.7.2.1 Main Tube. Riser main tube and the associated couplings are generally sized to be compatible with a specific BOP stack size. Compatible BOP bore and riser outer diameter combinations are:

13 5/8" (346.1 mm) BOP, 16" (406.4 mm) Riser

16 3/4" (425.5 mm) BOP, 18 5/8" (473.1 mm) Riser

18 3/4" (476.3 mm) BOP, 20" (508 mm) or 21" (533.4 mm) Riser

20 3/4" (527.1 mm) BOP, 22" (558.8 mm) or 24" (609.6 mm) Riser

21 1/4" (539.8 mm) BOP, 24" (609.6 mm) Riser

The main tube is specified by its outside diameter, wall thickness, and material properties.

2.7.2.2 Riser Couplings. There are four basic riser coupling designs: 1) dog type, 2) flanged, 3) threaded union, and 4) breech-block.

Each riser manufacturer usually offers couplings with different strength ratings.

2.7.2.3 Choke/Kill and Auxiliary Lines. Typically, riser joints have choke/kill and auxiliary lines attached to the exterior of the main riser tube by support brackets. On most risers, these lines pass through the riser support shoulder. These riser-mounted choke/kill and auxiliary lines are described in Section 2.12.

2.7.3 Selection Criteria. The following items should be considered when selecting, designing or specifying riser joints.

2.7.3.1 Riser Main Tube.

a The riser main tube should have adequate strength to withstand combined loads from waves, current, applied tension, motion of the rig, and drilling fluid weight in accordance with Table. 3.1. Collapse pressure and handling loads should also be considered. The strength characteristics of the main tube are dictated by its diameter, wall thickness, and grade of steel. Steel grades commonly used in risers are X-52, X-65, and X-80, where the numbers refer to the minimum yield strength (ksi) of each grade.

b. The inside diameter must provide sufficient annular space to accommodate the desired casing program.

c. Typically, riser joint lengths range from 50 to 75 feet. The storage and handling characteristics on the rig must be considered in selection of the length.

2.7.3.1.1 Pup Joints. Pup joints are riser joints that are shorter than full length riser joints. Pup joints of various lengths should be available to accommodate riser space-out. See Section 4.3.1.

2.7.3.2 Riser Couplings. Coupling selection should be based on:

Strength

Load rating of support ring

Stress amplification factor (fatigue resistance)

Reliability

Speed of make-up

Preload for make-up

Maintenance requirements

Main tube dimensions

Strength to weight ratio

2.8 LOWER MARINE RISER PACKAGE (LMRP).

2.8.1 Function. The Lower Marine Riser Package typically includes an assemblage of a riser adapter, flex/ball joint, one, two, or no annular BOPs, subsea control pods, and a hydraulic connector mating the riser system to the BOP stack. The LMRP provides a releasable interface between the riser and the BOP stack. In addition, it provides hydraulic control of BOP stack functions through the control pods. Jumper hoses provide a flow path around the flex/ball joint for the choke and kill lines.

2.8.2 Typical Design. The LMRP can be designed to a variety of configurations depending upon the type, size, ratings, and operational water depth of its components. Some design considerations are:

a. Standard guidepost radius (see API RP 53)

b. Minimum bore size and compatible pressure ratings

c. Bending strength

d. Clearance for retrievable control pods

e. Accommodation for subsea accumulators

f. Loads and clearances during an emergency disconnect

g. Available space for storage and handling aboard drilling vessel

h. An emergency recovery system for deep water BOP's

i. Guidance system for reentry of guidelineless BOP's

j. Sequenced, retractable control pod stabs and choke/kill stabs on guidelineless systems

k. Flexible lines (see Section 2.10)

1. Guidance structure for BOP handling

2.8.3 Selection Criteria. The selection of LMRP components should be based on the following factors:

a Well control considerations

b. BOP pressure rating and bore

c. Guideline or guidelineless operations

d. Overall height and weight limitations

e. Operating environment and design loads

f. Method of BOP control and operational failsafe design features

g. Operational water depth

h. Method for running/retrieving control pods

i. Methods for reentry on guidelineless systems

j. Methods for emergency recovery

2.9 FLEX AND BALL JOINTS.

2.9.1 Function. Flex and ball joints are used to allow angular misalignment between the riser and the BOP stack, thereby reducing the bending moment on the riser. They are also used at the top of the riser to allow for the motion of the rig. In some instances they may also be installed at some intermediate level in the riser string below the telescopic joint to reduce stresses in the riser. The rotational stiffness of flex joints makes them more effective than ball joints in controlling riser angles. Typically, the rotational stiffness of a flex joint is a nonlinear function of angle and ranges from 10,000 to 30,000 foot-pounds per degree of rotation. Rotational stiffness may also vary with temperature.

2.9.2 Typical Design

2.9.2.1 Flex Joints. The flexure members of a flex joint are typically bonded laminations of elastomer between stacks of spherically shaped steel rings. The elastomer provides flexure and pressure sealing. Some designs provide a landing shoulder for a readily removable wear bushing. Still others provide a wear ring which can be replaced during periodic overhaul of the flex joint. Because of the design of flex joints, repair of major keyseat damage may prove to be uneconomical. The user should request the supplier to provide a list of facilities with the capabilities to repair keyseat damage.

2.9.2.2 Ball joints. A ball joint is a forged steel ball and socket containing a cylindrical neck extension with a riser adapter attached at the end of the neck. The ball and socket employs a seal which contains the drilling fluids. In most designs, replaceable wear rings or wear bushings are used. Some ball joints require pressure balancing.

2.9.3 Selection Criteria. The following items should be considered when selecting, specifying or designing flex joints and ball joints.

a Flex/ball joint function and location in the riser system.

b. Maximum angular rotation and maximum rotational stiffness required. These can be determined by a preliminary riser analysis.

c. Pressure rating. The flex/ball joint should maintain pressure integrity throughout exposure to wellbore fluids, maximum anticipated temperatures, maximum design mud weight, and maximum design water depth.

d. Maximum tensile load to he applied.

e. Maximum torque to he applied.

2.10 FLEXIBLE CHOKE AND KILL LINES.

2.10.1 Function. Flexible choke and kill lines allow relative movement at the telescopic joint (drape hose) and at flex/hall joints (jumper hose) in the riser system.

2.10.2 Typical Design. Three basic designs are commonly used, flexible pipe, steel reinforced hoses, or flow loops with threaded, clamped, or flanged end fittings. If threaded end fittings are used, they must contain a sealing means other than the threads.

2.10.3 Selection Criteria Flexible lines should be compatible with the rest of the choke and kill piping system and with the BOP stack, riser, and choke and kill manifold. Selection of flexible lines should take into account the following considerations:

a. Length requirement and tolerance

b. End fitting compatibility

c. Pressure rating (gas and liquid)

d. Collapse rating

e. Temperature rating (maximum, minimum, and ambient conditions)

f. Minimum bend radius

g. Fluid compatibility

h. Resistance to wear by abrasive fluids

i. Corrosion resistance

j. Fatigue resistance to bend and pressure cycling

2.11 RISER RUNNING EQUIPMENT.

2.11.1 Function. Riser and diverter handling tools are used for hoisting and lowering the riser and BOP stack. The riser spider is used to support the riser and BOP stack while they are being run or retrieved. When used, guidelines direct the riser and associated subsea equipment to the wellhead.

2.11.2 Typical Design

2.11.2.1 Handling Tools. Riser handling tools make up to the top of the riser during deployment and retrieval. The top connection is a short length of pipe which is supported by the hoisting equipment.

Another tool of importance is the diverter handling tool which may be used to carry the entire riser system load prior to landing the stack on the wellhead. If the diverter handling tool is used to support the entire riser and BOP stack, it should meet the same standards as the riser handling tool.

2.11.2.2 Riser Spiders. A riser spider provides support for the riser and BOP stack at the drillfloor. Shock-absorbing spiders are designed to reduce impact loads on riser support shoulders. Gimballing spiders reduce bending moments on the shoulders.

2.11.2.3 Guidelines. Guidelines may be used to direct the riser and associated subsea equipment to their mating connections near the seafloor. Generally, four wire rope guidelines, forming the corners of a square, extend up from the temporary guidebase to the floating drilling vessel where each is tensioned by a guideline tensioner (similar to a riser tensioner). Typically, the guideline attachment points are six feet from the center of the well bore forming a square approximately 8.5 feet on a side.

2.11.3 Selection Criteria The selection, rating, and testing of riser running equipment should be based on the following:

a Maximum static loading capacity.

b. Dynamic loads induced by vessel motions, waves, and currents.

c. Bending loads during riser running operations.

d. Impact loads

2.12 RISERMOUNTED CHOKE/KILL AND AUXILIARY LINES.

2.12.1 Function. These lines carry fluids along the length of the riser. On most risers, they are an integral part of each riser joint and are attached on the outside of the riser main tube by support brackets. Generally, these lines are used for the following:

a. Choke/Kill lines are used to provide a controlled flow of oil, gas or drilling fluid from the wellbore to the surface when the blowout preventer stack is closed.

b. Mud Boost lines are used as conduits for drilling fluid which is pumped into the riser just above the blowout preventer stack to increase annular circulating velocities.

c. Air Inject lines are used to supply air to increase riser buoyancy for air can buoyancy risers.

d. Hydraulic Supply lines carry hydraulic operating fluid to the blowout preventer subsea control system. Most blowout preventer systems incorporate a flexible hydraulic fluid supply line inside the control line hose umbilical.

2.12.2 Typical Designs. Typical riser joints have integral choke and kill lines. This provides redundancy and also allows for the following well control operations:

a. Circulating down one line and up the other line.

b. Circulating down the drill pipe and up one line.

A mud boost line is incorporated for some risers. Air inject lines are required for riser systems which use air-chamber buoyancy systems. Hydraulic supply lines can be used as either a primary or secondary supply line.

Generally, choke/kill and auxiliary lines of one riser joint are connected to their counterparts on adjoining riser joints by stab-in couplings. The box contains an elastomeric radial seal which expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized. These stab-in couplings also facilitate fast make-up while deploying the riser.

2.12.3 Selection Criteria The following items should be considered when selecting, designing or specifying choke/kill and auxiliary lines for riser joints.

a The Type of Fluid to be carried by the line. Hydraulic supply lines are generally constructed of corrosion-resistant material to prevent rust particles from clogging hydraulic operator ports and damaging seals and sealing surfaces. Choke/kill and mud boost lines are generally constructed of steel.

Care should be taken to ensure that proper galvanic protection is provided between the steel components of the riser joints and the hydraulic supply lines if corrosion-resistant material (e.g. stainless steel) is used.

b. The Operating Pressures which the line may be exposed to during its lifetime.

1) Hydraulic Supply Lines: Working pressure rating should be compatible with the working pressure rating of the BOP control system.

2) Mud Boost Lines: Pressure rating should be suitable for the intended service.

3) Choke/Kill Lines: Pressure rating should be the same as that of the BOP stack.

c. The Choke/Kill and Auxiliary Line Couplings. These couplings must be able to seal against full pressure while allowing for relative motion between the box and pin caused by: (1) Poisson's effect, (2) structural compression caused by pressure exerted on the ends of the pins, (3) temperature differences between the fluid in the main riser and the fluids in the choke/kill or auxiliary lines, (4) bending loads imposed by deflections of the riser.

This relative motion can cause fatigue cracking of the support bracket if adequate gap is not provided between the support bracket and the coupling.

d. Internal Diameter of the Line. The ID of the choke/kill lines should be selected to suit well control operations. The ID of the mud boost line should be selected to suit drilling fluid requirements. The ID of the hydraulic supply line should be selected to suit control system requirements.

e. Failsafe design and orientation of choke/kill and auxiliary lines. To prevent accidental mismatching of the choke/kill and auxiliary lines when the riser is deployed, the couplings should be oriented asymmetrically around the riser support ring. To prevent accidental over-pressuring of the mud boost line while testing during deployment, the test caps for the choke/kill lines should be designed so that they cannot be installed on the mud boost line.

f. Support bracket design The support brackets attach the lines to the riser and prevent buckling when they are pressurized. The spacing of the support brackets is dependent upon the rated pressure of the choke/kill lines and the buckling characteristics of the pipe.

g. H_2S service requirements. If H_2S can enter the choke and kill lines, material selection should meet the requirements of NACE MR-01-75.

h. Pressure ratings. All pressure piping should be designed in accordance with API Specification 16C.

i. Corrosion/erosion allowances. The minimum design thickness should include a corrosion/erosion allowance of 0.05" as recommended in API RP 14E.

2.13 BUOYANCY EQUIPMENT.

2.13.1 Function. Buoyancy equipment may be attached to riser joints to reduce top tension requirements by decreasing the submerged weight of riser joints.

2.13.2 Typical Designs

a. Foam modules. Syntactic foam is typically a composite material of hollow spherical fillers in a matrix or binder. The most common forms of syntactic foam consist of tiny glass microspheres in a matrix of thermosetting plastic resin, often with larger micospheres of glass fiber reinforced plastic.

The diameter of syntactic foam modules depends primarily on the buoyancy requirements and the foam density. The foam density depends on the design water depth. Denser material is normally used for deeper water to withstand higher collapse pressures. Maximum allowable diameter is determined by the bore of the diverter housing and/or other restrictions through which the riser joint must pass. See Section 5.3 for high current operations.

Typically, foam modules are installed in pairs around the riser joint, several pairs per joint, and have cutouts to accommodate choke, kill, and auxiliary lines. The modules are held in place either by circumferential straps or other suitable means. Fastener material should be selected to avoid galvanic corrosion.

The vertical lift of the foam module is imparted to the riser by a thrust collar fitted to the riser pipe just below the upper coupling. A matching collar is generally installed at the lower end of the assembled modules to retain them in place during riser handling.

b. Open-bottom air chambers. Open-bottom air cans are typically attached to the riser coupling and provide an annular space around the riser. Air injection and pilot lines provide the means to inject air at ambient hydrostatic pressure. Air displaces seawater from the annular space to provide buoyancy. A float valve in the injection line near the bottom of the chamber maintains the water at the preset level. Air can be bled from the system through a discharge valve actuated by the pilot line. Valves can be arranged and adjusted to provide the desired buoyancy level. Compressors aboard the drilling vessel are used to supply air through the injection line to the air chambers.

2.13.3 Selection Criteria. Foam modules should be selected to provide the required lift and resistance to pressure at the rated service depth. Their design should be such that they do not restrain the bending of the riser tube and can be safely handled and stored. Maintenance and repair procedures should be investigated to ensure that they can be performed on the rig with minimal difficulty. For foam densities and water absorption considerations, see manufacturer's specifications.

Open-bottom air cans are relatively resistent to handling damage, but they can increase bending stresses at the riser coupling because of the added stiffness of the air cans. This should be investigated by the designer to make sure adequate provision is made for this in the riser operating program. The systems required to operate and maintain the riser should be evaluated to ensure that adequate redundancy is provided for critical equipment such as air compressors.

2.14 SPECIALTY EQUIPMENT.

2.14.1 Thirty-Inch Latch (Pin Connector). Under some conditions, it is advantageous to have the riser deployed while drilling the 26" hole. In that event, a 30" latch is used to connect the marine riser to the 30" wellhead housing. A ring joint pressure seal is effected between the latch assembly and the wellhead housing. Hydraulically operated multiple segments are used to form the mechanical latch engagement; the segments extend radially inward to engage a support shoulder on the wellhead housing O.D. The 30" latch is normally controlled by a dedicated hydraulic hose bundle run from the surface diverter/POP control system. The 30" latch is usually fitted with a flex/ball joint and a riser adapter.

2.14.2 Riser Hang-off System. When environmental conditions exceed the limits for safe operation with the riser connected, the riser and LMRP are disconnected from the BOP stack and may be hung-off until weather conditions improve. The disconnected riser may be hung off from the hook, the spider, the diverter housing, or specially designed beam structures. The dynamic loads of the heaving riser should be considered to ensure that the hang-off system components provide adequate strength to support the axial and transverse loads imparted by the suspended riser without damage to either the riser or the vessel.

SECTION 3
RISER RESPONSE ANALYSIS

3.1 GENERAL CONSIDERATIONS. The drilling riser has very little inherent structural stability. Its ability to resist environmental loading is derived from the applied tension. The marine drilling riser should be designed, and the top tension selected, based on the riser's response to the environmental and hydrostatic loads as well as the requirement that it properly performs its functions. Among the functional constraints are the angles at both the lower flex/ball joint and the telescopic joint, the mean and alternating stresses, the resistance to column buckling and hydrostatic collapse, the percentage of the DTL applied to the top of the riser, and forces and moments transferred to the BOP stack, wellhead and casing.

Specialized computer programs are generally used to predict riser behavior under the design conditions, and to determine top tension requirements, maximum permissible vessel offsets, and maximum loads on riser components.

Because of the manner in which the riser is employed, design of the drilling riser components cannot be separated from operational procedures. For example, when drilling, upper and lower flex/ball joint angles should be maintained within rather low limits. However, in the presence of severe weather, drilling may be suspended and the limitation on flex/ball joint angles relaxed. himiting criteria for riser design may then become maximum stresses. During such a change of operational mode, proper handling of the riser may dictate a change in the top tension. In an even more severe condition, the proper riser handling may dictate disconnecting the bottom of the riser and hanging it off from the rig. Decisions such as when to make such changes are part of the riser design process and require analysis of the riser in each of the potential operational modes.

This section applies equally to the design of a new riser system or the site specific evaluation of an existing riser system. Riser analyses should be performed for a range of environmental and operational parameters. If the riser is being designed, this will require starting with a proposed design and then iterating until the riser parameters, such as wall thickness and material strength, are found which satisfy the design objectives. For an existing riser system, the options available to the analyst include:

a Specifying the appropriate top tension for each combination of environmental and drilling parameters.

b. Coordinating the mooring system design to evaluate the position of the top of the riser.

c. Specifying the distribution of bare and buoyant riser joints throughout the riser string.

d Selecting the conditions at which the operational mode is changed (from drilling to nondrilling, and when to disconnect.)

3.2 RISER ANALYSIS PROCEDURE. Appendix B is a data worksheet for recording data prior to performing a riser analysis.

3.2.1 Vessel Station Keeping Considerations. The vessel's station keeping ability should be determined and used in conjunction with the riser analysis to assess flex/ball joint angles and riser stresses. The mooring and riser analyses are used to define operating limits for the riser. In some cases, mooring lines may be adjusted in response to long term variations in environmental conditions such as current and/or wind.

3.2.2 Riser-Induced Load Considerations. The riser introduces shear, bending, and tension loads into the LMRP, the BOP stack, the hydraulic connectors, the wellhead, and the casing. These loads and moments should be evaluated to ensure maximum stresses are within design allowables and the fatigue life is acceptable. The riser also induces loads on the drilling vessel that may need to be considered in the station keeping analysis.

3.2.3 Currents. For currents exceeding two knots, see section 5.3.

3.2.4 Drilling Fluid Density. Top tension requirements should be determined for several values of drilling fluid density ranging from that of sea water up to the maximum anticipated density.

3.3 DESIGN AND OPERATING LIMITS.

3.3.1 Operating Modes. Three operating modes are normally encountered in offshore drilling operations:

a Drilling Mode — The drilling mode is that combination of environmental and well conditions in which all normal drilling activities can be safely conducted including drilling ahead, tripping, under reaming, circulating, etc. Special operations, such as running casing, cementing, or formation testing, may dictate more restrictive operating limits.

b. Connected Nondrilling Mode — In this mode, the only drilling operations which should be conducted are circulating and tripping out drill pipe. The drill pipe should not be rotated. The riser may be displaced with sea water and preparations made to shut in the well and disconnect the riser if necessary.

c. Disconnected Mode — If environmental conditions exceed the limits for safe operation in the connected nondrilling mode, the riser should be disconnected to avoid possible damage to surface or subsea equipment.

3.3.2 Recommended Limits for Design and Operation. Selection of the appropriate combination of environmental conditions and hydrodynamic coefficients for the analysis involves judgment, experience, and an understanding of the type of riser analysis being employed. Design and operating limits for the key riser parameters — upper and lower flex/ball joint angles, mean and alternating stress, and the appropriate factor of safety on DTL — are selected based on sound engineering principles and successful operating experience.

Table 3.1 defines recommended operating and design guidelines for the three operating modes. It contains two stress criteria methods for the drilling mode, at least one of which should be satisfied. Generally, Method A is appropriate for most water depth locations and Method B is recommended for deep water locations. Table 3.1 addresses riser analysis for exploratory drill-

TABLE 3.1
MARINE DRILLING RISERS
MAX. OPERATING AND DESIGN GUIDELINES,,,

DESIGN PARAMETER	RISER CONNECTED: DRILLING	RISER CONNECTED: NON-DRILLING	RISER DISCON-NECTED
MEAN FLEX/BALL JT. ANGLE (UPR & LWR)	2.0 deg.	N/A	N/A
MAX. FLEX/BALL JT. ANGLE (UPR & LWR)	4.0 deg.	90% avail. [8]	90% avail.
STRESS CRITERIA [3]:			
• METH."A" • ALLOWABLE STRESS [4]	0.40 σ_y [2]	0.67 σ_y	0.67 σ_y
• METH."B" • ALLOWABLE STRESS [4]	0.67 σ_y [2]	0.67 σ_y	0.67 σ_y
• SIGN. DYN. STRESS RANGE			
@ SAF ≤ 1 5 [5]	10 KSI	N/A	N/A
@ SAF > 1.5 [5]	15 ÷ SAF	N/A	N/A
MINIMUM TOP TENSION [6]	T_{min}	T_{min}	N/A
DYNAMIC TENSION LIMIT [7]	DTL	DTL	N/A
MAX. TENSION SETTING	90% DTL	90% DTL	N/A

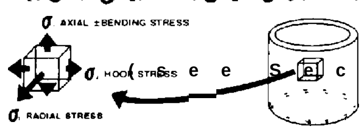
Notes:

[1] These Guidelines apply to the Global Riser Response.

[2] σ_y is the minimum yield strength of the material

[3] All stresses are calculated according to von Mises stress failure criterion:

$$\sigma^2_{vm} = \tfrac{1}{2}[(\sigma_1 - \sigma_2)^2 + (\sigma_2 - \sigma_3)^2 + (\sigma_3 - \sigma_1)^2]$$



(see Sect. 3.3.2)

[4] The Stress Criterion is the static stress plus max. dynamic stress amplitude.

[5] See Glossary for definition of "Stress Amplification Factor" (SAF).

[6] The min. Top Tension required to prevent global buckling of the riser is:

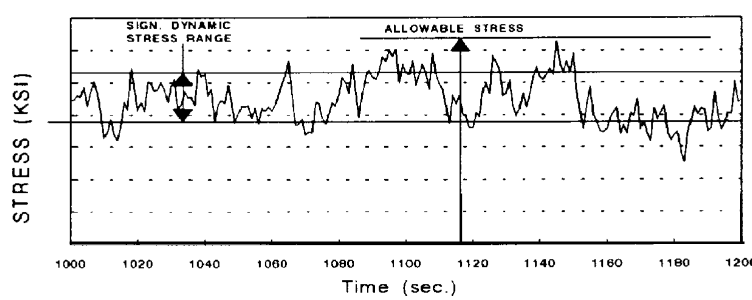
$$T_{min} = T_{SRmin} \times N \div [R_f (N-n)]$$ (see Sect. 3.3.2)

[7] Dynamic Tension Limit:

$$DTL = P_A \times A_{CYL} \div N_{LP}$$ (see Sect. 2.4.3.f)

[8] Reduce further with drill pipe in hole

ALLOWABLE STRESS & SIGN. DYN. STRESS RANGE



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ing. In cases of extended drilling on a harsh environment location, such as on a North Sea template, a fatigue analysis of the riser may be advisable. The mean and maximum flex/ball joint angle limits given for the normal drilling mode are intended to prevent wear and keyseating damage to the riser and flex/ball joint.. Prudent operational procedure should strive to maintain these angles as small as possible, and consider 2.0 degrees (mean) and 4.0 degrees (maximum) as upper bounds. The maximum flex/ball joint angle limits for the connected nondrilling mode and disconnected mode are intended to prevent damage to the riser, flex/ball joint, and BOP stack. The upper flex/ball joint angle rarely has a significant effect on riser design; however, this angle should be considered when evaluating clearances in the moonpool area.

The purpose of the maximum stress analysis is to ensure that the riser is strong enough to support the maximum design loads. This is accomplished by requiring the riser to support the maximum design loads while keeping the maximum stresses below the allowable stress. This limit is intended to prevent structural deformation that could lead to failure and includes a margin of safety. All stresses in Table 3.1 refer to the von Mises stress criterion (see Higdon, et al (1976)). Local peak stresses (see Glossary, Appendix A) are not considered for the maximum load analysis; however, these peak stresses could be of concern for evaluating the fatigue life of the riser. Fatigue analysis is discussed in Appendix C, Section C.2.

A minimum tension setting is required to ensure the stability of the riser. The tension setting should be sufficiently high so that the effective tension, as addressed in Section 3.4.3, is always positive in all parts of the riser even if a tensioner should fail. In most cases the minimum effective tension is encountered at the bottom of the riser.

The minimum top tension, T_{min}, is determined by:

$$T_{min} = T_{SRmin} N/[R_f (N-n)]$$

where,

$$T_{SRmin} = \text{Minimum Slip Ring Tension}$$
$$= W_s f_{wt} - B_n f_{bt} + A_i [d_m H_m - d_w H_w]$$

and

W_s = Submerged Riser Weight above the point of consideration

f_{wt} = Submerged Weight Tolerance Factor (minimum value = 1.05 unless accurately weighed)

B_n = Net Lift of Buoyancy Material above the point of consideration

f_{bt} = Buoyancy Loss and Tolerance Factor resulting from elastic compression, long term water absorption, and manufacturing tolerance. (Maximum value = 0.96 unless accurately known by submerged weighing under compression at rated depth)

A_i = Internal Cross Sectional Area of Riser including choke, kill, and auxiliary fluid lines

d_m = Drilling Fluid Weight Density

H_m = Drilling Fluid Column to point of consideration

d_w = Sea Water Weight Density

H_w = Sea Water Column to point of consideration including storm surge and tide

N = Number of Tensioners Supporting the Riser

n = Number of Tensioners Subject. to Sudden Failure

R_f = Reduction Factor Relating Vertical Tension at the Slip Ring to Tensioner Setting to account for fleet angle and mechanical efficiency (usually 0.9 - 0.95)

Note that in the above equation for T_{SRmin}, the exterior pressure, $d_w H_w$, is multiplied by the internal cross sectional area of the riser, A_i, rather than the exterior cross sectional area, A_o. This is because the buoyancy of the riser pipe walls, $d_w H_w (A_o - A_i)$, has been included in the submerged riser weight, W_s.

See Sample Calculation D.2 in Appendix D for a determination of minimum tension setting.

The significant dynamic stress range limit should also be used in conjunction with the maximum load analysis. This limit is intended to provide some control on the fatigue damage accumulated by the riser. Incorporation of this limit in the maximum load analysis eliminates large dynamic stresses which can lead to accelerated fatigue.

Additional operating modes which might influence design should be considered. Specifically, the disconnected mode, handling tool interfaces, hang-off on either spider or riser hang-off structure, special handling situations, and emergency conditions should be reviewed for their impact on riser system design.

The load and resistance factor design (LRFD) procedure, based on reliability rather than working stress, is rapidly gaining acceptance. This approach is described in Appendix C, Section C.3.

3.3.3 Riser Operating Manual. Results of the design analysis should be appended to the riser operating manual (See Section 4.2). Instructions for determining required top tensions as a function of all the relevant parameters should be included. The operating tensions provided to the operating personnel should be the tensions which are to be set on the tensioner units. These tensions are to include corrections for tensioner line fleet angles and losses through the tensioner system. Sufficient tension should be set so as to prevent riser buckling in the event of a tensioner unit. failure.

3.4 RISER ANALYSIS. The mathematical models and the solution techniques which can be used to analyze a drilling riser constitute a highly technical and specialized subject which has been widely treated in the literature. A bibliography is provided for the reader desiring detailed information, and the following text is limited to a general discussion of the pertinent. aspects of riser analysis. In particular, reference is made to the API Bulletin 16J, "Comparison of Marine Drilling Riser Analyses."

3.4.1 The Use of Riser Analysis. As a general rule, riser analysis has two distinct and different functions.

Prior to ordering a new riser, a set of analyses should be carried out to establish the design specifications. At this time, the environmental conditions are chosen to reflect the maximum operating conditions expected during the design life. Design criteria such as maximum and alternating stresses are used in selection of parameters such as wall thickness and material properties. The analysis includes the performance of the drilling vessel and should also be used for specifying the vessel's riser tensioning requirements.

Riser analysis may also be used in preparation for operating with an existing riser and vessel on a new site. In that case, the objective is to establish top tensioning requirement3 for the anticipated environmental conditions and drilhng fluid densities. Further, the analysis indicates at what environmental conditions drilling should be stopped, and when it is prudent to pull the riser. The analysis will likely also include special conditions such as hanging off in a storm or the effect of a broken mooring line.

3.4.2 Structural Model. For purposes of riser response analysis, the drilling riser is a tensioned beam which rarely, if ever, develops an angle greater than 10" from the vertical. For small angles, the fundamental Bernoulli-Euler beam equation adequately describes the response of the riser. The beam equation for the riser is developed by first examining a differential element and the forces which act upon it. Geometric nonlinearities should be considered in an analysis if the riser develops an angle greater than approximately 10 degrees.

Figure 3.1 shows the hydrostatic pressures of sea water and drilling fluid, the tension in the pipe wall, and the weight. It also shows the deformation of riser pipe over an elemental length. Finally, the horizontal hydrodynamic forces are indicated. The equations of equilibrium and simple beam theory leads to the equation of motion. The group of terms forming the coefficient of Y" (Figure 3.1) is commonly called the "effective tension". This form of the equation governing de behavior of the riser has been recognized and reported in the literature for years. Riser problems are analyzed by modeling the riser as a discretized or lumped parameter representation. This results in a system of simultaneous equations which allows for variations in riser properties and for the introduction of such other nonuniformities as flex/ball joints and soil restraints.

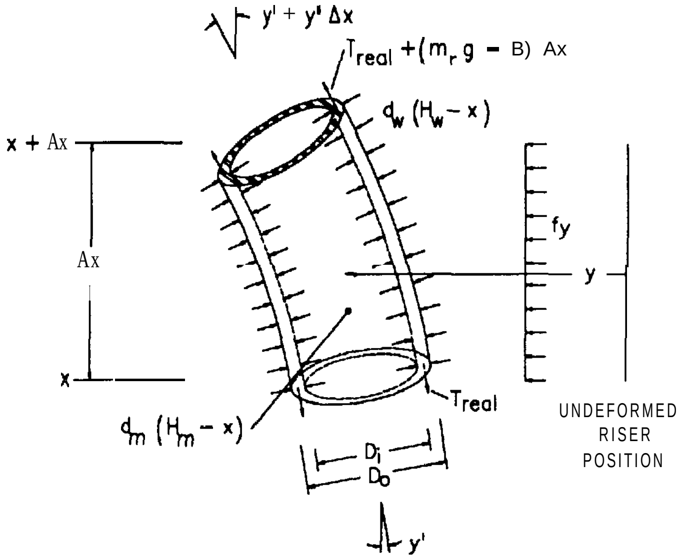
Modeling Considerations. In the global riser analysis, the riser is modeled as a tensioned beam subjected to loads throughout its length, and with boundary conditions at each end.

a The tensioned beam element descriptions include riser geometry, riser mass, and riser material properties. The lengths of the beam elements are important. Elements which are too long will not provide an accurate stress distribution along the riser while elements which are too short will increase run time and cost. Element lengths should be specified with respect to expected riser response along the riser with shorter elements in areas where either the loading or riser geometry is rapidly changing. Typically, this occurs near the top of the riser in the wave zone and near the bottom of the riser in the vicinity of the lower flex/ball joint. Any intermediate flex/ball joint (see Section 2.9.1) also represents an area of rapidly changing riser geometry.

b. Loading on the riser includes internal and external pressures as well as environmental loads caused by waves and currents. Internal and external pressure loads are generally caused by the hydrostatic pressures of the drilling fluid and sea water respectively. Analyses should be performed for the full range of expected drilling fluid densities noting that the column of drilling fluid usually has a higher hydrostatic head than that of sea water. The joint is normally modeled using only the dimensions of the main riser tube to calculate the bending rigidity (EI) of the riser. The dimensions of the choke, kill, and auxiliary lines, in addition to the outside diameter of the main riser tube, should be considered in calculating the hydrodynamic forces on bare riser joints If buoyancy modules are attached to the riser joint, the outside diameter of the buoyancy module should be used to calculate the drag and inertial diameters. See Section 3.4.4. The model should account for possible shielding of the riser from the motions of the sea water. A riser deployed from a drillship is shielded from waves and currents until it emerges below the keel of the vessel while a riser deployed from a semisubmersible is exposed to wave and current loads everywhere below the waterline. The weight used in the analysis should equal the weight of the entire riser joint, including choke, kill, and auxiliary lines as well as support brackets and coupling.

c. Top boundary conditions generally include top tension, vessel offsets and motions, as well as a description of the rotational stiffness of the upper flex/hall joint. Typically, required top tension depends on the drilling fluid density. It may also vary with the operational and environmental conditions specified for each operational mode (see Section 3.1). A description of vessel motions is generally available in the form of Response Amplitude Operators (RAOs) and phase relationships. The vessel motions modeled at the top of the riser should result from the identical wave description (amplitude and phase) as that used to model the loads on the riser. Horizontal offset of the vessel should be consistent with the steady wind, wave, and current loads used in a stationkeeping analysis. Operational procedures may permit mooring line manipulations to relocate the vessel in the event of long term changes in environmental loads.

d The bottom boundary condition may result from either a connected or disconnected riser. (See Section 3.3.1 for operating modes.) In the connected modes, the riser model usually ends at the lower flex/ball joint in which case the rotational stiffness of that flex/ball joint is a bottom boundary condition and the horizontal and vertical loads as well as the bottom angle are outputs on the analysis. Some analysts prefer to choose the structural casing as the lower end of the riser in which case the lower flex/ball joint is modeled as an intermediate flex/ball joint and the LMRP, BOP, wellhead, and structural casing are parts of the riser model. For this situation, the rotational spring constant resulting from the soil interaction with the structural casing should be modeled. The bottom boundary condition of a discon-



GOVERNING DIFFERENTIAL EQUATION OF MOTION

$$f_y = M\ddot{y} + EI\, y'''' - t\, y' - T_e\, y''$$

where,

$$M = m_r + (\pi/4)(d_m D_i^2)/g$$

$$t = (\pi/4)(d_m D_i^2 - d_w D_o^2) + m_r g - B$$

$$T_e = (\pi/4)\{d_w (H_w - x) D_o^2 - d_m (H_m - x) D_i^2\} + T_{real}$$

TERMINOLOGY IN THE EQUATIONS

B	Buoyant Force per Unit Length
D_h	Hydrodynamic Diameter
D_o, D_i	Outside and Inside Diameters of the Riser Pipe
d_m, d_w	Weight Density of the Mud and Seawater
EI	Flexural Rigidity of the Riser
f_y	Distributed Hydrodynamic Force Acting in the "y" Direction
g	Gravitational Acceleration
H_m, H_w	Total Depth of the Mud and the Seawater
M	Total Mass (Riser ond Mud) per Unit Length
m_r	Mass of the Riser (including Buoyancy) per Unit Length
T_e	Effective Tension
T_{real}	Actual Tension in the Pipe Wall
t	Variation of the Effective Tension
x	Vertical Coordinote Measured *from* the Bottom of the Riser
y	Horizontal Riser Translation at Station "x"
$(\dot{\ })$	$\partial / \partial t$
$(\ )'$	$\partial / \partial x$

FIGURE 3.1
DIFFERENTIAL ELEMENT OF THE RISER

nected riser should include the mass of either the BOP stack or only the LMRP depending on the situation.

3.4.3 Effective Tension. The effective tension controls the stability of risers and therefore represents a concept of great importance. It can be defined in several ways:

- It appears as the coefficient of the Y" term in the basic differential equation describing riser behavior (See Figure 3.1)
- It is the axial tension that is calculated at any point along a riser by considering only the top tension and the apparent weight of the riser and its contents. (Sparks (1964))

Effective tension, T_e, is related to the axial pipe wall tension, T_{real}, (also called real tension or true tension) by the following equation:

$$T_e = T_{real} - P_iA_i + P_oA_o$$

where P_i, P_o, A_i, A_o are the internal and external pressures and cross sectional areas, respectively.

T_{real} is derived from free body diagrams of the riser structure.

The riser should be designed so that the effective tension is always positive in all parts of the riser. See the discussion of minimum tension setting in Section 3.3.2 and Sample Calculation D.2 in Appendix D.

3.4.4 Hydrodynamic Model. There are three different hydrodynamic aspects to be considered:

- Sea Surface — a description of wave height and period variations either as regular waves or in the form of a wave spectrum.
- Wave Kinematics — a relationship specifying water velocity caused by wave motion, as a function of distance below the sea surface.
- Force Algorithm — A relationship specifying the force exerted on the riser from the relative velocity of sea water past the riser.

All three depend primarily on empirical evidence. Although extensive data has been gathered in each area, there is as yet no final resolution as to the most accurate general model.

a. Sea Surface. It is apparent from observation that, with few exceptions, the surface of the ocean is a random, multidirectional process. Nevertheless, most design analyses for offshore structures are based on a periodic, unidirectional wave. There are probably two principal reasons for this. First, the periodic wave is much simpler to deal with and second, in a severe weather design condition, a single frequency wave often predominates. Nevertheless, the desire of many analysts to use as realistic a model as possible has led to random wave analysis which requires the use of a wave spectrum such as Pierson-Moskowitz, Jonswap, ICSS, etc. (Sarpkaya and Issacson (1981), Chakrabarti (1987)). This includes both the linearized frequency domain method, and the more accurate time domain solution. (Burke and Tighe (1971), Hudspeth (19751, Botke (1975)).

b. Wave Kinematics. For a number of years, researchers have worked on models to predict the fluid velocity and acceleration profile beneath the wave surface. In attempting to satisfy the boundary conditions, they have come up with a number of highly nonlinear representations such as the Stokes III, Stokes V, Stream Function, etc. (Sarpkaya and Issacson (1981)). Each of these is rather complicated and for practical reasons, is generally used only with the single, periodic wave model. Environmental data indicates that the easy-to-use linear Airy wave theory is quite adequate for modelling regular wave kinematics for a great deal of offshore locations and environmental conditions. It is particularly appropriate for drilling riser analysis because drilling risers are not normally deployed in shallow waters where the applicability of Airy wave theory is limited. The linearity of Airy wave theory renders it applicable for combining individual wave kinematics into a spectral representation. However, some limitations remain in all of the wave kinematics theories. None of the theories are accurate near the wave crests or troughs, and the combination of currents with waves is not well understood,

c. Hydrodynamic Force Algorithm. Hydrodynamic forces are typically evaluated using the Morison equation (Morison, et. al. (1950)). There is, however, extensive debate as to the selection of the drag and mass coefficients, especially in severe seastates. Further complicating the issue for the riser designer is the fact that most of the coefficient data has been acquired from fixed structures. The influence of the riser's relative motion in the waves should be considered.

Drag and Mass coefficients vary significantly with cross-section shape, roughness, Reynold Number, Keulegan-Carpenter Number and orientation of auxiliary lines. The correct choice of C_d is a prime factor in determining riser behavior because drag controls both hydrodynamic excitation and damping. The selection of an artificially large C_d value is not always conservative.

Commonly used values of C_d and C_m are:

buoyant riser (based on the diameters of the buoyancy module)

	C_d	C_m
Re c 10^5	1.2	15-2.0
10^5 < Re < 10"	1.2-0.6	1.5-2.0
Re > 10^6	0.6-0.8	1.5-2.0

bare riser (based on the diameter of the main tube)

	C_d	C_m
Re < 10^5	1.2-2.0	1.5-2.0
10^5 < Be c 10^6	2.0-1.0	1.5-2.0
Re > 10^6	LO-1.5	1.5-2.0

where Re specifies the Reynold's Number.

An alternate practice is to use an "equivalent diameter and "equivalent area" (riser main tube plus choke, kill, and auxiliary lines) based on the sum of projected diameters and areas with appropriate values of C_d and C_m.

The Morison equation estimates the hydrodynamic force on a body caused by the relative velocity and acceleration of the surrounding fluid. The force is parallel to the flow. In addition, under certain circumstances, there may be a relatively high frequency oscillating force, predominantly transverse to the flow, caused by the shedding of vortices. When the riser (or an integral line) has natural frequencies of vibration near the shedding frequency, vibrations of substantial amplitude may occur. Although this phenomenon is most likely in high currents and/or in uniform current profiles, it has also been observed in large waves. "Vortex-induced vibration" is accompanied by a large increase in drag. Methods for predicting vortex-induced vibration and drag increase for risers in real environments are not well established although general guidelines are available (Every, King and Weaver (1982)).

3.4.4.1 Biplanar Analysis. Thus far in this BP and in most of the published literature, riser analysis methods have been based on planar motion. The assumptions are that the vessel, the wave, the current, and the riser all move in a plane. In reality, waves come from various directions which do not necessarily correspond with the current direction. Also, the vessel responds in some combination of surge and sway. The implication is that to be totally comprehensive, an analysis method should permit riser motions in both horizontal directions. This would permit the analysis of riser response in multi-directional, random seas with currents acting at any angle relative to the sea and the vessel motion. The equations of motion remain unchanged, they simply double in number. There is one set of equations for each of the two horizontal, orthogonal directions and the two sets of equations are coupled to each other through any nonlinear terms such as the hydrodynamic forces.

The question remains as to whether the additional cost of biplanar (3-D) analysis is warranted. The answer to this seems to be associated with at least one of two criteria. Either the biplanar analysis can detect some phenomenon which planar analysis does not, or the biplanar analysis must predict some otherwise unpredicted failure mode. There seems to be no instance of either criterion. Any conservative engineering design is based on a worst case combination of environmental conditions. If the waves are of random direction, then the worst case is when the predominant wave and vessel motion are coplanar with the current. Similarly, if the current can vary in direction with depth then the design condition is when all of the current is acting in the same direction. Response due to multi-directional phenomena may be of academic interest but, aside from vortex induced vibrations, it does not seem to be important for design loading conditions of a single riser.

3.4.5 Lumped Parameter Model. The partial differential equation which governs riser behavior is not directly applicable for analyzing general problems. It is, therefore, usually converted to a system of finite length elements using either a finite difference or finite element technique. The behavior of the riser can then be described in terms of the nodes at which these elements are joined. The solution involves finding the translations and rotations, bending moments, etc., at each node of the riser. While each of these idealized elements has uniform properties, the nonuniformities of the riser are accounted for by the variation of properties from element to element. This discretization of the riser leads to a series of simultaneous equations which are conveniently and rapidly solved on a computer.

Finite difference and finite element techniques are alternative means of formulating simultaneous equations. The finite difference procedure involves conversion of the continuous derivatives into linear finite differences. Perhaps the most often referenced illustration of this method for riser analysis is the work done for the Mohole project by NESCO (1965). Later, Botke (1975) went through an extensive derivation of the riser equations and finite difference method of solution.

In the finite element method, the deformation of segments is assumed to be expressible as the summation of a series of deformation functions related to the deflections of the nodes. This method, as applied to risers, has been described in detail by Gardner and Kotch (1976).

Both methods are appropriate and can be expected to give accurate and reliable results if used with care and understanding. Perhaps the most critical consideration is the number of elements into which the riser is divided. The spacing of the nodes should be fine in the areas where high bending moments tend to occur. These are always in the wave zone and near the bottom of the riser where the tension is the lowest. Because the finite element method uses higher order functions between the nodes than does the finite difference method, accurate finite element solutions are generally possible with fewer nodes than from comparable finite difference solutions. As a general rule, the number of nodes may vary from 30 to 40 for a shallow water riser when using the finite element method to several hundred for a deep water riser using the finite difference approach.

3.4.6 Solution of the Simultaneous Equations. The previous section dealt with the mathematical techniques for converting the spatial derivatives into discrete translation coordinates for solution as simultaneous equations. In addition, the governing equation for the riser includes a time derivative in the inertia term. Inclusion of the inertia term yields a mass matrix and the acceleration at each of the nodes. Structural damping, if important, may be added to the equation. When these dynamic terms are included, additional mathematical techniques are required for solution.

For a two dimensional global riser analysis, it is the wave action and associated vessel motion that provide the dynamic excitation. The waves impose time-varying hydrodynamic forces on the riser while the vessel drives the top of the riser back and forth, producing additional contributions to the time-varying forces. The applied riser tension also has time-varying components caused by the nonideal characteristics of the tensioner system and the inertia and geometric effects associated with the vessel, riser string, and slip joint motions.

Static, Quasi-Static or Dynamic Method. The static method only considers the riser's response to a constant vessel offset and a current profile which can change with depth but not with time.

In the quasi-static method, the time-dependent parameters are varied in a series of static solutions. The inertia effects are not included. Also excluded from the hydrodynamic calculation is the relative velocity of the riser passing through the water. The wave and vessel motion are "stepped" past the riser, the static solution is calculated for each step, and the maximum values of the critical parameters are observed over one wave period.

There are two different approaches for solving the equations while including dynamics and relative velocities. A time domain solution is the more direct and straightforward method and encompasses a direct integration of the equations. Runge-Kutta and Newmark-Beta [see Zienkiewicz (1977)] are two of the well known methods of numerical integration. They permit the inclusion of all nonlinearities such as the nonlinear hydrodynamic force, nonlinear soil behavior, nonlinear friction characteristics, etc. There is virtually no limitation on the phenomena which may be included. The drawback is cost. The solutions should be carried out over a relatively large number of iterations and each solution represents only one combination of parameters.

Burke (1974) outlines a frequency domain technique which, through the use of simplifications, allows a great reduction in cost. All of the input forces and motions are assumed to be sinusoidal, and all the nonlinear functions linear about a quasi-steady or mean value. The primary difficulty in this method comes with the nonlinear hydrodynamic drag force. An iterative procedure is used whereby the equivalent linear drag is varied in successive solutions until it gives the same amplitude as does the nonlinear drag. Later, Krolikowski and Gay (1980) reported a modification to the frequency domain technique which, for combined current and waves, substantially increases its accuracy with little increase in the solution cost.

3.4.7 Local Finite Element Analysis. Most riser programs use the finite element method (beam elements) to calculate the global response of the riser structure. The solutions from these global programs do not address the local details of the riser structure. These local details include the connection points (couplings) of two joints of riser, connection of the riser joint to the flex or ball joint, and connection of the riser joint to the slip joint.

If the designer has concern with these connections because of an over stress situation, high stress concentration factors (which greatly reduces fatigue life), excessive distortions, etc., a local finite element analysis should be undertaken to calculate the state of stress and distortion for the connection.

A general purpose finite element program is needed to model the connection using either three dimensional finite elements or axisymmetric elements. If plane stress or plane strain elements are used (two dimensional analysis), considerable care must be used to ensure that the local finite element model is experiencing plane stress or plane strain conditions.

All structural components of the local detail should be modelled to ensure proper interaction of the structural components. Input of loads for the local finite element model will be derived from the global riser analysis for various loading conditions. Depending on the finite element model, displacements and rotations rather than forces and moments may be used to transfer the loadings from the global model to the local model.

The local finite element mesh should be created with good modeling practices paying particular attention to finite element aspect ratios, finite element selection (what type of shape function is assumed for the element's derivation), boundary conditions, and mesh densities. Mesh densities are especially important in areas where the stress is rapidly changing.

SECTION 4
OPERATING PROCEDURES

4.1 INTRODUCTION. Efficient deployment and subsequent retrieval of the riser and BOP stack are integral parts of the marine riser design. The designer should consider not only normal procedures, but also emergency disconnect and hang-off procedures as employed during a storm. These conditions may dominate the design criteria.

This section presents examples of riser procedures. Operating personnel on each floating drilling vessel should be equipped with a written procedure for use of the marine riser. These procedures should include operating guidelines for the specific riser equipment, vessel storage, and handling equipment.

The care and use of a marine riser system should be supervised by trained and qualified personnel, i.e., designated personnel who by reason of experience and instruction are familiar with both the operation to be performed and the potential hazards involved.

4.2 RISER OPERATING MANUAL. Information about the marine riser system for the drilling vessel should be consolidated in a riser operating manual. At all times a copy of the manual should be located on the vessel and should be updated to reflect the current configuration of the riser system. This manual should contain as a minimum the following information concerning the riser system.

a. Manufacturer's drawings of the riser system components outlining critical dimensions, weights, and part numbers of the various components.

b. Manufacturer's load ratings for the critical components of the riser system.

c. Internal and collapse pressure ratings of the riser and integral lines.

d. Inspection and maintenance procedures for each component.

e. Procedure for running and retrieving the riser.

f. Procedure for establishing maximum and minimum tension settings.

g. Operating limits and emergency procedures.

h. An accurate log of operating history.

i. Recommended spare parts inventory list.

j. Criteria and procedures for cutting and slipping tensioner lines.

4.3 PREPARING TO RUN RISER. This section describes the preparation required prior to running the *riser* and landing the BOP stack. Although there are exceptions, normally the structural and conductor casings have been set and cemented, and the wellhead landed before the riser and BOP stack are run.

The preparation involves the following steps:

4.3.1 Site-Specific Marine Riser Length Determination. The water depth should be measured before operations are begun, and the elevation of the wellhead above the mudline should be measured at the time the wellhead is cemented in place. Determining the marine riser length involves choosing the number of riser joints that will properly make up the riser string. A good method to check water depth and determine the required length of the riser string is to measure the actual length of the 20-inch landing string. The riser string length is normally planned so that the length of the telescopic joint will be near or short of its mid-stroke length when the BOP stack is latched onto the wellhead and the rig is at its normal drilling draft at mean sea level. Only rarely can an exact mid-stroke position be achieved because of the discrete lengths of available pup joints and the time variance of water depth at a given location.

In the mid-stroke position, part of the telescopic joint stroke can accommodate the increased riser length resulting from vessel offset; and rig personnel have a visual warning of excessive vessel heave because they can see the near complete retraction of the telescopic joint. If either the extension or retraction limits of the telescopic joint are exceeded, the riser and associated equipment can be damaged. If the telescopic joint extends to its limit, tensile loading will dramatically increase, and if it retracts to its limit, the riser could buckle. Both conditions should be avoided.

The following dimensions should be considered when calculating riser length (see Figure 4.1):

Dimension (A) Wellhead Height From Mud Line

Dimension (B) BOP and LMRP Stack Up Height

Dimension (C) Required Riser Length

Dimension (D) Telescopic Joint Length When Set Slightly Short of Mid-Stroke (see Appendix E under 'Running the riser and BOP stack")

Dimension (E) Distance From Bottom of Diverter to Top of Rotary Kelly Bushing (RKB)

Dimension (F) RKB to Mud Line

Dimension (G) Length of 20-Inch Running String

Dimensions (B),(D), and (E) are fixed while dimensions (A), (F), and (G) are measured at the well site.

Thus the riser length, Dimension (C), can be calculated as either:

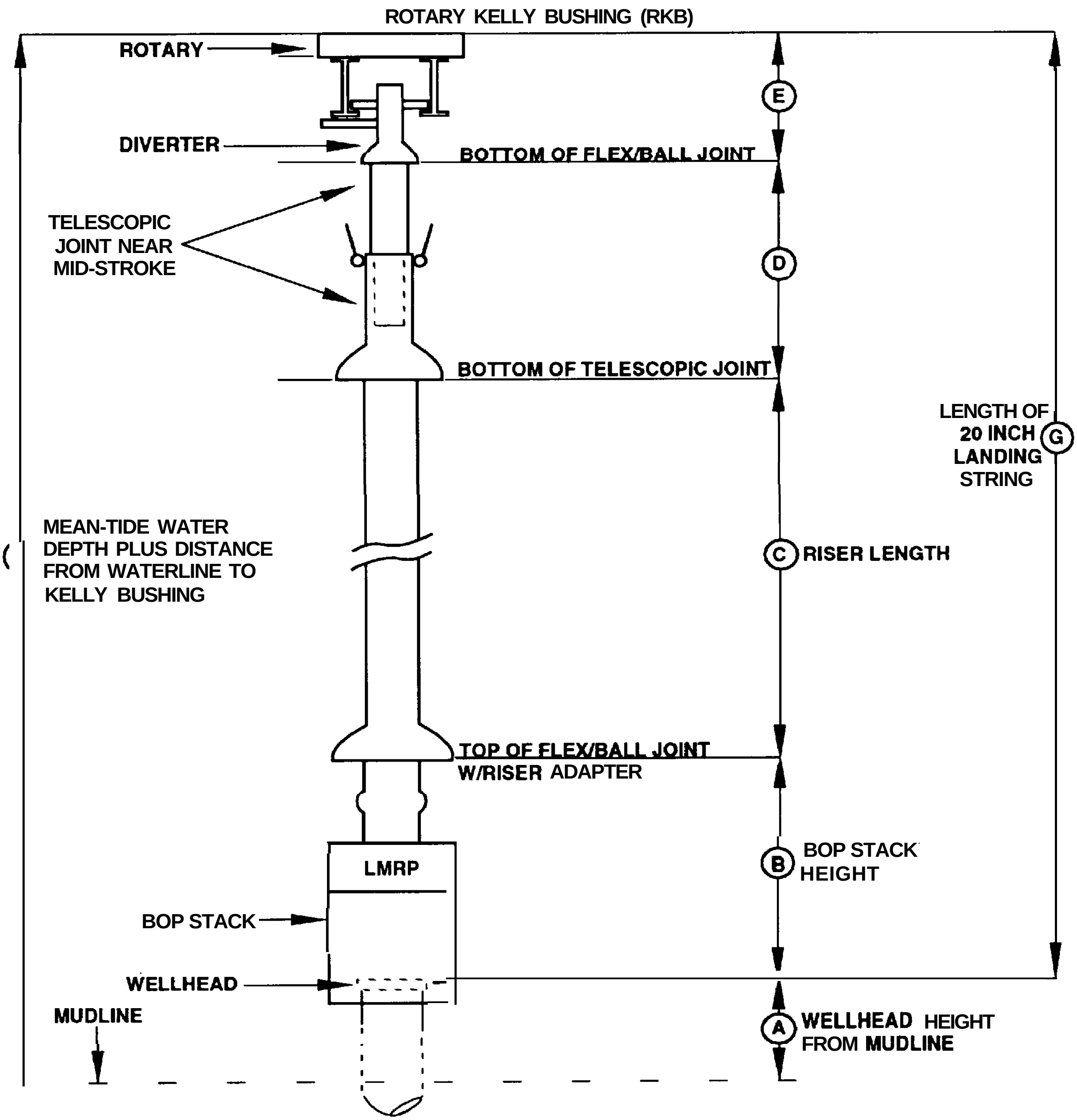
$$C = F - (A+B+D+E) \text{ or}$$

$$C = G - (B+D+E)$$

depending on whether the water depth or the length of the 20-inch running string was used. See Sample Calculation D.1 in Appendix D.

4.3.2 Riser Inspection Prior to Running. Before running the riser:

a Externally inspect the riser pipe, auxiliary lines, and buoyancy equipment (if used) for any damage; and ensure that the auxiliary lines are properly clamped.



$$C = F-(A+B+D+E) \quad \text{OR}$$
$$C = G-(B+D+E)$$

FIGURE 4.1
DETERMINATION OF MARINE RISER LENGTH

b. Inspect the coupling locking mechanism for damage and actuate to ensure proper operation.

c. Check that sealing devices are installed.

d. Review the marine riser manufacturer's Care and Use Instructions for the riser joint to ensure that any special instructions are followed.

e. Remove the box and/or pin protector and inspect the bore of the riser and auxiliary lines for obstructions and wear. Also clean and inspect the pins of the riser and auxiliary lines. Unless a handling system is used which protects the box and pin, the box and/or pin protectors should be re-installed and not removed until the joint is on the rig floor.

f. Inspect riser handling tools and treat couplings the same as those on the riser joints.

g. Check riser spider for proper operation.

h. Check inner barrel shoe of telescopic joint for keyseating.

4.4 PROCEDURES FOR RUNNING, OPERATING, AND PULLING THE RISER..

4.4.1 Running the Riser. Within the industry, many safe and efficient riser running procedures are employed. The use of a particular procedure may depend on the specific equipment aboard the rig, experience of personnel, or contractor or operator preference. An example running procedure is presented in Appendix E.

4.4.2 Riser System Monitoring Devices. The marine riser system should be suitably instrumented and monitored to ensure safe and reliable performance. The degree of instrumentation should suit the severity of the operating and environmental conditions. Operating personnel should have a fundamental understanding of the relationships which affect riser performance and understand the operating principles of the instrumentation system. Routine riser monitoring instrumentation includes riser angle indicators, hole position indicators, tensioner pressure gauges, and television systems.

4.4.3 Suspending Operations With the Riser Connected. In case of worsening environmental conditions or some equipment failures, the drilling operation should be suspended. If the situation is not sufficiently critical to warrant disconnecting the riser, the following steps are recommended:

a. Flex/ball joint angle, vessel offset, drilling fluid weight, and riser tension on board the vessel should be monitored.

b. If the mean flex/ball joint angle is in excess of 3.0 degrees and cannot be corrected by adjustment of riser tension and vessel offset, preparations should be made to suspend any operations that involve moving pipe in the well.

c. If conditions continue to worsen, appropriate steps should be taken to allow for a controlled riser disconnect.

4.4.3.1 Hydraulic Tensioner Failure. A hydraulic tensioner may fail because of a malfunction in the hydraulic system or a break of a tensioner line. If a tensioner fails, operating personnel should follow a preplanned step-by-step procedure. The procedure should be in the operating manual.

Typically, when a tensioner fails, drilling operations should be immediately suspended until adjustments are made such that it becomes safe to continue. The guidelines outlined below are to be considered in determining the course of action to follow.

1. If adequate capacity is available from the units which remain in service, drilling operations may continue after increasing the tensioner settings to apply the required tension required for the operating conditions and allowable flex/ball joint angle. Sufficient tension should always be maintained to allow for the sudden loss of an additional single or dual tensioner. Operating personnel should carefully monitor the operating conditions (wave height, vessel offset, drilling fluid weight, flex/ball joint angle, etc.) and be prepared to take appropriate action if any condition changes.

2. If the requirements outlined in (1) cannot be met, drilling operations should remain suspended with the riser connected to the BOP stack. Sufficient tension to prevent buckling of the riser, while allowing for the loss of an additional tensioner, should be set on the tensioners (see Section 3.3.2). If tensioner capacity is not capable of meeting this requirement, drilling fluid may be circulated out of the riser to reduce the required tension.

3. If conditions worsen, the marine riser should be disconnected and hung off or pulled.

4.4.3.2 Loss of Buoyancy. External buoyancy on marine risers may be syntactic foam modules or open-bottom air cans. Syntactic foam modules may lose buoyancy when deployed beyond their design water depth. Open-bottom cans may lose buoyancy by leakage which may be replenished through the air inject line.

Loss of buoyancy because of such failures is not detectable at the surface except by monitoring devices (or perhaps, the appearance of bubbles). It does, however, result in loss of riser tension below the depth of buoyancy loss. Such reduced tension can lead to increased bending stress, increased flex/hall joint angle, and riser buckling. Loss of buoyancy can be detected by monitoring the lower flex/ball joint angle, tension in an instrumented riser joint just above the lower flex/ball joint, or by TV inspection for damage or air leaks.

4.4.4 Disconnecting. If the situation that caused suspension of the drilling operations becomes too severe to be adequately controlled by the steps of Section 4.4.3, a disconnect procedure should be implemented. Disconnect modes include:

4.4.4.1 Normal. Under normal disconnect conditions, the procedures mentioned in Section 4.4.3 will have been completed. Lower flex/ball joint angle should be monitored. By adjusting tension and offset, an attempt should be made to both maintain a small enough lower flex/ball joint angle to facilitate release of the riser connector and lower the tension to slightly above the hanging weight of the riser and LMRP. If time permits, it is preferred that the riser be disconnected at the riser connector, allowing the riser tensioners to lift the riser clear of the stack. After disconnect, the vessel should be moved off the well location and guidelines slackened to prevent the heaving riser and LMRP from striking the BOP. If conditions permit, the riser and LMRP can be retrieved and stored on the vessel. Otherwise the riser should be raised as high as possible and hung off.

4.4.4.2 Emergency. Each rig should be equipped with written emergency disconnect procedures which account for various tubulars being in the BOP bore, peculiarities in the BOP and control equipment, and characteristics of position keeping or mooring equipment. An emergency disconnect is necessitated in the case of excessive vessel excursion from position over the wellhead or sometimes in the case of a blowout.

4.6 MAINTENANCE AFTER RISER RETRIEVAL. After retrieval, the riser should be rinsed with fresh water, visually inspected, serviced and stored in accordance with the manufacturer's recommendations.

4.6 OTHER RISER SYSTEM MAINTENANCE.

4.6.1 Riser Tensioners. The tensioner piping should be checked for leaks before putting the system into operation. Visual checks of the system for hydraulic leaks and correct fluid level should be made periodically. Consult manufacturer's operation and maintenance guide for procedure and fluid type. Lubricate tensioner rods and determine a specific schedule to keep the exposed rods lubricated. Check sheave groove for wear, lubricate the idler sheave bearings and inspect bearing seals for damage. For wire rope systems, inspect wire line for broken strands and correct type per manufacturer's recommendation.

Take particular note of the wire condition at contact points with the sheaves during low heave operating conditions. When the limit of wireline life is approached, the line should be either cut and slipped to change the wear points, or replaced, to prevent wireline failure. When slipping the wire line, be certain that the lengths of line that were working over the sheaves before are not working over sheaves after slippage. Also, be certain that the tensioner ring clamp line attachments are secure and properly installed. A qualified re-termination procedure and personnel qualified for that procedure should be used. All the air pressure vessels should be regularly drained of any liquids as specified by the manufacturer.

4.6.2 Telescopic Joint. The inner barrel telescopes into the outer barrel and should be bolted or pinned to the outer barrel when handling.

Maintaining minimum pressure to effect a packoff will prolong the life of the packing element.

The telescopic joint should be inspected and serviced in accordance with manufacturer's recommendations.

4.63 Flex/Ball Joints. Flex/ball joints should have a protective cover at the upper neck to prevent the entry of cuttings and debris. The boot should be inspected prior to running, and replaced when necessary. Flex joints should be inspected to make sure the bore protectors and retaining studs and nuts are intact. After retrieval, wash all exposed surfaces with fresh water and inspect for both internal and external wear. A pressure-balanced ball joint should be tested in accordance with the manufacturer's recommendations to verify pressure integrity.

4.7 TRANSPORTATION, HANDLING, AND STORAGE.

4.7.1 General Handling and Storage. In general, marine riser components are made with precision parts that require careful handling. Protectors should be provided for the pin-end (and box-end if specified by the manufacturer) couplings of each riser joint. The couplings should be lubricated according to manufacturer's recommendations. The joints should always be handled individually and with protectors in place. Foam buoyancy material on risers is especially vulnerable to damage. If it is necessary to pick up and move the riser joints with a crane when automatic handling equipment is not available, a properly designed sling should be utilized. Handling slings should be designed to support the fully assembled riser joint. Telescopic joints typically weigh substantially more than riser joints and slings should be designed accordingly. Most riser joints are provided with lifting eyes located near the box and pin-ends for the sling attachments. Riser joints should not be lifted by choke, kill, or auxiliary lines or their brackets.

Caution should be exercised when stacking riser joints. When bare joints are stacked for shipping or storage, support shims should be provided under the bottom layer and between successive layers. The shims should be designed to prevent contact between adjacent joints. The weight of the joint should not be carried by unsupported sections of the choke or kill lines. Riser joints equipped with syntactic foam buoyancy may be stacked on top of each other without shims in accordance with the buoyancy manufacturer's recommendations.

4.7.2 Rig Storage Racks. To provide for adequate restraint and support for the riser during stored periods, riser storage racks or cradles should be used.

The design of the racks or cradles will vary with the specific constraints of the vessel and riser design; however, some guidelines can be stated.

a Cradles should be designed for supporting the weight of the riser, including all dynamic and environmental loadings.

b. Support of buoyed riser joints should be made in accordance with the buoyancy manufacturer's specifications.

c. No portion of the riser should be supported by the choke, kill, or auxiliary lines or their brackets.

d. The racks should not hinder access to the pin and/or box protectors or covers for maintenance and inspection.

e. The racks should be able to support the riser and prevent load shifting for any expected list of the rig.

4.7.3 Land Base Storage. Riser joints should be stored with support shims under the bottom layer and between successive layers. The first tier of joints should be off the ground to keep moisture and dirt away from the joints. The support shims should be spaced to prevent bending of the pipe and damage to the coupling. Joints should be stacked at a safe and accessible height, slightly inclined to assure proper drainage of water. Joints should be cleaned internally and externally, and protective coatings should be applied or touched up as necessary before storing. Riser couplings and all mating surfaces should be maintained according to manufacturer's specifications.

4.7.4 Transportation. When riser system components are transported, supervision should be provided at the time of loading to ensure that the load is tied down securely to prevent shifting, that painted or coated surfaces are protected from tie-down chains or straps, that guidelines for handling and storage (Section 4.7.1) are followed, that the components do not come in contact with chemicals, corrosives, bilge water, or other damaging substances, that other materials are not loaded on top of or inside the riser, and that all relevant regulations are satisfied.

4.8 SCHEDULED FIELD INSPECTION AND MAINTENANCE. Regularly scheduled inspection and maintenance should be performed on all riser system components. Detailed procedures should be developed for the performance of the following inspection and maintenance tasks and should be contained in the Riser Operating Manual.

4.8.1 Visual Inspection for Corrosion, Cracks, and Wear. After each retrieval, the marine riser joints should be visually inspected for corrosion, cracks, and wear. The box and pin of the riser connector should be cleaned thoroughly before inspection. Other critical areas, as specified by the manufacturer, should be more #oroughly checked and remedial action taken as needed.

4.8.2 Nondestructive Inspection. Liquid penetrant or magnetic particle inspection methods should be used to investigate critical areas for cracks. Ultrasonic or other suitable means should be used to check the main tube wall thickness. Acceptance criteria should be agreed upon between operator and drilling contractor. These inspections should be conducted at least once a year unless results of previous inspections warrant a longer inspection interval. An inspection is recommended after abnormal conditions such as over-tensioning, under-tensioning, or shock loads during running or retrieving the riser. Inspection and remedial action should be in accordance with the manufacturer's recommendations.

4.8.3 Corrosion Protection. The riser should be checked for areas of cracked or flaking paint. These areas should be thoroughly cleaned and repainted according to user's or manufacturer's specifications.

4.8.4 Parts Replacement. When replacement of moving parts in the riser system is required, it should be done in accordance with the manufacturer's recommendations. These instructions should be included in the operating manual and outlined with sufficient clarity for use by rig supervisory personnel. Reliable records of inventory and replacement requirements should be kept.

Replacement of parts should be accompanied by special attention given to cleanliness of parts, inspection for damage, assurance of correct items by part numbers, lubrication if required, correct assembly, and proper installation.

4.8.5 Welding. No welding should be performed on any riser component without first consulting with the manufacturer. Field welding should not be performed without explicit authorization from the manufacturer accompanied by approved procedures and performed by welders qualified for those procedures.

SECTION 5
SPECIAL SITUATIONS

5.1 DEEP WATER DRILLING. Technical development of risers and control systems has progressively extended water depth capabilities.

Deep water is generally considered in excess of 2000 feet, ultradeep water in excess of 5000 feet. Drilling riser systems have routinely been deployed in less than 2000 feet of water. Several wells have been drilled with a riser system in water depths exceeding 5000 feet, with the deepest water depth in excess of 7500 feet.

Drilling in deeper water imposes greater physical and functional demands on the marine drilling riser system. These additional requirements can include:

- Higher Load Rating: Stronger couplings, thicker walled pipe and/or higher strength steel, higher hoop stresses at the bottom.
- Weight Control: Removal of unnecessary metal from couplings and support brackets, use of longer standard joints (reduces overall weight per foot), use of rolled and welded pipe (rather than seamless pipe) for the riser main tube.
- Streamlined Deployment and Retrieval: Use of semiautomated methods for storage, handling and pressure testing, use of quick makeup/breakout couplings, use of longer standard joints.
- Emergency Disconnect Capability: Automatic LMRP release capability and anti-recoil system.
- Augmented Riser Lift: Syntactic foam and/or air-can buoyancy, increased riser tensioner capacity aboard the rig.
- Instrumentation: Extra instrumentation to permit closer monitoring of critical parameters such as applied tension, riser angle, pipe wall tension at the bottom of the riser, and current profile.
- Annulus Pressure Control: An automatic fillup valve to prevent collapse, an annulus closing device positioned below the telescopic joint to control internal pressure in the event of gas influx.
- Extra Auxiliary Lines: A rigid conduit hydraulic supply line for delivery of power fluid to the BOP stack control valves, a mud boost line to assist return of cuttings up the riser annulus.
- Storm Hangoff System: Special apparatus to permit suspension of a long riser as the vessel rides out a storm.
- Interface With Multiplex Control System: Nonretrievable control pods on the LMRP, clamps on each riser joint for mux umbilical cables.
- Reentry System: ROV, acoustic, and/or video guided apparatus for guidelineless wellhead or BOP stack orientation and reentry operations.

5.1.1 Weight Control. The deck weight and storage requirements of a deep water drilling riser may be several times greater than that of a conventional riser. The large deck weights and space requirements of these risers, as well as their overall cost, often represent a significant percentage of both the variable deck load and the cost of the drilling vessel. Consequently, a cost and weight control program should be used throughout the design and manufacturing of the deep water riser.

The large weight of the riser results not only from the extra length of riser required in deep water, but also from requirements for increased pipe wall thickness, stronger couplings, additional auxiliary lines, and increased buoyancy requirements. While the contribution to the overall riser joint weight of such items as auxiliary line support brackets may be small, their effect is often magnified by the necessity to offset this weight with additional buoyancy material. Buoyancy materials and associated components should be optimized for high lift efficiency and reliability.

5.1.1.1 Pipe Wall and Buoyancy Tolerances. The large wall thickness tolerances permitted by API Spec. 5L are inappropriate for deep water riser main tube applications because significant weight and buoyancy penalties may be incurred. Consideration should be given to rolled and welded pipe with tighter thickness tolerances. Riser pipe and coupling dimensions should be engineered and selected to meet practical requirements. Material tolerances should be specified and negotiated with the steel mills. Likewise, tolerances for attached buoyancy modules are equally important and should be held within practical limits.

5.1.1.2 Tensioner Systems. Current emerging technologies aim to reduce cost and weight of tensioner systems, while maintaining suitable performance. See Appendix C, Section C.l.

5.1.1.3 Alternative Materials. In ultradeep water, the cost and efficiency of buoyancy must be strongly weighed against the weight and cost of the riser itself. Increased depth demands increased riser strength (and consequently weight), but buoyancy becomes less efficient as water depth increases. There is a point at which non-traditional approaches may be more cost effective.

Inherently, materials used in deep water should enhance the strength/weight ratio of the riser joint, thereby creating lesser demands on buoyancy. Emerging technologies aim at substituting lighter weight high-strength fiber composites or titanium for high tensile steel. When considering alternative materials in an ultradeep drilling riser design, their characteristics must be assessed in an overall integrated system approach, including considerations for cost and performance of the riser string, buoyancy, tensioners, dynamics/fatigue, weight/space, and handling systems.

5.1.1.3.1 Fiber Composites. Progress has been made in the design and experimental deployment of composite choke and kill lines attached to large bore steel risers. These are small diameter, thin wall, steel tubes that are filament wound with a lightweight, high-strength, pi-e-tensioned synthetic fiber (aramid), embedded in a thermoplastic resin matrix (Tamarelle and Sparks (1987), Guesnon (1989), Sweeney and Fawley (1989)). This composite construction has permitted a significant reduction in weight for auxiliary high pressure lines attached to the riser.

Designs are emerging that apply this same technology to the riser tube itself. Steel riser tubes can be wound with an aramid fiber. Axial strength requirements are retained within the steel tube and coupling, while largely relying on the winding to resist hoop stresses caused by pressure from the column of drilling fluid.

Similar to filament winding for steel tubes, all-fiber composites, such as spirally wound graphite and S-glass epoxy matrixes are currently being developed for use as production risers. Such designs may eventually find a role in high-tech drilling risers, provided that coupling designs and drill pipe wear concerns can be satisfied.

5.1.1.3.2 Titanium. Titanium alloys are very light, very strong, and resistant to both the marine environment and fatigue. The material can be formed, forged, welded, and machined.

Typical alloys to be considered in riser designs exhibit yield strengths from 120 to 160 KSI, having densities of approximately 60% of steel; i.e., the weight/strength advantage is on the order of 2.5 to 3.3 when compared with 80 KSI yield steel.

The principle detriment to the use of titanium has been its cost. Another disadvantage arises from the low modulus of elasticity of titanium (about half that of steel) which may cause a suspended ultradeep titanium riser to exhibit high axial dynamic responses. To date, titanium has been utilized successfully in special applications, such as a riser stress joint in a production riser.

5.1.2 Storage and Handling Considerations. The deployment or retrieval of a deep water riser can require days. The drilling vessel should be equipped to remove the riser joints from the storage area and present them to the drill floor in a controlled and efficient manner. To deploy or retrieve a deep water riser in a minimum of time, modern deep water drilling vessels use longer joints (up to 80 feet) and utilize semi-automated handling systems. Because the time required to roundtrip a BOP for maintenance/repair is an important economic factor, the time used for making up, testing, and breaking out the riser couplings is important in the selection of the coupling.

In addition to providing adequate storage space for the long riser, the deep water drilling vessel should also provide storage for the drilling mud contained in that riser.

During deployment, retrieval, and hang off, a long, suspended marine riser can experience sign&ant dynamic response. Because of the vessel's heave and the length of the riser, the dynamic response in the axial direction is of particular concern. The suspended mass of the riser and associated subsea equipment can be extremely large while, because of buoyancy, its effective submerged weight may be quite low. Any axial acceleration of this mass induced by the heave motion of the drilling vessel will produce large dynamic force variations about the static hanging weight. The dynamic force variations should be controlled to prevent the maximum safe load of the cables being exceeded, the cables becoming slack, or the riser tube experiencing compression. This requirement generally determines the limiting sea state for riser deployment or retrieval activities, and in turn, the maximum sea state in which drilling operations can be safely conducted.

In heavy sea conditions, a long riser should be secured to the vessel and not suspended from the hook or cables.

5.1.3 Emergency Disconnect. When drilling from a dynamically positioned vessel, a loss of station may occur because of a failure in the vessel's control or power systems. In the event of a drive off or drift off, the drilling riser should be quickly disconnected (typically 30 seconds) from the BOP stack and suspended below the vessel.

The emergency release of the riser from the BOP stack requires special procedures and equipment. The riser tensioning system should be equipped with an anti-recoil system. The tensioning system should continue to apply force to the riser for a short time after disconnect to ensure the riser lifts clear of the BOP stack. However, this tension should be carefully attenuated or too much momentum, or riser recoil, can be imparted to the riser. This can result in large impact loads as the telescopic joint is retracted and the riser is propelled upward, with great hazard to the riser, the vessel, and human life.

An automatic disconnect system secures and/or shears the drill string in the BOP, disconnects the riser, and activates the anti-recoil system.

5.1.4 Buoyancy. Buoyancy systems are generally needed in water depths exceeding 2000 feet. The purpose of riser buoyancy is to provide lift thus reducing top tension requirements, preventing excessive stresses in the riser, and reducing hook load during deployment/ retrieval of the BOP. Both syntactic foam and air can buoyancy systems have been used for deepwater riser systems, either individually or in combination.

Syntactic foam buoyancy systems become less efficient as water depth increases. To withstand higher hydrostatic pressures, the syntactic foam is made stronger and denser. Thus for a required net lift, not only is more foam needed, but usually at a higher cost per unit weight.

Air can buoyancy systems are charged with air as they are deployed. Increased amounts of compressed air are needed with depth, requiring large compressor systems. The density variation of air with increased hydrostatic pressure must be considered.

Air can systems may incorporate a venting feature which allows control of the riser buoyancy by releasing air to the ocean. This may be useful, or necessary, for controlling the responses of a riser suspended in deep water.

5.1.5 Gas Influx. Formation gas that may enter the riser before a BOP is closed expands as it ascends in the riser annulus. In a long riser, the consequent volumetric rate of flow at the surface could be hazardous and loss of the mud column may result in riser collapse.

A proposed method of controlling this flow incorporates an annulus closing device (such as an annular BOP) positioned in the riser string just below the telescopic joint. Beneath this device is a side outlet with a valve connected by means of a drape hose to a choke. With this arrangement, the riser could be shut in when gas is detected at the bottom of the riser. Thereby, the gas could be circulated out by pumping down the mud boost line and up the riser annulus to the choke. See Hall, Roche, and Boulet (1986).

5.2 GUIDELINELESS SYSTEMS. Guidelineless systems may be used for deployment of drill strings, casing strings, the drilling riser and 30" latch, or the drilling riser and subsea BOP stack or LMRP. They were developed for use with dynamically positioned drilling units but can also be used with moored vessels.

Guidelineless reentry encompasses basically the following:

1. Some means of locating the position of the equipment being run relative to the wellhead, typically an acoustic positioning system for course alignment and television for fine alignment and observation.

2. Some means such as either a dynamic positioning system or a mooring system to maneuver the drill vessel until the equipment being run and the wellhead are aligned within a few feet.

3. Final mechanical alignment and guidance into the hole or onto the wellhead (usually with a funnel structure).

Typically, a guidelineless well is started by jetting or drilling in structural casing that has a guidelineless reentry guide base and a 30-inch wellhead housing attached to the top. An acoustic beacon is mounted on the guidebase so that the drilling vessel can use an acoustic positioning system to monitor the position of the guide base.

During the deployment of the riser and BOP stack, for example, an acoustic beacon is either attached to the BOP stack or lowered on wireline down the outside of the riser to enable the vessel to monitor the approximate position of the stack with respect to the guide base. Once the stack is near the seafloor, a television camera is lowered through the riser on an armored cable to visually observe the reentry operation. The vessel is maneuvered using the thrusters or the mooring system until the BOP stack can be stabbed into a guide funnel on the guide base. Alternatively, a remotely operated vehicle (ROV) or stack-mounted camera can provide the visual observation of this final stabbing operation.

5.3 HIGH CURRENTS. Generally, operation of a riser system in currents exceeding two knots causes difficulties. Problems arise because of high drag loads on the riser, vessel, and mooring system, and because of vortex induced vibrations of the riser (Gardner and Cole (19821).

High current drag forces will result in large riser angles and possibly high bending stresses. To reduce the riser angle, increased top tension is required which causes higher axial stresses and increased bottom tension. Lower flex/ball joint angles can be reduced by mooring the vessel upstream of the wellhead. For such situations, caution should be exercised to ensure that the upper flex/ball joint angle remains within acceptable limits.

Aside from high drag forces, high currents may also cause lateral structural vibrations of the riser which, in turn, further increases drag and fatigue damage. Riser fairings have been used successfully (Gardner and Cole (1982)) to cope with the above described effects. Fairings are streamlined air-foil shaped appendages. Usually they are fabricated from fiberglass and attached to the riser so that they are allowed to weathervane. Depending on design, they may reduce current drag by more than two-thirds, and prevent vortex induced vibrations. They are very effective but are cumbersome to install and remove. This will significantly slow down riser deployment and retrieval.

Another method to counteract the effects of vortex induced vibrations is the use of strakes (Gardner and Cole (1982)). These devices are clamped onto the riser in a helical pattern. They are effective in suppressing vibrations but, in the absence of vibrations, a straked riser experiences higher drag loads than does an unstraked riser.

The staggering of riser joints, with and without buoyancy, has been found to be effective in reducing the magnitude of vortex induced vibrations. (Brooks (1987))

High currents may also cause lateral vibrations of choke, kill, or auxiliary lines. Uneven spacing of support brackets has been effective in reducing these vibrations.

High current drag loads on the vessel and its mooring system cause high mooring line tensions and corresponding increased vessel offset with its detrimental effect on riser angle. Mooring capability should include evaluation of the loads on the riser system (refer to APl RP 2P for design and analysis of spread mooring systems).

A riser restraint system may be needed while deploying or retrieving a riser in high currents. Such a system is designed to prevent contact with the sides of the moonpool and diverter housing. A restraint system has been built that consists of a hydraulically tensioned frame having pneumatic rollers which bear against the riser joint while it is being run (Marsh, Denison and Pekera (1984)). In some instances, a flex or ball joint has been installed below the telescopic joint to reduce stresses in the riser.

Provision of adequate clearance through the diverter housing for deploying and retrieving the riser should be considered. It has also been found useful to trim or heel the vessel to achieve suitable alignment of the housing with the riser.

Use of heavy mud in the riser and retention of the lower BOP stack have been found to be effective in controlling the displacement and tilt of the riser during deployment and retrieval. Caution is advised in checking the capabilities of both the derrick and hook to ensure they can safely support static and dynamic loads imposed by such a heavy riser.

5.4 COLD WEATHER CONSIDERATIONS. Low air temperature and sea ice affect riser operations. Steel components exposed to temperatures below -4°F (-20°C) should be qualified for cold temperature applications. Such qualification may require material testing at low temperatures. Testing should be performed in accordance with ASTM A 370, E 23. The operating range of elastomeric materials should also be consistent with cold weather operations.

5.4.1 Ice Formation. Operation of a marine riser in sub-freezing temperatures can lead to problems including:

- Ice formation inside the exposed choke and kill lines, terminal fittings, drape hoses, and surface piping,
- Ice formation inside the control hoses for functions such as energizing the telescopic joint packer,
- Freezing of the telescopic joint packer lubricating fluid.

These problems can be avoided by:

- Using ethylene glycol solutions for pressure testing, hydraulic control and lubrication,
- Enclosing the moonpool and cellar deck space below the drill floor with windwalls and sealable access doors, as permitted,
- Introducing heated air into the enclosed spaces,
- Allowing a small amount of drilling mud to flow past the telescopic joint packer.

5.4.2 Ice at Sea Ice at sea may be of either land (glacier) or sea origin. Generally, land origin ice is composed of floating chunks of ice while sea origin ice exists as floating sheets of ice. Except for very thin or small broken ice (mush), ice poses a significant and possibly severe hazard to the drilling vessel, its mooring or thruster system, and the riser itself

Generally, ice is classified by size (thickness, elevation above water, surface area) and by age (Bowditch (1977)).

If at all possible, operations in ice infested waters should be avoided. A moving ice sheet places severe loadings on the drilling vessel and its positioning system. Floating chunks of ice that are too low in the water to be detected by radar are particularly hazardous because they can get close to the vessel without detection.

A ship's hull tends to protect the riser from smaller broken-up sheet ice. With sufficient current or wind, ice may be pushed under the vessel. An "ice lip" around the moon pool can deflect ice from entering the moon pool and impacting the riser.

Semisubmersibles generally offer less protection to the riser. Special skirts or donut-shaped columns which extend below the ice zone can he effective in protecting the riser.

5.6 RISER COLLAPSE CONSIDERATIONS. When a marine riser is partially evacuated (well control situations, emergency disconnect), it is subject to differential pressures that can collapse the riser tube.

Factors which affect the depth at which a tensioned pipe will collapse include:

a. The diameter to thickness ratio, D/t

b. The yield strength

c. Dimensions and tolerances (OD, wall thickness, eccentricity, out of roundness)

d. Corrosion, keyseat wear, local damage

e. Axial tension

f. Bending stress in riser

g. Density of internal fluid

Typically, risers can collapse from external pressure by two mechanisms:

a. Purely elastic collapse failures

b. A combination of elastic and plastic deformation called the transition collapse mode.

The mechanism of failure can be determined from the D/t ratio, the yield strength, and the axial stress of the riser pipe according to the tension collapse formulas in API Bulletin 5C3. Other recognized methods may also be considered. Generally, the higher the D/t ratio, the more likely is elastic behavior of the pipe. However, smaller diameter or thicker wall riser tubulars should be checked for transition mode collapse since it can occur at lower external pressure.

For drilling risers, collapse is more likely to occur in the elastic region than in the transition mode. Increased axial tension contributes to the probability of occurrence of failure in the transition mode.

5.6 H_2S CONSIDERATIONS. Factors required for H_2S cracking to occur are:

a An H_2S cracking susceptible material,

b. An environment which promotes H_2S cracking (H_2S and water),

c. Stress on the susceptible material. The stress may be external (mechanical loading or pressure) or internal (residual stress from high strength material and/or welding).

The usual method of controlling the materials' H_2S stress cracking susceptibility is to control the drilling environment by methods such as: 1) inhibitors, 2) use of oil based drilling fluid, or 3) controlled pH (minimum pH=10).

If the environment cannot be reliably controlled, it becomes necessary to specify H_2S resistant materials. Users are encouraged to clearly specify quality assurance and product testing for critical equipment. Refer to NACE MR-01-75.

APPENDIX A
GLOSSARY

Accumulator (BOP). A pressure vessel charged with gas (nitrogen) over liquid and used to store hydraulic fluid under pressure for operation of blowout preventers.

Accumulator (Riser Tensioner). A pressure vessel charged with gas (nitrogen generally) over liquid that is pressurized on the gas side from the tensioner high-pressure gas supply bottles and supplies high pressure hydraulic fluid to energize the riser tensioner cylinder.

Actuator. A mechanism for the remote or automatic operation of a valve or choke.

Air Can Buoyancy. Tension applied to the riser string by the net buoyancy of an air chamber created by a closed top, open bottom cylinder forming an air filled annulus around the outside of the riser pipe.

Annulus. The space between two pipes, when one pipe is laterally positioned inside the other.

Apparent Weight. Weight minus buoyancy (commonly referred to as weight in water, wet weight, submerged weight, or effective weight).

Auxiliary Line. A conduit (excluding choke and kill lines) attached to the outside of the riser main tube. Example: Hydraulic supply line, buoyancy control line, mud boost line.

Back Pressure. The pressure resulting from restriction of fluid flow downstream.

Ball Joint. A ball and socket assembly having central through passage equal to or greater than the riser internal diameter which may be positioned in the riser string to reduce local bending stresses.

Blowout. An uncontrolled flow of well fluids from the wellbore.

Blowout Preventer (BOP). A device attached immediately above the casing, which can be closed to shut in the well.

Blowout Preventer, Annular Type. A remotely controlled device which can form a seal in the annular space around any object in the wellbore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

BOP Stack. An assembly of well control equipment including BOP's, spools, valves, hydraulic connectors, and nipples that connects to the subsea wellhead. Common usage of this term sometimes includes the Lower Marine Riser Package (LMRP).

Bottom-Hole Assembly (BHA). An assembly composed of the bit, stabilizers, reamers, drill collars, various types of subs, etc., that is connected to the bottom of a string of drillpipe.

Box. The female member of a riser coupling, C&K line stab assembly or auxiliary line stab assembly.

Breech-Block Coupling. A coupling which is engaged by rotation of one member into an interlock with another member by a small-angle rotation.

Buoyancy Control Line. An auxiliary line dedicated to controlling, charging or discharging air can buoyancy chambers.

Buoyancy Equipment. Devices added to riser joints to reduce their apparent weight, thereby reducing riser top tension requirements. The devices normally used for risers take the form of syntactic foam modules or open-bottom air chambers.

Choke and Kill (C&K) Lines. External conduits arranged laterally along the riser pipe and used for circulation of fluids into and out of the well bore to control well pressure.

Control Pod. An assembly of subsea valves and regulators which when activated from the surface will direct hydraulic fluid through special porting to operate BOP equipment.

Coupling. A mechanical means for joining two sections of riser pipe in end-to-end engagement.

Diverter. A device attached to the wellhead or marine riser to close the vertical flow path and direct well flow away from the drillfloor and rig.

Dog-Type Coupling. A coupling having wedges (dogs) that are mechanically driven between the box and pin for engagement.

Drape Hose. A flexible line connecting a choke, kill, or auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure. A U-shaped bend or "drape" in this line allows for relative movement between the inner barrel of the telescopic joint and the outer barrel of the telescopic joint as the vessel moves.

Drift Off. An unintended lateral move of a dynamically positioned vessel off of its intended location relative to the wellhead, generally caused by loss of stationkeeping control or propulsion.

Drilling Fluid. A water or oil-based fluid circulated down the drillpipe into the well and back up to the rig for purposes including containment of formation pressure, the removal of cuttings, bit lubrication and cooling, treating the wall of the well and providing a source for well data.

Drive Off. An unintended move of a dynamically positioned vessel off location driven by the vessel's main propulsion or stationkeeping thrusters.

Dynamic Positioning (Automatic Station Keeping). A computerized means of maintaining a vessel on location by selectively driving thrusters.

Effective Hydraulic Cylinder Area. Net area of moving parts exposed to tensioner hydraulic pressure.

Effective Tension. See the equation in Section 3.4.3.

Effective Weight. See Apparent Weight.

Factory Acceptance Testing. Testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings.

Fail Safe. Term applied to equipment or a system so designed that, in the event of failure or malfunction of any part of the system, devices are automatically activated to stabilize or secure the safety of the operation.

Fillup Line. The line through which fluid is added to the riser annulus.

Flange-Type **Coupling.** A coupling having two flanges joined by bolts.

Fleet Angle. In marine riser nomenclature, the fleet angle is the angle between the vertical axis and a riser tensioner line at the point where the line connects to the telescopic joint. See Figure **1.1.**

Flex Joint. A steel and elastomer assembly having central through-passage equal to or greater in diameter than the riser bore that may be positioned in the riser string to reduce local bending stresses.

Gooseneck. A type of terminal fitting using a pipe section with a semicircular bend to achieve a nominal 180” change in flow direction.

Guidelineless Reentry. Establishment of pressure containing connection between the BOP stack and the subsea wellhead or between the LMRP and the BOP stack using a TV image and/or acoustic signals instead of guidelines to guide the orientation and alignment.

Handling Tool (Running Tool). A device that joins to the upper end of a riser joint to permit lifting and lowering of the joint and the assembled riser string in the derrick by the elevators.

Heave. Vessel motion in the vertical direction.

Hot Spot Stress. See Local Peak Stress.

Hydraulic Connector. A mechanical connector that is activated hydraulically and connects the BOP stack to the wellhead or the LMRP to the BOP stack.

Hydraulic Supply Line. An auxiliary line from the vessel to the subsea BOP stack that supplies control system operating fluid to the LMRP and BOP stack.

Instrumented Riser Joint (IRJ). A riser joint equipped with sensors for monitoring parameters such as tension in the riser pipe wall, riser angular offset, annulus fluid temperature and pressure, etc.

Jumper Hose. A flexible section of choke, kill, or auxiliary line that provides a continuous flow around a flex/ball joint while accommodating the angular motion at the flex/ball joint.

Keyseating. The formation of a longitudinal slot in the bore of a riser system component caused by frictional wear of the rotating drill string on the riser component.

Kill Line. See Choke and Kill Lines.

Landing Joint. A riser joint temporarily attached above the telescopic joint used to land the BOP stack on the wellhead when the teleswpic joint is collapsed and pinned.

Landing Shoulder. A shoulder or projection on the external surface of a riser coupling or other riser component for supporting the riser and BOP stack during deployment and retrieval. Sometimes referred to as Riser Support Shoulder.

LMRP (Lower Marine Riser Package). The upper section of a two-section subsea BOP stack consisting of a hydraulic connector, annular BOP, ball/flex joint, riser adapter, jumper hoses for the choke, kill, and auxiliary lines, and subsea control pods. This interfaces with the lower subsea BOP stack.

Local Peak Stress. Highest stress in the region or component under consideration. The basic characteristic of a peak stress is that it causes no significant distortion and is principally objectionable as a possible initiation site for a fatigue crack. These stresses are highly localized and occur at geometric d&continuities. Sometimes referred to as hot spot stress.

Madeup Length. The actual length contributed to a riser string by a made-up riser component (overall component length minus box/pin engagement).

Makeup Time (Riser Coupling). Begins when the box and pin are stabbed, ends when the coupling is fully preloaded.

Makeup Tool (Preload Tool). A device used to engage and/or preload coupling members.

Maring Drilling Riser. A tubular conduit serving as an extension of the well bore from the equipment on the wellhead at the seafloor to a floating drilling rig.

Maximum Tensioner Setting. See Section 2.4.3.g.

Mud. See Drilling Fluid.

Mud Boost Line. An auxiliary line which provides supplementary fluid supply from the surface and injects it into the riser at the LMRP to assist in the circulation of drill cuttings up the marine riser, when required.

Nipple Up. To assemble a system of fluid handling components.

Nominal Stress. Stress calculated using the nominal pipe wall dimensions of the riser at the location of concern.

Pin. The male member of a riser coupling or a choke, kill, or auxiliary line stab assembly.

Preload. Compressive bearing load developed between box and pin members at their interface. This is accomplished by elastic deformation during makeup of the coupling.

Protector, Box **or Pin. A** cap or cover used to protect the box or pin from damage during storage and handling.

Pup Joint. A shorter than standard length riser joint.

RAO. See Response Amplitude Operator.

Rated Load. A nominal applied loading condition used during riser design, analysis and testing based on maximum anticipated service loading.

Response Amplitude Operator (RAO). For regular waves, it is the ratio of a vessel’s motion to the wave amplitude causing that motion and presented over a range of wave periods.

Riser Adapter. Crossover between riser and flex/hall joint.

Riser Annulus. The space around a pipe (drillpipe, casing or tubing) suspended in a riser; its outer boundary is the internal surface of the riser pipe.

Riser Connector (LMRP Connector). A hydraulically operated connecter thal joins the LMRP to the top of the BOP stack.

Riser Disconnect. The operation of unlatching of the riser connector to separate the riser and LMRP from the BOP stack.

Riser Hangoff System. A means for supporting a disconnected deepwater riser from the drilling vessel during a storm without inducing excessive stresses in the riser.

Riser Joint. A section of riser main tube having ends fitted with a box and pin and including choke, kill and (optional) auxiliary lines and their support brackets.

Riser Main Tube (Riser Pipe). The seamless or electric welded pipe which forms the principal conduit of the riser joint. The riser main tube is the conduit for guiding the drill string and containing the return fluid flow from the well.

Riser Recoil System. A means of limiting the upward acceleration of the riser when a disconnect is made at the riser connector.

Riser Spider. A device having retractable jaws or dogs used to support the riser string on the uppermost coupling support shoulder during deployment and retrieval of the riser.

Riser String. A deployed assembly of riser joints.

Riser Support Shoulder. See Landing Shoulder.

Riser Tensioner. Means for providing and maintaining top tension on the deployed riser string to prevent buckling.

Riser Tensioner Ring. The structural interface of the telescopic joint outer barrel and the riser tensioners.

RKB (Rotary Kelly Bushing). Commonly used vertical reference from the drillfloor.

Running Tool. See Handling Tool.

SAF. See Stress Amplification Factor.

Slip Joint. See Telescopic Joint.

Stab. A mating box and pin assembly that provides pressure-tight engagement of two pipe joints. An external mechanism is usually used to keep the box and pin engaged. For example, riser joint choke and kill stabs are retained in the stab mode by the make-up of the riser coupling.

Standard Riser Joint. A joint of typical length for a particular drilling vessel's riser storage racks, the derrick V-door size, riser handling equipment capacity or a particular riser purchase.

Storm Disconnect. A riser disconnect to avoid excessive loading from vessel motions amplified by inclement weather conditions.

Strakes. Helically wound appendages attached to the outside of the riser to suppress vortex induced vibrations.

Stress Amplification Factor (SAF). Equal to the local peak alternating stress in a component (including welds) divided by the nominal alternating stress in the pipe wall at the location of the component. This factor is used to account for the increase in the stresses caused by geometric stress amplifiers which occur in riser components.

Strumming. See Vortex Induced Vibration.

Submerged Weight. See Apparent Weight.

Subsea Fillup Valve. A special riser joint having a valve means to allow the riser annulus to be opened to the sea. To prevent riser pipe collapse, the valve may be opened by an automatic actuator controlled by a differential-pressure sensor.

Support Brackets. Brackets positioned at intervals along a riser joint that provide intermediate radial and lateral support from the riser main tube to the choke, kill and auxiliary lines.

Surge. Vessel motion along the fore/aft axis.

Sway. Vessel motion along the port/starboard axis.

Syntactic Foam. Typically a composite material of hollow spherical fillers in a matrix or binder.

Telescopic Joint (Slip Joint). A riser joint having an inner barrel and an outer barrel with sealing means between. The inner and outer barrels of the telescopic joint move relative to each other to compensate for the required change in the length of the riser string as the vessel experiences surge, sway and heave.

Telescopic Joint Packer. The means of sealing the annular space between the inner and outer barrels of the telescopic joint.

Terminal Fitting. The connection between a rigid choke, kill, or auxiliary line on a telescopic joint and its drape hose, effecting a nominal 180" turn in flow direction.

Threaded Union Coupling. A coupling having mating threaded members on the pin and box to form engagement. Threads on one side of the coupling are free to rotate relative to the riser pipe so that the joint does not have to rotate to make up the coupling. The threads do not form the seal.

Thrust Collar. A device for transmitting the buoyant force of a buoyancy module to the riser joint.

Type Certification Testing. Testing by a manufacturer of a representative specimen (or prototype) of a product which qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture.

Vortex Induced Vibration. The in-line and transverse oscillation of a riser in a current induced by the periodic shedding of vortices.

Wellhead Connector (Stack Connector). A hydraulically operated connector that joins the BOP stack to the subsea wellhead.

APPENDIX B
RISER ANALYSIS DATA WORKSHEET

Location Waterdepth/ Reference	
Vessel Name Vessel Type Vessel Draft Drill Floor to WL Moonpool Dimensions	

Tensioner Svstem			
No. Tensioners No. Tens./ Accumul. Tens. Line Fleet Ang. Tens. Line B.S. (kip) Wire Wt. @ Tens. (kip)			

Telescoping Joint			
Collapsed Length (ft) Space-out to UFJ (ft) Outer BBL dia (in) O.B. Air Weight (lbs) Load Rating (kip) Drag Diameter (in) Mass Diameter (in)		Fully Ext. Lngth (ft) Mud Ret. bel. DF (ft) O.B. Wall Thickn. (in) O.B. Subm. Wt. (lbs) O.B. Yield Point (ksi) CD1/CD2 (lo/hi Re) Mass Coefficient, CM	

Riser Joints	Type 1	Type 2	Type 3
No. Joints Buoyancy M.U. Length of Jt. (ft) Coupling Type Cplg. Load Rtg. (kip) Cplg. Yield (ksi) Cplg. Stress Amplif. F. Cplg. Weight (lbs)			
Main Tube OD (in) Main Tube Wall T. (in) Mn. Tube Yield (ksi) Tube Stress Amplif. F.			
C+K Line OD/ID (in) Mud B. L. OD/ID (in) Hydraulic L. ID (in) Bare R. Air Wt (lbs) Submerged Wt. (lbs) Steel Wt. Toler. (%)			
Buoyancy Type Foam Density (lb/ft³)			

Riser Joints — cont'd	Type 1	Type 2	Type 3
Buoy. Dia. (in) Buoy. Length (ft/Jt.) Buoy. Air Wt. (lbs/Jt) Net Pos. Buoy. (lbs/Jt.) Buoy. Wt.Tol.(mean %) Buoy. Loss (E+T) (%)			
Drag Diameter (in) Mass Diameter (in) CD1/CD2 (lo/hi Re) Mass Coeff. CM			

Pup Jt. M.U.Length (ft)				
Main Tube OD (in) Main Tube Wall T. (in) Air Weight (lbs) Subm. Weight (lbs)				

Flex/ Ball Jts.+Adapt	Upper	Lower	Intermed.
Bating (kip) Rot. Ctr. abv. Sea Floor UFJ Top.bel.Drill Fl. Ctr. - Top (ft) Ctr. - Btm. (ft) Effect. Air Wt. (lbs) Effect. Subm.Wt. (#) Axial Stiffn. (kip/in) Rot. Stiff. (K. ft/deg) Max. Rotation (deg.) Drag Dia. (in.) CD1/CD2 (io/hi Re) Mass. Coeff. CM			

Stack/ Well Head	LMRP	Lower Stack	Well Head
Height (ft) Air Weight (lbs) Subm. Weight (lbs) Drag Diameter (in) Hydrod. Vol. (ft^3/ft) Max. Tension (kip) Max. Bend. Mom. (K. ft)			

Drilling Parameters	Drilling	Non-Drilling	Disconnected
D.F. Weights (ppg) Vessel Offsets (% WD) Top Tensions (% DTL)			

Environmental Conditions						
Operating Mode	Drilling		Non-Drilling		Disconnected	
Design Wave Ht (ft) Wave Period (sec.)						
Sign. Wave Ht. (ft) Mean Period T_z (sec.) Peak Period (sec.) Spectrum Type						
Current Profile	WD (ft)	kn	WD (ft)	kn	WD (ft)	kn
Max. Storm Surge+Tide						

Vessel Motion Response (amplitude ÷ amplitude)								
Surge/Sway			Heave (ft/ft)			Roll/Pitch (deg/ft)		
T sec.	RAO ft/ft	0 deg.	T sec.	RAO ft/ft	0 deg.	T sec.	RAO deg/ft	0 deg.

APPENDIX C
ASSOCIATED TOPICS

C.1 EMERGING TENSIONER SYSTEM DESIGNS. Seldom is a passive tensioner stroke of 50 ft required for a semisubmersible. Typically, actual heave motions of 15 to 20 ft might be anticipated for modern semisubmersibles, even in worst sea conditions. An active/passive tensioner system has been designed that strives to reduce passive stroking to 25 ft, but permits active repositioning, under load, equivalent to a 50 ft stroke. This aim is achieved by decreasing high pressure air supply, and introducing a hydraulically activated ram adjustment to reposition the mid-stroke point. Such an arrangement has been shown to reduce overall weight of a tensioner system by as much as 30%.

Another way to achieve similar results is to reduce stroking length of the hydraulic cylinders by providing a line take-up device at the wire rope bitter end. Weight savings of up to 50% are feasible with such an arrangement.

Two other tensioner systems have evolved. The "unitized tensioner" has all rams and accumulators arranged into a simple direct acting unit, thus eliminating all wire ropes and sheaves (MacPhaiden and Abbot (1985)). The "tensioning slip joint" combines the functions of the telescopic joint and direct acting tensioner arms (Lim and Pfeifler (1986)).

Typical drilling vessels are equipped with up to 960 Kips of total tension, a few deep water vessels with up to 1,600 Kips total tension. Ultradeep water designs call for total installed tension of up to 3000 Kips. Single tensioner units have been built and installed with capacities from 60 to 125 Kips. At least one experimental unit has been built for 250 Kips.

Special tensioner lines utilizing "Die-Formed" strand wire rope and "Plastic-Filled-Valley" (PFV) wire rope construction have been successfully utilized to enhance fatigue performance.

C.2 FATIGUE. There are two fundamental approaches to a fatigue analysis. The first approach is based on fatigue tests and S-N (Stress range versus Number of cycles) curves and can take the form of either deterministic or stochastic (spectral method) calculations. The second approach is based on fracture mechanics principles. For a drilling riser, both approaches require knowledge of the magnitude and probability of occurrence of the expected sea states during either the riser's life or recommended inspection interval. These expected sea states form the "Fatigue Weather Spectrum" to be used in the fatigue analysis. The fatigue life of the riser is defined as the total life to *riser* failure, i.e., the life to which the riser parts ("critical failure").

In the S-N approach, "peak" stress ranges are calculated for each sea state in the fatigue weather spectrum. These "peak" stress ranges are equal to the product of the dynamic "pipe wall" stresses obtained from the riser analysis and the SAFs (stress amplification factors) calculated for the riser components. The dynamic "pipe wall" stresses are calculated from the dynamic bending momenta and the dynamic tension variations. The SAFs are derived by local finite element analysis of a structural component. The SAFs represent the increased stress caused by geometry, three-dimensional effects, and load paths through the structural component.

Fatigue curves specifically for risers have not yet been adopted. However, fatigue curves published for offshore structures have been used to assess riser fatigue. (See API BP 2A, UK DEN (1990), DNV (1984), NPD (1982).) A difficulty in assessing fatigue for a drilling riser arises from the mobility of the floating drilling vessel. Over the life of a drilling riser, it is employed at a variety of locations with differing environmental conditions whereas an offshore production structure occupies a single location throughout its lifetime.

For deterministic and stochastic fatigue analysis methodologies, see the procedures in API BP 2A.

It must be understood that the concern in the fatigue analysis is cyclic stress or stress range rather than the mean stress itself. Tension-tension, tension-compression, and compression-compression regimes receive equal consideration in the fatigue analysis. If the stress in a structural component remains constant, that component has a fatigue life of infinity and cannot fail because of fatigue.

Care must be taken in calculating the stresses and SAFs to be used in the fatigue analysis. Relatively small changes in the stresses and SAFs can result in large differences in the resulting fatigue life. Since fatigue life is proportional to the stress ranges and SAFs, each raised to the power of the inverse slope of the S-N curve (which ranges from 3 to 5), it can be demonstrated that, for an S-N slope of 5, doubling of either stress range, SAF, or any product of these, decreases the fatigue life of a structural component by a factor of 32. For example, if the structural component had a fatigue life of 100 years, doubling of the product of stress range and SAF would reduce it to 3 years.

In the fracture mechanics approach, a structure is assumed to have small defects inherent in the parent material and/or weld material. These defects may propagate in the material once a cyclic loading is applied to the zone containing the defect, and the life of the structure is determined from the time these propagating defects take to fail the structure. Once a defect has reached a critical size, brittle fracture may control as the failure mechanism. The fracture mechanics method is based on six parameters: Defect Assessment, based on the size of the initial defect and location in the material; Propagation Parameters, based on material constants and stress ratios; Stress Intensity Factor, the influence of geometry on the crack tip as well as the long-term distribution of stress range (this term should not be confused with stress amplification factors); Fracture Criterion, evaluates the mode of fatigue failure by incorporating brittle fracture; Boundary Conditions; and Residual Stresses, stresses inherent in the material due to the method of fabrication or welding. See BSI PD 6493.

The S-N approach is a good method to estimate the initial fatigue life of a riser for assumed environmental conditions. The fracture mechanics method, when coupled with an inspection program, is appropriate for estimating the remaining fatigue life of a riser after use.

C.3 LOAD AND RESISTANCE FACTOR DESIGN (LRFD). LRFD format is based on reliability, in contrast to the standard API format which is based on working stress design (WSD). In the WSD approach, a large factor of safety is imposed on the allowable stress with no differentiation between loadings and how they add to the state of stress. In LRFD, load factors are assigned to loading mechanisms in accordance to the degree of uncertainty in the determination of each of the loads. Large factors of safety on the design stresses are eliminated. For example, the self weight of the riser joints and the drilling fluid density are known to a relatively high degree of accuracy in comparison to the vertical tension and vessel offset which are known to a slightly lesser degree, and the environmental loads are known to an even lesser degree. LRFD attempts to account for these differences in uncertainty, WSD does not.

Three major components are considered in the develop ment of the LRFD method: uncertainties, risk, and economics. A probabilistic representation of each random variable describes the uncertainties, including unavoidable scatter as well as objective and subjective modeling uncertainties.

1. Uncertainties are measured by the statistical spread in the data.

2. Risk expresses the probability of an unfavorable consequence. The reliability design model invariably defines both loads and strengths as probabilistic random variables. Risk depends on the degree of overlap of the load and strength probability density curves. An important point is that there is no risk free environment.

3. Economics must enter the decision process since there is no zero risk operation. Higher safety margins will move apart and reduce, but not eliminate the load and strength overlap. As risk decreases and initial cost increases, a balance or optimum is reached at which an incremental initial cost is just balanced by an equal decrease in expected consequence cost. The balance point establishes the optimal total cost and the corresponding optimal risk, and hence in principle can be used to derive design criteria, safety margins, etc. A limitation to a direct application of this approach is the limited available data to model the distributions.

While the load and resistance factors have been chosen based on reliability considerations, the designer is not faced with carrying out probabilistic calculations. This work will already have been completed in the development of the LRFD code and incorporated in the appropriate design factors.

In the LRFD format an effort is made to maintain an engineering understanding of the load and resistance formulations. Formulas are used which were developed for traditional engineering practice rather than relying on a multitude of factors to be read from tables and graphs. All the checking equations are intended to reflect the mean estimate of the members ultimate capacity. For the most part the LRFD formulas are similar to the WSD formulas.

An LRFD type format has been adopted by several codes in the U.S. and other countries. Some of these codes are AISC, ACI (American Concrete Institute), AASHTO (American Association of State Highway and Transportation Officials), DnV, BSI (British Standards Institute), CSA (Canadian Standards Association), and API.

APPENDIX D
SAMPLE RISER CACULATIONS

D.1 RISER LENGTH DETERMINATION

D.1.1 Problem. A semisubmersible is drilling a well at a 2000 foot (MLW) water depth location. The wellhead has been cemented in place and its elevation above the mudline measured. Equipment, environmental, and operational data have been input into the accompanying Riser Analysis Data Worksheet. Determine the riser length using appropriate pup joints.

D.1.2 Solution. Refer to Section 4.3.1 and Figure 4.1.

Riser Length = C = F (A+B+D+E)

F = (MLW) + (mean tidal change) + (distance from waterline to RKB)
= 2000 ft + 2.5 ft + 85.5 ft
= 2088 ft

A = Wellhead height above mudline
= 4.8 ft

B = (Lower stack height) + (LMRP height)
= 22.7 ft + 20.0 ft
= 42.7 ft

D = (Collapsed length) + 1/2 (stroke)
= 61.2 ft + 1/2 (111.2 - 61.2) ft
= 86.2 ft

E = (Top of flex/ball joint below RKB (drill floor) + (made-up length of flex/ball joint)
= 10.1 ft + (1.0 + 3.3) ft
= 14.4 ft

C = 2088 ft - (4.8 + 42.7 + 86.2 + 14.4) ft
= 1939.9 ft

Use 38, 50-foot riser joints plus 25- and 15-foot pup joints. This makes telescopic joint slightly short of mid-stroke position as recommended in Section 4.3.1.

*All lengths and heights are based on made-up dimensions.

D.2 MINIMUM TOP TENSION DETERMINATION

D.2.1 Problem. Using the Riser Analysis Data Worksheet and riser length determination from the previous example, the accompanying riser diagram has been drawn for this location. Determine the minimum top tension for the following cases:

a. Drilling with 14.0 ppg drilling fluid
b. Non-drilling with 14.0 ppg drilling fluid
c. Drilling with 12.0 ppg drilling fluid
d. Non-drilling with 12.0 ppg drilling fluid
e. Drilling with 8.555 ppg drilling fluid (seawater)
f. Non-drilling with 8.555 ppg drilling fluid

Assume that the minimum effective tension is at the bottom of the riser.

D.2.2 Solution. Per Section 3.3.2, the minimum top tension, T_{min}, is determined by:

$T_{min} = T_{SRmin} N / [R_f (N-n)]$

T_{SRmin} = Minimum Slip Ring Tension

$= W_s f_{wt} - B_n f_{bt} + A_i (d_m H_m \; d_w H_w)$

W_s = Submerged Riser Weight (lb)

f_{wt} = Submerged Weight Tolerance Factor

B_n = Net Lift of Buoyancy Material (lb)

f_{bt} = Buoyancy Loss and Tolerance Factor resulting from elastic compression, long term water absorption and manufacturing tolerance

A_i = Internal Cross Sectional Area of riser tube (ft^2)

d_m = Drilling Fluid Weight Density (7.48 • ppg [lb/ft^3])

H_m = Drilling Fluid Column (ft)

d_w = Sea Water Weight Density (64 lb/ft^3)

H_w = Sea Water Column, including storm surge and tide (ft)

SAMPLE CALCULATION D.1 & D.2
RISER ANALYSIS DATA WORKSHEET

Location	U.S. East Coast
Waterdepth/ Reference	2000' Mean Low Water
Vessel Name	"SPICED JAR"
Vessel Type	Semisubmersible
Vessel Draft	65
Drill Floor to WL	85.5'
Moonpool Dimensions	- - -

Tensioner System			
No. Tensioners	12	DTL Rating (ea., kip)	80
No. Tens./ Accumul.	2/ (1)	Ten.RF: Rot./Non-Rot.	.95/.90
Tens. Line Fleet Ang.	3 deg	Tens. Line Dia (in)	2.0
Tens. Line B.S. (kip)	396	Termination Type	Wdg. Sckt.
Wire Wt. @ Tens. (kip)	.55	Termin. Efficiency	.65

Telescoping Joint			
Collapsed Length (ft)	61.2	Fully Ext. Lngth (R)	111.2
Space-out to UFJ (ft)	4.3	Mud Ret. bel. DF (R)	6.4
Outer BBL dia (in)	24	O.B. Wall Thickn. (in)	0.5
O.B. Air Weight (lbs)	11,177	O.B. Subm. Wt. (lbs)	9,713
Load Rating (kip)	1,000	O.B. Yield Point (ksi)	55
Drag Diameter (in)	32.5	CD1/CD2 (lo/hi Re)	1.2/ .9
Mass Diameter (in)	25.1	Mass Coefficient, CM	2.0

Riser Joints	Type 1	Type 2	Type 3
No. Joints	26	2	12
Buoyancy	No	No	Yes
M.U. Length of Jt. (ft)	50	50	50
Coupling Type	Brand X	Brand X	Brand X
Cplg. Load Rtg. (kip)	1,250	1,250	1,250
Cplg. Yield (ksi)	-		-
Cplg. Stress Amplif. F.	-	-	
Cplg. Weight (lbs)	2,400	2,400	2,400
Main Tube OD (in)	21	21	21
Main Tube Wall T. (in)	.5	.625	.625
Mn. Tube Yield (ksi)	65	65	65
Tube Stress Amplif. F.	1.5	1.5	1.5
C+K Line OD/ID (in)	4.0/2.625	4.0/2.625	4.0/2.625
Mud B. L. OD/ID (in)	4.0/3.375	4.0/3.375	4.0/3.375
Hydraulic L. ID (in)	-	-	-
Bare R. Air Wt (lbs)	10,850	12,553	13,403
Submerged Wt. (lbs)	9,429	10,909	11,647
Steel Wt. Toler. (%)	± 5	± 5	± 5
Buoyancy Type	-		Synt. Foam
Foam Density (lb/ft³)	-		25

Riser Joints — cont'd	Type 1	Type 2	Type 3
Buoy. Dia. (in)	-		40
Buoy. Length (ft/Jt.)	-		45
Buoy. Air Wt. (lbs/Jt)	-		6,030
Net Pos. Buoy. (lbs/Jt.)		-	9,240
Buoy. Wt.Tol.(mean %)		-	± 2
Buoy. Loss (E+T) (%)		-	2
Drag Diameter (in)	29.0	29.0	40.0
Mass Diameter (in)	22.1	22.1	40.0
CD1/CD2 (lo/hi Be)	1.2/ .9	1.2/ .9	1.21.8
Mass Coeff. CM	2	2	2

Pup Jt. M.U.Length (ft)	5	10	15	25
Main Tube OD (in)	21	21	21	21
Main Tube Wall T. (in)	.5	.50	.50	.50
Air Weight (lbs)	2,453	3,361	4,349	6,165
Subm. Weight (lbs)	2,132	2,921	3,779	5,357

Flex/ Ball Jts.+Adapt	Upper	Lower	Intermed.
Bating (kip)		830.7	–
Rot. Ctr. abv. Sea Floor		39.8	–
UFJ Top.bel.Drill Fl.	10.1	-	–
Ctr. - Top (ft)	1.0	7.7	
Ctr. - Btm. (ft)	3.3	3.3	–
Effect. Air Wt. (lbs)	-	11,754	–
Effect. Subm.Wt. (#)		10,214	–
Axial Stiffn. (kip/in)		4,400	–
Rot. Stiff. (K. ft/deg)	0	20.0	–
Max. Rotation (deg.)	10	10	–
Drag Dia. (in.)	45	32.5	
CD1/ CD2 (lo/hi Re)	1.5/1.5	1.5/1.5	–
Mass. Coeff. CM	2	2	–

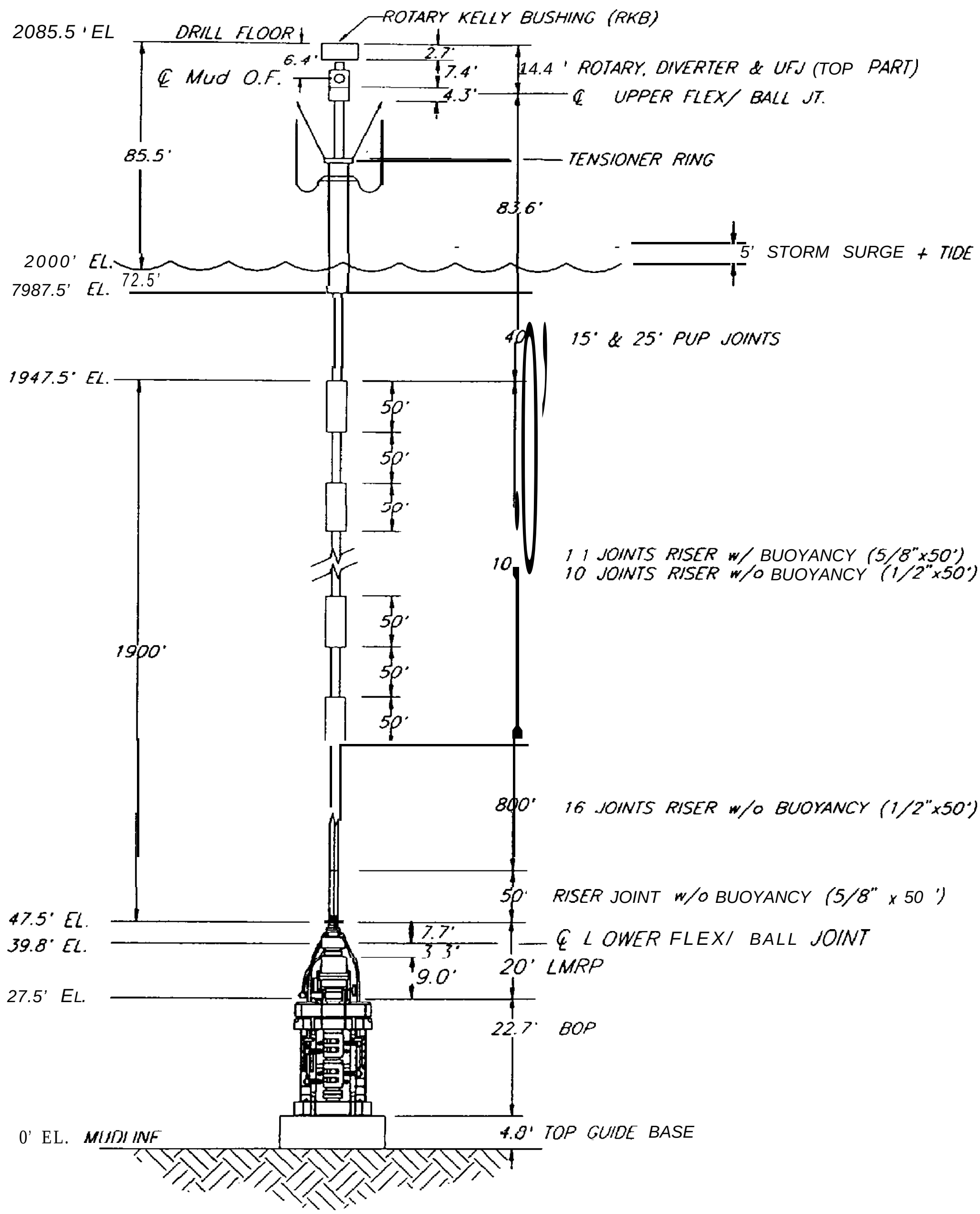
Stack/ Well Head	LMRP	Lower Stack	Well Head
Height (ft)	20.0	22.7	4.8
Air Weight (lbs)	70,000	260,000	–
Subm. Weight (lbs)	60,830	225,940	–
Drag Diameter (in)	66	120	–
Hydrod. Vol. (ft^3/ft)	20	50	–
Max. Tension (kip)	2,000	2,000	2,000
Max. Bend. Mom. (K. ft)	2,000	2,000	2,000

Drilling Parameters	Drilling	Non-Drilling	Disconnected
D.F. Weights (ppg)	12 & 14	8.56, 12 & 14	8.56
Vessel Offsets (% WD)	0 & 2	2 & 4	6
Top Tensions (% DTL)	50-90	50-90	-

Environmental Conditions						
Operating Mode	Drilling		Non-Drilling		Disconnected	
Design Wave Ht (ft) Wave Period (sec.)	- -		- -		- -	
Sign. Wave Ht. (ft) Mean Period T_z (sec.) Peak Period (sec.) Spectrum Type	16.0 8.80 9.94 Jonswap		21.4 9.20 10.93 Jonswap		26.9 9.70 13.90 Jonswap	
Current Profile	WD (ft)	kn	WD (ft)	kn	WD (ft)	kn
	0	1.75	0	2.00	0	2.25
	33	1.75	33	2.00	33	2.25
	377	.58	377	.66	377	.75
	873	.52	873	.59	873	.67
	1509	.35	1509	.40	1509	.45
	2000	.22	2000	.25	2000	.28
Max. Storm Surge+Tide	5		5		10	

Vessel Motion Response (amplitude ÷ amplitude)								
Surge/Sway			Heave (ft/ft)			Roll/Pitch (deg/ft)		
T sec.	RAO ft/ft	θ deg.	T sec.	RAO ft/ft	θ deg.	T sec.	RAO deg/ft	Ø deg.
0	.0	0	5.66	.030	123	0	.0	0
3	.039	27	6.01	.030	150	3	.005	270
4	.091	90	6.37	.020	165	4	.012	90
5	.150	270	6.76	.010	164	5	.019	90
6	.234	270	7.18	.001	58	6	.041	270
7	.133	270	7.62	.026	1	7	.122	270
8	.024	90	8.08	.058	-11	8	.179	270
9	.179	90	8.58	.106	-16	9	.206	270
10	.310	90	9.10	.169	-16	10	.212	270
11	.417	90	9.66	.240	-13	11	.207	270
12	.503	90	10.25	.306	-9	12	.194	270
13	.575	90	10.88	.361	-6	13	.180	270
14	.633	90	11.55	.405	-3	14	.163	270
15	.682	90	12.25	.438	-2	15	.147	270
16	.723	90	13.01	.462	-1	16	.133	270
17	.761	90	13.82	.476	0	17	.119	270
18	.799	90	14.69	.477	0	18	.106	270
19	.833	90	15.64	.459	0	19	.095	270
20	.870	90	16.68	.406	0	20	.084	270
			17.84	.267	-1			
			19.14	.206	-173			
			20.60	3.000	-75			
			22.28	1.799	-1			
			24.19	1.330	0			
			26.39	1.181	0			
			28.91	1.112	0			

SAMPLE CALCULATION D.2
RISER DIAGRAM



SEMISUBMERSIBLE "SPICED JAR"
EXAMPLE RISER CONFIGURATION 2000' W.D MLW

D.2.2.1 Riser Submerged Weight times Tolerance Factor $(W_s f_{wt})$

Riser Joints	W_s/Jt.	W_s	f_{wt}	$W_s f_{wt}$
26 @ type 1	9,429	245,154	1.05	257,412
1 @ type 2	10,909	10,909	1.05	11,454
11 @ type 3	11,647	128,117	1.05	134,523
15' pup joint	3,779	3,779	1.05	3,968
25' pup joint	5,357	5,357	1.05	5,625
slip joint (abv. WL)	11,177	11,177	1.05	11,736
$\Sigma\ W_s f_{wt}$		404,493 lb		424,718 lb

D.2.2.2 Riser Net Buoyancy times Tolerance Factor $(B_n f_{bt})$

Riser Joints	B_n/Jt.	B_n	f_{bt}	$B_n f_{bt}$
11 @ type 3	9,240	101,640	0.96	97,574
$B_n f_{bt}$		101,640 lb		97,574 lb

D.2.2.3 Internal Drilling Fluid Cross Section of Riser, (including auxiliary lines) at bottom of riser (A_i) for Type 2 riser at bottom:

$A_i = \pi/4\,(19.75^2 + 2 \cdot 2.625^2 + 3.375^2)/144 = 2.2647\ ft^2$

D.2.2.4 Drilling Fluid Pressure Column $(d_m H_m)$

a. Drilling Fluid Weight Density (d_m)

$d_m = 8.555\ ppg \cdot 7.48\ gal/ft^3 = 64\ lb/ft^3$

$d_m = 12\ ppg \cdot 7.48\ gal/ft^3 = 89.76\ lb/ft^3$

$d_m = 14\ ppg \cdot 7.48\ gal/ft^3 = 104.72\ lb/ft^3$

b. Drilling Fluid Column Height to overflow, including storm surge (H_m)

$H_m = 50 + 800 + 1{,}050 + 40 + 83.6 + 14.4 - 6.4 + 5 = 2{,}036.6\ ft$

c. Drilling Fluid Pressure Column $(d_m H_m)$

(1) With sea water in riser:

$d_m H_m = 2{,}036.6 \cdot 64 = 130{,}342.4\ lb/ft^2$

(2) With 12 ppg drilling fluid:

$d_m H_m = 2{,}036.6 \cdot 89.76 = 182{,}805.22\ lb/ft^2$

(3) With 14 ppg drilling fluid:

$d_m H_m = 2{,}036.6 \cdot 104.72 = 213{,}272.75\ lb/ft^2$

D-2.2.5 Sea Water Pressure Column $(d_w H_w)$

a Sea Water Column Density (d_w)

$d_w = 64\ lb/ft^3$

b. Sea Water Column Height to center LFJ, including storm surge (H_w)

$H_w = 2{,}000 - 4.8 - 22.7 - 20 + 5 = 1{,}957.5\ ft$

c. Sea Water Pressure Column

$d_w H_w = 1957.5 \cdot 64 = 125{,}280.0\ lb/ft^2$

D.2.2.6 Internal Cross Section Area times Pressure Differential

a With sea water in riser:

$A_i\,(d_m H_m - d_w H_w) = 2.2647\ (130{,}342 - 125{,}280) = 11{,}464\ lb$

b. With 12 ppg drilling fluid:

$A_i\,(d_m H_m - d_w H_w) = 2.2647\ (182{,}805 - 125{,}280) = 130{,}277\ lb$

c. With 14 ppg drilling fluid:

$A_i\,(d_m H_m - d_w H_w) = 2.2647\ (213{,}273 - 125{,}280) = 199{,}278\ lb$

D.2.2.7 Minimum Slip Ring Tension (lb)

$Ts_{,} = W_{s}f_{wt} \cdot B_{n}f_{bt} + A_{i}(d_{m}H_{m} \cdot d_{w}H_{w})$

a. With sea water in riser:

T_{SRmin} = 424,718 • 97,574 + 11,464 = 338,608 lb

b. With 12 ppg drilling fluid:

T_{SRmin} = 424,718 • 97,574 + 130,277 = 457,421 lb

c. With 14 ppg drilling fluid:

T_{SRmin} = 424,718 • 97,574 + 199,278 = 526,422 lb

D.2.2.8 Minimum Required Top Tension (lb)

$T_{min} = T_{SRmin}\ N / [R_{f}(N\text{-}n)]$

N = Number of Tensioners Supporting the Riser = 12

n = Number of Tensioners Subject to Sudden Failure = 2

R_f = Reduction Factor **Relating** Verticle Tension at the Slip Ring to Tensioner Setting to account for line angle and mechanical efficiency (usually 0.9 • 0.95)

= 0.95 (drilling)

= 0.90 (non-drilling)

a **Drilling with 14 ppg drilling fluid:**

T_{min} = 526,422 • 12 / [.95 • 101 = 664,954 lb

b. Non-drilling with 14 ppg drilling fluid:

T_{min} = 526,422 • 12 / [.90 • 101 = 701,896 lb

c. Drilling with 12 ppg drilling fluid:

T_{min} = 457,421 • 12 / [.95 • 101 = 577,795 lb

d. Non-drilling with 12 ppg drilling fluid:

T_{min} = 457,421 • 12 / [.90 • 10] = 609,895 lb

e. Drilling with 8.555 ppg (seawater):

T_{min} = 338,608 . 12 / [.95 • 10] = 427,715 lb

f. **Non-drilling with 8.555 ppg (seawater):**

T_{min} = 338,608 • 12 / [.90 • 101 = 451,477 lb

APPENDIX E
EXAMPLE RISER RUNNING PROCEDURE

E.1 MOVING STACK INTO RUNNING POSITION. Safe handling of the BOP stack depends on the magnitude of vessel motions and the nature of the handling equipment on the particular rig. Some rigs are equipped with special transfer and guidance equipment to guide the BOP stack through the moonpool and the splash zone.

If the vessel motion characteristics permit, the stack can be moved into the running position. On most floating rigs, a set of spider beams is set across the moonpool either on the rig floor or cellar deck level. The stack is moved and positioned on top of the spider beams either by overhead trolleys or a bottom supporting cart or skid. The BOP stack components should be function tested and pressure tested as required using the BOP control system for functioning. This testing can be done either before or after the stack is positioned on the spider beams. After successful testing, the BOP stack is ready to be run.

E.2 RUNNING THE RISER AND BOP STACK For a typical running procedure, the following steps include the most critical running operations.

a. Prior to lifting the BOP off the spider beams, the BOP controls should be set in the running position and the riser connector should be verified to be latched. The controls should not be operated again until the stack is landed.

b. The first riser section (usually two joints) above the BOP stack should be long enough to allow the BOP stack to be run into the water without stopping. When the BOP stack is in the water, its motions are damped.

c. The riser couplings should be made up in accordance with manufacturer's recommended procedures. Correct make-up and preload of each coupling should be verified prior to its use as a tensile member. The make-up and break-out tools should be calibrated frequently and set to impart the proper preload to the riser coupling. (See RP2R for a further discussion of preload.)

d. Ensure that the riser spider is properly engaged and supporting the riser before removing the handling tool. A gimballed spider should be considered when vessel pitch or roll motions cause large bending moments on the coupling.

e. As riser joints are added to the string, the choke and kill lines and appropriate auxiliary lines should be pressure tested at regular intervals (usually every fifth joint). The choke and kill lines should be filled with water, control system supply lines should be filled with control fluid.

f. The correct number and length of riser pup joints should be run so that, at mean sea level with the BOP stack latched to the wellhead, the outer barrel of the telescopic joint will be sufficiently above mid-stroke to accommodate stroke out caused by vessel offiet.

g. The collapsed and pinned telescopic joint should be made-up to the uppermost joint in the riser string and the outer barrel should be hung off in the spider. On most rigs, the BOP stack is landed with the telescopic joint collapsed and pinned, the additional string length provided by the temporary installation of an extra riser joint (referred to as a landing joint) above the telescopic joint. On some rigs, however, the diverter is made up at this point so that the telescopic joint can be unpinned and fully extended to prepare for landing the BOP stack. The shoe on the inner barrel and the pins joining the inner and outer barrels should each be designed to support the combined submerged weight of the BOP stack and riser as well as loads from dynamic effects. To avoid confusion, only the collapsed and pinned case will be further considered here.

h. The riser, supported by the hook attached to the landing joint, should be lowered sufficiently to allow the riser tensioner lines to be attached to the outer barrel of the telescopic joint. The riser tensioners should be adjusted to reduce the hook load while the telescopic joint is supported on the hook. At this point, the BOP stack is in position to be landed.

E.3 LANDING THE STACK. The BOP stack landing operation can be monitored using the underwater television system, divers, or a remote operated vehicle (ROV).

Caution should be exercised during the landing operation to avoid putting the riser in compression. Therefore, the BOP stack should be landed with the tensioners supporting more than the weight of the telescopic and riser joints, and the hook or heave compensator supporting the balance of the total weight.

APPENDMF
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