Recommended Practice for Design and Operation of Completion/Workover Riser Systems

API RECOMMENDED PRACTICE 17G
FIRST EDITION, JANUARY 1, 1995

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005

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Exploration and Production Department

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FOREWORD

API Recommended Practice (RP) 17G is under the Jurisdiction of the API Committee on Standardization of Subsea Production Systems. This is the first edition and was approved by letter ballot in June 1994.

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

Recommended Practice for Design and Operation of Completion/Workover Riser Systems

1 Scope

1.1 This recommended practice provides guidelines for the design and operation of subsea completion/workover riser systems run from a floating vessel. It is to serve as a reference for designers and those responsible for the selection of system components. In addition to basic engineering principles, this RP incorporates the accumulated experience of offshore operators, contractors and manufacturers.

1.2 Section 4 describes the primary functions of a completion/workover riser and defines the various types of risers normally used. Each riser component is described in Section 5 with emphasis on design considerations for each component. Section 6 deals with riser analysis and outlines the data requirements and desired analyses results. Section 7 provides a summary of testing and operational considerations. Materials and quality assurance are discussed in Section 8.

1.3 Risers fabricated from special materials such as titanium or fiberglass/composite materials and flexible risers are beyond the scope of this Recommended Practice.

1.4 Workover Control Systems are beyond the scope of this Recommended Practice.

2 References

The following standards should be considered in part or in whole in using this recommended practice. It is recognized that additional standards, specifications, guidance notes and recommended practices have been developed by other bodies. Therefore, this listing is representative and should not be considered as either all inclusive or exclusive of other standards relating to topics covered in this Recommended Practice.

American Institute for Steel Construction

ASD	Specification for Structural Steel Buildings Allowable Stress Design

American Petroleum Institute

RP 2R	*Design, Rating and Testing of Marine Drilling Riser Couplings*
SPEC 5CT	*Specification for Casing and Tubing*
BUL 5C2	*Performance Properties of Casing, Tubing, and Drill Pipe*
BUL 5C3	*Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties*
SPEC 5L	*Specification for Line Pipe*
SPEC 5LC	*Specification for CRA Line Pipe*
RP 5LW	*Transportation of Line Pipe on Barges and Marine Vessels*
SPEC 6A	*Specification for Wellhead and Christmas Tree Equipment*
BUL 6AF	*Capabilities of API Flanges Under Combinations of Load*
RP 7G	*Drill Stem Design and Operating Limits*
SPEC 8C	*Specification for Drilling and Production Hoisting Equipment (PSL1 and PSL2)*
SPEC 16A	*Specification for Drill Through Equipment*
BUL 16J	*Comparison of Marine Drilling Riser Analyses*
RP 16Q	*Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*
RP 17A	*Design and Operation of Subsea Production Systems*
RP 17C	*TFL (Through Flowline) Systems*
SPEC 17D	*Specification for Subsea Wellhead and Christmas Tree Equipment*
RP 57	*Offshore Well Completion, Servicing, Workover and Plug and Abandonment Operations*
STD 1104	*Welding of Pipelines and Related Facilities*

American Society of Mechanical Engineers/
American National Standards Institute

B 31.3	*Chemical Plant and Petroleum Refinery Piping*
Section IX	*Welding and Brazing Qualifications*

National Association of Corrosion Engineers

MR 01-75	*Sulfide Stress Cracking Resistant Metallic Material for Oilfield Equipment*
RP 01-75	*Control of Internal Corrosion in Steel Pipelines and Piping Systems*
RP 06-75	*Control of Corrosion on Offshore Steel Pipelines*
RP 01-76	*Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production*

Society of Automotive Engineers

100 R	*Hydraulic Hose and Hose Assemblies*
J 343	*Tests and Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies*
J 517	*Hydraulic Hose*

American Society for Testing Materials

ASTM A213	*Seamless Ferritic and Austenitic Alloy Steel Boiler, Superheater, and Heat Exchanger Tubes*
ASTM A269	*Seamless and Welded Austenitic Stainless Steel Tubing for General Service*

National Aerospace Standard

NAS 1638	*Cleanliness Requirements for Parts Used In Hydraulic Systems*

American Welding Society
AWS D1.1 *Structural Welding Code*

3 Abbreviations and Definitions

For the purposes of this recommended practice, the following abbreviations and definitions apply.

3.1 ABBREVIATIONS

AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing Materials
BUL	Bulletin
C/WO	Completion/Workover
EDP	Emergency Disconnect Package
FAT	Factory Acceptance Test
LWRP	Lower Workover Riser Package
NACE	National Association of Corrosion Engineers
NAS	National Aerospace Standard
NDT	Non-Destructive Testing
PGB	Permanent Guidebase
RAO	Response Amplitude Operator
RP	Recommended Practice
SAE	Society of Automotive Engineers
SIT	System Integration Test
SCSSV	Surface Controlled Subsurface Safety Valve
SPEC	Specification
TFL	Through Flowline
THRT	Tubing Hanger Running Tool
TRT	Tree Running Tool
WCT-BOP	Wireline Coiled Tubing BOP

3.2 DEFINITIONS

3.2.1 completion/workover riser (C/WO riser): The temporary riser used during completion or workover operations.

3.2.2 drift: To gauge or measure pipe by means of a mandrel passed through it to ensure the passage of tools, pumps, and other well servicing equipment.

3.2.3 emergency disconnect package (EDP): A subsea equipment package interfacing to the completion riser for bore isolation and circulation, and to the LWRP, the production tree, and the tree cap for installation/retrieval purposes.

3.2.4 environmental seal: The outermost pressure-containing seal at a connector interface. This seal normally separates a pressurized medium from the surrounding environment.

3.2.5 factory acceptance test (FAT): A test conducted by the manufacturer to verify that the manufacture of a specific assembly meets all intended functional and operational requirements.

3.2.6 floating vessel: An offshore drilling structure that floats and is not secured to the seafloor except by means of anchors. Semisubmersible drilling rigs and drill ships are floating vessels.

3.2.7 lifting device: A tool dedicated for lifting.

3.2.8 lower workover riser package (LWRP): A subsea equipment package containing valving and BOP rams, which are sometimes required for safe well completion and workover operations through the subsea tree.

3.2.9 lubricator adapter: The means of attaching a wireline lubricator or coiled tubing unit to the top of the surface tree.

3.2.10 operating envelope: That limited range of parameters in which operations will result in safe and acceptable equipment performance.

3.2.11 pressure containing parts: Those parts whose failure to function as intended would result in a release of retained fluid to the atmosphere. Examples are bodies, bonnets, and stems.

3.2.12 pressure controlling parts: Those parts intended to control or regulate the movement of pressurized fluids, such as valve bore sealing mechanisms and hangers.

3.2.13 reentry spool: The uppermost part of a subsea tree to which the C/WO riser is attached to gain vertical well access. Also, the uppermost part of a LWRP to which an EDP connector is attached to provide a single disconnect point.

3.2.14 splash zone: The area where waves strike the support members of an offshore structure.

3.2.15 stab subs: Male half of sealing mechanism between component interfaces. Stab subs may use elastomeric or metal seals.

3.2.16 subsea tree (tree): An assembly of valves and fittings attached to the uppermost connection of the subsea wellhead, used to control well production.

3.2.17 subsea wellhead: Wellhead assembly used during drilling and completion operations that has provisions to lock and seal to a subsea BOP stack and to the subsea tree.

3.2.18 tensioning ring: Attachment point on the C/WO riser for the rig tensioning lines.

3.2.19 tree running tool (TRT): Device used to run and land the tree on the subsea wellhead.

3.2.20 tubing: Pipe used in wells to conduct fluid from the well's producing formation into the subsea tree.

3.2.21 tubing hanger: A mechanism used to support the downhole completion tubing string. It is also typically used to seal and contain the completion annulus from the environment.

3.2.22 tubing hanger running tool (THRT): Device used to run, land and lock the tubing hanger inside the wellhead, tubing spool, or subsea tree.

4 Description of Systems

4.1 GENERAL

The completion/workover (C/WO) riser is, in effect, an extension of the production and/or annulus bore(s) of a subsea well to a surface vessel. C/WO risers consist of one or more pressure containing conduits which provide full-bore, unrestricted access into the production and/or annulus bores of a subsea tree or tubing hanger, or into the production tubing. The riser may also include the necessary hydraulic control lines for operation of the running tools or subsea tree. See Figure 1 for C/WO riser general system arrangements.

The C/WO riser system typically includes the following major components:

- BOP Adapter Joint
- Lower Workover Riser Package
- Emergency Disconnect Package
- Stress Joint
- Riser Joints
- Tension Joint
- Slick Joint
- Surface Tree Adapter Joint
- Surface Tree
- Spider (or False Rotary Table)
- Handling and Test Tools
- Wireline/Coiled Tubing BOP
- Miscellaneous Ancillary Components

4.2 FUNCTION OF C/WO RISERS

C/WO risers are used during well completion operations to install and retrieve the tubing hanger and subsea tree. During workover operations, C/WO risers are used for wireline or coiled tubing access to the production and annulus bores.

4.3 TYPES OF C/WO RISERS

There are two basic types of C/WO risers: non-integral and integral.

4.3.1 Non-Integral Risers

The non-integral riser is made up of independent production and annulus strings or bores. They are normally run with joints slightly staggered to allow conventional tubing or drill pipe handling tools to be used for make-up of joints. Clamping the tubular members as they are assembled provides ease of handling and some structural stiffening. Non-integral C/WO risers can be grouped into two types—drill pipe risers and tubing risers.

4.3.1.1 Drill Pipe Risers

Drill pipe risers consist of a single string of drill pipe with an attached hydraulic control umbilical. Drill pipe risers are somewhat limited in application and capability due to the limitation of a single access bore. Drill pipe risers are typically used in applications where minimal access into the production bore or annulus is required.

4.3.1.2 Tubing Risers

Tubing risers consist of one or more individual strings of production tubing and a hydraulic control umbilical. If multiple tubing strings are used, they can be left either independent of each other, or secured together using some type of clamping device. The hydraulic control umbilical is normally clamped or strapped to one of the tubing strings as it is run.

4.3.2 Integral Risers

Integral style C/WO risers are risers in which the pressure containing conduits are mounted into a common assembly or joint. Integral risers are typically classified as either jacketed or non-jacketed. The integral riser joint allows the production and annulus lines to be made up simultaneously.

4.3.2.1 Jacketed Risers

Jacketed style C/WO risers consist of one or more pressure containing conduits housed inside of an outer structural housing. Jacketed C/WO risers may also contain hydraulic control lines inside of the structural housing. These types of risers are typically used in applications where high tensile or bending loads are anticipated.

4.3.2.2 Non-Jacketed Risers

Non-jacketed risers consist of multiple pressure containing conduits (pipe or tubing) which are assembled together by mechanical clamps or other means, and are secured by a common connection device. A separate hydraulic control umbilical is normally run with and strapped to the riser.

Non-jacketed risers are typically used in applications where frequency of use is high, but where the load conditions are not as severe as for jacketed type risers.

4.4 PRESSURE RATING OF C/WO RISERS

The pressure rating of the C/WO riser system should equal or exceed the maximum expected working pressure at the wellhead during completion or workover activities (including injection, stimulation or kill operations). Higher pressure

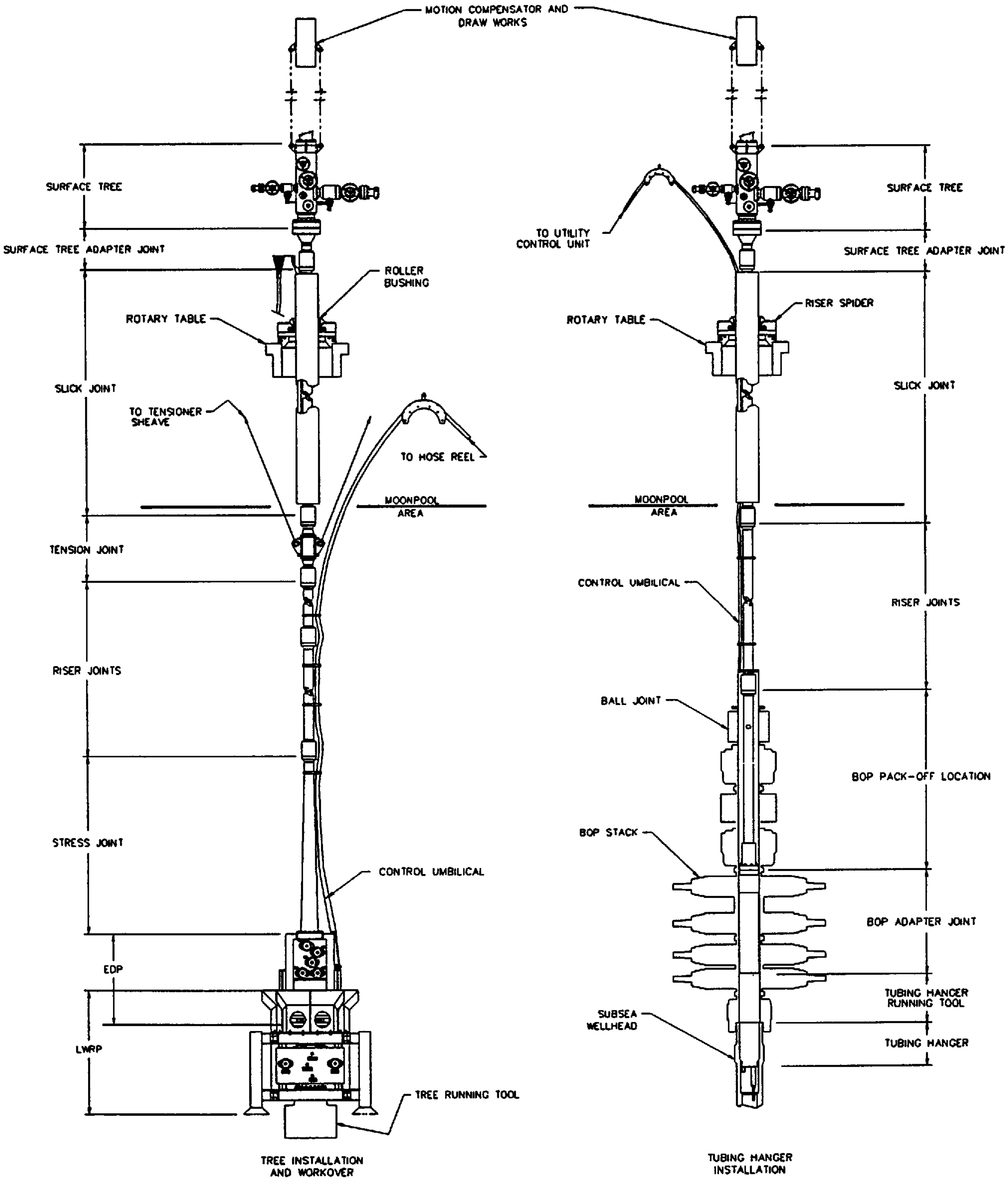

Figure 1—Completion/Workover Riser General Arrangement

ratings may be required where leakage from higher pressure sources (e.g., SCSSV control lines) may be contained. The load and pressure capacity of the lowest rated end connection and/or tubing will define the pressure rating of the riser system.

5 Description of Components

5.1 This section provides guidelines for the design of the individual components that comprise the C/WO riser system. Each component is defined in terms of its function and system interfaces and a typical design configuration is described. Any special design considerations are discussed and, where applicable, acceptance criteria are presented.

5.2 BOP ADAPTER JOINT

5.2.1 Definition and Function

The BOP adapter joint (sometimes referred to as BOP spanner joint) is a specialized C/WO riser joint used when the C/WO riser is deployed inside a drilling riser and subsea BOP to install and retrieve a subsea tubing hanger. It provides the same structural and functional requirements (e.g., axial load support, fluid and pressure transmission) as the standard C/WO riser joint. In addition, it may provide the following functions:

- Interface for the control lines and riser bores.
- Crossover from the riser to the tubing hanger running tool (THRT).
- Tubing hanger orientation.
- Annular BOP packoff area at the subsea BOP for testing, well control, and possibly tool operation.

5.2.2 Interfaces

The lower end of the BOP adapter joint is designed to connect to the top of the THRT. The upper end of the joint is designed to connect to a standard C/WO riser joint. The geometry at the upper and lower connections may differ (e.g., the centerline spacing of the C/WO riser and THRT/tubing hanger bores). The BOP adapter joint provides a crossover to mate these features in the complete riser string.

Control line interfaces are provided at both the upper and lower ends of the BOP adapter joint. The upper end connects to the control lines of the C/WO riser joint or an umbilical and at the lower end connects to the control lines of the THRT. This configuration allows the subsea BOP rams and the annular BOP to close against the BOP adapter joint when the tubing hanger is landed in the wellhead.

5.2.3 Typical Designs

The BOP adapter joint design may be "orienting" or "non-orienting" as dictated by the design of the tubing hanger and its THRT.

5.2.3.1 In an orienting BOP adapter joint, there are typically two basic designs, a key/slot arrangement or a pin/helix arrangement. In the first design, a retractable key engages a fixed slot when orientation is correct. The fixed slot may be in the wellhead, the drilling BOP or a removable bushing which keys off the wellhead or drilling BOP. Typically, the key is on the THRT or tubing hanger, rather than on the BOP adapter joint. Designs may use "active" orientation, requiring the tubing and handling strings to be rotated by personnel on the drill floor to engage the mechanism. Alternatively, the design may use "passive" orientation which is self aligning by means of a helical guide leading the key directly to the slot.

5.2.3.2 In the second design, a fixed, retractable pin in the BOP stack engages a helical slot or groove, either on the BOP adapter joint or on the THRT. Downward or upward motion of the hanger and THRT are converted to rotation at the pin/helix, and no torque need be applied at the rig. This design uses "passive" orientation, as it does not require application of torque to the handling string. This is especially helpful in deep water, where torque transmission through a long handling string could be a problem.

5.2.4 Design Considerations

5.2.4.1 Load and Pressure Capacity

The pressure capacity of the jacket must accommodate the pressure applied internally and externally for testing and well control. The internal test pressure for pipe which is used as a pressure containing external jacket of a riser assembly should be the lower value of either 80% collapse pressure or 1.5 times working pressure of the tubing contained inside.

The collapse pressure of the jacket should be evaluated using recognized calculation techniques (such as those in API Bulletin 5C3); the working pressure should not exceed 60% of the collapse pressure, and the test pressure should not exceed 80% (4/3 of working pressure). Collapse pressure testing is not suggested.

The load capacity should be designed to accommodate:

- Loads required in running the tubing hanger and completion string.
- Overpull required to retrieve the tubing hanger.
- Overpull required to verify tubing hanger lockdown.

5.2.4.2 Handling

Consideration should be given to attachments for handling the BOP adapter joint in the shop and on the rig. Refer to API Specification 17D Section 303.7 for guidance on lifting devices.

5.2.4.3 Orientation

If required, orientation of the tubing hanger during installation is a critical operation. Design of the orientation mechanism should address the following:

- Torque transmission through the riser string
- Accumulated rotational misalignment due to tolerance stack-up
- Positive indication of tubing hanger alignments
- Variations in BOP stack configurations

5.2.4.4 Packoff

The BOP adapter joint provides a relatively smooth surface to allow pressure sealing (packoff) in the BOP stack. The smooth surface allows closing of the casing rams, or an annular BOP around the BOP adapter joint, thus allowing for pressure testing the tubing hanger from the top, or in some cases for operation of the THRT. It also provides for well control in case of emergencies.

5.2.4.5 Jacket Diameter

The BOP adapter joint design must contain all of the tubing bores and control lines in a jacket of a common casing diameter. The jacket may also be large enough to accommodate any offsets in the center spacing of the internal tubing bores.

Pressure end loads will be generated on the tubing hanger, the THRT, and on the BOP adapter joint based on the seal diameter areas of each. A large jacket diameter may lead to large upward loads, possibly beyond the offsetting effect of tubing weight or hanger lockdown strength.

5.2.4.6 Length

The BOP adapter joint jacket should be long enough to extend to the rams or annular BOP used for well control. The joint should also be long enough so that any bore center spacing changes can be gradual enough to accommodate passage of wireline tools. Should the length of the joint be such that it will extend through the ball or flex joint, then its diameter should be evaluated with respect to the allowable drilling riser angle and/or offset.

5.2.4.7 Tubing Bores

The inside surfaces of the tubing bores should be smooth and free of sharp shoulders, and be able to pass appropriate drift tools.

5.2.4.8 Pressure Seals

At least two seal barrier elements should be used to contain produced and injected fluids. The seals should be easily accessible and field replaceable.

5.2.4.9 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.2.5 Acceptance Criteria

The BOP Adapter Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.3 LOWER WORKOVER RISER PACKAGE (LWRP)

5.3.1 Definition and Function

The lower workover riser package (LWRP) is the lowermost equipment package in the riser string when configured for workover. It provides a separately retrievable extension of the subsea tree for routine well control during workovers. It may consist of a wireline and coiled tubing BOP (WCT-BOP) or a shearing valve package. Reference Figure 2, (b) and (c).

5.3.2 Interfaces

The LWRP includes a connector at the bottom to mate with the tree reentry spool, and a reentry spool at the top to interface with an optional emergency disconnect package (EDP). Both interfaces include control line connections to interface with the WCT-BOP and the tree.

Other interfaces may include guidance structure for reentry and/or diver or remote operated vehicle (ROV) control function interfaces.

5.3.3 Typical Designs

The LWRP should be configured with its reentry spool connector profile identical to that on the tree so that the tree and riser may be run without the LWRP.

The LWRP typically includes a crossover loop between the riser tubing bores to allow purging the lines prior to subsea disconnection. This crossover loop includes an isolation valve. This task may also be accomplished using the crossover loop/valve in the subsea tree.

The bottom of the LWRP includes a connector, commonly referred to as the Tree Running Tool (TRT), to mate with the tree's reentry spool.

The upper end of the TRT mates with the rest of the LWRP package or directly to the lower end of the stress joint, as illustrated in Figure 2. A flange, hub or proprietary riser connector may be used.

5.3.4 Design Considerations

5.3.4.1 Connector/Spool/Seal Interface

Design of connectors such as the LWRP connector, flanges and clamps, the reentry spool, and their seal inter-

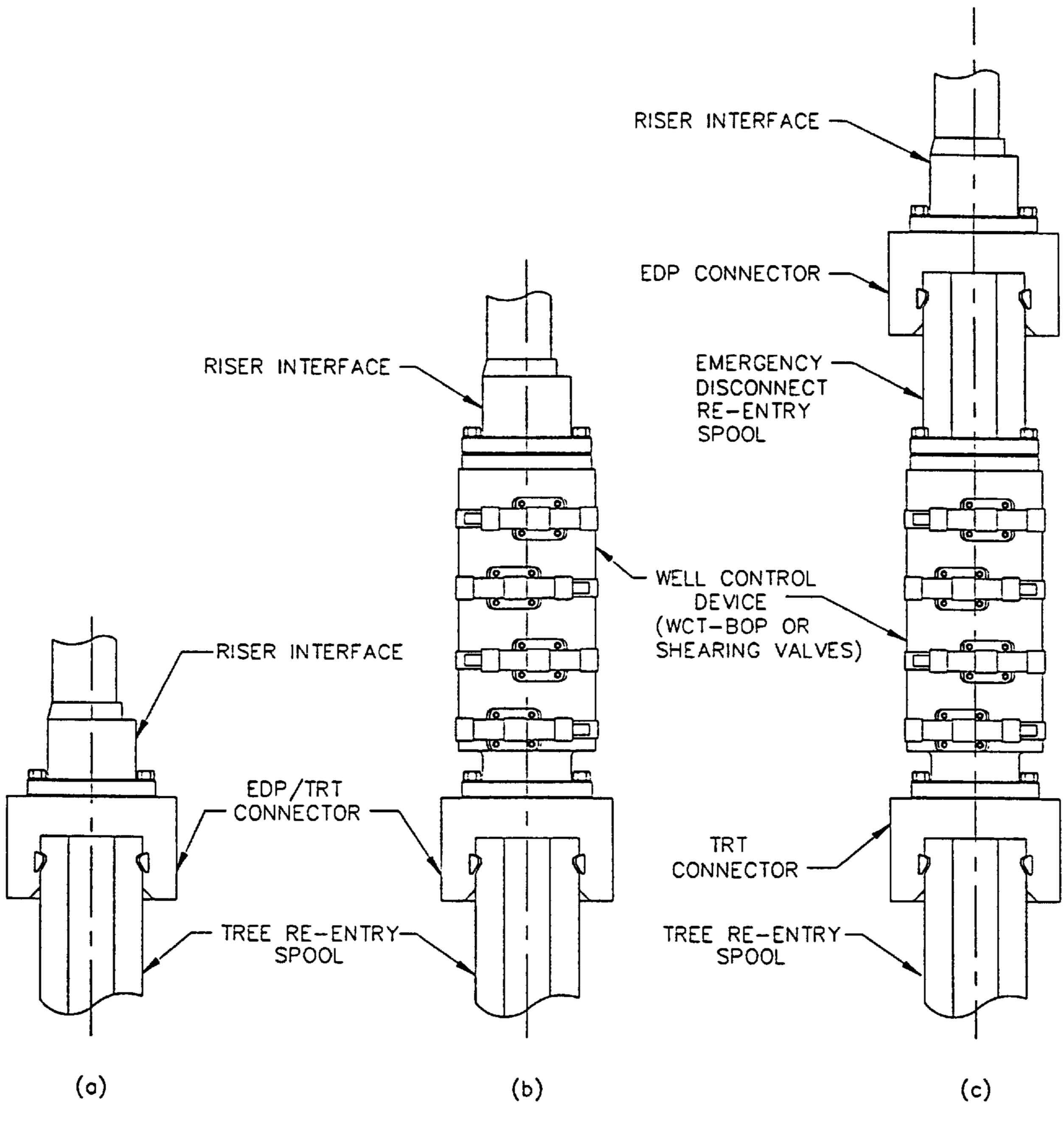

Figure 2—C/WO Riser/Tree Interface Configuration

faces should address:

- Lateral loads
- Bending moment
- Fatigue
- Environmental loads

5.3.4.2 Tree Running Tool (TRT)

The TRT may be remotely operable, provide for high-angle release and include a secondary unlock function.

5.3.4.3 Tubing Bores

The inside surfaces of the tubing bores should be smooth and free of sharp shoulders, and be able to pass appropriate drift tools.

5.3.4.4 Pressure Seals

At least two seal barrier elements should be used to contain produced and injected fluids. The seals should be easily accessible and field replaceable.

5.3.4.5 Environmental Seal

In the event an environmental seal is used, consideration to pressurizing control lines by possible communication with the production or annulus bore should be given. Effects of pressure end loads acting over the area enclosed by the environmental seal should also be considered in the design since one or more of the interior seals could leak.

5.3.4.6 Guidance

Guidance design should address the following:

- Seal make-up tolerance
- Angle of reentry and release
- Damage to control interfaces and seal surfaces
- Ability to access existing guidelines, posts or reentry funnels, wherever appropriate
- Orientation

5.3.4.7 Crossover Loop

The LWRP may include a provision to purge the riser bores with sea water prior to disconnection from the tree. Typically, this provision consists of crossover piping between the tubing bores, with a normally closed isolation valve.

5.3.4.8 Stackup Height

Consideration should be given to the possibility of overhead clearance problems when stacking or handling the LWRP and subsea tree together in the cellar deck. Stackup height will affect riser design relative to moment loading at the tree and LWRP interfaces.

5.3.4.9 Handling

Consideration should be given to attachments for handling the LWRP in the shop and on the rig. Refer to API Specification 17D, Section 303.7 for guidance on lifting device.

5.3.4.10 Closure Device (WCT-BOP or shearing valves)

Refer to Section 5.13 for design considerations.

5.3.4.11 Corrosion

A corrosion allowance and/or the use of corrosion resistant materials should be considered given the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.3.5 Acceptance Criteria

The Lower Workover Riser Package (LWRP) should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.4 EMERGENCY DISCONNECT PACKAGE (EDP)

5.4.1 Definition and Function

The emergency disconnect package (EDP) is the second lowermost equipment package in the riser string, normally located just above the LWRP when configured for workover. Its function is to provide a quick release point just above the WCT-BOP in the event of a rig drive-off or other emergency that could move the rig from over the well location.

Alternatively, the emergency disconnect point may be at the tree reentry spool interface (see Figure 2, (a)). In this case, the LWRP lower connector would serve as the EDP and the tree valves would be used for well shut-in.

5.4.2 Interfaces

The EDP includes a lower connector to mate with the LWRP reentry spool. The upper end has a connection to mate with the lower end of the stress joint—this connection may be studded, flanged, clamped, or proprietary. The EDP includes control line connections at its lower connector to interface with the LWRP (or, optionally, with the tree).

5.4.3 Typical Designs

The EDP includes a hydraulically actuated connector such as a wellhead-type connector to mate with the LWRP or tree reentry spool. A manual, diver or ROV operated connector is not recommended. Typical designs include a guidance means for reentry onto the LWRP reentry spool.

The upper end connection of the EDP mates with the lower end of the stress joint. A flange, hub or a proprietary riser connector may be used. The upper end connection may also provide a transition of tubing bore centerline spacing, and possibly of bore size.

5.4.4 Design Considerations

5.4.4.1 Connector/Spool/Seal Interface

Design of connectors such as the lower LWRP connector, flanges and clamps, the reentry spool, and their seal interfaces should address:

- Lateral loads
- Bending moment
- Fatigue
- Environmental loads

5.4.4.2 Connector

It is beneficial, but not essential, for the connector to be remotely operable, to provide for high-angle release, and to include a secondary unlock function.

5.4.4.3 Tubing Bores

The inside surfaces of the tubing bores should be smooth and free of sharp shoulders, and be able to pass appropriate drift tools.

5.4.4.4 Pressure Seals

At least two seal barrier elements should be used to contain produced and injected fluids. The seals should be easily accessible and field replaceable.

5.4.4.5 Environmental Seal

In the event an environmental seal is used, consideration should be given to pressurizing control lines by possible communication with the production or annulus bore. Effects of pressure end loads acting over the area enclosed by the environmental seal should also be considered in the design since one or more of the interior seals could leak.

5.4.4.6 Guidance

Guidance design should address the following:

- Seal make-up tolerance
- Angle of reentry and release
- Damage to control interfaces and seal surfaces
- Ability to access existing guidelines, posts or reentry funnels wherever appropriate

5.4.4.7 Handling

Consideration should be given to attachments for handling this item in the workshop and on the rig. Refer to API Specification 17D, Section 303.7 for guidance on lifting devices.

5.4.4.8 Corrosion

A corrosion allowance and/or the use of corrosion resistant materials should be considered given the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.4.5 Acceptance Criteria

The Emergency Disconnect Package (EDP) should be tested and documented in accordance with Section 7.2 and Section 8. In addition, the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.5 STRESS JOINT

5.5.1 Definition and Function

The stress joint is a specialized riser joint. It is the lowermost riser joint in the riser string when configured for workover. It fulfills the same structural and functional requirements (e.g., axial load support, fluid and pressure transmission) as the standard riser joint. In addition, it fulfills two other specific requirements: bending transition, and bore centerline crossover.

The stress joint provides the riser system with a transition zone of a stiffness intermediate to those of the tree and the riser. In this way, high localized stresses are reduced; typically, fatigue life is lengthened; and/or the operating envelope of the system is increased.

5.5.2 Interfaces

The upper end of the stress joint connects to the lowermost riser joint using a riser connector compatible with a standard riser joint.

The lower end of the stress joint may connect to the EDP connector or the LWRP. This connection is typically larger and stronger than the riser connectors, providing stiffness and fatigue resistance. A flange, a hub, or a proprietary riser connector may be used.

Control umbilical interfaces may be required at both ends of the stress joint to provide continuity in the control lines from the surface to the EDP, the LWRP, and the tree.

5.5.3 Typical Designs

The stress joint provides the stiffness transition. The joint may be heavy walled, or have an extra load carrying jacket, or both. The joint may be tapered over its length and that taper may be smooth or step-wise. The length and wall thickness consideration should be carefully coordinated with the overall riser system analysis and the subsea tree and wellhead system design.

5.5.4 Design Considerations

5.5.4.1 Operations

The end connections should be small enough to pass through the rotary. Ease of field installation to the LWRP in the moon pool should be considered.

5.5.4.2 Tubing Bores

The inside surfaces of the tubing bores should be smooth, free of sharp shoulders and able to pass appropriate drift tools.

5.5.4.3 Pressure Seals

At least two seal barrier elements should be used to contain produced and injected fluids. The seals should be easily accessible and field replaceable.

5.5.4.4 Handling

Consideration should be given to attachments for handling this item in the workshop and on the rig. Refer to API Specification 17D, Section 303.7 for guidance on lifting devices.

5.5.4.5 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.5.5 Acceptance Criteria

The Stress Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.6 RISER JOINT

5.6.1 Definition and Function

The riser joint consists of tubular members and riser connectors. Riser joints are typically provided in 30 ft. to 50 ft. (9,14m to 15,24m) lengths. Shorter joints, "pup joints," may also be provided to ensure proper space-out while running the subsea tree, tubing hanger, or during workover operations. The tubular members act as an extension of the production and/or annulus bore(s) from the subsea tree or tubing hanger to the surface. The basic function is to contain wellbore fluids during completion or workover operations while providing vertical access to the production and annulus bores for wireline or coiled tubing operations.

The riser joints may be connected by either premium thread connectors or with mechanical specialty connectors which provide an easy means of connecting and disconnecting the riser joints. The connector may also provide a shoulder for hanging off the weight of the riser string on the riser spider while running the riser. The connectors may provide lifting points for loading and unloading riser joints on and off the rig. Tension loads due to running the subsea tree or the rig tensioning system are carried through the tubular members and are transferred from joint to joint through the riser connector.

5.6.2 Interfaces

Since the riser joint is the primary tubular member, it may be connected to any number of specialty joints such as: the BOP adapter joint, stress joint, tension joint, slick joint, and surface tree adapter joint.

In the case of a non-jacketed riser, a control umbilical may be used to provide hydraulic power to the tree and tubing hanger functions. A clamp or strap typically is used to attach the umbilical to the riser joint.

In the event a jacketed-type riser is used, integral control lines with stab subs at each connector typically are used to supply hydraulic power to tree and tubing hanger functions. However, a separate control umbilical could be used with this type of riser.

5.6.3 Typical Designs

Integral riser joints have the production, annulus, and in some cases, the control lines all attached structurally to form a unitized joint that is made up to the riser string with a single connector. Typical designs may either be jacketed or non-jacketed.

In the case of non-integral risers, the production and annulus joints, which may be either tubing or drill string, are run independently (normally random lengths) and may be clamped together as the riser is assembled.

See Section 4.3 for additional descriptions of integral and non-integral riser systems.

5.6.4 Design Considerations

5.6.4.1 Structural

- Consideration should be given to bending, tension and torsional loads induced in both the installation mode and the workover mode.
- Consideration should be given to structural loads induced during handling of the riser joint.
- For the non-integral riser, a sufficient number of riser clamps should be used to provide adequate lateral stability of the tubular members.
- Consideration should be given to column stability since multiple joints may be racked in the derrick during installation and retrieval of the riser.
- Shoulders or plates used for supporting the riser joint in

the riser spider while running the riser should be adequately designed for maximum anticipated hang-off loads.

- Riser connectors should be designed to minimize loosening under the dynamic conditions of operation.

5.6.4.2 Fatigue

The riser connector should be analyzed for fatigue based on the analysis recommended in Section 6.

5.6.4.3 Lifting Requirements

Padeyes and other lifting devices should be designed in accordance with API Specification 17D, Section 303.7.

5.6.4.4 Pressure Containment

Internal working pressure and test pressure should be considered. Sealing surfaces in the riser connection should be designed to minimize damage during handling of the riser joints. For stab-type connections, at least two field replaceable seals should be used to contain hydrocarbons, well control, completion and kill fluids.

5.6.4.5 Collapse Pressure

Some riser joints may be subject to net external pressure (e.g., from hydrostatic head). If a joint is to be capable of withstanding external pressure, the collapse pressure of the tube should be evaluated using recognized calculation techniques (such as those in API Bulletin 5C3). The working pressure should not exceed 60% of this collapse pressure, and the test pressure should not exceed 80% (4/3 of working pressure). Collapse pressure testing is not suggested.

5.6.4.6 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.6.4.7 Drift

The inside surface of the tubular members and riser connector should be free of sharp shoulders and be able to pass required drift tools.

5.6.5 Acceptance Criteria

The Riser Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition, the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.7 TENSION JOINT

5.7.1 Definition and Function

The tension joint provides a means for tensioning the C/WO riser with the rig tensioning system during the workover mode. When in use, the tension joint is located below the slick joint.

5.7.2 Interfaces

The top of the tension joint interfaces with the slick joint. It provides continuity of production and annulus bores. The bottom of the tension joint is connected to a standard riser joint.

5.7.3 Typical Designs

The tension joint typically has the same end connections as the riser joint. It should provide an adequate number of padeyes to allow connection to the rig tensioning system.

5.7.4 Design Considerations

Considerations for the connectors and tubular members are the same as for the standard riser joint. Refer to Section 5.6.4.

5.7.4.1 Lifting Requirements

Padeyes used should be adequately sized to support the required tensioning loads. Use of API Specification 8C is recommended for padeye design. A sufficient number of padeyes should be used to provide alignment with rig tensioners. This will minimize torque in the riser system. Alternatively, the padeyes should be allowed to swivel to enhance alignment with the rig tensioners. To facilitate smooth operation, bearing rings are sometimes used.

5.7.4.2 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.7.5 Acceptance Criteria

The Tension Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.8 SLICK JOINT

5.8.1 Definitions and Function

The slick joint is a specialty riser joint that is designed to protect the riser from damage due to rig heave. This may be an integral part of the surface tree adapter joint described in

Section 5.9. When installed, the slick joint provides a protective sleeve that extends through the rotary table. The sleeve may be in two parts such that it is removable.

5.8.2 Interfaces

The top of the slick joint is connected to the surface tree adapter joint. The bottom of the slick joint is connected to the tension joint.

5.8.3 Typical Designs

For the non-integral riser, a standard riser joint fitted with a removable protective outer sleeve may be used. The control umbilical should be enclosed inside the protective sleeve. For the integral riser, the outer jacket serves as the protective sleeve.

5.8.4 Design Considerations

Handling and ease of field installation should be considered. For the non-jacketed riser, adequate space should be provided for the umbilical between the tubular members and the outer sleeve.

5.8.5 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.8.5 Acceptance Criteria

The Slick Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.9 SURFACE TREE ADAPTER JOINT

5.9.1 Definitions and Function

The purpose of the surface tree adapter joint is to provide a crossover from the standard riser joint connector to the connection at the bottom of the surface tree. Its bore configuration should be consistent with the standard riser joint. This specialty joint is usually made up to the surface tree prior to installation.

5.9.2 Interfaces

The top of the surface tree adapter joint connects to the bottom of the surface tree. This connection may be a flange, threaded or other proprietary connection. The bottom of the surface tree adapter joint is connected to the slick joint using a matching riser connection, or may be an integral part of the slick joint. If a control umbilical is used, it may be clamped to the surface tree adapter joint using an umbilical clamp. In the case of jacketed risers, the control line will normally exit the adapter joint through a junction plate.

5.9.3 Typical Designs

The surface tree adapter joint typically has a flange connection at the top and a riser connector at the bottom. Other proprietary connections may be used. If a separate adapter joint is used, its length should be relatively short [5 to 10 ft (1,52m to 3,05m)] to facilitate handling of the surface tree. This component should be made-up at the factory and shipped as an integral unit with the surface tree.

5.9.4 Design Considerations

Considerations for the connector and tubular members in the adapter joint are the same as for the riser joint. The upper end connection should be evaluated for applied bending, tension, torsional, and pressure loads. Typically, stab subs are used to maintain the pressure communication in the production and annulus bores between the adapter joint and the surface tree. The surface tree adapter joint typically is not an integral part of the surface tree.

5.9.5 Corrosion

In sizing the tubular members, a corrosion allowance should be assumed. Consideration should also be given to the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.9.6 Acceptance Criteria

The Surface Tree Adapter Joint should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.10 SURFACE TREE

5.10.1 Definition and Function

The surface tree (terminal head or flow head) provides flow control of the production and/or annulus bores during both tubing hanger installation and subsea tree installation/workover operations. It may also have provisions to support the weight of the completion/workover riser system.

5.10.2 Interfaces

The bottom of the surface tree is attached to the surface tree adapter joint. Wing outlets have provisions to attach to flexible pipes or swivel connections. The top of the surface tree has provisions for attachment of a lubricator adapter. Some integral riser systems may have provisions to route C/WO riser controls through the surface tree.

5.10.3 Typical Designs

Typically, the surface tree is constructed using an integral valve block; however, stacked valve designs are also common.

5.10.3.1 The surface tree valve arrangement should consist of at least one valve in each vertical bore and one wing valve for each bore. In some applications, two valves in the vertical bore and/or a crossover valve may also be used. Valves can be manually, pneumatically, or hydraulically operated. However, it is recommended that at least one of the valves in the flow path be remotely operated.

5.10.3.2 The lubricator adapter attaches to the top of the valve block, thus allowing a wireline lubricator and coiled tubing/snubbing unit to be attached. The most common adapter is a threaded union, although flanged adapters are also used. In some cases, pressure gauges and needle valves access the area between the valve block and the lubricator adapter. They monitor and vent pressure respectively.

5.10.3.3 Work platforms are sometimes provided to allow rig personnel to stand while opening or closing the valves. These platforms are constructed from steel framework and grating. As an option, a structure which protects the surface tree, primarily as it is being moved through the V-door, can be provided. This can either be integral with the work platform or be a separate structure.

5.10.4 Design Considerations

5.10.4.1 Lifting Requirements

The surface tree should be capable of lifting the entire C/WO riser string, including the tubing hanger system or tree, and accommodate "overpull" requirements to verify equipment has been properly landed and locked in place. It should also support the lubricator adaptor. Padeyes and other lifting devices should be designed in accordance with API Specification 17D, Section 303.7.

5.10.4.2 Drift

The vertical bores of the surface tree should permit the clear passage of wireline tools. To insure this, the surface tree should be drifted to API Specification 6A requirements.

5.10.4.3 Work Platform/Protective Structure

If a work platform is used, it should be of sufficient strength to support personnel operating the surface tree valves. The design of the structure should take into account the safety of the personnel. Size of the structure should allow passage of the assembly through the V-door and avoid interference with the guiderails of the traveling block.

5.10.4.4 Tensioning Ring

If a tensioning ring is incorporated into the surface tree design, consideration should be given to number of tension points, ability of the rings to rotate and the possibility of side loading. To facilitate smooth operation, bearing rings are sometimes employed. Tension rings should facilitate the use of elevator bails or heavy duty slings. Padeyes used should be adequately sized to support the required tensioning loads. Use of API Specification 8C is recommended for padeye design.

5.10.4.5 Casing Elevator

For handling or tensioning purposes, the top of the surface tree may provide a profile to interface with a standard casing elevator. The OD and load shoulder should be consistent with standard casing collars of similar size.

5.10.4.6 Lubricator Adapter

Bending loads on the adapter should be considered when designing the surface tree.

5.10.4.7 Corrosion

A corrosion allowance and/or the use of corrosion resistant materials should be considered given the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.10.5 Acceptance Criteria

The Surface Tree should be tested and documented in accordance with Section 7.2 and Section 8. In addition, the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.11 SPIDER

5.11.1 Definition and Function

The handling spider sits either on the rotary bushing or in the rotary table. It provides a hang-off point for the integral C/WO riser. Some spiders will lock to the rotary via the kelly drive pin holes in the master bushing. With the pins engaged, the spider can resist torque. For non-integral risers, tubing slips and false rotaries are used in lieu of the spider.

5.11.2 Interfaces

The handling spider interfaces with the C/WO riser and the rotary table. Spiders either sit in the rotary table or on top of the master bushing. Handling spiders must support the C/WO riser system, plus all suspended weights of the tubing hanger system or tree system while the riser connection is being made or disconnected.

5.11.2.1 Some spiders have automated open/close mechanisms. Typically, these spiders will require either pneumatic or hydraulic supply. In this case, there must be compatible lines and fittings between the spider and workover control system or rig air.

5.11.2.2 In some cases, the tubing hanger running tool will require an umbilical or individual control lines to be strapped to the exterior of the completion riser. Since the hydraulic supply typically originates on the rig floor (for completion operation) or on the rig cat walk, the umbilical must pass through the spider, down through the diverter and into the drilling riser.

5.11.3 Typical Designs

Handling spiders have a base which interfaces with the rotary and dogs that extend inward to support the C/WO riser. The spider dogs can be manually, hydraulically or pneumatically operated. Spiders which resist torque (threaded riser connectors) often have pins which engage in the kelly drive pin holes. There are two basic configurations of handling spiders: split body and one-piece body (main body). Both designs have dogs which extend and retract. Either design can be operated manually, hydraulically or pneumatically.

5.11.3.1 Split Body

These designs normally have a hinge arrangement that allows the spider to be placed around a running string while the string is being supported by the draw works. One advantage of the split body design is that it does not cover the rotary table when running the production tubing and tubing hanger. Therefore, no special arrangements for supporting the tubing are required other than standard slips and/or false rotaries.

5.11.3.2 One-Piece Body

The one-piece body design should be in place prior to running the tubing and tubing hanger.

5.11.4 Design Considerations

5.11.4.1 Completion Riser Joint

The spider must provide a place to hang off the riser joint. It should fully support the completion system both statically and dynamically.

5.11.4.2 Handling/Test Tool

The spider should address the interface requirements of the riser handling tool.

5.11.4.3 Control Umbilical(s)

In some cases, the tubing hanger umbilical or control lines are outboard of the riser joint. Spider designs should accommodate the umbilicals/control lines.

5.11.4.4 Sliding Surfaces

Spiders which have sliding surfaces should be designed to minimize the amount of dirt, trash, and drilling fluids which could interfere with its operation.

5.11.4.5 Manual Spiders

Design of manual spiders should consider the "human factor" to prevent fingers or hands from getting pinched or trapped.

5.11.4.6 Pneumatic or Hydraulic Spiders

Locking devices to hold the spider dogs in the open and closed positions should be considered to avoid accidental operation of the spider.

5.11.4.7 Dynamic Loading

The effects of vessel movement, waves and shock loads should be considered when designing a spider.

5.11.4.8 Static Loading

The load effects of the tubing hanger, tubing, riser joints, tree, lower riser package, tree running tools, stress joint, surface tree, and weight of the completion fluid should be considered when designing the spider.

5.11.4.9 Rotary

The size and type of rotary and rotary bushings must be considered during the design of the spider.

5.11.4.10 Operational Interface

Interface of all tools used during the completion and workover operations should be considered when designing a spider. They should include tubing hanger running tool, tubing make-up tools, and stress joint.

5.11.5 Acceptance Criteria

The spider should be tested and documented in accordance with Section 7.2 and Section 8. In addition, the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.12 HANDLING AND TEST TOOLS

5.12.1 Definition and Function

Riser handling and test tools are designed for general handling of the riser joints and riser components, support of the complete riser string and testing of the riser system prior to and during installation and recovery of equipment.

5.12.2 Interfaces

Handling tools typically have an API tool joint at the top and a riser coupling facing down. Some handling tools may be designed to interface with the casing elevators where handling loads are beyond the tool joint safe working capacities. Normally, the riser can be pressure tested through the handling tool. Control line couplings are provided for jacketed, integral risers to allow testing and operation of the tubing hanger control lines while running the riser.

These tools are designed to interface with each of the riser components. To test and handle the C/WO riser joints, the tools must attach to the riser connector.

5.12.3 Typical Designs

Typically, the riser handling tool should interface with the male or pin end of the riser joint. With an API tool joint at the top, the tool needs only to be long enough to provide an area for drill pipe elevators to interface and adequate space for making up any control or testing lines. Four to six feet (1,22 to 1,83 meters) is a typical size range.

5.12.3.1 Handling Tools

Typically, handling tools have a riser coupling at the bottom and a tool joint connection at the top.

5.12.3.2 Test Tools

Generally, test tools have a riser connector facing down and a pressure test port facing up. They also may have provisions to test the control lines in the riser.

5.12.4 Design Considerations

5.12.4.1 General Handling

The tool should fully support the riser, including any suspended loads of the tubing hanger system and the tree system, both statically and dynamically.

5.12.4.2 Design Loading

The following loading should be considered when designing handling tools:

- Horizontal and vertical riser joint handling.
- Vertical suspended loads including the load effects of the tubing hanger tubing, riser joints, tree, lower riser package, tree running tools, stress joint, surface tree, and weight of the completion fluid.
- The effects of vessel motion, wave loading and current.

5.12.5 Acceptance Criteria

The Handling and Test Tools should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

5.13 SUBSEA WIRELINE/COILED TUBING BOP'S (WCT-BOP) AND SHEARING VALVES

5.13.1 Definition and Function

The WCT-BOP and shearing valve assemblies are subsea well control devices associated with the LWRP.

5.13.1.1 WCT-BOP

A WCT-BOP is a subsea BOP that attaches to the top of a subsea tree to facilitate wireline or coiled tubing intervention. WCT-BOP rams are designed to shear wireline or coiled tubing and seal the bore, all in one operation.

5.13.1.2 Shearing Valves

These are gate valves or ball valves designed to shear wireline or coiled tubing and seal the bore, all one operation.

5.13.2 Interfaces

The interface at the lower end of the WCT-BOP or shear valve package should be compatible with the tree running tool. The upper end should be compatible with the EDP. If an EDP is not used, either the riser stress joint or a standard riser joint will typically connect to the upper end. Interface connections should be compatible with the same bore and pressure rating as the tree with which the mechanism is to be used.

5.13.3 Typical Designs

The WCT-BOP or shearing valve assembly is usually an integral block design having all BOP or valve assemblies unitized into a single assembly. Stacked BOP or valve designs may be used, but riser bending loads at flange interfaces should be considered. Reduced weights are another reason for using an integral block design.

The number of BOP rams or shearing valves used in a string may vary depending on the design of the closure device and operator preference. The sealing function may be accomplished by a second ram or shearing valve.

A crossover valve may be included in the WCT-BOP assembly to allow purging of the riser. Alternatively, the use of the tree crossover valve may serve the same function.

5.13.4 Design Considerations

5.13.4.1 Body

The body should provide all mechanical support and be able to withstand the combined effects of both riser tension and bending as well as internal and external pressure.

5.13.4.2 Bore Size and Spacing

The bore should be the same or larger than the bore of the subsea tree. Transitions may have to be provided in mating riser components to accommodate changes in bore sizes or spacing between the LWRP and the tree.

5.13.4.3 Multiple Bore Designs

Multiple bore designs should have seal subs or gaskets to isolate the bores and the main gasket. Each seal sub or gasket must be capable of withstanding an internal pressure equal to or greater than the pressure rating of the subsea tree.

5.13.4.4 Methods of Shearing

Shearing/cutting devices may shear in either a "single shear" or "double shear" manner. A double shear device will leave a slug of coiled tubing or wire line behind when activated. The system should be designed to accommodate the spent slug.

5.13.4.5 Direction of Sealing

The effects of unidirectional or bidirectional sealing of the bore cavities should be considered in the system design.

5.13.4.6 Replaceable Seals

The system should be designed to accommodate field replaceable seals.

5.13.4.7 Locking Devices

Actuator locking devices, that prevent opening of the sealing devices when the riser is removed in an emergency, may be used.

5.13.4.8 Corrosion

A corrosion allowance and/or the use of corrosion resistant materials should be considered given the types of hydrocarbons, well completion, stimulation and kill fluids that will be introduced into the system.

5.13.5 Acceptance Criteria

In addition to testing and documentation of the WCT-BOP or shearing valve assembly per Section 7.2 and Section 8, the following guidelines for acceptance should be followed:

- Hydrostatic proof testing of WCT-BOP's should conform to API Specification 16A.
- Shear valves should be tested per API Specification 6A before shearing to manufacturer's written specification.
- Shear specimen sizing should be per manufacturer's written specification.

Design and operations documentation should be made available by the manufacturer, for review by the purchaser. This documentation should include:

- Design calculations
- Test data (design verification and FAT)
- Operating instructions including operating pressure rating, temperature rating, and water depth rating
- Physical data including rated cutting/shearing/sealing information
- Storage and shipping information
- Maintenance and field testing information
- Rework information

5.14 MISCELLANEOUS ANCILLARY COMPONENTS

5.14.1 Definition

Miscellaneous and ancillary special components include but are not limited to: umbilical clamps, make-up tools, buoyancy modules, gimbals, and false rotaries.

5.14.2 Interfaces

Generally, these components are designed to interface with C/WO riser joints.

5.14.2.1 Umbilical Clamps

These clamps attach the umbilical(s) to the C/WO riser joints.

5.14.2.2 Make-Up Tools

These tools facilitate the make-up of the riser joint connectors.

5.14.2.3 Buoyancy Modules

These modules are typically strapped or clamped to the exterior of completion riser joints.

5.14.2.4 Gimbals

The gimbals interface with the spider and the riser joint.

5.14.2.5 False Rotaries

This component sits on the drilling rotary and provides a slip profile for dual or triple tubing strings. It allows the THRT umbilical to feed into the drilling riser without interfering with the slips.

5.14.3 Typical Designs

Designs for this equipment vary with the different completion riser connectors, type of riser and water depth.

5.14.3.1 Umbilical Clamps

Designs include a bolt on clamp with a hinge door. Simpler designs include nylon straps and soft rope. Some designs can accommodate both the tubing hanger umbilical and the tree umbilical. The clamps may be integral to the riser joint or separate.

5.14.3.2 Make-Up Tools

Designs of make-up tools vary with the type of riser system employed. Examples include spanner, wrenches or hydraulic torque wrenches.

5.14.3.3 Buoyancy Modules

These modules are usually molded syntactic foam which attach to the outside of the riser. Typically, they will be in 15-foot (4,57 meter) lengths and split in half longitudinally. Molded profiles for strapping may also be provided.

5.14.3.4 Gimbals

These designs typically have a spherical profile on bottom and a flat riser landing profile on top.

5.14.3.5 False Rotaries

These designs usually have a slot which allows the false rotary to be put around the tubing string(s). On top, they have a slip bowl for tubing slips. Some designs can provide support of the tubing hanger during running operations.

5.14.4 Design Considerations

5.14.4.1 Umbilical Clamps

These clamps should be capable of supporting the weight of the filled umbilical between clamps, both in and out of water, without slipping. Consideration should be given to the ease and quickness of installation.

5.14.4.2 Make-Up Tools

Maximum riser coupling make-up or break-out forces should be considered when designing these tools. Additionally, consideration should be given to method and ease of handling on deck (i.e., lift points).

5.14.4.3 Buoyancy Modules

These modules should partially support the weight of the riser system since a net downward force in the riser system is required to keep the string in tension. Modules should be rated to the maximum water depth of the riser system. Reaction rings on riser joints must transfer the buoyancy loads. Strapping and bolting should be corrosion resistant.

5.14.4.4 Gimbals

The effects of vessel movement, waves and shock loads should be considered when designing gimbals. Additionally the load effects of the tubing hanger, tubing, riser joints, tree, lower riser package, tree running tools, stress joint, surface tree, and weight of the completion fluid should be considered.

5.14.4.5 False Rotaries

Designs should accommodate the weight of the riser system plus the joint strength of the production tubing. False rotaries should sit squarely on the rotary table/bushing.

5.14.5 Acceptance Criteria

The Miscellaneous Ancillary Components should be tested and documented in accordance with Section 7.2 and Section 8. In addition the manufacturer should provide written assembly and test procedures as well as a maintenance plan as per Section 7.4.

6 Riser System Analysis

6.1 SCOPE

This section identifies the minimum stress analysis necessary to design and adequately predict the operating limits of a C/WO riser system. The analyses are intended to be used to verify the detailed design and determine operating limits. Refer to Section 5 for specific recommendations on the detail design of each component within the C/WO riser system including input data requirements, description of calculations to be performed, output results and record keeping.

6.2 GENERAL

This section describes recommended analyses which should be performed to ensure confidence in the C/WO riser system's dynamic behavior, integrity of the design and estimated fatigue life. Analyses of C/WO riser systems are based on a mathematical model of a nearly-vertical tensioned beam subjected to lateral loads arising from hydrodynamic/structure interaction. Each riser component is mathematically described in terms of its structural characteristics, hydrodynamic characteristics, and reactions to forces and moments applied by adjacent components. Riser analyses typically proceed in the following steps:

- Gather and review input parameters
- Specify allowable design and operating criteria
- Perform dynamic riser analysis and calculations using input parameters
- Apply the design and operating criteria to the calculated output to develop operating envelopes
- Conduct fatigue analysis
- Verify component performance with calculated riser loads
- Prepare output and analyses documentation

6.2.1 Input Parameters

Table 1 of this document lists typical input data and design and operating criteria required to perform stress and deflection analysis of a C/WO riser system.

6.2.2 Recommended Analysis

6.2.2.1 Dynamic riser analysis should be performed using both time domain and frequency domain techniques. The time domain method is superior in accuracy and reliability to the frequency domain method. The time domain solution method is required to predict dynamic or transient riser response as well as to confirm the suitability and reliability of the frequency domain method to model riser dynamic behavior. Frequency domain solutions predict steady-state conditions and are often used because of faster computation time. For each technique, both connected and hang-off conditions for lateral motions should be addressed.

6.2.2.2 Fatigue analysis is a statistical compilation of dynamic riser analyses results to evaluate the cumulative effects of environmental loads and vessel motions on the C/WO riser to estimate the probable fatigue life (in years) of the C/WO riser system. Either time domain or frequency domain solutions may be used to calculate the stress range variations along the C/WO riser. The analysis is based on a defined set of operating storms, usually specified by a wave scatter diagram.

6.2.2.3 Discussion of typical riser analysis methods are presented in API Recommended Practice 16Q and Bulletin 16J for drilling risers. These documents should be referenced for general information purposes.

Note: There are key differences between drilling risers and C/WO risers which may prevent direct application of drilling riser criteria and analysis methods to C/WO risers. These differences include: functional requirements, pressure containment, structural size, dynamic behavior, tension levels, fatigue life, buoyancy systems and soil/well structure interaction.

6.2.2.4 Based on generally accepted industry practice with C/WO risers, the following are recommended guidelines for system design and analysis:

a. Maximum von Mises stress levels in the riser tube(s) and its components should not exceed 67% of yield strength at normal operating conditions ("green zone," as described in Section 6.2.4). Maximum stress levels should not exceed 80% of yield under extreme operating conditions ("yellow zone," as described in Section 6.2.4.

b. A weight loss corrosion allowance should be included in the wall thickness of production tubing joints within the riser. Analysis should be performed with the initial wall thickness. Analysis may be done later using the reduced wall thickness over the life of the C/WO riser to verify its fit for purpose.

c. Analysis of flanges should be performed in accordance with the flange rating method described in API Bulletin 6AF, or other mechanical analysis. Examples of analysis methods include: distortion energy theory analysis, fatigue analysis, bearing load analysis, finite element analysis, experimental testing and proof testing, as described in the design and performance section of API Specification 6A.

d. Axial motions (including fluid column vibration) associated with the hang-off condition should be addressed in the analysis.

e. Riser components such as connectors, stab assemblies and running tool interfaces should be designed to meet or exceed the mechanical strength of the riser tubing strings (and jacket) used in a C/WO riser assembly. Design documentation should demonstrate the mechanical strength of components through mechanical analysis. Examples of analysis methods include: distortion energy theory analysis, fatigue analysis, bearing load analysis, finite element analysis, experimental testing and proof testing, as described in the design and performance section of API Specification 6A.

f. The maximum disconnect angle of the emergency disconnect package (EDP) should be defined for input operating condition limits for the riser analysis.

g. The maximum drilling riser angle of deflection at the ball, flex, or stress joint to allow passage of the tubing hanger, tubing hanger running tool and the C/WO riser's BOP adapter joint should be defined for input operating condition limits for the riser analysis.

h. The means for supporting and tensioning the upper portion of theC/WO riser assembly (such as spider assembly/rotary table lateral support, applied tension location at the tensioning joint or surface tree) must be adequately defined and modeled to ensure satisfactory performance of the C/WO riser in relation to the surface vessel suspending the riser. Some typical concerns which should be addressed by the analysis include:

- Riser tensioner capacity, both vertical and lateral.
- The limits of a free-standing riser/surface tree above the riser tensioning system, including vibration and axial/lateral oscillations and the necessity for lateral support.
- The motion limits of the upper riser assembly so as not to interfere with other riser system equipment or contact the surface vessel.
- Operating limits of the spider assembly.
- Safe and maximum riser angles at the top of the riser bounded by allowable distances to the side of a moonpool or vessel structure.

i. Vortex shedding induced vibration analyses should be performed to assess the potential for occurrence of vortex induced vibrations.

j. Fatigue analysis should take into account both first order wave response and components associated with low frequency vessel motion.

k. C/WO risers should be designed around the assumption that the subsea wellhead and subsea tree are rigidly anchored in the sea floor. However, if soil/well structure interaction data is available, then its behavior may be included in the riser analysis on a site specific basis. In some instances, the pliant behavior of the soil/well structure interaction may lead to significant attenuation of loads at the bottom of the C/WO riser.

6.2.3 Output and Analyses Documentation

Listed below are the data from the riser analysis that should be recorded and retained.

- Original input design parameters (Table 1) and/or typical computer input data file(s).
- Areas of maximum stress and their magnitude.
- Rated static load capacity (tension capacity).
- Fatigue analysis of maximum stressed areas.
- Loads imposed to the subsea tree and wellhead by the C/WO riser.

6.2.4 Operating Envelope Chart

6.2.4.1 A useful form of the riser analysis output is the op-

Table 1—Typical Data for Completion and Workover Riser Analysis

1. Environmental
   • Water Depth
   • Specified storm cases (wave spectrum, energy spectra model, current and wind profiles)
   • Wave scatter diagram (for fatigue analysis)
2. Type of Riser Attachment
   • Connected
   • Hang-off
3. Riser Configuration
   • Length of standard joints
   • Length of pups
   • Height of subsea tree above mudline
   • Height of lower workover riser package (LWRP) above tree
   • Height of emergency disconnect package (EDP) above LWRP
   • Height of stress joint above EDP
   • Elevation of rig floor above mean water level (MWL)
   • Weight of subsea tree, LWRP, EDP and stress joint
4. Riser Joint and Tension Joint Properties
   • Outer jacket
   •• Outside diameter
   •• Inside diameter
   •• Material yield strength
   •• Weight per foot
   •• Weight of end couplings
   • Inner tubing strings
   •• Outside diameter
   •• Inside diameter
   •• Material yield strength
   •• Weight per foot
   •• Location coordinates of centers of each tube
   • Umbilical
   •• Diameter
   •• Weight per foot (filled) in air
   •• Weight per foot (filled) in water
5. Stress Joint and Flex Joint Properties
   • Dimensional and stiffness properties of stress joint
   • Stiffness of flex joint
   • Maximum flex joint angle
   • Maximum disconnect angle of EDP
6. Buoyancy Devices
   • Outside diameter
   • Length per joint
   • Weight in air
   • Lift in water
7. Hydrodynamic Effects
   • Drag coefficient (lateral and axial) with and without buoyancy
   • Added mass coefficient (lateral and axial) with and without buoyancy
   • Drag coefficient (lateral and axial) of subsea tree, LWRP, EDP, and stress joint
   • Added mass coefficient (lateral and axial) of subsea tree, LWRP, EDP, and stress joint
8. Vessel Motions
   • Mean vessel offset from subsea wellhead
   • Dynamic motions (RAO's), including a complete mathematical definition of the phase angle in terms of wave excitation and vessel response
9. Maximum Top Tension Available
10. Mud and Completion Fluid Density
11. Operating Pressures for Specified Storm Conditions
12. Geotechnical Data
   • Soil/well structure interaction characteristics

erating envelope chart which should be referenced and used by personnel to maintain the C/WO riser within its design parameters while in use offshore (see Figure 3). The chart (or series of charts) plots riser tension vs. vessel offset away from vertical. The chart provides a "green" zone and a "yellow" zone which are bounded by allowable stress levels and/or geometric conditions while the riser is connected to hardware on the sea floor and supported by the surface vessel. Outside these zones, the stress and loads acting on the riser may exceed design limits and consideration of remedial or disconnect operations may be necessary. The zones provide a range of tension and vessel offset conditions which can easily be monitored and adjusted as environmental conditions vary. Each chart is generated for a unique set of environmental conditions (wave, current, etc.), water depth, and tubing bore pressure inside the riser.

6.2.4.2 The bounding curves that create the operating envelope on the chart in Figure 3 are illustrated separately in Figure 4, and may include:

a. The safe riser angle at which the C/WO riser approaches the allowable distance from a side of the moonpool or vessel structure.
b. The maximum riser angle at which the C/WO riser touches a side of the moonpool or vessel structure, or C/WO riser buckling limits.
c. The allowable stress limits of associated C/WO riser equipment under combined pressure, bending, and tension (such as riser joint end couplings, clamp, or flange connections to the EDP, LWRP, etc.).

One example of established allowable limits is the criteria for API flanges under combined loads and pressures, as referenced in API Bulletin 6AF. Using the charts in API Bulletin 6AF, in combination with a compilation of riser analysis cases defining generated bending moments, establishes an asymptotic curve for the allowable limits of the flange as a function of tension vs. vessel offset.
d. The allowable stress limits of the C/WO riser tube(s) and/or jacket as a compilation of riser analysis cases. (Both 67% and 80% curves are provided for normal and extreme operating conditions.)

7 Testing/Operations

7.1 SCOPE

This section provides general guidelines and recommendations for testing and operation of completion/workover (C/WO) risers, associated components and running tools.

7.2 TESTING

7.2.1 General

This section establishes guideline for testing the C/WO riser components and system.

7.2.2 Pretest Requirements

All test procedures should be prepared well in advance of the scheduled test dates. Such procedures should be reviewed by manufacturers and operations personnel. Procedures should have a clear purpose/objective, use a test method that will produce the desired output data and have clearly stated acceptance criteria. The test site should have adequate room, facilities, calibrated equipment and safety arrangements.

7.2.3 Test Procedure Format

A typical format for a test procedure should include the following:

- Purpose/objective
- Scope
- Fixtures
- Facilities description
- Equipment requirements
- Environmental description
- Personnel requirements and safety
- Performance data
- Acceptance criteria
- Reference information

7.2.4 Pressure Testing

Pressure testing of all pressure containing components other than tubulars and tubular connections should be carried out in accordance with API Specification 6A, PSL-2 or 3. Additional test requirements may be provided by the operator.

7.2.5 Hydraulic Cleanliness

Since the riser system control circuits are used for the operation of the subsea tree, SCSSV and various running tools, cleanliness of hydraulic controls systems is important. The manufacturer should provide procedures to obtain specified NAS 1638 cleanliness requirements.

7.2.6 Performance Verification

The manufacturer should complete performance verification on any new or unproven component to be used in the C/WO riser system. Performance verification should be carried out in accordance with API Specification 17D, Section 307. In the case of used or rental equipment, previously documented performance verification should be made available.

7.2.7 Factory Acceptance Testing (FAT)

7.2.7.1 The manufacturer should complete a series of tests prior to supply of the C/WO riser system to confirm the correct functioning of each item as a unit and as part of the com-

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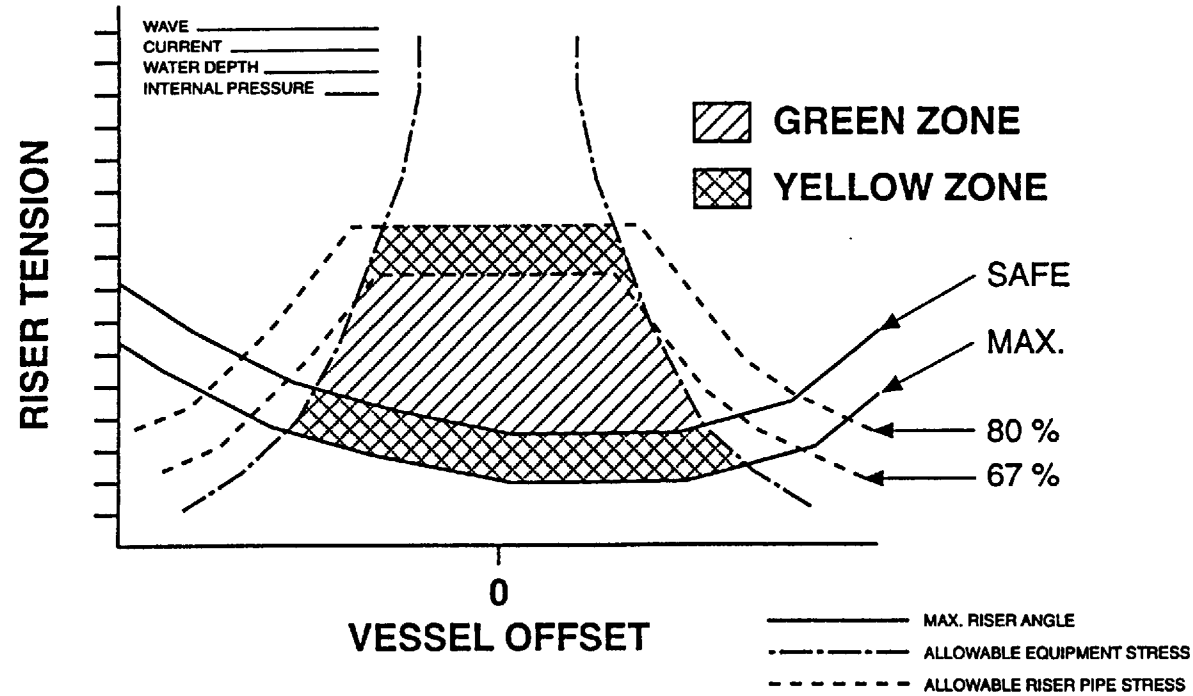

Figure 3—Operating Envelope Chart

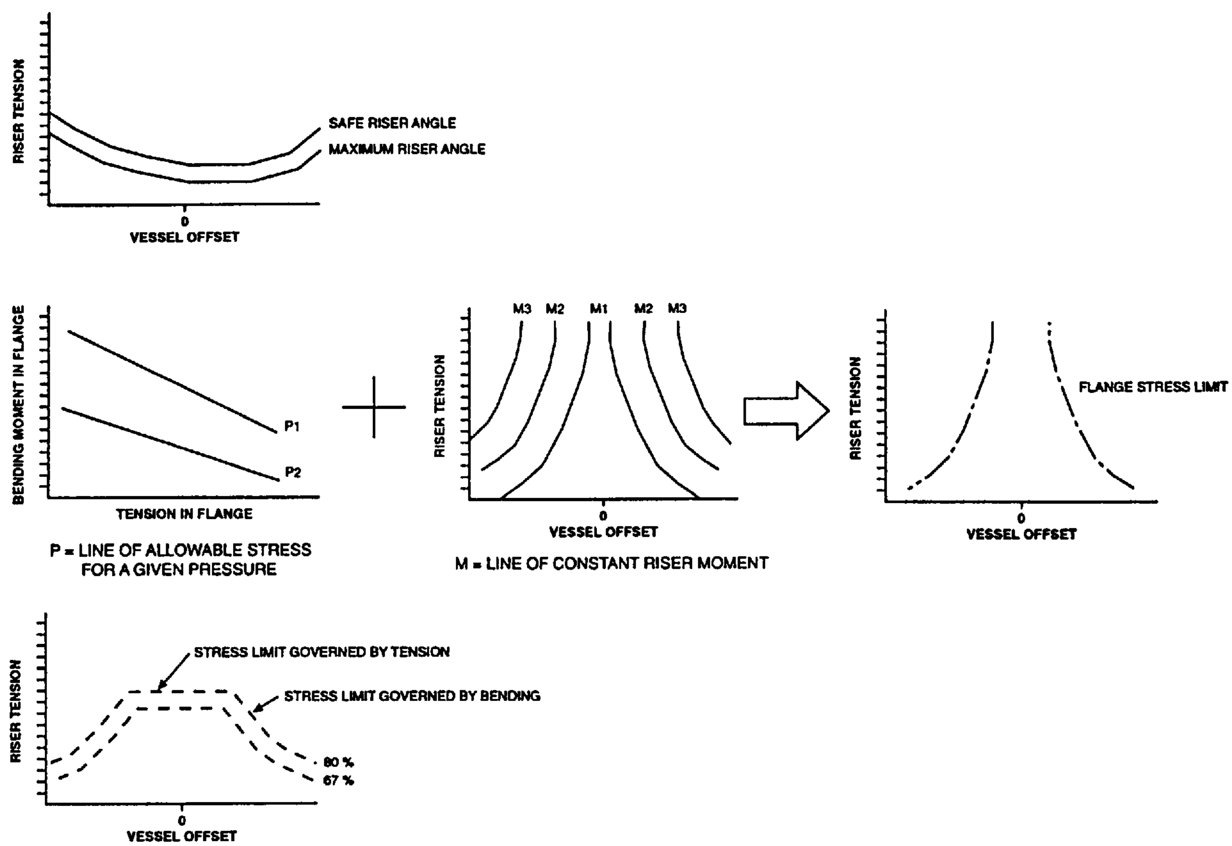

Figure 4—Parameters of Operating Envelope Chart

plete system. These tests should have the following goals:

- Ensure all manufactured components meet the design specification.
- Ensure that the individual components can be assembled into the final structure of components, within the bounds of good and safe engineering practice.
- When an individual component forms part of a larger assembly, this component should pass appropriate component testing and inspection requirements before assembly.
- Each assembled length of C/WO riser should be connected with a manufacturer's standard end cap or connection fixture to assure riser interchangeability and connection continuity, and to verify that pressure integrity is maintained.
- Ensure integrity and continuity of connections among assembled components.
- Demonstrate that interfaces between assemblies can be made and broken without compromising integrity or safety.

7.2.7.2 Each assembled length of C/WO riser should be subjected to hydrostatic pressure tests. Procedures for conducting these tests should comply with those established in API Specification 6A. The test pressure for hydraulic hose, mechanical tubing, and associated hydraulic fittings should be 1.5 times the rated working pressure.

7.2.7.3 Drift testing of each riser component should be conducted using a specified drift and taking into account the effects of full bore wireline tool strings that may be used within the system. Drift testing should also be carried out on the combined, made-up series of two or more components.

7.2.7.4 The internal test pressure for pipe which is used as a pressure containing external jacket of a riser assembly should be the lower value of either 80% collapse pressure or 1.5 times working pressure of the tubing contained inside.

7.2.8 System Integration Tests (SIT)

7.2.8.1 The scope of testing may be subject to the availability of a subsea tree. If a subsea tree is not available, then the tests should be conducted using the tree running tool test skid to confirm pressure integrity/operation of the control interface.

7.2.8.2 Additionally, overhead space may limit stack-up height such that the SIT may have to be done in two setups: (1) the LWRP and subsea tree, and (2) the LWRP and the EDP. If space is available, a complete system stack-up including the stress joint and tree should be conducted.

7.2.8.3 As a minimum, the following tests should be carried out on the C/WO riser system after completion of satisfactory component testing and the FAT. Optionally, these tests may be included in the FAT:

a. LWRP Interface with Tree.
   - The LWRP assembly should be landed on the tree to verify form, fit and function.
   - With the LWRP connected to the tree, a pressure test between the LWRP and the tree should be conducted to working pressure. Additionally, functional tests of all tree and LWRP valves should be carried out.
   - With the LWRP connected to the tree, the production and annulus bores should be drifted using an API tubing drift. Additionally, if plugs are used, they also should be run through the LWRP and tree to assure proper function.

b. Emergency Disconnect Package with LWRP.
   - The stress joint with the EDP connector should be landed on the LWRP to verify form, fit and function.
   - With the EDP connected to the LWRP, functional tests of the LWRP rams or shear valves should be completed to verify proper control interface.
   - With the EDP and stress joint connected to the LWRP, the production and annulus bores should be drifted with an API tubing drift.

   Note: Some operators may require special long drifts for the stress joint.

   - Connect and disconnect angles should be simulated to verify proper function of the EDP under riser load conditions.
   - The seals and sealing surfaces should be thoroughly inspected after disconnection of the EDP.

7.3 OPERATIONS

7.3.1 General

This section provides guidelines for handling and use of the C/WO riser and its associated running tools and surface equipment.

7.3.2 Riser Preparation

7.3.2.1 Riser joints should be inspected and generally refurbished as required prior to shipment to the rig. Critical parts and surfaces should be adequately protected during shipping, handling, and temporary storage. Adequate spare seals and/or complete joints should be available.

7.3.2.2 In general practice, riser joints should be reinspected after and prior to each use to determine if damage has been incurred during usage, storage or handling. Additionally, risers should be inspected for corrosion and loss of coating.

7.3.3 Riser Handling Considerations

7.3.3.1 Prior consideration should be given to deck space and loading requirements for the completion riser system. The need for minimum footprint storage racks should be considered.

7.3.3.2 Riser design should facilitate handling from the pipe deck into the derrick. The handling scenario should allow for existing rig cranes, elevators, etc.

7.3.3.3 The riser should facilitate vertical racking in the derrick. Protecting critical parts and surfaces in this state and selection of optimum joint length should be considered.

7.3.3.4 Space out and heave considerations usually require that the surface tree and surface tree adapter joint be preassembled and set aside.

7.3.3.5 Handling and support of the surface tree in the derrick should be considered. Support of a free-standing surface tree should be considered due to vessel motion and the mass of the surface tree.

7.3.3.6 The handling of umbilicals should be considered. This should include optimum placement of umbilical reels and the need for and location of umbilical support sheaves. Preconnecting, filling, flushing, and testing of the surface tree and its umbilical prior to "racking back" or setting aside in the derrick should be considered.

7.3.4 General Riser Installation Considerations

7.3.4.1 Consideration should be given to personnel access and safety during riser installation.

7.3.4.2 Consideration should be given to ensuring that riser connectors are made-up to prescribed torque/preload values. Consideration should be given to transmission of torque through the riser connector/joint and into the riser spider.

7.3.4.3 Riser connector make-up tools should be selected to facilitate handling by rig personnel. Balanced tools suspended from tugger lines are recommended.

7.3.4.4 Consideration should be given to pressure testing riser connections immediately after the joint make-up operation rather than after installation.

7.3.4.5 Consideration should be given to the method and necessity for filling the control lines of integral jacketed risers with integral control lines. (See Section 7.3.5.2)

7.3.4.6 Consideration should be given to the design of riser umbilical clamps. Clamps should ideally be readily made-up by one person. Loose parts should be avoided if possible. Make-up torques/forces should be defined and controlled to prevent excessive collapse forces being applied to the umbilicals.

7.3.4.7 Consideration should be given to the ease of making up the riser tension joint. Tension line attachment points should accommodate the orientation of the existing rig tensioner system. The riser spider should be designed to allow passage of the riser tension joint.

7.3.4.8 Care should be taken to ensure the riser system is properly spaced out with pup joints. The tension joint location in conjunction with the existing tensioning system must provide for required tension within the defined vessel operating envelope (heave, offset and sea state limits). Consideration should be given to the space-out of the surface tree above the rotary to avoid interference between the surface tree and the rotary or spider at maximum operating limits.

7.3.4.9 The design of the surface tree should consider make-up of production and annulus test/flowlines. Special requirements of test lines should be considered as part of the surface tree space out requirements. Additionally, the surface tree design should address personnel access and safety requirements for wireline and coiled tubing operations. The need for work platforms, ladders and safety railing should be considered.

7.3.4.10 Completion riser system operating parameters should be closely monitored at all times to ensure the riser is being operated within prescribed limits. Operating parameters generally include heave, vessel offset and top tension.

7.3.5 Running Tubing Hanger

In this operation, the BOP and drilling riser are attached to the wellhead. The tubing hanger is run through the drilling riser on the C/WO riser. In this operation, the first consideration is to verify that the rams are fully open.

7.3.5.1 Riser Length Measurement

a. The riser length is important for several reasons:
- When a BOP orientation pin is used to rotate and orient the tubing hanger, vertical positioning of the orientation cam is critical. If the pin is extended too early or too late, the pin or cam may be damaged. Other orientation methods may also require stack-up measurements.
- Landing the tubing hanger gently or cautiously into the wellhead is important to avoid seal or mechanism damage. Therefore, knowledge of the position of the tubing hanger relative to the wellhead is critical.
- The surface tree should be preassembled with the correct length riser or tubing pups to properly position the surface tree relative to the rotary.

b. Typical methods of obtaining proper space out measurements are as follows:
- Running Last Casing Hanger. Measure running string as the last casing hanger is run and landed. Knowledge of the positions of the casing hanger landing profile relative to the top of the wellhead is required.
- Running Impression Block Tool. Measure running string during the running of the impression tool. Again, knowledge of landing profiles relative to the top of the wellhead is important.
- Tagging on BOP Rams. Close one of the rams and tag

it during the running of a tool such as a BOP test plug. Knowing the position of the running string relative to the BOP ram will allow the string to be properly measured.

c. All measurements should be recorded and critical landing points marked on the C/WO riser.

7.3.5.2 Control Line Considerations

a. If an integral riser with internal control lines is used, control of the tubing hanger running tool is lost during the time between the removal of the riser joint running tool and the attachment of the next riser joint. For this reason, the tubing hanger running tool should be designed to maintain its lock functions in the absence of hydraulic power from the riser.

b. Another concern with the integral C/WO riser is the filling of control lines from the top prior to attachment of the next riser joint. It is difficult to remove all the air from the small diameter control lines while filling from the top. Excessive air in the control lines may cause erratic operation of the running tools. Some riser systems provide a means of filling from the bottom up by using a fill line and a distribution manifold just above the tubing hanger running tool.

c. The use of a continuous umbilical between the tubing hanger running tool and the surface allows direct, continuous control of the running tool at all times and requires no filling since the umbilical should be pre-filled. This umbilical can be strapped or clamped to the side of an integral riser or clamped within the pattern of a tubing-type riser system. Operationally, the spider or slips must have provisions for passage of the umbilical through the rotary.

7.3.5.3 Orienting and Landing the Tubing Hanger

The drilling riser ball or flex joint angle is very important during this operation. The stiffness, diameter and length of the tubing hanger, tubing hanger running tool and the adapter joint may require the drilling riser to be close to vertical to avoid locking or jamming the assembly as it passes through the ball or flex joint. Information on riser angle should be known prior to conducting this operation. The C/WO riser analysis should address the maximum operating limits.

If the tubing hanger is concentric, orientation of the tubing hanger relative to the subsea tree is not required. Dual bore hangers do require orientation and this operation is critical to the completion success. Several proven methods have been used and include:

a. Orientation Key (Active Orientation). A key integral to the running tool engages a slot in the BOP connector body. The key is normally spring loaded to allow it to deflect inward until it is flush with the OD of the running tool. Another method is to locate the key on the tubing hanger body and engage a slot inside a tubing spool body. The engagement of the key into the slot is accomplished by rotating the riser from the surface. Therefore, this method requires the riser to be capable of transmitting torque.

b. Orientation Bushing (Passive Orientation).

- An orienting bushing is installed in the wellhead or tubing spool prior to installatlon of tubing or the hanger. The orienting bushing features an external spring loaded key and an internal orientation helical cam. The orienting bushing is landed on the wellhead or tubing spool. The bushing is then rotated until the key engages a slot inside the BOP connector body or inside the tubing spool, properly positioning the helix inside.
- Once the key and helix engage, the tubing hanger will automatically rotate to the proper position as the C/WO riser is lowered. After the hanger is installed and the running tool removed, the bushing is retrieved.
- This method is suited for tubing string risers which cannot transmit rotational loads from the surface. This method is limited to tubing hanger designs which are not "full bore."

c. Orienting Pin in the BOP (Passive Orientation).

- A retractable orientation pin is located in one of the BOP's choke and kill outlets to engage a helical cam sleeve on the riser, just above the tubing hanger running tool. The pin is extended or retracted hydraulically by way of the BOP's control system.
- Two cam (helix) sleeve configurations have been used: (a) cam facing down, and (b) cam facing up. With the cam facing down, it is important to keep track of the riser orientation cam position relative to the BOP. If the pin is extended prematurely or too late, damage to the system could occur.
- With the cam facing up, it is not necessary to accurately know the riser space out.The tubing hanger is landed in the wellhead first, but is not locked. The orientation pin can then be extended. The tubing hanger is pulled out of the wellhead as the upward facing cam engages the orientation pin. With the tubing hanger oriented, it is then lowered into the wellhead, and locked in place.
- This method is suited for applications involving large vessel heave where transmitting rotational torque is not practical. This method requires some modification to a BOP if an orienting pin is not already part of the BOP system.
- As the hanger passes through the BOP, the speed should be reduced to minimize the possibility of damage to the tubing hanger main body seals as it enters the wellhead and landing area. The riser tension should be reduced after landing to keep vessel motion from scrubbing the tubing hanger seals.

7.3.5.4 Testing Tubing Hanger

After locking the tubing hanger in the subsea wellhead, an overpull is usually applied to the running string to verify proper engagement. Depending on hanger design and operator preference, pressure testing can be conducted from either the top and/or bottom of the tubing hanger to test the seal between the tubing hanger and subsea wellhead. The C/WO riser system analysis should address loading resulting from all field testing operations.

7.3.6 Reentry of Tubing Hanger

In this operation, the drilling riser and BOP are attached to the wellhead and the C/WO riser and THRT are run through the drilling riser. The THRT must orient and attach to the tubing hanger and establish hydraulic control with the tubing hanger. Procedures should address careful inspection of all THRT functions and seal sub interfaces prior to running the C/WO riser. Since reentry of the tubing hanger normally requires the reestablishment of control lines through the C/WO riser, special consideration should be given to stabbing profiles on control couplers and orientation tolerances where required.

7.3.7 Running the Tree

In this operation, the riser is vulnerable to the open sea environment since the drilling riser is no longer present. Riser analysis should address the free hanging riser arrangement with the tree, and the LWRP attached. Consideration should be given to lowering of the tree and LWRP through this critical splash zone rapidly to avoid potential equipment damage. When the tree is landed onto the wellhead, riser tension loads should be reduced to avoid heave loads from lifting the tree. When the tree is locked to the wellhead, tension loads should then be increased to specified working levels.

7.3.8 Disconnecting from Tree

Prior to disconnecting the C/WO riser system from the tree, the following operations should be considered:

- The riser system should be purged of hydrocarbon products. This can be accomplished either through a crossover valve on the tree or on the LWRP.
- Specified riser tension and release angle should be verified prior to release of the tree running tool.

7.3.9 Emergency Disconnect

If an emergency event, such as loss of a vessel anchor or bad weather, causes a riser disconnect condition, the disconnect operation may not permit time for purging of the riser. If a WCT/BOP is used, it is recommended that the emergency disconnect point be provided above the LWRP. Thus, the tree and LWRP will provide barriers to the well fluids.

7.3.10 Running Tree Cap

Normally, the C/WO riser is not used to run the tree cap. Instead, the cap is run on drill pipe using a running tool equipped with a drill pipe adapter. However, some tree cap designs include tubing plugs located in the tree cap body. In this case, the C/WO riser should be used to run the cap.

7.4 INSPECTION AND MAINTENANCE

The owner of the riser should maintain operations records and establish an inspection program to ensure a high operational reliability. Although there is no recognized method of accurately maintaining records of all modes of riser use, as a minimum, the owner's records should contain the following information:

- Job description (operator, field, water depth, etc.)
- Environmental conditions
- Days used
- Damage descriptions
- Maintenance/inspection records
- Repair records
- NDE testing/results
- Unusual operating conditions

The owner should make available to the operator all riser records and a written inspection/test procedure prior to its use or reuse.

8 Quality Assurance, Materials, and Corrosion

8.1 SCOPE

This section provides guidelines for the establishment of quality procedures, material selection and corrosion control for components and assemblies of a C/WO riser consistent with functional, environmental and safety requirements.

8.2 QUALITY ASSURANCE

8.2.1 Quality Assurance Program

A documented quality assurance program covering activities, items, and services should be planned, implemented and maintained in accordance with requirements of applicable specifications. The program should provide for a staff trained to assure compliance with the applicable specifications. The staff must be independent of the manufacturing organization. Management should periodically assess the program and take corrective action, as needed.

8.2.2 Quality Assurance Manual

The quality assurance program should be described in a quality assurance manual.

8.2.3 Product Specification Level (PSL)

References to API Specification 6A for C/WO riser equipment should be with respect to PSL 2 or PSL 3.

8.3 QUALITY CONTROL

8.3.1 General

C/WO riser system components should comply with appropriate specifications for quality control requirements established for dimension and tolerance standards, process of manufacture, chemical composition and inspection. Examples of specifications include:

- Oil Country Tubular Goods (OCTG): API Specification 5CT.
- Pressure Controlling and Other Pressure Containing Components: API Specification 6A and 17D and 16A (for clamp profiles).
- Hydraulic Tubing: ASTM A269 or ASTM A213, and/or ANSI/ASME B31.3.
- Hydraulic Hose: SAE 100 and/or J517.
- Hydraulic Cleanliness: NAS 1638.

8.4 MATERIAL SELECTION

8.4.1 General

This section provides guidelines for the selection of metallic and non-metallic materials suitable for conditions and service experienced by completion/workover risers during use. Particular attention should be paid to their ability to withstand the forces applied during installation, testing and operation as well as their resistance to well fluids and well treatment chemicals.

8.4.2 Metals

Metallic components may vary depending upon the service but should comply with the manufacturer's written specifications. Manufacturer specifications should define:

a. Chemical composition limits
b. Heat treatment conditions
c. Mechanical property limits
   - Tensile strength
   - Yield strength
   - Elongation
   - Reduction in area
   - Hardness
   - Impact strength
d. Melting practice
e. Forming practice

8.4.3 Dissimilar Metals

The use of dissimilar metals in an assembly should be avoided in order to prevent galvanic corrosion. If dissimilar metals must be used, care should be used in selecting metals with similar galvanic potentials to minimize corrosion.

8.4.4 Non-Metals

Non-metallic materials should be capable of withstanding the operating, pressures, temperatures, and chemical environments specified by the operator and should be compatible with the intended service.

8.4.5 Closure Bolting Considerations

NACE Class II bolting is not necessary for risers designed for NACE service because the bolting is not in an environment that would allow H_2S to concentrate.

8.5 WELDING

8.5.1 General

Welding procedures and subsequent inspection of various C/WO riser components should be qualified and inspected in accordance with appropriate specifications. Examples of specifications include:

- Oil Country Tubular Goods (OCTG): API Standard 1104; API Specification 6A, Welding Section; ASME, Section IX, or other recognized pressure containing piping welding code.
- Pressure Containing Components: API Specification 6A, Welding Section; or ASME, Section IX.
- Weld Overlays for Pressure Containing Components: API Specification 6A, Welding Section.
- Pressure Controlling Components: API Specification 6A, Welding Section; or ASME, Section IX.
- Lifting Devices and Structural Components: API Specification 17D, Section 502.
- Non-Critical Structural Components (work platforms, tansport baskets/bins, skids, etc.): AWS D1.1, ASME Section IX, or other recognized structural welding code.

8.5.2 Quality Control of Welded Components

Padeyes and other lifting devices attached by welding should be inspected by either magnetic particle and/or dye penetrant methods, as established in API Specification 6A (for weld NDE-surface, PSL 2 bodies, bonnets, end and outlet connections) or other recognized structural welding code. Non-critical structural components which are welded together (such as the surface tree's work platform, transport baskets/bins, skids, etc.) should comply with the quality control requirements established in AWS D1.1 and AISC codes for process of manufacture, chemical composition, and inspection of structural components.

8.6 CORROSION

8.6.1 General

C/WO risers may be exposed for brief periods internally to corrosive produced fluids along with completion fluids and well treatment chemicals. Externally the riser is exposed to a salt water "splash zone" environment. Between uses, risers may be exposed (internally and externally) to long-term corrosion and weathering due to outside storage.

8.6.2 Internal

The type of fluids being handled by the riser should be considered and special allowances made for fluids that are particularly corrosive. Corrosion rates due to produced fluids and any treatment fluids must be considered when determining tubing/pipe wall thickness. Care in selection of tubing joint threaded connections can minimize corrosion in dead spaces. Where necessary, internal corrosion may be mitigated by one or more of the following: flushing/scouring at regular intervals with inhibitors, bactericides, dehydrators, etc.; applying a temporary coating, such as grease, to minimize surface exposure; end capping; and applying a more permanent internal coating such as plastic or epoxy.

8.6.3 External

External contact with fluids should be considered in the riser's material and external coating selections. "Splash zone" effects will require additional protection due to sunlight, sea water spray, and some mechanical damage. Where required, external coating systems should include the following considerations:

a. Mechanical loading considerations, including: thermal growth (or contraction), handling/installation loads, fatigue loads, damage due to make-up and break-out of riser connections, and friction against riser connector mating components.
b. Resistance to damage from temporary exposure to internal fluids during make-up or break-out of riser connections.
c. Resistance to under film water migration.
d. Resistance to debonding, cold flow, embrittlement, chalking and cracking.
e. Incorporating a corrosion-resistant primer coat (such as inorganic zinc) since cathodic protection systems may be impractical.
f. Easy repair and/or re-application.
g. Assuring that metals are well coated to discourage galvanic corrosion. Specifically, cathodic materials should be well coated with respect to adjacent anodic materials (small cathode-large anode rule).

8.7 STORAGE AND SHIPPING

C/WO riser assemblies should be stored and shipped as specified by API Specification 17D, Section 800 and the manufacturer's recommendations.

APPENDIX A—STANDARDIZATION OF C/WO RISER INTERFACE

The industry has recognized the importance of sharing or renting of C/WO riser systems and as a result, has proposed standardizing a common interface that will allow risers to be used with several different tree systems. The proposed interface is between the top of the tree running tool (TRT) and the bottom of the WCT-BOP. See Figure A-1.

A 13⁵/₈ in (346mm), 10,000 psi (69,0 MPa) API flange is proposed as the interface connection. The seal mechanism is proposed to be a stab sub/pocket using a primary metal-to-metal seal with an elastomeric back-up. An environmental seal should be provided to isolate the stab subs. This environmental seal is proposed to be a BX seal ring/groove. The BX seal ring size is provided in Table A-1.

At this time, two riser sizes have been proposed to incorporate the standard interface: a 5 in x 2 in, 10,000 psi (69,0 MPa) system, and a 4 in x 2 in, 10,000 psi (69,0 MPa) system. The proposed bore centers and offset dimensions are shown in Figure A-2 and Table A-1.

Notes:
1. The BX 158 seal ring used for the 4 in x 2 in interface is smaller than normally used for a 13⁵/₈ in (346mm), 10,000 psi (69,0 MPa) flange. The smaller ring reduces the separation load, which is critical in the deeper water riser applications where bending loads are already significant. In the case of the 5 in x 2 in riser interface, the BX 159 ring is the smallest ring possible.
2. Risers having bore diameters larger than the tree bores can be used in conjunction with the smaller tree bores as long as the mating bores are arranged so as to allow passage of all downhole tools that will be used in conjunction with the riser system (i.e., a 4 in x 2 in, 10,000 psi (69,0 MPa) riser could be used with a 3 in x 2 in, tree having the same bore centers as the 4 in x 2 in, 10,000 psi, (69,0 MPa) riser interface).
3. A transition or adapter spool may be required to allow riser usage with different tree manufacturers since stab sub designs are generally proprietary.
4. Other bore centers and offsets can be used. However, it is recommended that specifications for any new C/WO riser system be reviewed with the manufacturer for dimensional confirmation with any industry interface standards that are in existence or evolution.

Table A-1—Center Distances of Bores for Dual Bore Riser/TRT Interface (Ref. Fig. A-2)

Valve Bore Sizes in. (psi) [mm (MPa)]	A Bore Center to Bore Center in. (mm)	B Large Bore Center to Flange Center in. (mm)	C Small Bore Center to Flange Center in. (mm)	Flange & BX Ring Size in (psi) [mm (MPa)]
4¹/₁₆ x 2¹/₁₆ (5k,10k) [103 x 52 (34,5; 69,0)]	5.000 (127,00)	1.625 (41,28)	3.375 (85,72)	13⁵/₈ (10k), BX-158* [346 (69,0)], BX-158
5¹/₈ x 2¹/₁₆ (5k,10k) [130 x 52 (34,5; 69,0)]	5.375 (136,52)	1.875 (47,62)	3.500 (88,90)	13⁵/₈ (10k), BX-159 [346 (69,0)], BX-159

*A BX-158 ring is used to minimize separation load.

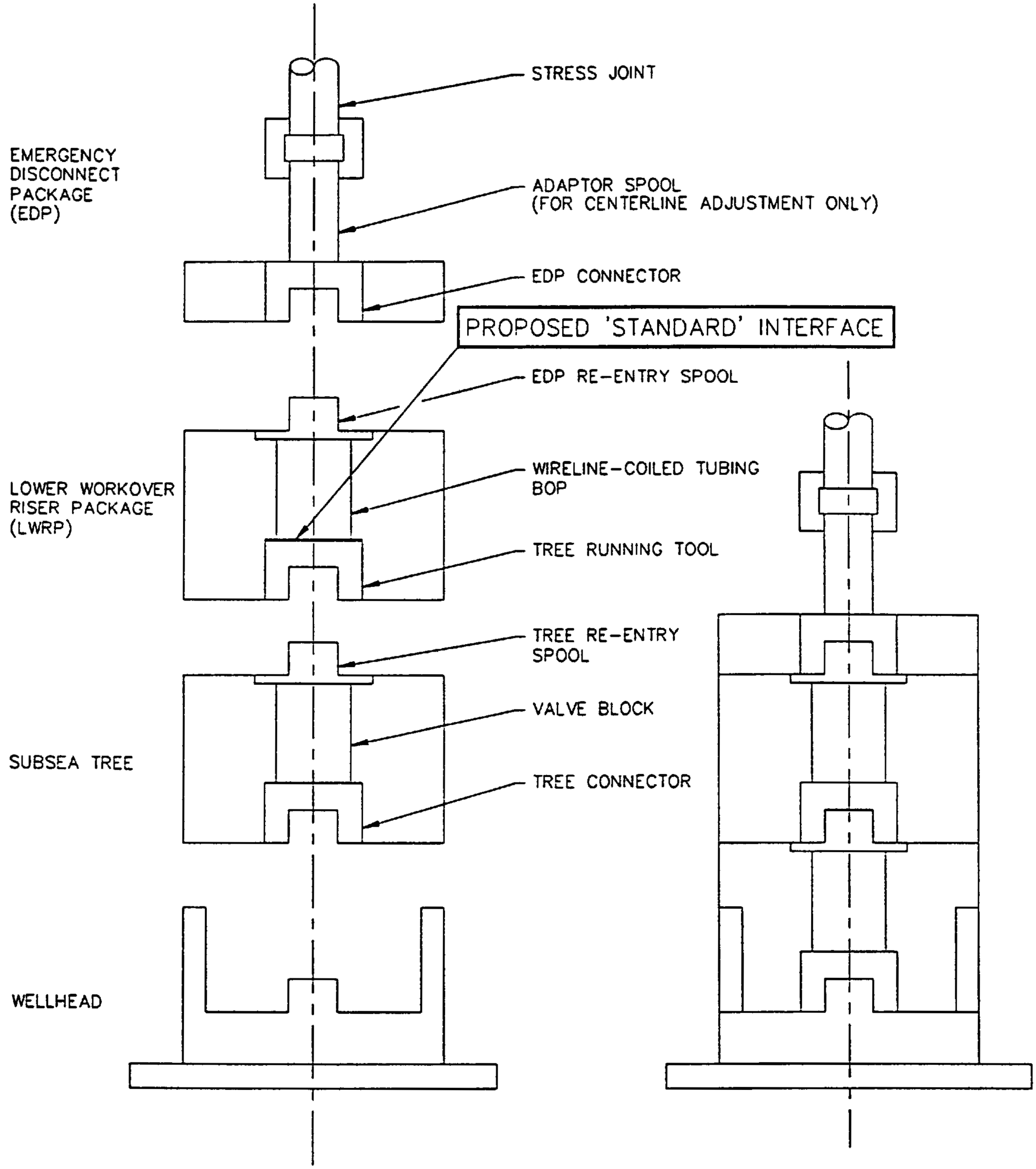

Figure A-1—Location of Proposed Standard Completion/Workover Riser Interface

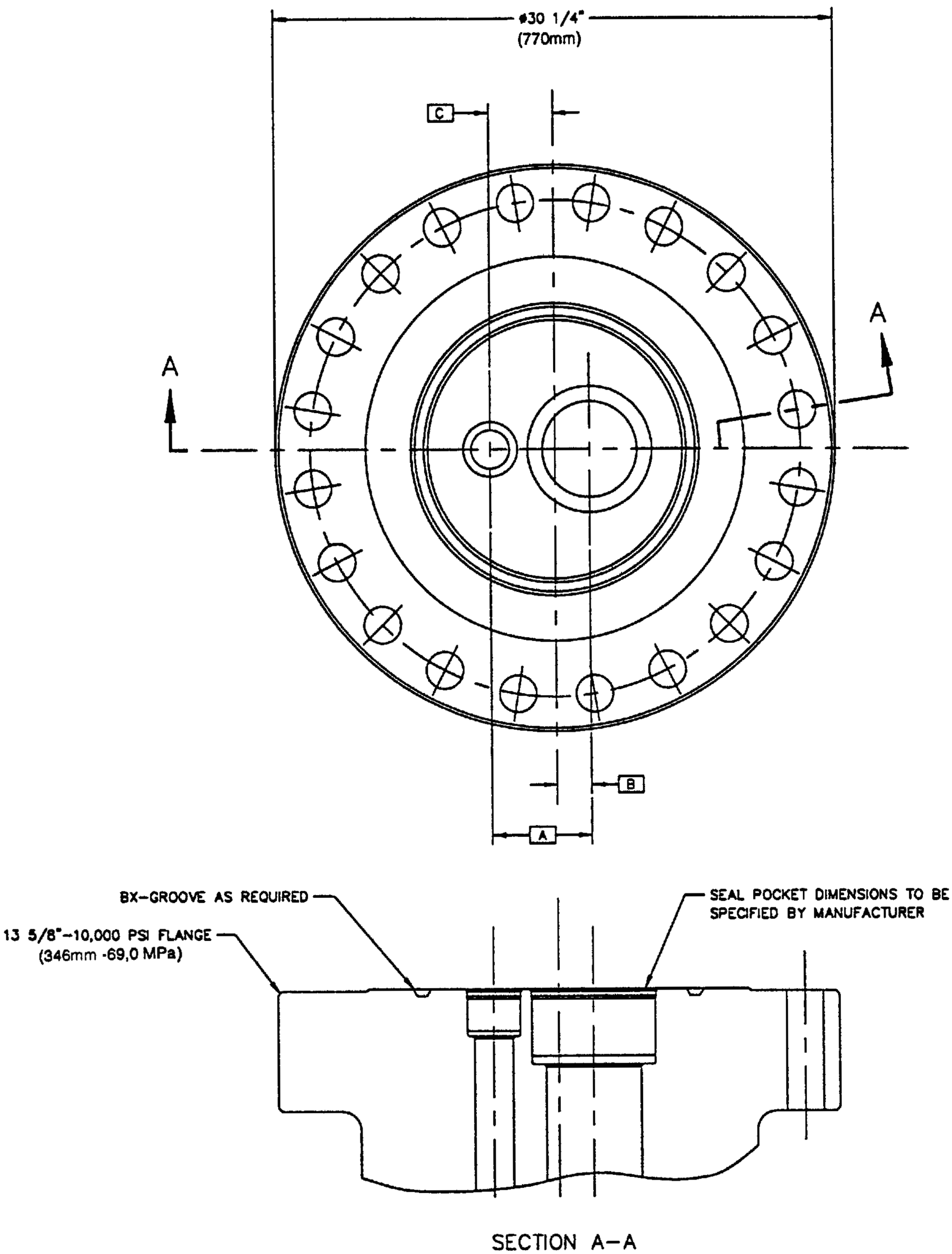

Figure A-2—Proposed Standard Interface Detail 13⁵/₈"—10,000 PSI (364mm-69,0 MPa) API 6BX Flange (Ref. Table A-1)

APPENDIX B—SI UNITS

Conversions of U.S. Customary units to International System (SI) metric units are provided throughout the text of this document in parentheses, except for certain non-dimensional, rounded nominal sizes used as a convenience in Appendix A, e.g., 5" x 2" system. Note use of the comma as a decimal marker in SI unit values, e.g., 30 ft (9,14 m). The factors for conversion of U.S. Customary units to SI units are listed below.

Table B-1—SI Units

Quantity	U.S. Customary Unit	SI Unit
Length	1 inch (in)	25,4 mm (exactly)
	1 foot (ft)	0,3048 m (exactly)
Pressure	1 pound per square inch (psi)	0,006894757 MPa

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