

Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems

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Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems

1 Scope

API 16Q provides requirements for the design, selection, operation, and maintenance of typical marine riser systems for floating drilling operations from a mobile offshore drilling unit (MODU) with a subsea blowout preventer (BOP) stack. 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, consultants, and manufacturers.

Since technology is continuously advancing in this field, methods and equipment are improving and evolving. Each owner and operator is encouraged to observe the recommendations outlined herein and to supplement them with other proven technology that can result in a more cost-effective, safer, and/or more reliable performance.

The marine drilling riser is best viewed as a system. It is necessary that designers, contractors, and operators realize that the individual components are recommended and selected in a manner suited to the overall performance of that system. For the purposes of this document, a marine drilling riser system includes the tensioner system and all equipment between the top connection of the upper flex/ball joint to the lower flex joint. However, it specifically excludes the diverter. Also, the applicability of this document is limited to operations with a subsea BOP stack.

Sections 1 through 7 are applicable to most floating drilling operations. In addition, special situations and topics are addressed in Section 8 dealing with deepwater drilling, cold weather environments, riser collapse, hydrogen sulfide (H₂S), well testing, and managed pressure drilling (MPD). It is important that all riser primary load-path components addressed in this document be consistent with the load classifications specified in API 16F.

2 Normative References

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

API Specification 16C, *Choke and Kill Equipment*

API Specification 16F, *Specification for Marine Drilling Riser Equipment*

API Specification 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*

API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells*

API Recommended Practice 64, *Recommended Practice for Diverter Systems Equipment and Operations*

ANSI ¹/NACE MR0175 ²/ISO 15156 ³, *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production*

¹ American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.

² NACE International, 15835 Park Ten Place, Houston, Texas 77084, www.nace.org.

³ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.

ASTM A370 ⁴, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

ASTM E23, *Standard Test Methods for Notched Bar Impact Testing of Metallic Materials*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

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

3.1.1

accumulator

Pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

3.1.2

actuator

Mechanism for the manual, remote, or automatic operation of a valve or choke.

3.1.3

air can

Closed top, open bottom cylinder forming an annulus around the outside of the riser pipe that is filled with air (or other low-density fluid) to provide buoyancy.

3.1.4

air can buoyancy

Uplift applied to the riser string by the net buoyancy from air (or other fluid) trapped in the air can.

3.1.5

annulus

Space between the inner diameter of pipe A and the outer diameter of pipe B when pipe B is positioned inside pipe A.

3.1.6

auxiliary line

Rigid line attached to the outside of the riser main tube [exclusive of the choke and kill (C/K) lines]; e.g. hydraulic supply line, mud boost line, air line.

3.1.7

back pressure

Pressure resulting from restrictions to fluid flow downstream.

3.1.8

ball joint

See **flex joint**.

3.1.9

blowout

Uncontrolled flow of well fluids and/or formation fluids from the wellbore to the surface or into lower pressured subsurface zones (underground blowout).

⁴ ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

3.1.10**blowout preventer
BOP**

Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars or in an open hole during well drilling, completion, and testing operations.

NOTE BOPs are not gate valves, workover/intervention control packages, subsea shut-in devices, well control components (per API 16ST), intervention control packages, diverters, rotating heads, rotating circulating devices, capping stacks, snubbing or stripping packages, or nonsealing rams.

3.1.11**blowout preventer stack**

Complete assembly of well control equipment, including preventers, spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies, consisting of the lower marine riser package (LMRP) and lower stack.

3.1.12**BOP landing and assist tool****BLAT****shuttle tool**

A tool intended to be utilized near the top of the riser string that allows the rig to support the riser string and BOP system from the rig hoisting system without removing the diverter.

NOTE Typically, the load is shared between the tool and the riser tensioning system.

3.1.13**bottomhole assembly**

Assembly composed of the bit, stabilizers, reamers, drill collars, various types of subs, etc., that is connected to the bottom of a string of drill pipe.

3.1.14**box**

Female member of a riser coupling or an external line stab assembly.

3.1.15**breech-lock coupling**

Coupling that is engaged by rotation of one member into an interlock with another member by a small angle, generally less than 45°.

3.1.16**buoyancy control line**

Auxiliary line dedicated to controlling, charging, or discharging air can buoyancy chambers.

3.1.17**buoyancy equipment**

Devices added to riser joints to reduce their weight in water and reduce riser top tension requirements.

NOTE The devices normally used for risers are syntactic foam modules or air cans.

3.1.18**choke and kill lines****C/K lines**

High-pressure line that allows fluids to be pumped into or removed from the well with the BOPs closed.

3.1.19**collapse pressure**

Differential (external minus internal) pressure at which structural failure is initiated within a tubular.

3.1.20**control pod**

Assembly of valves and regulators (either hydraulically or electrically operated) that when activated directs hydraulic fluid through special apertures to operate the BOP equipment.

3.1.21**coupling**

Mechanical means for joining two sections of riser pipe end-to-end.

3.1.22**crossover joint**

Special joint that provides for the interface between two different coupling designs.

3.1.23**diverter**

Device attached to the marine riser or wellhead to close the vertical flow path and direct the flow in a predetermined direction.

3.1.24**dog-type coupling**

Coupling having wedges (dogs) that are mechanically driven to engage the pin and box coupling members.

3.1.25**drape hose****(moonpool line)**

Flexible line connecting a choke, kill, and auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure.

NOTE A U-shaped bend in this flexible line accommodates vessel and telescopic joint inner barrel movement, while the outer barrel remains fixed and under tension.

3.1.26**drift-off**

Unintended lateral move of a dynamically positioned (DP) vessel off of its intended location relative to the wellhead, generally caused by the loss of stationkeeping control or propulsion.

3.1.27**drilling fluid**

Water or oil-based fluid that is circulated down the drill pipe into the well and back up the annulus 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 acting as a media for the pulsed transmission of well and drilling data to surface.

3.1.28**drive-off**

Unintended lateral move of a DP vessel off of its intended location caused by the vessel's main propulsion or stationkeeping thrusters.

3.1.29**dual gradient drilling****DGD**

Drilling technology that uses or simulates the effect of two fluids of different gradients in the annulus to create dual hydrostatic gradients to better manage the annular pressure profile.

NOTE This technology is used to facilitate well construction through enhanced wellbore pressure management.

3.1.30**dynamic positioning
(automatic stationkeeping)**

Computerized means of maintaining a vessel on location by selectively driving thrusters.

3.1.31**effective hydraulic cylinder area**

Net area of the cylinder inside diameter (ID) subjected to internal pressure.

3.1.32**effective tension**

Actual tension (a.k.a. " T_{REAL} ") in the pipe minus the internal pressure times the internal area of the riser plus the external pressure times the external area of the riser $T_{\text{EFF}} = T_{\text{REAL}} - p_i A_i + p_o A_o$.

3.1.33**effective weight**

Total submerged weight including contents (drilling mud, etc.) of an entire riser or a section of a riser.

3.1.34**external line**

A conduit attached laterally along the riser main pipe used for a variety of riser, BOP, or well functions.

3.1.35**factory acceptance testing**

Testing by the manufacturer to verify product performance to applicable specifications.

3.1.36**failsafe**

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

3.1.37**fill-up line**

Line usually connected to the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the riser main tube, at atmospheric pressure.

3.1.38**flange-type coupling**

Coupling having two flanges joined by threaded fasteners.

3.1.39**fleet angle (for riser tensioners)**

In marine riser nomenclature, the angle between the vertical axis and a riser tensioner line or the hydraulic cylinder rod (for direct-acting tensioners) at the point where the line (rod) connects to the telescopic joint.

3.1.40**flex joint****ball joint**

Device(s) installed between the bottom of the diverter and the telescopic joint (upper flex or ball joint), in the top section of the LMRP (lower flex or ball joint), or under a keel joint (intermediate flex or ball joint, if used), to permit relative angular movement of the riser and reduce stresses due to vessel motion and environmental forces.

NOTE Upper flex ball joint is sometimes called a diverter flex ball joint.

3.1.41**full-length riser joint**

Riser joint of standard length for a particular drilling vessel design or a particular riser string purchase.

3.1.42**gooseneck**

Type of terminal fitting designed to achieve a nominal 180° change in flow direction.

NOTE It can be a hands-free device.

3.1.43**guidelineless reentry**

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

3.1.44**hot spot stress**

See **local peak stresses**.

3.1.45**hydraulic connector**

Mechanical device that is activated by hydraulic pressure and connects and seals the BOP stack to the wellhead or the LMRP to the lower stack.

3.1.46**hydraulic supply line**

Auxiliary line from the vessel to the subsea LMRP control pods that supplies system operating fluid to the LMRP and the lower stack control functions.

3.1.47**instrumented riser joint****IRJ**

Riser joint equipped with sensors for collecting and transmitting data such as riser pipe tension, riser angular offset, annulus fluid temperature, pressure, etc.

3.1.48**intermediate flex joint****IFJ**

See **flex joint**.

3.1.49**jumper line (hose)**

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

3.1.50**keel joint**

Riser joint designed to withstand contact between the riser and the bottom of the moonpool.

3.1.51**keyseating**

Formation of a longitudinal slot on the ID of a riser component due to a loss of material caused by friction wear from the rotating drill string or tripping equipment.

3.1.52**landing joint**

Riser joint installed temporarily above the telescopic joint and used to land the BOP stack on the wellhead.

3.1.53**landing shoulder**

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.

3.1.54**local peak stresses**

Highest stress in the region or component under consideration that causes no significant distortion and is principally objectionable as a possible initiation site for a fatigue crack.

NOTE 1 These stresses are highly localized and occur at geometric discontinuities.

NOTE 2 This is sometimes referred to as hot spot stress.

3.1.55**lower marine riser package****LMRP**

Upper section of a subsea BOP stack that interfaces between the lower stack and drilling riser, typically consisting of a hydraulic connector, annular BOP, ball/flex joint, riser adapter, jumper lines for the choke, kill, and auxiliary lines, and subsea control pods.

3.1.56**lower stack**

Lower section of a subsea BOP stack that contains BOP spools, valves, hydraulic connectors, and nipples that typically connect to the subsea wellhead, subsea tree, or tubing head spool (below) and LMRP (above).

3.1.57**main tube****(riser pipe)**

Pipe that is the principal conduit of the riser joint; the conduit for guiding the drill string into the well and returning fluid flow from the well.

3.1.58**makeup time****(riser coupling)**

Total clock time to fully engage the male coupling to the female coupling during riser deployment.

NOTE This may include makeup of riser flanges, seal sub, and flange bolts and torque bolts during riser deployment.

3.1.59**makeup tool**

Device used to engage and disengage coupling members.

3.1.60**managed pressure drilling****MPD**

Adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore.

3.1.61**marine drilling riser**

Tubular conduit made up of a series of independent joints coupled together to serve as an extension of the wellbore from the BOP stack on the wellhead to a floating drilling rig.

3.1.62**mud**

See **drilling fluid**.

3.1.63**mud boost line**

Auxiliary line that provides supplementary fluid supply from the surface to (or near) the LMRP to assist in the circulation of drill cuttings up the marine riser.

3.1.64**nominal stress**

Stress calculated using nominal dimensions at the desired location away from local peak stresses.

3.1.65**pin**

Male member of a riser coupling or an external line stab assembly.

3.1.66**preload**

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

3.1.67**pressure-containing equipment**

Equipment (parts or members) whose failure to function as intended can result in a release of fluids to the environment.

3.1.68**primary load-carrying equipment**

Equipment (parts or members) whose failure can compromise the integrity of the entire riser string.

3.1.69**protector, pin or box**

Cap or cover used to protect the box or pin from damage during storage and handling.

3.1.70**pup joint**

Riser joint that is shorter than standard length.

3.1.71**rated load**

Load used in the product design, analysis, and performance testing.

3.1.72**remote gooseneck termination**

Separate piece of equipment that mates the rig drape hoses to the appropriate riser external lines with little or no direct physical worker involvement and that generally interfaces with the telescopic joint in the moonpool area.

3.1.73**response amplitude operator****RAO**

Ratio of a vessel's motion to the wave amplitude causing that motion and presented over a wide range of wave periods.

3.1.74**riser adapter**

Crossover between the first riser joint and flex/ball joint on the LMRP.

3.1.75**riser annulus**

Space between the riser string inner diameter and the outer diameter of the pipe (drill pipe, casing, tubing) suspended inside the riser string.

3.1.76**riser connector****(LMRP connector)**

See **hydraulic connector**.

3.1.77**riser disconnect**

Operation of unlatching the riser connector to separate the riser and LMRP from the lower stack.

3.1.78**riser fill-up valve**

Special riser joint with a valve that can open to the sea when bore pressure is lost to prevent riser pipe collapse.

3.1.79**riser hangoff system**

Means of supporting a disconnected riser from a drilling vessel during a storm without inducing excessive stresses in the riser.

3.1.80**riser joint**

One section of the riser string having the main tube fitted with a box and pin coupling, choke, kill, and auxiliary lines (optional), and brackets, clamps, thrust collars, and buoyancy modules, as applicable.

3.1.81**riser management system****RMS**

System designed to document, evaluate, and diagnose the design, fabrication, operation, and maintenance history of a riser component, assembly, or system through its lifecycle.

3.1.82**riser recoil system**

Means of controlling the upward acceleration of the riser when a disconnect is made at the riser connector.

3.1.83**riser spider**

Device having retractable load-bearing members used to support the riser string on the uppermost riser coupling load shoulder during deployment and retrieval of the riser.

3.1.84**riser string**

Deployed assembly of riser joints.

3.1.85**riser tension ring**

Structural interface of the telescopic joint outer barrel and the riser tensioners.

3.1.86**riser tensioner**

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

3.1.87**rotary kelly bushing****RKB**

Bushing that rotationally connects the rotary table to the drill string kelly bar, the top of which is commonly used as vertical reference for the drill floor.

3.1.88**rotating control device****RCD**

Drill-through device with a rotating seal that allows continued drilling operations while maintaining pressure in the wellbore.

3.1.89**running tool**

Manual or hydraulic device that interfaces between the drill string elevator and the riser joint that permits the deployment and retrieval of the riser string and BOP stack.

3.1.90**slick joint**

Riser joint of standard length without attached buoyancy.

3.1.91**slip joint**

See **telescopic joint**.

3.1.92**stab**

Mating pin and box assembly that provides a pressure tight connection but requires an external force to keep the assembly together.

3.1.93**storm disconnect**

Riser disconnect to avoid excessive loading from vessel motions amplified by inclement weather conditions.

3.1.94**strakes**

Helically wound appendages attached to the outside of the riser to suppress vortex-induced vibrations (VIVs).

3.1.95**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.

3.1.96**strumming**

See **vortex-induced vibration**.

3.1.97**submerged weight**

In-air weight minus buoyancy due to water displacement.

NOTE 1 The submerged weight of a riser string depends on the mode of operation, i.e. connected or suspended. For a connected riser and a suspended riser, internal and external pressures act on internal and external surfaces of the pipe and buoyancy.

NOTE 2 For a suspended riser, pressure end loads occur at the exposed areas at the bottom of the riser string.

3.1.98**support brackets****(clamps)**

Structural members positioned at sufficient intervals along the riser main tube to support the choke, kill, and auxiliary lines and prevent line buckling.

3.1.99**syntactic foam**

Composite material of hollow spherical fillers in a matrix or binder used in the manufacture of buoyancy modules.

3.1.100**telescopic joint****(slip joint)**

Riser joint having a stroking inner barrel (pipe) inside an outer barrel (pipe) with a sealing means between them to retain bore pressure.

3.1.101**telescopic joint packer**

Means of sealing the annular space between the inner and outer barrels of a telescopic joint.

3.1.102**terminal fitting**

Connection, commonly referred to as a gooseneck, between a rigid choke, kill, or auxiliary line on a telescopic joint and its mating drape hose, affecting a nominal 180° turn in flow direction.

3.1.103**termination joint**

Special riser joint that provides for the redirection of fluid flow for one or more external lines on the marine riser string.

NOTE It is generally used for ending the booster line at the bottom of the riser string or redirecting flow for the choke, kill, and auxiliary lines at the top of the riser string.

3.1.104**threaded union coupling**

Coupling having mating threaded members on the pin and box to form engagement.

NOTE 1 Threads on one side of the coupling are free to rotate relative to the riser pipe such that the joint does not have to rotate to make up the coupling.

NOTE 2 The threads do not form a seal.

3.1.105**thrust collar**

Structural member for transmitting the vertical force from buoyancy modules to the riser to help restrain the buoyancy modules from moving along the riser joint.

3.1.106**type certification testing**

Testing of a representative product by the manufacturer that qualifies the design and validates the integrity of subsequent products of the same design, materials, and manufacture.

3.1.107**vortex-induced vibration****VIV**

In-line and transverse oscillation of the riser string as the result of the periodic shedding of vortices from sea currents.

3.1.108**wellhead connector****(stack connector)**

See **hydraulic connector**.

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations shall apply.

ABP	applied back pressure
BHA	bottomhole assembly
BLAT	BOP landing and assist tool
BOP	blowout preventer
C_a	hydrodynamic added mass coefficient
C_d	hydrodynamic drag coefficient
C/K lines	choke and kill lines
C_m	hydrodynamic inertia coefficient
DGD	dual gradient drilling
DP	dynamically positioned
EDS	emergency disconnect sequence
H ₂ S	hydrogen sulfide
HFGN	hands-free gooseneck
HPHT	high pressure, high temperature
ID	inside diameter
IFJ	intermediate flex joint
IRJ	instrumented riser joint
LMRP	lower marine riser package
LRFD	load and resistance factor design
MBR	minimum bend radius
MODU	mobile offshore drilling unit
MPD	managed pressure drilling
MUX	multiplex
NDE	nondestructive examination (ultrasonic, radiographic, dye penetrant, acoustic emissions, etc.)
OD	outside diameter

OEM	original equipment manufacturer
POD	point of disconnect
RAO	response amplitude operator
RCD	rotating control device
RKB	rotary kelly bushing
RMS	riser management system
ROV	remotely operated vehicle
SAF	stress amplification factor
$T_{\max}$	maximum tension setting
TJ	telescopic joint
UFJ	upper flex joint
VIV	vortex-induced vibration
WSD	working stress design

4 Component Function and Selection

4.1 Introduction

General requirements common to all components are outlined in 4.2, and where appropriate, individual components are addressed in the rest of Section 4. 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.

In addition, Annex A provides details on riser management system (RMS) (QA/QC) for riser systems used.

4.2 Component Selection Criteria

The design of a riser system begins by specifying riser operating and performance requirements. An engineering analysis is required to meet riser system performance requirements such as tension rating, pressure capacity, buoyancy requirements, tensioner system requirements, running equipment requirements, etc. Factors that influence the riser system design include the water depth, drilling fluid weight, dimensional requirements (bore, wall thickness, etc.), auxiliary line specifications, rotary table and diverter housing size, connection type, environmental conditions, vessel motions, hangoff capacity, BOP stack design, storage and running conditions, etc. Some special requirements may also exist depending on the modes of operation to be conducted (e.g. MPD). Once performance requirements are met, the design process moves to the selection of appropriate riser system components to meet the needs of the expected or desired operations.

4.3 Marine Drilling Riser System

The marine riser system provides a conduit from the BOP stack to the drilling vessel (see Figure 1).

The primary functions of the marine riser system are as follows.

- a) Assist in controlling wellbore hydrostatic pressure.
- b) Provide for fluid communication between the well and the drilling vessel:

- 1) in the riser annulus under normal drilling conditions,
 - 2) through the C/K lines when the BOP stack is being pressure tested or used to control the well.
- c) Support the choke, kill, and auxiliary lines.
 - d) Guide tubulars and equipment into the well.
 - e) Serve as a running and retrieving string for the BOP stack.

4.4 Tensioner System

4.4.1 Function

Riser tensioners are used to apply vertical force to the top of the marine drilling riser to provide stability to the riser and control its stresses, displacements, and angles. They are normally located on the drilling vessel near the periphery of the drill floor. They provide tension to the riser while the floating drilling vessel moves in response to the wind, waves, and current.

4.4.2 Typical Designs

There are currently two types of tensioners typically used with drilling riser consisting of wireline tensioners and direct-acting tensioners, as follows.

- 1) Wire rope tensioner systems use hydraulic rams with a large volume of compressed air or inert gas to maintain approximately constant pressure in the system and tension in the wire ropes. One end of each rope is attached to the tension ring. Typically, a four-part reeving system is used so that the displacement of ropes where they terminate on the tension ring is four times the displacement of the rods that extend from the tensioner cylinders.

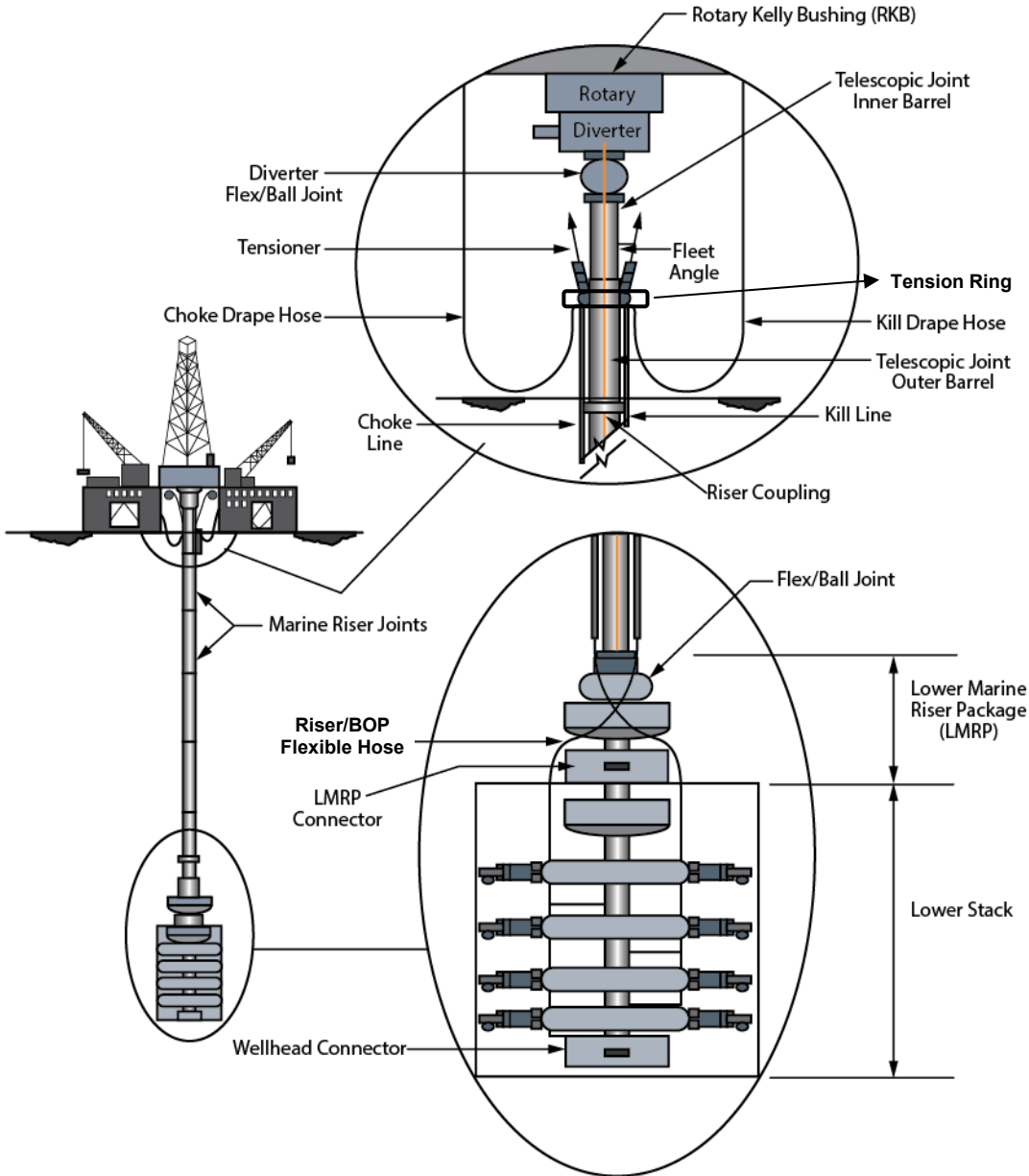


Figure 1—Marine Riser System and Associated Equipment

- 2) The direct-acting tensioner systems consist typically of multiple cylinders suspended from the drill floor substructure and connected to the tension ring by shackles or ball joints. It is possible to arrange the cylinders in many configurations to fit the specific layout of the substructure and the layout of pipe/BOP running equipment. This type of design is based on production riser tensioning designs where the rod side of the cylinder is the working side and uses a large volume of compressed air or inert gas to support the cylinder rod and tension ring upwards.

A tensioner may be provided in either a single tensioner or dual tensioner configuration, depending on the specific design. In direct-acting tensioner systems, tensioners are typically configured as singles. The number, capacity, and stroke of the tensioners determine the total capacity of the tensioner system. The tension applied by each tensioner or tensioner pair can be varied by increasing or decreasing pressure within appropriate limits determined by the manufacturer. The tensioner system should have sufficient capacity for all conditions in which the riser is expected to operate, as determined by riser analysis and operating policy.

4.4.3 Selection Criteria

Some important considerations for specifying a tensioner system are as follows.

- a) *Maximum tension setting ($T_{\max}$)*—The highest permissible tension setting with the vessel on location that provides sufficient margin so that anticipated conditions (such as wave-induced vessel motions, rig excursion, and/or tide change) do not cause any tensioner system relief valves to open, cause the tension experienced in the tensioners to exceed the limits of the design, or cause the pressure in the tensioners to exceed the limits of the design. With these considerations in mind, tension on any individual tensioner should not exceed this limit and the maximum tension setting for the riser, $T_{\max}$, should not exceed this limit multiplied by the number of active tensioners. Other considerations (e.g. riser and wellhead loading, recoil, etc.) may impose additional restrictions on tension setting.
- b) *Stroke*—Each tensioner should provide enough stroke to accommodate wave-induced vessel motions, offset-induced changes in stroke, tidal variations, pup joint increment, changes in riser length due to changes in tension setting, etc. (see 6.4.2 for more details).
- c) *Number of tensioners*—On some vessels, the tensioner system is configured to permit one tensioner or tensioner pair to be out of service for maintenance or repair without jeopardizing the ability of the remaining tensioners to provide the required tension to the marine drilling riser.
- d) *End cushioning*—many riser tensioner cylinders include some form of end cushioning to limit forces when the tensioner rods reach their stroke limit. The configurations vary from one tensioner system to another. Some forms of end cushioning can interfere with efficient movement of the tensioner rods in the portion of the stroke range in which they are active.
- e) *“Fleet angle”*—The angle from vertical at which the riser tension is applied to the riser.
- f) *Wire rope considerations*—Wire rope life is a function of many parameters, including wire rope construction, sheave diameter, applied tension, operating circumstances related to travel, etc. (see API 9B).
- g) *Accumulators and pressure vessels*—For tensioners that have an air-oil interface on the working side of the tensioner, an accumulator should be provided that has sufficient accumulator volume to store a volume of hydraulic fluid greater than the cylinder volume of the tensioner unit. The volume of air pressure vessels (or nitrogen pressure vessels) has a direct influence on the stiffness of the tensioners.
- h) *Fluid and air flow requirements*—Pipe size, length, and fittings that connect riser tensioner components should be such to keep hydraulic friction losses within acceptable limits for the maximum anticipated flow rates.
- i) *Friction and inertia losses*—Mechanical friction in the tensioner cylinders and sheaves and inertia of sheaves, wire rope, tensioner rods, and pistons all contribute to tension variations. The design of the tensioner system should strive to minimize the effects as much as is practical.
- j) *Velocity-limiting device*—Many riser tensioner systems include a feature in each tensioner to limit tensioner rod speed in the event of a sudden loss of load in the tensioner (such as a parted wire rope or parted tensioner shackle). The design and location of these devices varies.
- k) *Recoil control systems*—Many riser tensioner systems include a recoil control system that is intended to limit riser and tensioner speeds in events such as an emergency disconnect. Recoil analysis is discussed in 5.7.

4.5 Diverter System (Surface)

4.5.1 Function

The diverter system manages the returns coming up the riser main tube. The diverter system incorporates a closure device that is installed in the housing. When closed, this device directs flow away from the rig floor. Diverter valves located in the diverter system divert the returns either overboard, to the trip tank, to the shakers, or to a gas line. Typically, the diverter system includes an annular sealing device, valves to open and close the lines, and a control system.

4.5.2 Location

Diverter systems are usually installed directly below the rotary table. The diverter unit is latched into a fixed 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. The diverter valves are mounted to outlets coming off the diverter housing.

4.5.3 Operation

API 64 provides standard operational practices for diverter systems.

4.6 Riser Tension Ring

4.6.1 Function

The riser tension ring is mounted to the outer barrel of the telescopic joint (TJ) and transmits the load from the tensioner system to the outer barrel and the riser. In some cases, the riser tension ring may be integral to the TJ.

The riser tensioner lines can attach to the riser tension ring near the top of the TJ outer barrel. However, for direct-acting tensioner systems, the connection point may be lower on the outer barrel of the TJ. This attachment provides the structural interface between the marine riser and the tensioner system. The riser tension ring accommodates lift points at the ends of the tensioner lines or direct-acting tensioners.

4.6.2 Optional Features of the Riser Tension Ring

The tension ring may include a rotating mechanism to accommodate vessel heading changes.

In some cases, the rotating mechanism may be integral to the TJ.

For operational convenience, on some vessels the riser tension ring is detached from the outer barrel and attached to the bottom of the diverter housing for storage. This arrangement eliminates the time-consuming operations of connecting/disconnecting tensioner lines when deploying or retrieving the riser.

Direct-acting tensioner systems may have a split tension ring that stays connected to the tensioner during storage.

The tension ring may include a hands-free gooseneck (HFGN) for attaching the drape hose terminal fittings to the riser string.

4.6.3 Selection Criteria

Selection criteria should include but is not limited to the following:

- a) primary and secondary locking methods used for storage or attachment to the riser string;

- b) operational and storage ratings consistent with the riser system for which it is chosen (noting loads from high current operation cases, environmental loading considerations, rig motions);
- c) effects of lost or offline tensioners;
- d) tensioner attachments consistent with the type of tensioning system in use (their orientation should align with the positions of the tensioner line sheaves or direct-acting tensioners);
- e) method of storage when not in use and method of attachment to riser string;
- f) verification of proper storage and attachment to the riser string;
- g) consideration of torsional loads.

4.7 Telescopic Joint (Slip Joint)

4.7.1 Function

The basic function of the TJ is to compensate for the relative movement between the vessel and the riser. The outer barrel provides structural support for riser tension loads. The inner barrel translates vertically inside the outer barrel to account for movement between the vessel and the riser. The TJ has a packer(s) sealing element(s) between the inner and outer barrel to eliminate fluid discharged to the environment.

Most TJs have an interface to attach goosenecks for terminating the riser choke, kill, and auxiliary lines. In other cases, a separate termination joint provides that functionality.

4.7.2 Typical Design

4.7.2.1 General

A TJ has an outer barrel that is connected to the drilling riser and an inner barrel that is connected to the drilling vessel. The outer barrel typically includes two packers to seal against the inner barrel and an interface for the riser tension ring. The C/K and auxiliary lines are typically included on the outer barrel and terminate to gooseneck connections that connect to drape hoses for interfacing with the rig piping.

The inner barrel is typically designed to prevent it from slipping out from the outer barrel in the fully extended condition.

The TJ may include a rotational mechanism to accommodate vessel heading changes.

4.7.3 Selection Criteria

The selection of a TJ should include consideration and evaluation of the following basic items.

- a) Tension ratings—In both its retracted and extended positions, the TJ should support the weight and dynamic loads of the riser and BOP stack. The outer barrel tension rating below the tension ring interface should be greater than or equal to the tension rating of the riser system.
- b) Stroke length—The maximum stroke length required for the TJ should accommodate the combined expected heave, vessel offset, tidal change, maximum anticipated vessel excursion in the event of a stationkeeping failure, and pup joint increment. An additional consideration for stroke length is having the ability to land the top flange of the inner barrel on the riser spider to install the diverter without requiring a spacer joint. Tensioner system stroke and telescoping joint stroke should be considered to ensure they adequately complement each other. Typically, the TJ stroke is greater than the tensioner system stroke.

- c) External lines—Attachments for auxiliary lines, C/K lines, and the TJ packing pressure line should accommodate the layout of the rig and the ease of attaching/detaching the gooseneck(s) during deployment and retrieval operations.
- d) Packing elements—The packing element seals between the outside of the inner barrel and the inside of the outer barrel and is available in single-, double-, or triple-element units. Double- or triple-element units provide backup sealing capabilities, thus maintaining the seal between the drilling fluid and the environment without shutting down drilling operations to replace a worn or failed primary sealing element.
- e) Running and storage—The TJ is typically longer and heavier than standard riser joints and has unique running and storage requirements.

4.8 Hands-free Gooseneck/Hands-free Handling Mechanisms and Related Equipment (Connection Devices)

4.8.1 Function

The HFGN remotely attaches drape hose terminal fittings to the riser string with minimal direct human contact.

4.8.2 Typical Design

The HFGN may be mounted to the termination joint instead of the TJ when external lines are terminated on the termination joint.

4.8.3 Storage

Examples of HFGN storage methods include but are not limited to:

- on the sides of the moon pool, utilizing hydraulic arms;
- in the moon pool area with a combination of a mechanical arm and a winch system to lower them into position;
- on the tension ring or diverter housing when not in use.

4.8.4 Selection Criteria

The selection of a HFGN/hands-free device should include consideration and evaluation of the following:

- a) BOP stack deployment or retrieval (i.e., interference with moon pool hoses);
- b) service ratings consistent with the riser system;
- c) method of storage when not in use and method of attachment to riser string;
- d) moon pool hose attachments;
- e) operational considerations/methods/risk assessment;
- f) configuration and service ratings consistent with other interfacing equipment;
- g) verification of proper storage and attachment to the riser string.

4.9 Riser Joints

4.9.1 Function

The string of riser joints represents the principal component of the marine riser system and is used to perform the riser system functions listed in 4.3. When the marine riser system is being deployed, the riser joints are coupled together on the drill floor and lowered into the water. The box or pin coupling at the upper end of the riser joint usually has a landing shoulder that supports the loads (static and dynamic) of the marine riser and BOP stack when it is suspended from the riser spider (see 4.11.2.2). The coupling may also provide support for choke, kill, and auxiliary lines and load reaction from buoyancy devices.

4.9.2 Typical Designs

4.9.2.1 Main Tube

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

- 13 ⁵/₈ in. (346.1 mm) BOP stack, 16 in. (406.4 mm) riser;
- 16 ³/₄ in. (425.5 mm) BOP stack, 18 ⁵/₈ in. (473.1 mm) riser;
- 18 ³/₄ in. (476.3 mm) BOP stack, 21 in. (533.4 mm) or 21 ¹/₂ in. (546.1 mm) riser;
- 20 ³/₄ in. (527.1 mm) BOP stack, 24 in. (609.6 mm) riser;
- 21 ¹/₄ in. (539.8 mm) BOP stack, 24 in. (609.6 mm) riser.

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

4.9.2.2 Riser Coupling

There are four basic riser coupling designs:

- 1) dog type,
- 2) flanged,
- 3) threaded union, and
- 4) breech-lock.

Each riser manufacturer usually offers couplings with different strength ratings.

4.9.2.3 Choke, Kill, and Auxiliary Lines

Typically, riser joints have choke, kill, and auxiliary lines attached to the exterior of the riser main tube by support brackets. On most riser joints, these lines pass through the riser landing shoulder. These riser-mounted external lines are described in 4.12.

4.9.3 Selection Criteria

4.9.3.1 General

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

4.9.3.2 Riser Main Tube

4.9.3.2.1 General

The riser main tube should have adequate strength to withstand combined loads from waves, current, applied tension, vessel motions and vessel offsets, external seawater pressure, and internal pressure due to the drilling fluid. Collapse pressure and running loads should also be considered. The strength characteristics of the main tube are dictated by its diameter, wall thickness, and grade of steel. Material yield strengths commonly used in drilling risers range from 52 ksi to 80 ksi.

The ID must provide sufficient annular space to accommodate the desired casing program.

Typically, riser joint lengths range from 50 ft to 90 ft. The storage and running characteristics on the rig as well as transportation to and from the rig must be considered in selection of the length.

4.9.3.2.2 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 proper riser string space-out for various water depths.

4.9.3.3 Riser Coupling

Coupling selection should be based on:

- strength,
- load rating of hangoff shoulder,
- stress amplification factor (SAF) and fatigue resistance properties,
- reliability,
- speed of makeup,
- preload for makeup,
- maintenance requirements,
- main tube dimensions,
- strength-to-weight ratio.

4.10 Lower Marine Riser Package

4.10.1 Function

The LMRP typically includes an assemblage of a riser adapter; a flex/ball joint; one, two, or no annular BOPs; subsea control pods; and a hydraulic connector mating the riser system to the lower stack. The LMRP provides a releasable interface between the riser and the lower stack. In addition, it provides hydraulic control of BOP stack functions through the control pods. Jumper hoses or hard piped flex loops provide a flow path around the flex/ball joint for the C/K lines and/or auxiliary lines.

4.10.2 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 17D);
- 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) emergency recovery system for deepwater BOP stacks;
- i) guidance system for disconnect and reentry of guidelineless BOP stacks;
- j) sequenced, retractable control pod stabs and C/K stabs on guidelineless systems;
- k) flexible lines (see 4.10);
- l) guidance structure for BOP stack handling;
- m) keyseat damage;
- n) C/K and auxiliary line valve arrangements.

4.10.3 Selection Criteria

The selection of LMRP components should be based on the following factors (refer to API 53):

- a) well-control considerations;
- b) BOP stack 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 stack control and operational failsafe design features;
- g) operational water depth;
- h) method for running/retrieving control pods;
- i) methods for and ease of disconnect and reentry on guidelineless systems;
- j) methods for emergency recovery;
- k) circulation methods;
- l) remotely operated vehicle (ROV) functions;
- m) temperature requirements.

4.11 Flex and Ball Joints

4.11.1 Function

Flex and ball joints are used to allow angular rotation of the riser with respect to the BOP stack. 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 an intermediate level in the riser string below the telescopic joint to enable the riser to tolerate some level of contact with the moonpool in an extreme event. Typically, the rotational stiffness of a flex joint is a nonlinear function of angle and has a large range of stiffness available per degree of rotation. Rotational stiffness can also vary with temperature.

4.11.2 Typical Design

4.11.2.1 Flex Joints

The flexure members of a flex joint are comprised of alternating bonded layers of spherically-shaped steel rings and elastomer. The elastomer provides flexure and pressure sealing.

Some designs provide a landing shoulder for a readily removable wear bushing, while others provide a wear ring that can be replaced during periodic overhaul of the flex joint. Because of the design of flex joints, major keyseat damage can occur in service and require repair or replacement.

4.11.2.2 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 that contains the drilling fluids. In most designs, replaceable wear rings or wear bushings are used. Some ball joints require pressure balancing.

4.11.3 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, which 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 being applied;
- e) maximum torque being applied;
- f) temperature requirements;
- g) maximum through bore clearance.

4.12 Flexible C/K and Auxiliary Lines

4.12.1 Function

Flexible external lines allow relative movement at the telescopic joint (drape hose) and at the flex/ball joints (flex loops) in the riser system.

4.12.2 Typical Design

Three basic designs are commonly used: flexible pipe, steel-reinforced hoses, or flow loops with threaded, clamped, or flanged end fittings.

4.12.3 Selection Criteria

Flexible lines should be compatible with the rest of the rig piping system and with the BOP stack, riser, and C/K 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 (MBR);
- g) fluid compatibility;
- h) resistance to wear by abrasive fluids;
- i) corrosion resistance;
- j) fatigue resistance to bend and pressure cycling;
- k) fire resistance;
- l) inner diameter.

4.13 Riser Running Equipment

4.13.1 Function

Riser running equipment is used for supporting, hoisting, lowering, and guiding the riser and BOP stack.

4.13.2 Typical Design

4.13.2.1 Running Tools

Riser running tools make up to the top of the riser during deployment and retrieval. The top connection is a stem that is supported by the hoisting equipment. Typically, an elevator attaches to the stem, which supports the entire riser string and BOP stack. The riser running tool can either be hydraulically or manually locked into the riser joint.

Test caps are typically included as part of the running tool for pressure testing the C/K and auxiliary lines. To prevent accidental overpressuring of the mud boost line while testing during deployment, the test caps for the C/K lines should be designed to prevent installation on the mud boost line.

The diverter running tool typically only supports the telescopic joint inner barrel, diverter flex joint, diverter, and any spacer joint that may be located between the diverter and telescopic joint inner barrel. If the diverter running tool is required to lift the entire string and BOP stack, it shall meet the same standards as the riser running tool.

4.13.2.2 Riser Spiders

A riser spider provides support for the riser and BOP stack at the drill floor during deployment and retrieval. Riser spiders can be either of a split design or one piece design. The spider can also be used to hang off the riser or BOP stack during storm conditions, for example. Typical designs use support dogs or are a gate-type design.

4.13.2.3 Riser Gimbals

When used, the riser gimbal is mounted under the riser spider. Riser gimbals reduce impact loads on the riser and promote even distribution of hangoff loads during rig movement.

4.13.2.4 Guidelines

Guidelines may be used to direct the riser and associated subsea equipment to the mating connections near the seafloor. Generally, four wire rope guidelines, forming the corners of a square, extend up from the temporary guide base to the floating drilling vessel where each is tensioned by a guideline tensioner (similar to a riser tensioner). Typically, the guideline attachment points are 6 ft from the center of the wellbore, forming a square approximately 8.5 ft on the side. Typically, guidelines systems are used on shallow water depths, not in deepwater drilling applications.

4.13.3 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 and axial loading during riser running operations;
- d) impact loads.

4.14 Riser-mounted C/K and Auxiliary Lines

4.14.1 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 purposes.

- a) C/K lines are high-pressure lines that allow pumping fluids into or removing fluids from the wellbore below a closed BOP.
- b) Mud boost lines are used as conduits for drilling fluid that is pumped into the riser just above the BOP stack to increase circulating velocities in the annulus.
- 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 BOP subsea control system. Most BOP systems incorporate a flexible hydraulic-fluid supply line inside the control line hose umbilical.

Riser designs may include additional auxiliary lines, e.g. glycol lines used to supply glycol to the annulus, seawater lines, mud return lines, etc. C/K and auxiliary lines that are employed on marine drilling risers may be exposed to tension loads due to load sharing. Load sharing is the transfer and distribution of tensile forces into the external lines after any float gap between the riser main coupling and the line's mounting arrangements is closed due to riser joint tube elongation under tension, pressure, thermal growth, or bending.

The tensile forces transferred to the line can be a large percentage of the total tension on a riser joint. If the riser design permits load sharing, the resulting stresses must be evaluated as primary membrane stresses.

4.14.2 Typical Designs

Typical riser joints have two integral C/K lines. This provides conduits for well control when the BOP stack is shut in.

A mud boost line is available on some riser joints to facilitate the return of cuttings to the vessel. Air-inject lines are required for riser systems that use air-chamber buoyancy systems. Hydraulic supply lines can be used as either a primary or secondary supply line of hydraulic power to the BOP stack.

Generally, C/K and auxiliary lines of one riser joint are connected to their counterparts on adjoining riser joints by stab connections. The box contains an elastomeric radial seal(s) that contacts abrasion-resistant sealing surface of the pin. These stab connections also facilitate fast makeup and breakout while deploying and retrieving the riser.

4.14.3 Selection Criteria

The following items should be considered when selecting, designing, or specifying C/K and auxiliary lines for riser joints.

- a) The type of fluid. 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. C/K 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.
 - 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) C/K lines: Pressure rating should be the same as that of the BOP stack or greater.
- c) The C/K and auxiliary line couplings. These couplings shall 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 boxes and pins;
 - 3) temperature differences between the fluid in the main riser and the fluids in the C/K or auxiliary lines;
 - 4) bending loads imposed by deflections of the riser.

NOTE This relative motion can cause fatigue cracking of the support bracket if, for example, an adequate gap is not provided between the support bracket (see 4.12.3.f) and the coupling or because of tensile and bending loads due to load sharing.
- d) Internal diameter of the line. The ID of the C/K 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.