Specification for Marine Drilling Riser Equipment

API SPECIFICATION 16F
FIRST EDITION, AUGUST 2004

EFFECTIVE DATE: FEBRUARY 1, 2005

REAFFIRMED, AUGUST 2010

ADDENDUM 1, SEPTEMBER 2014

ADDENDUM 2, NOVEMBER 2014

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This publication is under jurisdiction of the API Subcommittee on Drilling Well Control Systems. This specification was formulated to serve as an aid to procurement of standardized equipment and materials as well as provide instructions to designers and manufacturers of marine drilling riser equipment. It identifies requirements for design, materials, processing and testing of standardized equipment.

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CONTENTS

Specification for Marine Drilling Riser Equipment

1 Scope

1.1 PURPOSE

These specifications establish standards of performance and quality for the design, manufacture, and fabrication of marine drilling riser equipment used in conjunction with a subsea Blowout Preventer (BOP) Stack.

1.2 COVERAGE

This specification provides the requirements for the following major subsystems in the marine drilling riser system:

a. Riser tensioner equipment.*
b. Flex/ball joints.*
c. Choke, kill and auxiliary lines.
d. Drape hoses and jumper lines for flex/ball joints.
e. Telescopic joint (slip joint) and tensioner ring.*
f. Riser joints.*
g. Buoyancy equipment* (only syntactic foam modules eligible for API Monogram).
h. Riser running equipment.*
i. Special riser system components.
j. Lower riser adapter.*

Note: Only those subsystems above that are marked with an asterisk may be considered for API monogramming.

Section 4 of the specification gives a general description of each of these components listed above. Section 5 provides general design requirements for riser components. Section 6 addresses materials, including the riser pipe. Paragraph 6.13 covers welding of couplings to riser pipe and welding of pipe to pipe. It also covers other types of welds used in the fabrication of riser equipment.

Sections 7 through 16 address the following for each component:

a. Service classification.
b. Design.
c. Materials.
d. Dimensions.
e. Process control.
f. Testing.
g. Marking.
h. Packing/Shipping.

2 Normative References

This specification includes by reference, either in total or in part, other API and industry standards listed below. The latest edition of these standards shall be used unless otherwise noted.

API

RP 2RD	*Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)*
Bull 5C3	*Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties*
Spec 5L	*Line Pipe*
Spec 6A	*Wellhead and Christmas Tree Equipment*
TR 6AM	*Material Toughness*
Spec 8C	*Specification for Drilling and Production Hoisting Equipment*
Spec 9A	*Wire Rope*
RP 9B	*Application, Care and Use of Wire Rope for Oil Field Service*
Spec 16A	*Drill-through Equipment*
Spec 16C	*Choke and Kill Systems*
Spec 16D	*Control Systems for Drilling Well Control Equipment*
RP 16Q	*Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*

Spec 16R	*Marine Drilling Riser Couplings*
RP 64	*Diverter Systems Equipment and Operations*

AISC[1]

Code of Standard Practice for Steel Buildings and Bridges

ANSI[2]

ANSI/AWS D1.1 *Structural Welding Code, Steel*

ASME[3]

B31.1	*Power Piping*
B31.3	*Process Piping*

Boiler and Pressure Vessel Code, Section VIII, Divisions I & II

Boiler and Pressure Vessel Code, Section IX

ASNT [4]

Recommended Practice No. SNT-TC1A

ASTM[5]

A 370	*Standard Test Methods and Definitions for Mechanical Testing of Steel Products*
A 703	*Steel Casings, General Requirements, for Pressure-Containing Parts*
D 2240	*Standard Test Method for Rubber Property-Durometer Hardness*
B 850	*Standard Guide for Post-Coating Treatments of Steel for Reducing Risk of Hydrogen Embrittlement*
E 8	*Test Methods for Tension Testing of Metallic Materials (For Non-ferrous Alloys)*
E 10	*Standard Test Methods for Brinell Hardness of Metallic Materials*
E 18	*Standard Test Method for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials*
E 23	*Notched Bar Impact Testing of Metallic Materials*
E 140	*Standard Hardness Conversion Tables for Metals*
E 165	*Standard Test Method for Liquid Penetrant Examination*
E 399	*Standard Test Method for Plane-Strain Fracture Toughness of Metallic Materials*
E 709	*Standard Guide for Magnetic Particle Examination*
E 1290	*Standard Test Method for Crack-Tip Opening Displacement (CTOD) Fracture Toughness Measurement*

IEC[6]

61892	*Mobile and fixed offshore units—Electrical installations*

ISO [7]

13625	*Petroleum and natural gas industries—Drilling and production equipment—Marine drilling riser couplings*

NACE [8]

MR-01-75/ ISO 15156	*Materials for use in H_2S-containing environments in oil and gas production*

National Electrical Code 1 Class I Division 2

Underwriter's Laboratory[9]

UL 94	*Test for Flammability of Plastic Materials for Parts in Devices and Appliances*

[1]American Institute of Steel Construction, Inc., One East Wacker Drive, Suite 3100, Chicago, Illinois 60601. www.aisc.org
[2]American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036. www.ansi.org
[3]ASME International, 3 Park Avenue, New York, New York 10016-5990. www.asme.org
[4]American Society for Nondestructive Testing, Inc., 1711 Arlington Lane, P.O. Box 28518, Columbus, Ohio 43228-0518. www.asnt.org
[5]ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959. www.astm.org
[6]International Electrochemical Commission, 3, rue de Varembé, P.O. Box 131, CH-1211 Geneva 20, Switzerland. www.iec.ch
[7]International Organization for Standardization, 1, rue de Varembé, Case postale 56, CH-1211 Geneva 20, Switzerland. www.iso.org
[8]NACE International, 1440 South Creek Drive, P.O. Box 218340, Houston, Texas 77218-8340. www.nace.org
[9]Underwriter's Laboratory, Inc., 333 Pfingsten Road, Northbrook, Illinois 60062-2096. www.ul.com

3 Definitions and Abbreviations

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

3.2 accumulator (riser tensioner): A pressure vessel charged with gas 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.

3.3 actuator: A mechanism for the remote or automatic operation of a valve or choke.

3.4 air can buoyancy: Tension applied to the riser string by the net buoyancy of a chamber created by a 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.

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

3.6 auxiliary line: A conduit (excluding choke and kill lines) attached to the outside of the riser main tube (e.g., hydraulic supply line, buoyancy control line, mud boost line).

3.7 back pressure: The pressure resulting from restriction of fluid flow downstream.

3.8 ball joint: A ball and socket assembly having central through-passage equal to or greater than the riser internal diameter that may be positioned in the riser string to reduce local bending stresses.

3.9 blowout: An uncontrolled flow of well fluids from the wellbore.

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

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

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

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

3.14 buoyancy control line: An auxiliary line dedicated to controlling, charging or discharging air can buoyancy chambers.

3.15 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.

3.16 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.

3.17 collapse pressure: As defined in API Bull 5C3.

3.18 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.

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

3.20 diverter: A device attached to the wellhead or marine riser to close the vertical flow path and direct well flow away from the drill floor and rig.

3.21 drape hose (moonpool line): A flexible line connecting a choke, kill, and auxiliary line terminal fitting on the telescopic joint to the appropriate piping on the rig structure. A U-shaped bend in this line allows for relative movement between the vessel and the outer barrel of the telescopic joint as the vessel moves.

3.22 drilling fluid: A water or oil-based fluid circulated down the drill pipe 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.

3.23 effective hydraulic cylinder area: Net area of moving parts exposed to tensioner hydraulic pressure.

3.24 factory acceptance testing: Testing by a manufacturer of a particular product to validate its conformance to perform specifications and ratings.

3.25 fill-up line: The line through which fluid is added to the riser annulus.

3.26 fleet angle: In marine riser nomenclature, the fleet angle is the angle between the vertical axis and a riser tensioner line (or hydraulic cylinder rod for direct acting tensioners) at the point where the line (or rod) connects to the telescopic joint (see API RP 16Q).

3.27 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.

3.28 full length 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.

3.29 handling tool (running tool): A device that joins to the upper end of a riser joint to permit the lifting and lowering of the joint and the assembled riser string in the derrick by the elevators.

3.30 heave: Vessel motion in the vertical direction.

3.31 hot spot stress: See 3.41.

3.32 hydraulic connector: A mechanical connector that is activated hydraulically and connects the BOP Stack to the wellhead or the LMRP to the BOP Stack.

3.33 hydraulic supply line: An auxiliary line from the vessel to the subsea BOP Stack that supplies control system operating fluid to the LMRP and the BOP Stack.

3.34 instrumented riser joint: 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.

3.35 internal yield pressure: As defined in API Bull 5C3.

3.36 jumper line: 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.

3.37 key-seating: The formation of a longitudinal slot in the bore of a riser system component caused by friction wear of the rotating drill string on the riser component.

3.38 kill line: See 3.16.

3.39 landing joint: A riser joint temporarily attached above the telescopic joint used to land the BOP Stack on the wellhead when the telescopic joint is collapsed and pinned.

3.40 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 lines for the choke, kill, and auxiliary lines; and subsea control pods. This interfaces with the lower subsea BOP Stack.

3.41 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 discontinuities. Sometimes referred to as hot spot stress.

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

3.43 main tube (riser pipe): Pipe that 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.

3.44 makeup time (riser coupling): Begins when the box and pin are stabbed, ends when the coupling is fully preloaded.

3.45 makeup tool (preload tool): A device used to engage and/or preload coupling members.

3.46 marine 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.

3.47 mud: See 3.22.

3.48 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.

3.49 nominal stress: Stress calculated using the nominal pipe wall dimensions of the riser at the location of concern.

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

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

3.52 pressure-containing component: A component whose failure to function as intended would cause a release of pressurized fluid to the environment.

3.53 primary-load-carrying component: Component whose failure would compromise the structural integrity of the marine drilling riser system. Examples are components that carry all or a major part of the tension in the riser.

3.54 protector, box or pin: A cap or cover used to protect the box or pin from damage during storage and handling.

3.55 pup joint: A shorter-than-standard-length riser joint.

3.56 rated load: A nominal applied loading condition used during riser design, analysis and testing based on maximum anticipated service loading.

3.57 rated working pressure: The maximum internal pressure equipment is designed to contain and/or control. Working pressure is not to be confused with test pressure.

3.58 riser adapter: Crossover between riser and flex/ball joint.

3.59 riser annulus: The space around the pipe (drill pipe, casing or tubing) suspended in a riser; its outer boundary is the internal surface of the riser pipe.

3.60 riser connector (LMRP connector): A hydraulically operated connector that joins the LMRP to the top of the BOP Stack.

3.61 riser disconnect: The operation of unlatching of the riser connector to separate the riser and LMRP for the BOP Stack.

3.62 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.

3.63 riser recoil system: A means of limiting the upward acceleration of the riser when a disconnect is made at the riser connector.

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

3.65 riser string: A deployed assembly of riser joints.

3.66 riser support shoulder: See 3.39.

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

3.68 riser tensioner ring: The structural interface of the telescopic joint outer barrel and the riser tensioners.

3.69 RKB (Rotary Kelly Bushing): Commonly used vertical reference for the drill floor.

3.70 running tool: See 3.29.

3.71 SAF: See 3.74.

3.72 slip joint: See 3.81.

3.73 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.

3.74 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. The factor is used to account for the increase in the stresses caused by geometric stress amplifiers that occur in riser components.

3.75 submerged weight: See 3.86.

3.76 subsea fill-up 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, an automatic actuator controlled by a differential-pressure sensor may open the valve.

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

3.78 surge: Vessel motion along the fore/aft axis.

3.79 sway: Vessel motion along the port/starboard axis.

3.80 syntactic foam: Typically a composite material of hollow spherical fillers in a matrix or binder.

3.81 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 moves.

3.82 telescopic joint packer: The means of sealing the annular space between the inner and outer barrels of the telescopic joint.

3.83 terminal fitting: The connection between a rigid choke, kill, or auxiliary line on a telescopic joint and its drape hose, affecting a nominal 180-degree turn in flow direction.

3.84 thrust collar: A device for transmitting the buoyancy force of a buoyancy module to the riser joint.

3.85 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.

3.86 wet weight: Weight minus buoyancy (commonly referred to as weight in water, submerged weight, or apparent weight).

4 Components of a Marine Drilling Riser System

4.1 GENERAL

The marine drilling riser system connects the subsea BOP Stack to the drilling vessel (see Figure 1). It is a continuation of the well bore from the seabed to the surface.

4.2 FUNCTIONS OF MARINE DRILLING RISER SYSTEM

The primary functions of the marine riser system are to:

a. Provide for fluid communication between the drilling vessel and the BOP Stack and the well:
   1. through the main bore during drilling operations;
   2. through the choke and kill lines when the BOP Stack is being used to control the well;
   3. through the auxiliary lines such as hydraulic fluid supply and mud boost lines.

b. Guide tools into the well.

c. Serve as a running and retrieving string for the BOP Stack.

4.3 SYSTEM DIMENSIONS

Basic dimensions and interchangeability are fundamental to the design of a marine drilling riser. Riser system component integration and standard riser equipment running procedures require that selected dimensions be examined for compatibility. Those of a basic nature include:

a. Minimum inside diameter of all components that make up the riser string to allow passage of all bits, casing hangers, wear bushings, and any other equipment that may be run down to the BOP/wellhead.

b. Maximum outside diameter of all components in the riser string to allow passage through the rotary table and/or diverter housing.

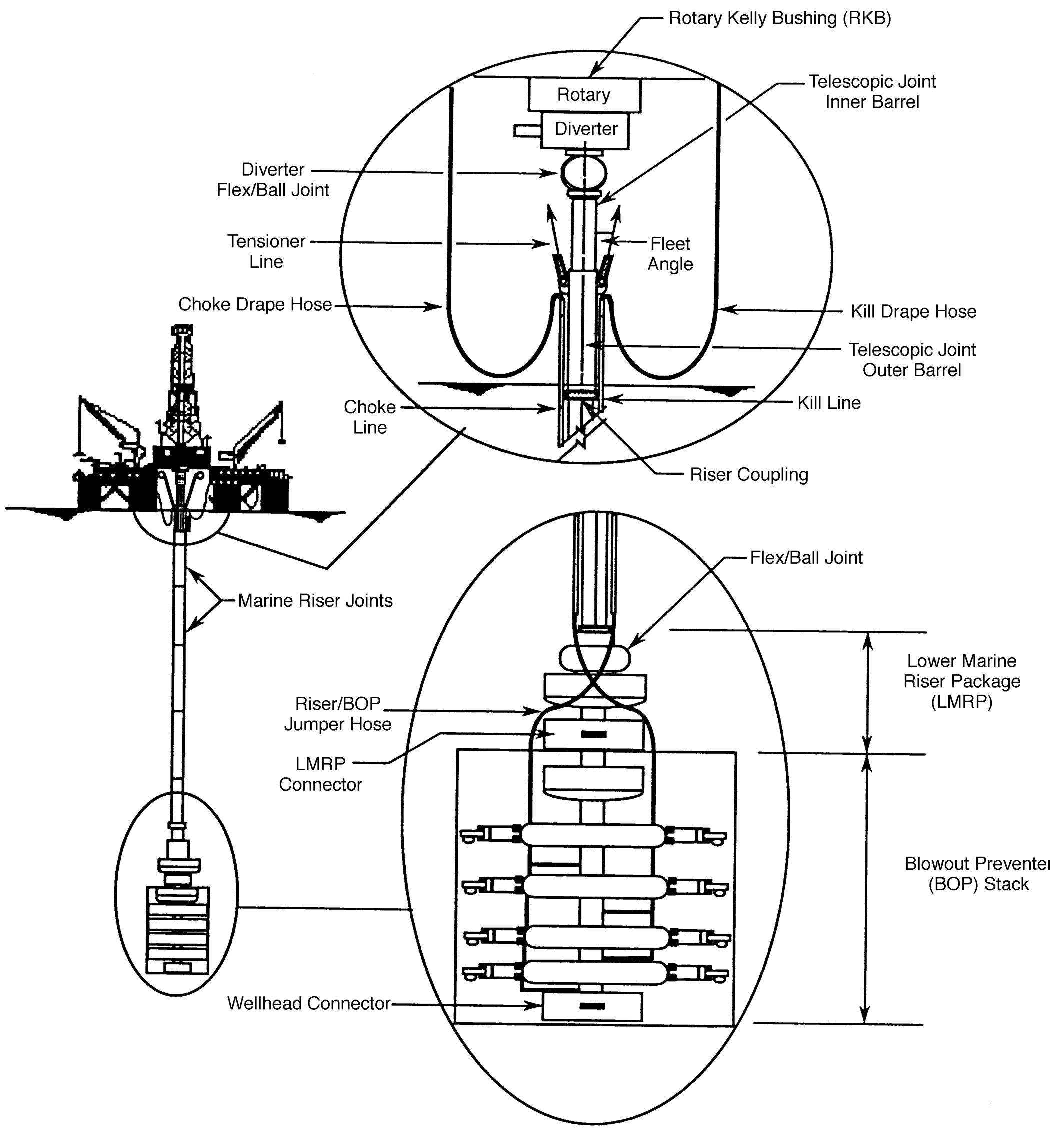

Figure 1—Marine Drilling Riser System and Associated Equipment

Other basic dimensions to consider include telescopic joint/riser tensioner stroke requirements along with the interface between the handling spider and rotary table. The component manufacturers shall provide these, and other basic dimensions requested by the purchaser.

4.4 TENSIONER EQUIPMENT

Tensioner units are used to apply tension at or near the top of the marine drilling riser to prevent the riser from buckling and to support it in a near vertical position. The units are normally located on the drilling vessel near the periphery of the drilling floor. They provide reasonably steady axial tension to the riser while the floating drilling vessel moves vertically and laterally with the wind, waves and current. The units generally maintain this tension through the energy transferred from a bank of high-pressure air reservoirs to the hydraulic cylinders of the tensioners.

4.5 RISER SPIDER

The riser spider is used to support the riser while it is being run or retrieved. When in use, the riser spider is typically located on the drilling rig floor. For deepwater applications, it may be necessary to cushion impact loads on the riser coupling support plates and also to provide a way to isolate the riser from the roll and the pitch motion of the vessel. For such applications, a gimballing and/or shock-absorbing spider may be used. A gimballing and/or shock-absorbing riser spider may consist of a standard riser spider resting on a structure that utilizes either hydraulic or pneumatic accumulators and pistons or elastomeric bearings to provide shock absorbing and gimballing.

4.6 SURFACE DIVERTER

The top of the riser system interfaces with the surface diverter. The diverter system is not considered to be part of the marine drilling riser system. API RP 64 addresses diverter system equipment.

4.7 FLEX/BALL JOINT

Flex/ball joints permit relative angular displacement of the riser elements without excessive bending stresses. Typically, a flex/ball joint is positioned between the surface diverter and the telescopic joint and another is positioned below the lower riser adapter in the LMRP (see 4.12). Occasionally an intermediate flex joint is used just below the telescopic joint. These lower flexible joints transmit axial riser tension loads. The upper flex/ball joint permits the riser to accommodate roll, pitch, and offset of the vessel.

4.8 TELESCOPIC JOINT AND TENSIONER RING

Typically, the outer barrel of the telescopic joint connects to the uppermost riser joint, and the inner barrel connects to the flex/ball joint at the base of the surface diverter. The basic function of the telescopic joint, also called the slip joint, is to continuously adapt the riser length to compensate for the horizontal and vertical displacement of the vessel. The telescopic joint has a packer that seals between the inner and outer barrel to prevent fluid leakage from the riser. The telescopic joint serves to transmit the flow of drilling mud as it returns from the well. It typically has terminal fittings for connecting the choke, kill, and auxiliary line drape hoses to the rigid lines on the riser. A riser tensioner ring is typically attached to or incorporated in the upper portion of the telescopic joint outer barrel. Its function is to transmit the support load from the riser tensioner lines to the outer barrel of the telescopic joint. In some cases, it permits rotation of the vessel around the riser.

4.9 RISER JOINTS

A riser joint is typically an assembly of riser pipe, coupling box and pin, choke and kill lines, auxiliary lines, choke/kill/auxiliary line support brackets, and other devices for guidance and/or supporting buoyancy modules. Riser couplings provide a means of quickly connecting and disconnecting riser joints. Riser couplings also provide a landing/support shoulder to transmit the weight of the deployed string to the riser spider while the riser is being deployed or retrieved. The couplings also provide support points for choke, kill, and auxiliary lines and load reaction points for buoyancy devices. API Spec 16R and ISO 13625 provide specifications for marine drilling riser couplings.

4.10 CHOKE, KILL AND AUXILIARY LINES

Choke and kill lines run the entire length of the riser and terminate at the BOP. The lines are an integral part of a riser joint and are equipped with stab-in connectors. They are used for well control and for periodic pressure testing of the BOP Stack. Where relative motions occur between elements of the riser system, flexible bypass lines are used to maintain continuity of the choke and kill lines. Such relative motions may occur between the outer barrel of the telescopic joint and the vessel and across any flex/ball joints in the riser string. Auxiliary lines can serve a variety of purposes, including: drilling fluid circulation (e.g., “mud boost line”), hydraulic fluid supply for BOP control functions, and air injection and piloting for air can riser flotation.

4.11 LOWER RISER ADAPTER

The lower riser adapter connects the lowermost riser joint to the flex/ball joint on the LMRP. The upper end is a standard riser coupling box or pin and may contain kickouts for the choke, kill, and/or auxiliary lines to facilitate the connection of the bypass lines around the lower flex joint. It may also have provisions for mounting an internal wear bushing.

4.12 LOWER MARINE RISER PACKAGE (LMRP)

The LMRP is the assembly located at the bottom of the drilling riser. Typical components, from top to bottom are:

a. Lower riser adapter.
b. Flex/ball joint bypass lines for choke, kill and auxiliary lines.

c. Lower flex/ball joint.
d. Hydraulic connector (riser connector) for mating the riser to the BOP Stack.

The LMRP also accommodates the subsea control pods of the BOP Stack control system. The LMRP permits the riser and BOP control pods to be tripped separately from the BOP Stack. It commonly will also contain at least one annular BOP.

4.13 BUOYANCY EQUIPMENT

Buoyancy is added to the marine drilling riser for the purpose of offsetting all or part of the riser weight in seawater, thereby reducing the load on the riser tensioning system and facilitating drilling in deeper water. Two types of buoyancy equipment have been employed: syntactic foam modules (see 13.2) and air can systems (see 13.3).

4.14 RISER PUP JOINTS

Pup joints are riser joints that are shorter than full-length riser joints and are used to establish a deployed riser length within a desired tolerance to accommodate different water depths.

4.15 RISER HANDLING TOOLS

A riser-handling tool is used in conjunction with the drawworks and derrick overhead equipment to deploy and retrieve the riser and BOP Stack.

4.16 SPECIAL MARINE DRILLING RISER COMPONENTS

Special marine drilling riser components include:

a. *Riser flood valve joint*—The riser flood valve joint provides a means for external water to enter the riser. Its principal purpose is to prevent riser collapse in deep water if pressure in the riser drops significantly below the external sea water pressure.
b. *Mud discharge valve joint*—The mud discharge or dump valve joint is a device used to control riser pressure (and hence well-bore pressure) by establishing direct communication between the riser bore and the sea.
c. *Instrumented riser joints*—Instrumented riser joints can be used to measure and monitor parameters such as riser tension and bending stresses; external water pressure and temperature; drilling fluid density, flow rate, temperature and pressure; tool joint location; and riser angle.
d. *Riser crossovers*—Riser crossovers are special purpose adapter joints that may be used to connect riser joints of different designs. Riser crossovers have one end that mates with the bottom end of one type riser joint and one end that mates with the top end of another type riser joint.
e. *Secondary disconnect equipment*—Secondary disconnect equipment provides a means of quickly disconnecting the marine drilling riser from the BOP Stack when a primary disconnect fails.
f. *Riser circulation joint*—A riser circulation joint is intended to facilitate pressure control in a deepwater riser if pressurized gas enters at the bottom of the riser. The riser circulation joint shall permit closure of the riser annulus at a location below the telescopic joint. It shall also permit the circulation of the riser annulus fluids by pumping down the mud boost line and discharge of return flow through a choke. The closure system shall meet the requirements of API Spec 16A and its control system shall meet the requirements of API Spec 16D.

5 Design

5.1 GENERAL

These design standards apply to all riser system components that are in the primary load path, including but not limited to: riser couplings, riser main tube, riser adapters, riser tensioner rings, telescopic joints, flex/ball joints, and special riser joints. Requirements for specific components are in Sections 7 through 16.

5.2 SERVICE CLASSIFICATIONS

The riser manufacturer shall provide the following design information for each riser model. This data shall be based on design load (defined in 5.6 of this document) and verified by testing (defined in 5.5).

a. Size (riser pipe diameter, wall thickness, and grade of steel).
b. Choke and kill and auxiliary line description (diameters, wall thickness, and grade of steel).

c. Rated load of riser joint.
d. Buoyancy thrust load.
e. Coupling description (manufacturer, model, coupling rated load).
f. Stress Amplification Factors (SAF).
g. Rated working pressures, burst and collapse (under zero tension).
h. Minimum, working, and maximum temperatures for various riser lines/components.

Note: Procedures for determining design loads are detailed in API RP 16Q. Guidelines for care and operation are also given in API RP 16Q. Specifications for coupling design are given in API Spec 16R and ISO 13625.

5.2.1 Size and Coupling Model

Riser systems are categorized by size of the main tube and the manufacturer's coupling model designation. Riser pipe outer diameter, wall thickness, and grade of steel for which the riser system is designed shall be documented. The categorization also includes the characteristics of choke and kill and auxiliary lines (diameters, wall thicknesses, and grades of steel for each).

5.2.2 Rated Load

To qualify for a particular rated load, neither calculated nor measured stresses in a riser component in the main tube load path shall exceed the allowable stress limits of the component material when subjected to the rated load. The allowable material stresses are established in Annex B. The load rating of a riser joint may be less than the coupling rating.

Rated loads correspond to the total combined load that may be applied to the component. The total combined load includes the axial tension, bending loads, and pressure separation loads applied to the component. The bending loads shall be combined with the axial tension using the equivalent tension formula given in 5.6. Internal pressure, external pressure, and temperature shall also be considered if they reduce the component's load rating.

5.2.3 Stress Amplification Factor

The SAF accounts for the increase in the stresses caused by geometric stress amplifiers that occur in riser components. It is a measure of the fatigue resistance of the component. The calculated SAF values shall be documented at the locations of highest stress and at locations where SAFs are highest. SAF is equal to the local peak alternating stress in a component divided by the nominal alternating stress in the pipe wall at the location of the component. SAF is a function of pipe size and wall thickness. It is calculated as follows:

$$\text{SAF} = \frac{\text{Local Peak Alternating Stress}}{\text{Nominal Alternating Stress in the Pipe}}$$

Local Peak Alternating Stress—Highest maximum principal alternating stress in the region of the riser component under consideration. The basic characteristic of a peak stress is that it causes no significant distortion and is only objectionable as a possible cause of fatigue failure. These stresses are highly localized and occur at geometric discontinuities.

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

The SAFs shall be calculated using minimum preload and shall include tolerances for multiple load paths. The SAFs for the bolts of riser components in the primary load path shall also be determined. Since the SAFs may vary with tension, the SAFs shall be determined for a range of tensions up to the rated working load to check for dependence of SAF on load. The SAFs shall be calculated using the stresses obtained for adjacent load increments.

5.2.4 Pressure Ratings

The manufacturer shall document the rated differential pressures (internal and collapse pressures) for the riser system component and the tension conditions for which they apply.

5.2.5 Temperature Criteria

The minimum design temperature for the choke, kill, auxiliary lines, and main tube shall be 32°F (0°C) unless the purchaser specifies a lower temperature. The maximum temperatures for design will vary for the different lines. Maximum fluid temperature for choke and kill lines and main tube shall be at least 180°F (82°C), for both design and working conditions. For all auxiliary lines the maximum temperature shall be at least 135°F (57°C). Different combinations of minimum temperatures and working condition temperatures in the table below shall be used to determine loads from differential temperatures in various lines.

Type of Line	Minimum Fluid Temperature	Maximum Fluid Temperature	Working Condition Temperature
Choke & Kill Line	32°F (0°C)	180°F (82°C)	180°F (82°C)
All Auxiliary Lines	32°F (0°C)	135°F (57°C)	Ambient
Main Tube	32°F (0°C)	180°F (82°C)	180°F (82°C)

5.3 RISER LOADING

5.3.1 General

A drilling riser's ability to resist environmental loading depends primarily on applied tension. The environment consists of the hydrodynamic forces of current and waves, the motions induced by the floating vessel's dynamic response, and the loads imposed by the contained fluid and tubulars. The determination of a riser's response to the environmental loading and determination of the mechanical loads developed in the riser require specialized analysis using computer programs. The procedure used to determine riser system design loads and responses is described in API RP 16Q. Additional sources of applied load may significantly affect the riser equipment design and shall be included in the design calculations. These additional loads are described below.

5.3.2 Loads Induced by Choke and Kill and Auxiliary Lines

Riser joints typically provide support for choke and kill and auxiliary lines. This support constrains the lines to assume the same curvature as the riser pipe. Loads can be induced on the joint both from pressure in the lines and from deflections imposed on the lines. Another possible source of loads is differential temperatures in the lines. The manufacturer shall document those loads induced by choke, kill, and auxiliary lines for which the riser has been designed.

5.3.3 Loads Induced by Buoyancy

Riser joints may provide support for buoyancy that induces loads on the joints. The manufacturer shall document the buoyancy thrust loads for which the riser has been designed.

5.3.4 Loads Induced during Running and Retrieval

Temporary loads are induced by suspension from a handling tool and/or spider. The manufacturer shall document the riser handling loads for which the riser is designed and how these loads are applied.

5.4 DETERMINATION OF STRESSES BY ANALYSIS

Paragraph 5.7 requires detailed knowledge of the stress distribution in the riser component. This information shall be acquired by appropriate analysis. Analysis of the critical sections shall be performed and documented. The analysis shall provide peak stresses, and shall include effects of wear, corrosion, friction, and manufacturing tolerances. When finite element analysis is performed, the following shall be documented and included in the analysis: grid size, applied loads, and preload losses.

5.5 STRESS DISTRIBUTION VERIFICATION TEST

The testing described in this section is to be performed where appropriate at the manufacturer's discretion. After completion of the design studies, a typical riser component in the load path should be tested to verify the stress analysis. The testing has two primary objectives: to verify any assumptions that were made about preloading, separation behavior, and friction coefficients and to substantiate the analytical stress predictions. Strain gage data should be used to measure preload stresses as they relate to make-up or displacement. Strain gages should be placed, when physically possible, in the five most highly stressed regions as predicted by the finite element analyses performed in accordance with 5.4 and five locations away from stress concentrations. Rosettes should be used. All strain gage readings and the associated loading condition should be recorded in a manner that should be retained as part of the component design documentation. Normal design qualification tests defined in this document should be performed simultaneously with this stress distribution verification testing.

Note: It is often difficult to acquire sufficient strain data to totally correlate with the analytical results. High-stress areas may be inaccessible and are sometimes so small that a strain gage gives an average rather than the peak value. The testing should serve to verify the pattern of strain in regions surrounding the critical points.

5.6 RISER DESIGN LOAD

The riser design load is used to rate a riser system in accordance with this specification. It represents the maximum load-carrying capacity of the system. The manufacturer shall establish the design load for each riser component based on the methods and criteria given in 5.3. For simplicity, the design loading condition is taken to be axisymmetric tension. In using this simplification, riser bending moment is converted to equivalent tension (T_{EQ}). The design load can be specified either as an axisymmetric tension of magnitude (T_{DES}) or it may be considered to be any combination of tension (T) and bending moment (M) such that

$$T + \frac{McA}{I} = T + \frac{M32t(D-t)^2}{D^4 - (D-2t)^4} = T + T_{EQ} = T_{DES}$$

where

A = pipe wall cross section area,

c = mean radius of riser pipe,

I = moment of inertia of riser pipe,

D = outside diameter of riser pipe,

t = wall thickness of riser pipe.

Using this relationship, the maximum calculated riser pipe stress at the middle of the pipe wall is the same for pure bending and pure tension. To rate a particular riser design, the components in the load path shall be analyzed only for an axisymmetric tensile load (T_{DES}). While the riser design load provides a means of grouping riser design models regardless of manufacturer or method of makeup, it does not include all loads affecting riser design. Appropriate auxiliary loads as defined in 5.3 shall also be included in the evaluation of riser designs.

Note: The moment capacity of the assembled component may have limiting factors other than the main tube stresses; for example, a riser joint may be limited by the tensile stress in choke, kill, or auxiliary lines produced by moment in the joint. As a result, the moment/tension relationship above may not accurately apply beyond a specific maximum combination of loads, as moment may have a disproportionate effect on the riser external lines.

5.7 DESIGN FOR STATIC LOADING

5.7.1 The design of a riser system for static loading requires that it support the design load and preload, if any, while keeping the maximum cross-sectional stresses within specified allowable limits (see B.2). The manufacturer shall document the procedures he uses and the results (see Annex A). For all system components except couplings; coupling bolts; and choke, kill, and auxiliary lines, stress levels shall be kept below the values given in Annex B.

5.7.2 Riser couplings and riser coupling bolts shall meet the requirements of API 16R or ISO 13625.

5.7.3 Choke, kill, and riser auxiliary lines shall meet the requirements of this specification, Section 9.

5.8 DESIGN OF LIFTING ATTACHMENTS

Drilling riser equipment that requires lifting with the rig cranes during the normal course of operations shall be fitted with suitable lifting attachments. The design load for the lifting attachments shall be 2.0 times the static sling load in the direction of the sling plus 10% of the static sling load applied perpendicular to the face of the attachment at the center of the hole for the shackle pin (parallel to the shackle pin). The attachment shall be designed to meet the requirements of AISC or other nationally or internationally recognized standard. The AISC increase in allowable stresses for short-term loads shall not be used.

5.9 DESIGN DOCUMENTATION

For each riser system size, design, and service classification, the manufacturer shall retain the following documentation for a minimum of 10 years after the manufacture of the last unit of that size, design and service classification.

a. Service classification, design bases, and SAFs used as described in 5.2.
b. Design loads (tensile, bending, and others) as defined in 5.3.
c. Finite Element Analysis performed in accordance with 5.4.
d. Results of tests performed in accordance with 5.5.

6 Materials and Welding Requirements

6.1 GENERAL

This section describes material and welding requirements for primary-load-carrying components and/or pressure-containing components. These requirements shall be in addition to those specified in the sections pertaining to specific equipment. These requirements do not apply to components that are covered by other API specifications. Other parts shall be made of materials that satisfy the design requirements in Section 5 when assembled into API Spec 16F equipment. If the flow of formation fluids is handled by diverting the flow at the sea floor BOP through the choke and kill lines, the drilling riser pipe, riser connection, ball or flex joints, and telescoping joints (materials and welding) need not comply with NACE MR0175/ISO 15156. If, however, the riser system is expected to be exposed to sour environments, materials and welding used shall meet the applicable requirements of NACE MR0175/ISO 15156.

Note: Composite materials are outside the scope of this document.

6.2 MATERIALS SELECTION

6.2.1 Material selection for primary-load-carrying components and pressure-containing components shall include consideration for the type of loading, fatigue and fracture considerations, temperature range, corrosive conditions, strength requirements, and consequences of failure. These considerations shall be included as part of the design review documentation.

Note: Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Care should be exercised in the selection of materials for applications requiring high strength, corrosion resistance, and resistance to hydrogen embrittlement. Materials which have shown this susceptibility include martensitic stainless steels and more highly alloyed steels having yield strengths over 150,000 psi (1034 MPa). Other materials subject to this phenomenon are hardened low-alloy steels, particularly with hardness levels above 35 Rockwell C, precipitation hardened nickel-copper alloys, duplex stainless steels, and some high-strength titanium alloys.

6.2.2 Material selection for nonmetallic (e.g., elastomers and thermoplastics) materials shall include consideration for the type of loading, temperature range, explosive decompression resistance (if appropriate), environmental resistance, strength and ductility requirements, and consequences of failure. These considerations shall be included as part of the design review documentation.

6.3 WRITTEN SPECIFICATIONS

6.3.1 All materials (including non-metallic) used for primary-load-carrying components and pressure-containing components shall conform to a written specification. The written specification shall be either a standard in Section 2, another nationally or internationally recognized standard, or the manufacturer’s document.

6.3.2 Specifications for metallic components shall define the following:

a. Material chemical composition with tolerances.
b. Forming practices—forging, casting, etc.
c. Heat treatment procedures including cycle time and temperature with tolerances, heat treating equipment, and cooling media.
d. NDE requirements.
e. Mechanical property requirements including tensile, hardness and fracture toughness (impact) properties.

6.3.3 Specifications for non-metallic components shall define the following:

a. Material type—base material/polymer.
b. Service temperature range.
c. Tensile strength, elongation, elastic modulus and tear strength.
d. Acceptable hardness range—shore (ASTM D 2240).
e. Density, compression set, fluid compatibility and fluid swell.
f. Fiber reinforcement—type, composition and properties.

6.4 METALLIC MATERIALS

6.4.1 Steels

All steel materials shall meet the requirements of 6.5, 6.6, and 6.7.

6.4.2 Tubulars for Main Tube

Riser main tube pipe may be longitudinally seam-welded or seamless. No spiral-welded pipe is permitted.

6.4.3 Non-ferrous Alloys

Non-ferrous alloys such as titanium, nickel-base alloys, aluminum, etc., may be used if mechanical properties, toughness, fatigue strength, corrosion and wear properties, and weldability meet the design requirements.

6.4.4 Bolting

6.4.4.1 General Service

For carbon or alloy steel, the minimum requirements shall be as specified in API Spec 6A. Maximum hardness for primary-load-carrying components shall not exceed 35 Rockwell C without approval of the purchaser.

For other materials, the materials shall be shown to be fit for purpose to the satisfaction of the purchaser.

6.4.4.2 Cathodically Protected Equipment

Bolting in direct electrical contact with cathodically protected equipment (including components coated with thermally-sprayed aluminum) shall be of materials that have shown to have low susceptibility to hydrogen embrittlement.

6.4.4.3 Coatings

Bolting may be coated with various materials for lubricity, corrosion protection, and/or environment isolation. Regardless of application, coatings shall not alter the bolting design and/or material selection unless agreed to by the purchaser. All coatings applied by electrochemical or autocatalytic means shall have a quality assurance procedure that includes adequate thermal bake-out to increase resistance to cracking caused by hydrogen embrittlement (e.g., see ASTM B 850).

6.5 CHEMICAL COMPOSITION

6.5.1 All steel materials shall conform to the chemical composition specified in the written specification. This specification shall include limits and tolerances on the elements carbon, manganese, phosphorous, sulfur, silicon, and any other elements added intentionally. Residual elements shall meet the requirements of the written specification. Chemical composition shall be determined on a heat basis in accordance with the written specification.

6.5.2 All other metallic materials shall meet the chemical composition requirements specified in the manufacturer's written specification.

6.6 MECHANICAL PROPERTIES

6.6.1 General

All materials shall meet the minimum mechanical properties specified in the manufacturer's written specification.

6.6.2 Impact Strength

The Charpy V-notch impact values of the main tube shall meet the requirements of API Spec 5L, PSL 2. Other components shall meet the requirements of API Spec 16A.

All test coupons shall meet the requirements of 6.7. All other materials shall meet the requirements of the manufacturer's written specification.

When agreed upon by the manufacturer and the purchaser, the manufacturer may substitute fracture toughness testing in lieu of Charpy V-notch impact testing. The minimum acceptable values for the fracture toughness shall be determined by engineering analysis with agreement by the purchaser (see API TR 6AM, ASTM E 1290, ASTM E 399).

6.6.3 Hardness

All materials shall meet the hardness requirements specified in the manufacturer's written specification. For equipment applications subject to a chloride stress corrosion cracking environment, all materials (including weld materials) for carbon or low-alloy steel shall be limited to 35 Rockwell C maximum unless otherwise approved by the purchaser.

6.6.4 Tensile Properties

The tensile properties of the materials for all primary-load-carrying and pressure-containing equipment shall be in conformance with the requirements of the written specification chosen for the parts by the manufacturer/purchaser as provided for by 6.3. The material shall meet the requirements for yield strength, ultimate strength, elongation and when appropriate the reduction of area as required by the design.

6.7 QUALIFICATION TEST COUPONS (QTC)

6.7.1 General

Mechanical testing to determine the material properties shall be performed on specimens from an acceptable Qualification Test Coupon (QTC) as defined below.

6.7.2 Tubulars

For tubulars, multiple QTCs shall be taken per the requirements of API Spec 5L. Additional QTCs may be required per the manufacturer's written specification.

6.7.3 Forgings and Wrought Products

6.7.3.1 For forgings, extrusions, and wrought products, the QTC shall consist of prolongations, sacrificial forgings, or separately forged test coupons. The separately forged QTC shall be from the same heat as the production parts it represents and shall exhibit hot working ratios that are equal to or less than that used on the production parts. The size of the QTC shall be based on the equivalent round (ER) method as outlined in API Spec 16A. The equivalent round (ER) of the QTC shall be equal to or greater than the dimensions of the part it qualifies, but need not exceed 5 in. (127 mm).

6.7.3.2 The QTC should be heat treated with the production parts it represents whenever practical and shall accompany the parts throughout all heat treat cycles. The QTC shall be furnished in the same heat treat condition as the parts it represents. When the QTC is not heat treated with the parts, the austenitizing and/or tempering temperature of the QTC shall be within 25°F (14°C) of those used for the parts. For parts that are quenched and tempered, the QTC shall be quenched in the same media used to quench the production parts. "Production Type" furnaces shall be used. Cycle time for the QTC at the qualifying temperature shall not exceed that for the part.

6.7.4 Castings

QTCs for castings shall comply with API Spec 16A. Castings shall not be used for primary-load-carrying components.

6.8 MECHANICAL TESTING

6.8.1 General

The material for tests of mechanical properties shall be taken from the relevant Qualification Test Coupon (QTC) after final heat treatment.

6.8.2 Tensile Testing

Tensile properties shall be as specified in the written specification. The main tube shall meet the requirements of API Spec 5L for PSL 2. Test specimens and test methods shall be per ASTM A 370 or equivalent. Specimen orientation and location shall be in accordance with API Spec 16A or equivalent except that test specimen shall be taken at a minimum distance of $^1/_4$ of the total thickness from any surface. As-heat-treated dimensions shall be used for determining the component thickness. Tensile testing of non-ferrous alloys shall be performed in accordance with ASTM E 8.

6.8.3 Impact Testing

6.8.3.1 Charpy V-notch impact tests shall be conducted per ASTM A 370 or E 23 or equivalent using specimens removed from the QTC. Standard size (10 mm × 10 mm) Charpy V-notch specimens shall be used whenever practical. Charpy values may be reduced by a factor of 0.883 and 0.667 for $^3/_4$ size and $^1/_2$ size specimens, respectively. One set of three test specimens shall be removed from the QTC at an orientation and location as specified in 6.8.2.

6.8.3.2 When full size impact specimens are impractical, $^3/_4$ size (7.5 mm × 10 mm) or $^1/_2$ size (5 mm × 10 mm) specimens Charpy V-notch specimens may be used based on the guidelines of Table F-1 of API Spec 5L. Tapered specimens per API Spec 5L may also be used if full size specimens are impractical.

6.8.3.3 Impact testing shall be conducted at the minimum specified temperature or lower.

6.8.4 Hardness Testing

The hardness of components and the QTC shall be determined per ASTM E l0 or E 18 or equivalent. A minimum of one hardness test shall be performed on the QTC after the final heat treatment cycle. Conversion of hardness values between test methods shall be per ASTM E 140.

6.9 MATERIALS FOR LOW-TEMPERATURE SERVICE

For low-temperature applications, Charpy V-notch testing at a temperature lower than T-0 in API Spec 16A may be required. In these cases, the purchaser shall clearly indicate on the purchase order the test metal temperature and the impact values required. The required testing shall be performed in accordance with ASTM A 370 or E 23.

6.10 MATERIALS TO RESIST SULFIDE STRESS CRACKING

6.10.1 The metallic materials that can be exposed to wellbore fluids in the choke and kill lines (including bolting) shall meet the requirements for sour service defined in NACE MR0175/ISO 15156.

6.10.2 If the flow of formation fluids is handled by diverting the flow at the sea floor BOP through the choke and kill lines, the drilling riser pipe, riser connection, ball or flex joints, and telescoping joints need not comply with NACE MR0175/ISO 15156. If, however, the riser system is expected to be exposed to sour environments, materials used shall meet the applicable requirements of NACE MR0175/ISO 15156.

6.11 MANUFACTURING PRACTICE

6.11.1 Melting Practice

The melting practice shall meet the requirements of the manufacturer's written specification.

6.11.2 Forming Practice

The forming practice shall meet the requirements of the manufacturer's written specification.

6.11.3 Casting Practice

The casting practice shall meet the requirements of the manufacturer's written specification.

6.12 HEAT TREATING

6.12.1 Heat Treating Equipment Qualification

The manufacturer shall perform all heat treating of parts and QTCs with “Production Type” equipment meeting the requirements specified. “Production Type” heat treating equipment shall be considered equipment that is routinely used to process production parts having an ER equal to or greater than the ER of the subject QTC.

6.12.2 Furnace Loading

The loading of material into furnaces shall be such that the presence of one part does not adversely affect the heat treating response of any other materials within the same heat treatment load.

6.12.3 Temperatures

Time at temperature and temperature level for heat treatment cycles shall be determined in accordance with the manufacturer’s written specification.

6.13 WELDING

6.13.1 Primary-load-carrying Weldments and Pressure-containing Weldments

6.13.1.1 The requirements in 6.13.1 shall apply in full to primary-load-carrying and pressure-containing weldments except as amended or superseded by other requirements in the equipment specific Sections 7 through 16.

6.13.1.2 All welds and welders or welding operators shall be qualified in accordance with ASME Section IX or other recognized industry standard approved by the purchaser. All welding procedures shall be qualified to meet the same impact requirements as the base material.

6.13.1.3 Weld procedure qualifications, welder and welding operator qualifications, and welding processes shall be in accordance with the welding requirements for API Spec 16A.

Note: These are considered minimum requirements that should be supplemented with requirements necessary for the prevention of hydrogen delayed cracking of welds to hardenable forging alloys. Particular attention must be paid to prevent lack-of-fusion type defects that can influence fatigue life.

6.13.1.4 For fabrication welding and repair welding, the API Spec 16A welding requirements shall apply.

6.13.1.5 For weld overlays for corrosion resistance or hard facing, the API Spec 16A requirements shall apply.

Note: When corrosion resistant overlay or hard facing overlay does not affect the strength or fatigue resistance of the part, then impact test and tensile tests are not required.

6.13.1.6 Butter welds shall be approved by the purchaser. A butter weld is a weld metal buildup by the deposition of surface filler weld metal on one or more surfaces of the weldment face. This surface buildup is intended to provide metallurgically compatible weld metal for the subsequent completion of the weldment joint. Butter weld joints and joining welds require Procedure Qualification Records (PQRs) for the buttering weld process and for the joining weld process. A Welding Procedure Specification (WPS) is required for the entire completed weldment joint.

6.13.1.7 Transition welds shall be approved by the purchaser. Each of the two weldments at either extremity of a transition joint requires a separate WPS and PQR to complete the entire weldment transition joint. A weld transition joint is a length of metallic transition material of suitable length welded between two separate and different base material compositions. The transition material may be chosen for use when the two base materials are difficult to weld directly to one another and achieve the desired mechanical properties of the weldment joint. The transition material is intended to provide metallurgical compatibility between the two separate base materials.

6.13.1.8 Welds shall be qualified using weld qualification test coupons with a chemical composition, heat treat condition, and mechanical properties that comply with those of the material specification that controls the properties of the production materials. The PQR and the WPS shall be qualified in accordance with ASME Section IX or other recognized industry welding specification.

6.13.1.9 Additional essential welding variables shall be by agreement between purchaser and manufacturer.

6.13.1.10 All welding procedure qualifications shall measure the notch toughness of the weld metal and heat-affected zone. For procedure qualification tests joining dissimilar materials, both heat-affected zones shall be tested.

6.13.1.11 Preheating of assemblies or parts, when required, shall be performed to manufacturer's written procedures. If required, these procedures shall address post-weld temperature maintenance to prevent delayed cracking.

6.13.1.12 The controlled cooling rate of the weldment joint after welding or the maintenance of the preheat or the interpass temperature prior to the PWHT if and when either is required shall be shown in the WPS.

6.13.1.13 The storage, care and control of welding consumables shall be defined in the quality assurance procedures that control the manufacturers welding operations.

6.13.1.14 All welds on pressure-containing and primary-load-carrying components shall have 100% volumetric inspection by either RT or UT.

6.13.2 Non-primary-load-carrying Weldments and Non-pressure-containing Weldments on Components Required to Meet NACE MR0175/ISO 15156

The requirements of 6.13.1 shall apply in full to non-primary-load-carrying and non-pressure-containing weldments on components required to meet NACE MR0175/ ISO 15156 except as amended or superseded by other requirements in the equipment specific Sections 7 through 16.

6.13.3 Non-primary-load-carrying Weldments and Non-pressure-containing Weldments on Components Not Required to Meet NACE MR0175/ISO 15156

6.13.3.1 The requirements in 6.13.3 shall apply in full to non-primary-load-carrying weldments and non-pressure-containing weldments on components not required to meet NACE MR0175/ISO 15156 except as amended or superseded by other requirements in the equipment specific Sections 7 through 16.

6.13.3.2 Weld procedure qualifications, welder and welder operator qualifications, and welding processes shall be in accordance with the requirements in API Spec 16A.

6.13.3.3 For fabrication welding and repair welding, the API Spec 16A welding requirements shall apply.

6.13.3.4 For weld overlays for corrosion resistance or hard facing, the API Spec 16A shall apply.

6.13.4 Structural Welds

Structural welds shall be qualified and the production welds shall be performed in accordance with the requirements of ANSI/ AWS D1.1 or other recognized industry structural welding specification. By agreement between the manufacturer and purchaser, welding procedures for structural welds shall be qualified to and the production welding of the structures shall be performed in accordance with recognized industrial welding standards such as ASME Section IX. The purchaser may choose to review and approve the WPS and PQR for structural welding performed to welding standards other than the structural welding codes prior to the commencement of any structural welding.

6.13.5 Lifting Devices

Except as amended or superseded by other requirements in the equipment specific Sections 7 through 16, weld procedure qualifications, welder and welder operator qualifications, and welding processes for lifting devices shall be in accordance with the requirements in API Spec 16A.

7 Riser Tensioner Equipment

7.1 GENERAL

Required stroke, maximum tension, and tension variation with stroke determine performance requirements for riser tensioners. Riser tensioning systems on dynamically positioned vessels shall be equipped with anti-recoil systems to protect the riser and vessel following emergency riser disconnects as a result of a drive off or drift off. Specifications for anti-recoil systems are generally custom designed for the specific tensioner system and are beyond the scope of this document. See Section 11 for telescopic joints and riser tensioner rings (see Bibliography for references).

7.2 SERVICE RATINGS

7.2.1 Rated Tension

7.2.1.1 Marine riser tensioners that utilize wire lines and sheaves shall be rated according to the maximum tension produced in the wire line at the last sheave of the tensioner. The rated tension is the result of multiplying maximum operating pressure times the effective piston area, minus the weight of the piston rod assembly, rod end attachments, and wire line wrapped around the tensioner, then dividing by the number of parts of line used.

7.2.1.2 Marine riser tensioners that connect directly to the riser shall be rated according to the maximum pull produced by the tensioner. The maximum pull is the result of multiplying the maximum operating pressure times the effective piston area, minus the weight of the piston rod assembly and rod end attachments.

Note: Most riser tensioning devices connect to the riser with some amount of fleet angle that varies as a function of the vessel heave. Total riser tension is the sum of the vertical components of each tensioning device.

7.2.2 Rated Stroke

The maximum related translational motion that can be accommodated by the tensioner system shall determine the rated stroke.

7.3 TENSION VERSUS STROKE

The manufacturer shall provide calculated tension vs. stroke relationship for the tensioner for 90% tension capacity. Tension vs. stroke calculations for other tension capacities may be agreed upon by the manufacture and the purchaser. The calculations shall include adiabatic compression and expansion characteristics of the gas. Estimated seal friction, bearing and sheave friction, and other losses in the dynamic tension system may be included at the option of the manufacturer.

Note 1: Because vessel motion characteristics, weather design criteria, and tension variance allowed for or required by riser analysis results vary widely from one application to another, this document establishes no specific limits for tension variation vs. stroke.

Note 2: Interconnecting piping is usually outside of the manufacturer’s scope of supply. The purchaser will need to properly size these lines to limit tension variations caused by piping system pressure losses to values that are appropriate for the application.

7.4 PRESSURE

The maximum operating pressure (MOP) shall be limited to no more than 93% of the maximum allowable working pressure (MAWP) to prevent “simmering” or “popping” of the pressure relief valves during vessel heaving.

7.5 DESIGN STANDARDS

7.5.1 Pressure Vessels

Pressure vessels shall be designed, fabricated, and tested in accordance with ASME Pressure Vessel Code, Section VIII, Division 1 or Division 2; or other nationally or internationally recognized standard. Each vessel shall be equipped with a shut-off valve, drain valve, and rupture disk or pressure relief valve.

7.5.2 Cylinders

Cylinders shall be designed, fabricated, and tested in accordance with ASME Pressure Vessel Code, Section VIII, Division 1 or other nationally or internationally recognized standard. Any associated rods, rams, or like elements shall be designed in accordance with the above pressure vessel code, API Spec 8C, and AISC or other nationally or internationally recognized standard. Each vessel shall be equipped with a shut-off valve, drain valve, and a rupture disk or pressure relief valve.

7.5.3 Piping

All piping shall be designed in accordance with ASME B31.1 or other nationally or internationally recognized standard. Compatibility between piping and certain working fluids may require compliance with ASME B31.3.

7.5.4 Wire Rope

All wire rope used in marine riser tensioners shall comply with API Spec 9A. The rope shall be sized to have a minimum design safety factor of 3.0. This factor shall be calculated according to API RP 9B.

7.5.5 Sheaves

Sheave diameters shall be determined in accordance with recommendations given in API RP 9B. The service classification shall be "A" or "B." Otherwise the sheaves shall comply with API Spec 8C.

7.5.6 Electrical Wiring

Electrical equipment and wiring shall comply with the National Electrical Code 1 Class I Division 2 or IEC 61892.

7.5.7 Other Structural and Mechanical Elements

All other structural and mechanical elements shall be designed in accordance with AISC or other nationally or internationally recognized standard.

7.6 TENSIONER FOUNDATIONS

The manufacturer shall provide the mounting and installation information to the designer/purchaser, including design load, orientation, alignment, allowable fleet angle, and minimum clearances.

7.7 OPERATIONAL CONTROLS AND MONITORING EQUIPMENT

The tensioner system shall, as a minimum, include equipment to control and monitor the tension level.

7.8 TEMPERATURE CONSIDERATIONS

7.8.1 Structural Design Consideration

Cited design codes may not address extreme low-temperature service. The manufacturer shall clearly state the appropriate service temperature range claimed for all tensioner components.

7.8.2 Fluids and Elastomers

Working fluids and elastomers also affect system reliability and performance and shall be considered when establishing the overall service temperature rating.

7.9 FLUIDS

The manufacturer shall provide a list of materials with which the tensioner fluid is to be compatible and key fluid characteristics necessary for correct performance of the tensioner. These key characteristics shall include:

a. Viscosity (with temperature relation).
b. pH value.
c. Corrosion properties.
d. Lubricity value.
e. Ignition characteristics.
f. Operating temperature range.
g. Foaming characteristics.
h. Color so as to permit ready detection of leaks.

Note: Ceramic-coated rods may be subject to corrosion in the underlying base material if using a water-glycol hydraulic fluid. In the presence of some materials and design configurations, some fluids may act as an electrolyte and thus produce an electrical potential across the rod.

7.10 FAILURE CONTROL PROVISIONS

The riser tensioner system shall incorporate provisions to limit additional damage to the riser tensioning equipment resulting from a sudden loss of pressure, from a failure of the tensioner ropes, or from any other sudden loss of tension in the principle load-carrying components. The manufacturer shall demonstrate the effectiveness of his system by type certification test and analyses.

7.11 MARKING

The manufacturer shall provide on a nameplate or otherwise affix to each tensioner the following information:

a. Name of manufacturer.
b. Date of manufacture.
c. A unique serial number.
d. API load rating and stroke.
e. Operating temperature range.
f. API Spec 16F.

8 Flex/Ball Joints

8.1 SERVICE CLASSIFICATION

8.1.1 Tensile and Compressive Capacity

8.1.1.1 The tensile load capacity rating for flex/ball joints is the same as that defined in 5.2.2.

8.1.1.2 Upper flex/ball joints installed above the telescopic joints are not normally subjected to the same severity of loading as riser couplings. Service loads may vary from tensile to compressive. For such applications, manufacturer shall specify both tensile and compressive design load limits.

8.1.2 Rated Working Pressure

The manufacturer shall specify the applicable pressure rating. Internal pressure ratings for upper flex and ball joints are commonly 300 psi or 500 psi. Lower and intermediate flex and ball joint ratings commonly range from 600 psi – 6000 psi.

8.1.3 Combined Loading

The flex/ball joint will be subjected to simultaneous tensile loads, pressure differentials, and angular rotations. The tensile capacity of the unit is seldom applicable over its full operation pressure range. The manufacturer shall specify the combined tensile/pressure design load limits.

8.1.4 Flex Angle

Flex angle is the angular deviation from the longitudinal axis permitted by a flex joint. Flex and ball joints shall be capable of flexing to the specified maximum flex angle in any plane passing through the longitudinal axis. The flex angle limit for upper flex and ball joints is commonly ± 15°. The flex angle limit for lower and intermediate flex/ball joints is commonly ± 10°. The manufacturer shall specify flex angle limits.

8.2 LOAD/DEFLECTION CURVE

The manufacturer shall provide the bending load/deflection curve suitable for riser analysis to the purchaser.

8.3 DESIGN

8.3.1 Structural and Pressure Members

Design criteria for structural and pressure members shall comply with the guidelines established in Section 5 of this document.

8.3.2 Flex Joints

Flex joints for drilling risers use a laminated structure of elastomer and metal. A design certification report or series of reports shall be prepared to qualify each flex joint design. This report shall include:

a. Summary of design requirements.
b. Applicable specifications and references.
c. Description of design.
d. Bill of material with material properties.
e. Fluid compatibility data.
f. Stress analysis of all loaded components including the flex elements.
g. Failure modes (e.g., yielding, buckling, stability, external collapse, mechanical failure).
h. Qualification test report that includes test criteria and results.

8.3.3 Ball Joints

A ball joint is a ball and socket assembly that may or may not require pressure balancing. A pressure-balanced ball joint requires a hydraulic fluid bearing between the ball and socket when service loads are applied. The manufacturer shall furnish recommended balancing pressure settings as a function of riser tension, water depth and mud weight.

8.4 MATERIAL SELECTION

Material selection shall comply with the requirements of Section 6.

8.5 DIMENSIONS

8.5.1 Bore Size

The manufacturer shall provide calculated drift capability (length and diameter) relative to flex angle.

8.5.2 Outer Diameter

The manufacturer shall specify the maximum OD of the flex or ball joint.

8.6 TESTING

8.6.1 Design Type Certification Testing

8.6.1.1 For type certification of a design, the supplier shall demonstrate that the flex joint or ball joint is designed in accordance with a basis developed and supported by results from actual full scale testing. The flex or ball joint shall be cycled to ± 50% of the specified maximum flex angle for 100,000 cycles in one plane of flexure without visible deterioration of the flex elements or structural and pressure members. The joint shall be pressure tested to verify pressure integrity at full rated working pressure following the cyclic flexure test.

8.6.1.2 For type certification of each design, the design shall be verified.

8.6.2 Factory Acceptance Testing

Each new flex joint and ball joint shall be subjected to hydrostatic testing at 1.5 times rated working pressure. In addition, each ball joint balancing chamber hydraulic circuit shall be pressure tested at 1.5 times the maximum operating pressure.

8.7 MARKING

The manufacturer shall provide on a nameplate or otherwise affix to each flex joint or ball joint the following information:

a. Name of manufacturer.
b. Date of manufacture.
c. A unique serial number.
d. Tensile load rating.
e. Compressive load rating.

f. Rated working pressure.
g. API Spec 16F.

9 Choke, Kill and Auxiliary Lines

9.1 DESIGN

9.1.1 The design of all riser choke, kill, and auxiliary lines shall be in accordance with API Spec 16C.

9.1.2 Corrosion/erosion allowances: minimum corrosion/erosion allowance shall be 0.05 in. (1.3 mm). This may be reduced to zero for corrosion resistant alloys in non-erosive service, such as hydraulic conduit lines. These minimums shall be observed regardless of internal and external coatings. There is no requirement for external corrosion/wear allowance if the line is suitably protected from external corrosion.

9.1.3 Analysis shall account for joint tension; joint flexure in bending; thermal expansion of both main tube and choke, kill, and auxiliary lines; and applications of from zero pressure to full rated working pressure on any combination of the lines and main tube. Combined working loads shall not result in combined membrane stress exceeding yield stress of the auxiliary, choke, or kill line. Stresses resulting from choke, kill, and auxiliary line internal pressure and pressure end loading when the line is not shouldered shall be considered primary stresses for the choke, kill, and auxiliary line. Stresses resulting from thermal expansion, tension, and joint bending shall be considered secondary stresses, as the main tube will absorb these loads if the choke, kill, and auxiliary lines yield slightly.

9.1.4 Proof test pressure shall be 1.5 times rated working pressure. Proof test is normally conducted prior to the installation of the choke, kill and auxiliary lines into the finished riser joint assembly; the riser joint and choke, kill and auxiliary lines are not required by this specification to withstand proof test pressure as an assembly. Note that the stress situation of the choke, kill and auxiliary lines being tested outside of the riser joint assembly is significantly different than the stress situation of these lines being tested installed in the riser joint. The riser joint assembly shall withstand working loads and a maximum or rated working pressure applied to the choke, kill, or auxiliary lines (see 5.2.5 for temperature criteria).

9.2 MATERIALS

Material shall be in accordance with API Spec 16C.

9.3 WELDING AND QUALITY PROCESS CONTROL

Welding and quality process control shall be in accordance with API Spec 16C.

10 Drape Hoses and Jumper Lines for Flex/Ball Joints

10.1 SERVICE CLASSIFICATION

10.1.1 Drape Hoses

Drape hoses (moonpool lines) at the telescopic joint shall be classified according to internal pressure and relative movement between the riser and the drilling vessel. The internal pressure rating of the lines should be at least as large as that of the lines to which they connect. The drape hoses should be long enough to accommodate the design stroke of the telescoping joint and any rotation that may occur between the drilling vessel and the telescoping joint.

10.1.2 Jumper Lines

Jumper lines around the flex or ball joint shall be classified for internal pressure and relative movement between the riser and the BOP Stack. The internal pressure rating of the lines should be at least as high as that of the lines to which they connect. The jumper lines should accommodate the design rotation of the flex or ball joint and any relative displacements this rotation may induce between the ends of the jumper.

10.2 DESIGN

The design of all moonpool and jumper sections of riser auxiliary, choke, and kill lines shall be in accordance with API Spec 16C.

10.3 PROCESS CONTROL

Process control shall be in accordance with API Spec 16C.

11 Telescopic Joint (Slip Joint)

11.1 SERVICE CLASSIFICATION

11.1.1 General

The three loading conditions for telescopic joint load classification are:

a. Supporting the riser with the tensioners.
b. Supporting the riser from the top end of the telescopic joint (with the handling tool or the spider) with the inner barrel collapsed and locked.
c. Supporting the riser with the top end of the telescopic joint with the inner barrel stroked out.

11.1.2 Load Capacity

Load capacity of the telescopic joint shall be based on stress magnitude in the weakest load-carrying element when subjected to design load. Allowable stress limits enumerated in Section 5 shall apply to all load-carrying elements of the telescopic joint when the riser system is in service with design load applied. Note that the telescopic joint may have independent load ratings for:

a. Tension in service, no pressure on C & K lines.
b. Tension in service, pressure on C & K lines.
c. Collapsed and locked (pinned).
d. Fully extended, supporting load on inner barrel shoe at maximum wear allowance. Maximum wear allowance for the inner barrel shoe shall be listed in the telescopic joint's Operations and Maintenance Manual.

11.1.3 Stress Amplification Factor (SAF)

SAF shall be calculated for critical section (see 5.2.3) to be used in a fatigue analysis.

11.1.4 Friction in Tensioner Ring Swivel

For dynamically-positioned (DP) and turret-moored vessel systems, the tensioner ring must swivel. The swiveling mechanism will inherently have a degree of rotational friction. A design certification report or series of reports shall be prepared to qualify each tensioner ring joint design. This report shall include:

a. Description of design.
b. Summary of frictional performance as a function of tension load and of any swivel operating parameters, e.g., hydraulic pressure.
c. Proper lubrication type and frequency of lubrication.

11.2 DESIGN

11.2.1 A method shall be provided for easily locking the telescopic joint in the closed position to facilitate handling. The packing elements that affect a dynamic seal between the inner and outer barrel shall be designed for easy access and replacement. The packers should be energized to allow control of the sealing and lubricating features and shall hold pressure of 200 psi while experiencing relative movement induced by vessel motion. A primary and a secondary packer shall be provided, with the primary packer replaceable while the telescopic joint is in service with a mud column in the bore.

11.2.2 A tensioner ring shall be incorporated to allow attachment of the purchaser-specific number of riser tensioning lines. The tensioner ring shall be of either the fixed or swiveling type as specified by the purchaser. Purchaser shall specify the maximum individual load ratings of the tensioning lines. For dynamically-positioned and turret-moored vessels, the tensioner ring shall be designed to permit the ring to rotate while design tensile load is applied to the outer barrel.

11.2.3 If integral choke, kill, and auxiliary lines on the marine riser terminate at the telescopic joint, provisions shall be made for terminal fittings connected to drape hoses that allow for relative motion between the riser and the vessel. For choke and kill lines, the terminal fittings shall be designed for erosion resistance.

11.3 MATERIALS

Materials shall meet the requirements of Section 6.

11.4 DIMENSIONS

Telescopic joint inner barrel ID shall be no smaller than the ID of the drilling riser to which it attaches.

11.5 PROCESS CONTROL

Dimensional and weight tolerances for the inner barrel pipe shall be in compliance with API Spec 5L. The sealing surface of the inner barrel shall have a surface finish of standard pipe in accordance with API Spec 5L free from scale and corrosion.

11.6 TESTING

11.6.1 Pressure Test Procedures

Each pressure test, whether type certification testing or factory testing, shall consist of three parts:

a. The primary pressure-holding period, which shall not be less than 3 min.
b. The reduction of the pressure to zero.
c. The secondary pressure-holding period, which shall not be less than 15 min.

Timing shall not start until the test pressure has been reached and stabilized and the external surfaces of the body members have been thoroughly dried. Pressure sealing integrity is confirmed if there is no visible leakage.

11.6.2 Type Certification Testing-packer Design

Telescopic joint packer designs shall be subjected to type certification testing. Such testing is performed to ensure the capacity of the design to meet the intended service requirements. Specimens used for type certification testing shall be of the same materials and physical dimensions and tolerances as production units. Test fixtures that accurately simulate the geometric constraints and sealing surface may be used. Tests shall include:

11.6.2.1 Hydrostatic Test

Internal bore pressure tests shall be conducted at 25 psi, 50 psi, 100 psi, and 200 psi. Each test shall demonstrate the pressure retention capability of the telescopic joint packer system by holding test pressure without visible leakage for a period not less than 15 min. All tests shall be conducted with water.

11.6.2.2 Friction Test

While sealing bore pressure, the force required to move the inner barrel in both directions shall be determined. Separate tests shall be conducted at bore pressures of 25 psi, 50 psi, 100 psi, and 200 psi. No lubrication of the inner barrel is permitted for this test.

11.6.2.3 Reciprocation Test

The packer system shall be subjected to an inner barrel reciprocation test. There shall be no visible leakage for 100 cycles of 10-ft single-amplitude stroke (10 ft one direction and reverse, total 20 ft of travel full cycle); maximum cycle time is 20 sec. (1 ft/sec. minimum speed average). Separate tests shall be conducted at bore pressures of 25 psi, 50 psi, 100 psi, and 200 psi. The inner barrel may be lubricated with water; any other lubricating fluid shall be documented in the test report.

11.6.2.4 Wear Test

The packer system shall be subjected to a reciprocating inner barrel wear test. With the packer system energized sufficiently to seal 25 psi bore pressure, reciprocate the inner barrel for 50,000 cycles of 2-ft stroke (2 ft one direction and reverse, total 4 ft of travel full cycle); maximum time per cycle is 10 sec. The inner barrel may be lubricated with water; any other lubricating fluid shall be documented in the test report. The test shall not consume more than 10% of the available sealing element as established by the manufacturer. After the wear test is completed, the packer system shall satisfy the hydrostatic test requirements as defined in 11.6.2.1.

11.6.3 Design Type Certification Testing—Swiveling Tensioner Rings

For type certification of a swivelling tensioner ring design, a scaled model or full-scale ring shall be tested. The amount of torque needed to rotate the swivel shall be measured for at least four tension loads in equal increments up to the maximum tension rating of the swivel. Tests shall be run at each tension load in increasing order and then repeated in decreasing order (it is not necessary to repeat the test at the highest tension.) using the following procedure:

a. At each tension load increment level, rotate the ring under test load through 360-degrees (or maximum design range) at 2 – 4 degrees per min. in increments of at least 90 degrees. Peak and average torque shall be documented at each increment of rotation. The data shall also be summarized as peak and average torque for each load level over the entire range of rotation.
b. At each load increment, rotate the ring under test load 10 degrees in less than 30 sec. and document peak and average torque.

If scaled model testing is used in place of full-scale testing, the manufacturer shall demonstrate that the extrapolated stresses and torques do not under-predict the full-scale values.

11.6.4 Factory Testing

Telescopic joint packer operating chambers shall be pressure tested at 1.5 times maximum rated operating pressure in accordance with 11.6.1.

11.7 MARKING

The manufacturer shall provide on a nameplate or otherwise affix to each telescopic joint the following information:

a. Name of manufacturer.
b. Date of manufacture.
c. A unique serial number.
d. API load rating and stroke.
e. API Spec 16F.

12 Riser Joints

12.1 SERVICE CLASSIFICATION

The service classification for rated load capacity shall be determined by the weakest structural element (see 5.6).

12.2 DESIGN

12.2.1 The riser joint design shall incorporate the following features:

a. The riser joint design shall provide means for making up and sealing not only the riser bore itself but also the choke and kill lines and any auxiliary lines when two riser joints are connected.
b. Choke, kill, and auxiliary lines, shall meet the requirements of Section 9 of this specification. Support brackets for such lines shall be designed and axially spaced to support the choke and kill and auxiliary lines under the full range of service loads.
c. The riser pipe collapse pressure for the new pipe shall be calculated per API Bull 5C3 and shall be given for pipe axial loads equivalent to 9%, $33^1/_3$%, and 50% of the minimum specified pipe yield strength.
d. The assembled riser joint shall be rated on the basis of minimum design wall thickness of the main tube. The minimum design wall thickness of the main tube is the nominal wall thickness less the manufacture undersize tolerance, and less a corrosion/wear allowance. A 0.050-in. allowance is suggested, but the purchaser and manufacturer should agree upon the figure.

Note: The user should provide for an inspection frequency that ensures that marginal joints are identified and removed from service prior to being used at or below minimum wall thickness. Joints with thin walls shall be either removed for repair, or the joint shall be re-rated on the basis of a thinner wall.

12.2.2 The support from the auxiliary lines and choke and kill lines, if any, may be considered in the load rating. Care should be exercised that no combination of allowed tension, bending moment, internal or external pressure, or thermal expansion of any of the parts of the assembled component will allow stresses to exceed allowable limits set forth in this specification.

12.2.3 Riser pup joints shall be similar to standard riser joints except for length, and shall meet the same design requirements specified for riser joints.

12.2.4 Specifications for marine drilling riser couplings are provided in API Spec 16R and ISO 13625.

12.3 MATERIALS AND WELDING

Materials and welding shall meet the requirements of Section 6.

12.4 DIMENSIONS

The inside diameter of the riser joint shall be consistent with the BOP and the drilling programs as specified by the customer. The choke and kill line connections shall be consistent with the pressure rating of the BOPs and flow rate capacity as expected and specified by the purchaser. The outside clearance diameter of the riser joint shall be small enough to allow clearance through the specified rotary table.

12.5 DRIFT

The purchaser of marine riser systems shall specify drift requirements. Such requirements shall be clearly documented in the purchase agreement and shall specify the following:

a. Riser components to be drift tested.
b. Percentage of components to be drift tested.
c. Minimum drift diameter.
d. Minimum drift length.
e. Required markings; type and location.

12.6 PROCESS CONTROL

It shall be the manufacturer's responsibility to maintain documentation to assure conformance of the riser joint design to this specification.

Additionally, raw material traceability to heat number, including the physical and mechanical properties on load bearing and pressure-containing materials, shall be maintained.

12.7 MARKING

The riser joint shall be permanently marked using a low stress method. Marking shall include a serial number that corresponds to a data sheet for the joint and API Spec 16F. The data sheet shall include as a minimum the manufacturer's name and part number, the maximum load ratings, the as-built assembled weight excluding buoyancy and protectors, and indication of conformance to API Spec 16F.

13 Buoyancy Equipment

13.1 GENERAL

Buoyancy is generally provided by the use of syntactic foam modules. Alternatively, air cans provide buoyant lift in some applications.

13.2 SYNTACTIC FOAM MODULES

13.2.1 Service Classification

Syntactic foam buoyancy equipment shall be classified according to its rated service depth, which is the maximum depth in seawater at which it will provide buoyancy within design limits. The manufacturer shall type certify the service depth rating for each syntactic foam composition by hydrostatic testing as described in 13.2.6.4.

13.2.2 Design

13.2.2.1 The purchaser shall specify the net lift per joint to be provided by the equipment. The buoyancy calculation shall be based on the weight in seawater of the riser and all its metal accessories, as shown in the following example:

Riser joint weight in air = 11,250 lbs.
Riser joint weight in seawater = 0.87 × 11,250 = 9,788 lbs.
Desired buoyant lift = 95% (defined by purchaser)
Net lift per joint = 0.95 × 9,788 = 9,298 lbs.

Note: This is nominal buoyancy; tolerances on buoyancy are defined in 13.2.6.3. The above calculation is based on a standard carbon steel riser and a nominal seawater density of 1.025. Other seawater densities and/or riser material will require alternate calculation formulas.

13.2.2.2 The design and construction of the modules shall take into consideration the requirements of riser handling, storage, and maximum riser deflection (under dynamic conditions) based on parameters of the stacking arrangements provided by the purchaser (i.e., cordwood vs. vertical, battens/no battens, etc.). The material shall be strong enough to permit riser joints with buoyancy to be safely stacked without affecting performance. The manufacturer shall state the maximum height to which joints can be stacked without damage under conditions specified by the purchaser. These conditions shall be documented.

13.2.2.3 The length of the buoyancy equipment shall be such that sufficient clearance is provided for riser couplings and for supporting the riser on the spider during running or pulling operations. The buoyancy equipment shall also provide adequate clearance for choke/kill, and auxiliary lines and couplings.

13.2.2.4 Thrust collars shall be provided for the transfer of longitudinal forces into the riser pipe or connectors. The downward longitudinal force shall be assumed to be at least twice the full dry weight load (to account for impact loads) and the upward force shall be the total net buoyancy force.

The syntactic foam modules shall be attached to the riser with material of sufficient strength to hold the modules securely in place. The design shall be such that the attachment means is not exposed to damage in normal handling. Corrosion shall be considered in the design.

13.2.3 Material

13.2.3.1 Syntactic foam is typically a composite material of hollow spherical fillers in a matrix or binder. The most common form of syntactic foam consists of tiny glass microspheres in a matrix of thermosetting plastic resin, often with larger macrospheres of fiber-reinforced plastic.

13.2.3.2 The exterior of syntactic foam shall resist impact and abrasion encountered in normal handling. Sunlight, weathering, or climactic extremes shall not appreciably degrade the material.

13.2.3.3 All of the materials used to construct the buoyancy equipment shall be fully compatible with the shipboard environment. If any special precautions are required, the manufacturer shall so state.

13.2.3.4 The manufacturer shall meet the following requirements from UL 94 for material classed HBF (Horizontal Burning Foamed):

a. No specimen shall have a burning rate that exceeds 40 mm per min. over a 100 mm span.
b. A specimen shall cease to burn before flaming or glowing reaches the 125 mm gauge mark.

See UL 94 for test procedures.

13.2.4 Dimensions

The internal radius of the modules shall conform to the outer radius of the riser pipe without binding or excessive looseness. The purchaser shall specify any special shape requirements. Flexure lugs or elastomeric spacers may be located on the inner radius of each module to provide clearance and prevent transfer of bending forces between riser and buoyancy equipment.

13.2.5 Process Control

The manufacturer shall establish a process and records system that identifies the process variables associated with the manufacture of each individual buoyancy module.

Complete records shall be kept of the manufacturing process and made available to the purchaser. At minimum, the records shall include the following:

a. Module serial number and date of molding.
b. Quality control data of the molding material.
c. Quality control data of the curing process.
d. Dimensional measurements.
e. Hydrostatic testing.
f. Finished weight in air and seawater buoyancy.

13.2.6 Inspection and Testing

Testing of core sections or coupons is unacceptable for either qualification or conformance testing.

13.2.6.1 Quality Assurance Plan

Buoyancy modules shall be dimensionally and mechanically inspected to ensure conformance to drawings and specifications at no less than the following intervals:

a. "First article" of the first part molded.
b. "Mold approval" on the first part from each mold.
c. "Random sampling" of at least 5% of production from each mold.

13.2.6.2 Module Documentation

A production/inspection data sheet, containing the following information as a minimum, shall be prepared for each module:

a. Serial number and date of molding.
b. Service depth rating.
c. Measured dry weight.
d. Calculated wet weight in sea water* (SG = 1.025).
e. Displaced volume of water.*
f. Specified foam density.
g. Actual foam density.*
h. Net buoyancy in fresh and seawater* (SG = 1.025).
i. All critical dimensions.
j. Flatness/straightness.
k. Serial number of mold used to produce the module.
l. Flammability rating.

* To be provided on the basis of a 5% random sample of modules produced from each mold.

13.2.6.3 Buoyancy Verification

Tolerance limits on net lift shall be:

a. Any individual module: ± 5% from design.
b. Average of all modules: ± 2% from design.

Net lift for a module is the lift provided by the module calculated using the measured weight of the module, the average volume of the type of module at approximately atmospheric pressure, and the density of seawater with a specific gravity of 1.025. The manufacturer shall document the details of the calculation method and data used for the net lift calculations.

Note: For riser analysis:

a. Take into account mounting hardware and stop collars, either with the module weight and volume used, or accounted for separately.
b. Consider temperature effects and seawater specific gravity differences for specific geographic locations separately.
c. Consider buoyancy loss caused by pressure effects, water ingress, etc., separately. Hydrostatic sampling of modules provides data for making appropriate allowances in the analysis.

13.2.6.4 Hydrostatic Testing Requirements

Three levels of hydrostatic testing are required:

a) Type certification testing

1. These tests shall provide assurance that the syntactic foam does not absorb water at an excessive rate while under pressure. The manufacturer shall perform tests or produce records of prior tests that confirm that the material is qualified for rated service depth.

2. The qualification test material shall be the same nominal density (specific weight) as the material to be used for production parts.

3. Crush strength shall be at least 1.25 times the hydrostatic pressure at service depth.

4. Compression of material at service depth shall not cause more than 1.50% loss of net volume.

5. A minimum of two modules shall be tested. The modules submitted for testing shall not have been subjected to prior pressure testing.

6. Testing shall follow the procedure given in 13.2.6.4. The test pressure shall correspond to the service depth rating of the modules. The test duration shall be 96 hours.

Note: Fluorescent dye may be added to the water in the test chamber so that water ingress can be determined after sectioning the modules at the conclusion of the tests.

7. Acceptance criteria:

   a. The total buoyancy loss of a module shall not exceed 5%, based on the results of the 96-hour tests with the last 72 hours of data extrapolated over a 12-month period.

   b. Compression of material at service depth shall not cause more than 1.50% loss of net volume.

8. Mechanical damage shall not exceed manufacturer's written specification

b) Initial production testing

1. One complete set of first production modules for each depth rating produced by the supplier shall be tested. The tests shall follow the procedures given in 13.2.6.4 with the exception that test Step 6, cyclic testing, is not required.

2. Acceptance criteria:

   a. The total buoyancy loss of a module shall not exceed 5%, based on the results of a 24-hour tests with the last 20 hours of data extrapolated over a 12-month period.

   b. The modules shall not have any visual defects that exceed those allowed by the manufacturer's written specification.

   c. The modules must be dimensionally correct and provide the required amount of buoyancy within the tolerances of the manufacturer's written specification.

3. These modules, if they pass the test, may be considered as part of the production order.

c) Production sample testing

1. Actual production shall be subject to sample conformance testing. The manufacturer or an independent testing facility shall test at least 5.0% of the modules (one out of a batch of 20) at hydrostatic pressure corresponding to the rated service depth.

2. The tests shall follow the procedures given in 13.2.6.4 with the exception that test Step 6, cyclic testing is not required and that the test duration shall be 24 hours.

3. Acceptance criteria:

   a. Manufacturer shall have written criteria for inspection and acceptance of buoyancy subjected to hydrostatic pressure test, The total buoyancy loss of a module shall not exceed 5% based on the results of the 24-hour tests with the last 20 hours of data extrapolated over a 12-month period.

   b. If the sample module, selected by a method agreed to by the customer and the manufacturer, fails the above acceptance criteria for conformance testing, the following procedure shall be followed:

      - If the sample module fails the test, the supplier shall proceed with testing of two additional modules from the same batch. If both of these modules pass the test, then the entire bath shall be regarded as acceptable. If one or both of these test modules fail the test, then the entire batch will be rejected. The supplier, at their discretion, may elect to test each individual module remaining in the batch. Only modules that pass the acceptance criteria shall be deemed as acceptable. Modules not passing the acceptance criteria may, at the customer's discretion, be re-rated for another depth rating, or accepted as is with the test failure noted.

13.2.6.5 Hydrostatic Test Procedure

The following procedures shall be followed:

a. Weigh and record the weight of each module in air.
b. Immerse in fresh water in a hyperbaric chamber and verify the module weight in water. Calculate and record actual density. Correction for actual buoyancy in seawater shall be recorded.
c. Seal hyperbaric chamber and gradually increase test pressure over a one to two-hour period until maximum test pressure is attained. Check and record buoyancy loss during this period.
d. Maintain test pressure continuously for the specified test duration. Record changes in buoyancy and temperature at intervals of no less than 5 min. during this period.
e. Depressurize the chamber.
f. Re-pressurize the chamber. Test for 6 cycles raising the pressure to the maximum test pressure and hold for 10 min., then depressurize. Monitor and record results. Finally, depressurize the chamber and verify weight gain.
g. Remove modules from chamber. Weigh and record results. Inspect for mechanical damage.
h. Extrapolate the *total* buoyancy loss data over a 12-month period from the results obtained.

Note: Total buoyancy loss includes initial compressive losses resulting from the bulk modulus and the losses caused by water ingress and damage.

13.2.7 Markings

Syntactic foam buoyancy modules shall be pigmented or painted a highly visible color.
Each module shall have as a minimum, the following information printed indelibly on its surface:

a. Manufacturer.
b. Module serial number (see 13.2.5).
c. Service depth rating.
d. API Spec 16F.

Serial numbers shall be located in a minimum of three places on each module; the outer surface, the inner surface, and the end of the module.
Each module shall be identified with a color code for each depth rating as agreed by manufacturer and purchaser.

13.2.8 Data Sheet

A data sheet shall be provided for each module. The data sheet shall include as a minimum the module's serial number, volume, air weight, calculated net lift in seawater, and average water absorption versus time for the batch.

13.2.9 Packaging

The manufacturer shall supply packaging that will ensure damage free shipment and storage.

13.3 AIR CAN SYSTEMS (INFORMATIVE)

13.3.1 Concept

An air can is typically an inverted container open to the water at its lower end. An air can is charged with air or other suitable buoyant fluid that displaces a specified volume of water to provide the desired buoyancy.
An air can system may be adjustable, variable or fixed. The adjustable type permits presetting the air or buoyant fluid volume prior to deploying the riser. The variable type allows injection or removal of buoyant fluid after deployment of the riser. The fixed type does not allow adjustment of buoyancy.
An air can is open at the bottom and centralized around the riser pipe so that water directly interfaces with the air inside. Thus the maximum differential pressure across the wall of the can is equal to a water head of one can length, regardless of the water depth at which the joint is operating.

13.3.2 Design Features

Since the pressure differential on the air can structure is a function of can length, not water depth, the buoyant air can system is suitable for deep-water service. Each air can joint may be equipped with a device to independently control air injection and thus buoyancy for each riser joint. Each riser joint may contain a means for dumping air from the cans to increase the effective riser string weight.

The air can should be sufficiently rugged to allow the joints to be handled and stored in a conventional manner without causing mechanical damage.

Note: Most damage that occurs should be easily repaired in the field using rig personnel.

13.3.3 Inspection and Testing

Each joint may be submerged to test for pressure integrity and to certify buoyancy. The pressure differential during this test should be the maximum differential the joint will encounter. For example, the maximum pressure differential for a 50-ft joint would be approximately 22 psi.

The weight in air and weight submerged should be marked in each air can joint.

14 Riser Running and Handling Equipment

14.1 INTRODUCTION

14.1.1 General

Handling tools for the riser and the diverter, if used to support the riser and the BOP stack, shall be designed for hoisting and lowering the riser system through the riser spider and rotary table, and be designed and rated in accordance with Section 14.2 of this specification.

Riser hang-off spiders shall be rated to support the riser system and BOP stack at the drill floor level. The riser spider and gimbal/shock absorber, if applicable, shall be designed and rated in accordance with Section 14.2 of this specification.

Testing of the riser handling tools, riser spider, and gimbal/shock absorber shall follow the requirements of Section 14.3 of this specification.

14.1.2 Coverage

This section provides the requirements for the following riser running and handling equipment:

a. Manual riser running tools.
b. Hydraulic riser running tools.
c. Riser spiders.
d. Riser gimbals.
e. Equipment used to lift, run, retrieve, or support the riser string and BOP stack.

14.2 DESIGN

14.2.1 Loading

Equipment in Section 14.1.1 shall be designed considering the following loads:

a. Maximum rated static load capacity.
b. Angular capacity of gimbal—maximum rated static load capacity at maximum angular capacity shall be reported.
c. Bending loads (during handling).
d. Loads due to pressure.

14.2.2 Strength Analysis

14.2.2.1 General

The equipment design analysis shall address yielding, buckling, deflection, and rupture as possible modes of failure.

Finite element analysis, in conjunction with closed form analytical solutions, may be used. All forces that may govern the design shall be taken into account. For each cross section to be considered, the most unfavorable combination, position and direction of forces shall be used.

14.2.2.2 Design Safety Factor

The design factor for all equipment referenced in Section 14.1.1 shall be as stated below.

The design safety factor is intended as a design criterion and shall not under any circumstances be construed as allowing loads on the equipment in excess of the load rating.

The design safety factor, SF_D, shall equal 2.25.

14.2.2.3 Allowable Stress

Linear elastic theory shall be employed for the determination of stress distributions within components. Equivalent stress shall be determined based on the Von-Mises Hencky theory as provided in Annex B.

Linearized primary membrane stresses caused by the rated load shall not exceed the maximum allowable stress, $\sigma_{allow,m}$, as calculated by equation (1).

$$\sigma_{allow,\,m} = \frac{\sigma_{ys}}{SF_D} \tag{1}$$

Linearized primary membrane plus primary bending stresses caused by the rated load shall not exceed the maximum allowable stress, $\sigma_{allow,m+b}$, as calculated by equation (2).

$$\sigma_{allow,\,m+b} = \frac{1.5 \times \sigma_{ys}}{SF_D} \tag{2}$$

Linearized membrane plus bending secondary stresses caused by the rated load shall not exceed the maximum allowable stress, $\sigma_{allow,s}$, as calculated by equation (3).

$$\sigma_{allow,\,s} = \frac{3.0 \times \sigma_{ys}}{SF_D} \tag{3}$$

Bearing stresses are allowed to exceed the yield strength of the material provided that the shear and tensile stresses in the vicinity of the bearing load are within acceptable limits. When bearing loads are applied to parts having free edges, the possibility of a shear failure shall be considered.

Where σ_{ys} is the material minimum yield strength per ASTM A370.

14.2.2.4 Shear Strength

For purposes of design calculations involving shear (primary stress), the ratio of yield strength in shear to yield strength in tension shall be 0.58. The design safety factor is to be applied in accordance with Section 14.2.2.3.

14.2.2.5 Contact Stresses and Geometric Discontinuities (Secondary Stresses)

The method of Section 14.2.2.6 may be performed for any one of the following conditions:

a. For contact areas and bearing loads exceeding yield;
b. For areas of highly localized stress concentrations caused by part geometry exceeding the requirements of Section 14.2.2.3.

For these areas the primary membrane stress in the section must meet the requirements of Section 14.2.2.3.

14.2.2.6 Ultimate Strength (Plastic) Analysis

The lower bound true stress-true strain curve, with strain hardening and change in geometry can be used for determining the rated load, local strain, and shakedown. Using this method does not require satisfying the limits on primary and secondary stress in Section 14.2.2.3. The curve has to be based on the specified minimum yield stress. The material model for this type of analysis must be defined by the following:

1. The yield surface defining when plastic strains are generated must be modeled using von Mises plasticity.
2. kinematic hardening model defining how the yield surface changes for plastic strains or a combination of both.

The load is increased incrementally in the FEA model of the structure until the model fails to converge, or the deformation is large enough such that the structure no longer serves its purpose per the functional requirements. This is the lower bound load. The rated load is the lower bound load divided by the safety factor in Section 14.2.2.2.

The use of the method in this section requires local strains to be analyzed for a few cycles of the rated load to determine if shakedown occurs, i.e. no progressive distortion or stress ratcheting.

14.2.2.7 Limit Analysis (Elastic-Perfectly Plastic Analysis) (Alternate Method)

Nonlinear analysis may be conducted with a material model that defines yielding using bilinear von Mises plasticity typically based on small displacement analysis. For this method, stress less than the yield strength has a slope equal to the elastic modulus of the material, above yield the slope is as near zero as practical.

The model shall be loaded until the lower bound collapse load is identified by failure of the model to converge. This is the limit load. The rated load is the limit load divided by the safety factor in Section 14.2.2.2.

The results of the limit analysis may be used to justify primary stresses exceeding the stress allowables in Section 14.2.2.3, but not secondary stresses.

The method in Section 14.2.2.6 may be used to justify secondary stresses. The rated load determined using the method in Section 14.2.2.6 must be greater than the rated load determined using the limit analysis method to justify the secondary stresses.

14.2.2.8 Bolted Connections

Bolts subject to the primary load shall meet the requirements of equations (5) and (6) below:

$$\frac{2.25 \times Rated\ Load}{A_{bolt}} \leq \sigma_{ys} \tag{5}$$

$$\frac{Preload \times Rated\ Load}{A_{bolt}} \leq 0.83\sigma_{ys} \tag{6}$$

where

A_{bolt} is the minimum cross section of the bolt being considered.

Equation (6) considers the effective joint stiffness, i.e. bolt stiffness plus the clamped components stiffness. Both equations (5) and (6) consider only the membrane stresses through the bolt section and do not account for secondary and bending effects.

14.2.2.9 Pressure Containing Components

Pressure containing components shall be designed using the design methodology and stress allowables described in Annex B.

14.2.3 Design Verification

The design shall be verified using an independent source outside of the design process plus prototype testing.

14.3 TESTING

14.3.1 Prototype Testing

Prototype testing shall be performed for design validation. Prototype testing shall be used to verify the strength analyses conducted by either of the methods described in Section 14.2.2. The component rated load shall be applied to verify any assumptions made.

Strain measurements must be determined as near as physically possible to at least five of the highly stressed locations and five locations away from stress concentrations as predicted by the methods in Section 14.2.2. The measurements shall correlate to the design methodology used to within manufacturer's acceptance criteria.

14.3.2 Production Testing

14.3.2.1 Proof Load Test

To ensure conformity with specified requirements the design shall be validated using test of production products to a minimum load of 1.5 times the rated load capacity of the component. Gimbals need only be loaded in the axial direction.

The equipment shall be mounted in a test fixture capable of loading the equipment in essentially the same manner as in actual service and with essentially the same areas of contact on the load-bearing surfaces.

The test load, equal to 1.5 times the rated load, shall be applied for a period not less than 5 minutes.

All primary-load-carrying components shall be inspected in accordance with Section 14.6 after the production load test.

14.3.2.2 Functional Test

Functional test shall be performed to ensure proper operation of the components. The function test shall be performed after the completion of the production load test and inspection in accordance with Section 14.6.6.

14.3.2.3 Pressure Test

Pressure containing systems shall be pressure tested to 1.5 times the maximum rated pressure of that system for a period not less than 5 minutes after stabilization with no detectable leaks. The pressure test shall be performed after the production load test and inspection in accordance with Section 14.6.

14.4 MATERIAL

14.4.1 General

All materials shall be suitable for the intended service.

The remainder of Section 14.4 describes the various material qualification, property and processing requirements for primary-load-carrying components and pressure-containing components unless otherwise specified.

14.4.2 Written Specification

Written specifications of materials used for riser running equipment shall follow the requirements of Section 6.3.

14.4.3 Mechanical Properties

Materials shall meet the property requirements specified in the manufacturer's material specification.

The impact toughness shall be determined from the average of three tests, using full sized test pieces if the size of the component permits. If it is necessary for sub-size impact test pieces to be used, the acceptance criteria for impact values shall be those stated below but multiplied by the appropriate adjustment factor listed in Table 14.2. Sub-size test pieces of width less than 5 mm shall not be used.

For materials of a specified minimum yield strength of at least 310 MPa (45 ksi), the average impact toughness shall be 42 J (31ft-lb) at –20°C (–4°F) with no individual value less than 32 J (24 ft-lb).

For materials with a minimum specified yield strength of less than 310 MPa (45 ksi), the average impact toughness shall be 27 J (20ft-lb) at –20°C (–4°F) with no individual value less than 20 J (15 ft-lb).

For design temperatures below –20°C (–4°F) (e.g. arctic service), the following supplementary impact toughness requirements shall apply:

1. The maximum impact test temperature for materials used in primary-load-carrying components with a required minimum operating temperature below –20°C (–4°F) shall be specified by the purchaser.
2. Impact testing shall be performed in accordance with this section and ASTM A370. The minimum average Charpy impact energy of three full-size test pieces, tested at the specified (or lower) temperature, shall be 27 J (20 ft-lb) with no individual value less than 20 J (15 ft-lb).
3. Each primary-load-carrying component shall be marked "LTT" to indicate that low temperature testing has been performed using low-stress, hard die-stamps near the load rating identification. Each primary-load-carrying component shall also be marked to show the actual design and test temperature in degrees Celsius.

Where the design requires through-thickness properties, materials shall be tested for reduction of area in the through-thickness direction in accordance with ASTM A770. The minimum shall be 25%.

Components shall be fabricated from materials meeting the applicable requirements for ductility specified in Table 14.1 and Table 14.2.

Table 14.1—Elongation Requirements

Yield Strength		Elongation, minimum %	
MPa	ksi	$L_0 = 4d$[a]	$L_0 = 5d$[a]
Less than 310	Less than 45	23	20
310 to 517	45 to 75	20	18
Over 517 to 758	Over 75 to 110	17	15
Over 758	Over 110	14	12

a) Where L_0 is the gauge length and d is the diameter.

Table 14.2—Adjustment Factors for Sub-size Impact Specimens

Specimen Dimensions (mm)	Adjustment Factor
10.0 × 7.5	0.833
10.0 × 5.00	0.667

14.4.4 Material Qualification

The manufacturer shall perform the mechanical tests on qualification test-coupons representing the heat and heat treatment lot used in the manufacture of the component. Tests shall be performed in accordance with ASTM A370, or equivalent standards, using material in the final heat treated condition. For the purposes of material qualification testing, PWHT is not considered heat treatment, provided that the PWHT temperature is below that which changes the heat treatment condition of the base material.

Qualification test coupon size shall be determined per Section 6.7.

Test specimens shall be removed from integral or separate qualification test-coupons so that their longitudinal centerline axis is entirely within the center core $^1/_4$-thickness envelope for a solid test-coupon or within 3 mm ($^1/_8$ in.) of the mid-thickness of the thickest section of a hollow test-coupon. The gauge length on a tensile specimen or the notch of an impact specimen shall be at least $^1/_4$ thickness from the ends of the test-coupon.

Test specimens taken from sacrificed production parts shall be removed from the center core $^1/_4$-thickness envelope location of the thickest section of the part.

Testing of QTC shall be performed per Section 6.8 considering the requirements of Section 14.4.3 above.

14.4.5 Manufacture

The manufacturing process shall ensure repeatability in producing components that meet all the requirements of this Standard.

All wrought materials shall be manufactured using processes which produce a wrought structure throughout the component

All heat treatment operations shall be performed utilizing equipment qualified in accordance with the requirements specified by the manufacturer or processor. The loading of the material within heat treatment furnaces shall be such that the presence of any one part does not adversely affect the heat treatment response of any other part within the heat treatment lot. The temperature and time requirements for heat treatment cycles shall be determined in accordance with the manufacturer's or processor's written specification. Actual heat treatment temperatures and times shall be recorded, and heat treatment records shall be traceable to relevant components.

The manufacturer shall specify the melting, refining, casting, and working practices for all components. The specified practices shall be recorded in the required written material specification.

14.4.6 Chemical Composition

The material composition of each heat shall be analyzed for all elements specified in the manufacturer's written material specification.

The maximum mass fraction of sulfur and phosphorous shall each be 0.025, expressed as a percentage.

14.5 REPAIR WELDING

14.5.1 General

This section describes the requirements for repair welding, where permitted, of primary-load-carrying components and pressure-containing components, including attachment welds. The term "repair," as referred to in Section 14, applies only to the repair of defects in materials during the manufacture of new equipment. Section 6 shall apply in full to primary-load-carrying and pressure-containing weldments except as amended or superseded by Section 14.5

14.5.2 Access

There shall be adequate access to evaluate, remove and inspect the non-conforming condition causing the need for the repair.

14.5.3 Forgings

All repair welding shall be performed in accordance with properly qualified welding procedures.. Welding procedure specifications shall be documented..

Prior to any repair the manufacturer shall document the following criteria for permitted repairs:

- Defect type;
- Defect size limits;
- Definition of major/minor repairs.

All excavations, prior to repair and the subsequent weld repair, shall meet the quality control requirements specified in Section 14.6

For major weld repairs as defined by the manufacturer shall also produce a dimensional sketch of the area to be repaired and the repair sequence. Documentation of repairs shall be maintained in accordance with requirements of Section 17.

14.5.4 Heat Treatment

The welding procedure specification used for qualifying a repair shall reflect the actual sequence of weld repair and heat treatment performed on the repaired item.

14.6 QUALITY CONTROL

14.6.1 General

Section 18.1 specifies the quality control requirements for all primary-load-carrying components and/or pressure-containing equipment and components unless otherwise specified below.

14.6.2 Chemical Analysis

Methods and acceptance criteria shall be in accordance with 14.4.6.

14.6.3 Tensile Testing

Methods and acceptance criteria shall be in accordance with 14.4.3 and 14.4.4.

14.6.4 Impact Testing

Methods and acceptance criteria shall be in accordance with 14.4.3 and 14.4.4.

14.6.5 Traceability

Fasteners not in the primary load path and pipe fittings shall be exempt from traceability requirements provided they are marked in accordance with a recognized industry standard.

14.6.6 Surface NDE

14.6.6.1 General

NDE and inspection, in accordance with the below requirements, shall be performed after final heat treatment and final machining operations in welds, primary load path components and high stress regions as determined by Section 14.6.8.

If the equipment is subjected to a load test, the qualifying NDE shall be carried out after the load test. For materials susceptible to delayed cracking, as identified by the manufacturer, NDE shall be done not earlier than 24 h afters the load test. The manufacturer shall establish the critical areas for inspection. Conductive surface coatings shall be removed prior to examination. Non-conductive surface coating shall be removed prior to examination unless it has been demonstrated that the smallest relevant indications defined in 14.6.6.2 can be detected through the maximum applied thickness of the coating.

14.6.6.2 Method

Ferromagnetic materials shall be examined by the magnetic particle method in accordance with ASME BPVC, Section V, Subsection A, Article 7, and Subsection B, Article 25 or ASTM E709. Machined surfaces shall be examined by the wet fluorescent method; other surfaces shall be examined by a wet method or dry method.

Non-ferromagnetic materials shall be examined by the liquid penetrant method in accordance with ASME BPVC, Section V, Subsection A, Article 6, and Subsection B, Article 24 or ASTM E165.

If the use of prods cannot be avoided, all prod burn-marks shall be removed by grinding and the affected areas shall be re-examined by the liquid penetrant method.

14.6.6.3 Evaluation of Indications

Only those indications with major dimensions greater than 2 mm ($^1/_{16}$ in.) and associated with surface ruptures shall be considered relevant indications. Inherent indications not associated with a surface rupture (i.e. magnetic permeability variations, non-metallic stringers, etc.) shall be considered non-relevant. If magnetic particle indications greater than 2 mm ($^1/_{16}$ in.) are believed to be non-relevant, they shall either be examined by the liquid penetrant method to confirm they are non-relevant or they shall be removed and re-inspected to confirm they are non-relevant.

Relevant indications shall be evaluated in accordance with the acceptance criteria specified in 14.6.6.4.

14.6.6.4 Acceptance Criteria

The following acceptance criteria shall apply for surface NDE of wrought materials:

- No relevant indication with a major dimension equal to or greater than 5 mm ($^3/_{16}$ in.);
- No more than ten relevant indications in any continuous 40 cm^2 (6 $in.^2$) area;
- No more than three relevant indications in a line separated by less than 2 mm ($^1/_{16}$ in.) edge-to-edge;
- No relevant indications in pressure-sealing areas, in the root area of rotary threads or in stress-relief features of threaded joints.

14.6.7 NDE of Welds

14.6.7.1 General

Essential welding variables and equipment shall be monitored during welding. The entire accessible weld, plus at least 13 mm ($^1/_2$ in.) or surrounding base metal, shall be examined in accordance with methods and acceptance criteria of 14.6.7.

The NDE required under 14.6.7 shall be carried out after final heat treatment.

14.6.7.2 Fabrication Welding

14.6.7.2.1 Visual Examination

All fabrication welds shall be visually examined in accordance with ASME BPVC, Section V, Subsection A, Article 9. Undercuts shall not reduce the thickness in the affected area to below the design thickness, and shall be ground to blend smoothly with the surrounding material.

Surface porosity or exposed slag are not permitted on, or within 3 mm ($^1/_8$ in.) of sealing surfaces.

14.6.7.2.2 Surface NDE

All primary-load-carrying and pressure-containing welds and attachment welds to main load bearing and pressure-containing components shall be examined as specified in 14.6.6.2.

The following acceptance criteria shall apply:

- No relevant linear indications (i.e. having a length of at least three times the width);
- No rounded indications with a major dimension greater than 4 mm ($^1/_8$ in.), for welds whose depth is 17 mm ($^5/_8$ in.) or less;
- No rounded indications with a major dimension greater than 5 mm ($^3/_{16}$ in.) for welds whose depth is greater than 17 mm ($^5/_8$ in.);
- No more than three relevant indications in a line separated by less than 2 mm ($^1/_{16}$ in.) edge to edge.

14.6.7.3 Repair Welds

The term "repair," as referred to in Section 14, applies only to the repair of defects in materials during the manufacture of new equipment

14.6.7.3.1 Weld Excavations

Magnetic particle examination shall be performed on all excavations for weld repairs, with the method and acceptance criteria as specified 14.6.6.

14.6.7.3.2 Repair of Welds

NDE of the repairs of weld defects shall be identical to that of the original weld; 14.6.7.2.

14.6.8 Critical Area Maps

The manufacturer shall establish and maintain area drawings, identifying high-stress areas, which shall be used in conjunction with this section. For purposes of this section, critical areas shall be all areas where the stress in the component exceeds the value of:

$$High\ Stress \geq \frac{\sigma_{ys}}{1.33 SF_D} \tag{7}$$

If critical areas are not identified on critical area drawings then all surface areas of the component shall be considered critical.

Areas of components in which the stress is compressive, and/or where the stress level is less than the results of Equation (8), may be considered non critical. The low stress areas, thus defined, may be defined on the critical area map.

$$Low\ Stress \geq \frac{0.1\sigma_{ys}}{SF_D} \tag{8}$$

14.7 DIMENSIONS

Verification of dimensions shall be carried out on a sample basis as defined and documented by the manufacturer.

All main load-bearing and pressure-sealing threads shall be gauged to the requirements of the relevant thread specification(s).

The manufacturer shall specify the maximum diameter of riser string component that can pass through the spider with the dogs or jaws retracted.

The Verification of external interface dimensions shall be carried out on each components and/or assembly as relevant.

14.8 PROCESS CONTROL

It shall be the manufacturer's responsibility to maintain documentation to ensure conformance of the riser running equipment design to this specification.

Additionally, raw material traceability to heat number, including of the chemical, physical, and mechanical properties of primary load bearing and pressure-containing components materials shall be maintained through the complete manufacturing cycle except those components excluded from traceability in Section 14.6.7.

14.9 MARKING

Components designed to Section 14 shall be marked using permanent low-stress, metal impression stampings with the following information:

a. Name of manufacturer;

b. Date of manufacture;

c. Unique serial number;

d. Maximum load rating;

e. API 16F.

15 Special Riser System Components

15.1 GENERAL

Special riser system components may be required in some applications as necessitated by water depth, rig configuration, well-control requirements, riser system configuration, environmental considerations and/or operator or regulatory authority specifications.

15.2 SERVICE CLASSIFICATION

Service classification for load capacity shall be determined by the weakest component in the assembly. This includes the riser couplings, any riser pipe, and any special load-carrying bodies.

15.3 DESIGN

All special riser system components, such as a riser flood valve, a riser circulation joint, or a riser crossover joint, shall meet the requirements defined in Section 12 of this specification. Water depth limitations (if applicable) of any component shall be documented.

The riser flood valve joint shall include a valve that allows rapid filling of the drilling riser with sea water to reduce the chance of riser collapse in the event that pressure in the riser drops significantly below the external sea water pressure.

15.4 TESTING

The manufacturer shall conduct and document type-certification tests on special riser components (see 11.6). In addition, the manufacturer shall perform a functional operating test. Documentation shall be furnished to ensure compatibility with the other parts of the drilling riser system.

16 Lower Riser Adapter

16.1 GENERAL

The lower riser adapter is typically the bottom interface of the marine drilling riser with the LMRP. The lower riser adapter usually includes a box or pin looking up, stabs with kick outs for choke, kill and auxiliary line interface with jumper lines and a bottom flange or hub for connecting to the lower flex/ball joint. Section 12 design standards shall apply to the lower riser adapter.

16.2 MARKING

Marking shall be in accordance with 12.7.

17 Operation and Maintenance Manuals

17.1 GENERAL

The manufacturer shall provide, at purchaser request, operation and maintenance manuals that shall include, but not be limited to, the following items in this section.

17.2 EQUIPMENT DESCRIPTION

The following shall be included:

a. Written description of the system and each major component.
b. Drawings of the system and each major component. Photographs may be included.
c. Applicable schematic drawings (hydraulic, pneumatic and/or electrical as necessary).

17.3 FUNCTIONAL DESCRIPTION

A written explanation of the method of operation and physical function of the system and each major component.

17.4 INSTRUCTIONS FOR EQUIPMENT USAGE

The following shall be included:

a. Riser choke, kill and joint pickup and handling.
b. Coupling makeup and breakout.
c. Pressure testing of choke, kill and auxiliary lines.
d. Riser joint storage and racking.
e. Compatible packer fluids for telescopic joint.

17.5 MAINTENANCE INSTRUCTIONS

The following shall be included:

a. Graphic chronological schedule of routine maintenance tasks.
b. Sample maintenance forms or check lists as necessary.
c. Log sheets for recording cumulative use of each riser joint and telescopic joint.
d. Storage instructions and replacement schedule for rubber goods and other consumables.
e. Specified fluids, lubricants, tools, etc., required to operate and maintain the equipment.
f. Procedure for fatigue crack inspections.
g. Procedure for checking the wall thickness (see 12.2.1).
h. Drawing(s) showing critical dimensions and limits for in-service interface and sealing of mating parts.

17.6 REPAIR INSTRUCTIONS

The following shall be included:

a. Step-by-step disassembly and assembly procedures.
b. Schedule for change out of replaceable coupling components.
c. Buoyancy equipment repair procedures, if applicable.

17.7 WARNINGS AND CAUTIONS

Significant hazards (including misconnections, oversights, exceeding design limits, etc.) shall be identified.

18 Quality Control Requirements

18.1 GENERAL

This section specifies the quality control requirements for primary-load-carrying components and/or pressure-containing components or equipment manufactured to this specification. The main tube shall meet the requirements of API Spec 5L, PSL 2. Other components shall meet the applicable quality control requirements of API Spec 16A with the following exceptions.

18.2 SOUR SERVICE

If the flow of formation fluids is handled by diverting the flow at the sea floor BOP through the choke and kill lines, the drilling riser pipe, riser connection, ball or flex joints, and telescoping joints (materials and welding) need not comply with NACE

MR0175/ISO 15156. If, however, the riser system is expected to be exposed to sour environments, materials and welding used shall meet the applicable requirements of NACE MR0175//ISO 15156.

18.3 EQUIPMENT TRACEABILITY

All assemblies as defined in 1.2 shall be serialized with a unique number that will allow the assembly and all major components to be traced back through the manufacturing process to the raw material heat certification documents.

18.4 QUALITY CONTROL DOCUMENTS

The requirements of API Spec 16A shall apply with the exception that records required to substantiate conformance to NACE requirements are not required unless the riser system is expected to be exposed to sour environments.

ANNEX A
(Normative)
Stress Analysis

For non-axisymmetric components, three-dimensional analysis is necessary to account for variation in stress around the circumference. If a coupling has axial planes of symmetry (planes which include the pipe axis), the three-dimensional analysis may be based on a single sector bounded by two such planes. For example, a component having six planes of symmetry would require analysis of a 30-degree sector (one twelfth). The axial loading on such a 30-degree sector can be considered to be that caused by the design tension uniformly distributed around the pipe. Determination of the equivalent load for bending is discussed in 5.6. Two-dimensional analysis may be valid for axisymmetric components.

The use of finite element analysis permits determination of stresses in complex structures, but accuracy of the analysis is very sensitive to the skill of the analyst. Care and judgment must be exercised in developing the finite element model. For example, highly stressed regions of the structure require a fine mesh of elements. Therefore, the analyst must predict where high stresses are likely to occur. Some stresses will be affected by the structural properties of the riser pipe. Therefore, the model must be continued far enough away from critical areas to ensure that results are free from boundary effects. Finally, the finite element model must be designed so that the finite elements are not distorted beyond their ability to produce accurate results.

Analysis of the effects of preload and the possibility of separation may require special treatment in the finite element analysis. All sub-components that affect the stiffness of the components shall be considered in the model. If separation can occur, then provision for it must be included in the analysis if possible. If not possible, then an iterative method involving several solutions shall be required.

Maximum stresses almost always occur at surfaces. The finite element model shall be designed so that, in critical regions, stresses are calculated on the surface as well as near it.

ANNEX B

(Normative)

Design for Static Loading

The design of a riser component for static loading requires that it support the preload and the design load while keeping the maximum cross-sectional stresses within allowable limits specified in this section. Load peak stresses are not considered for static loading, but are of primary concern for evaluating fatigue life as discussed in 5.2.3.

B.1 Stresses to Consider

The following paragraphs define the stress types and stress categories that are pertinent to riser components per API RP 2RD. A thorough understanding of these stresses is necessary to properly design riser components.

The three principal stresses should be calculated at all critical locations in the riser. At locations with axisymmetric geometry such as plain pipe, the principal stresses will usually be in the axial, hoop and radial directions. For non-axisymmetric geometry, the directions may be different. The principal stress components should be classified as one of the following:

<table>
<tr><td rowspan="3">Primary</td><td colspan="2">Any normal or shear stress that is necessary to have static equilibrium of the imposed forces and moments. A primary stress is not self-limiting. Thus, if a primary stress substantially exceeds the yield strength, either failure or gross structural yielding will occur.</td></tr>
<tr><td>Membrane</td><td>σ_p is the average value across the thickness of a solid section excluding the effects of discontinuities and stress concentrations. For example, the general primary membrane stress in a pipe loaded in pure tension is the tension divided by the cross-sectional area. σ_p may include global bending as in the case of a simple pipe loaded by a bending moment.</td></tr>
<tr><td>Bending</td><td>σ_b is the portion of primary stress proportional to the distance from the centroid of a local cross section, excluding the effects of discontinuities and stress concentrations.</td></tr>
<tr><td>Secondary</td><td colspan="2">σ_q is any normal or shear stress that develops as a result of material restraint. This type of stress is self-limiting which means that local yielding can relieve the conditions that cause the stress, and a single application of load will not cause failure.</td></tr>
</table>

Notice that a principal stress component can be separated into more than one stress category. For example, consider a bolt in a bolted flange. The stress in the bolt is equal to the sum of a primary membrane stress caused by the loads applied to the flange and a secondary stress caused by the bolt preload. The preload stresses are considered to be secondary stresses because they are self-limiting. However, once the applied load reaches a magnitude that relieves all of the connector preload (i.e., the flange face separates), the stresses in the bolts are considered to be primary stresses only.

It should be noted that functional requirements should also be considered when evaluating stress levels in the riser components. In the bolted flange example given above, allowing the combined primary plus secondary stresses in the bolts to exceed yield would result in loss of preload and possible leakage when the load is relieved.

Some of these stresses, such as general primary membrane stresses, can be accurately calculated using hand calculations, but most cannot due to the complex geometry and loading of riser couplings. For this reason it is required that the stresses in each component be calculated with a finite element analysis method as described in 5.4.

The load cases for which a component must be analyzed depend on whether or not the component is preloaded and if the preload stresses are considered as primary or secondary.

If a component is not preloaded, only one load case must be analyzed: design axial tension (coupling design load) or combined maximum operational conditions.

If a component is preloaded, the component must be analyzed for three load cases:

a. Design preload,
b. Design preload plus design axial tension, and
c. Design axial tension only.

Classifying stresses induced by preload as primary or secondary depends on component function and not on overstressing the component. If preload stresses are classified as secondary, they are allowed to be twice the yield strength. This can result in large permanent deformations, but not in structural failure.

Some component designs can tolerate large permanent deformations without jeopardizing their ability to safely function, and other component designs will not function after large permanent deformations. Sealing is an example of a functional requirement that often is affected by large permanent deformation.

If preload stresses are considered as secondary, the designer must demonstrate that the permanent deformations induced by preload will not cause the component to lose any necessary functional capability.

Normally, riser components exhibit a linear or bilinear relationship between load and stress. For these components, stresses at loads other than the analysis loads can be calculated using the rules of linear interpolation or extrapolation. For those components with a non-linear relationship between load and stress, linear interpolations or extrapolations cannot be used. These components must be analyzed for several values of load, and plots of load versus stress must be developed. The component's rated load must be determined from these curves.

B.2 Allowable Stresses

For all components except couplings and coupling bolts (see API Spec 16R or ISO 13625), and auxiliary, choke and kill lines (see Section 9 of this document), the von Mises equivalent stresses shall be less than the allowable stresses defined by the right hand side of the following inequalities.

$$(\sigma_p)_e < 0.667\sigma_y$$

$$(\sigma_p + \sigma_b)_e < \sigma_y$$

$$(\sigma_p + \sigma_b + \sigma_q)_r < 2.0\sigma_y \text{ or } < 1.0\sigma_u \text{ (see Note)}$$

where

σ_y = material minimum yield strength, defined for steel as the tensile stress required to produce a total elongation of 0.5% of the test specimen gage length,

σ_u = material minimum tensile strength,

$(\sigma_p + \sigma_b + \sigma_{q)r}$ = range of stress intensity of secondary membrane plus bending stress (excluding local stress concentrations).

Note: *ASME Boiler and Pressure Vessel Code*, Section VIII, Division II, Appendix 4 explains this criterion.

For bolts in the primary load path, the manufacturer must establish the allowable stress levels for membrane stresses and bending stresses in the bolts.

Bolt stresses, pure shear stresses, and bearing stresses are compared directly with their respective allowables. No manipulation of the finite element data is required.

The other stresses must be linearized, separated into membrane and bending components, categorized, and converted to von Mises effective stresses before they can be compared to the allowable stresses. The following paragraphs describe this procedure in detail.

In general there are six components of stress across any section: three normal components and three shear stress components.

Each of the significant stress components must be linearized and separated into membrane and bending components.

This is graphically shown in Figure B-1. This figure shows the axial stress across the wall of a riser coupling at a section where the wall thickness changes. The load on the components is axial tension. The solid line shows the stress distribution reported by the finite element model, and the dashed line represents the linearized stress distribution. The membrane stress component is the average value of the linearized stress distribution and the bending stress component is the difference between the largest and the average values of the linearized stress distribution.

Next the membrane and bending stress components must be categorized into one of the following stress categories: general primary membrane stress, local membrane stress, primary bending stress, or secondary stress.

For example, in Figure B-1 the membrane stress is the axial stress induced by the axial force. Since this stress is necessary to equilibrate the axial force, it is general primary membrane stress. The bending stress is induced by the local bending moment caused by the discontinuity in the wall thickness. This stress is necessary only to ensure the coupling has continuity of deformations at the discontinuity; thus, it is secondary stress.

This procedure is repeated for all of the six stress components that are significant: then the von Mises effective stress is calculated using the following equation:

$$\sigma_e = \frac{1}{\sqrt{2}}[(S_x - S_y)^2 + (S_y - S_z)^2 + (S_z - S_x)^2 \; + \; 6(T_{xy}^2 + T_{yz}^2 + T_{xz}^2)]^{\frac{1}{2}}$$

where

σ_e = von Mises effective stress,

S_x, S_y, S_z = three normal stress components,

T_{xy}, T_{yz}, T_{zx} = three shear stress components.

Note: All stresses are not included when calculating every von Mises effective stress. For example, when the general primary membrane stress is being checked only general primary membrane stresses are included in the equation; secondary stresses, bending stress and local primary stresses are not included.

The maximum shear stress theory of failure can be used in lieu of von Mises theory of failure. Using the maximum shear stress theory of failure requires that twice the maximum shear stress, defined as the stress intensity, be compared with the allowable stresses instead of the von Mises effective stress. This approach is equal to or slightly conservative when compared to the von Mises approach, but is much easier to use.

B.3 Bolting and Threaded Connections

For coupling bolting, see API Spec 16R or ISO 13625. Unless otherwise specified, all other bolting and threaded connections for primary load path and/or pressure-containing components shall be designed in accordance with API Spec 6A.

B.4 Bibliography

Langer, B. F., "Criteria of the ASME Boiler and Pressure Vessel Code for Design by Analysis in Sections III and VIII, Division 2," *Pressure Vessels and Piping: Design and Analysis*, Volume One, American Society of Mechanical Engineers, New York.

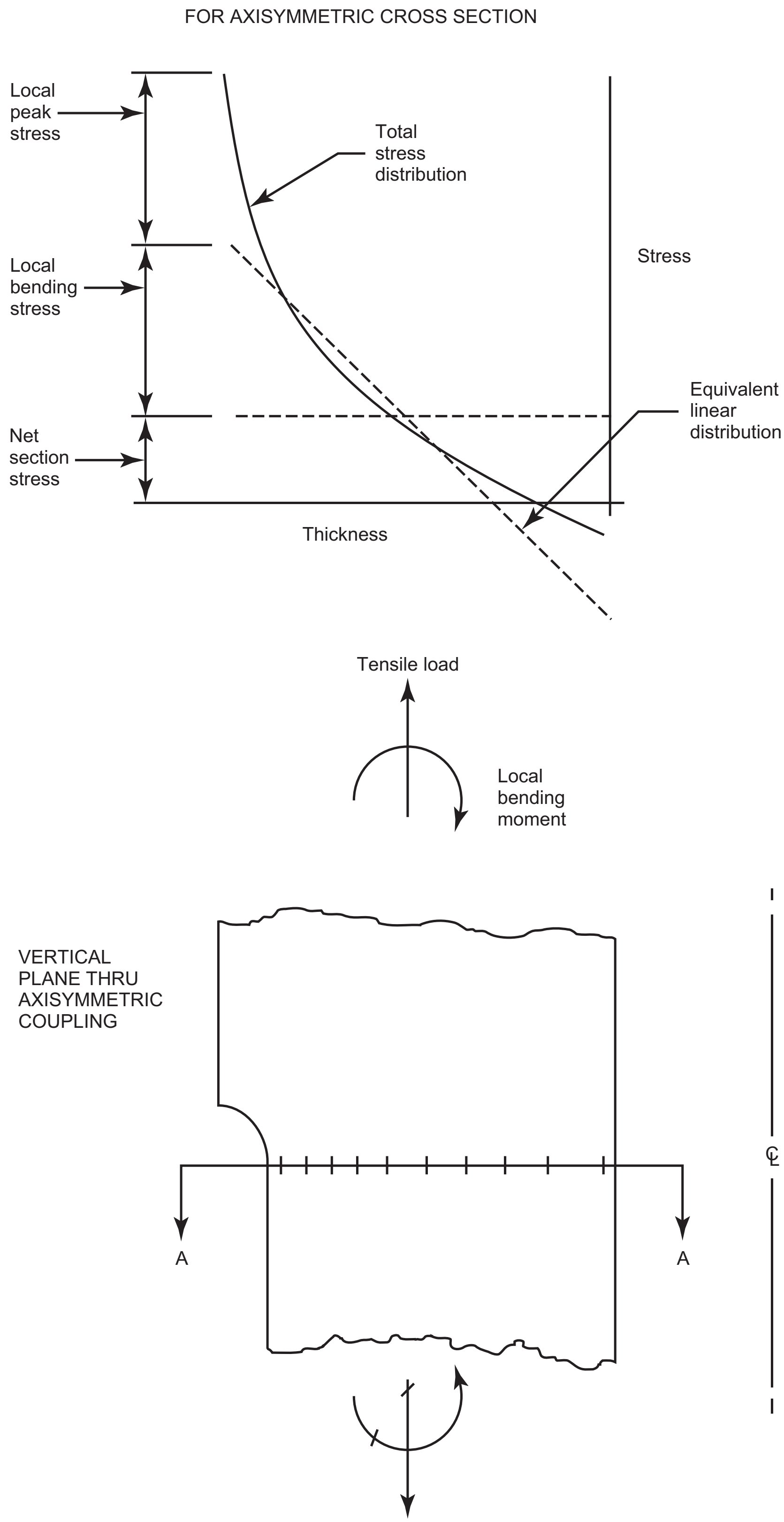

Figure B-1—Stress Distribution Across Section A-A

ANNEX C
(Informative)

API Monogram

C.1 Introduction

The API Monogram Program allows an API Licensee to apply the API Monogram to products. Products stamped with the API Monogram provide observable evidence and a representation by the Licensee that, on the date indicated, they were produced in accordance with a verified quality management system and in accordance with an API product specification. The API Monogram Program delivers significant value to the international oil and gas industry by linking the verification of an organization's quality management system with the demonstrated ability to meet specific product specification requirements.

When used in conjunction with the requirements of the API License Agreement, API Spec Q1, including Annex A, defines the requirements for those organizations who wish to voluntarily obtain an API License to provide API monogrammed products in accordance with an API product specification.

API Monogram Program Licenses are issued only after an on-site audit has verified that the Licensee conforms to both the requirements described in API Spec Q1 in total, and the requirements of an API product specification.

For information on becoming an API Monogram Licensee, please contact API, Quality Programs, 1220 L Street, N. W., Washington, DC 20005 or call 202-682-8000 or by email at quality@api.org.

C.2 API Monogram Marking Requirements

These marking requirements apply only to those API Licensees wishing to mark their products with the API Monogram.

In addition to the marking requirements found in this specification, the API Monogram shall be stamped on the product in place of "API Spec 16F" (see Table C-1).

Application of the API Monogram shall be per the manufacturer's API Monogram Marking Procedure as required by API Spec Q1.

Table C-1—Marking Requirements

Marking	Riser Tensioner Equipment	Flex/Ball Joints	Telescopic Joint (Slip Joint) and Tensioner Ring	Riser Joints[a]	Buoyancy Equipment[b] (Syntactic Foam Modules)	Riser Running Equipment[c] (Riser Spider)	Lower Riser Adapter[d]
Name of manufacturer	Nameplate or other means	Nameplate or other means	Nameplate or other means		Body		
Date of manufacture	Nameplate or other means	Nameplate or other means	Nameplate or other means				
Unique serial number	Nameplate or other means	Nameplate or other means	Nameplate or other means	Body	Body	Body	Body
API load rating and stroke	Nameplate or other means		Nameplate or other means				
Operating temperature range	Nameplate or other means						
Tensile load rating		Nameplate or other means					
Compressive load rating		Nameplate or other means					
Rated working pressure		Nameplate or other means					
Service depth rating					Body		
API Spec 16F or API Monogram	Nameplate or other means	Nameplate or other means	Nameplate or other means	Body	Body	Body	Body

[a]The riser joint shall be permanently marked using a low stress method. Marking shall include a serial number that corresponds to a data sheet for the joint and API Spec 16F (or API Monogram). The data sheet shall include as a minimum the manufacturer's name and part number, the maximum load ratings, and the as-built assembled weight excluding buoyancy and protectors.
[b]Syntactic foam buoyancy modules shall be pigmented or painted a highly visible color with required markings printed indelibly on its surface. Serial numbers shall be located in a minimum of three places on each module: the outer surface, the inner surface, and the end of the module. Each module shall be identified with a color code for each depth rating as agreed by manufacturer and purchaser.
[c]The riser spider shall be marked using permanent low-stress, metal-impression stamping specifying a serial number that corresponds to a data sheet for the spider. The data sheet shall include as a minimum the manufacturer's name and part number, the maximum load rating, and indication of conformance to API Spec 16F (or API Monogram).
[d]Marking shall be in accordance with manufacturer's written specifications.

ANNEX D

Anti-recoil Systems (Informative)

Bibliography

1. “Operating Guidelines for Emergency Disconnect of Deepwater Drilling Risers,” Matthew J. Stahl and Fereidoun Abbassian, OMAE2000/OSU OFT-4040, proceedings of ETCE/OMAE2000 Joint Conference, February 14 – 17, 2000.
2. “Design of a Riser Recoil Control System and Validation through Full-Scale Testing,” M.J. Stahl and C.J. Hock, SPE 62959, 2000 SPE Annual Technical Conference, October 1 – 4, 2000.
3. “Design Installation and Testing of a Deepwater Riser Emergency Disconnect Anti-Recoil System,” C.J. Hock and R.D. Young, IADC/SPE 23858, 1992 IADC/SPE Drilling Conference, February 18 – 21, 1992.
4. “Comparison of Analysis and Full-Scale Testing of Anti-Recoil System for Emergency Disconnect of Deepwater Riser,” C.J. Hock, Geir Karlsen, and J.W. Albert, OTC 6892, 24th Annual OTC, May 4 – 7, 1992.
5. “Analysis and Design of Anti-Recoil System for Emergency Disconnect of a Deepwater Riser: Case Study,” R.D. Young, C.J. Hock, Geir Karlsen, and J.E. Miller, OTC 6891, 24th Annual OTC, May 4 – 7, 1992.

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