

Coiled Tubing Well Control Equipment Systems

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Introduction

This standard represents a composite of the practices employed by various operating and service vendor companies in well intervention operations. This recommended practice is under the jurisdiction of the API Committee on Standardization of Oilfield Equipment and Materials.

The objective of this recommended practice is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of well control equipment and preservation of the environment for land and marine well intervention operations. This recommended practice is published to facilitate the broad availability of proven, sound engineering and operating practices that meet the stated objective through practices that improve reliability and reduce risk to acceptable levels.

This Recommended Practice is provided to meet the need for assembly and operation of coiled tubing well control equipment and systems. Coiled tubing well control practices typically rely on mechanical barriers as the primary means for well control. This recommended practice does not present all of the operating practices that can be employed to successfully install and operate well control equipment systems in coiled tubing well intervention services. Practices set forth herein are considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices can be used to accomplish the same objectives. Individuals and organizations using this standard are cautioned that operations must comply with requirements of federal, state or local regulations. These requirements should be reviewed to determine whether violations can occur.

Coiled tubing well intervention services are being conducted with full regard for personnel safety, public safety and preservation of the environment in such diverse conditions as metropolitan sites, wilderness areas, ocean platforms, deepwater sites, barren deserts, wildlife refuges and arctic ice packs. The information presented in this recommended practice is based on this extensive and wide-ranging industry experience.

Coiled Tubing Well Control Equipment Systems

1 Scope

1.1 General

This Recommended Practice (RP) addresses coiled tubing well control equipment assembly and operation as it relates to well control practices. Industry practices for performing well control operations using fluids for hydrostatic pressure balance are not addressed in this RP.

This document covers well control equipment assembly and operations used in coiled tubing intervention and coiled tubing drilling/milling applications performed through:

- tree equipment constructed in accordance with API 6A or API 11IW or both,
- a surface flow head or surface test tree constructed in accordance with API 6A,
- a fracture stimulation wellhead assembly (with at least two gate valves installed for isolation),
- drill pipe or workstrings with connections manufactured in accordance with API 5CT, API 5DP or API 7-1, or a combination thereof.

1.2 Operations Not Covered in this Document

The following operations are not covered in the scope of this document:

- a) coiled tubing well intervention operations without the tree equipment (or surface test tree) in place;
- b) coiled tubing drilling operations without the tree equipment (or surface test tree) in place;
- c) coiled tubing less than $\frac{1}{2}$ in. outside diameter (OD) used in well intervention operations;
- d) coiled tubing intervention operations within pipelines and flowlines;
- e) open-water coiled tubing intervention operations;
- f) reverse circulation of solids-laden fluids or gas through the coiled tubing workstring.

2 Normative References

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

API Specification 5ST, *Specification for Coiled Tubing*

API Specification 6A, *Specification for Wellhead and Tree Equipment*

API Technical Report 6AF1, *Technical Report on Temperature Derating of API Flanges under Combination of Loading*

API Specification 7NRV, *Specification for Drill String Non-Return Valves (1st Edition July, 2006)*

API Specification 7K, *Specification for Drilling and Well Servicing Equipment*

API Specification 16A, *Specification for Drill-through Equipment*

API Specification 16C, *Specification for Choke and Kill Systems*

API Specification 16D, *Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

API Specification 20E, *Alloy and Carbon Steel Bolting For Use in the Petroleum and Natural Gas Industries*

API Specification 20F, *Corrosion Resistant Bolting For Use in the Petroleum and Natural Gas Industries*

ASME B31.3¹, *Process Piping*

ASTM D5720-95², *Standard Practice for Static Calibration of Electronic Transducer-Based Pressure Measurement Systems for Geotechnical Purposes*

NACE MR0175/ISO 15156³, *Sulfide Stress Cracking Resistant-Metallic Materials for Oilfield Equipment*

3 Terms, Definitions, Abbreviations, and Acronyms

3.1 Terms and Definitions

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

3.1.1

accumulator

A pressure vessel charged with a non-reactive or inert gas used to store hydraulic fluid under pressure for operation of well control equipment.

3.1.2

accumulator bank

An assemblage of multiple accumulators sharing a common manifold.

3.1.3

accumulator precharge

An initial inert gas charge in an accumulator, which is further compressed when the hydraulic fluid is pumped into the accumulator thereby storing potential energy.

3.1.4

actuation test

The closing and opening of a well control component to assure mechanical functioning.

3.1.5

adapter

A pressure-containing piece of equipment having end connections of different API size designation and/or pressure ratings, used to connect other pieces of equipment of different API size designation and/or pressure ratings.

¹ ASME International, 3 Park Avenue, New York, New York 10016, www.asme.org.

² ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

³ NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218–8340, www.nace.org.

3.1.6**annular preventer**

A device with a generally toroidal shaped steel-reinforced elastomer packing element that is hydraulically operated to close and seal around any coiled tubing size and CT BHA or to provide full closure of the wellbore.

3.1.7**anti-buckle guide**

A device located between the top of the stripper assembly and the bottom of the injector gripper blocks that provides lateral support to the coiled tubing as it is pushed into the well control stack preventing or reducing the tendency for the tubing to buckle in this area.

3.1.8**articulated line**

Pump, choke, and kill lines assembled as a unit with rigid pipe, swivel joints, and end connections designed to accommodate specified relative movement between end terminations.

3.1.9**backflow**

Fluid flow in a direction opposite to the intended direction of flow.

3.1.10**back-pressure valve**

A flow check device that is installed on the deployed end of the coiled tubing string and prevents well fluids from flowing out of the well through the ID of the CT Workstring.

NOTE In coiled tubing services, a back-pressure valve is typically disconnected from the end with applied internal coiled tubing pressure or with a mechanical release mechanism (shear-out sub).

3.1.11**barrier element (CT)**

Pressure and flow-containing device or system used in coiled tubing well control that contributes to well integrity by preventing the unintended communication of pressure and the flow of fluids (liquid, gas or both).

3.1.12**bend cycle**

The coupling of two tube bending events.

NOTE Consists of one straightening event and one bending event, where the material strain is equal in magnitude.

3.1.13**bleed-off line**

The assembly of valves and piping used to release trapped pressure from the pump line(s) or kill line(s).

3.1.14**blind ram**

The ram assembly in a well control stack which is designed to seal opposing elastomeric elements against each other in an unobstructed bore to isolate pressure below the ram in the well control stack.

NOTE Not designed to seal against the coiled tubing.

3.1.15**bolting**

All threaded fasteners including studs, tap end studs, double ended studs, headed bolts, cap screws, screws and nuts.

3.1.16**bottomhole assembly****BHA**

The assemblage of tools and equipment installed on the end of the coiled tubing workstring used to perform a prescribed service in the wellbore.

3.1.17**bottomhole assembly connector****BHA connector****CT end connector**

A mechanical device used to attach the bottomhole assembly tools to the coiled tubing workstring.

3.1.18**choke**

A device with either a fixed or variable aperture used to control the rate of flow of liquids or gas, or both.

3.1.19**choke line**

High-pressure line connected to the well control stack for the transmission of well fluids to the choke manifold during well control operations.

3.1.20**choke line valve**

Valve(s) connected to and a part of the well control stack that controls the flow to the choke line and manifold.

3.1.21**choke manifold**

Assembly of valves, chokes, gauges, pressure sensors and lines used to control the rate of flow from the well during well intervention and well control operations.

3.1.22**circulation (conventional)**

The movement of fluid from the pump(s) through the coiled tubing workstring which discharges through the CT BHA deployed within the well and returns to surface up the annular space in the wellbore.

NOTE The flow of fluids may exit the well control stack through the flow cross/flow tee or production flowline within the tree equipment.

3.1.23**circulation (reverse)**

The movement of fluid from the pump(s) into the annular space between the coiled tubing workstring OD and the ID of the wellbore which is directed into the CT BHA and returns to surface through the ID of the coiled tubing workstring.

NOTE The flow of fluids exits through the CT reel swivel and is directed through surface piping to the choke line and choke device(s).

3.1.24**closing ratio**

Area of the actuator piston(s) exposed to the close operating pressure, divided by the cross-sectional area of the piston shaft exposed to wellbore pressure.

3.1.25**closing unit**

System of pumps, valves, accumulators, fluid storage and mixing equipment, manifolds, piping, hoses, control panels and other items necessary to hydraulically operate the coiled tubing well control stack equipment.

3.1.26**coiled tubing workstring**

Continuously milled carbon or alloy steel tubular product spooled onto a reel that is used in well intervention operations.

3.1.27**coiled tubing connector****tube-to-tube connector**

A mechanical device used to join two segments of coiled tubing together. This type of connection may be rigid or spoolable.

3.1.28**collapse**

The flattening of CT due to the application of differential pressure (external to internal), with or without an axial tensile load.

3.1.29**competent person**

Person with characteristics or abilities gained through training, experience or both, as measured against the manufacturer's or equipment owner's established requirements.

3.1.30**concentric well intervention operations**

Well intervention operations conducted within conventional tubing or tubing-less well completions.

NOTE These operations are normally performed with the tree equipment in place using a coiled tubing unit, wireline unit, hoisting unit, hydraulic workover (snubbing) unit or small jointed-tubing rig.

3.1.31**connection**

Flanges, and studded connections manufactured in accordance with API specifications, including dimensional requirements.

3.1.32**control console**

An enclosure displaying an array of switches, push buttons, lights, valves, various pressure gauges and/or meters to control or monitor coiled tubing operation functions.

3.1.33**control fluid**

Hydraulic fluid (at atmospheric pressure) to be used for operation of the well control components, injector, stripper assembly and CT reel.

3.1.34**cross****flow cross**

A pressure-containing fitting with a minimum of four openings.

NOTE Usually all four openings are oriented at 90 degrees to one another in the same plane.

3.1.35**deployment bar**

Pressure isolated bar(s) installed in the bottomhole assembly (BHA) used for the safe insertion and removal of tool strings in two or more sections with surface pressure present, if the tool string length exceeds the available height of the well control stack above the tree.

3.1.36**diametral growth**

The enlargement of the coiled tubing diameter due to the effects of applied internal pressure when the coiled tubing is subjected to bend-cycling events.

3.1.37**energized fluid**

A fluid having compressed gas potential energy.

3.1.38**effective hydraulic actuator pressure**

The pressure determined by subtracting the ram piston balance pressure from the observed hydraulic actuator system pressure acting on a given ram.

3.1.39**equipment owner**

Purchaser or renter of the equipment to be installed on the tree equipment, wellhead or wellhead assemblies.

NOTE In most cases, this is the coiled tubing service vendor or a rental equipment company.

3.1.40**equipment user
user**

Company that owns the well, wellhead or wellhead assemblies on which the equipment is to be installed who references this recommended practice.

NOTE This entity may also be the equipment owner in cases where the equipment is rented from a third-party supplier, in part or wholly, depending on the level of equipment supplied.

3.1.41**fatigue**

The process of progressive localized permanent structural change occurring in a material subjected to conditions which produce fluctuating stresses that may culminate in cracks or complete failure after a sufficient number of fluctuations.

3.1.42**Flange**

A protruding rim, with holes to accept bolts and having a sealing mechanism, used to join pressure containing equipment together by bolting one flange to another.

3.1.43**flexible line**

An assembly of a pipe body and end-fittings.

NOTE 1 The pipe body comprises a combination of materials that form a pressure-containing conduit.

NOTE 2 The pipe structure allows for large deflections without a significant increase in bending stresses.

3.1.44**flow check device**

A valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the reverse direction.

3.1.45**force (pressure-affected cross-section)** F_{pacs}

Force created by differential pressure acting across an energized sealing element on the pressure-affected cross-sectional area of a tubular member, such as a coiled tubing or snubbing workstring.

3.1.46**force (snub)**

Sum of F_{pacs} and stripper friction acting on the CT workstring which must be overcome by the CT injector to deploy the CT workstring into a wellbore with surface pressure present.

3.1.47**force (thrust)**

Sum of snub force and secondary reactive axial force(s) acting on the CT workstring which must be overcome by the injector to deploy the CT into a wellbore with surface pressure present.

3.1.48**full-opening valve**

A valve capable of passing a sphere of the valve's nominal size through the closure mechanism when the valve is in its fully opened position.

NOTE The closure mechanism may or may not be of the same size as the end connections.

3.1.49**function**

The operation of a well control component, choke or kill valve, or any other component in one direction.

EXAMPLE Closing the blind ram is one function, and opening the blind ram is a separate function.

3.1.50**gauge and test port**

Hole drilled and tapped into equipment through which internal pressure can be measured or through which pressure can be applied to test the sealing mechanism.

3.1.51**hydrostatic pressure**

Pressure that is exerted at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.52**intervention**

Well servicing operations conducted within a completed wellbore.

3.1.53**kill**

The act of balancing the formation pressure in a wellbore with the hydrostatic pressure derived from a vertical column of fluid with a given density.

NOTE The formation is a subsurface completion interval which serves as the source for production of accumulated hydrocarbons or the injection of disposal fluids.

3.1.54**kill line**

A high-pressure line run from the pump(s) to a connection below the blind ram or shear-blind ram that allows fluid to be pumped into the well or annulus with the designated ram closed during well control operations.

3.1.55**kill line inlet**

An inlet on the well control stack that provides a flow path to pump fluids into the sheared coiled tubing segment suspended within the wellbore or within the annulus between the coiled tubing string and the completion tubulars.

3.1.56**leakage**

Visible passage of the pressurized fluid from the inside to the outside of the pressure containment area of the equipment being tested and/or the loss of test pressure observed on the pressure-recording device.

3.1.57**lubricator**

An assembly of tube sections generally constructed with quick union-type integral seal end connections.

NOTE This term is applied to the assembly of pressure-control tubular sections installed between the stripper assembly and the upper-most well control stack-sealing ram and is typically used to house the BHA tool string.

3.1.58**maintenance**

Disassembly, inspection, reassembly, replacement of components and testing of equipment performed in accordance with equipment owner's maintenance program and the manufacturer's guidelines.

3.1.59**manifold**

An assemblage of pipe, hydraulic hoses, valves and fittings by which fluid from one or more sources is selectively directed to various systems or components.

3.1.60**maximum anticipated surface pressure**

The highest surface pressure predicted in the well which may be encountered while the well control equipment is installed.

3.1.61**maximum anticipated operating pressure**

The highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

The MAOP may be equal to or greater than the MASP.

3.1.62**original equipment manufacturer****OEM**

Design owner or manufacturer of the traceable assembled equipment, single equipment unit or component part.

NOTE If any alterations to the original design and/or assembled equipment or component part are made by anyone other than the OEM, the assembly, part, or component is not considered an OEM product.

3.1.63**other end connector (OEC)****OEC**

Connectors that are not specified in an API dimensional specification, including API flanges, pressure-containing hydraulic latch quick-connects and hubs with non-API gasket preparations and manufacturer's proprietary connections.

3.1.64**ovality**

The degree by which the roundness of a tubular component deviates from a perfect circle due to external forces.

3.1.65**pipe-heavy**

Condition occurring during concentric well intervention operations where the well pressure applied against the cross-sectional area of the tube acting at the stripper element or pressure isolation ram creates an upward acting force that is less than the buoyancy-compensated weight of the deployed workstring.

NOTE In this condition, mechanical assistance is required to support the weight of the tubing during deployment or retrieval operations.

NOTE 2 Buoyancy compensation of the workstring is a function of the weight of the fluid internal to the workstring, the weight of the fluid displaced by the workstring and the air weight of the workstring.

3.1.66**pipe-light**

Condition occurring during concentric well intervention operations where the well pressure applied against the cross-sectional area of the tube acting at the stripper element or pressure isolation ram creates an upward acting force that is greater than the buoyancy-compensated weight of the deployed workstring.

NOTE 1 In this condition, mechanical assistance is required to apply thrust to the tubing during deployment or to maintain control of the workstring when retrieving from the well.

NOTE 2 Buoyancy compensation of the workstring is a function of the weight of the fluid internal to the workstring, the weight of the fluid displaced by the workstring and the air weight of the workstring.

3.1.67**pipe ram**

The ram assembly in a well control stack which is designed to close and seal around the coiled tubing workstring, isolating pressure in the annular space below the ram.

3.1.68**pipe-slip ram**

The combination ram assembly in the well control stack designed to secure the coiled tubing within the slip inserts and isolate pressure in the annular space below the combination ram in a single operation.

3.1.69**power fluid**

Pressurized hydraulic control fluid used to operate the well control equipment components.

3.1.70**pressure**

Ratio of force to the area over which that force is distributed (i.e. pound force to an area (in.²), measured in “psi”).

- absolute pressure: Internal pressure that the equipment is designed to contain and/or control, or that is zero-referenced against a perfect vacuum; measured in psia.
- differential pressure: Difference in pressure between any two points (p1 and p2); measured in “psid”.
- gauge pressure: Pressure measured relative to the ambient pressure, measured in psig.

NOTE e.g. atmospheric for surface application, hydrostatic for subsea application.

3.1.71**pump line**

A high-pressure line between the pump(s) and the coiled tubing service reel or kill line.

NOTE This line is typically configured to pump fluid into the wellbore through the coiled tubing workstring or into the wellbore annulus when connected to the kill line.

3.1.72**quick union**

End connections that employ O-rings seals to hold pressure, while allowing thread make-up of the union connection by hand.

NOTE Used to join sections of lubricator and connect the stripper assembly to the top of the ram-type well control equipment.

3.1.73**ram piston balance pressure**

Amount of hydraulic actuator pressure acting on the ram piston required to create a force equal to the force generated by wellbore pressure acting on the cross-sectional area of the ram piston rod.

NOTE Typically determined by dividing the MASP by the closing ratio of the ram for ram performance testing purposes

3.1.74**rapid gas decompression****RGD**

Sudden depressurization of compressed gas in a system.

NOTE The rapid decrease in gas pressure causes the gas to expand rapidly and can cause blistering or internal damage to gas saturated elastomeric materials.

3.1.75**rated working pressure****RWP**

The maximum internal pressure the equipment component is designed to contain or control or both.

NOTE 1 Indicative of wellbore wetted rated components or actuator systems

NOTE 2 Should not be confused with test pressure

3.1.77**relief valve**

A device that is built into a hydraulic or pneumatic system to mechanically relieve (dump) any excess of the predetermined pressure setting.

3.1.78**repair**

Replacement of parts or correction of damaged components that does not include machining, welding, heat treating or other manufacturing operation.

3.1.79**reservoir**

A storage tank for control fluids used to operate the well control equipment operating system and other hydraulically actuated devices.

3.1.80**response time**

The time required to function a well control component closed and establish an effective pressure seal.

3.1.81**shear ram**

The ram assembly in a well control stack which is designed to shear the coiled tubing and any spoolable components inside the coiled tubing (including wire, tubing, and/or cable).

NOTE The shear ram blade is designed to maintain sufficient flow area at the cut to facilitate through-coiled tubing pumping and well kill operations.

3.1.82**shear-blind ram (standard)**

The combination ram assembly in the well control stack which is designed to shear the coiled tubing and any spoolable components inside the coiled tubing (including wire, tubing, and/or cable) and seal the wellbore in a single operation.

NOTE The shear-blind ram blade is designed to maintain sufficient flow area at the cut to facilitate through-coiled tubing pumping and well kill operations.

3.1.83**shear-blind ram (dedicated)**

The combination shear-blind ram assembly located as close to the wellhead as possible in the well control stack that is operated through a dedicated accumulator circuit designed to shear the coiled tubing and any spoolable components inside the coiled tubing (including wire, tubing, and/or cable) and seal the wellbore in a single operation.

NOTE The dedicated shear-blind ram blade design may or may not provide an opening or specific geometry of the lower cut end of the CT workstring.

3.1.84**slip ram**

The ram assembly in a well control stack which is equipped with tubing slips inserts that, when engaged, prevents movement of the coiled tubing but does not isolate pressure or control flow.

3.1.85**spacer spool(s)**

Pressure-containing pieces of equipment having flanged end connections which serves to space out the well control stack components with equal sized end connections.

NOTE Spacer spools may be located above or below the well control ram stack.

3.1.86**spoolable component**

Continuous manufactured length of tubular or stranded wire product installed within the ID of the CT workstring.

NOTE Spoolable components include wireline, capillary tubing and fiber optic line.

3.1.87**spoolable connector**

A tube-to-tube connector used to join segments of the CT workstring and capable of surviving bending forces encountered during deployment and retrieval which maintaining pressure sealing integrity.

3.1.88**stabilized pressure**

State in which the pressure change rate has decreased to within acceptable limits before beginning the hold period during a pressure test.

NOTE Pressure changes can be caused by such things as variations in temperature, setting of elastomer seals, or compression of air or fluids, etc.

3.1.89**stack rated working pressure**

The pressure containment rating of the ram components in a stack.

NOTE In the event that the rams are rated at different pressures, the stack maximum rated working pressure (RWP) is considered equal to the lowest rated ram component pressure.

3.1.90**stored hydraulic fluid**

Fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the pre-charge pressure.

3.1.91**stripper**

A pressure-controlling device with a resilient elastomeric element used to effect a seal in the annulus formed between the coiled tubing OD and stripper ID bore.

NOTE This device is primarily used to isolate well pressure from the atmosphere when deploying or retrieving coiled tubing strings in wellbores with surface pressure present.

3.1.92**swivel (CT reel)**

A pressure-containing component comprised of rigid elements joined by seal(s) and bearings that allow for the rotation of the rigid elements on the CT reel.

NOTE The swivel is mounted on the axis of the coiled tubing reel and can freely rotate in the direction of the reel motion.

3.1.93**swivel (articulated line)**

A pressure-containing component comprised of rigid elements joined by seal(s) and bearings that allow for the rotation of the rigid elements on the pump and/or kill lines.

NOTE The swivel is not intended to allow the articulated line to rotate freely after the line has been installed.

3.1.94**system pressure test**

The integrity test used to verify the ability of the pipe and pressure containment equipment in service to maintain a pressure seal.

3.1.95**tee****flow tee**

A pressure-containing fitting with three openings.

NOTE Two openings, opposite one another, form the run portion of the tee, and one opening at 90 degrees to the line of the run forms the branch.

3.1.96**tree equipment**

A combination of valves and fittings assembled above the top of the tubing hanger on a completed well to contain well pressure and control the flow of hydrocarbons and other fluids.

3.1.97**unassisted flow****sustained flow**

A flow capable from a wellbore with any formation open to the casing and tubing that can produce to the surface without the use of artificial lift.

3.1.98**usable hydraulic fluid capacity**

The fluid volume recoverable from the accumulator system between the maximum designated accumulator operating pressure to a pressure 200 psig above the pre-charge pressure.

3.1.99**visual position indicator**

Visible means of determining the position of a valve, ram, connector or annular activation to indicate full open or full close positions.

3.1.100**well control barrier**

A tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface.

NOTE The use of a weighted fluid is not considered a barrier in this document, which relies on tested mechanical equipment for well control.

3.1.101**well control stack**

An integral body or an assembly of well control components including ram-type components, stripper assemblies, annular components, spools, and valves connected to the top of the wellhead or tree to control well fluids.

3.2 Abbreviations and Acronyms

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

BHA	bottomhole assembly
CR	closing ratio
CT	coiled tubing
F_{pacs}	force acting on the pressure-affected cross-section
H ₂ S	hydrogen sulfide
ID	inside diameter
IOM	installation, operation and maintenance
MASP	maximum anticipated surface pressure
MAOP	maximum anticipated operating pressure
NDE	nondestructive examination
NIST	National Institute of Standards and Technology (U.S.)
OEC	other end connection
OEM	original equipment manufacturer
OD	outside diameter
P&ID	pipng and instrumentation diagram
PSIA	pounds per square inch absolute
PSIG	pounds per square inch gauge
PQR	procedure qualification record
RGD	rapid gas decompression
RWP	rated working pressure
SBR	shear-blind ram
WPS	weld procedure specification

4 Well Control Equipment

4.1 General

Coiled tubing well control equipment is designed to allow safe well intervention services to be performed under pressure. However, well pressure should be kept at a minimum to avoid unnecessary wear and tear on the well-control equipment. CT well control stack equipment shall conform to either API 16A, API 16C or API 6A-PSL3, where applicable. The selection of well control equipment for a given application should be consistent with the manufacturers' recommendations.

4.2 Coiled Tubing Operations

4.2.1 General

Well control equipment shall be identified, installed, tested, and used to promote and maintain control of the well at all times. The following should be reviewed and understood to ensure compliance with this requirement:

- a) maximum anticipated surface pressure (MASP);
- b) maximum anticipated operating pressure (MAOP);
- c) well control barriers;
- d) CT operational pressure categories;
- e) well control stack configurations;
- f) bore size, rated working pressure (RWP), and connections of well control equipment.

NOTE 1 MASP is the highest surface pressure predicted in the well which may be encountered while the well control equipment is installed.

NOTE 2 MAOP is the highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

4.2.2 Coiled Tubing Well Control Barriers

A CT well control barrier is defined as a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. Tested barrier elements incorporated in the well control stack and bottomhole assembly (BHA) shall demonstrate reliable and repeatable pressure and flow control performance through mechanical testing prior to being used for the prescribed service.

The following mechanical devices, or combination of mechanical devices, are CT well control barriers:

- a) the combination of a pipe ram sealing component, CT workstring and a flow check assembly installed within the CT BHA;
- b) a single blind ram and single shear ram;
- c) a shear-blind ram (SBR).

NOTE 1 The flow check assembly installed on the end of the CT workstring in combination with a pipe ram sealing component in the well control stack constitutes only one barrier, regardless of the number of pipe ram sealing devices installed in the well control stack. In the pressure categories where multiple pipe rams are recommended in the well control stack, these rams are intended to be located at specific points where annulus-sealing capability is required and does not constitute an increase in the number of barriers in the stack.

NOTE 2 The combination of a single blind ram with a single shear ram in the well control stack constitutes only one barrier, regardless of the number of blind ram sealing devices installed in the well control stack. Where more than one blind ram is installed in the well control stack, the additional blind rams do not constitute an increase in the number of barriers in the stack unless each blind ram is paired with a separate single shear ram.

4.2.3 Coiled Tubing Operational Pressure Categories

Minimum stack RWP should be selected to allow for a kill program to be implemented. The difference between the MASP and minimum stack pressure rating in Table 1 is a recommended pressure margin. Different kill margins may be applied, provided that calculations are performed for the pumped-fluid kill program. The kill procedure plan may include implementation of a circulation method, the lubricate and bleed technique, flowing the well to reduce surface pressure or pumping at lower rates to minimize friction pressure. MAOP or MASP which exceeds the limits of Pressure Category (PC) 4 are beyond the scope of this document.

Table 1—Pressure Categories for CT Well Control Equipment

Pressure Category (PC)	MASP Range psig	Minimum Rated Working Pressure of Stack ^b psig	Minimum Number of Barriers
PC-0	0 ^a	3000	1
PC-1	1 to 1500	3000	2
PC-2	1501 to 3500	5000	2
PC-3	3501 to 7500	10,000	2
PC-4	7501 to 12,500	15,000	2
^a PC-0 applies to those wells demonstrated as incapable of unassisted flow to surface (based on local regulatory agency guidelines).			
^b The minimum RWP of the stack shall be equal to or greater than the MAOP.			

4.2.4 Well Control Stack Configurations

4.2.4.1 General

The configuration of the well control stack will vary depending upon many factors, including, but not limited to, MAOP, MASP, CT string design, and execution of the prescribed service. All annular preventer, stripper and ram-type well control components and hydraulically-operated valves (where required) in the well control stack shall be controlled from a remote station that is typically located within or adjacent to the CT control cabin.

Excluding PC-0, the standard well control stack configuration for all pressure categories shall include the following components. The recommended order of the components (from the top down) is shown as follows:

- 1) one stripper well control component (see 4.3.1);
- 2) one blind ram well control component (see 4.3.2.1);
- 3) one shear ram well control component (see 4.3.3);
- 4) one kill line inlet (see 4.3.8);
- 5) one slip ram well control component (see 4.3.4);
- 6) one pipe ram well control component (see 4.3.2.2);
- 7) one dedicated SBR well control component (see 4.3.5).

4.2.4.2 Pressure Category 0 (0 psig)

The PC-0 well control components shall conform with the barrier requirements of Table 1 described as follows (from top down).

- a) For returns taken through the tree or wellhead below the well control stack, one pipe ram well control component in combination with a flow check assembly installed within the CT BHA.
- b) For returns taken through the flow cross or flow tee installed in the well control stack:
 - one pipe ram well control component in combination with a flow check assembly installed within the CT BHA,
 - one flow tee or flow cross,
 - one pipe ram (or pipe-slip ram) well control component.

If a flow check assembly is not installed, one blind ram and one shear ram or a combi SBR well control component shall be installed.

4.2.4.3 Pressure Categories 1–4

The acceptable options for arrangement of well control stack equipment which will conform with this recommended practice for Pressure Categories 1 through 4 from Table 1 shall be in accordance with Table 2. Example illustrations of well control stack options are seen in Annex A of this document.

Table 2—CT Well Control Stack Equipment Configuration

Well Control Equipment Component	PC–1	PC–2	PC–3	PC–4
Stripper Assembly (1 st in Service)	Required	Required	Required	Required
Stripper Assembly (2 nd in Service)	Optional	Optional	Optional	Required
Stack-to-Stripper Connection	Quick Union, Flanged or OEC (Note)	Quick Union, Flanged or OEC (Note)	Quick Union, Flanged or OEC (Note)	Flanged or OEC (Note)
Blind Ram Component ^a	Required	Required	Required	Required
Shear Ram Component ^a	Required	Required	Required	Required
Kill Line Inlet Connection ^c	Required	Required	Required	Required
Slip Ram Component ^b	Required	Required	Required	Required
Pipe Ram Component ^b (Upper)	Required	Required	Required	Required
Flow Cross/Flow Tee	Optional	Optional	Optional	Optional
Pipe Ram Component ^{b, c} (Lower)	Required	Required	Required	Required
Dedicated SBR ^{c, d}	Required	Required	Required	Required
NOTE A pressure-containing hydraulic latch connection may be used above the uppermost ram-type well control component.				
^a Manufacturer's single combination of the blind and shear ram (see 4.3.5) may be used. ^b Manufacturer's single combination of the slip and pipe ram (see 4.3.6) may be used. ^c On a dual combination-ram stack, a kill line inlet shall be installed between the combination shear-blind ram position, and the combination pipe-slip ram positions. ^d The dedicated SBR is operated through an independent accumulator circuit on the well control closing unit which is used exclusively to operate the SBR only.				

4.2.4.3.1 If a dual combination well control stack is used to supplement the standard well control stack configuration, the well control component order could change. In this configuration, the combination pipe-slip ram assembly will typically be located below the combination shear-blind ram assembly.

4.2.4.3.2 The recommendations for flow tee/cross, choke(s) and valve assemblies are specified in Section 8, with the recommendations for kill line(s) and valve assemblies provided in Section 9.

4.2.5 Bore Size, Rated Working Pressure, and Connections of Well Control Equipment

4.2.5.1 The bore of well control stack components (with the exception of the stripper assembly) should be greater than the maximum predicted width of collapsed CT (see 5.5).

4.2.5.2 In cases where the bore of well tubulars could deter the removal of collapsed CT, contingency plans should be in place.

4.2.5.3 End connections and outlet connections in the well control stack shall be in accordance with API 6A and/or API 16A.

External supports (e.g. guy wires, crane, support structure) shall be used to reduce the bending and transmitted loads from the equipment onto the connections. The following shall apply to connections for the specified pressure category.

- a) PC-0—All connections shall have a minimum pressure rating of 3000 psig.
- b) PC-1—All end connections from the tree to the uppermost required ram component in the well control stack configuration should be flanged and shall have a minimum pressure rating of 3000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 3000 psig. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of other end connectors (OEC)s shall be available and reviewed. For tree construction with a threaded connection only, the threaded connection shall meet the minimum pressure rating of 3000 psig and should be restricted to the connection between the tree and well control stack.
- c) PC-2—All end connections from the tree to the uppermost required ram component in the well control stack configuration should be flanged with a minimum pressure rating of 5000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 5000 psig. Where surface wellhead and tree construction prevents use of a flange connection, an installation plan for use of OECs shall be available and reviewed. For tree construction with a threaded connection only, the threaded connection shall meet the minimum pressure rating of 5000 psig and should be restricted to the connection between the tree and well control stack.
- d) PC-3—All end connections from the tree to the uppermost required ram component in the well control stack configuration shall be flanged with a minimum pressure rating of 10,000 psig. Flanged or other connection types used above the uppermost ram component shall have a minimum pressure rating of 10,000 psig.
- e) PC-4—All end connections from the tree to the uppermost required ram component in the well control stack configuration shall be flanged with a minimum pressure rating of 15,000 psig. Flanged or pressure-containing hydraulic latch connection types used above the uppermost ram component shall have a minimum pressure rating of 15,000 psig.

An appropriately sized crane or support structure is the primary means of minimizing loads within the well control stack and shall be capable of supporting these loads. Visual inspections shall be done to verify the well control stack and rig up are maintained as inline and straight with the tree as is practical.

4.2.5.4 All studs, and nuts used in connection with flanges shall be in accordance with API 20E or API 20F BSL-2. The installation of the flange fastener components shall be performed in a cross-flange pattern to the appropriate torque values by a competent person.

4.2.5.5 Ring gaskets shall conform with the requirements of API 6A.

4.2.5.6 Ring gaskets shall not be reused.

4.2.6 Pressure Isolation Protection Below the Well Control Stack Equipment

4.2.6.1 For rig-up of PC-1 through PC-4 CT well control stacks onto tree equipment, surface test tree or other connection to a wellbore exposed to produced fluids, the wellbore shall be isolated by at least two tested mechanical pressure isolation devices (e.g. valves) installed below the well control stack to establish safe operating conditions for installation of well control equipment.

4.2.6.2 Where rig up onto drill pipe or a jointed tubing workstring is required, the drill pipe or workstring shall be isolated by at least one mechanical pressure isolation device rated for the pressure end load (such as full-open safety valve, etc.), with a risk assessment performed to evaluate onsite conditions and determine the most appropriate means for providing secondary pressure isolation device.

NOTE A pressure end load is an axial force resulting from internal pressure applied to the area defined by the maximum seal diameter.

4.2.6.3 Where the isolation valve on the tree immediately below the CT well control stack connection is designed to be directional (seals pressure from below only), a separate two-way sealing valve should be installed above the tree directional-sealing valve to allow for proper pressure testing of the well control stack.

4.3 Well Control Components

4.3.1 Stripper Assembly (Pressure Controlling Device)

The stripper assembly component is a pressure controlling device designed to isolate well pressure and effluents from the atmosphere during CT operations. The purpose of the stripper assembly is to seal around the outside diameter (OD) surface of the CT workstring in both static and dynamic operating conditions.

4.3.1.1 For all CT operations where surface wellhead pressure is expected, at least one stripper assembly shall be installed in the well control stack to serve as the means for controlling wellhead pressure under dynamic CT operating conditions.

4.3.1.2 In all CT operations where surface wellhead pressure is expected, lateral support for the CT, such as an anti-buckle guide shall be incorporated. The anti-buckle guide may be an integral part designed into the stripper assembly or incorporated as a separate item attached to the stripper assembly.

NOTE The intent for use of an anti-buckle guide is to minimize the unsupported column length between the entry position of the CT into the stripper assembly and the lowest fully-supported gripper blocks within the injector chains to reduce the risk of catastrophic buckling failure.

A tubing force analysis shall be conducted to confirm that the CT segment above the energized stripper element will not experience catastrophic buckling due to force acting on the pressure-affected cross-section (F_{pacs}) generated by the differential pressure occurring across the sealing stripper element. The results of the tubing force analysis should be used to determine the maximum allowable thrust force to be applied to the CT workstring during snubbing operations (see 5.4).

4.3.1.3 For PC-4 CT operations, a second stripper shall be installed in the CT well control stack.

4.3.1.4 Where two stripper assemblies are installed within the well control stack, the stripper assembly which is protected with an anti-buckle guide should be designated as the “first-in-service” stripper which is intended to be used as the primary dynamic pressure control component. The “second-in-service” stripper assembly used to provide additional pressure containment should be as close to the “first-in-service” stripper assembly as practically possible.

4.3.1.5 Where service applications require applied snub force to be imparted through the “second-in-service” stripper, a tubing force analysis shall be performed to quantify the risk for potential catastrophic buckling failure of the unsupported column length above the “second-in-service” stripper assembly packer element due to F_{pacs} generated by the differential pressure occurring across the energized stripper element (see 5.4).

NOTE For general CT well intervention service, the uppermost stripper assembly in the well control stack should be designated as “first-in-service”.

4.3.1.6 Each stripper assembly in the well control stack shall serve as a single pressure control component. In normal operations, the two stripper assemblies shall not be used in combination to regulate wellhead pressure or trap pressure between the two sealing elements.

4.3.1.7 The general operational arrangement for each stripper assembly used in CT operations shall be subjected to a risk analysis to determine the following:

- a) The stripper assembly packer elements shall allow for removal and replacement during the well intervention program with the CT workstring deployed within the wellbore.
- b) The stripper assembly lateral support bushings shall allow for removal and replacement during the well intervention program with the CT workstring deployed within the wellbore.
- c) The stripper assembly components should provide sufficient mechanical support and wear resistance to complete the CT workstring deployment and retrieval program for the prescribed service conditions without having to replace the packer elements or support bushings.
- d) The stripper assembly shall provide a dynamic pressure seal on the OD surface of the CT workstring at the maximum speed that the CT workstring is to be deployed or retrieved from the wellbore.
- e) The maximum running speed for the stripper assembly using a specified OD size of CT workstring should be based on the following conditions:
 - 1) surface wellhead pressure;
 - 2) surface wellhead temperature;
 - 3) tube body roughness and general CT OD surface lubrication;
 - 4) wellbore fluids immediately below the stripper (liquids, gas, H₂S, etc.);
 - 5) stripper element chemistry (Nitrile, Buna-N, Viton, Polyurethane, etc.).

NOTE See 5.5, (Coiled Tubing Collapse) for additional guidance regarding collapse of coiled tubing when effecting a pressure seal within the stripper assembly.

4.3.1.8 Where an annular preventer is used in CT operations, the annular preventer is primarily used for sealing on areas of the CT BHA or the OD surface of deployment bars/through-tubing screens when the diameter of the assembly is different than the OD of the CT workstring. In these applications, the annular preventer is used only as a static annular seal component and is not intended to provide dynamic pressure sealing service.

4.3.1.9 When an annular preventer is installed, the stripper assembly shall be installed above the annular preventer. Once all tool deployment has been completed through the annular, the connection between the annular and the stripper assembly shall be pressure tested.

4.3.1.10 As the stripper assembly elastomeric sealing element is considered a consumable component, the elastomeric sealing element installed in each stripper assembly within the well control stack should be inspected prior to each deployment into the wellbore. If the elastomeric sealing element is observed to be damaged or worn, the stripper assembly elastomeric sealing element should be replaced prior to conducting the well intervention operations.

4.3.2 Pressure Sealing Rams (Blind and Pipe)

4.3.2.1 The blind ram is designed to seal the wellbore and isolate pressure when the bore of the ram is unobstructed. In CT operations, the blind ram (Figure 1) is normally the upper-most ram well control component in the standard well control stack configuration (see Annex A).

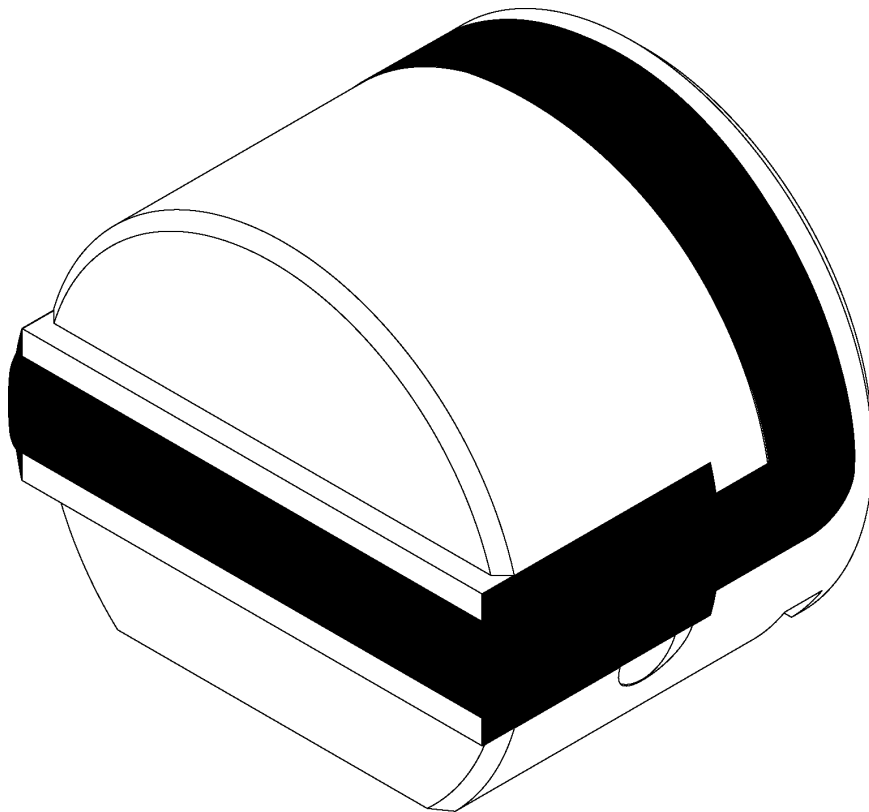


Figure 1—Blind Ram

4.3.2.2 The pipe ram is designed to isolate annulus pressure between the CT OD surface and the inside diameter (ID) of the well control stack bore. The pipe ram shall be sized for the CT OD in use and shall be configured with guides to center the CT workstring in the well control stack bore. The pipe ram (Figure 2) is normally the bottom ram well control component in the standard well control stack configuration (see Annex A).

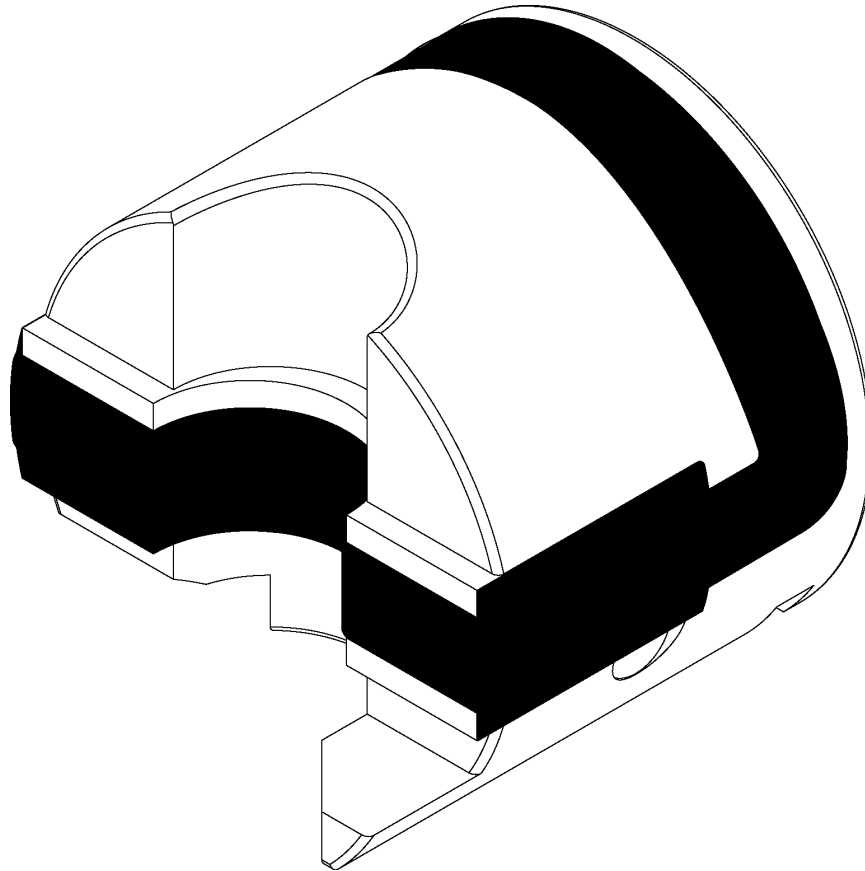


Figure 2—Pipe Ram

The pipe ram should support a differential pressure above the ram greater than or equal to the kill pressure margin.

The user should consult with the ram manufacturer to determine how much pressure the pipe ram design is expected to contain above the closed pipe ram.

NOTE 1 Kill pressure margin represents the pressure applied above the closed pipe ram needed to pump kill fluid into the shear cut end of the CT Workstring and through the CT suspended in the well control stack to either bullhead the fluid to the formation or circulate within the annulus to create a hydrostatic balance within the wellbore.

NOTE 2 For the differential pressure seal from above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable.

The user should consult with the ram manufacturer to determine how much pressure the pipe ram design is expected to contain above the closed pipe ram.

4.3.3 Shear Ram

4.3.3.1 The shear ram shall be capable of shearing the CT workstring body (and any spoolable components inside the CT workstring) at MASP of the well without tensile loads applied to the tubing or spoolable components inside the CT workstring. The shear ram (Figure 3) is normally located immediately below the blind ram in the standard well control stack configuration (see Annex A). The shear ram shall be sized appropriate for the OD of the CT workstring used in the prescribed service.

4.3.3.2 The shear ram shall be capable of a minimum of two cuts of the CT workstring OD size, wall thickness and grade in service. The shear cut shall provide an opening in the lower cut end of at least 30 % of the original ID cross-sectional area to facilitate subsequent through-tubing pumping and well killing operations. The geometry of the shear cut should also enable fishing operations.

4.3.3.3 The shear ram shall be capable of shearing the CT workstring when the tubing is secured within the slip ram or pipe-slip ram.

4.3.3.4 The closing pressure required to shear the CT workstring at MASP of the well (P_{crit}) shall be less than the retained pressure within the well control accumulator system at the projected point where the shear ram is to be closed (see G.3.2). The value of (P_{crit}) shall not exceed the manufacturer's RWP for the ram operating system.

4.3.3.5 The shear ram blades shall be replaced after each CT workstring shearing operation as soon as practically possible.

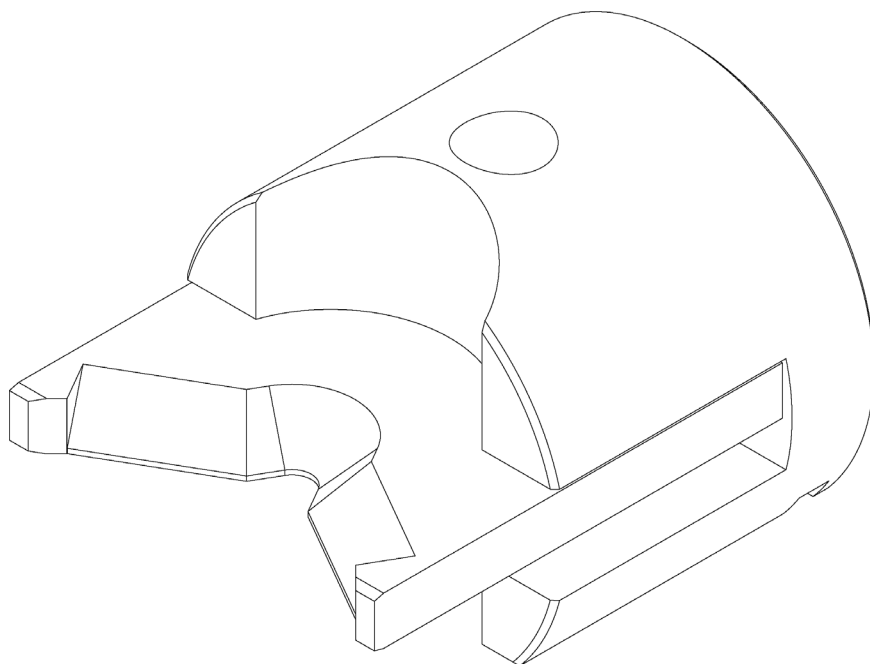


Figure 3—Shear Ram

4.3.4 Slip Ram

4.3.4.1 The slip ram shall be sized for the OD of the CT workstring used in the prescribed service and shall be configured with guides to center the CT workstring in the well control stack bore. The slip ram (Figure 4) is normally located immediately above the pipe ram in the standard well control stack configuration (see Annex A).

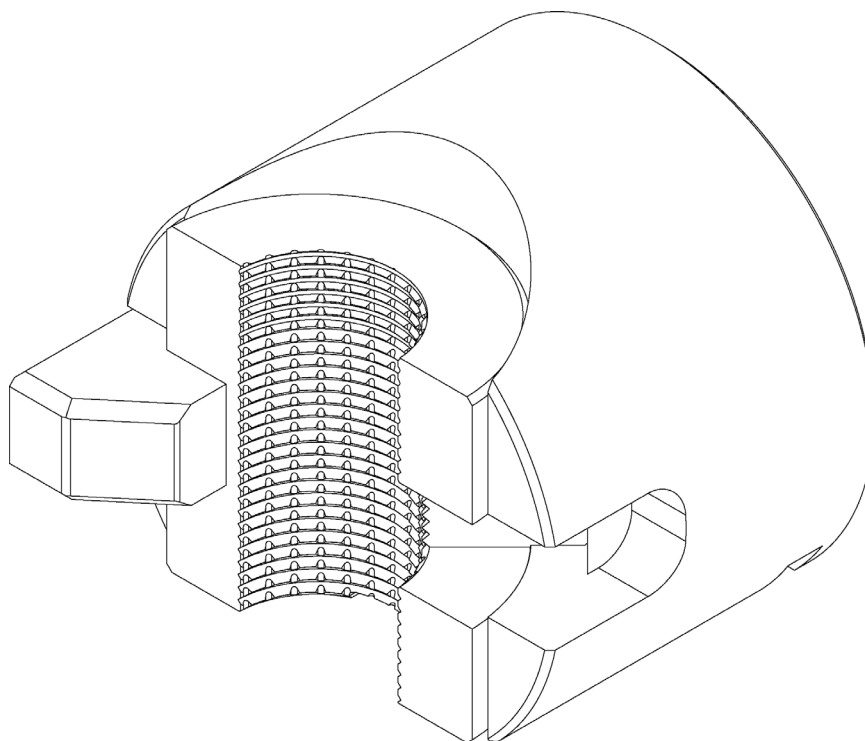


Figure 4—Slip Ram

4.3.4.2 The slip ram shall be capable of holding the maximum anticipated hanging weight of the CT workstring in the pipe-heavy condition without movement of the tubing within the slip inserts. In addition, the slip ram shall be capable of holding the CT workstring in the pipe-light condition to the force equal to the MASP multiplied by the cross-sectional area of the tube body without movement of the tubing within the slip inserts.

4.3.4.3 The tests to be conducted to determine closing pressure required to secure the CT workstring within the slip inserts at MASP of the well are defined in Annex D and shall not exceed the manufacturer's RWP for the ram operating system.

4.3.5 Shear-blind Combination Ram (SBR)

4.3.5.1 The SBR is a combination ram which incorporates two ram functions into a single well control ram component (Figure 5). Shearing and sealing shall be achieved in a single operation. The SBR shall be capable of shearing the CT workstring body (and any spoolable components inside the CT workstring) at the MASP of the well without tensile loads applied to the tubing or any of the spoolable components inside the CT workstring. Upon completion of the SBR actuation, the ram seals shall isolate the wellbore without requiring movement of the CT workstring. The SBR shall be sized appropriately for the OD of the CT workstring used in the prescribed service.

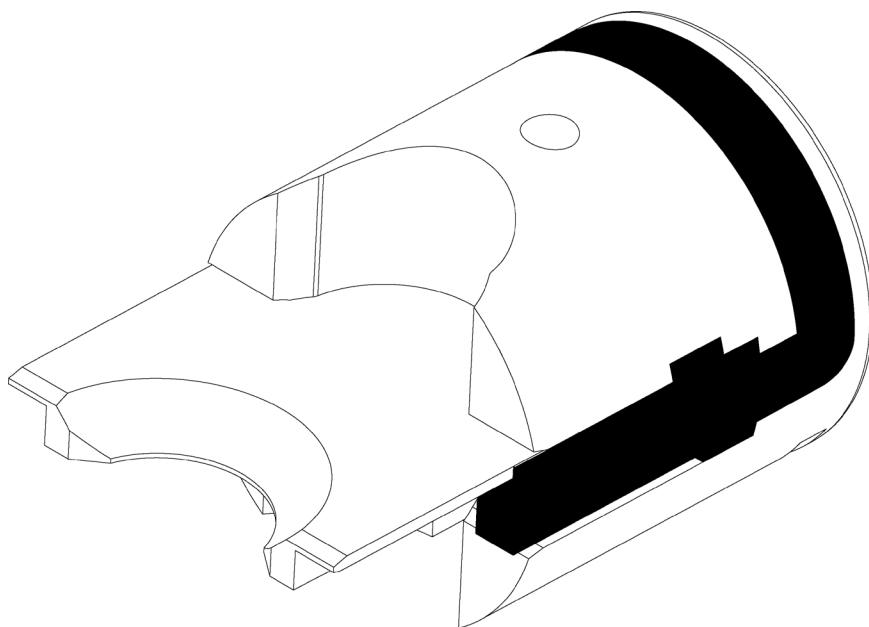


Figure 5—Shear-blind Combination Ram

4.3.5.2 The standard SBR shall be capable of a minimum of two shear and seal operations for the CT workstring OD size, wall thickness and grade in service. The SBR cut shall provide an opening in the lower cut end of at least 30 % of the original ID cross-sectional area to facilitate subsequent through-tubing pumping and well killing operations. The geometry of the SBR cut should also enable fishing operations.

4.3.5.3 The dedicated SBR shall be capable of a minimum of two shear and seal operations for the CT workstring OD size, wall thickness, and grade in service. The condition of the lower cut end of the CT workstring does not require an opening or special geometry when cut with the dedicated SBR.

4.3.5.4 The standard SBR and dedicated SBR shall be capable of shearing the CT when the tubing is secured within a slip or pipe-slip ram located below the SBR.

4.3.5.5 The closing pressure required to shear the CT workstring and seal the wellbore at the MASP of the well (P_{crit}) shall be less than the retained pressure within the well control accumulator system at the projected point where the SBR is to be closed (see Annex G.3.6). The value of (P_{crit}) shall not exceed the manufacturer's RWP for the ram operating system.

4.3.5.6 The SBR blades and required components shall be replaced after each CT workstring shearing operation as soon as practically possible.

4.3.6 Pipe-slip Combination Ram

4.3.6.1 The pipe-slip ram is a combination ram which incorporates two ram functions into a single well control ram component, holding the CT workstring and isolating annulus pressure between the surface of the CT OD and the ID of the well control stack bore in a single ram operation (Figure 6).

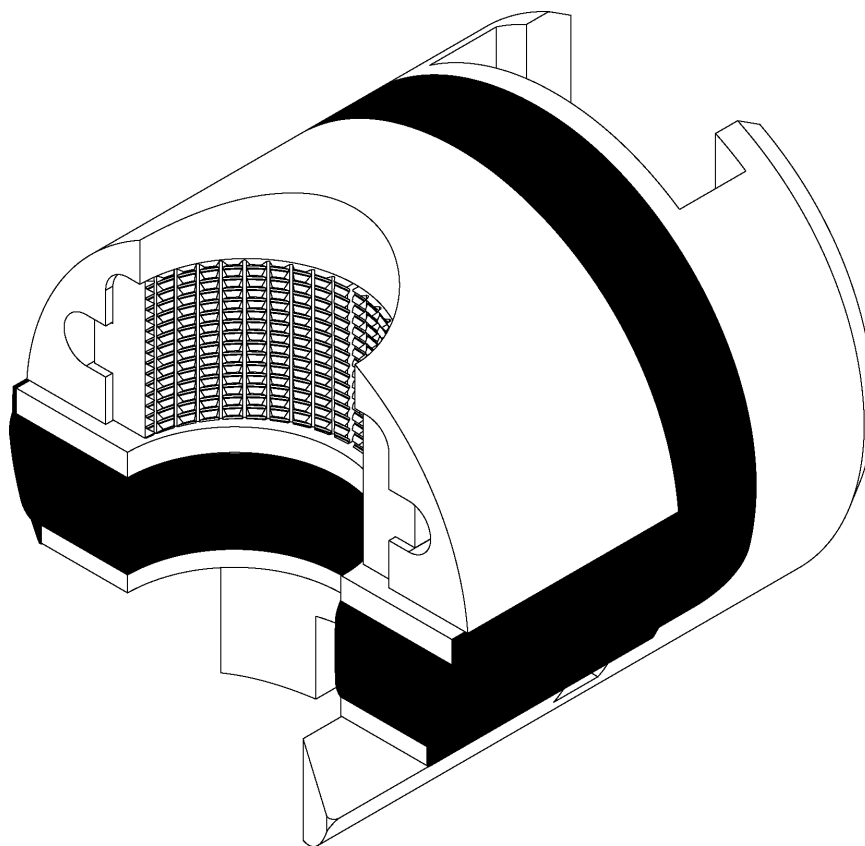


Figure 6—Pipe-slip Combination Ram

4.3.6.2 The pipe-slip ram shall be sized for the OD of the CT workstring used in the prescribed service and shall be configured with guides to center the CT workstring in the well control stack bore.

4.3.6.3 The pipe-slip ram shall be capable of sealing the annulus while holding the maximum anticipated hanging weight of the CT workstring without movement of the tubing within the slip inserts. In addition, the pipe-slip ram shall be capable of sealing the annulus while holding the CT workstring in the pipe-light condition to the force equal to the MASP multiplied by tube cross-sectional area without movement of the tubing within the slip inserts.

The pipe-slip ram should support a differential pressure above the ram greater than or equal to the kill pressure margin.

The user should consult with the ram manufacturer to determine how much pressure the pipe-slip ram design is expected to contain above the closed pipe-slip ram.

NOTE 1 Kill pressure margin represents the pressure applied above the closed pipe ram needed to pump kill fluid into the shear cut end of the CT Workstring and through the CT suspended in the well control stack to either bullhead the fluid to the formation or circulate within the annulus to create a hydrostatic balance within the wellbore.

NOTE 2 For the differential pressure seal from above the ram, a bubble tight seal is not required and some percentage of leakage may be acceptable.

4.3.6.4 The closing pressure required to secure the CT workstring within the slip inserts and seal the annulus at MASP of the well (P_{slip}) is defined in Annex D and shall not exceed the manufacturer's RWP for the ram operating system.

4.3.7 Ram Position

Each ram-type well control equipment component shall be equipped with a visual position indicator to determine the ram position for each ram component (as open or closed).

4.3.8 Kill Line Inlet

The kill line inlet shall be a flanged connection sized for at least a 2-in. nominal flange and a RWP at least equivalent to the well control ram body. The location of the integral kill line inlet is normally between the shear ram and slip ram in the standard well control stack configuration and between the SBR and pipe-slip ram in the dual combination ram well control stack configuration.

The kill line inlet should be used only as a flow path to pump fluids into the wellbore during well intervention services, pressure testing of the well control stack, or to equalize pressure across sealing rams, or a combination thereof.

4.3.9 Periodic Maintenance and Inspection

4.3.9.1 The inspection and maintenance of the well control equipment shall be performed in accordance with the equipment owner's maintenance system. The equipment owner's maintenance system should meet or exceed the OEM's maintenance recommendations.

4.3.9.2 The equipment owner's maintenance system shall address the inspection (e.g. internal/external visual, dimensional, NDE, etc.) of well control equipment components.

4.3.9.3 The well control stack, choke and kill equipment shall be inspected at least every five (5) years. Alternately, if the equipment owner wishes to establish an inspection frequency beyond the five-year period, the equipment owner shall collect, analyze and record condition-based data (including performance data) to justify this extended period. Individual components and subassemblies may be inspected on a staggered schedule. The inspection results shall be verified against one of the following:

- a) The manufacturer's acceptance criteria, or
- b) The equipment owner's acceptance criteria if the equipment owner collects and analyzes condition-based data and performance data to justify their criteria.

4.3.9.4 The inspection frequency period shall begin using one of the following criteria:

- a) The date the equipment owner accepts delivery of the well control component(s) unless placed into storage in accordance with 4.3.10.
- b) The date the inspected equipment is placed into service, where preservation and storage records in accordance with 4.3.10 are available.
- c) The date of the last inspection for the component, if preservation and storage records in accordance with 4.3.10 are not available.

4.3.9.5 For schedule- and condition-based inspection programs, slip ram inserts and pipe-slip ram inserts, along with their respective ram blocks and insert retention mechanism(s) shall be inspected during the mechanical ram performance test program seen in Annex D using visual inspection and surface NDEs. The inspection results shall be verified against the manufacturer's acceptance criteria.

4.3.9.6 For schedule- and condition-based inspection programs, shear ram blades and SBR blades, along with their respective ram blocks and blade retention mechanism(s) shall be inspected during the mechanical ram performance test program seen in Annex E using visual inspection and surface NDEs. The inspection results shall be verified against the manufacturer's acceptance criteria.

4.3.9.7 Inspections shall be performed by a competent person(s).

4.3.9.8 Elastomeric components and the finishes of their seal surfaces should be inspected when equipment is disassembled.

4.3.9.9 Documentation of all repairs and remanufacturing shall be maintained in accordance with 4.3.11.

4.3.10 Equipment Preservation and Storage

4.3.10.1 Well control equipment should be stored in a manner that prevents degradation of the equipment's integrity in accordance with the equipment owner's or manufacturer's requirements.

4.3.10.2 Before returning to service, the components shall be inspected and tested in accordance with the equipment owner's or manufacturer's requirements.

4.3.10.3 Any elastomer seals found to be outside of the manufacturer's recommended shelf-life expiration date shall be prohibited from installation in well control equipment systems.

4.3.10.4 Records related to the storage, preservation and subsequent inspection of the equipment components shall be maintained by the equipment owner.

4.3.11 Installation, Operation, and Maintenance

4.3.11.1 The coiled tubing well control equipment components assembled within the stack consist of parts which contain, control or retain pressure and are critical to safe and effective operation.

4.3.11.2 The installation, operation and maintenance (IOM) of parts which contain, control or retain pressure within each stack component shall be performed by a competent person.

4.3.11.3 A record of the maintenance, repair history and/or remanufacture file for each well control stack component assembly shall be retained by serial number or unique identification number and available for review by the user.

NOTE Remanufacture involves disassembly, reassembly and testing of equipment where machining, welding heat treating or other manufacturing operations are employed.

4.3.11.4 Replacement parts (consumables) shall be in conformance with the relevant API standards and satisfy the design/operating requirements as specified by the original equipment manufacturer (OEM).

4.3.11.5 Operation of the well control stack components shall be conducted by a competent person, following the operating practices specified by the OEM.

4.3.11.6 The IOM manuals (either hard copy or electronic storage) shall be available onsite for the well control equipment in service.

4.4 Additional Well Control Components

4.4.1 Well Control Elastomers

Elastomers used in well control equipment which are exposed to well fluids and/or corrosive gases shall be qualified for use in the well intervention service. See Section 7 for review of the elastomers and materials referenced in this document.

4.4.2 Equalizing Device

The well control stack shall have a means for equalizing pressure between cavities across each pressure-sealing ram set prior to opening the rams.

4.4.3 Ram Locking System

All pressure sealing and slip-type well control stack ram components shall have a system for locking the rams in the closed position. The ram locking system shall be capable of holding the rams in the closed position and conform with the individual performance requirements in the absence of closing pressure applied by the accumulator system.

4.4.4 Spacer Spools, Adapter Spools, Crossover Connectors and Lubricators

4.4.4.1 The spacer spools, adapter spools, and lubricators shall meet or exceed all requirements stipulated in 4.2.3 and 4.2.5, and API 6A.

NOTE Spacer spools, adapter spools, crossover connectors, and lubricators may be used when the CT BHA is too long to be contained within the well control stack or when the work environment necessitates spacing out the well control equipment.

4.4.4.2 Spacer spools, adapter spools, and lubricators shall be capable of withstanding the applied loads and combination of loads shown below (as a minimum):

- a) compression loads generated by the weight of the injector and well control equipment on top of the assembly plus loads resulting from the buoyed weight of the CT workstring suspended in the well;
- b) bending loads generated by the reel back tension, dynamic motion and wind loads;
- c) loads due to internal pressure.

4.4.4.3 Where the bending loads cannot be completely mitigated, the flanged connections shall be subject to derating as per API 6AF1.

NOTE Calculation details for derating are shown in API 6AF2.

4.4.4.4 The location of the stripper assemblies should not restrict the ability to fully retrieve the CT BHA above the upper-most ram in the well control stack.

4.4.4.5 When bottomhole assemblies are too long to be contained within the well control stack, alternate methods or processes conforming with the barrier requirements of Table 1 shall be acceptable. Alternate methods may include use of deployment bars, remotely-actuated connectors, etc..

4.4.5 Flow Cross or Flow Tee

The flow tee (seen in API Spec 6A) or flow cross (seen in API Spec 16A) is typically located below the standard well control stack configuration. If a flow tee or flow cross is installed, the flanged flow tee or flanged flow cross shall be in accordance with API 6A.

NOTE Spacer spools, adapter spools, crossover connectors, and lubricators may be used when the CT BHA is too long to be contained within the well control stack or when the work environment necessitates spacing out the well control equipment.

4.4.6 Well Control Stack Pressure-Containing Welds

Spacer spools, adapter spools, lubricators, flow crosses and flow tees having welded end connections shall conform to the following:

- a) All welds of wellbore pressure-containing and load bearing components shall be performed in accordance with the applicable API standards and performed by a welder qualified/certified to the specific welding procedure and practice.

- b) All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE MR0175/ISO 15156.
- c) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the repair facility.
- d) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, Article II.
- e) All welded end connections shall be subjected to nondestructive examination (NDE) inspection (X-ray or ultrasound shear wave) and the records of the latest NDE inspection shall be available for review.

NOTE A pressure-containing weld is a weld whose absence or failure will reduce or compromise the pressure-containing integrity of the component.

4.5 Well Control Equipment for Hydrogen Sulfide Service

All well control equipment, inclusive of surface piping, manifolds, valves, and fittings exposed to hydrogen sulfide (H_2S) shall be in accordance with NACE MR 0175/ISO 15156. Shear blades (which are assembled with a Shear Ram body), Shear blade inserts and Slip inserts need not conform with the requirements of NACE MR 0175. The Shear Ram blade shall not be considered to be a Shear Ram body.

5 Coiled Tubing Workstring and Connectors

5.1 Coiled Tubing Workstring

The CT workstring is an integral part of the well control equipment system. The pipe ram cannot establish an effective seal and the stripper assembly cannot establish an effective pressure controlling seal unless the CT workstring within the wellbore maintains pressure integrity and the tube geometry remains within the sealing tolerance of the well control equipment. The CT workstring consists of the full length of coiled tube and all tube-to-tube connections (including welded connectors and spoolable connectors). Where used as a well control barrier element, the CT connector shall provide an effective pressure seal.

The CT workstring and tube-to-tube connections shall be in accordance with the CT well control stack pressure ratings shown in Table 1 as integral parts of the well control system.

5.1.1 Welding on Coiled Tubing Workstrings During the Manufacturing Process

As per API 5ST, all coiled tubing strings are manufactured having a longitudinal seam weld created using the high frequency induction (HFI) welding practices. Further, the reference end connection (attaching the CT workstring to the CT reel piping) is typically constructed by welding a “slip-on” type Figure 1502 union onto the end of the CT workstring. The welding practices typically associated with the manufacture of a CT workstring shall comply with the following:

- a) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the manufacturing facility.
- b) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, API 1104 or the manufacturer’s documented welding requirements. The weld record shall include the qualification/certification of the welder for the respective welding practice.
- c) The longitudinal welded seam shall have NDE performed using either ultrasonic or electromagnetic methods in accordance with API 5ST.
- d) The tube-to-reference end fitting weld shall have NDE performed using the liquid penetrant method as a minimum.

5.1.2 Welding on Coiled Tubing Workstrings After the Manufacturing Process

Welding performed on “post-manufactured” CT workstrings include repair welds (tube-to-tube) and end connection welds (at the CT reference end or the CT BHA end connection). The welding practices typically associated with the “post manufacture” of a CT workstring shall comply with the following:

- a) Verification of compliance shall be established through the implementation of a written WPS and the support PQR from the manufacturing or repair facility.
- b) Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME BPVC, Section IX, API 1104 or the manufacturer’s documented welding requirements. The weld record shall include the qualification/certification of the welder for the respective welding practice.
- c) The tube-to-tube weld shall have NDE performed using either radiographic (X-ray) or ultrasonic shear wave methods in accordance with API 5ST.
- d) The tube-to-CT BHA connector fitting weld shall be pull-tested to the limits specified by the tube purchaser.
- e) The tube-to-CT BHA end fitting weld shall have NDE performed using the liquid penetrant method (for slip-on fittings) or volumetric methods (radiographic or ultrasonic shear wave) for tube-to-tube end connections.

5.2 Coiled Tubing String Selection

5.2.1 General

The CT material properties and tube body geometry typically change as a result of bend-cycling throughout the service life of the workstring. The material yield strength typically decreases due to work softening (typically described as the Baushinger Effect) and reduces the performance capability of the tube. The changes in tube body geometry can include ovality, diametral growth and wall thinning. The changes in tube body geometry are typically not uniform along the length of the string.

To comply with this Recommended Practice, the CT workstring shall be designed and constructed to meet or exceed the manufacturing standards of API 5ST.

The CT workstring should be selected such that the combined stresses of pressure and tension do not exceed the working limits, based on the material properties.

5.2.2 Ovality and Diametral Growth

As the CT workstring is used in service, the cross-section of the tube body becomes oval. When the CT workstring is subjected to bend-cycling with internal pressure present, the diameter of the tube body will increase. The effects of ovality and diametral growth on well control includes:

- a) a reduction in collapse pressure rating compared with that of round tube;
- b) a reduction in the ability of the pipe ram (or pipe-slip ram) and stripper assembly to establish an effective pressure seal on the circumference of the tube body;
- c) greater difficulty in installation of the CT BHA connector;
- d) a reduction in pressure integrity of the flow check assembly seals on the OD of the CT body;
- e) a reduction in the gripping performance of the slip ram (see 4.3.4) or pipe-slip ram (see 4.3.6);
- f) decreased clearance between the CT body, the stripper bushings and/or anti-buckle guide.