



Slickline Training Manual

Reference Number: Slickline

Version:

Release Date: Provisory

Owner: SophiaPublish-SRC-General

Author: John Mayzel



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1 INTRODUCTION

1.1 Safe Working Procedures and Practices

Each employee is responsible for their own actions and should develop an awareness of the action of personnel around them. A safe approach to all aspects of wellsite work is essential.



Note

To enable potential hazards to be identified in the working environment, and to help prevent the occurrence of undesirable or hazardous conditions.

1.1.1 Housekeeping

- The work environment should be kept clean and tidy.
- Maintain and respect the environment in which you work by disposing of waste correctly.
- Stairways, passages and escape routes must be kept clear at all times.

1.1.2 Personal Protective Equipment

Standard items for offshore personnel are as follows:

- Safety Hat
- Safety Glasses
- Work Boots
- Work Gloves
- Proper Coveralls (loose clothing is not acceptable)
- Hearing Protection
- A Copper or Brass Hammer should be used in the makings up of hammer unions.

1.2 Safety Rules

- Never hammer or strike the lubricator or flow line while under pressure.
- Access to elevate positions on the Christmas tree must be made using a safety harness or certified scaffolding.

- Open the swab, master or wing valves slowly until the pressure equalizes or flow stabilizes, then proceed to fully open the valve.
- Count the number of turns to fully open and close each valve on the Christmas tree.
- When coming out of the hole, operators assisting in the slickline operation should stand to the side or behind the tree as the toolstring nears the stuffing box. Listen for the light tap as the rope socket hits the lower part of the stuffing box.
- Always wait for a signal from the slickline unit operator before closing the swab valve.
- Confirm the pressure is bled off before attempting to loosen or break any connections or quick unions.
- When cutting the wire from the tool string, hold the end going to the reel securely and cut the wire about 6 in. from the rope socket. If the ends are not secured, the free end may recoil and cause serious injury.
- Never try to knock the wire protruding from the top of the rope socket with the palm of the hand (even while wearing gloves). Tap it out on a work bench or similar solid surface.
- Respect pressure and the effect it may have on equipment operation.
- Keep the work area around the tree and the slickline unit clear of any material or objects not pertaining to the slickline operation.
- Ensure a work permit is obtained prior to starting any work.
- Ensure all personnel are aware of work being carried out in the area.
- Ensure all barriers and signs are posted to prevent access to hazardous areas.
- Ensure announcements are made to inform personnel of pressure testing taking place.
- Ensure correct positioning of equipment and tie down where necessary.
- Hold safety meeting prior to operation commencing.
- Pressure-test all temporary lines prior to use.
- Regular shift updates should be held with the slickline crew and field foreman.

- A radio should be provided for the slickline crew when performing a flowing gradient survey so that continuous communication can be maintained with the control room.
- Do not manipulate any tree valve unless you are the operator or are instructed to do so by the operator.
- Never step over or go under the wire at any time.
- Any equipment, which is liable to move under tension, should be securely fixed to a suitable anchor point using certified equipment.
- Pre-job safety meetings, post-job debrief meetings and regular safety meetings should be held and all relevant parties must be involved.
- All hoses and temporary lines should be inspected and tested on a regular basis.
- Shift hand-over procedures should be conducted on every changeover.
- Radios should be used when performing critical operations to ensure communications can be constantly maintained.
- All personnel should fully understand their tasks and work to installation procedures.
- All wire ropes used must be certified and inspected before use. (Color codes are used to aid identification).

1.2.1 Hand Tools

- Use the right tools for the task.
- Inspect tools before use and report any damaged tools immediately.
- Replace all worn parts or tools before use.
- Only trained competent personnel should use portable power tools.
- Electrical tools should not be used in an explosive environment unless specifically rated for such use.
- Pneumatic power tools should be used in an explosive environment.
- Do not leave tools lying in place that may cause a hazard to others.

1.2.2 Lifting and Moving Equipment

- Use correct personal lifting techniques to prevent spinal or muscular injury.
- Check the weight of the item to be moved.

- Get help if the load is too heavy for one person.
- Use approved slinging equipment in the correct manner.
- Adhere to the Safe Working Load (SWL) limits for cranes, slings and shackles.

1.2.3 Work Permits

Always observe the permit to work procedures required at the work site. Such procedures have been designed to protect well site personnel and it is the responsibility of all personnel to ensure the established guidelines are observed.

1.3 Slickline Operations

1.3.1 Introduction to Slickline

The term Slickline relates to the use of a wire or braided line to convey downhole tools or equipment in a wellbore.

The first use of wire in a wellbore was as a measuring device. In the construction of the early wells dug by hand, sticks were used to measure depth. The stick was laid on the ground and the distance/length stepped off. Occasionally, for important measurements a surveyor's chain would be used. To create a hole in the ground, early drilling operations used a pointed tool on a rope. However, as the work progressed, the rope stretched and often broke. The length of the rope could not then be used as an accurate measure.

To overcome the weakness of rope, wire cable was used. By this time, a method had to be devised to measure the depth of the hole. Normally the hole had water in it to help soften up the dirt, clay sandstone or limestone rock. If the driller used a rope with markings, the rope would be wet as it came out of the hole and would rot while being rolled up on a winch type spool or drum. The drillers started using cable, but it was bulky and as it stretched going in the hole, the weight of the cable either broke it or stretched between the markings on the cable.

Around the same time as the use of rope and cable, some drillers were using a flat steel tape with markings on it. The tape would be lowered into the wellbore, however, it suffered the same problems as the cable and rope, as weight exceeded the strength of the tape cross-section, it would part.

The subsequent use of wire offered several advantages. It weighed less than a cable, was easier to handle than a rope and the length or depth to which the wire could be used was be greater. This was accomplished by putting the wire on a drum, which could be lowered and raised by a winding handle. As the

wellbores increased in depth, a winding handle with a gear ratio was added to pull up the greater weight. By this time, a brake hand was added to the other side of the drum to control the speed of the line going in the hole. The principal power source at this time was steam and a steam operated engine was used to pull the line out of the hole.

The first noted use of slickline was by Halliburton to follow a cement plug down while cementing a well. These units were originally mounted on the rig, although they later became part of the equipment of the service engineer and were operated off of the left rear wheel of a car or pickup truck.

From this early efforts a unit known as a side-winder was developed – a spool of wire on a drum would slide out on a frame from the bed of a pickup truck. The left rear wheel was jacked up, a sheave, drum or cathead was attached and a rope was run around it to the drum of wire. This was prevalent in the 1940's.

The operator told the helper how fast to run the engine and winch, the helper being positioned in the cab of the truck with his foot on the gas pedal! There was no weight indicator and the operator had to guess how much he was pulling on the wire by how far he could push down on it.

To measure how deep he had gone in the hole, the operator would count the number of layers of wire that had gone in the hole and come up with a figure for depth, determined by the circumference of the drum. This was a crude guess, but an experienced operator would generally be off only 5 to 10 ft if measured by a counter.

From that method came the skid units with belt drives and clutches to improve control of the winch. A counter head and a device to measure the amount of pull (weight) on the wire had been developed by this time. The counter head was developed by Halliburton and the OD of the wire determined the size of the wheel in which the wire ran. To measure the pull on the wire, there were two methods, electric and hydraulic.

Much of the same principals are still applied in the design and use of modern slickline equipment. However, with increased wellbore depths and the growing complexity of downhole completion equipment, the applications for slickline have increased significantly. Almost every wellbore will at some time be accessed by slickline. Even highly deviated or horizontal wells can require slickline access for the installation or servicing of upper wellbore components.

Slickline (and occasionally braided line) is commonly used in the following operations:

- Checking the production tubing drift

- Checking the build up of wax, scale or wellbore deposits
- Confirming the well depth or clearance to perforations
- Running and pulling plugs or flow control devices
- Opening and closing sliding side-doors or similar completion equipment
- Conducting pressure and temperature surveys using mechanical or electrical gauges and recorders
- Installing tubing pack-offs or similar completion devices
- Logging and perforating

The majority of blowouts and pressure related incidents are caused during well intervention, using equipment and techniques such as slickline, CTU, snubbing or workover rig operations.

Efficient, safe slickline operations are essential, but can only be achieved through good planning and implementation of correct procedures. The use of appropriate tools and correctly maintained equipment is an integral part of successful, safe, slickline operations. The necessary skills and operator competency are a result of thorough theoretical education and practical training.

Supervisors and operators should be fully aware of the constraints imposed during slickline operations. The most significant of these is that the operator is essentially working 'blind', and must rely on surface indications and observations to 'sense' the functioning of his tools. This may be difficult when the tool being used is several thousand feet down a wellbore, at the end of a relatively thin wire and possibly in heavy mud or thick crude oil.

Examples of wellbore or operating conditions that can affect slickline operations include:

- Tubing corrosion
- Sand or wellbore fill
- Scale deposits
- Wellbore deviation and profile
- Well pressure
- Tubing size
- Slickline type or specification
- Wellbore fluid viscosity

- Equipment design limitations
- Well temperature (for instruments)

The adverse risks associated with the above factors can be minimized through good planning and preparation for the slickline operation.

The careful analysis of job data and performance indicators can highlight problems and initiate improvements to operations. Well records should be referenced prior to a slickline operation to identify problems previously encountered, and enable alternative options to be applied where necessary.

1.3.2 The Well

An understanding of wellbore design and familiarity with completion components is essential for all slickline operators. This knowledge helps enable the operator visualize the action of the tools and equipment downhole.

1.3.2.1 Drilling and Casing the Wellbore

Prior to a well being 'spudded in', a conductor (large casing) is placed in the surface formation to provide a starting point for drilling operations.

On land wells, a cellar may be constructed and the conductor driven into the ground with a pile driver. Alternately, a post hole type boring rig may be used to make a hole in which the conductor can be cemented.

On offshore wells, the conductor is typically installed in slots designed into the platform structure.

The well is drilled in stages and cased to prevent hole collapse and the movement of formation fluids into the wellbore. The number and size of casings is determined by the final well depth, formation conditions and final well pressure and service (oil or gas, single or dual, etc.).

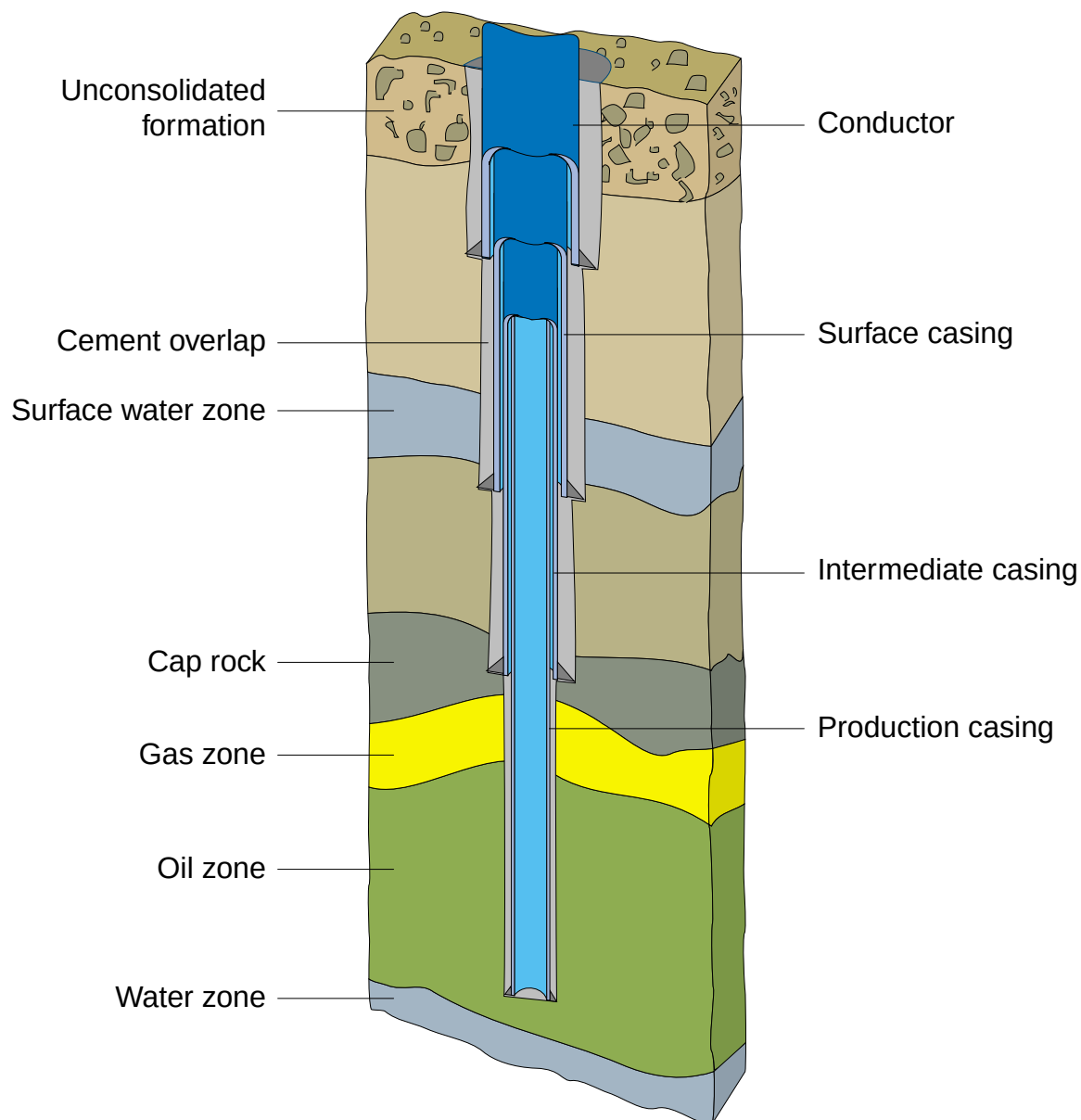


Figure 1-1: Drilling and Casing the Wellbore

The diagram in [Figure 1-1 Drilling and Casing the Wellbore](#) shows a typical three-casing onshore well. With each casing string being cemented in place, the formation conditions and well location determine how much cement overlap is applied in each casing string.

A good cement bond between the formation and casing is essential to prevent the migration of fluids between the producing zones or to the surface. This can be checked or confirmed by running a CBL (Cement Bond Log) run on electric line before continuing with the next stage of drilling and completing the well.

Care is taken at all phases of drilling to ensure that the surface facilities are isolated from the downhole formation pressures. This is achieved by the density of the drilling mud (creating hydrostatic pressure in the wellbore to balance formation pressure) and the use of blowout preventers (BOP). The BOP stack is mounted immediately below the rig floor on land wells and jack-up rigs. On semisubmersible rigs and subsea completions, the BOP stack is mounted on a template on the seabed.

The wellbore is drilled to a depth just below the area of strata where the oil or gas is trapped. This area is known as the reservoir formation and is usually a layer of sand, shale or rock, which contains the gas or oil. The thickness of the reservoir can vary from only a few feet to several hundred feet or even several thousand feet in prolific fields.

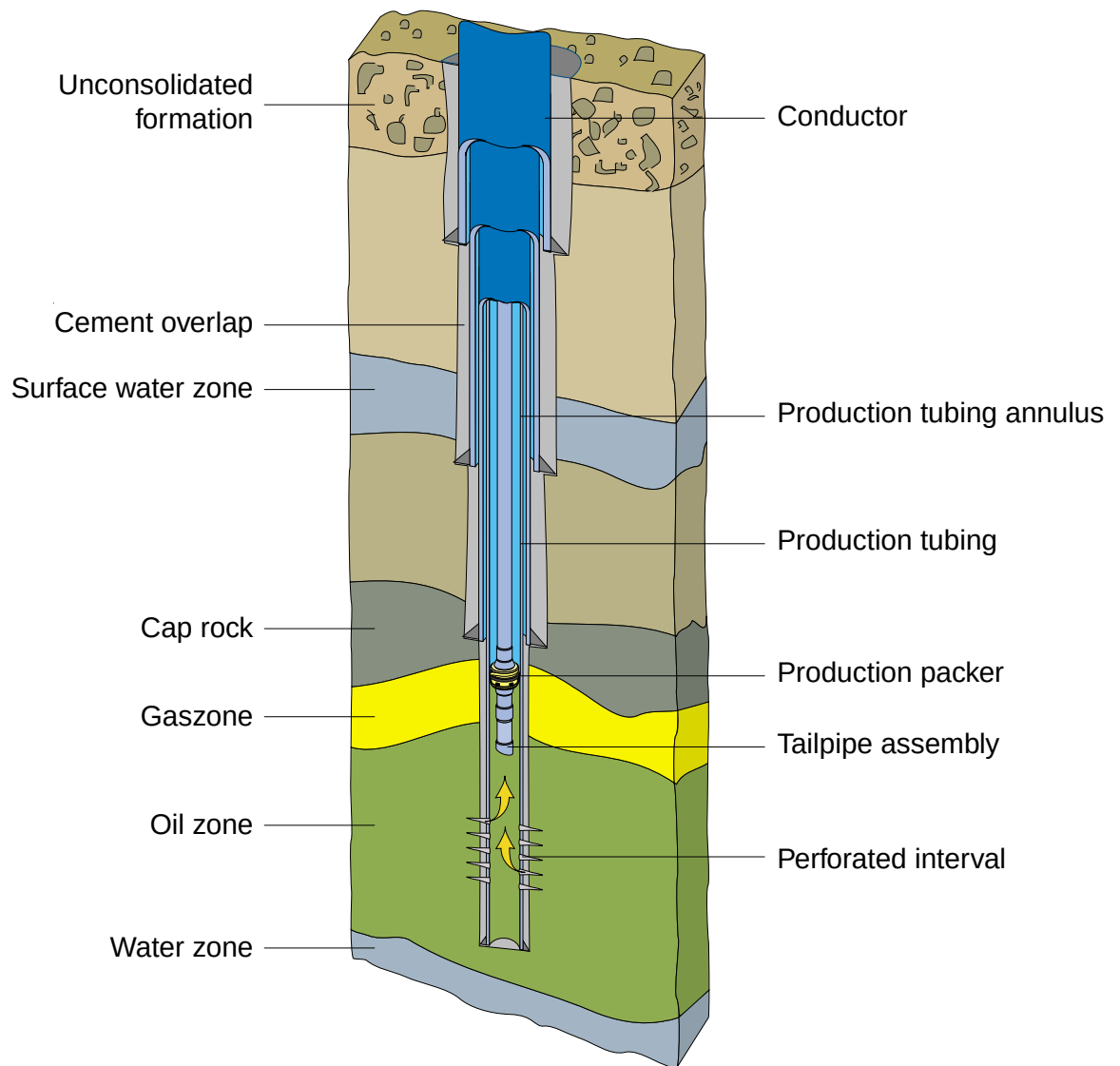


Figure 1-2: Perforated and Completed Wellbore

To allow the reservoir fluids, i.e., oil and gas, to enter the wellbore, perforations are made through the casing within the reservoir interval. The perforating gun is generally lowered into the wellbore on electric wireline. Alternately tubing conveyed perforating systems permit the running of the perforating explosives with the production tubing string. After confirming proper placement, the perforating gun is fired electrically from the surface or in the case of TCP, a drop bar may be used to detonate the guns.

When the perforating gun is fired, a perforation tunnel is created through the casing and cement sheath and into the reservoir formation. This provides clear channels through which the oil and gas can enter the casing, where it is produced to surface through the production tubing.

During the completion phase of a well, the production tubing and packer are installed. Production tubing is a smaller diameter pipe, which is lowered inside the casing to a point somewhere above the perforations. Attached to the lower end of the tubing, is the production packer.

The packer incorporates slips (teeth) to secure the packer in place and one or more sealing elements to provide hydraulic isolation. With the tubing and packer are at the desired depth, the slips and the rubber seal elements on the packer are activated, usually either by rotating the tubing or by applying hydraulic pressure through the tubing bore. This causes the slips on the packer to expand and bite into the casing and also causes the rubber seal elements of the packer to expand and seal off against the internal diameter of the casing.

With the packer anchored in place, the gas and oil enters the casing through the perforations and flows up to the packer, where it enters the production tubing and flows to surface.

The tubing-casing annulus is the space between the outside diameter of the tubing and the inside diameter of the casing above the packer. This space is generally filled with fluid, such as water or brine containing a corrosion inhibitor, to protect the tubing and casing from corrosion.

The hydrostatic pressure (weight) of the annulus fluid tends to hold the packer in place and also provides a means of killing the well, when necessary, by admitting the annular fluid into the tubing string.

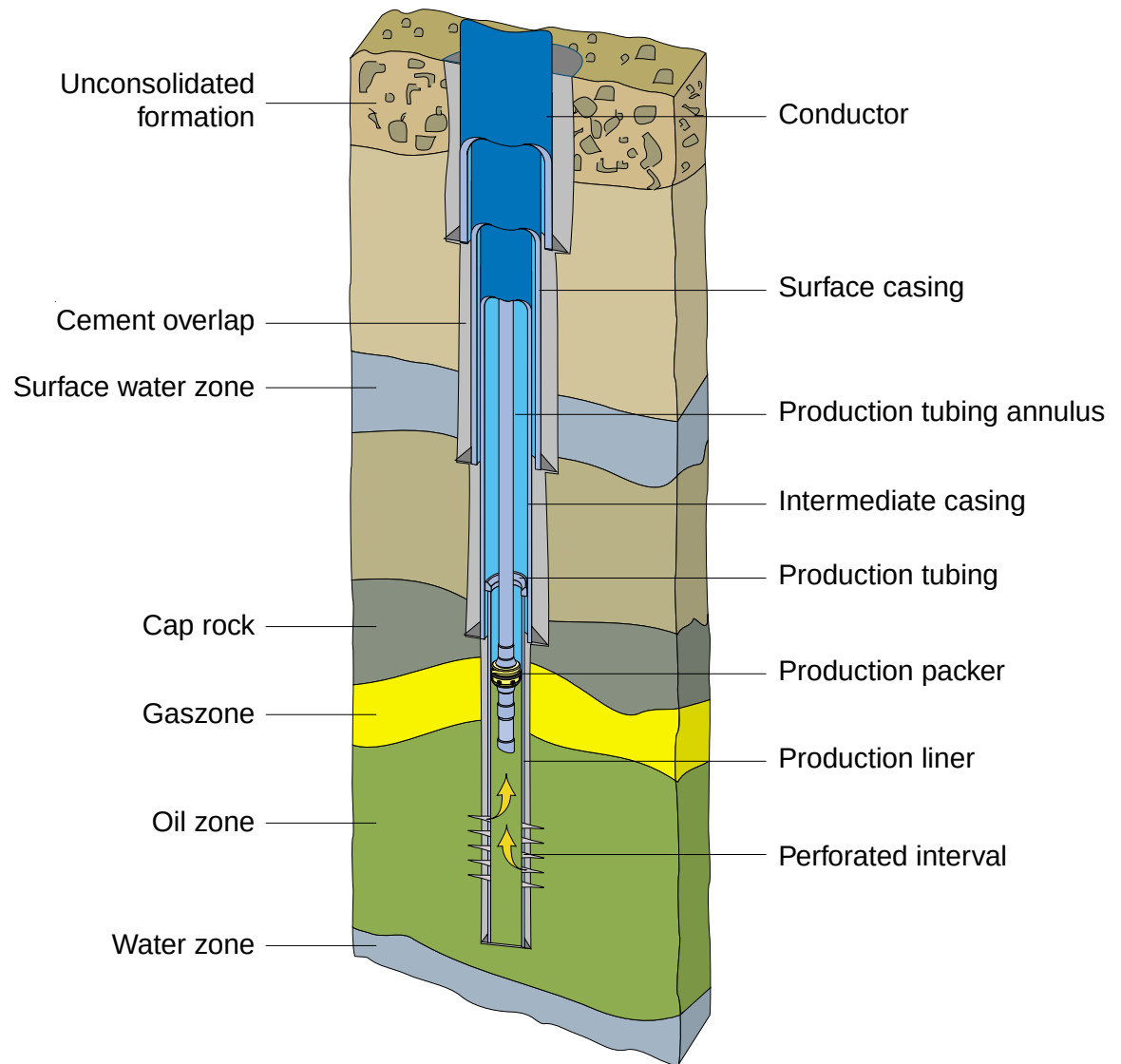


Figure 1-3: Liner Completion

Some wells are constructed with a liner. This option requires a smaller hole and does not require a casing string to run all the way to the surface, representing a significant cost saving in drilling time and casing costs.

The liner hanger system supports the liner off the bottom of the well until the cementing operation is completed. Liner hangers can also be installed when an existing well is worked over and the depth increased.

1.3.2.2 Surface Equipment

The surface connection of the wellbore is to the Christmas tree, a series of valves installed on the wellhead to control the flow of fluids from the well. There are many types and designs to suit the wellsite and reservoir fluid conditions. Wellhead pressure, fluid type, corrosive content, temperature and available space, are some of the parameters affecting the choice of tree or valve design and specification.

It is important that slickline operations personnel are familiar with the basic types options available.

Single Composite Tree

Used on low pressure (up to 3000 psi) oil wells; this type of tree is in common use worldwide. The number of joints and potential leakage points make it unsuitable for high-pressure applications or for use on gas wells.

Composite dual trees are also available but are not in common use.

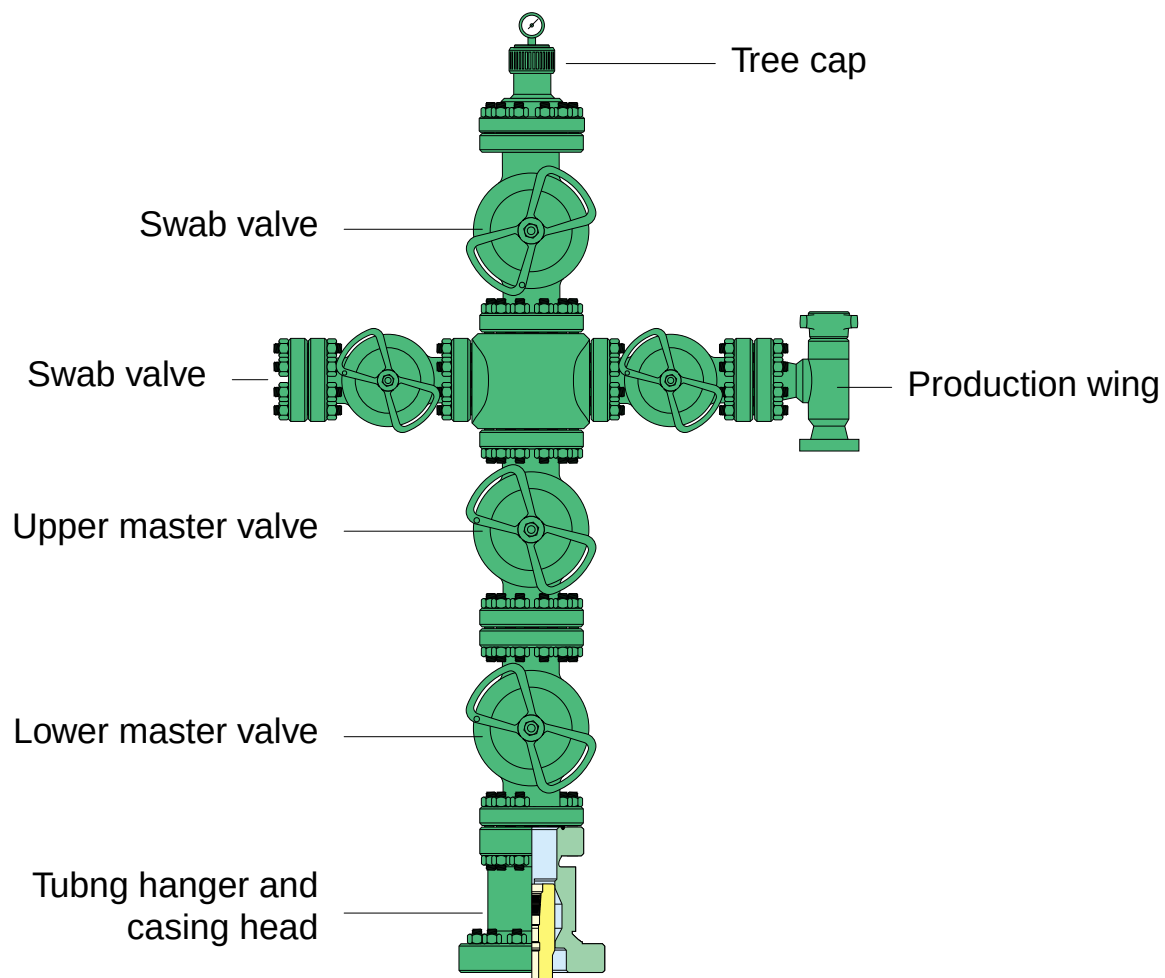


Figure 1-4: Single Composite Tree Configuration

Single Solid Block Tree

For higher-pressure applications, the valve seats and components are installed in a one-piece solid block body. Trees of this type are available up to 10,000 psi or even higher if required.

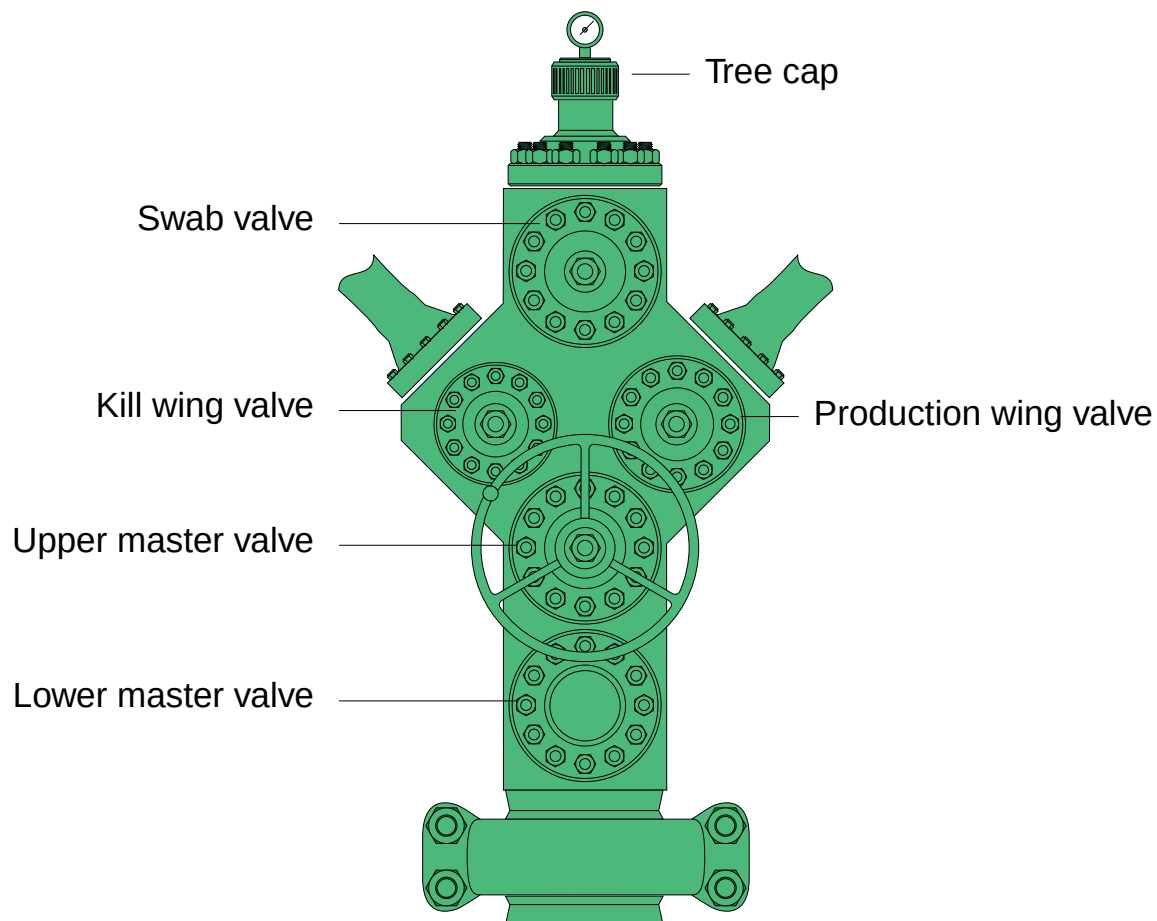


Figure 1-5: Single Solid Block Tree

Dual Solid Block Tree

For dual tubing strings, the solid block tree is the most widely used configuration. The two options shown are the most common designs.

The valves controlling the flow from the deeper zone, the long string, are the lower valves on the tree. While there are some exceptions to this convention, unless the tree is clearly marked it can be assumed that the valve position reflect the subsurface connections.

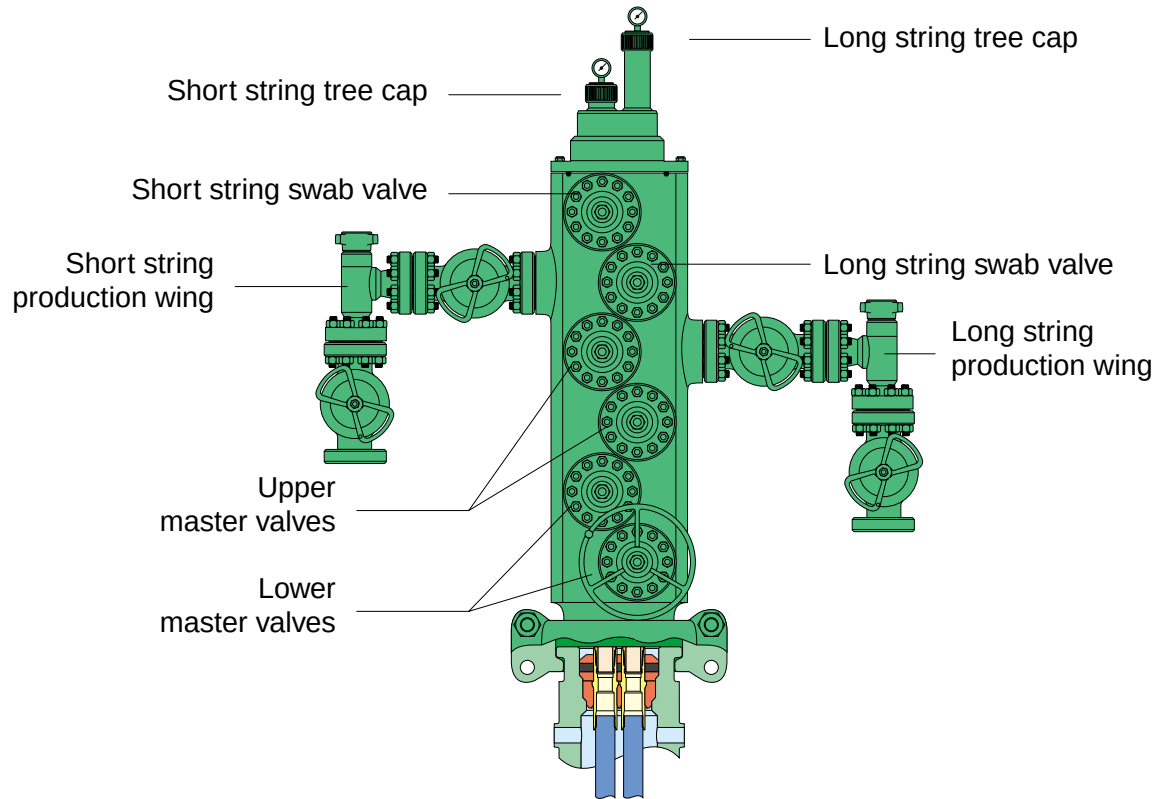


Figure 1-6: Dual Solid Block Tree

Wellhead Valve Operating Precautions

The valves must be operated carefully when opening or closing. Some valve types have a shear pin between the handle and stem, which will shear to protect the valve's internal components, if excessive force is applied.

The master valve should not be used to close in a flowing well, except in an emergency. The swab or wing valves are typically used. Each time the gates of the valve shut in a flowing well, the increase in velocity of the well fluids during the closing action can cause wear across the seal faces. It is easier and safer to replace the seats and gates in valves, other than the master valve in the tree.

Always count the number of valve turns made when closing. This is a prudent check against jamming the toolstring or wire in the tree, in the event that the tools have been raised fully into the lubricator.

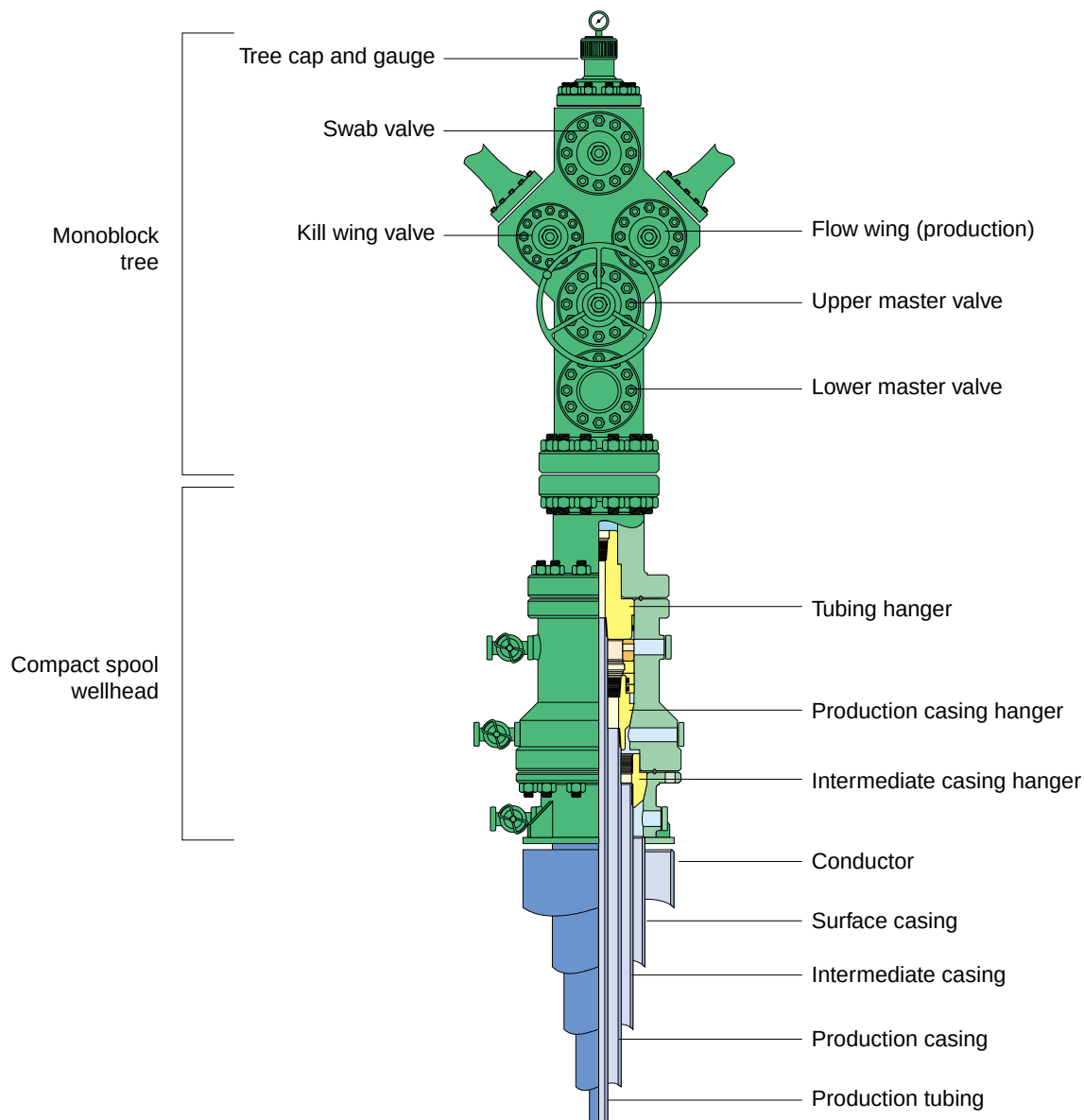


Figure 1-7: Wellhead and Christmas Tree General Configuration

1.3.2.3

Tubing Hanger

The tubing hanger is the device that supports the production tubing within the tubing head. A seal assembly on the body of the tubing hanger provides a hydraulic seal between the tubing hanger and the body of the tubing head.

Tubing hangers, in most circumstances, are designed with an extended neck which seals in the bottom of the adapter flange to isolate the well fluids from the tubing head ring joint seal.

Internal profiles on the tubing hanger provide a means for inserting a tubing back-pressure valve (BPV).

The body of the tubing hanger is ported for the routing of a small control line that is connected to the sub-surface ball valve.

The threaded connections top and bottom of the tubing hanger are compatible with the tubing string being suspended.

In the lifetime of the wellhead, the tubing hanger is the component that will most commonly be removed and replaced.

1.3.2.4 Christmas Tree

The Christmas tree is an assembly of valves and fittings used to control the flow of the well fluids and provide access into the tubing string or production conduit.

The adapter flange is the connection on the bottom of the Christmas tree that mates with the top flange of the tubing head and is of the same size and pressure rating of the tubing head flange.

The internal profile of the adapter flange accepts the extended neck of the tubing hanger, with some designs of adapter flange the profile will include a secondary seal.

Around the outside of the bottom flange are a series of fittings for test ports and bleeder ports. These ports are used to energize the secondary pack-off and perform a ring joint test between the two mating flanges, the lower annulus seal, and the secondary pack-off. To match up with the porting on the tubing hanger neck, an additional port is used for the control line fluid to pass to the downhole safety valve.

The top connection is used for the first valve of the Christmas tree. In a bolt-up style of tree, normally the adapter flange is integral to the Christmas tree valve and termed as part of the Christmas tree unit.

In a composite style Christmas tree, the adapter flange will form the bottom flange of the Christmas tree.

Valve Assemblies

Each valve on the Christmas tree has a specific function:

Lower Master Valve	a valve that is normally kept in the open condition and is only closed in the event that all the other valves fail.

Upper Master Valve	the valve that is usually operated to open and close the wellbore. This valve is often fitted with an actuator so that the valve can be controlled remotely.
Swab Valve	the valve that is kept closed during flowing of the well and is opened to allow access into the tubing string when maintenance of the tubing string is required.
Flowline Wing Valve	used in conjunction with the upper master valve in controlling the well. This valve is normally fitted with an actuator similar to that of the upper master valve so that the valve can be controlled remotely.
Kill Line Valve	used when the well has to be killed. The size of this valve may be smaller than other valves.
Tree cap	a cap or plug that is removed to allow access for service tools.
Choke	attached to the downstream side of the flowline wing valve, the choke is used to control or regulate the flow of produced fluids. The choke can be of varying styles, positive, adjustable or multi-orifice and in some instances may be fitted with a remote actuator.

Associated Equipment

To ensure that the wellhead and Christmas tree are correctly installed, there are various pieces of equipment that are normally used. These tools can be divided into two distinct groups, installation tools and service tools.

Installation Tools

Blowout Preventer Tester	Prior to the commencement of drilling after the installation of any casing or tubinghead, each of the connections within the wellhead assembly should be tested. The BOP tester is a simple piece of equipment that is lowered into the tubing head to seal off the annulus allowing all the connections above to be tested.

Bushing

The most critical surface of any casing or tubing head is the internal area where the annular seals energize. During drilling operations, it is important to protect this surface from the drillstring, this is achieved by installing a wear bushing.

J-Pin Running Tool

The J pin running tool is used in conjunction with the wear bushing and is used to install and remove the wear bushing from the wellhead. The tool has four small round pins positioned around its outside diameter that locate into corresponding slots in the wear bushing for carrying the wear bushing into position.

Service Tools

During the normal lifetime of the wellhead, the need may arise to remove or replace certain parts of the wellhead or Christmas tree. The following tools allow these operations to be carried out in a safe and controlled manner.

Valve Removal Plug

This plug is used with the valve removal tool to allow the removal of any of the series of valves that are bolted to any of the casing or tubing head side outlets. The plug is installed into the female threads that are a part of the side outlet porting, when fitted the plug isolates and seals off the annulus pressure from the atmosphere.

Valve Removal Tool

The valve removal tool is used to install a valve removal plug through a side outlet valve into the threaded portion of the side outlet on the casing or tubing head.

Back Pressure Valve

The back pressure valve is used with the lubricator and when installed allows the removal of the christmas tree. The back pressure valve is installed in the internal profile of the tubing hanger and when in position, seals off the tubing string from pressure below.

Hydraulic Lubricator

The hydraulic lubricator is used to install a back pressure valve into the tubing hanger. The lubricator is fitted to the top of the christmas tree and is of sufficient stroke to pass the back pressure valve down through each of the open valves of the tree into the tubing hanger below.

1.3.2.5 Back Pressure Valves

Back pressure valves are installed in the tubing hanger to hold pressure from below during the following operations:

- Nipple down and up the drilling BOP stack.
- Nipple up or down Christmas tree.
- Test the Christmas tree (2-way check).
- Replace the master valve.

The most common types of BPV are the Cameron Type 'H' BPV and Petrolite 'ABC'.

A BPV is set in a profile provided in the tubing hanger using a special tool and lubricator assembly for threaded BPV models, or by slickline for profile set models. The BPV holds pressure from below to isolate well pressure, but allows flow from above to permit killing of the well if necessary in an emergency, i.e., the BPV functions as a check valve.

A two way check valve is designed to fit the same profile as the BPV. It holds pressure from both directions while allowing equalization when required and is used to test the tree and BOP assembly.

Cameron Type 'H' Back-pressure Valve

Type H back-pressure valves are used extensively in Cameron hangers to safely seal well pressure to 20,000 psi during removal of the blowout preventer and installation of the Christmas tree. Fluid may be pumped through the BPV. If the tree above the BPV is to be pressure tested, the type 'H' 2-way check valve may be landed in the tubing hanger for pressures to 20,000 psi.

If during the life of the well it becomes necessary to remove the Christmas tree or repair the lower master valve, the back pressure valve can be reinstalled in the hanger without killing the well. The lubricator consists of a rod, which works through a yoke provided with two stuffing boxes. By closing the vent valve and opening the equalizing valve, well pressure acts on both the top and bottom of the rod. The rod can then be moved up or down by means of a friction wrench. Experienced operators can utilize the well pressure in moving the rod by manipulation of the valves.

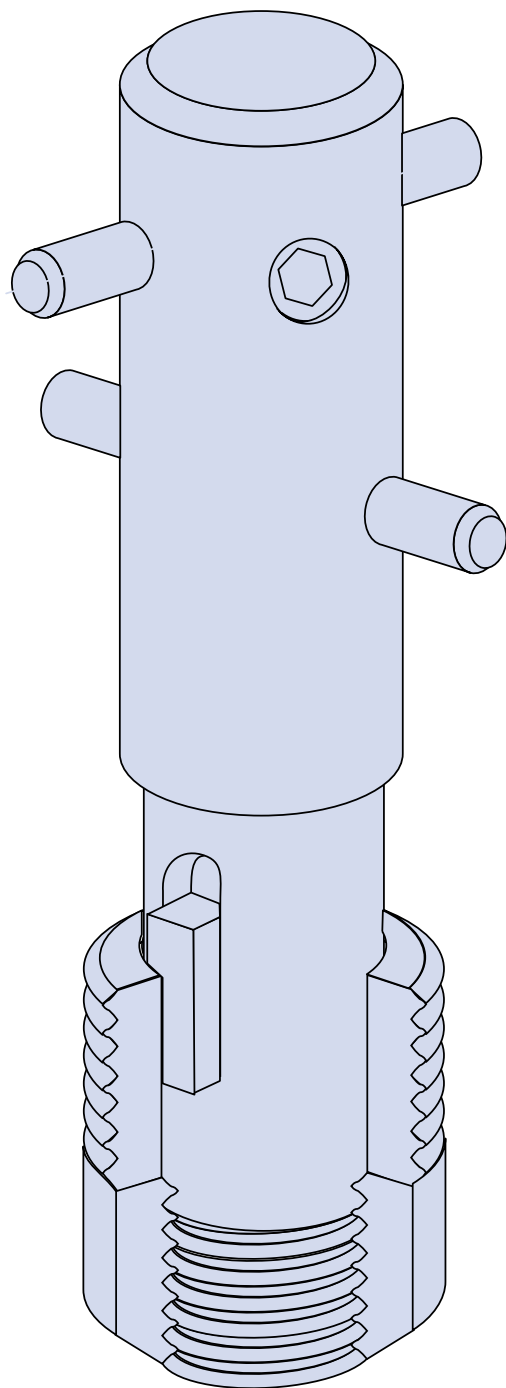


Figure 1-8: Back-Pressure Valve Running Tool

The running tool is inserted into the left-hand thread at the top of the valve, and then attached to the polished rod. When the valve has been lowered into the hanger, the rod is lowered so that the cross pin in the running tool engages in the slot on the top of the valve. Right hand (clockwise) rotation is applied to insert the valve. Once the valve is fully seated, moving the rod up to lift the pin from the slot and continuing a right hand rotation backs out the running tool.

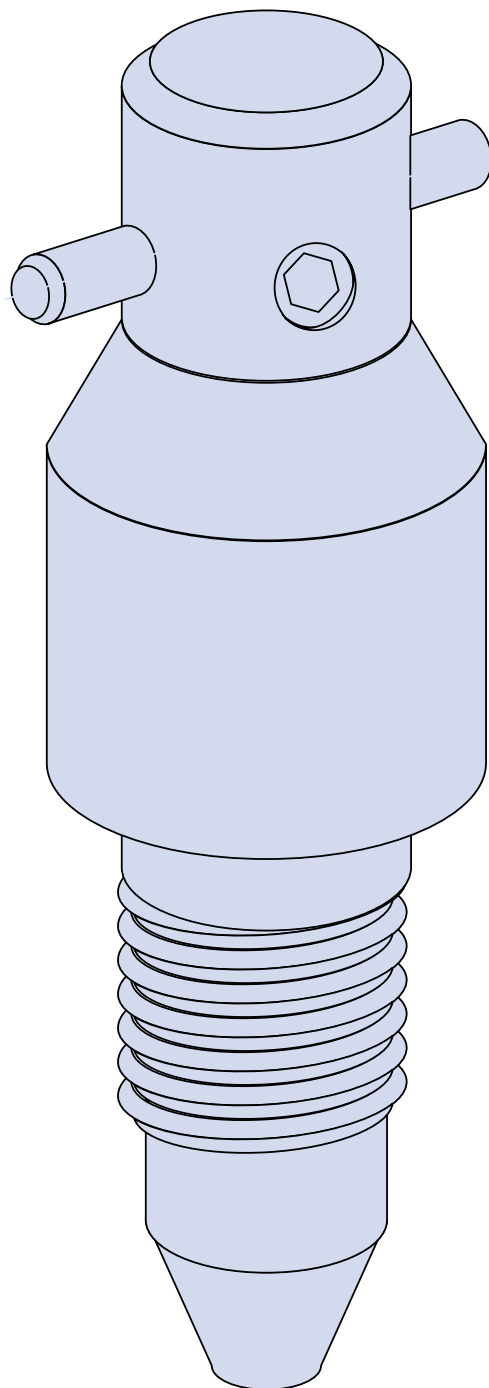


Figure 1-9: Back-Pressure Pulling Tool

The pulling tool is attached to the rod and lowered to the valve. Left-hand (anti-clockwise) rotation makes up the pulling tool and then removes the valve.

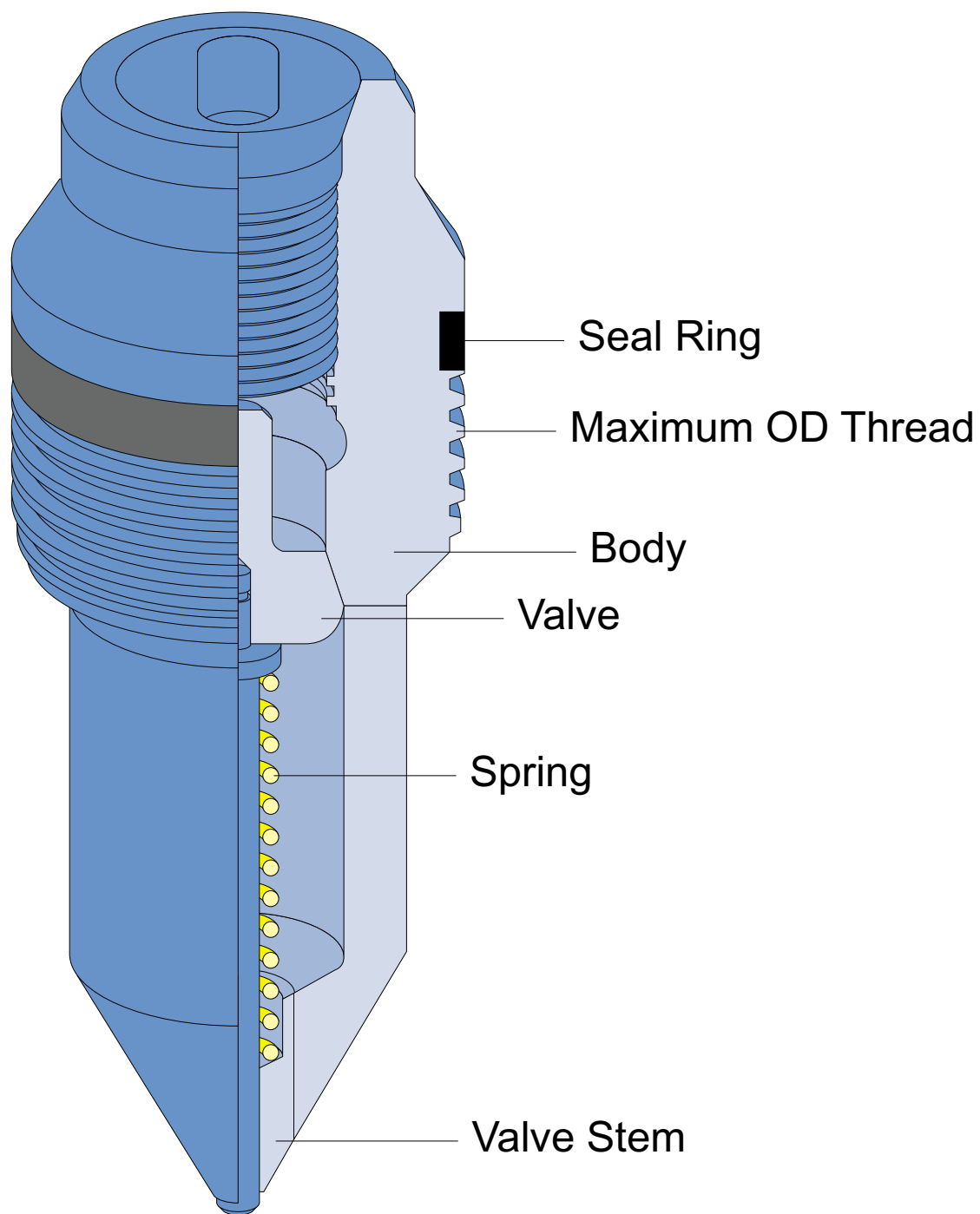


Figure 1-10: Cameron Type H Back-Pressure Valve

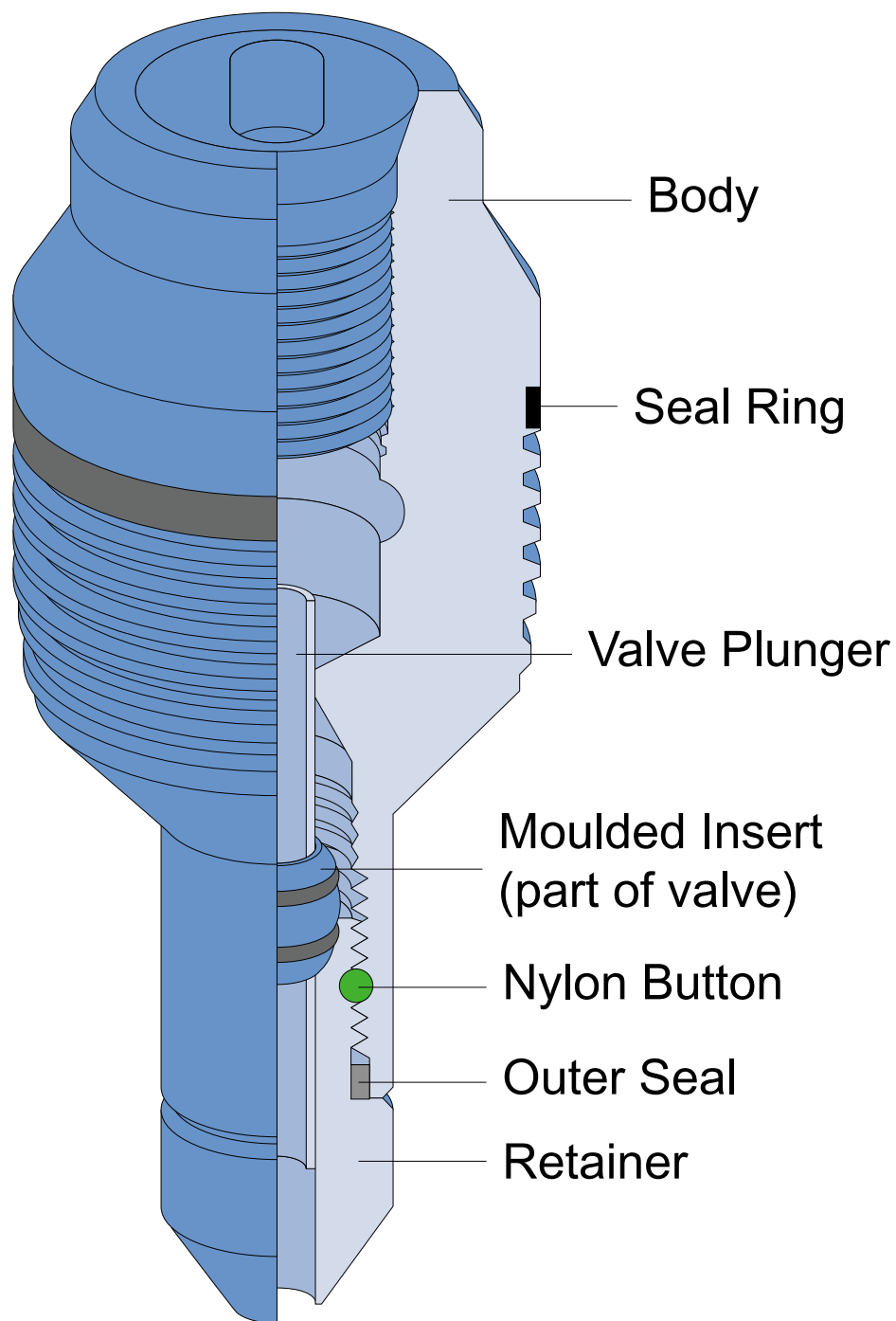


Figure 1-11: Two-way Check Valve

1.3.3 Well Completion Equipment

There are many types and designs of completion equipment in common use in oil and gas wells. In addition to the tubing string and packer found in almost all wells, there are several other key completion components that may be required and a number of optional completion accessories to add functionality to the completion.

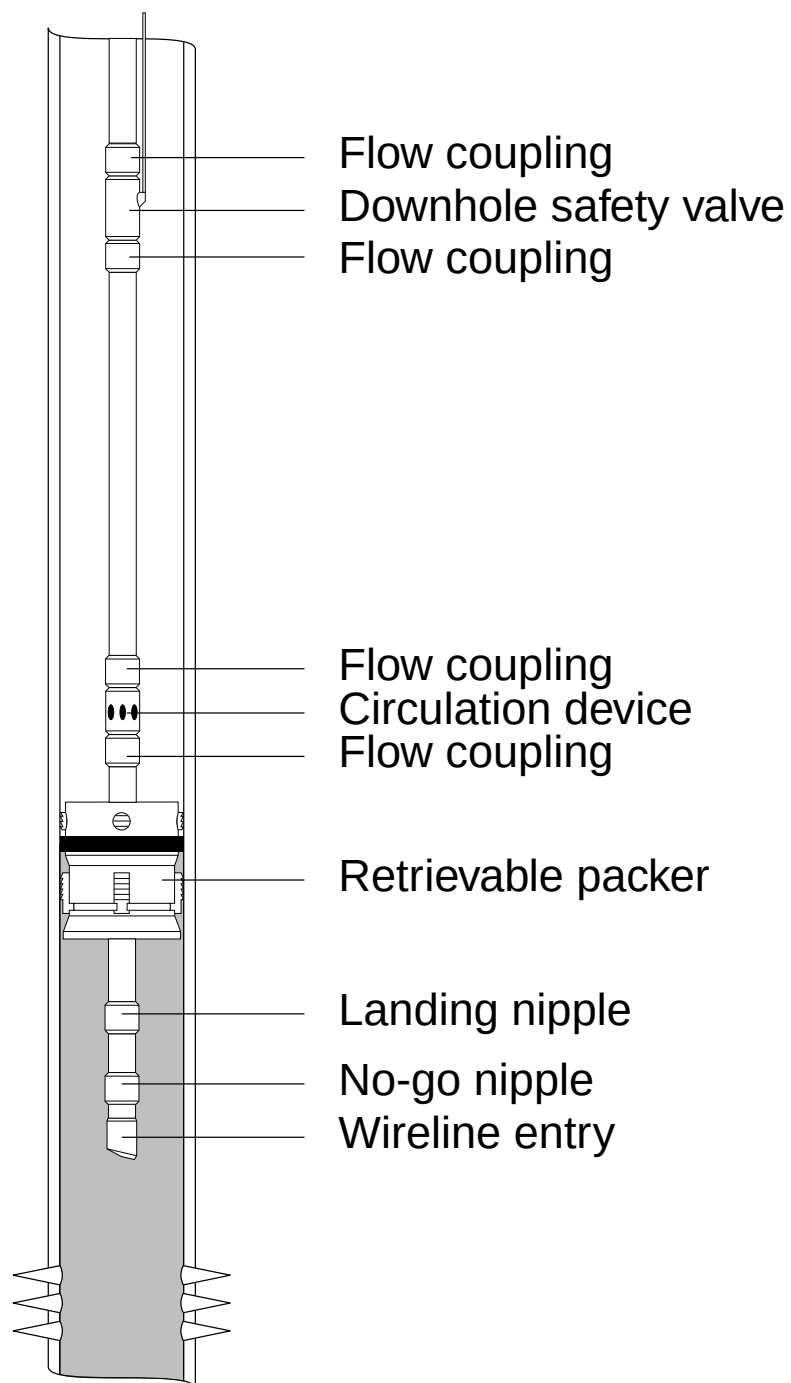


Figure 1-12: Single Completion Oil Well Schematic

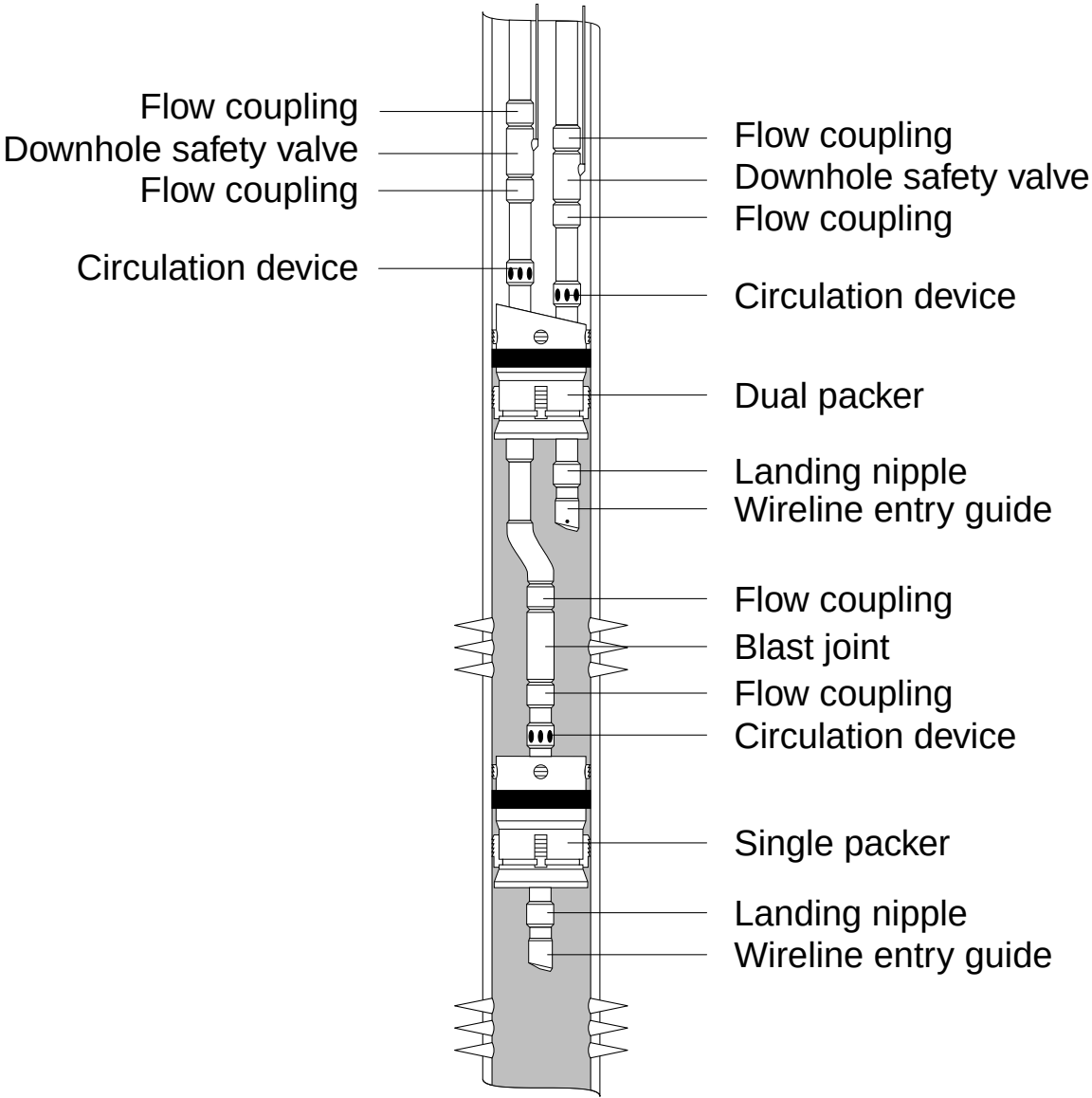


Figure 1-13: Dual Completion Oil Well Schematic

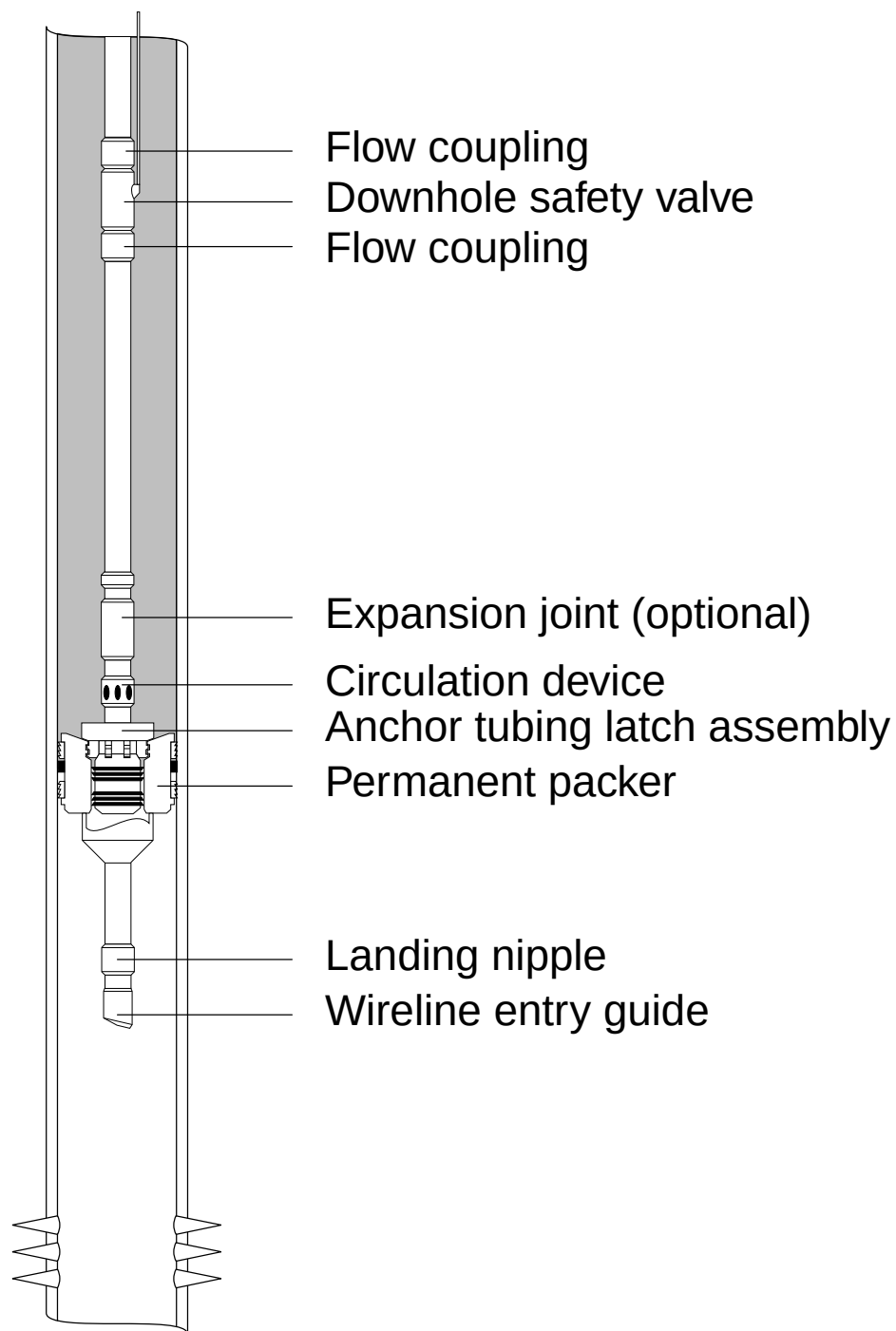


Figure 1-14: Single Completion Gas Well Schematic

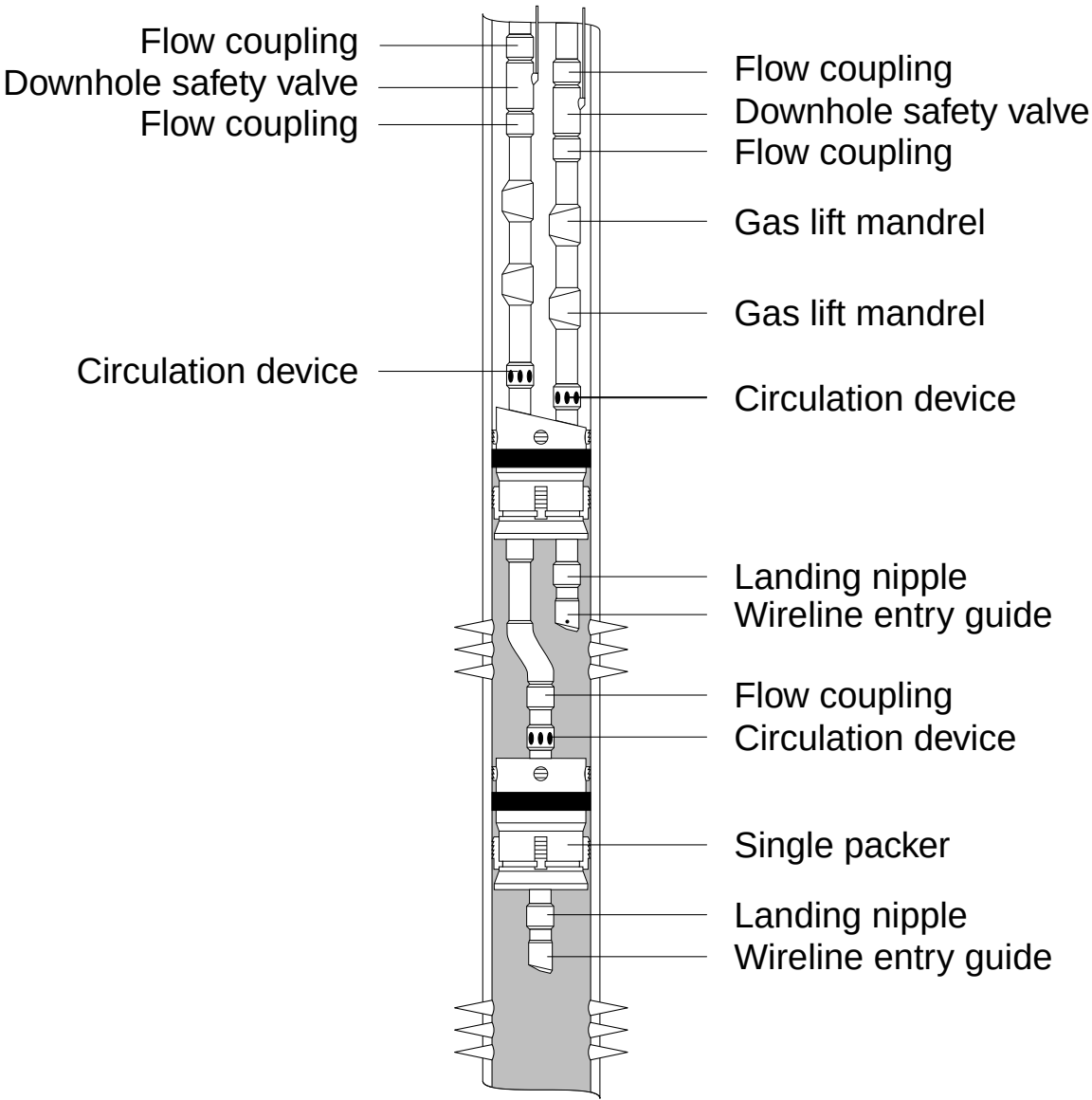


Figure 1-15: Dual Completion Gas Well Schematic

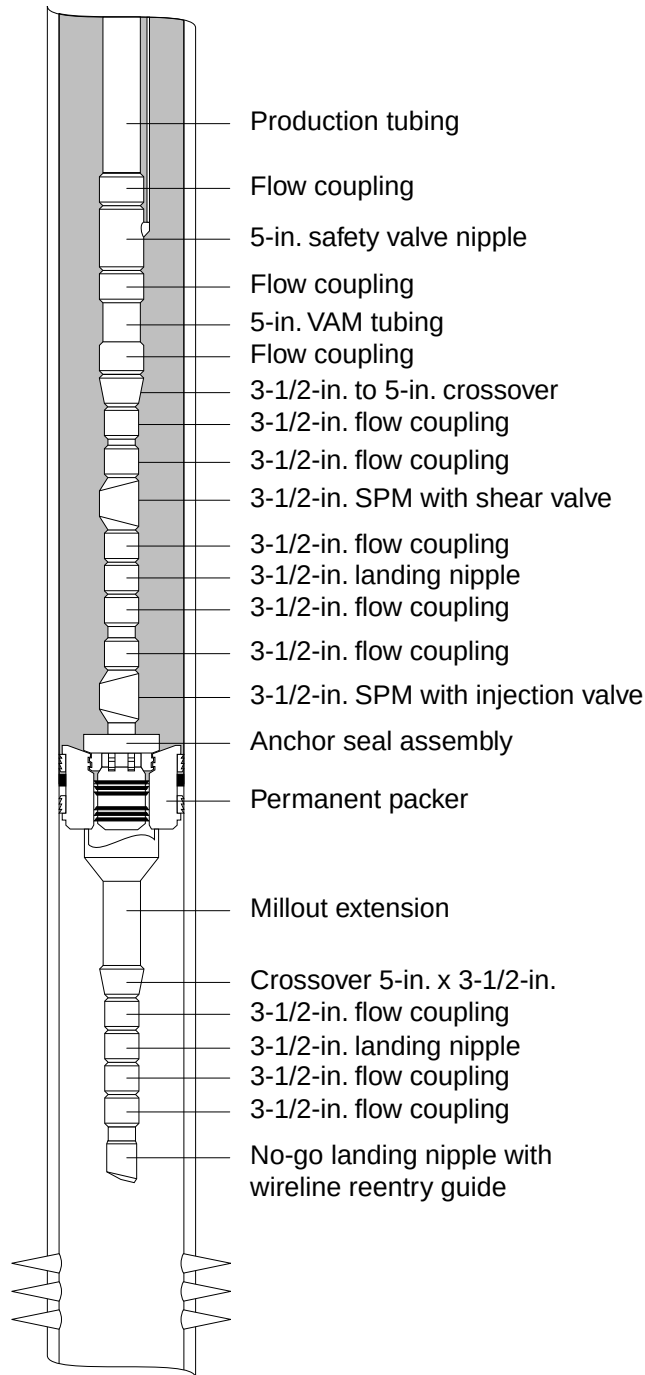


Figure 1-16: Typical Completion for Gas Well having Remote Kill and Chemical Injection Facilities

1.3.3.1 Tubing

The tubing is a smaller diameter pipe installed inside the casing to carry the reservoir fluids to the surface. Wear from erosion (flow related) and corrosion (chemical attack) is confined within the tubing string to protect the casing. If necessary, the production tubing can be replaced during a workover operation when required.

1.3.3.2 Packers

Available in a wide range of sizes and types, packers are designed to isolate production zones and the casing annulus from well pressure. The main types available are:

- Inflatable - typically used in open hole, low-pressure completions or in well intervention operations.
- Mechanical set - set by tubing string rotation, not common in completion applications.
- Hydraulic set - set with the application of hydraulic pressure, available in single or dual string configurations.
- Wireline set - permanent packers can be set on electric line, with a seal assembly attached to the tubing and are configured to enable the tubing string to be inserted or stabbed into a polished bore.

1.3.3.3 Nipples

Nipple profiles are installed at various intervals in the completion string to permit the installation of lock mandrels and flow-control devices during slickline interventions.

1.3.3.4 Circulation Devices

Circulation devices allow communication between the tubing and annulus or the formation and tubing. They are also known as sliding side doors (SSD) or sliding sleeves and generally contain a nipple profile at the upper end for contingency purposes.

1.3.3.5 Side Pocket Mandrels

Side pocket mandrels (SPM) are positioned in a completion to provide an injection point for lift gas or chemical inhibitors or provide a circulation facility for well kill purposes. A SPM allows communication between the tubing and annulus.

1.3.3.6 Blast Joints

Blast joints are externally hardened; heavy walled sections of tubing that are placed across the perforations of the upper zones to protect the tubing from abrasive wear.

1.3.3.7 Flow Couplings

Similar in appearance to blast joints but available in shorter lengths, flow couplings are installed above and below areas of reduced internal diameter, such as safety valves, to protect the tubing from internal erosion resulting from turbulence. Flow couplings are essential in high-rate gas wells.

1.3.3.8 Telescoping Travel Joint

Telescoping travel joints are installed in dual completions to assist in spacing out the second string and allow for thermal expansion of the tubing string.

1.3.3.9 Surface Controlled Subsurface Safety Valves

Surface Controlled Subsurface Safety Valves are available as tubing retrievable (TRSSV) or slickline retrievable (SLSSV) models and are installed on all offshore wells and some land wells. They are designed to secure the well in an emergency and are “failsafe” in operation, being normally held open by hydraulic pressure and closing automatically if the operating system pressure is released.

1.3.3.10 Tubing Specifications

Since it is always the tubing string in which slickline operations are carried out, it is necessary for the slickline operator to understand the specifications and tubing product options.

Size

Generally identified by the outside diameter of the tube (the nominal description size). The internal diameter of the tubing is generally approximate or rounded up to the nearest full size.

Grade

The tubing grade indicates the strength and type of steel used to make the tubing. It is specified by a letter and number, e.g., H-40, J-55, C-75, L-80, N-80 or P-105. The lower the number, the softer the steel. The number signifies the tensile strength in 1000 psi, i.e., N-80 with a cross-sectional area of one square inch will withstand a load of 80,000 lb.

Weight per Foot

Determines the wall thickness of the tubing. Since the OD is determined by the nominal tubing size, i.e., thicker wall reduces the ID in heavy weight tubing.

Drift

The drift diameter is a means of ensuring the quality control on the tubing ID. The process involves passing a precisely machined bar through the tubing joint or string. All tubing and completion components run in the well must be drifted.

Threads

Common thread types include:

EU	External upset tubing joints incorporate a collar and an internal recess.
NU	Non-upset, but otherwise same as the EU.
VAM	A premium type thread seal with a collar and no internal recess.
Hydril CS	A premium connection with no collar and incorporating a metal-to-metal, three point seal system and no internal recess.

The following table shows a summary of the common tubing sizes:

Table 1-1: Common Tubing Sizes and Drift Diameters

Nominal Size (in.)	Weight per Foot (lbm)	ID (in.)	Drilling Drift (in)	Slickline Drift (in.)
2 $\frac{3}{8}$	4.70	1.995	1.901	1.875
2 $\frac{7}{8}$	6.50	2.441	2.347	2.313
3 $\frac{1}{2}$	9.30	2.992	2.867	2.750
4 $\frac{1}{2}$	12.75	3.958	3.883	3.813
5 $\frac{1}{2}$	15.50	4.919	4.825	4.750

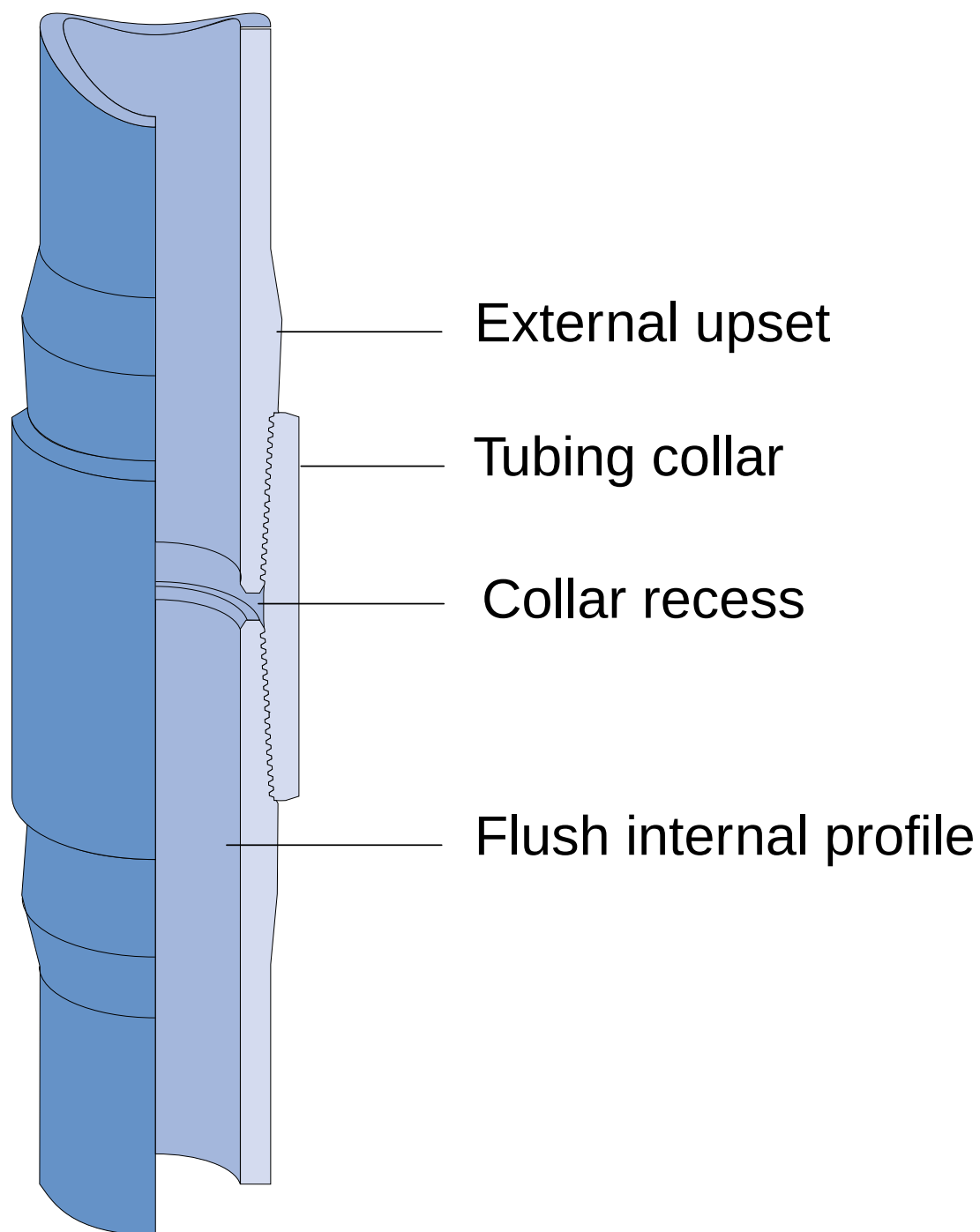


Figure 1-17: External Upset (EU) Thread Form for Low-Pressure Oil Applications

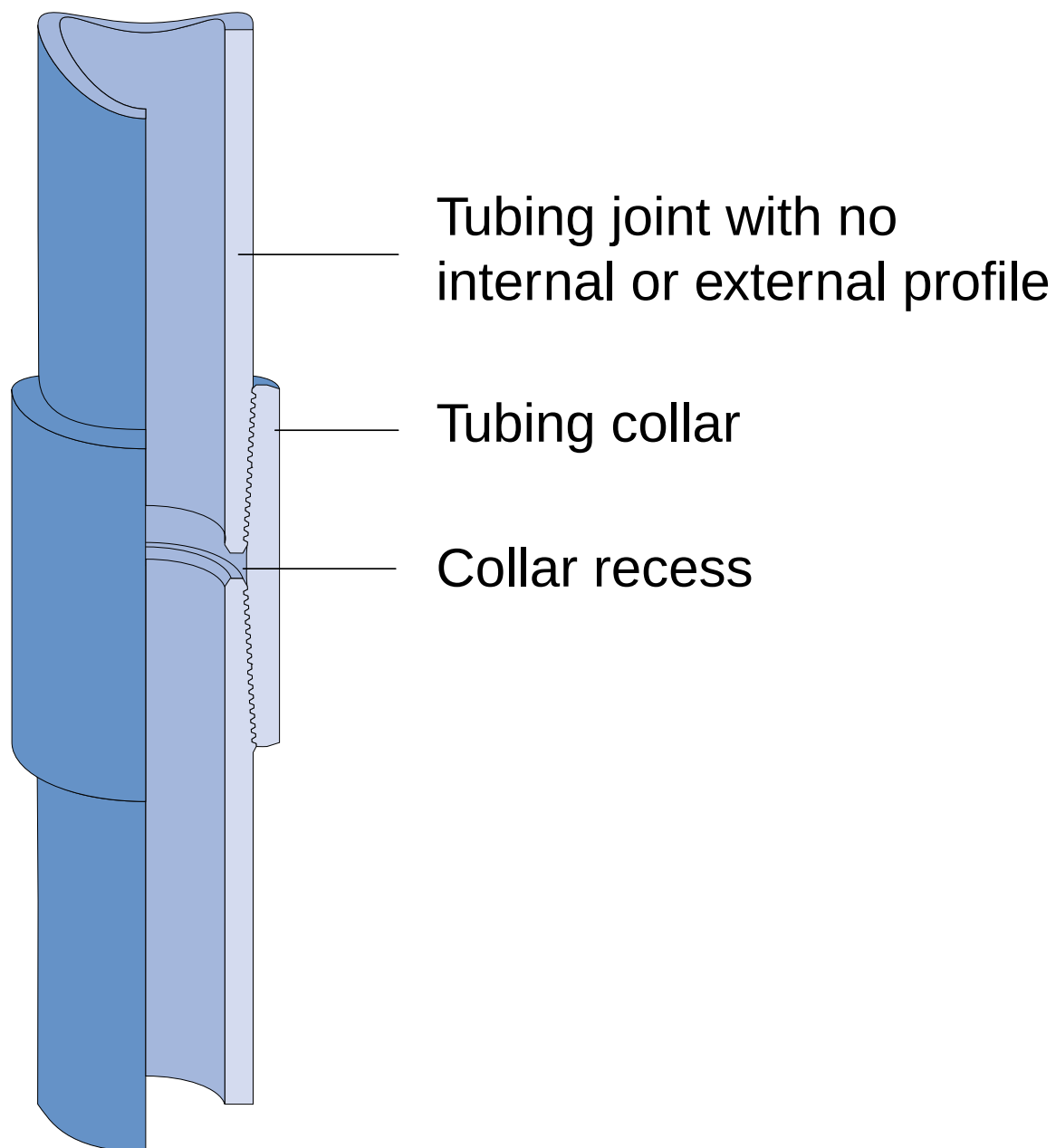


Figure 1-18: Non Upset (NU) Thread Form for Low-Pressure Oil Applications

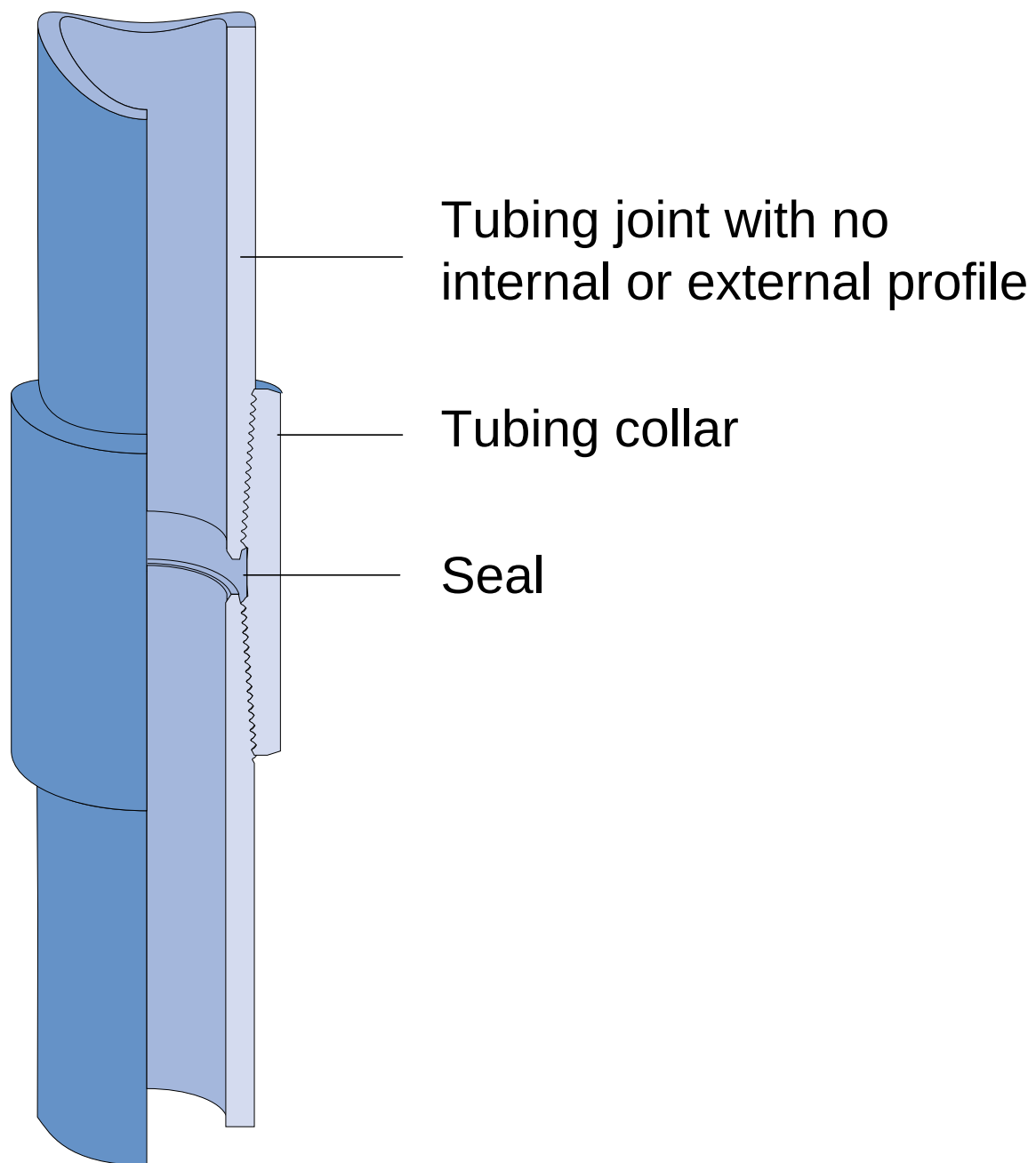


Figure 1-19: VAM Premium Thread Form for High-Pressure and Gas Applications

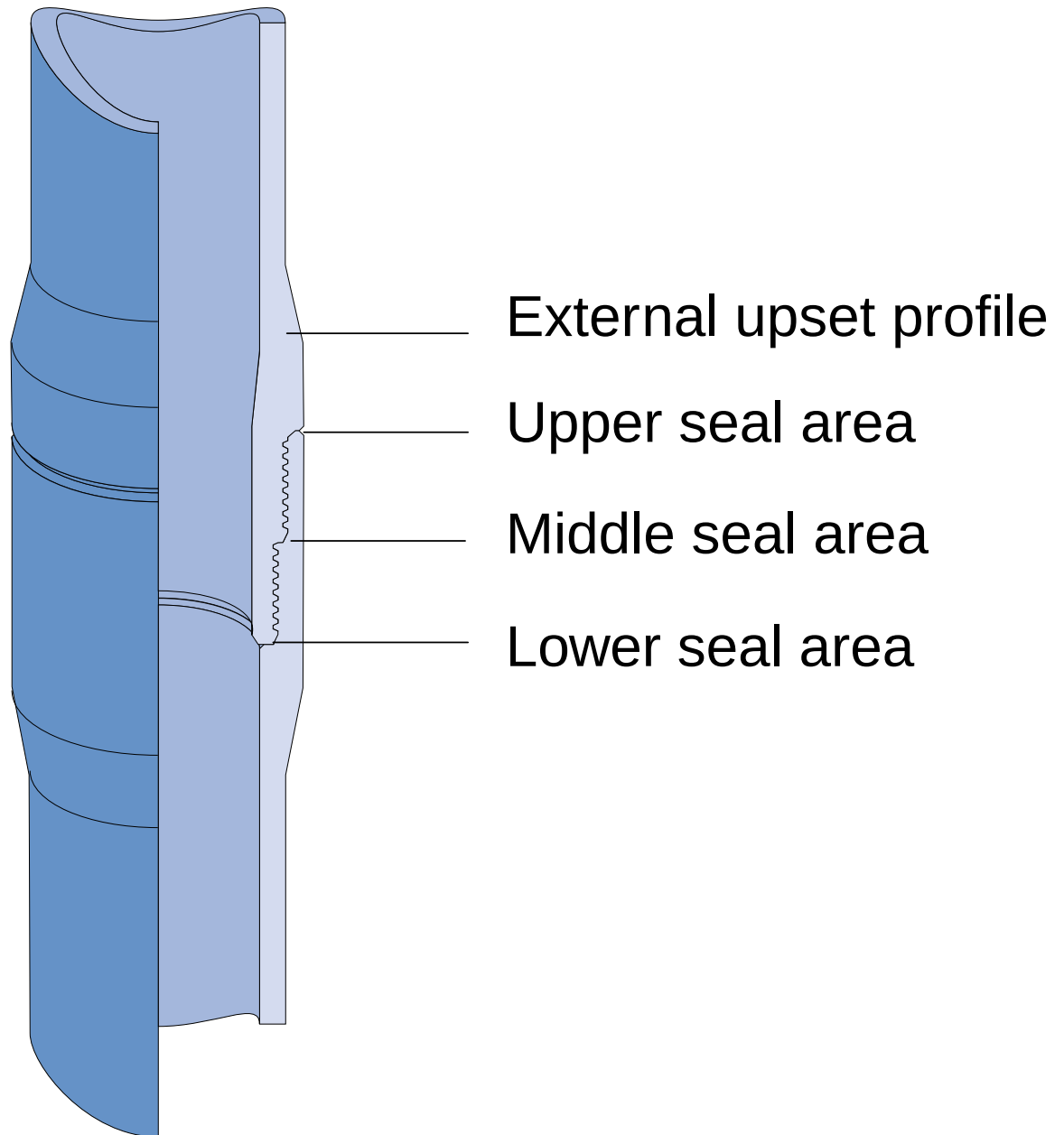


Figure 1-20: Hydril Thread Form for High-Pressure and Gas Applications

1.3.4

Well Construction Process Summary

The installation sequence for the components shown on the following drawing is summarized below. This is not intended as a complete procedure, but an explanation of the diagram only

- The cellar is prepared (onshore).

- The conductor string is installed by a surface rig or pile driving in preparation for the drilling rig commencing operations.
- The well is spudded and the wellbore drilled to surface casing depth.
- The surface casing string is run and cemented into place.
- A casing head housing (CHH) is attached to the surface casing.
- Drilling continues to the intermediate casing depth.
- The intermediate casing string is run and the casing hanger is landed in the CHH.
- The intermediate casing string is cemented.
- The casing head spool (CHS) is installed onto the CHH.
- Drilling continues to the production casing depth.
- The production casing string is run and the casing hanger landed into the CHS.
- The production casing string is cemented.
- The tubing head spool (THS) is made up onto the CHS.
- The well may be perforated by electric line casing guns, if required at this point (optional).
- Tubing and completion components are run and spaced out.
- The tubing hanger is attached to the tubing and landed in the THS.
- At this point the packers may be set.
- A back-pressure valve (BPV) is installed in the tubing hanger.
- The drilling BOP stack is removed and the Christmas tree is nipped up.

If the well was not perforated prior to running the tubing, it may be perforated now using tubing conveyed perforating (TCP) guns or thru-tubing guns run on electric line.

1.4

Glossary of Terms

Conductor Pipe

The largest diameter of pipe, which is pile driven or cemented into a pre-drilled hole, which provides a circulation system for the drilling fluid during the drilling phase. Installation of the lowermost casing head provides structural support of the wellhead completion.

Casing Strings

The steel pipe used to line a wellbore. The general functions include:

- Shut off formations, which will prove troublesome when drilling into deeper formations.
- To provide protection against blowouts.
- To enable control and production of the completed well.

The casing strings can be classified into three main categories:

- Surface casing - The second largest diameter of pipe used to seal off shallow water and sands and provides protection against shallow gas flows. It provides a base for the BOP stack and the wellhead assembly on the completed well.
- Intermediate casing - Set in a deeper well in a transitional zone or abnormally pressurized formation. Used to protect weak formations, helps prevent lost circulation, and provide blowout protection. In a deep well more than one intermediate string may be set.
- Production casing - This string can be considered as the well itself. It is used to provide control of the completed well and is the only string that reaches down to the production formation.

Tubing String

The smallest diameter pipe installed in a well to provide the conduit through which the well fluids flow to the surface.

Annulus

The space surrounding each pipe suspended in the well.

Blow-out Preventor (BOP)

The safety system attached to the wellhead during drilling to control pressures and to prevent the escape of fluids from the annular space between the drillpipe and casing or shut off the hole if no drillpipe is in the hole, should a blow-out occur.

Cementing	The operation pumping cement slurry down the casing string to place a cement sheath in the annulus, which sets to secure the casing string.
Back Pressure Valve	A device that is installed into the profile within the tubing hanger to seal-off the tubing bore to allow safe removal of the Christmas tree.
Sub-Surface Safety Valve	A hydraulically operated valve inserted into the tubing string, which is controlled from the well control room. This valve is used to shut in the well and will automatically close to shut in the well on lose of control pressure.
Actuator	A device that is assembled normally to the upper master valve of the Christmas tree to automatically open or close the valve.

Intentionally Blank

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2 SURFACE EQUIPMENT

2.1 Introduction

Pressure control equipment is necessary to enable a slickline operation to be safely conducted on a live well. Specialized systems have been developed for the various types of slickline, braided line and electric wireline used. The desire to gather more information on the reservoir and production characteristics of the completion has encouraged the development of equipment and techniques to enable safe and efficient wellbore access in live and flowing wells.

Modern pressure control equipment and techniques began to emerge in the 1940's and early 1950's. The original techniques used by electric wireline and slickline service companies were similar to the procedure used to swab in a well. A line wiper or stuffing box, consisting of a housing at the surface containing a resilient packing material, typically rubber, was used to seal off around the cable. The line wiper was mounted on top of the joint of tubing or pipe, called a lubricator. The lubricator served as a chamber above the wellhead, which the swabbing tools could be pulled into, permitting the swabbed fluids to flow uninterrupted through the flow line. The swabbing tools could then be retrieved while keeping the well pressure and fluids under control. However, this was an unsatisfactory method of controlling moderate to high-pressures because abrasive wear of the rubber seals by the stranded cable permitted well fluids, including oil, water or gas, to escape around and through the cable. This created obvious hazards at the wellsite and surrounding environment.

Following World War II, the industry developed new types of perforating guns using high-energy jet perforating charges. These improvements created a need for more sophisticated methods to contain well pressure. When it was necessary to enter a live well, the trend was to reduce electric line diameters to minimize the amount of weight required for the tools to be lowered into the well against pressure. The force resisting tools going into the hole is directly related to the well pressure acting on the cross-sectional area of the cable. As the well pressures increased, it became necessary to run weight bars with the perforating or logging tools to offset the force of the well pressure.

The friction developed around the cable by a conventional rubber-element stuffing box under pressure was severely limiting. For example, at 5000 psi, it was necessary to add 40 to 50 ft of weight bars to overcome the friction created by the stuffing box. This required a lubricator of 85 to 100 ft in length. Thus, going into the well under pressure became expensive and difficult due to the time and labor required in assembling, erecting, and disassembling a lubricator of this length.

Early solutions were directed toward the development of sealing devices designed to reduce friction to a minimum so that the only forces involved were directly related to line diameter and required minimum weight. Shell Development Company in Houston, Texas developed the use of grease as a means of sealing around cable and wireline in the 1950's. The patented concept not only required the use of a grease seal but used a pressure enclosed sheave wheel at the top of the lubricator which was power driven, forcing the cable into the well. The device never became widely used due to the expense and time needed to erect it over the wellhead.

Development of the flow tube followed. This used a controlled blow-by arrangement, within which there was no absolute seal. The flow tube principal relied on the fluid pressure drop from the bottom of the flow tube to the top. Well pressure would be reduced after it coursed through the close fitting turbulence chamber surrounding the cable. The fluid or gas emerged at the top of the flow tube with its energy dissipated to such a degree that the pressure at the top was only slightly more than atmospheric. This fluid was carried off through a drain hose and could be drained into a bucket or exhausted into the atmosphere under controlled conditions. A conventional line wiper was mounted above the flow tube.

The controlled blow-by flow tube became a standard in the industry for pressures up to 5000 psi. At pressures of more than 5000 psi, the device was unreliable and unsafe. The requirement for such high-pressure intervention resulted in the development of modern grease seal control heads.

Current technology enables slickline operations to be conducted on oil or gas wells, which have surface pressure in excess of 15,000 psi. These operations can be conducted safely with a positive seal around the wire or cable while allowing relatively high rates of line speed at well depths of over 25,000 ft.

Slickline techniques were developed over a period of years, with the first criteria for design being a high margin of safety in the design and operation of pressure control equipment.

Allowing well pressure to enter the lubricator positioned above the wellhead exposes the surrounding area, equipment and personnel to the hazard of possible failure of surface equipment.

A high degree of quality control and engineering effort has been devoted to building modern equipment to achieve maximum safety. A major contribution to the increased safety of pressure control equipment is a planned program of pressure testing and inspection of the equipment prior to every job. This is also supported by formal maintenance and inspection procedures.

Deep oil wells frequently encounter more extreme pressures, high temperatures and hazardous well fluids, sometimes with high hydrogen sulfide content, resulting in a need for more reliable pressure control equipment that must operate under more stringent operating conditions.

Such severe operating conditions have resulted in the creation of regulations, regulatory bodies and environmental controls to help ensure operations are conducted with safety.

2.2 Slickline Surface Equipment

To enable slickline tools to be run into a wellbore under pressure, the surface equipment listed below and shown in [Figure 2-1 Slickline Surface Equipment](#) is generally required:

- Stuffing box (alternate sealing wiper box, grease injector head)
- Lubricator bleed off valve
- Quick unions (Otis or Bowen)
- BOP
- Riser sections (Optional)
- Tree connection (Optional)
- Ginpole and rope blocks or similar lifting device
- Lifting clamp
- Slickline clamp
- Hay pulley
- Weight indicator sensor

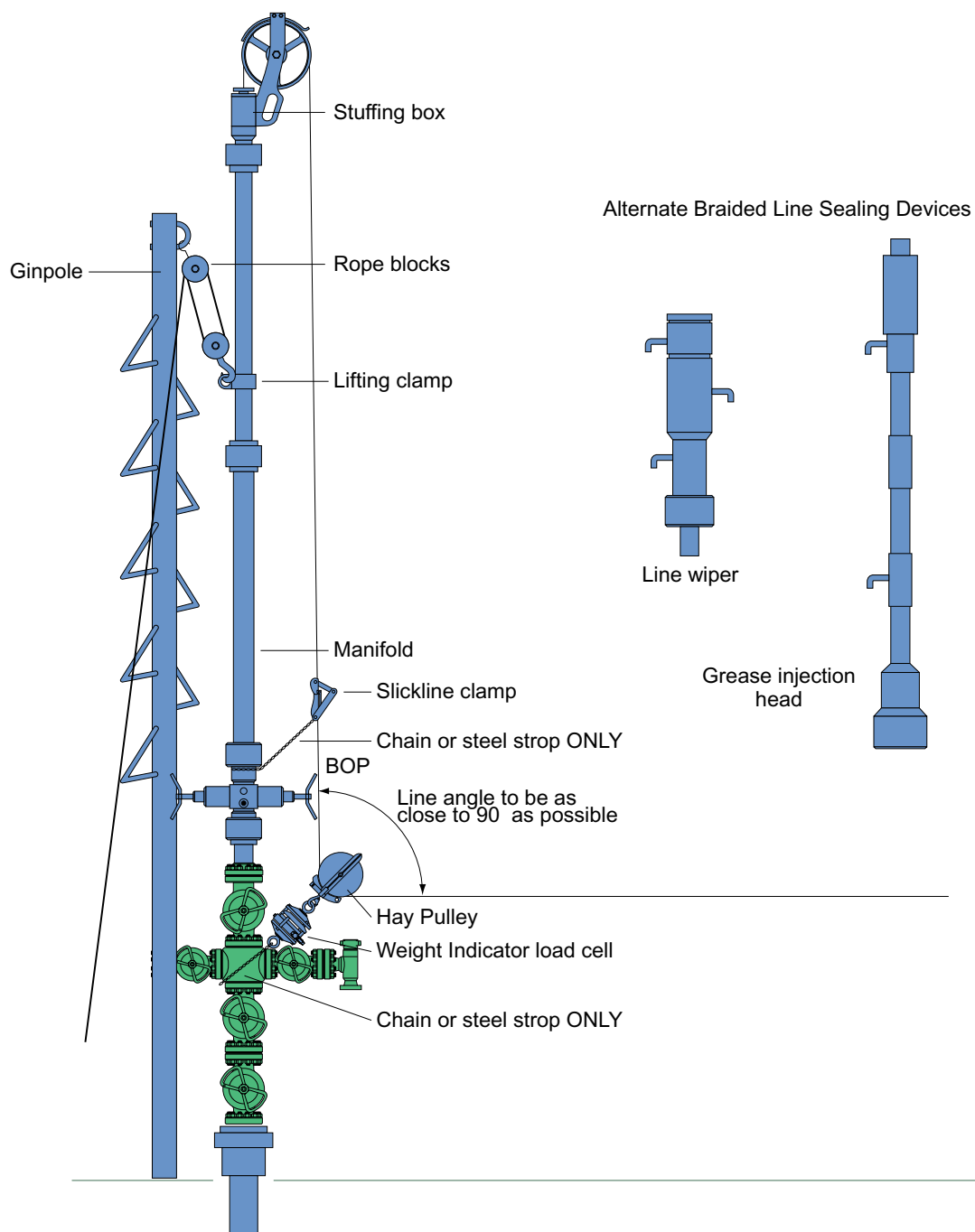


Figure 2-1: Slickline Surface Equipment

2.2.1 Stuffing Box

Containing wellbore pressure and fluids under dynamic conditions as the wire enters the wellbore is a critical factor in slickline operations. The selection of an appropriate sealing device is determined by the specification of the wire, the wellhead pressure and the characteristics of the wellbore fluid. Three types of sealing device are available:

- Stuffing box – suitable for all sizes of slickline
- Swabbing head – suitable for use with braided line, providing a partial seal during applications such as swabbing
- Grease injection head – designed for braided line and capable of providing an effective high-pressure seal

This section details the design and configuration of the stuffing box used for slickline applications.

2.2.1.1 Design Features

The principal function of a slickline stuffing box is to seal around the wire at the upper end of the lubricator during slickline operations, in both static and dynamic conditions.

An adjustable packing nut can be used to increase the compression force on the packing elements or rubbers as they wear. A swivel-mounted sheave wheel and guard to guide the wire as it enters or leaves the wellbore (having 360° free movement) are fitted to the top of the stuffing box. The standard stuffing box is rated for 5000 psi service, however, stuffing boxes of 10,000 psi and higher rating are available.

2.2.1.2 Size Range

The slickline size (diameter) determines the size of the sealing components of the stuffing box and the minimum diameter of the sheave wheel. The sheave diameter for 0.092 in. line is 10 in., and for 0.108 in. line it is typically 15 in. The sealing components and sheave wheels must be replaced when the equipment is used with a different wire size.

2.2.1.3 Broken Wire Protection

Most stuffing box designs contain a BOP plunger, which prevents wellbore fluid escaping through the gland in the event that the slickline breaks and the free end is pulled from the stuffing box. Well pressure acting on the cross-sectional area of the wire forces the wire out when the line weight is less than the upward force. With no wire in place, the flow causes the BOP plunger to activate, with the rubber seal on the upper end deforming to pack-off in the lower gland. With the plunger in place, the wellbore is isolated until the BOP or swab valve can be closed to fully secure the well.

The natural curling tendency of the wire form loops as the tension is removed when the line breaks. The sheave guard on the stuffing box is designed to trap wire, if a break occurs at surface.

2.2.1.4 Injection Port

Some designs of stuffing box incorporate an injection port that can be used for the following purposes:

- Injection of glycol or similar antifreeze fluid in low temperature environments or when working on high-pressure gas wells where hydrates may be a formed.
- Injection of a chemical inhibitor to protect the slickline in corrosive well conditions, e.g., H_2S
- Bleed-off pressure to activate the BOP plunger if the packing has to be changed under pressure. In most cases, an adequate seal can be regained by splitting one packing laterally and installing it with the existing packing. Re-energize the packing nut to activate the seal to enable the toolstring to be retrieved. The stuffing box can then be serviced before the next run.

2.2.1.5 Hydraulic Packing Nut

The use of a remote hydraulically activated packing nut enables the packing force to be adjusted from a safe distance. This feature is particularly useful when:

- The stuffing box cannot be easily reached during operation.
- On high-pressure wells when close proximity to a pressurized stuffing box is not advisable.
- On wells containing dangerous levels of H_2S .

**Note**

H₂S rated equipment must be used on wells containing H₂S in concentrations above the pressure/volume requirements.

2.2.1.6

Stuffing Box Operational Checks

In preparing for use, the following stuffing box checks should be carried out:

- Check the packing condition. If the packing nut is near the lower end of its movement, there may not be sufficient adjustment remaining to apply the packing compression force required to maintain a seal throughout the intended operation.
- Check the sheave diameter is the correct size for the line in use (10 in. for 0.092 in. or 15 in. for 0.108 in.).
- Check the upper and lower brass packing glands for wear. If worn or oversize, they should be replaced, since worn glands allow the wire to cut the packing faster.
- Check the sheave wheel and bearings for free spinning and side play. The sheave should not touch the sides of the support arms. Excessive free-play also leads to a worn upper gland and subsequent reduction in packing life.
- Check the alloy side arms for damage from side play in the sheave wheel. The complete sheave staff should be replaced if cutting/wearing action has occurred on the inside of these arms.
- Check the sheave staff for freedom of swivel movement. It is essential that the sheave follow the wire direction during rig-up or the wire can jump out of the groove and be damaged.
- Check the sheave guard is tight and adjusted close to the sheave to ensure it will trap the line in the event of a line break.
- Check the BOP plunger for wear and freedom of vertical movement.

Keeping the line oiled while running into the wellbore can extend the life of the packing. The choice of packing is also important. Check the manufacturer's recommendations for the appropriate material to suit the field conditions encountered.

2.2.1.7

Changing Packing

The following sequence will apply to most designs of stuffing box:

1. Remove the packing nut and upper gland.
2. Remove the worn packing elements with a packing hook.
3. New packing elements should be reamed on a piece of wire roughened up with cutter pliers to form a file. Insert the wire through the lower packing gland and push each new piece of packing into position with a piece of 3/16 in. brass shear stock.
4. Replace the upper packing gland and packing nut.
5. The wire can be removed or remain in place during transportation.

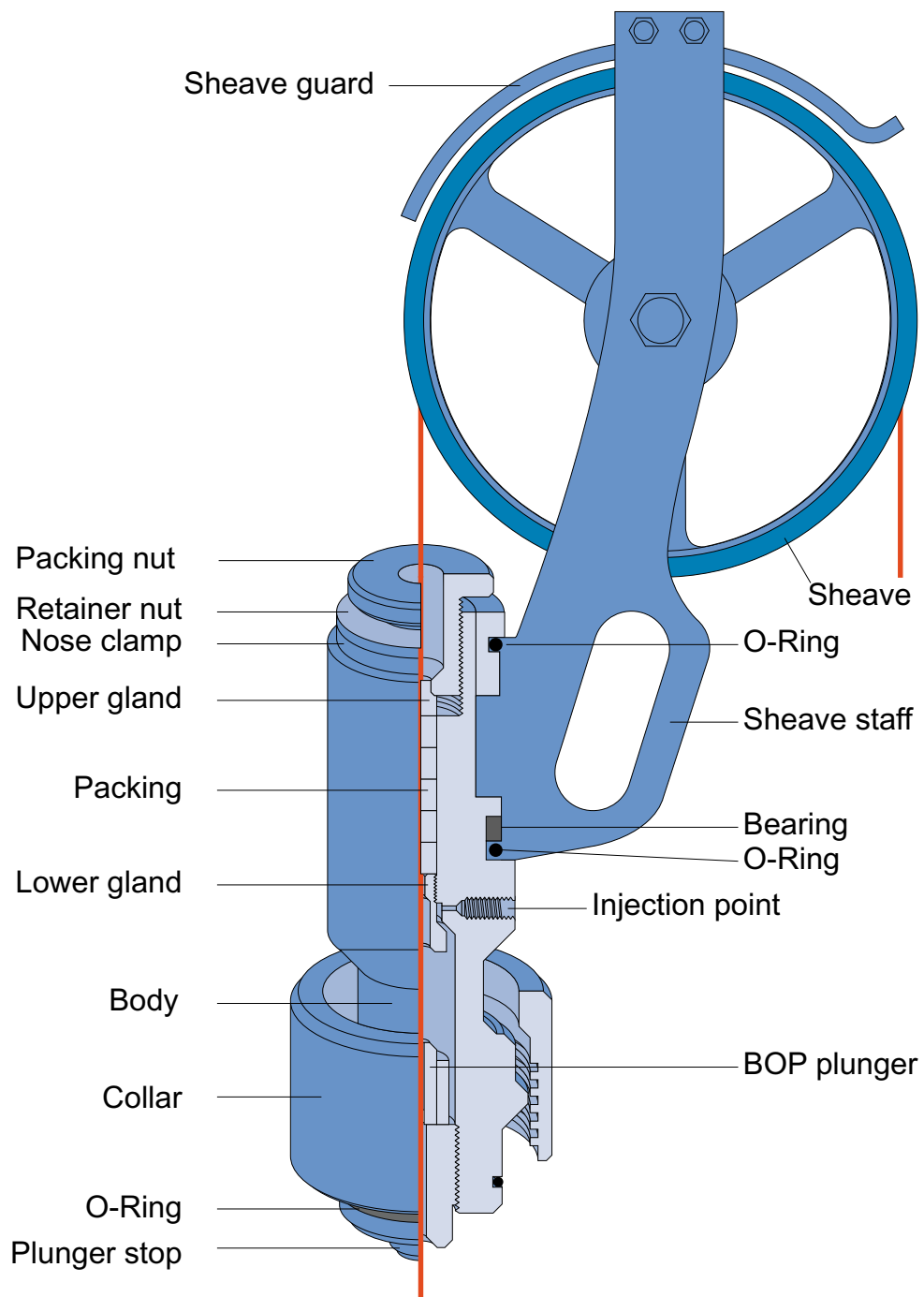


Figure 2-2: Stuffing Box Detail (a)

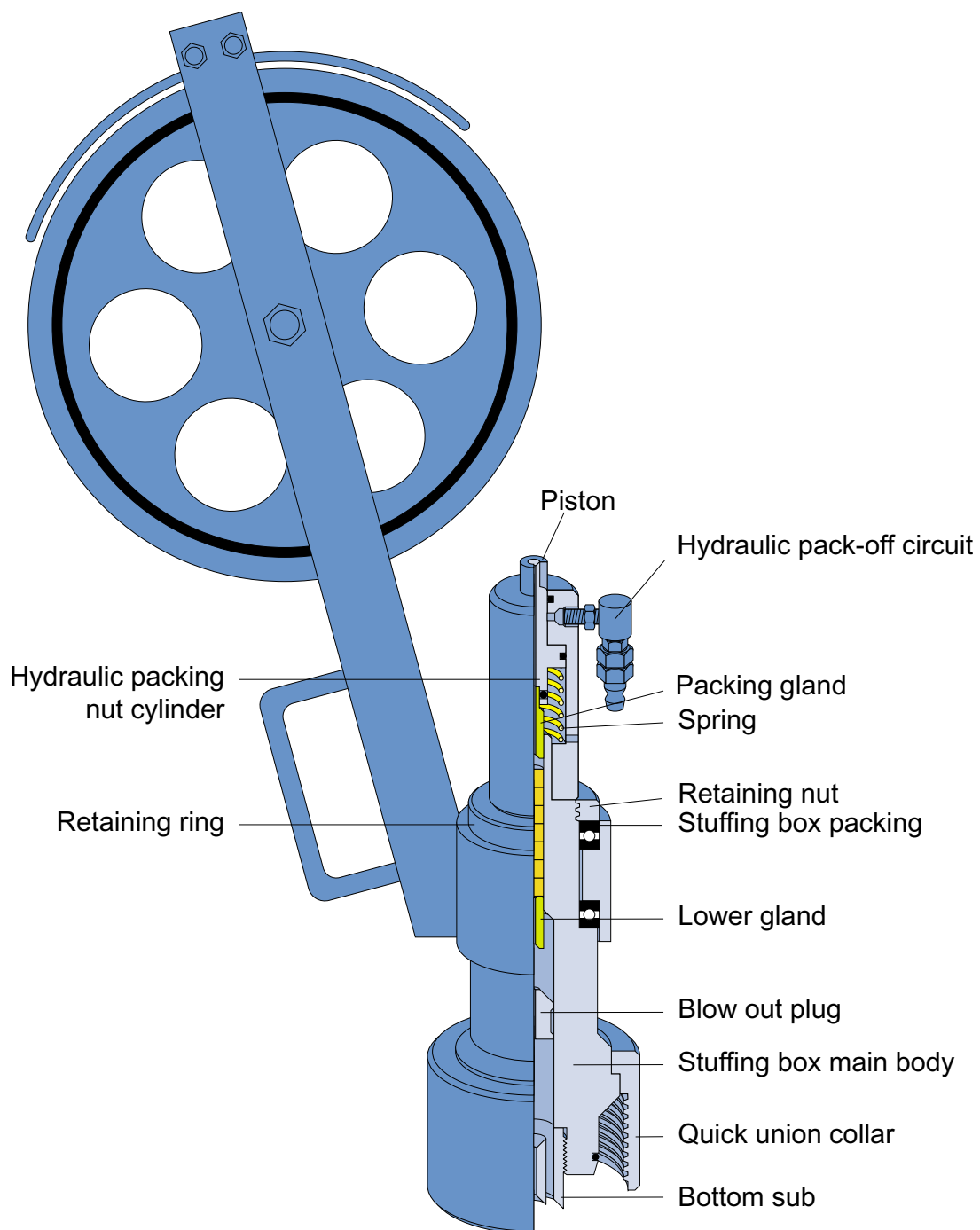


Figure 2-3: Stuffing Box Detail (b)

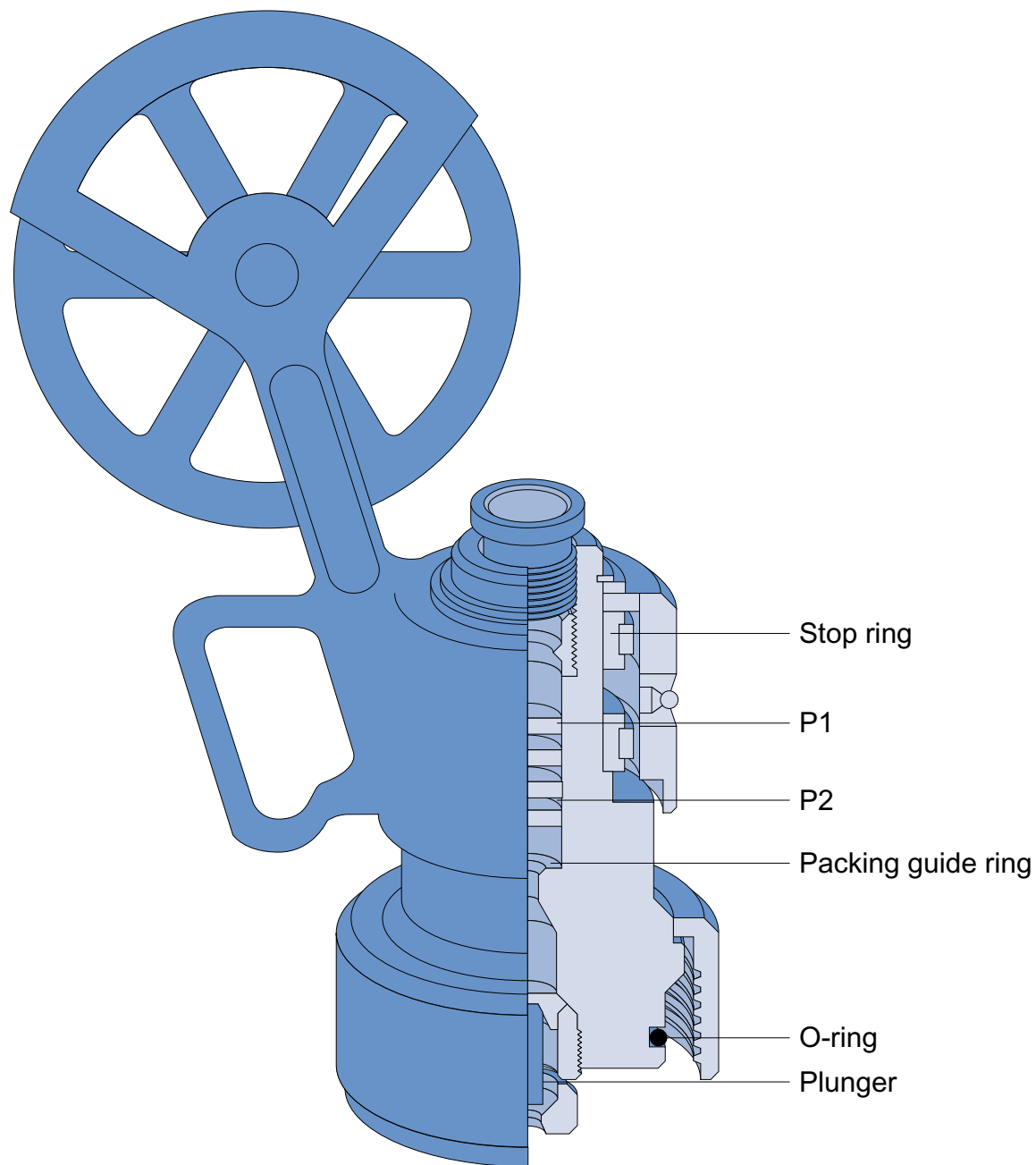


Figure 2-4: Stuffing Box Detail (Flopetrol)

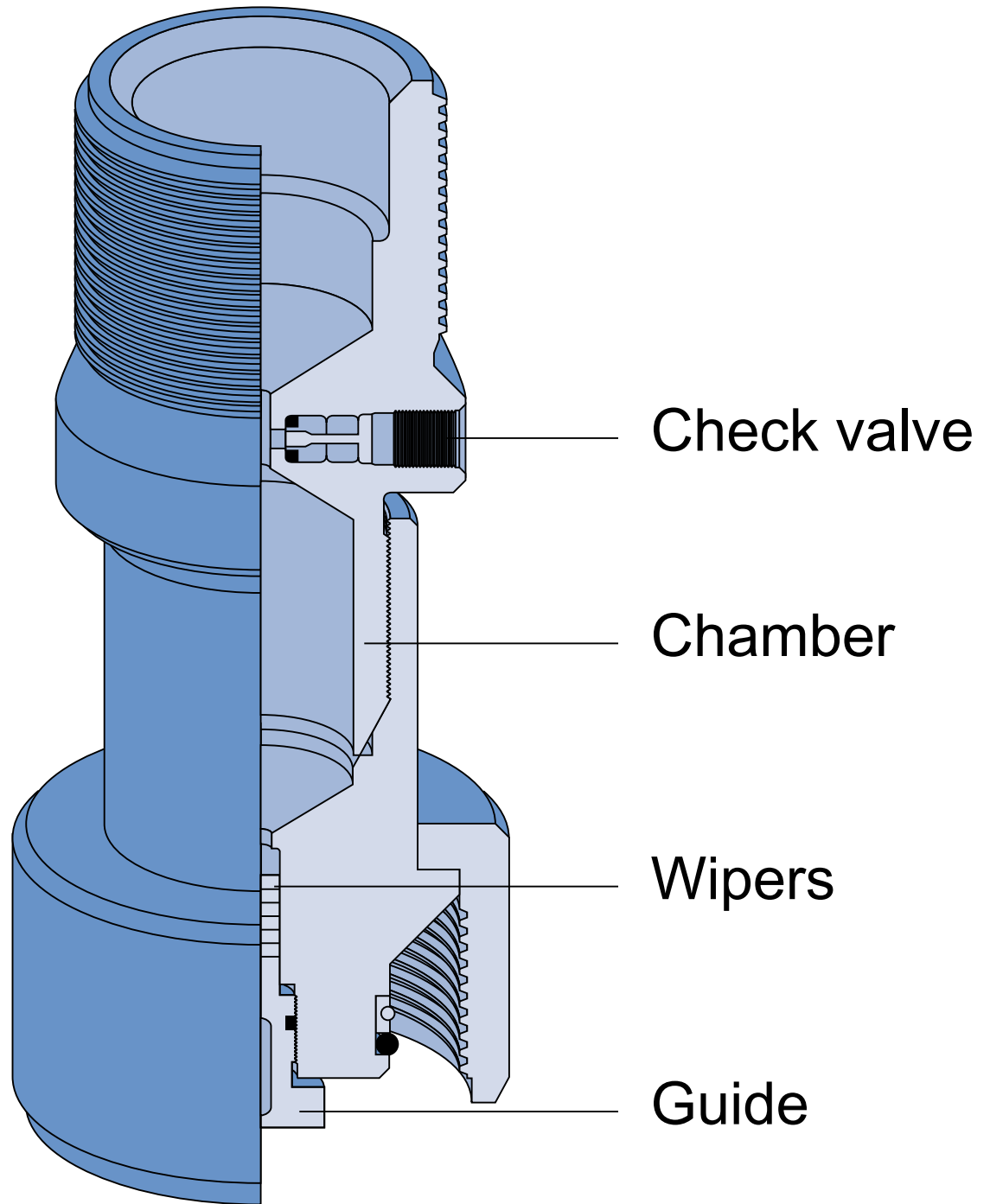


Figure 2-5: Liquid Chamber/Chemical Injection Sub

2.2.2 Camco Liquid Seal Head

The slickline pressure liquid seal head was developed to replace conventional stuffing boxes that employ mechanical packing assemblies. The liquid seal head contains a combination of wireline seal bores and a gas control mechanism. The design allows for superior control of well pressure within a shorter assembly length.

A liquid seal is created around the wire by a pressurized seal fluid. The pressure-tight, low-friction seal is created between the wire OD and the multi-stage, precision-machined wireline seal bores. A gas separation system located within the degasser section of the liquid seal head isolates gas bubbles from the line so that only seal fluid fills the void between the OD of the line and the ID of the seal bores. A controlled volume of seal fluid is allowed to exhaust into the well tubing during operations.

To inhibit the effects of H₂S or other corrosive fluids, the seal fluid is premixed with inhibitor. The liquid seal head coats the wire going into the hole with lubricant and inhibitor. While coming out of the hole, contaminated fluids are removed and the wire is coated with fresh inhibitor before it is spooled on the slickline reel.

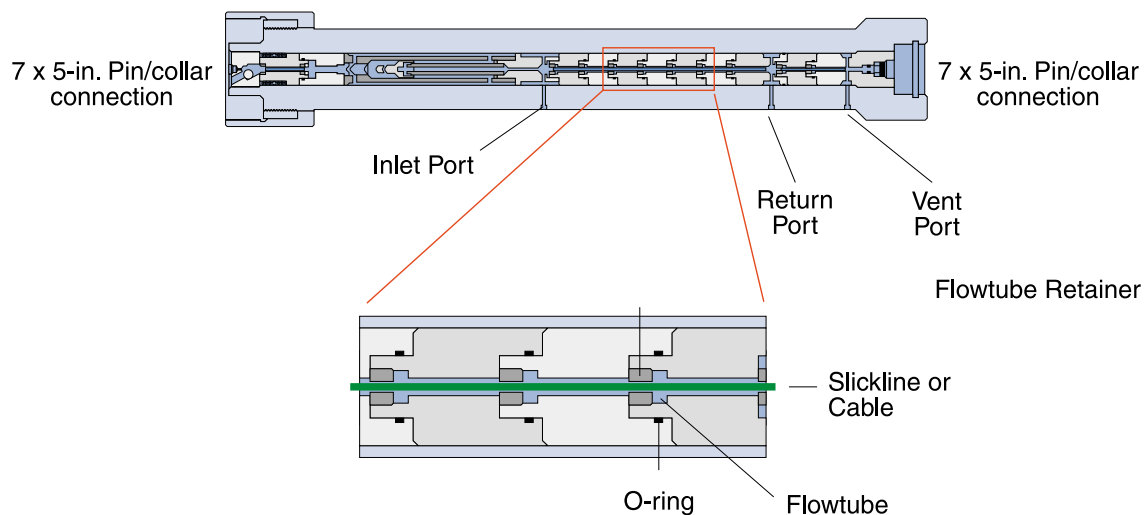


Figure 2-6: Liquid Seal Head Assembly

2.2.2.1 Liquid Seal Head Rig-Up

15K Stuffing Box

A stuffing box is located at the top of the slickline rig-up as secondary means of pack-off in case the liquid seal head leaks. The stuffing box packing should be reamed out larger than normal to minimize additional friction on the wire.

Liquid Seal Head

The primary function of the liquid seal head is to provide high-pressure, low-friction seal against wellbore pressure during slickline operations. The liquid seal head is certified to a maximum working pressure rating of 20,000 psi, however, the rig-up pressure rating is typically 15,000 psi maximum working pressure.

Lubricator Section

Only high-pressure specification lubricator sections should be used in the rig up.

Dual Slickline BOP

A dual wireline BOP assembly should be used to enable two pressure barriers in the event of a well shutdown or emergency condition.

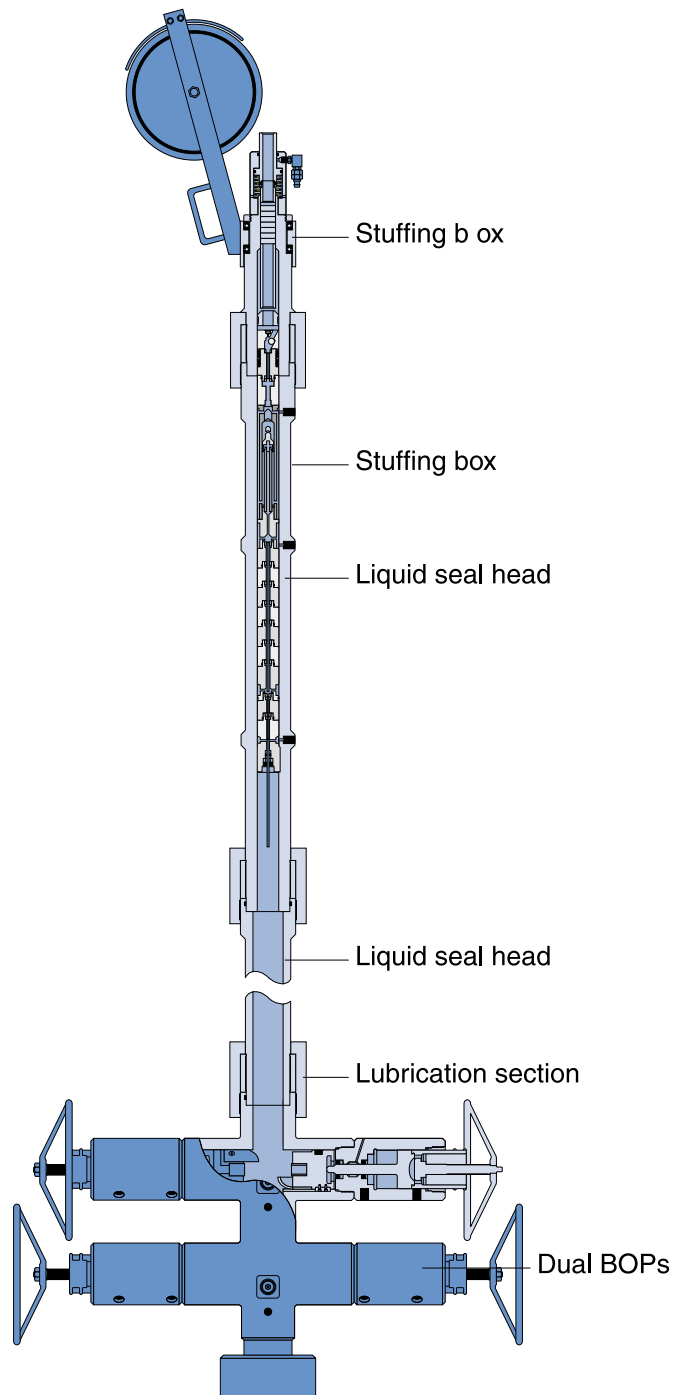


Figure 2-7: Liquid-Seal Head Configuration

2.2.2.2 Operating Procedures

Running In Hole

- Pressure-test the lubricator and liquid seal head assembly. Apply the test in stages, keeping liquid seal head pressure above lubricator test pressure.
- Set injection pressure 1000 - 2000 psi above the closed wellhead pressure (this pressure can be increased if well conditions dictate).
- Open wellbore and run in hole at a line speed of 150/170 ft per min.

Pulling Out of Hole

- Increase injection pressure 2000 – 3000 psi above the closed wellhead pressure (liquid seal consumption will be greater pulling out of hole, a frequent check on fluid consumption is advised).
- Pull out of hole at a speed of 150/170 ft per min.

Loss of Seal

1. Stop running into or pulling out of hole and close return line.
2. Increase injection pressure and observe returns from vent line.
3. If loss of seal is still evident, close the vent line and use the hydraulic stuffing box as a pack-off.
4. If stabilized, bleed the vent and hydraulic stuffing box lines to zero.
5. Slowly start running in or pulling out of the hole while monitoring injection pressure and returns.
6. If the returns are ok, open the return line.

2.2.3 Quick Unions

The connections used to assemble the slickline service lubricator and related equipment are commonly known as quick unions. They incorporate a coarse thread profile that is designed to be made-up by hand. Two types are in common use, Otis and Bowen.

**Note**

Otis and Bowen unions are not compatible - always check before assembly.

An O-ring on the pin section forms a hydraulic seal when assembled into the box. The collar has an internal ACME thread to match the external thread on the box. This thread makes up quickly by hand and should be kept clean. The O-ring should be thoroughly inspected for damage before use. A light film of oil or grease helps to make up the union and prevent damage to the O-ring as the connections are made up.

When the collar is made up, it should be backed off approximately one-quarter turn to eliminate any possibility of it sticking or locking due to friction when it is to be removed.

**Note**

Pipe wrenches, chain tongs or hammers should never be used to loosen the collar of the union. If it cannot be turned by hand, precautions must be taken to make sure that the well pressure has been completely released.

Rocking the lubricator to ensure it is perfectly straight will assist in loosening the quick union.

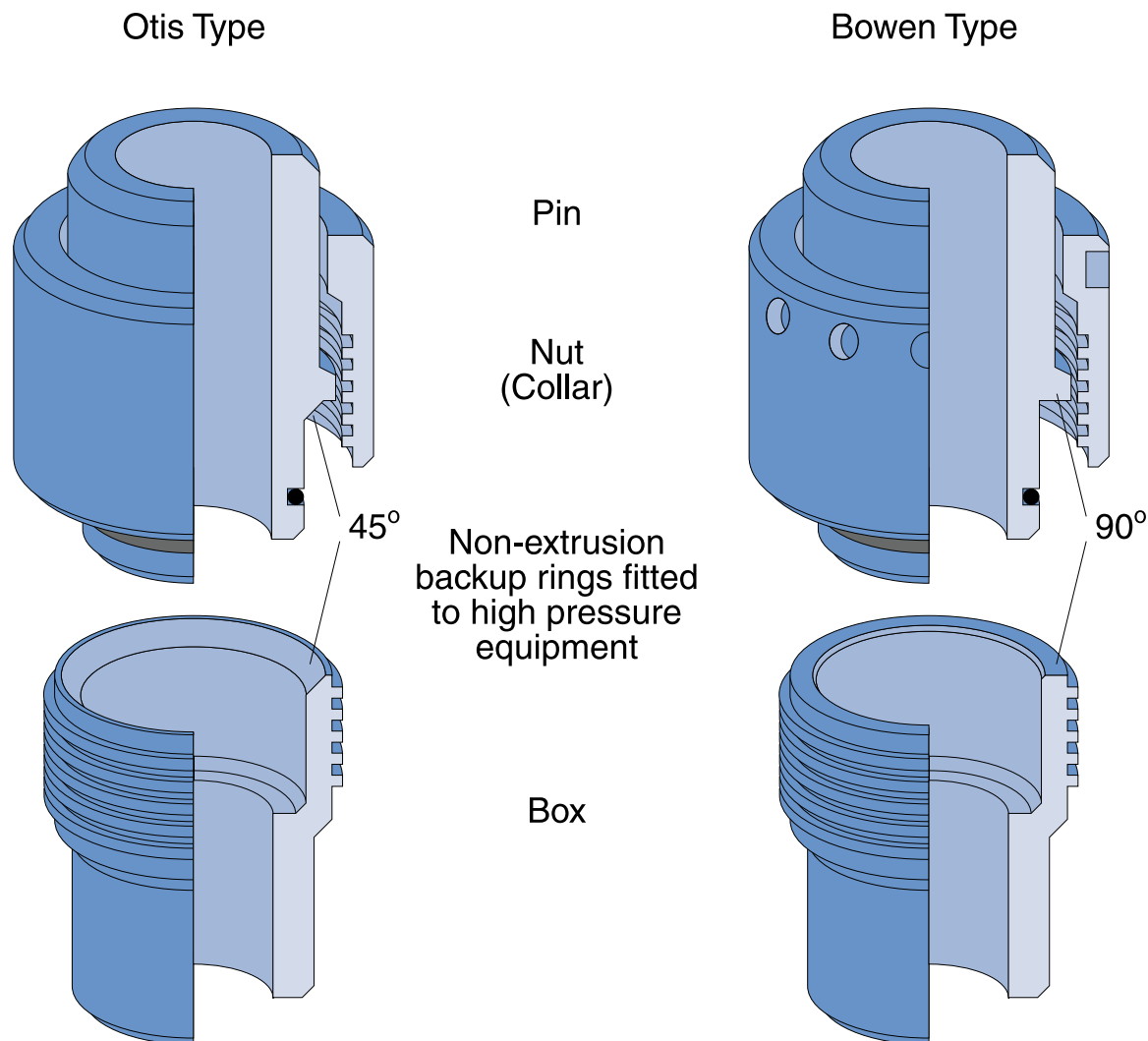


Figure 2-8: Quick Unions - Otis and Bowen

Quick unions are either welded to the lubricator section or are manufactured as a one-piece assembly. Older designs, rated up to 5000 psi were threaded, however, this configuration is no longer permitted. In more recent designs, the pin and box sections are machined in one piece and the collar is assembled over the pin and retained with a 'split nut' fitted internally in the collar.

2.2.3.1

Quick Union Maintenance

All types and sizes of lubricator quick union should be checked as follows:

- Inspect for general damage and corrosion.
- Visually inspect the internal bore for corrosion and 'wire tracking' wear grooves.

- The condition of the O-ring groove.
- The condition of the pin box-sealing surface.
- ☐ Check the pin and box sizes carefully.

**Note**

The maximum clearance between dimension 'B' and 'C' is 0.020 in. (0.010 in. on each per side).

The gap between the pin and box diameter has a direct bearing on the seal integrity and it is therefore critical that these tolerances be checked each time the lubricator arrives in the workshop.

Clean and inspect all components and replace the O-ring seals the thread protectors.

Table 2-1: Otis Type Quick Union Dimensions

Bore (A)	WP	Service	Connection (B)	Pin OD (C)	Box ID (D)	Thread OD (E)	O-ring # (F)
2.50	5000 10,000					5.000	338
2.50	15,000					5.000	338
3.00	5000 10,000					5.750	342
2.50	15,000					5.750	342
4.00	5000 10,000					6.500	348
3.00	15,000					7.500	354
5.00	5000a 10,000					8.250	434
4.00	5000 10,000	H ₂ S	8.375-4 ACME	5.244	5.250	8.375	427
6.38	5000	Std.	8.750-4 ACME	7.494	7.500	8.750	441
5.00	5000 10,000	H ₂ S	9.000-4 ACME	6.744	6.750	9.000	362
6.38	5000	H ₂ S	9.500-4 ACME	7.994	8.000	9.500	443
4.00	15,000	H ₂ S	9.500-4 ACME	6.244	6.250	9.500	435

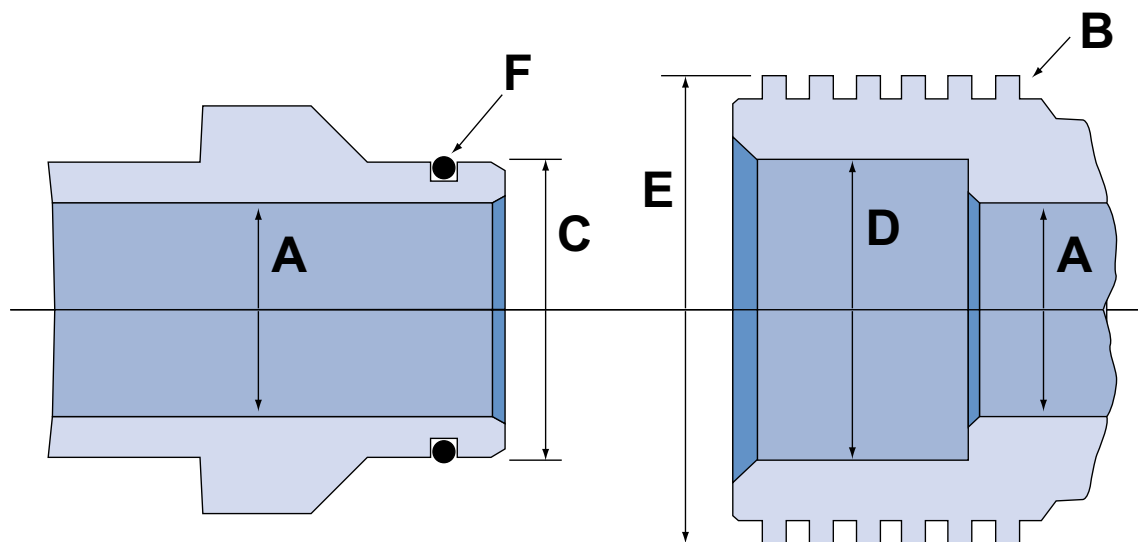


Figure 2-9: Otis Quick Union - Key Dimensions

Table 2-2: Bowen Type Quick Union Dimensions

Bore (A)	WP	Service	Connection (B)	Pin OD (C)	Box ID (D)	Thread OD (E)	O-ring # (F)
2.50	5000 10,000	Std H ₂ S	4.750-4 ACME	3.744	3.750	4.750	340
3.00	5000 10,000	Std	4.750-4 ACME	3.744	3.750	4.750	340
2.50	10,000 15,000	Std	4.7504 ACME	3.744	3.750	4.750	340
3.00	5000 10,000	Std	5.5004 ACME DL	4.369	4.375	5.500	345
3.00	10,000 15,000	Std	5.500-4 ACME DL	4.369	4.375	5.500	345
3.50	5000 10,000	Std	6.0004 ACME DL	4.869	4.875	6.000	349
2.50	15,000 22,500	Std	6.3124 ACME	4.369	4.375	6.312	345
2.50	10,000 15,000	H ₂ S	6.3124 ACME	4.369	4.375	6.312	345
2.50	5000	H ₂ S	4.7504 ACME	3.744	3.750	4.750	340
2.50	15,000 22,500	H ₂ S	6.3124 ACME	3.744	3.750	6.312	340
4.00	5000 10,000	H ₂ S Std	7.000-5 STUB ACME	5.244	5.250	7.000	427

Bore (A)	WP	Service	Connection (B)	Pin OD (C)	Box ID (D)	Thread OD (E)	O-ring # (F)
4.00	10,000 15,000	Std	8.2504 ACME	5.994	6.000	8.250	358
5.00	5000 10,000	H ₂ S Std	8.2504 ACME DL	6.744	6.750	8.250	438

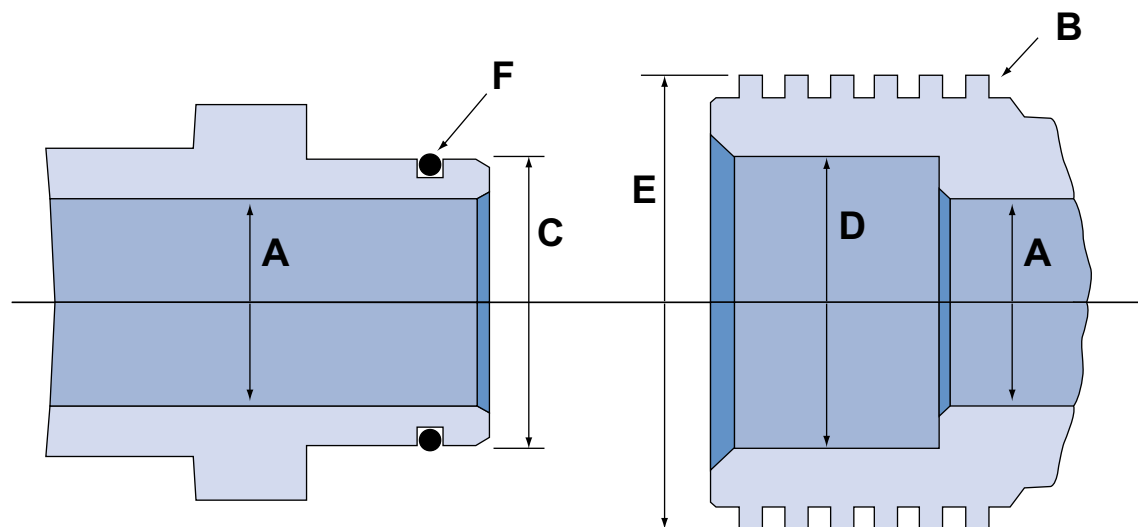


Figure 2-10: Bowen Quick Union - Key Dimensions

2.2.4

Lubricator

Lubricator sections enable the slickline toolstring and equipment to be inserted and removed from a well under pressure. In its simplest form, lubricator is a high-pressure tube with quick connections at each end. All lubricators should be x-rayed, magnifluxed for cracks and visually inspected at regular intervals - typically annually.

The pressure ratings of common lubricator are shown in [Table 2-3](#).

Table 2-3: Test Pressure for Wellhead Equipment

Working Pressure (psi)	Multiplier	Test Pressure (psi)	Remarks
20,000	x 1.5	30,000	Specialty equipment
15,000	x 1.5	22,500	
10,000	x 1.5	15,000	
5000	x 2.0	10,000	
5000	x 1.5	7500	Large ID (4.5 in. and above) equipment only

The lower section of lubricator must be of sufficient diameter (ID) to accommodate the tools or equipment being run (usually the same size as the tubing and wellhead). The lower section has a bleed off valve to vent pressure and fluid or to enable a gauge to be fitted. Upper lubricator sections may be smaller as only the toolstring is housed inside. Common lubricator sizes are 2 in., $2\frac{1}{2}$ in., $3\frac{1}{2}$ in., $4\frac{1}{2}$ in., $5\frac{1}{2}$ in. and 7 in.

The total length must be sufficient to take the toolstring plus any tools or equipment being recovered from the wellbore.

When rigging up and supporting the lubricator, the maximum length picked up with rope blocks on a ginpole is:

- 3 sections – if the lower section does not exceed $4\frac{1}{2}$ in.
- 2 sections – if both sections are $4\frac{1}{2}$ in.

For lubricator of greater diameter, a crane must be used.

Wire tracking inside the lubricator occurs when wire abrades the inside wall of the lubricator. This can significantly reduce the strength of the lubricator and should be monitored by regular visual inspection.

The various pressure ratings and service capabilities of lubricator sections are commonly identified by different color codes.

Riser sections are used to space-out the BOP stack or lubricator to a working level, i.e., Christmas tree to rig floor or impact deck. Riser sections are normally 10 ft to 40 ft in length and are of the same specifications as lubricator but with flanged connections.

2.3

Blowout Preventers

A slickline BOP (also known as a wireline valve) is generally installed between the tree connection and lower lubricator section. The BOP provides facilities for contingency and emergency procedures and must be included in all rig-ups.

The only exceptions by which a BOP is not rigged up next to the tree connection are:

- When installing or retrieving BPVs (back pressure valves) and there is a possibility of the toolstring remaining across the Christmas tree valves, the BOPs can then be mounted above the lower lubricator section. Check that this provides sufficient length to close the rams on the wire, i.e., above the rope socket.

- When running and pulling an SCSSV or a slickline retrievable BPV, the BOP can be positioned above the first section of the lubricator. Alternatively, a second BOP can be placed immediately below the stuffing box. This provides a means of isolating the well pressure and recovering the tools if the wire breaks at the rope socket and the tools drop across the Christmas tree valves.

The primary purposes of the BOP are to:

- Enable the well pressure to be isolated without cutting the wire by closing the master valve.
- Provide access for the assembly of a slickline cutter above the BOP rams.
- Allow a wireline cutter to be prepared and dropped if the toolstring becomes stuck in the well.
- Enable 'stripping' of the wire through closed rams, only when necessary.

Mechanical or hydraulic force is applied to close the BOP rams, which seal against the wire.

Several types or styles of ram are commonly encountered:

- **Slickline rams** - use blind rams with rubber inserts on the sealing faces to seal with or without wire across the rams.
- **Braided line** - use rams with a semicircular groove in the seals to match the line diameter.

All rams are equipped with a centralizing profile to ensure the wire is positioned centrally on the sealing face as the rams close.



Note

BOP rams will hold pressure differential in one direction only.

Slickline BOPs are available in manual or hydraulic operating modes and are used in the following configurations:

- **Single BOP** - Installed between the tree connection and lower lubricator.
- **Dual BOP** - Double or twin ram BOP are primarily used with braided line. Generally hydraulically operated, a dual BOP is generally configured in a single housing or body containing two sets of rams. To obtain a seal against braided line, a grease injection point is provided between the ram sets.

- **Multiple BOP** - On high-pressure gas wells, a third BOP is advisable. The lower set of rams is installed upside down so that they will hold pressure from above. Grease injected above these rams will be contained and form an efficient seal.

2.3.1 BOP Operation

The key design and operating features of slickline BOPs include:

2.3.1.1 Equalizing Valve

All BOPs have a means of equalizing the pressure across the closed rams. Any pressure differential acting on the cross-section of the rams creates a force that makes opening the rams extremely difficult. Attempting to open the rams without equalizing may result in internal damage.

The equalizing valve should normally be kept closed so that in an emergency, the BOP will hold pressure as soon as the rams are closed.

2.3.1.2 Function and Pressure Testing

All BOP's should be tested on a regular basis.

Full body tests are conducted with the rams open and applying 150% of the working pressure.

Working pressure tests are performed with the rams closed, applying 100% of the working pressure to test the ram seal against the wire diameter. A test rod of the same size as the wire to be used should be inserted between the rams.



Note

As a safety feature, ensure the test rod has an enlarged diameter below the ram to prevent it being blown out during testing.

The force created by pressure acting on the cross-sectional area of the test rod will act to push the rod out of the rams. For this reason, it is not recommended that any locally made devices be used unless they have been subjected to recognized inspection and certification.

2.3.1.3 **Transportation**

Prior to removing the BOP from the wellhead, it is strongly recommended that the rams be closed and the handles be removed. This will prevent accidental bending of the threaded stems and will protect the threads from corrosion.

2.3.1.4 **Design Features**

Some recent designs of hydraulic BOPs are fitted with gas vented hydraulic cylinders. A small hole in the adapter cylinder, close to the BOP body, prevents gas from passing the O-ring seal on the stem and entering the hydraulic system. If gas migrates into the hydraulic system, the following problems may be encountered.

- Components can be subjected to damaging pressures above their rating.
- Gas can cause the hydraulic fluid to expand and cause the rams to open.

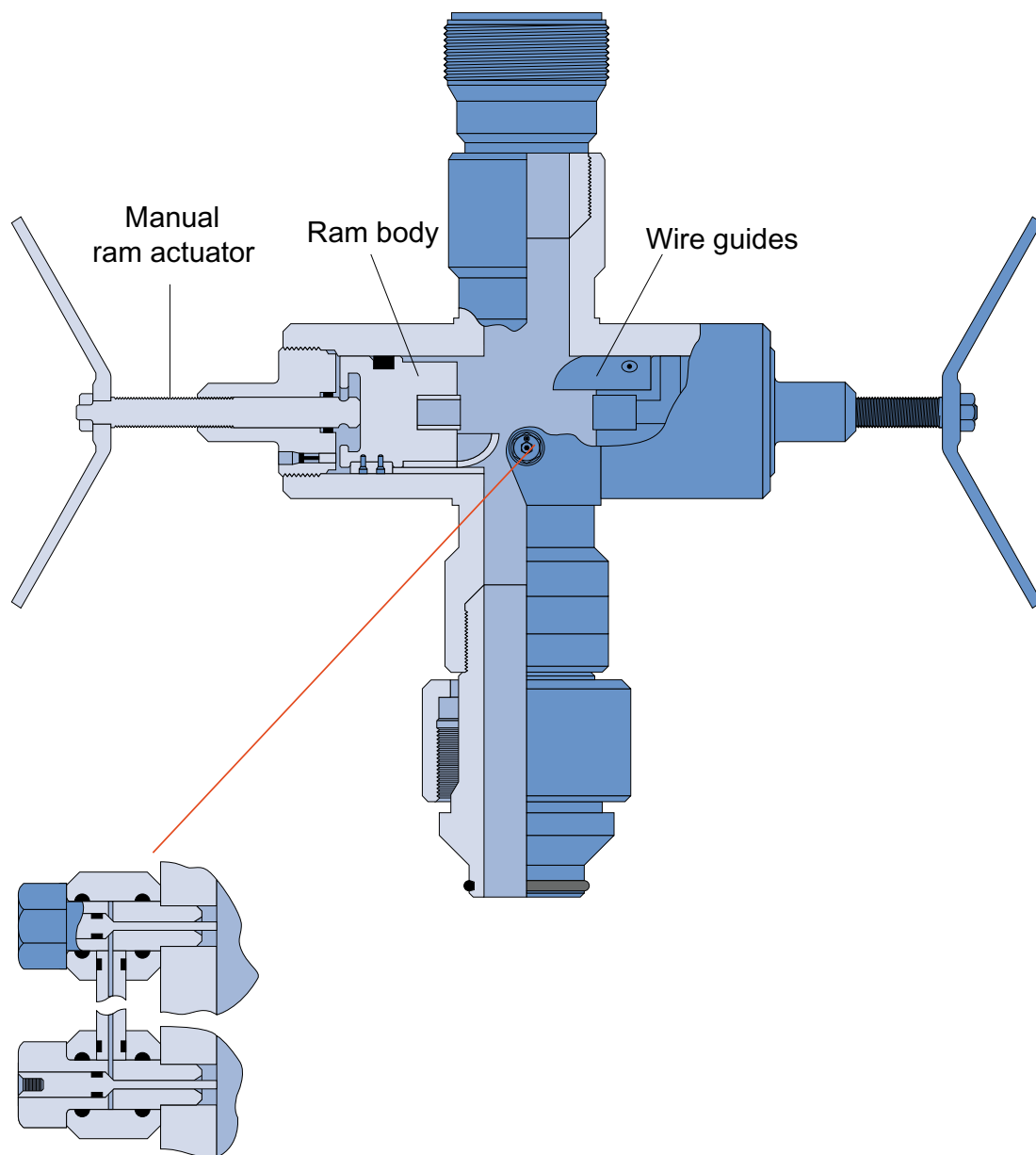


Figure 2-11: Single Ram Manual Slickline Valve

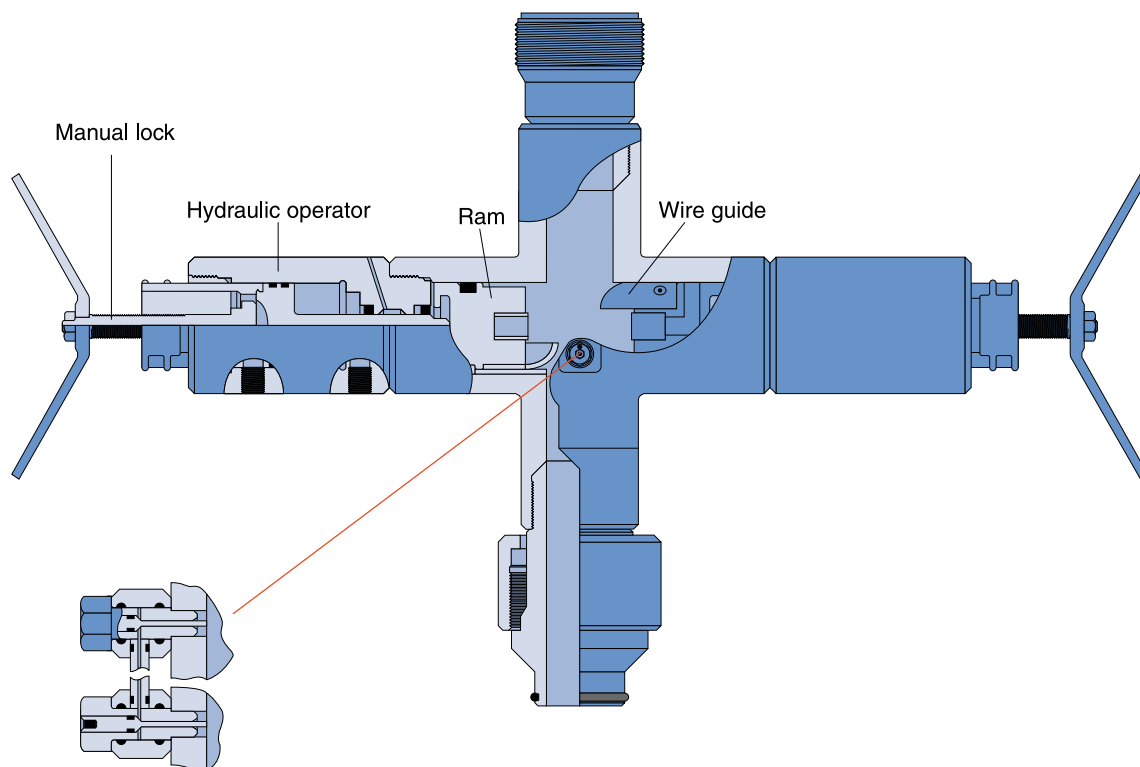


Figure 2-12: Single Ram Hydraulic Slickline Valve

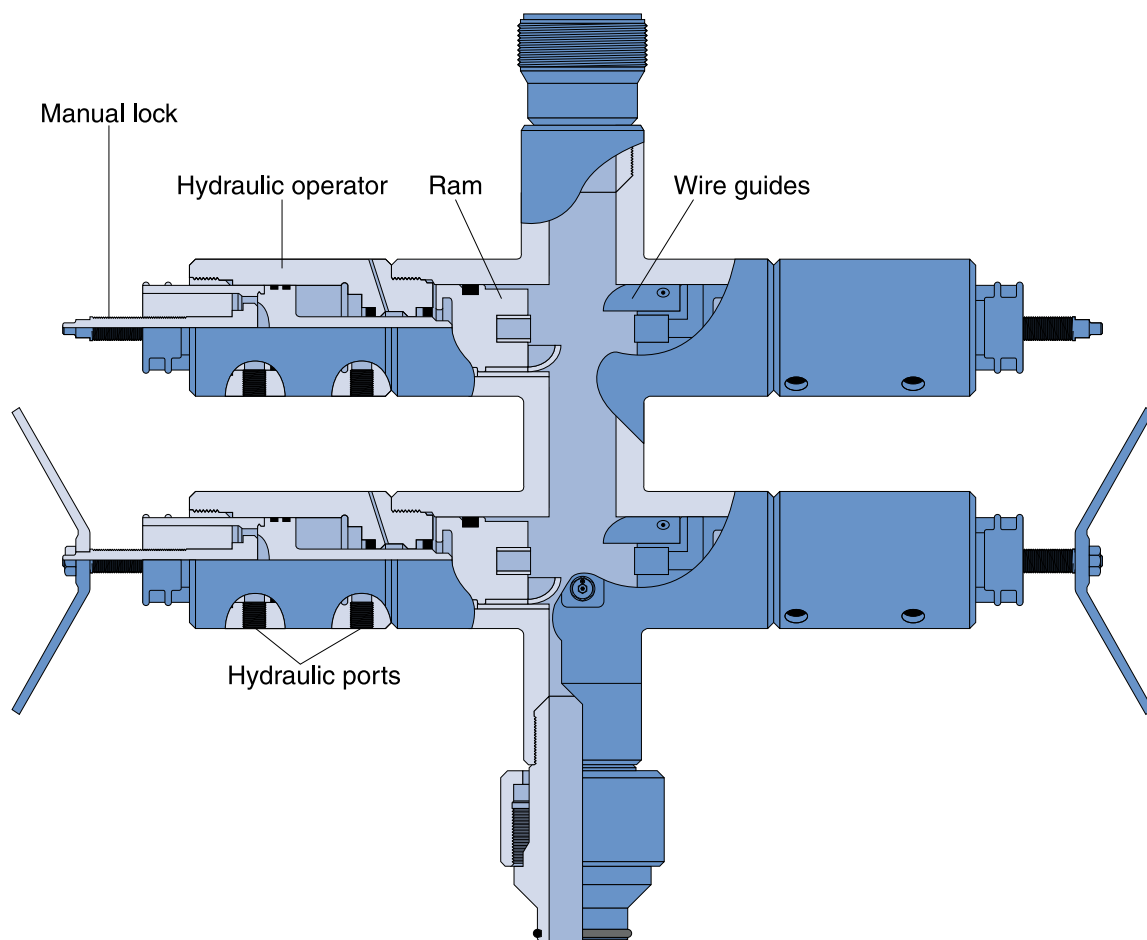


Figure 2-13: Dual Ram Hydraulic Slickline Valve

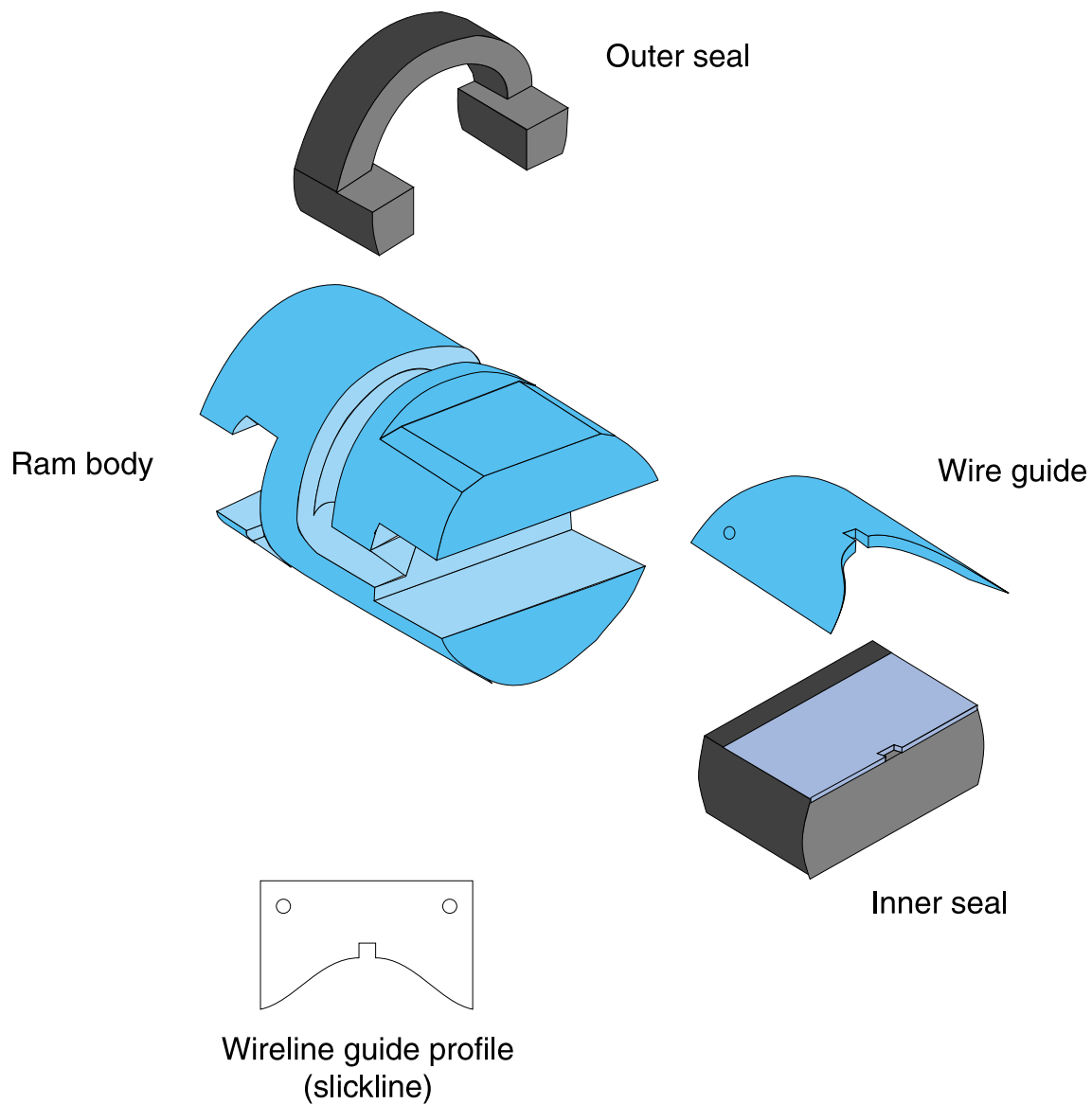


Figure 2-14: BOP Ram Details - Slickline

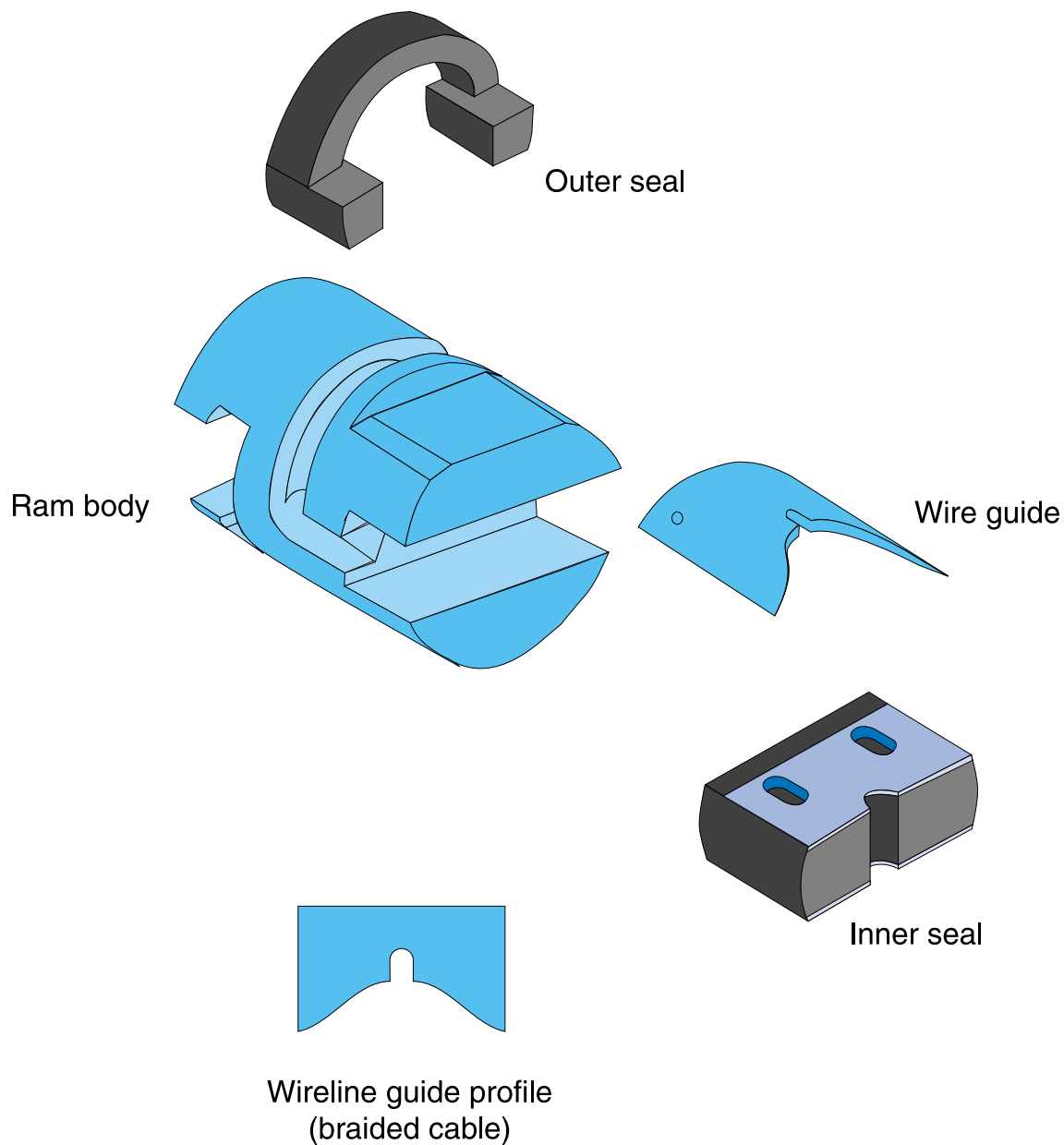


Figure 2-15: BOP Ram Details - Braided Cable

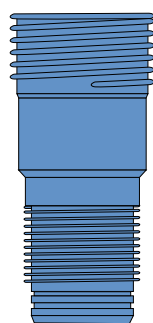
2.3.2

BOP Tree Connections

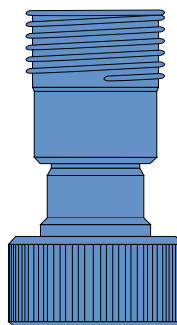
Tree connections are required to safely and securely connect the BOP to the Christmas tree. There are several different designs available, however, the main designs encountered are:

- Threaded - Not permitted in normal operations
- Unibolt or flanged

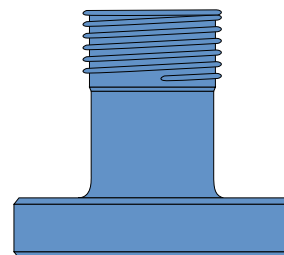
- Quick union



Acme thread
x
quick union



Quick union
x
quick union



API flange
x
quick union

Figure 2-16: Tree Connections

2.4

Weight Indicator System

The slickline weight indicator system is commonly configured as a sealed hydraulic system. The sensing load cell is attached to the Christmas tree by a chain and a high-pressure hose connected to the fluid filled pressure gauge which is calibrated in lb, kg or kN.

The load cell is attached to the hay pulley and Christmas tree forming a 90° angle. The system is calibrated to the right angle pull and accuracy will be slightly affected if the angle is not true, but the sensitivity of the system is always maintained.

The gauge is a 6 in. diameter fluid-filled instrument, which is fastened to the slickline winch operators panel. A damper is provided on the gauge to set the pointer motion to the required sensitivity. The fluid filled case eliminates severe vibrations and also lubricates and protects the working parts.

If fluid leaks out of the system, the plates of the load cell will close. If this occurs, the reading on the gauge will be incorrect and if the plates close sufficiently to touch, the gauge will no longer indicate accurate tension. The gap should be approximately 9/16 in. at the bellows and 3/16 in. at back plate.

In addition to preventing overload of the slickline, the weight indicator will also enable the operator to detect:

- Wellbore fluid levels
- Changes in fluid density
- Jar action

- Location of downhole equipment

A different weight indicator is used for 3/16 in. line because of the higher loads that can be exerted. The load cell for this instrument has a smaller cross-sectional area in the diaphragm and is matched to the higher range dial gauge. The gauge and load cell cannot be interchanged.

Maximum loading/dial marking:

- 0.108 in. unit = 2000 lbf (1000 kg)
- 3/16 in. unit = 4000 lbf (2000 kg)

Electronic strain gauges are also available in some locations. In addition, some counter assemblies have an in-built weight indicator. These eliminate the need for a long hose and operate on the same principle as a conventional weight indicator.

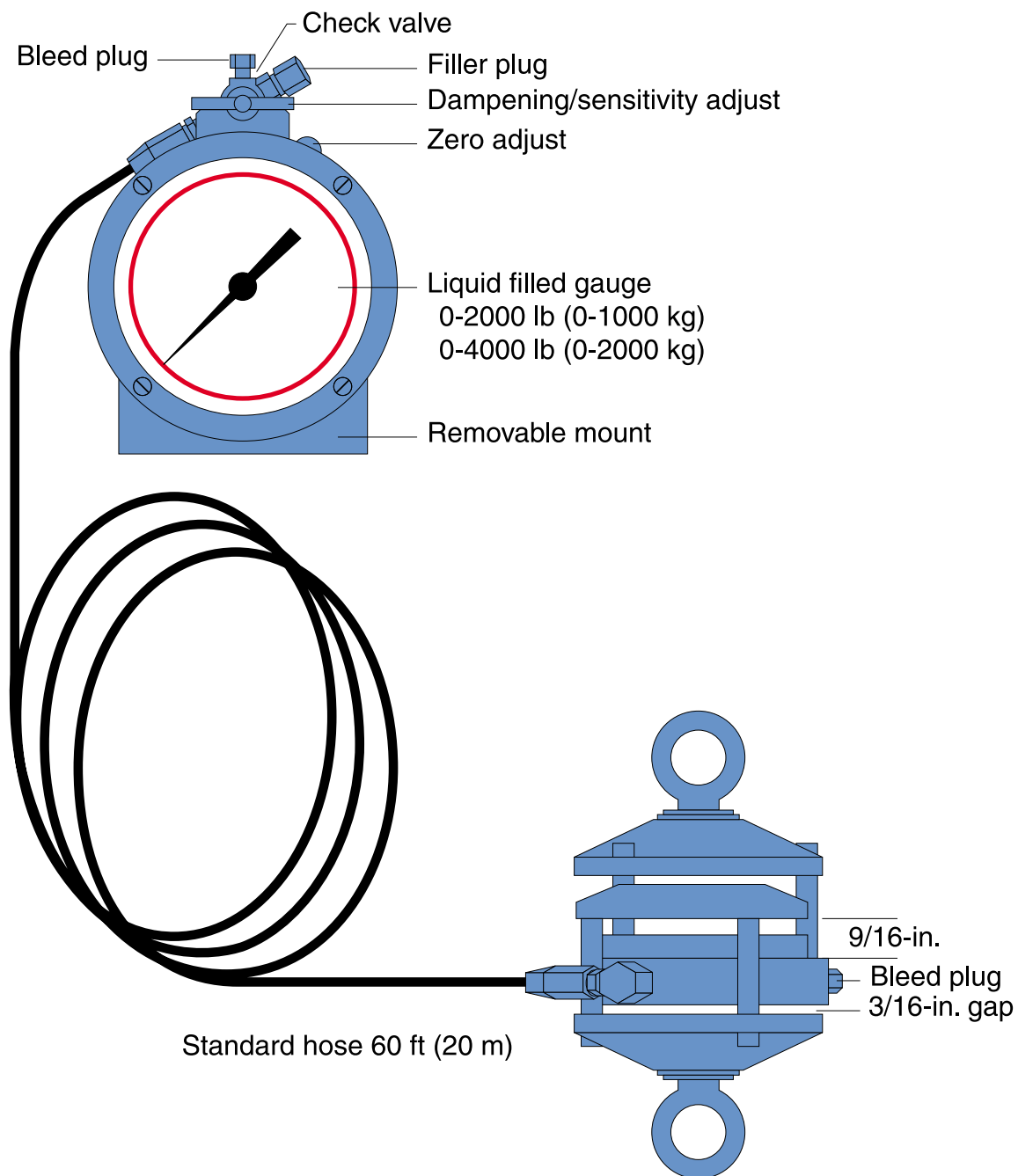


Figure 2-17: Weight Indicator Components

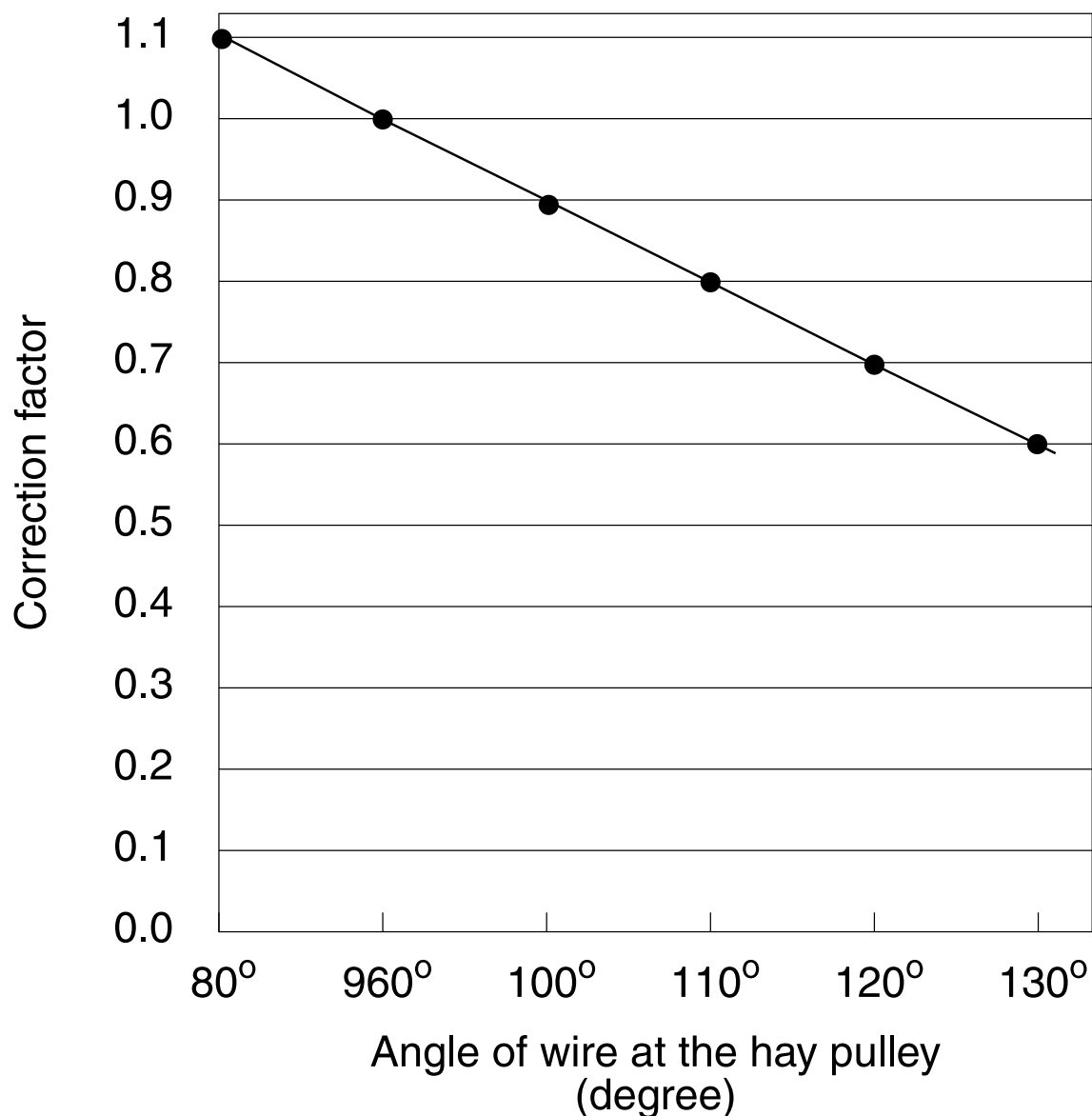


Figure 2-18: Correction Factors for Various Hay Pulley Angles

An investigation carried out by a leading wireline manufacturer reported the following findings:

- Under slow, steady loading conditions Martin Decker type weight indicating system, when correctly damped, can register true line loads.
- Excessive damping under slow, steady loading conditions may reduce the recorded loads.
- The Martin Decker type system is insensitive, even at the lowest degree of damping, to accurately record shock loads.

- No provision is made to record the maximum load by a separate free rotating secondary needle.
- It is unlikely that the slickline operator would observe an instantaneous shock load during a jarring operation.

These results suggest that excessive loads experienced during jarring may not be realized until premature failure.

2.4.1

Hay Pulley

Slickline sheaves, known as hay pulleys in the smaller slickline sizes, are an essential part of a slickline rig-up. They are used to route the slickline from the stuffing box into a horizontal track onto the slickline winch drum. The wire should be parallel to the lubricator to reduce side loading and bending stresses on the tree connection. The hay pulley is hooked directly onto the eye in the weight indicator sensor.

The hole in the frame of the hay pulley is to permit a line wiper attachment. The Hay Pulley must be rigged up with this hole at the bottom.

Always install with the locking pin 'up', to prevent the pin vibrating down and unlocking the hay pulley if the pin spring is weak. The size of hay pulley must be at least the minimum recommended for the line diameter and type in use.

Larger diameter sheaves require a frame to prevent toppling as the line tension is reduced.



Note

A rule of thumb used to establish the recommended hay pulley diameter is 120 times the wire OD.

Table 2-4: Recommended Hay Pulley Dimensions

Minimum Recommended (in.)	Pulley Diameter (in.)
0.0920	11.25
0.1080	13.00
0.1250	15.00
0.3125	12.00
0.2500	16.00
0.4375	20.00

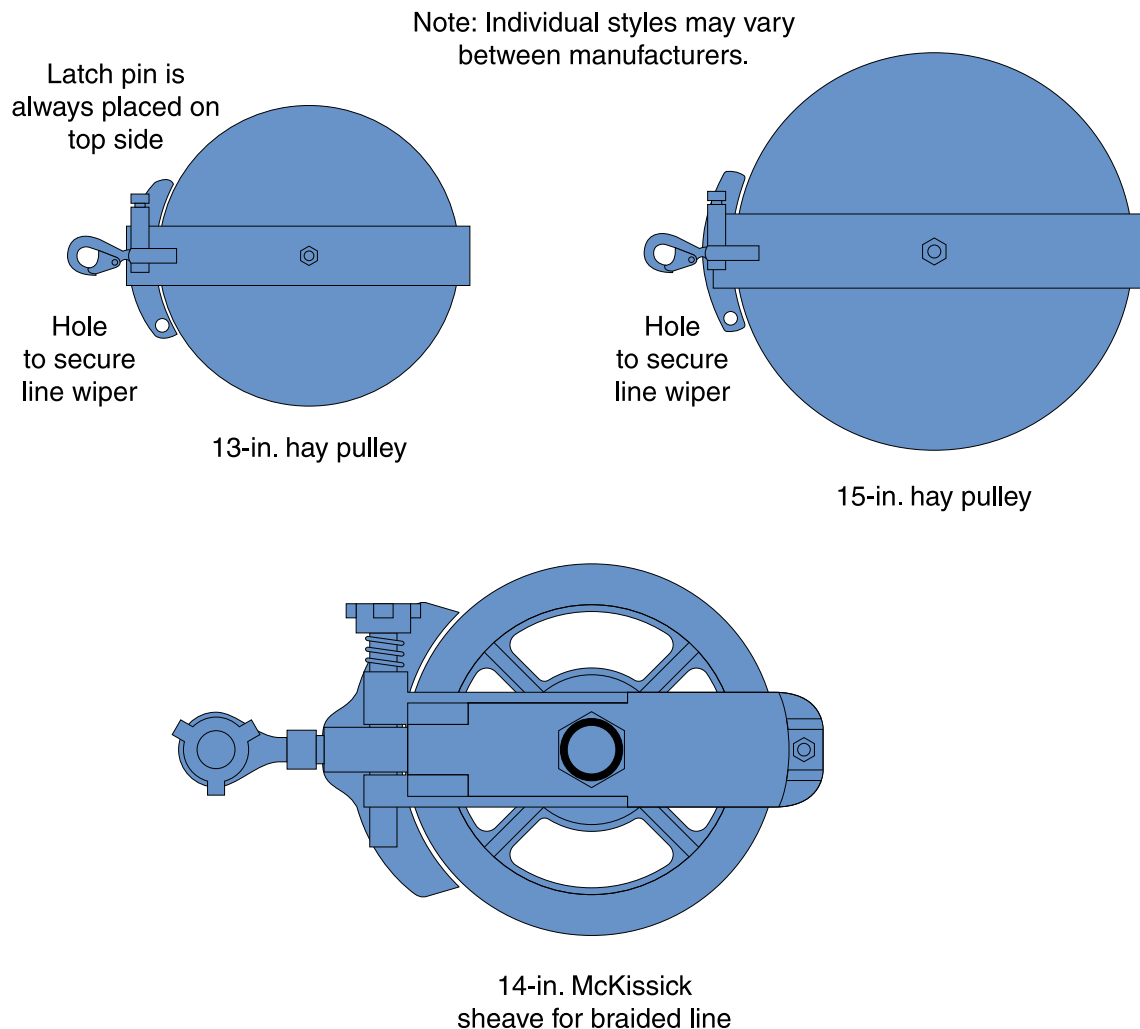


Figure 2-19: Hay Pulley and Sheave Options

2.4.2

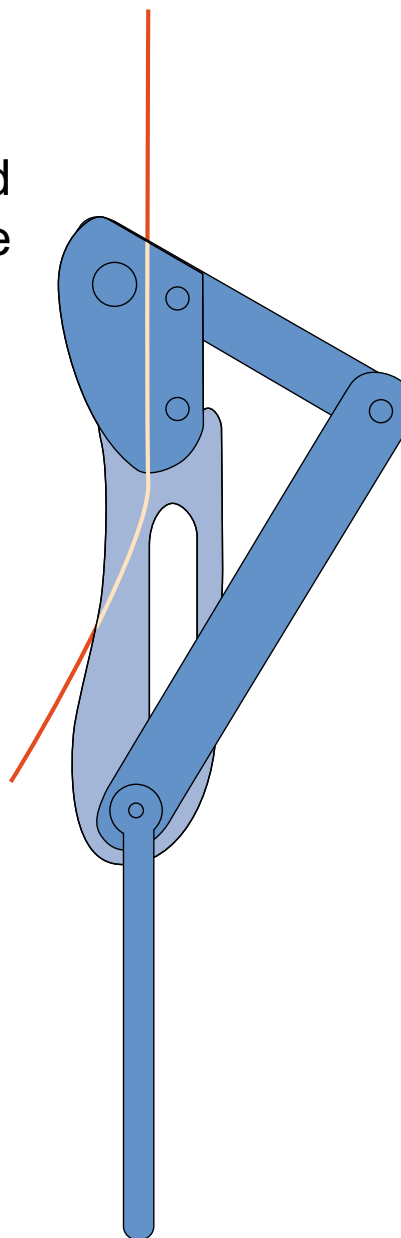
Wireline Clamp

The wireline clamp is used to secure the wire to the lubricator while rigging the equipment up or down. In addition it may be used during operations when the weight or tension has to be taken off the slickline, such as re-zeroing the weight indicator or hanging off the tools for an extended period.

The clamp is usually fastened to a bleed off valve, located on the lower most lubricator section by means of short chain or wire sling.

Care must be taken not to kink the wire at any point during the rig-up, as this will cause a weak point, which may break or stick in the stuffing box.

Apply downward
pressure here to release



Use correct size clamp
for wire in use

Secure to fixed
point with chain

Figure 2-20: Wireline Clamp Detail

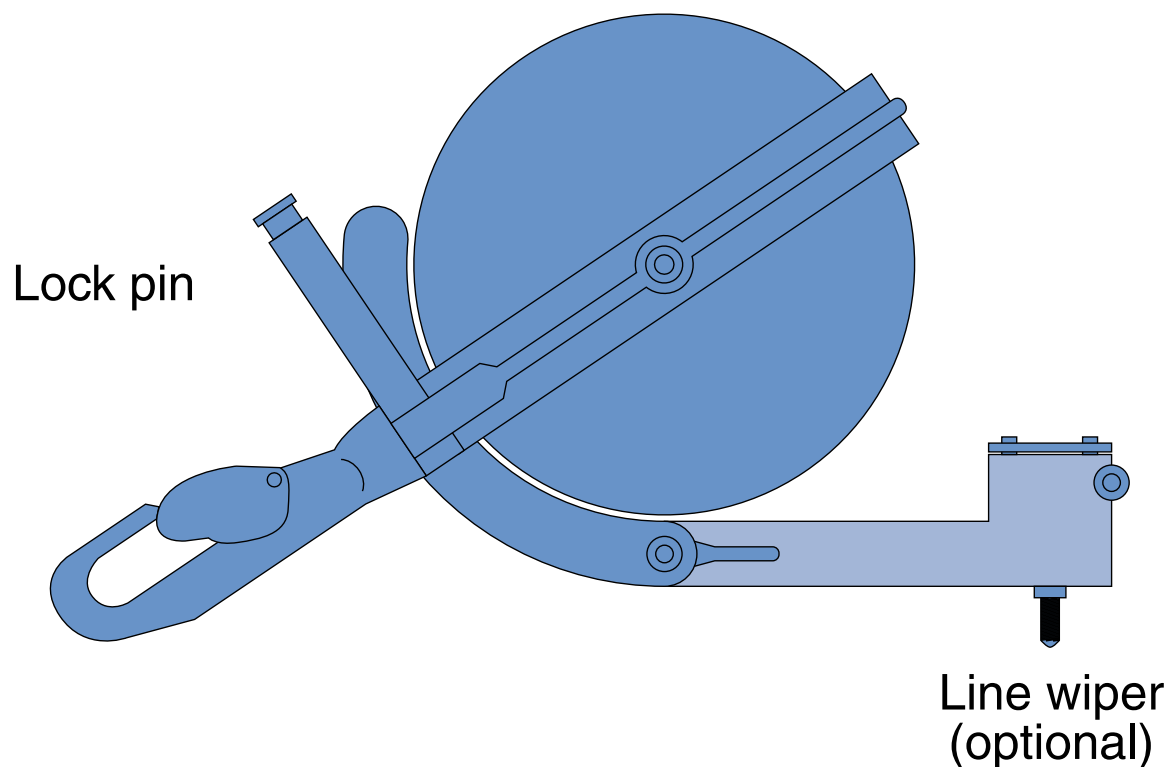


Figure 2-21: Latch Type Hay Pulley

2.4.3

Line Wiper

The purpose of the line wiper is to clean the wire when pulling out of the hole. It is generally attached to a pin on the hay pulley shroud. Precautions to be observed when using a line wiper include:

- Never install wiper when running in hole.
- Wiper must only be fitted horizontally.
- Always remove completely before jarring commences.

2.5

O-ring Seals

O-rings are used widely throughout the oil and gas industry to contain pressure both in static and dynamic applications. Correctly fitted and used within their design limits, O-rings perform well. The biggest cause of failure in the quick union application is damage caused when making-up the connection. Lubricating with oil or grease prior to assembly can avert this type of damage. Worn connections, where the gap between the pin and box exceeds tolerances, will also lead to failure through extrusion.

Other O-ring failure mechanisms include:

- Increased gap (A)
- Excessive pressure or insufficient back up ring support (B)
- Corrosion or wear increasing clearance (C)
- Hostile conditions
- Incorrect selection of O-ring material
- Excessive dynamic movement
- Excessive temperature

As fitted

In service

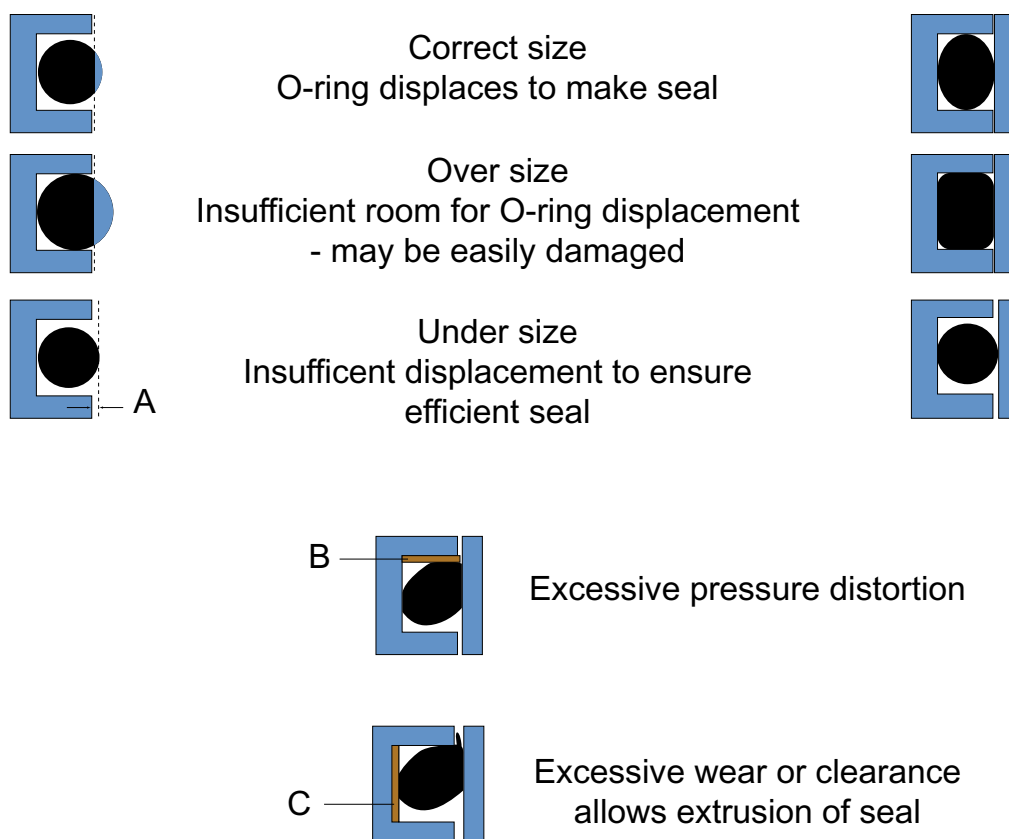


Figure 2-22: O-ring Deformation

Parbak Rings



Single parbak ring



Double parbak ring

Back-up Rings



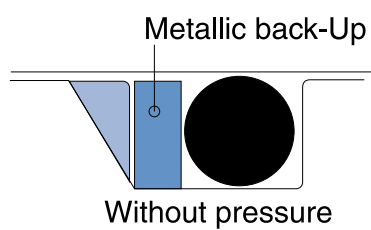
Scarf Cut



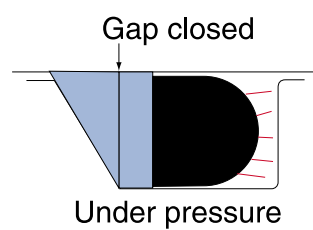
Spiral



Parbak

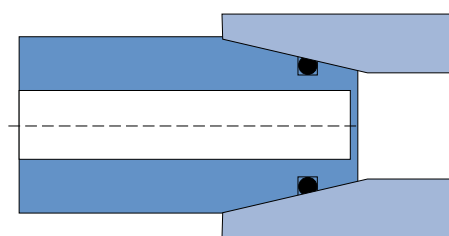


Without pressure

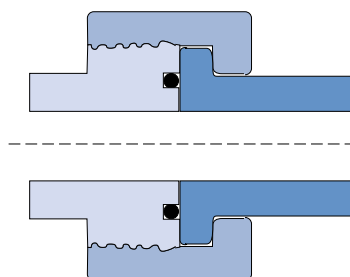


Under pressure

Zero clearance O-ring seals



Tapered seal



Face seal

Figure 2-23: O-ring Seal Configurations

2.6 Pressure Control Equipment Inspection

All pressure equipment should be inspected, at least annually by a third party inspection service. The report of any inspection is kept on file by the workshop supervisor. The following test methods are applied for detection of cracks or flaws:

- Magnetic Particle Inspection (MPI) – on connections.
- Magnafluxing (MF) – on connections.
- Radiographic Testing (RT) – on the collar/nut of the union.
- Hardness Test (HT or HRC) for H₂S equipment – on the connections and body.
- Wall thickness – at 90° intervals around the body.

2.6.1 Pressure Testing

All pressure control equipment should be pressure tested before use.



Note

Pressure testing requirements and procedures are detailed in the Slickline Pressure Operations Manual.

2.7 Operation Planning

Correct planning and preparation are essential components of a successful slickline operation.

2.7.1 Preparation

The steps in preparing for a slickline operation should include the following details or tasks:

- Liaison with production and/or drilling departments for work permits.
- An approved scope of work or similar work order.
- Provision of a wellbore diagram showing the current wellbore status, with all relevant sizes of tubing, casing, downhole accessories and flow controls noted.
- Christmas tree dimensions and characteristics, tree connection threads, SCSSV and SSV lock out features should appear on the work program.

- Check the well file/history for previous problems such as blockages, tight spots, corkscrewed tubing and any other areas of potential concern.
- It is essential that at least the latest slickline job report is read and checked.
- Transport and lifting requirements during mobilization and while on location.

Job planning can generally be divided into two segments relating to equipment requirements and the sequence of operations.

2.7.1.1 Equipment Requirements

- Ensure that slickline units are powerful enough to do the job and that the wire is twist and tensile tested.
- Surface equipment is pressure tested and dressed or maintained for the conditions to be encountered. The tree connection, BOP, lubricator, weight indicator and control panel should comply with minimum specifications.
- Check spare parts for all equipment is on hand or available at a convenient location. Small items such as fan belts, filters, counter cables, O-rings, etc. should be in the toolbox.
- Redress kits for wireline tools, backup toolstrings, wire cutting tools, hand tools, diesel, hydraulic oil, water, etc. are available.

2.7.1.2 Sequence of Operations

The job should be planned on a logical and conservative basis using a list of steps to achieve the program objectives, e.g., Run gauge cutters/rings whenever running in the hole for the first time or when going deeper.

2.7.1.3 Information Necessary Before Starting a Job

The following information is generally required to enable a thorough and complete planning process.

- Type of operation and requested time at well.
- Oil or gas well (field and name of well).
- Shut in wellhead pressure (tubing and casing).
- Tubing - type, drift diameter and restrictions

- Well conditions:
 - Deviation
 - Presence of H₂S (hydrogen sulfide)
 - Open-hole, cased-hole or liner completion
 - Total depth
 - Flow rate
 - Perforations, density and depth
- Well completion type
 - Subsurface equipment
 - Depth
 - Type
 - Dimensions
 - Manufacturers
 - Is drawing of completion available?
- Tree connection (crossover for BOP)
 - Size and type
- Position of zero point
- Is a gin pole or lifting equipment available on site?
- Is the client supplying the tools?
- Well location and instructions on how to reach it
- Name and contact details of the client representative who will supervise the job
- Special conditions - e.g., can the well be opened or closed

2.7.2

Rigging Up

The rigging up process, including preparation for access to the wellbore, can be summarized as follows.

- The lubricator, stuffing box, slickline and slickline toolstring, is assembled and positioned inside the lubricator. A metal cap should be fitted to the base of the lubricator.
- With the pressure released from the wellhead, the proper wellhead connection is installed on the wellhead.
- The slickline valve is installed on the wellhead and tested.
- The lubricator assembly is now raised to a point level with the union on top of the slickline valve, the hoisting device secured, the slickline placed into the hay pulley and the slack in the slickline taken up on the slickline unit.

- The clamp holding the slickline toolstring suspended in the lubricator can now be removed, allowing the toolstring to be lowered out of the lubricator controlled by the slickline unit to a point convenient for attaching the required service tool. With this tool attached and the odometer of the measuring head set on zero, the tools are pulled back up into the lubricator and the assembly installed onto the slickline valve.

**Note**

Reset the counter to zero, with the bottom of the slickline tool level with one of the following reference points as identified in the wellbore schematic diagram: Tubing hanger (TH), top of bottom flange (TBF) or rotary table (RT).

2.7.3 Reporting

The accurate recording of the sequence of activities and operations performed on the well is essential to the correct monitoring and long-term life of the well.

While actual wireline report formats and data required would vary in different locations, it should contain much of the following information:

- Date
- Well number
- Field location
- Tubing size(s)
- Completion type
- Tree type and size
- Tree connection type and size
- Back pressure valve profile
- Client details
- Crew details
- Tubing pressure
- Casing pressure
- Gas injection
- Time casing shut in
- Time well shut in

- Tool string components
 - Tool string size (diameter and length)
 - Fishing neck (type and dimension)
- Details of work carried out
- Details of tools or equipment installed in the wellbore
- Details of any wire or running equipment left in hole
- Time job, start time and completion time

**Note**

The above information should be recorded in the Talley Book before transferring into reports once the task is completed.

Intentionally Blank

3 The Slickline Unit

3.1	Introduction	3- 1
3.2	Mechanical and Chemical Properties	3- 2
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3 THE SLICKLINE UNIT

3.1 Introduction

The wire used in slickline operations is commonly described in a number of ways. Common local names include:

- Slickline
- Piano wire
- Solid line
- Measuring line

Multi-strand wirelines are typically described as braided line (3/16 in. diameter braided line being the most common).

In addition to the strength required of the slickline to accomplish the operation without the wire breaking, there is a need to keep the diameter of the wire as small as possible to:

- Minimize the load of its own weight
- Enable use of smaller diameter sheaves and use of smaller diameter spools or reels without overstressing the material when bending
- Minimizing the cross-section area to reduce the effect of wellhead pressure

The sizes of slickline in most common use are 0.092 in. and 0.108 in. diameter. However, slickline in 0.062 in., 0.072 in., 0.082 in. and 0.105 in. is also available but not in common use. Larger line diameters of 0.125 in. and 0.135 in. are now also available and are becoming popular for their added strength. Slickline is manufactured in drawing mills, formed in one-piece at lengths of 10,000 to 40,000 ft.

The most popular material for slickline is Improved Plow Steel (IPS) because of its high ultimate tensile strength, good ductility and relatively low cost. Experience indicates that improved plow steel usually performs better than the more expensive special steel lines, even in corrosive conditions when used with an appropriate inhibitor (e.g. Servo CK352 or CK356). For "sweet wells", IPS can be used with an inhibitor for high loads and long service. For "sour wells", IPS can be used with an inhibitor for high loads and short operating time.

When selecting slickline, several factors should be considered:

- Physical properties
- Total stress
- Resistance to corrosion
- Care and handling
- Effects of bending
- Environmental conditions, e.g., desert dusts, salt water, subzero temperatures.
- Well pressure
 - Influencing the effect of H_2S
 - Effecting the magnitude of force on the line diameter

3.2 Mechanical and Chemical Properties

Due to the H_2S and CO_2 content of many wells, special materials such as 0.092 in. Nitronic or stainless steels are used. Although these materials are not as strong as IPS, they have an excellent resistance to corrosion.

Bending stresses creating a weak point in the slickline are the most common cause of broken wire, but is often the least considered. Bending stress occurs when slickline deviates from a straight-line condition, such as when it passes over pulleys or reel drums or when it is flexed by hand. As with all metals, continued bending at one point will crystallize the material and lead to a fatigue fracture or break.

Each time the line passes over a pulley it is subjected to 2 bending stresses. When it changes from a straight to a curved path and again when it reverts to a straight path. It is subject to only one when it leaves the reel drum. So for each trip in and out of the well, the line experiences a minimum of 14 bending cycles.

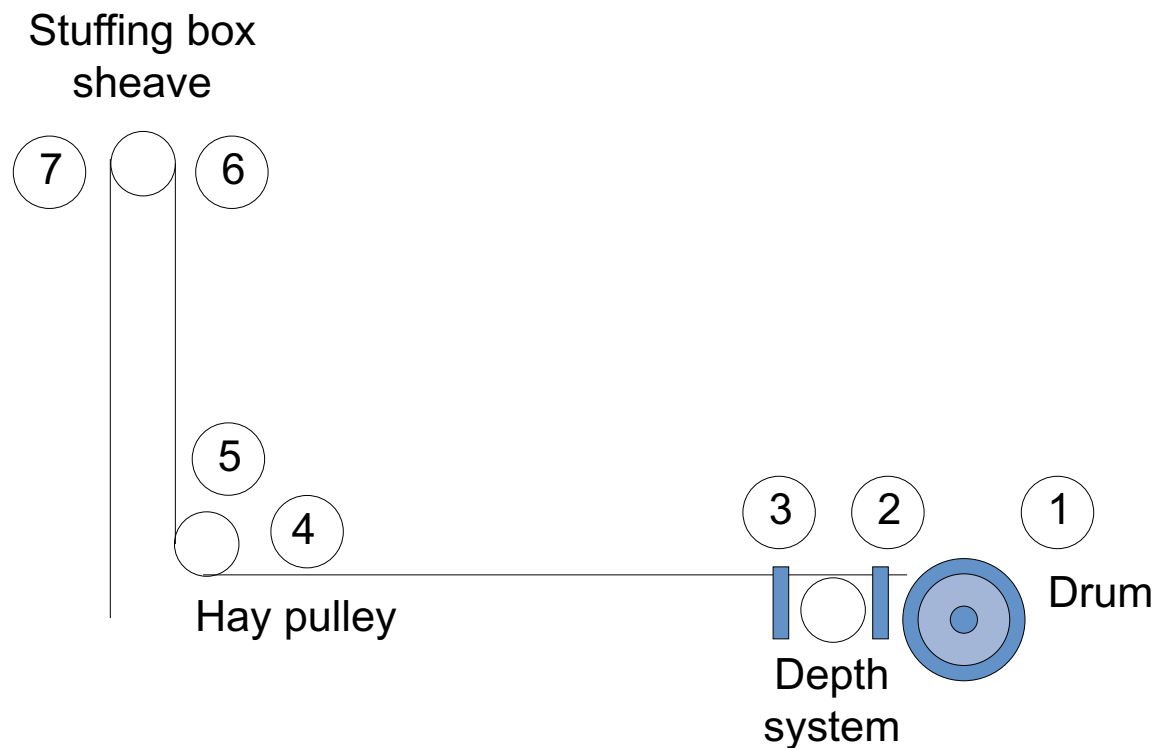


Figure 3-1: Wire Bending Cycles

Table 3-1: Relative Strength of IPS & UHT Slickline Material

Material	Diameter (in.)	Breaking Strength		Approximate Recommended Maximum load		Weight per 1000 meters		Characteristics
		kg (s)	(lb)	(kg)	(lb)	(kg)	(lb)	
IPS	0.092	701	1547	610.0	1125	33.50	74.0	For non-corrosive wells. Relatively inexpensive
	0.108	956	2109	816.0	1800	46.30	102.0	
	0.125	1288	2840	914.0	2016	62.10	137.0	
UHT	0.092	898	180	673.0	1485	33.50	74.0	For higher strength than IPS in similar conditions.
	0.108	1233	2720	925.0	2040	46.30	102.0	
	0.125	1651	3640	1238.0	2730	62.10	137.0	

Table 3-2: Chemical Composition of Slickline Material

Alloy	UNS	C	Si	Mn	Cr	Ni	Mo	Cu	N	Ti	Cb/Ta	Al	Co
316	S31600	0.08	0.75	2.0	16.0 - 18.0	10.0 - 14.0	2.0 - 3.0		0.10				
C20Cb3	N08020	0.06	1.00	2.0	19.0 - 21.0	32.5 - 35.0	2.0 - 3.0	3.00 - 4.00			8 x C min/ 1.0% max		

Alloy	UNS	C	Si	Mn	Cr	Ni	Mo	Cu	N	Ti	Cb/Ta	Al	Co
Incoloy 825	N08825	0.05	0.50	1.0	19.5 - 23.5	38.0 - 46.0	2.5 - 3.5	1.50 - 3.00		0.6 - 1.2		0.20	
Sanicro 28	N08028	0.02	1.00	2.5	26.0 - 28.0	29.0 - 32.5	3.0 - 4.0	0.60 - 1.4					
254SMO	S31254	0.02	1.00	1.0	19.5 - 20.5	17.5 - 18.5	6.0 - 6.5	0.50 - 1.00		1.9 - 2.4			
SUPA70	S31254	0.02	1.00	2.0	19.5 - 20.5	17.5 - 18.5	6.0 - 6.5	0.50 - 1.00	0.18 - 0.22				
AL6XN	N08367	0.03	1.09	2.0	20.0 - 22.0	23.5 - 25.5	6.0 - 6.5	0.75	0.18 - 0.25				
25-6MO, SUPA75, 1925HMO, GD31MO	N08926	0.02	0.50	2.0	19.0 - 21.0	24.0 - 26.0	6.0 - 7.0	0.50 - 1.50	0.12 - 0.25				
Inconel 686	N06686	0.01	0.08	0.75	19.0 - 23.0	BAL 55	15.0 - 17.0			0.02 - 0.25		W 3.0 - 4.4 Fe 5.0 max	
MP35N	R30035	0.025	0.15	0.15	19.0 - 20.0	33.0 - 37.0	9.0 - 10.0			1.0			BAL

Table 3-3: Mechanical Properties of Slickline Material

Alloy	Diameter (in.)	Safe Working Load (lb) Minimum	Breakload (lb) Minimum	Yield Load (lb) Minimum	Elastic Load Minimum	Stretch Factor (in. per 100°F/ 100 lb)	Weight per 1000 ft (lb)
316	0.092	700	1400	N/A	N/A	0.645	23.14
	0.108	925	1850			0.468	31.88
C20Cb3	0.092	614	1200	960	168	0.645	23.22
	0.108	821	1603	1282	1026	0.468	31.99
Incoloy 825	0.092	700	1400				
	0.108	950	1900				
Sanicro 28	0.092	850	1490	1340	1070	0.659	22.74
	0.108	918	1794	1435	1148	0.482	31.33
254SMO	0.092	700	1462	N/A	N/A	0.622	23.02
	0.108	1000	2013			0.452	31.71

Alloy	Diameter (in.)	Safe Working Load (lb) Minimum	Breakload (lb) Minimum	Yield Load (lb) Minimum	Elastic Load Minimum	Stretch Factor (in. per 100°F/ 100 lb)	Weight per 1000 ft (lb)
SUPA70	0.092	700	1400			0.622	
	0.108	1000	2000			0.452	
AL6XN	0.092	750	1500				
	0.108	1000	2000				
25-6MO, SUPA 75, 1925-HMO, GD31MO	0.092	750	1500	1200	992	0.780	23.13
	0.108	1000	2000	1700	1370	0.569	31.88
Inconel 686	0.092	800	1600				
	0.108	1050	2100				
MP35N	0.092	850	1700	1345	1076	0.547	24.26
	0.108	1100	2200			0.401	33.42

During slickline operations the following precautions should be observed:

- The maximum permissible line tension must never exceed the elastic limit (50% of the breaking strength)
- After every four hours of jarring with API 9A, pull out and cut off 20 ft of wire. Also retighten every connection in the toolstring.
- The line should be cut or changed if:
 - when the line is unwound on the ground, it no longer tends to form loops having the same diameter as the drum.
 - when making up the knot, the wire seems soft and breaks easily, but not with a clean break.
 - when there are kinks in the line which do not disappear when the line is under tension
- Routine slickline changes should be made:
 - every 250 to 300 working hours on 0.092 in. wire
 - every 300 to 350 working hours on 0.108 in. and 0.125 in. wire

3.3

Slickline Materials

Various materials have been developed over the years to suit different applications and well conditions.

3.3.1 API 9A and UHT

Materials classified as API 9A and UHT plain carbon steel slickline are the cheapest and most widely used. Slickline of 0.108 in. API 9A has a breaking load of 2120 lbf, compared with a 0.108 in. UHT minimum-breaking load of 2720 lbf.

Slickline manufactured from API 9A and UHT material will resist corrosion in downhole chloride environments, however, it will rust in storage if not properly cleaned and protected.

API 9A and UHT will undergo severe embrittlement in the presence of H₂O and CO₂. API 9A may be used in low levels (i.e., 2 to 3 ppm H₂S, 2% to 3% CO₂) with a suitable inhibitor (e.g., Blacksmith's polybutene multigrade), but UHT is not recommended at any concentration even with an inhibitor.

UHT wire, due to its high internal stresses, may be susceptible to age hardening at elevated temperatures, which may impair ductility.

3.3.2 304 Type Material (18% Cr, 9% Ni)

A stainless steel material, 304-type slickline was developed to operate in levels of H₂O and CO₂ up to 30%, however, it is susceptible to stress corrosion in the presence of chlorides. The minimum-breaking load for a 0.108 in. 304 type wireline is 2100 lbf.

3.3.3 316 Type Material (17.5% Cr, 11.5% Ni, 2.5% Mo)

Stainless steel slickline of 316-type material will operate in the same concentrations of H₂O and CO₂ as 304 type (i.e., 30%), and can also withstand chloride levels up to 2% to 3%. The breaking load of 0.108 in. 316 type slickline is 1920 lbf.

Due to the inherent susceptibility of the 300 series stainless steels to stress corrosion cracking in the presence of chlorides, a new range of Supa alloys were developed with the benefit of higher nickel content. These materials being more highly alloyed, are therefore more expensive.

3.3.4 Supa 60 (20% Cr, 25% Ni, 4.5% Mo)

Supa 60 slickline can perform in any concentration of H₂O and CO₂, even in the presence of high chlorides. The minimum-breaking load of a 0.108 in. Supa 60 wireline is 1720 lbf.

3.3.5 **Supa 70 (20% Cr, 175 Ni, 6.5% Mo)**

Supa 70 has higher corrosion resistance than Supa 60, by virtue of its increased molybdenum content. It has been known to operate successfully in 100% chloride and H₂O environments and has a minimum-breaking load of 2100 lbf. (0.108 in.).

3.3.6 **Supa 75 (20% Cr, 25% Ni, 6.5% Mo)**

Supa 75 is superior to Supa 70 in terms of corrosion resistance due to its higher nickel content. The minimum-breaking load for 0.108 in. Supa 75 is 2030 lbf.

3.3.7 **Bridon Service Strands**

Service strands are available in the size range 3/16 in. to 5/16 in. diameter, conventional and Dyform in various materials and constructions. Dyform strand offers higher strength and smoother surface to reduce pressure leakage.

A 3/16 in. diameter Supa 70/75 conventional strand has a minimum-breaking load of 1960 kg and a similar Dyform strand has a minimum 2250 kg breaking load.

3.4 **Spooling Slickline**

To enable the slickline to achieve an optimal life expectancy, it is important to spool slickline correctly.

- Tension - Approximately 300 lb (150 kg) of tension is recommended during spooling, to prevent the line cutting down into the drum under load when in use.
- Bedding Layers - Carefully aligned wraps of wire are recommended to provide a firm base and give an indication of the wire low level.
- Curvature - The natural curve of the line, as shipped, should be maintained as it is spooled onto the drum.

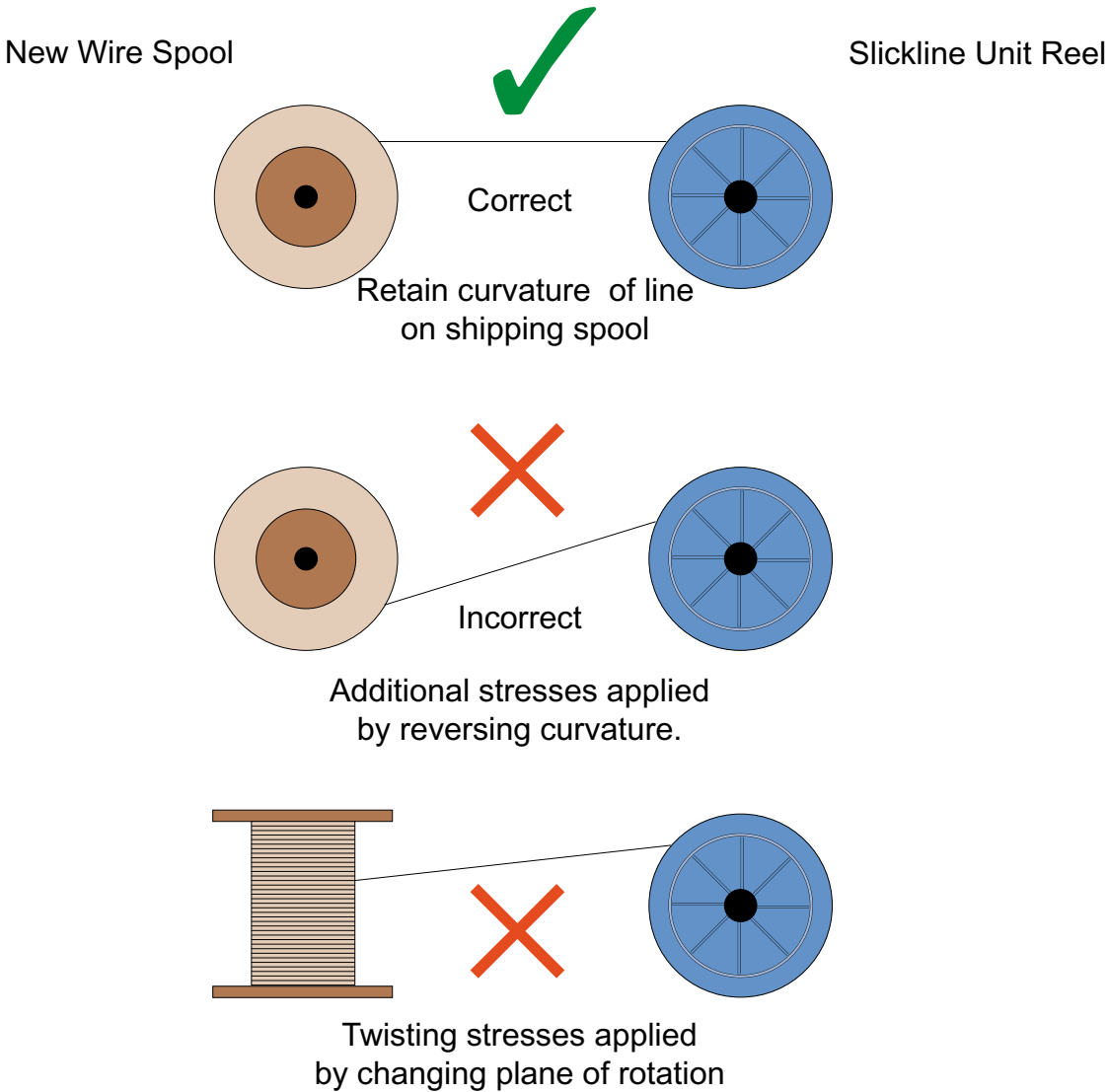


Figure 3-2: Slickline Spooling

3.4.1 Reel Capacity

The capacity of a reel or spool for a given size of wire can be determined through the following formula.

$$(A + B) \times (A) \times (C) \times (D) = \text{Capacity of reel (ft)}$$

Where:

A	Depth of spool (from core up to $\frac{1}{2}$ in. from top of flange)
B	Core diameter (in.)
C	Distance between flanges (in.)

D $D^2 / 262$ (Diameter of wire squared/divided by 262)

3.4.2

General Slickline Handling

The following examples outline faults or conditions that may effect the efficiency of slickline operations and the longevity of the wire. The likely result and corrective actions are also noted.

Table 3-4: Slickline Handling Precautions

Fault/Condition	Result	Corrective Action
Damage to reels Improper handling of the equipment causing damage to reels such as bending of the flanges and distortion of the barrel, caused by dropping.	Wire snagging during unwinding.	Use slings when handling reels or use ramps. Do not drop.
Corrosion in storage Carbon steel wire is oiled but if stored uncovered, corrosion will develop at varying rates depending upon the climate. Alloy steels are for use under corrosive conditions but they are not completely immune, and where there are wind blown salts slight damage may occur.	Under the worst conditions there will be pitting of the surface and local reduction in strength. Slight damage at this stage, scarcely visible, may increase the risk of alloy wire corrosion in service.	Store the reels upright (on edge) on a level solid base in dry covered conditions. If a permanent store is not available, support the reel off the ground under a waterproof cover. The latter should be kept out of contact with the wire, and fastened down just clear of the ground to allow air to circulate and minimize condensation.
Corrosion in service There are inevitable hazards of well condition environments.	There may be development of surface pitting. At worse, there may be stress corrosion or hydrogen embrittlement causing brittle failure.	When rewinding the wire, wipe off the well contamination. If carbon steel wire reels are to be returned into store, re-oil the wire during rewind. Do not leave any slickline in the wellbore during shutdown.
Wire winding practice Wire damage may be caused at various stages in winding onto the service reel from the supply reel, or in rewind during use. To ensure good spooling, it is recommended that an intermediate capstan is used between the supply reel and slickline unit drum to develop a high line tension without the risk of cutting down. Practices are followed in the running of slickline that have to strike a balance between operational convenience and wire life. To the user some possibilities listed here may seem unlikely to happen, but they are given so that if any should occur their significance will not be ignored.		

Fault/Condition	Result	Corrective Action
Uneven winding Variable tension and/or poor control of the wire traversing the barrel.	The wire pulls down between adjacent turns preventing free running, causing snags, and possibly the wire breaks.	Maintain a regular traverse of the wire across the full width of the barrel to give uniform build-up of the layers. The coarse pitch and tension in winding onto the reel will minimize the risk of the wire pulling down.
Loops and bends Insufficient braking on the supply reel.	Overrunning with the risk of snarls forming in looped wire. Even if the snarl is straightened out by hand, there can be a significant reduction in strength. Overrun wire may be pulled over a reel flange and be sharply bent.	Whatever the method to keep the wire under tension during winding, a brake on the supply reel is desirable so that too much slack wire does not appear between the two reels.
Wire abrasion Rubbing on the ground, caused by slack wire. Rubbing on the reel side, caused by incorrect traversing.	Reduction in wire strength as a result of the loss of the sectional area of steel. Reduction in sectional area.	Keep the tension and always wind from 'top' to 'top' of the reels. In service, rewind on top of the reel. Angle of the wire during traverse and total traverse must be controlled.
Wild wire Cause by slack winding or reversing the natural curvature of the wire.	The wire may be difficult to control and lead to tangles and snagging.	Always wind the wire in the direction of its natural curvature. Never wind from the top of one reel to the underside of the other.
Wire indentation Caused by 'crosscutting' between adjacent layers of wire.	Reduction in strength.	Avoid excessive tension in winding and excessive 'jarring' when operating downhole tools.
Friction on pulleys Possible during 'jarring'.	Embrittlement of wire surface. Shock loads can produce high surges out of all proportion to the assumed loads on the wire, and may cause failure.	Avoid excessive 'jarring' Cutting back the wire between uses minimizes the chance of cumulative damage
Fatigue cracks Caused by repeated bending under high stress.	Wire failure, particularly if other factors, noted above, are contributing.	Ratio of the pulley and wire diameters should preferably be 120:1 to reduce the significance of bending stresses.

3.5 Testing the Slickline

3.5.1 Tensile Testing

A sample of slickline cut from the end of the line should be tensile tested at periodic intervals. The testing frequency will vary with local conditions – e.g., the workload applied to the line, well fluids, location (sand or salt water), line material etc. The objective is to identify potentially weak or damaged line before it breaks in the well.

Several types of tensile testers are available, all being either manual or hydraulic operated. The length of the line sample to be tested is held between a fixed and movable point. As the distance between the points is increased, tension is applied to the line until the Ultimate Tensile Stress (UTS) is reached and the line parts. A display such as a dial or an electronic strain gauge displays the force at which the sample failed.

This value should be similar to the specifications for that particular size and type of line.

3.5.2 Torsion Testing

The torsion or twist test is method used to determine the condition of the line. Carbon steel lines should achieve a predictable number of complete turns below before failing.

**Note**

Stainless steel alloys have a very low resistance to twist testing and therefore this test cannot be applied to stainless alloys, as it has no bearing on their remaining life.

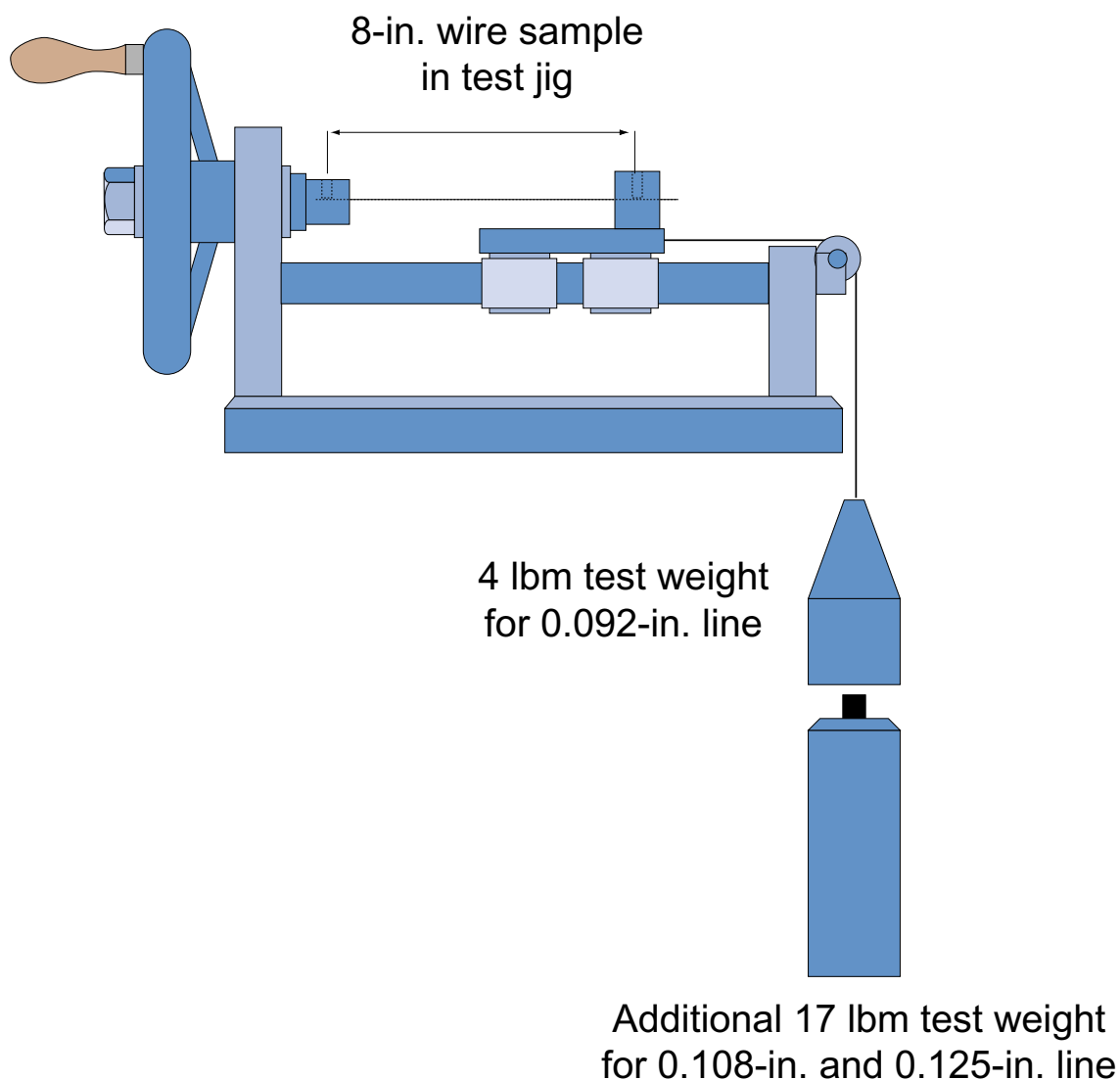


Figure 3-3: Torsion Testing Equipment

Table 3-5: Reference Table for IPS Line Torsion Testing

Reference Table for IPS Line (8 in. Sample Length)			
Line Diameter (in.)	0.092	0.108	0.125
Minimum breaking strain	1547	2108	2823
Minimum number of turns to break	23	19	17

3.6 Slickline Fracture Identification

3.6.1 Grade 1 Fracture Without Secondary Breaks

The test piece should show no evidence of spiral splitting along its length and should contain a single, ductile, primary fracture, which is perfectly square ended. This type of fracture is characteristic of carbon steel wireline and is usually, but not always, associated with a high number of twists to failure. A slickline exhibiting this type of fracture characteristic would be considered of suitable quality for further use under most circumstances. If however, the numbers of twists to failure are very low (e.g. 30% of the API 9A value) the line should be discarded.

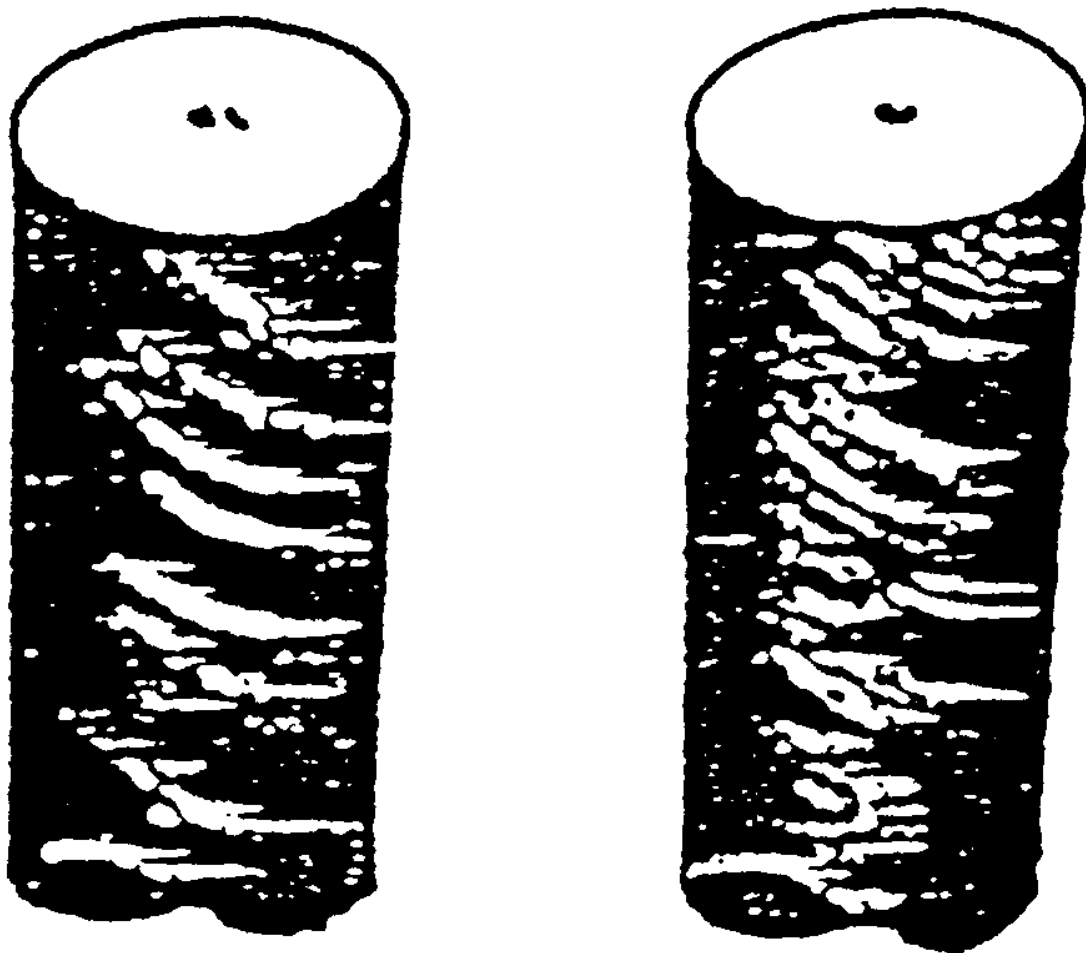


Figure 3-4: Single Square Ended Primary Fracture

3.6.2

Grade 1 Fracture With Secondary Breaks

It is possible, during torsion testing of wireline exhibiting exceptionally high tensile strength values, to experience secondary wire breaks which feature stepped, or helical fracture faces. These breaks are recoil fractures and are induced by the instantaneous release of stored energy in the wire when the primary fracture occurs. Although such breaks indicate a marginal reduction in slickline ductility, their presence can be discounted, the wire quality indicated by the characteristics of the primary fracture.

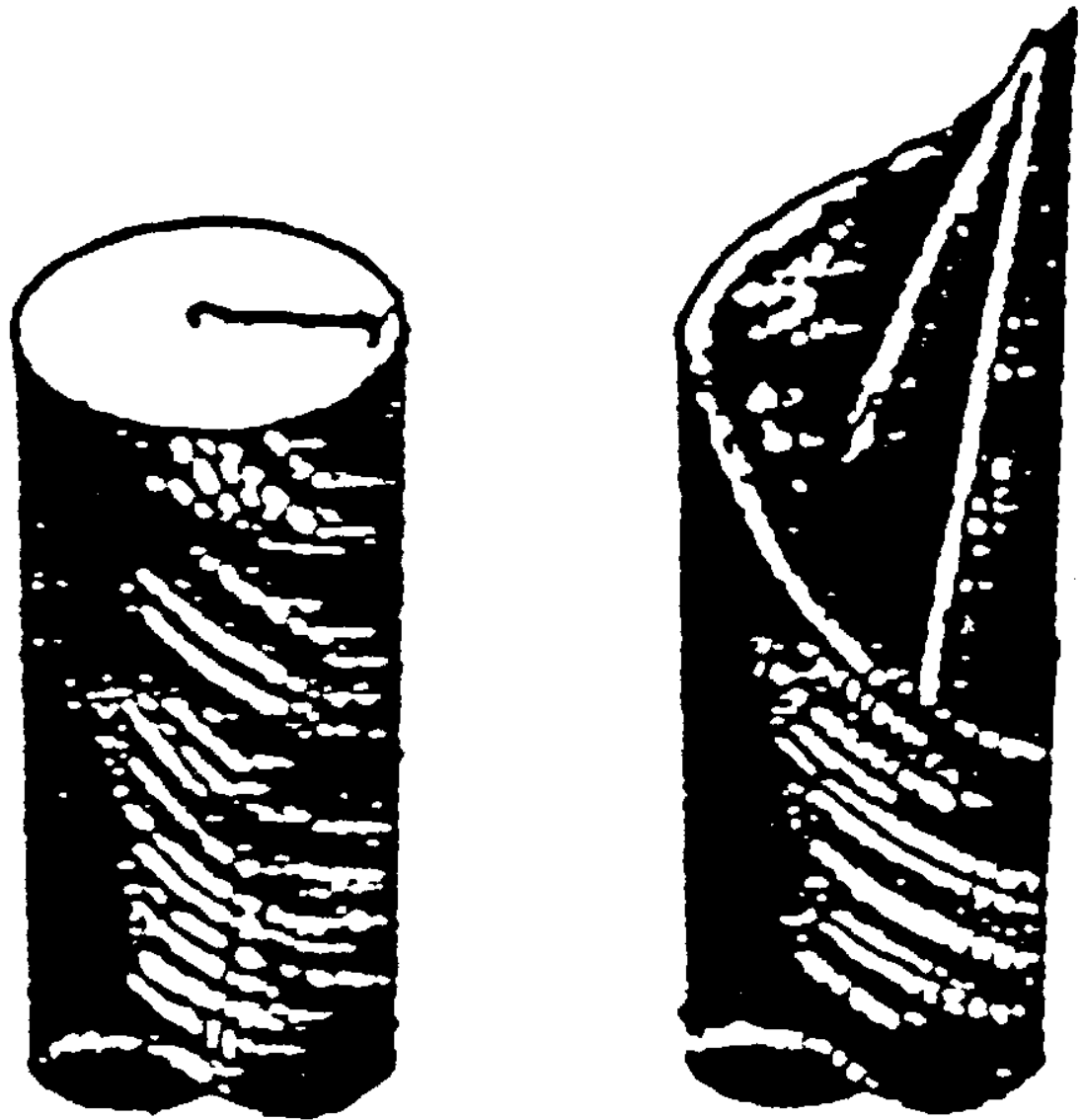


Figure 3-5: Single Square Ended Primary Fracture with Secondary (Recoil) Breaks

3.6.3 Grade 2 Fracture

The test piece may show evidence of waviness and the presence of slight spiral splitting along its length. The primary fracture, whilst preferably square ended, may be slightly stepped. Secondary recoil fractures may be present. This type of primary fracture is acceptable but it is associated with a reduced number of twists to failure, indicating a reduction in slickline quality. A slickline exhibiting such fracture characteristics would generally be considered suitable for limited further service, provided the number of twists to failure exceeded 60% of the API 9A value and provided ductility tests were carried out after each operation.



Figure 3-6: Slightly Stepped Primary Fracture

3.6.4

Grade 3 Fracture

The torsioned test piece may show evidence of uneven or localized twisting. Spiral splitting and waviness is invariably present and the primary fracture will exhibit severely stepped or helical fracture. Secondary, recoil fractures are

uncommon. This type of failure is unacceptable and is usually associated with a low number of twists to failure. A slickline exhibiting such torsional characteristics should be discarded immediately.

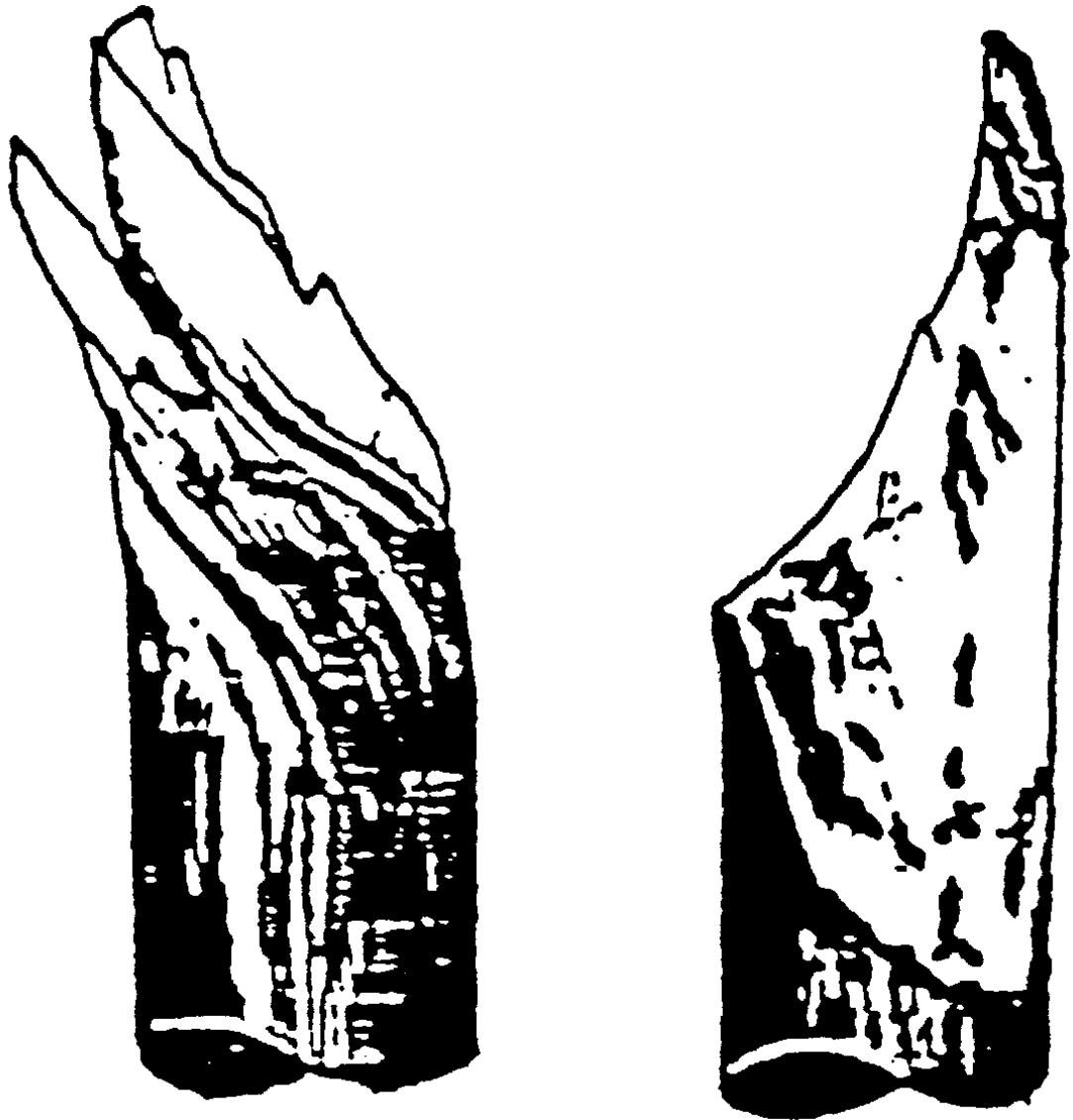


Figure 3-7: Single Helical Spear Type Fracture

General guidance notes

- Any torsion test performed relates only to the test piece and does not guarantee the quality of the remaining slickline.
- In the event of obtaining Grade 2 or Grade 3 type of fracture characteristics two repeat tests should be performed.

- If the quality of a slickline is variable, it is permissible to cut off a length of wire (say 200 ft) and re-test. Two subsequent tests should provide Grade 1 type fractures. This procedure may, if necessary, be repeated since it is well known that the ductility of a slickline deteriorates more rapidly at bottom hole temperatures.
- The ductility of a carbon steel slickline should be measured prior to slickline service operations.
- Where H₂S or acid conditions are encountered, suitable inhibitors should be used to combat embrittlement and corrosive attack. It is also recommended that the slickline be tested at regular intervals since rapid deterioration can occur.

3.7 Eddy Current Inspection

Eddy current inspection is based on the principles of electromagnetic induction. ECT inspection is used to detect and size defects in tubing. Conventional eddy current testing is also used for inspection of non-ferromagnetic tubing such as stainless steel, brass, copper-nickel alloys, hastelloy, titanium, etc.

ECT inspection is used in 4 frequencies in both differential and absolute modes. The differential mode detects pits and cracks and the absolute mode detects gradual wall loss. The multifrequency testing is done for two reasons:

- To differentiate between defects and metallic deposits. This is essential because metallic deposits can produce eddy current signals that resemble defect signals. Improper resolution of signals will result in unnecessary plugging of tubes.
- To detect defects under the support plates. This is done by using a two-frequency mix to cancel the support plate signal and detect defects under the support plate.

3.7.1 Calibration

Eddy current tester calibration is performed on an ASME standard. The calibration tube has five defects: 100%, 80%, 60%, 40% and 20% deep. These defects are used to establish the depth curve for flaw sizing.

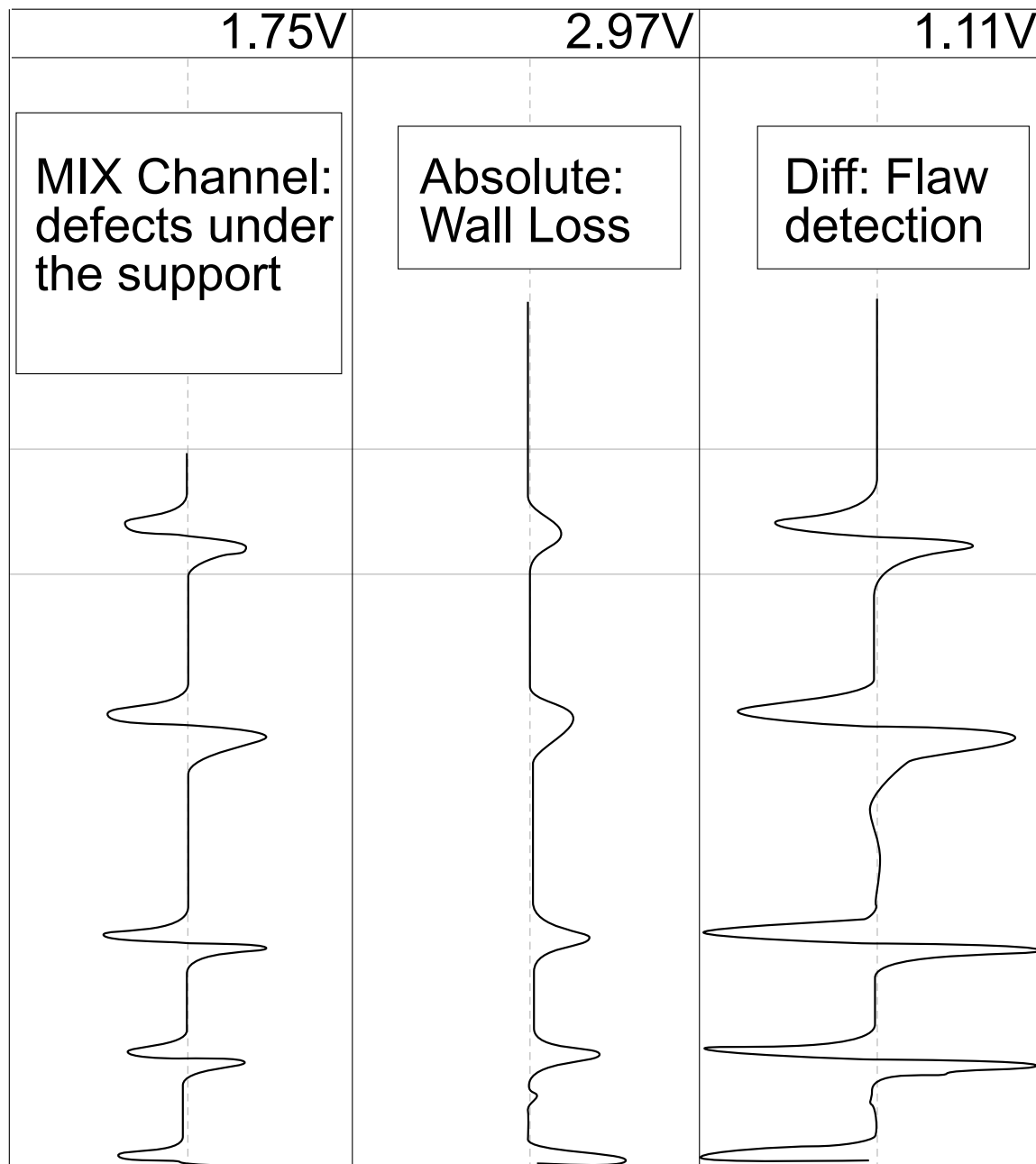


Figure 3-8: Eddy Current Tester Report - Graphical Format

3.8

Braided Line

Multi strand wireline is used for heavy work such as fishing jobs and swabbing operations. Because the additional forces created by the well pressure acting on the larger cross-sectional area may be significant, a well is sometimes killed before the fishing job is attempted. The most common size of wire used is 3/16 in., with the options of 1/4 in. and 5/16 in. for heavy-duty applications.

The conventional 3/16 in. cable comprises 16 (9 + 6 + 1) strands. The core and right-lay inner wires are thinner than the left-lay outer wires. By using right and left-lay, the twisting tendency of the wire under load is prevented.

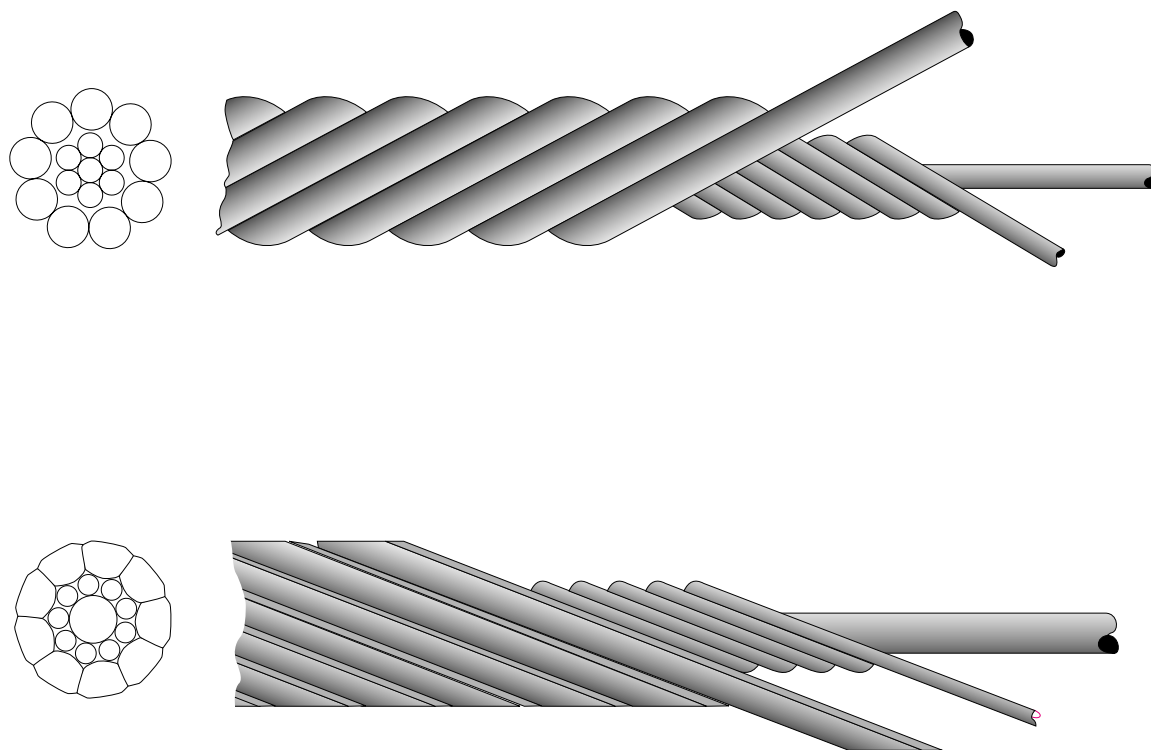


Figure 3-9: Braided Line Construction

A Dyform cable is configured in a similar manner. Around the single center core are 9 thinner right-lay wires, the outer wires are also right-lay but thicker. The finished cable is pulled through a die to provide the following improvements:

- 20% increase in breaking load, due to the area of steel in the same wire diameter.
 - Maximum breaking 6300 lbf
 - Working load 4800 lbf
- Smooth external surface and closer tolerance of OD, reducing leakage at the stuffing box.
- Higher crush resistance because of the increased steel content of the cable.
- Low twist tendency because of the Dyform process.
- Smaller interstitial spaces uses less grease from the grease injection sealing system.

3.8.1

Testing Braided Line

Braided cable tends to wear close to the rope socket. This end should be cut back regularly with approximately 1 ft of cable removed for every 1000 ft run in the wellbore. The torsion testing process for braided line includes the following steps.

1. A sample of the cable from the cut off point 1 ft long is required.
2. Carefully remove a single outer armour strand, preserving its natural helix shape.
3. Make a 90° bend by hand in the middle of the single strand.
4. Twist one part tightly around the outer to form a coil.
5. Good wire should allow a minimum of 5 twists to be made. If wire is brittle or worn, it will break after relatively few twists.
6. Continue to spool off and cut back the cable until a satisfactory test is achieved or change out the drum of cable.
7. A minimum of the well depth plus a 1000 ft is required on the drum for any operation.

Table 3-6: Braided Line Data Sheet

Size (in.)	Material	Breaking Load		Recommended Max. 80% Working Load		Weight per 100 m	
		(kg)	(lbf)	(kg)	(lbf)	(kg)	(lbf)
3/16	Galvanized Carbon Steel	2250	4.960	1800	3970	10.77	23.7
	Dyform Carbon Steel	2800	6174	2240	4940	12.70	28.0
	315 Stainless	1810	3990	1448	3193	10.60	23.4
	18/18/2 Stainless	1850	4080	1480	3263	10.60	23.4
	Nitronic-50 Alloy (Nickel)	1950	4300	1560	3440	10.60	23.4
7/32	Carbon Steel	3000	6615	2400	5292	14.30	31.5
	Dyform Carbon Steel	3700	8158	2960	6527	17.70	39.0
	316 Stainless	2400	5292	1920	4410	14.30	31.5
	18/18/2 Stainless	2500	5512	2000	4410	14.30	31.5

Size (in.)	Material	Breaking Load		Recommended Max. 80% Working Load		Weight per 100 m	
		(kg)	(lbf)	(kg)	(lbf)	(kg)	(lbf)
	Nitronic-50 Alloy (Nickel)	2700	5954	2160	4763	14.30	31.5
$\frac{1}{4}$	Carbon Steel	3920	8655	3136	6915	18.70	41.2
	Dyform Carbon Steel	5080	11201	4064	8961	22.00	48.5
	316 Stainless	3120	6880	2496	5504	18.70	41.2
	18/18/2 Stainless	3200	7056	2560	5645	18.70	41.2
	Nitronic-50 Alloy (Nickel)	3560	7850	2848	6280	18.70	41.2
5/16	Carbon Steel	6120	13495	4896	10796	29.20	64.4
	Dyform Carbon Steel	7960	17552	6368	14041	34.50	76.0
	316 Stainless	4800	10584	3840	8467	29.20	64.4
	18/18/2 Stainless	5000	11025	4000	8820	29.20	64.4
	Nitronic-50 Alloy (Nickel)	5500	12128	4400	9702	29.20	64.4

3.9

Effects of Wellhead Pressure

The force applied to slickline entering the wellbore is dependent on the wellhead pressure and the cross-sectional area of the wire or braided line.

Table 3-7: Force vs. Line Size

Diameter (in.)	Area		Weight (for IPS)	
	(in. ²)	(cm ²)	(lb/1000 ft)	(kg/1000 m)
0.25	0.049	0.316	135.7	187.0
0.187	0.027	0.174	72.4	107.7
0.125	0.0123	0.079	36.0	53.6
0.108	0.0092	0.059	31.11	46.3
0.105	0.0087	0.056	29.0	43.15
0.092	0.0066	0.043	22.58	33.6

The balance weight or weight at which the force pushing the wire out of the wellbore is equal to the force pulling the wire in.

**Note**

A minimum of 40 lbw (in addition to the balance weight) must be added to toolstring prior to entry into wellbore. This is necessary if jarring is required in the Christmas tree or tubing hanger.

VELOCITY OF FLUID FLOW
(SINGLE PHASE PRODUCTION).

IF NO OBSTRUCTION exists inside tubing (i.e. logging tool OD = d);

- Enter ID"

- Go to Q (BPD) to find V (ft/sec)

IF OBSTRUCTION EXISTS, enter (ID - d).

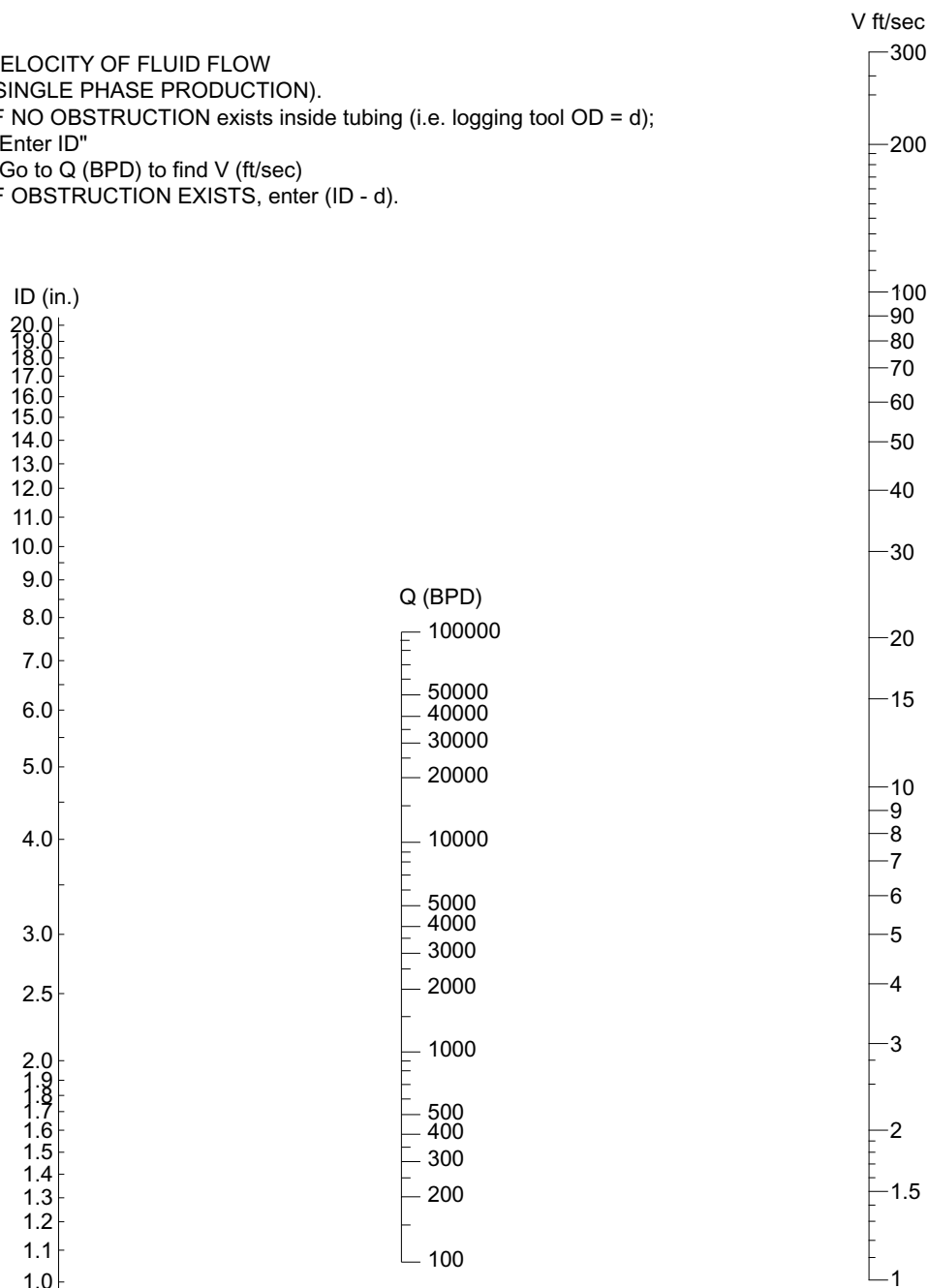


Figure 3-10: Velocity of Fluid Flow

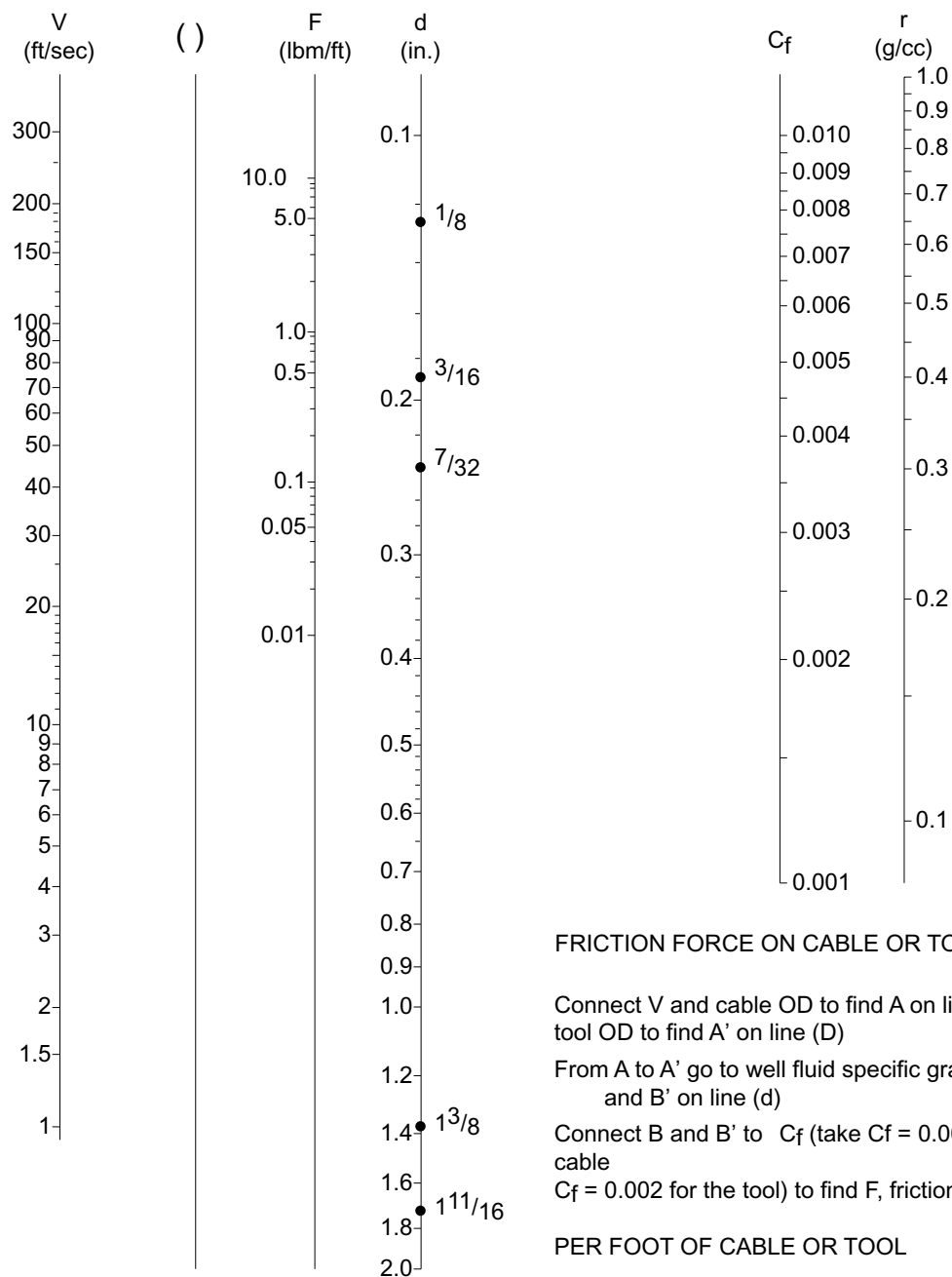
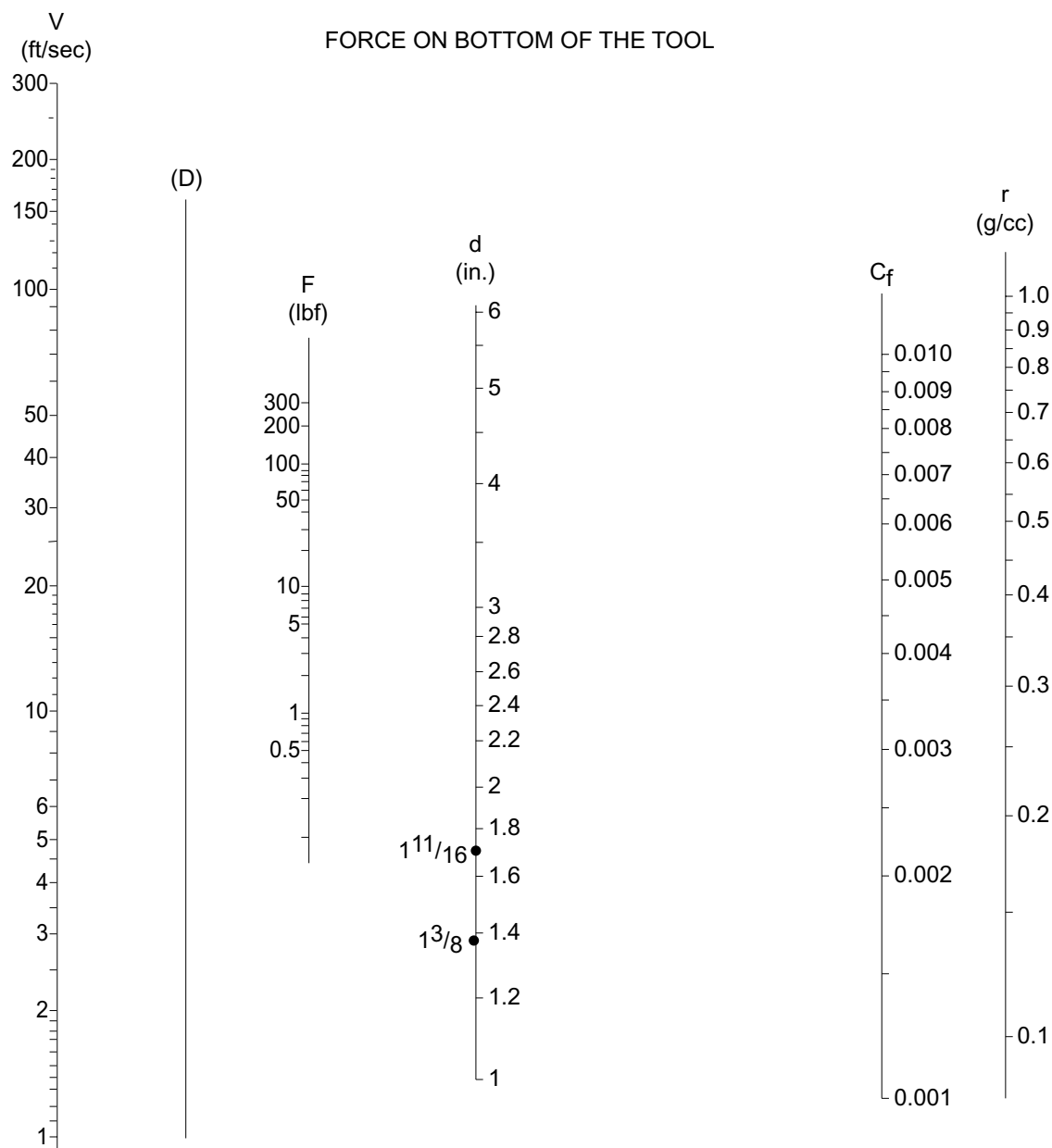


Figure 3-11: Friction Force on Cable



Connect V and and tool OD d (in.)

From intersection A with line (D) go to specific gravity r of well fluid to find F₄ on F scale

Figure 3-12: Force on Bottom of Tool

3.10

The Slickline Unit

A slickline winch, in good operating order, is an essential piece of equipment for any slickline work. Correct operation and maintenance assure the reliability and operational efficiency of the unit.

Before starting or attempting to operate the unit, the following checks must be made:

- Engine
 - Engine oil level
 - Coolant level (Note: Some engines are air cooled, e.g., Deutz and Lister)
 - Fan belt condition and tension
 - Battery fluid level
 - Diesel fuel level
 - Check operation and setting of the emergency shutdown system
 - On hydraulic start models, check the accumulator pressure
- Power Pack
 - Hydraulic oil level - The level should be above $\frac{1}{2}$ full - If the hydraulic oil level is too low, insufficient retention time will occur prior to the oil recirculating. This may result in trapped air bubbles circulating through the system, causing cavitation and resulting in loss of power and excessive wear.
- Reel Pack
 - Ensure gear is in neutral and the handbrake is on - the drum can spin as the engine starts, creating a 'birds nest'.
 - Check the drive chain tension

**Note**

Never carry out gas cutting or welding operations near spools of wireline. Heat or metal spray coming in contact with the wire could significantly change the condition of the steel and cause early failure in use. Never electric arc weld on a slickline unit with wire spooled on the drum. Serious weakening of the wireline will occur as a result of magnetic fields created.

The routine and programmed maintenance schedules, which will prolong the life of equipment and minimize breakdowns on location, should be observed. Maintenance is based on the following guidelines but will vary with unit design, location and local conditions.

- 50 hours - Change the engine oil and clean or change filters (oil/fuel/air)
- 150 hours - Grease and adjust the drive chain and grease the hydraulic motor
- 500 hours - Change the hydraulic oil and filters

There are two basic types of slickline unit drive system; open or closed loop systems. The open loop system has been in use for several decades and provides good control of the line force and speed. Ideally, a unit should be able to pull approximately 3000 lbf in low gear and run at approximately 3000 ft/ min in high gear with low load.

3.10.1 Open Loop Systems

Oil gravity feeds from the oil tank via a filter to a positive displacement vane type pump. A positive displacement pump outputs a fixed volume of oil on each rotation. Any obstruction to the output can cause failure of the pump or components, and it is therefore essential to have a pressure relief valve in the system.

The pump is rotated by a diesel engine, or in some cases an electric motor, with a power output of 40 to 80 HP.

On the high-pressure outlet side of the pump a pressure relief valve is set at the system operating pressure, typically 1500 to 3000 psi. Should a blockage or serious obstruction occur, oil is bypassed back to the tank.

Directional control is provided by a 4-way hydraulic valve (Hydreco or Barksdale) providing forward, neutral and reverse positions.

From the exhaust side of the 4-way valve, oil returns to the tank via an oil cooler and filter system. The hydraulic oil must be kept within an operating temperature range. At elevated temperatures, the oil can break down and damage the circuit components. Also, at high temperatures, the oil becomes a safety hazard in the event a hose or connection breaks.

From the outlet side of the 4-way valve, oil is directed to the vane motor connected to the transmission and reel.

Line speed control is provided by the 3 or 4 speed gearbox connected to the drum by a chain/sprocket system. Control of the force applied to the line is provided by the variable bypass valve, which allows oil pressure to divert around the 4-way valve.

**Note**

Select the direction with the 4-way valve and use the hydraulic relief valve and gears to control the tension. The 4-way valve should not be used in the partially shifted position.

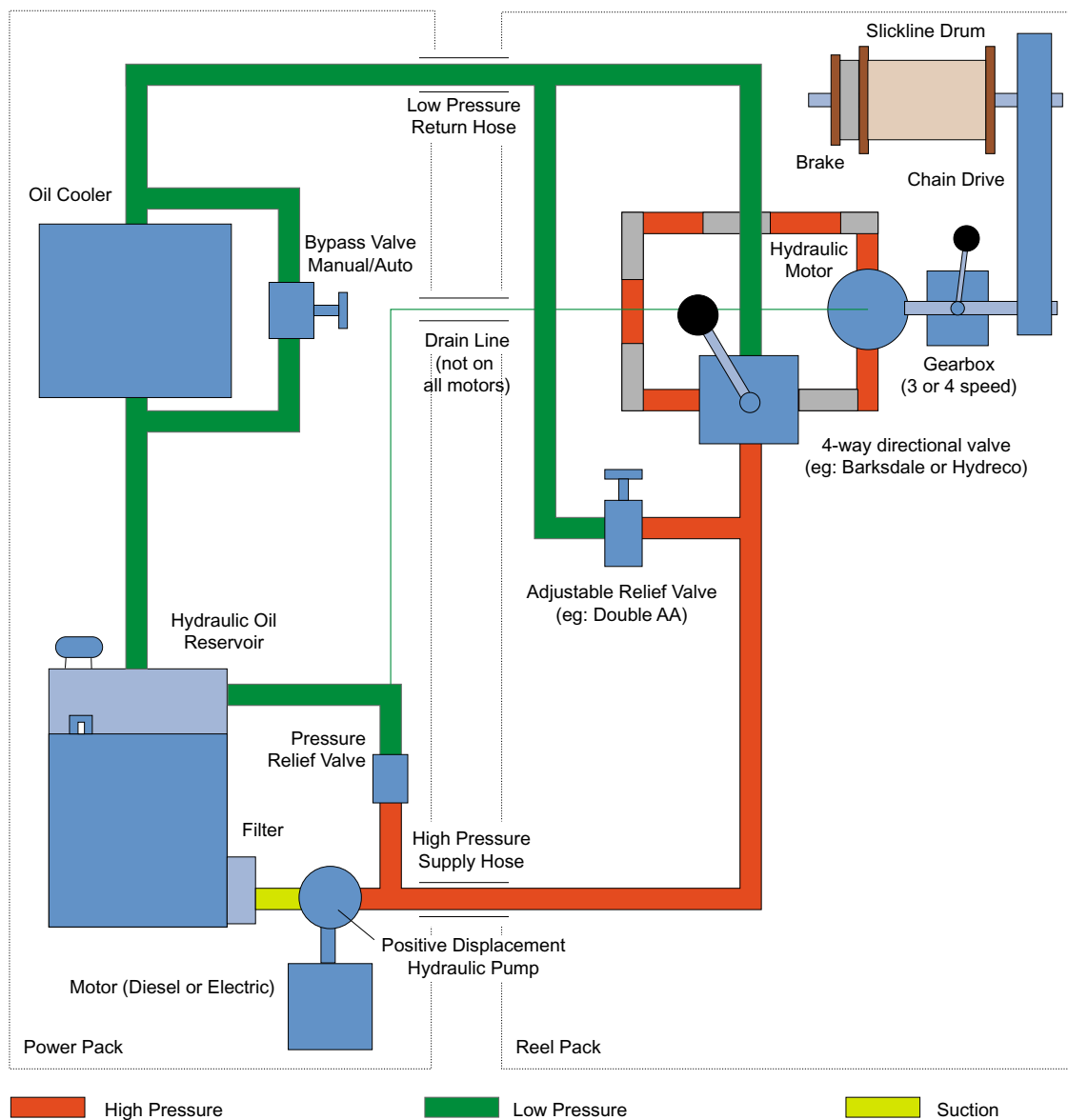


Figure 3-13: Open Loop Unit Schematic Diagram

3.10.2 Closed Loop Systems

The closed loop hydraulic system is becoming increasingly popular, since it provides more precise control of the line force and enables more rapid changes of direction. It is essential that the circuit components be correctly matched to obtain optimum performance. Closed loop units vary from open loop systems in the following ways:

- The circuit operating pressure is higher (approximately 5000 psi)
- The oil pump has a variable volume output
- When the drum is stationary, no oil is circulated through the circuit
- Less frictional heat is generated in the oil as it is not circulating constantly
- Circuit components are more expensive

Oil is supplied to the variable displacement pump by a charging pump to maintain an efficient pump inlet pressure. The output of the pump is variable as the angle of an internal swash plate is altered by the “oil output volume control” on the operators panel.

At 90° to the input shaft no oil is being displaced through the system. As the angle of the swash plate is increased, the stroke of the pistons increases to provide a greater volume of oil discharge. If the swash plate angle is reversed, the direction of the output oil is also reversed which provides potentially rapid drum reversal for jarring.

The motor is of similar construction to the pump and the angle of the internal swash plate determines the speed of which the drum rotates for any given input amount of oil.

The oil in the pump motor loop is maintained at approximately 5000 psi. Any excess pressure is bypassed back to the oil tank via the preset pressure relief valve. Advantages of the closed loop system include:

- Better response to speed and direction changes
- Improved control of line force applied
- Improved jar action through combination of above

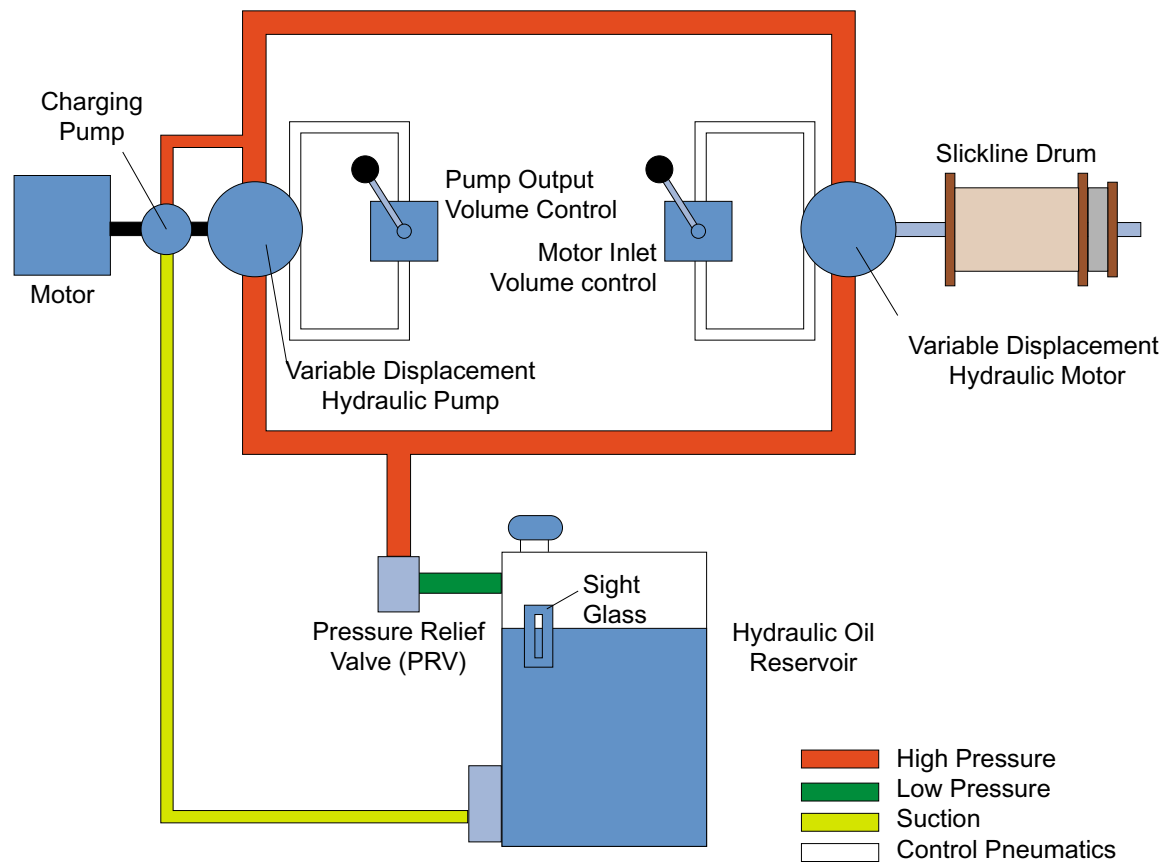


Figure 3-14: Closed Loop Unit Schematic Diagram

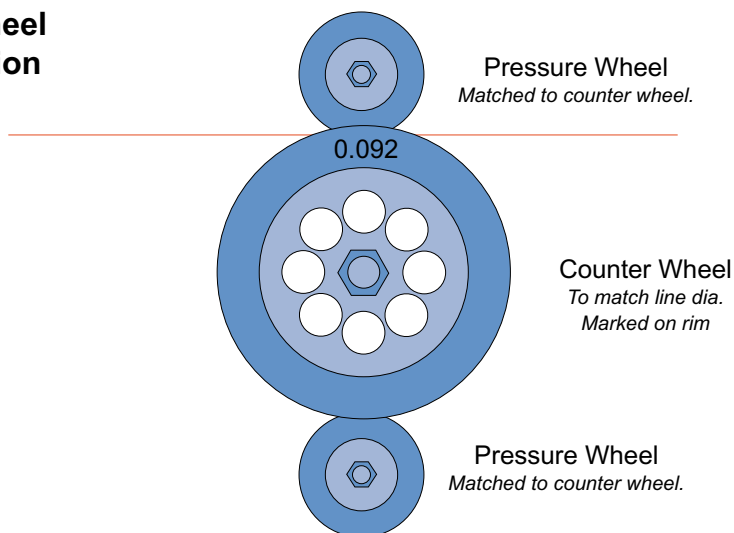
3.11

Depth Counters

The slickline depth counter is an essential component, necessary to accurately display the depth of the slickline tool string, in feet or meters.

The most common configuration of counter head is shown below.

Typical slickline counter wheel configuration



Typical slickline counter wheel configuration

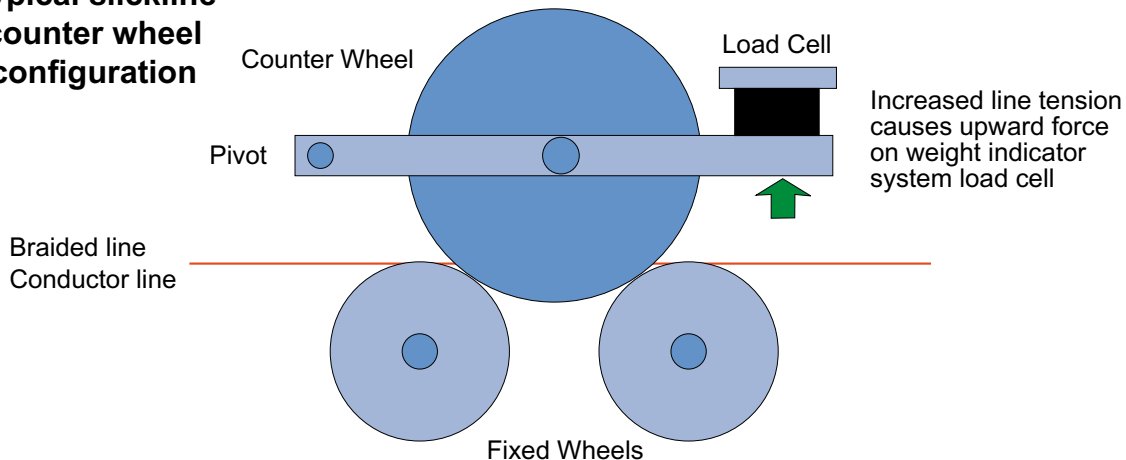
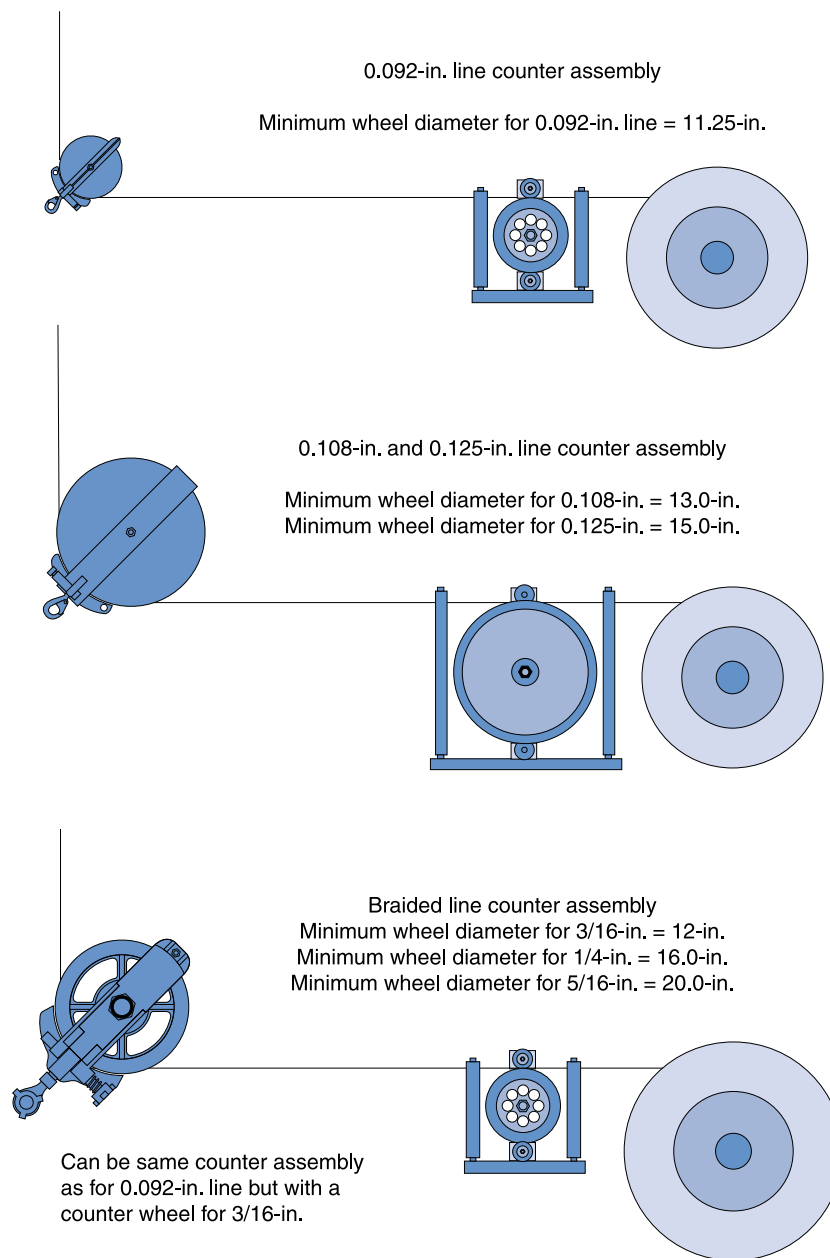


Figure 3-15: Slickline Depth Counter System

Before use, the depth counter system should be checked as follows:

- Ensure the counter wheel is free to rotate
- Check that rotation is being transmitted freely to the odometer
- Ensure the direction of rotation is correct
- Check the cable has no kinks as it passes through the system
- Check that the odometer is fully engaged after zeroing

It is essential that the counter wheel matches the line diameter in use. A wheel of the incorrect diameter or a worn wheel will give an unacceptable accumulated error especially in deep wells. Counter wheel diameters are shown below.



Wire can be wrapped around a counter wheel provided it is at least as large as the minimum diameters stated above. For extensive jarring operations it is recommended that line is not wrapped around counter.

Figure 3-16: Slickline and Braided Line Counter Systems

3.12 Slickline Termination

3.12.1 Rope Socket Knot

The rope socket knot used to terminate the slickline and enable reliable connection to the toolstring typically consists of 3 components - the fishing neck, locking collar and mandrel.

The slickline is threaded through the fishing neck and locking collar, then wrapped once or twice around the groove in the mandrel. The free end of the line is then wrapped in a tight helix 5 to 6 times around its own diameter and sheared off by twisting the wire in torsion. The line is then pulled back into the fishing neck where the wire in the mandrel groove is pressed onto the locking collar. The helical knot fits closely in the bore of the collar, which rests on a strong compression spring located within the fishing neck.

3.12.2 Pear Drop Termination

The pear drop termination generally consists of 5 components - an upper fishing neck, a thrust bearing, tapered sleeve, tapered plug and lower fishing neck. The slickline is threaded through the upper fishing neck, thrust bearing and tapered sleeve. The free end is bent back on itself to form a pear drop loop smaller in dimension than the tapered plug. The free end is cut to an appropriate length and the wire located in the groove in the plug. The plug is secured in position on the wire by a grub screw. The line is then pulled back into the fishing neck where the tapered sleeve, which rests on the bearing, is mated to the tapered plug and grips the wire, which stands proud in the groove.

Tests performed on these 2 types of termination have shown that the rope socket knot is only 62% efficient for API 9A wireline and 55% for stainless and Supa grades. The pear drop termination has proved to be 96% efficient for API 9A, and 94% for stainless and Supa grades.

The advantages and disadvantages associated with the rope socket knot and pear drop termination include:

Table 3-8: Advantages and Disadvantages of Slickline Termination Methods

Rope Socket Knot	Pear Drop Termination
(a) Low strength of termination	High strength
(b) Time consuming to perform	Quick to perform
(c) Difficult to perform	Easy to perform

Rope Socket Knot	Pear Drop Termination
(d) Twists/kinks may be introduced	Less likely to introduce kinks
(e) Vice/clamp required which may damage wire	No vice required
(f) High tensile and large diameter wire increases difficulty of performing knot	Suits all sizes/grades of wire

3.13 Slickline Failure

The majority of slickline failures are attributed to incorrect material selection or operational error and generally falls into the following ten categories:

3.13.1 Hydrogen Embrittlement

This may occur when the slickline is exposed to H_2S or CO_2 in downhole conditions. Both H_2S and CO_2 release atomic hydrogen, H (CO_2 by reacting with H_2O to form carbonic acid + H), which enters the steel and effectively locks within the microstructure, thus increasing the tensile strength of the wire but reducing the torsional ductility. As the wire is withdrawn from the well, it is brittle and prone to surface cracking as it bends over the pulleys. After removal from the well environment, then eventually the hydrogen leaves the steel and reverts back into the atmosphere. However, any micro-cracks incurred during withdrawal from the well remain and may cause premature failure during subsequent operations.

3.13.2 Age Hardening

This is a time-temperature dependent transformation potentially affecting UHT slickline due to the high internal stresses. Aging has a similar effect on the wire as hydrogen embrittlement. (i.e., the tensile strength increases, but the torsional ductility is severely impaired.)

3.13.3 Fatigue

This type of failure is often encountered when operating slickline with small pulley diameters. A pulley to slickline diameter ratio of 120:1 is required to ensure a reasonable fatigue life at normal working loads. It has been shown under laboratory conditions that increasing the pulley diameter from 8 in. to 14 in. increased the fatigue life of a 0.108 in. diameter Supa 70 wireline loaded to 25% of its breaking load from 4800 to 8000 cycles, i.e., increasing working life by 65%. Cutting back the wireline when working at fixed depths is recommended to avoid localized fatigue.

3.13.4 **Corrosion**

Corrosion may occur in the wellbore or in storage if the slickline is not cleaned and protected after use.

3.13.5 **Corrosion Fatigue**

This occurs when there is a combination of a corrosive environment and fatigue condition.

3.13.6 **Stress Corrosion**

This is a potential hazard when operating stainless slickline under heavy loads in a chloride environment. The combination of an aggressive environment and high stresses may cause catastrophic premature failure.

3.13.7 **Tensile Overload**

This is often experienced during heavy jarring. The weight indicator does not register the instantaneous shock load applied and consequently, the slickline is overloaded. A safe working load of 50% of the breaking load of the wire is commonly recommended.

3.13.8 **Snarl**

This occurs when the wire is bent and twisted at one point, for example when a kink forms under loss of tension during spooling.

3.13.9 **Mechanical Damage**

This type of damage can occur in many ways. For example, running off a pulley, jarring in a pulley, pinching in guide rollers or crushing on the reel.

3.13.10 **Hydrodynamic Deformation**

A number of slicklines have been observed to exhibit thinning over a short interval. Close examination has shown that the thinning has occurred by some form of deformation process and not by scraping or wear. No tensile test has been known to produce this effect and indeed it is not possible to reproduce this effect in pure tension under normal conditions of temperature and pressure.

Recent research has provided a theoretical model by which failure of this nature could be explained. It has been shown that the wire can be deformed by up to 30% reduction in area, by passing it through a molten polymer filled tapered tube of slightly larger diameter than the wire.

As the wire is pulled through the tube, shearing takes place at the wire polymer interface. This shearing action gives rise to a drag force, which generates hydrodynamic pressures of sufficient magnitude (typically 45,000 psi) to deform the wire.

A similar mechanism is thought to occur under certain circumstances when operating slickline (e.g. during heavy jarring). The stuffing box (basically a chamber containing tightly packed glands and pressurized grease) may act under certain conditions of wire velocity and axial load as the tapered tube in the theoretical model outlined above, with the rubber performing the same function as the molten polymer.

4 Basic Tool String

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4 BASIC TOOL STRING

4.1 Tool String Selection

Careful selection of tool string components is vital for the successful completion of any slickline operation. The key factors that determine the tool string selection and specification are outlined below.

4.1.1 Wire Size

Common sizes include:

- 0 .092 in. slickline
- 0 .108 in. slickline
- 0 .125 in. slickline
- 0 .135 in slickline
- 3/16 in. braided line
- 7/32 in. braided line

4.1.2 Tool String OD

When a small clearance between the tool fish neck and the tubing ID exists, it must be ensured that the appropriate pulling tool will latch and be able to pass any restrictions in the tubing bore.

Tool string OD (in.)	Tubing ID (in.)
$1\frac{1}{4}$	$2\frac{3}{8}$
$1\frac{1}{2}$	$2\frac{7}{8}$
$1\frac{7}{8}$	$3\frac{1}{2}$
$2\frac{1}{8}$	4
$2\frac{1}{2}$	$4\frac{1}{2}$

4.1.3 Intended Operation

Operations will have a range of requirements placed upon the tool string, depending on the application and well bore conditions. For example, the following applications have significantly differing requirements for operation and contingency planning.

- Plug running and pulling
- Gauge ring running
- Instrument running and retrieving

4.1.4 Depth of Well

The depth of well effects the suspended load and the ability to operate the tool string. For example, a 300 lb tool string on 0.125 in. wire to 15,000 ft gives a load of 930 lb.

$$300 \text{ lb} + (42 \text{ lb}/1000 \text{ ft} \times 15 (1000 \text{ ft})) = 930 \text{ lb}$$

In some applications, this may be too high a load to enable a safe operation.

930 lb + deviation + drag + swab factor = too heavy

4.1.5 Deviation

Deviated well bores may require that the tool string be modified to suit the conditions, for example:

- Light-weight tool string
- Roller stem
- Extra knuckle joint
- Centralizers

4.1.6 Tubing Head Pressure (THP)

The amount of stem required to overcome the force created by the tubing head pressure, neglecting friction (i.e., the balance weight), can be calculated thus:

$$A \times P = F$$

Where:

A = Cross-sectional area of slickline

P = Wellhead pressure (shut-in)

F = Force or weight of stem required (lbm)

4.1.7 Wellbore Fluid

The different densities and viscosities of well bore fluids will have differing drag effects on the tool string. In some conditions, the efficiency of the tool string may also be affected, e.g., viscous fluids may stifle jar action.

4.1.8 Tubing Type

The internal finish of the tubing string through which the slickline tool string is to be run may effect the tool string configuration. For example, on plastic coated or chromium tubing strings, nylon rollers may be required on the slickline tool string to prevent abrasive damage that could subsequently provide a site for corrosion initiation.

4.1.9 Basic Tool String Configuration

An example tool string incorporating the basic components for slickline operations is shown in [Figure 4-1: Basic Tool String Configuration](#).

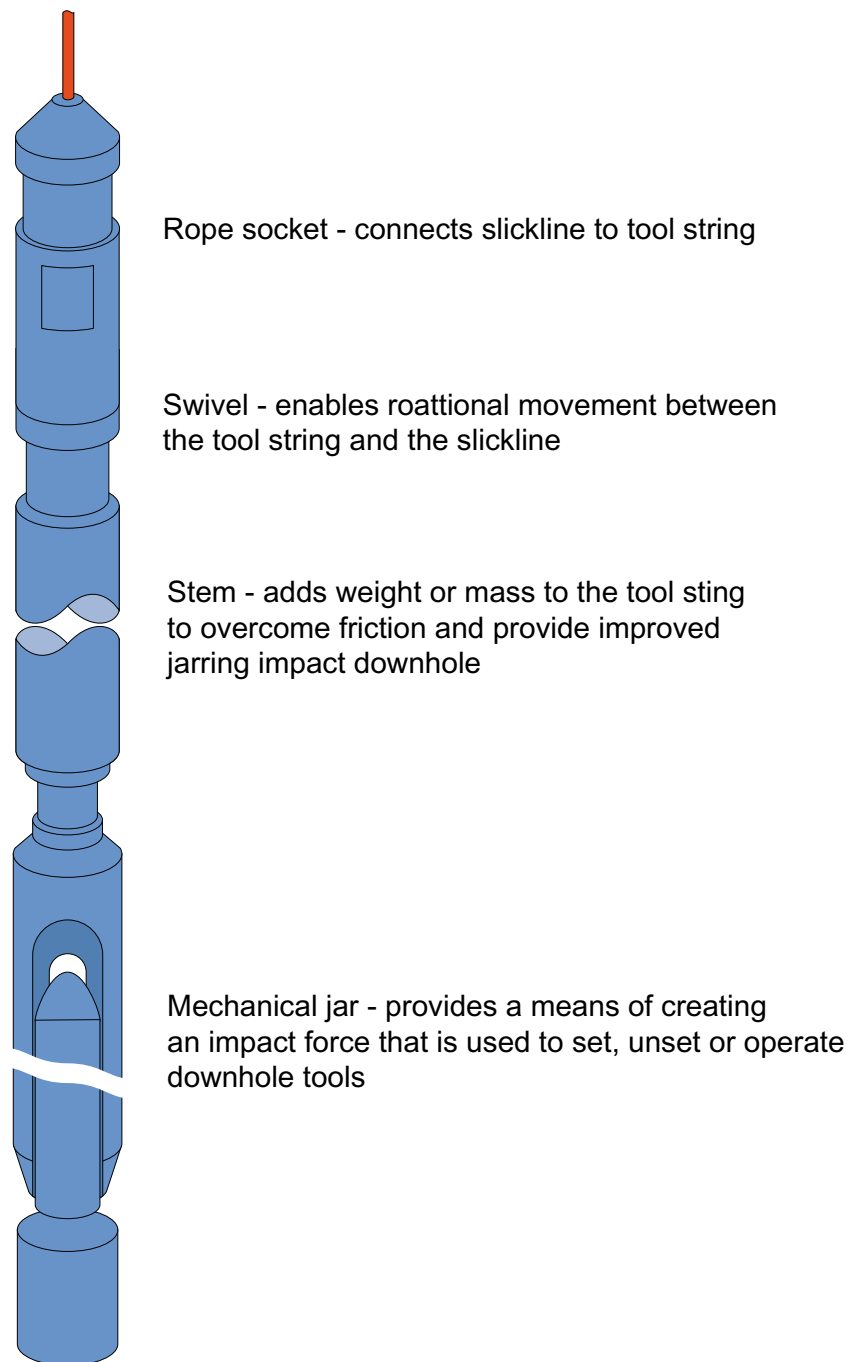


Figure 4-1: Basic Tool String Configuration

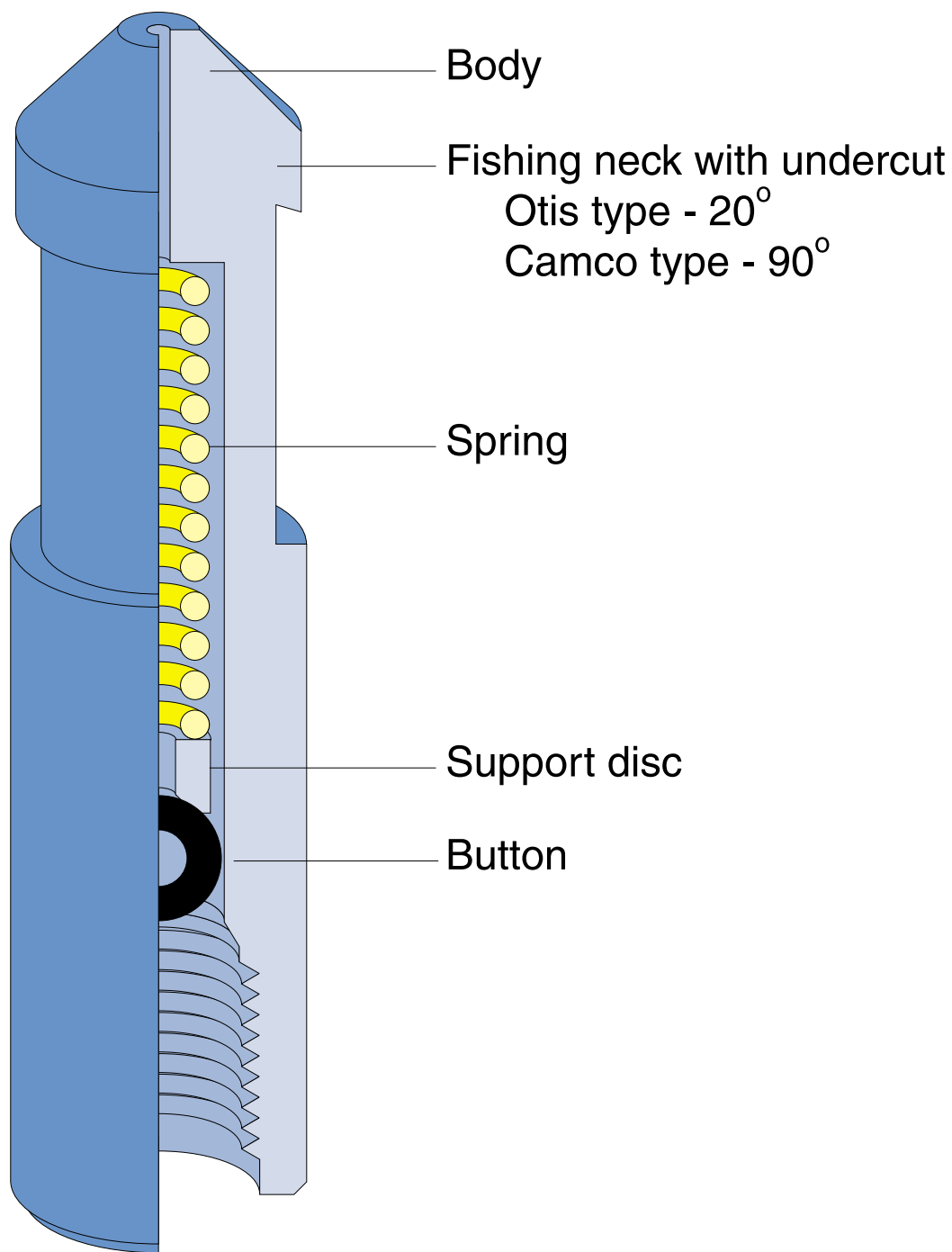
4.2 Tool String Components

4.2.1 Rope Socket

The rope socket is used to make the connection between the slickline and tool string. Several types are commonly found, selection generally being dependent on slickline size and type:

- 0.092 in. slickline - regular knot type
- 0.092 in., 0.108 in., 0.125 in. slickline - no-knot (teardrop) type
- 3/16 in. braided line

4.2.1.1

Regular Knot Rope Socket**Figure 4-2: Knot Type Rope Socket**

**Note**

Always wear gloves when tying the wire and beware of the sharp ends.

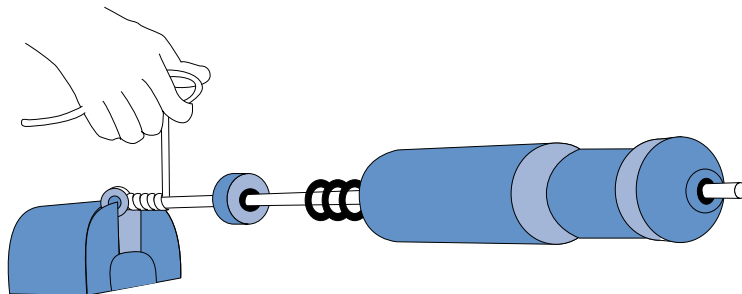
Preparation

Pass the end of the wire through the stuffing box and then pass the end of the wire through the slickline socket body, spring and spring support. Place the disc in a vice and run the wire down between the jaws behind the disc, then bend the end of the wire into a loop to form a handle that will be comfortable to grip. The disc should contact the wire approximately 10 in. to 12 in. from the loop. Grip the long end of the wire (the end connected to the drum) by wrapping it around your left forearm (if right-handed) and the handle with your right hand.

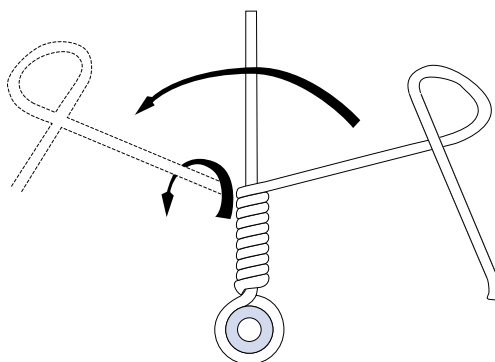
Holding the wire taut, start bending the wire about the disc (a). The wire should go around the disc once, then be wrapped around itself making sure there is a minimum of slack in the wire when starting to wrap. These wraps should be made smooth and even and should hug the wire closely with the coils touching one another. Continue wrapping in this manner until about 12 coils are made.

Move the wire in the direction shown in order to twist off the free end (b). Be careful to keep the loop pointed in the same direction or slightly twisted during this part of the operation, so that the torque is focused on the end of the last coil. The wire should twist off (c).

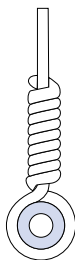
Place the disc crosswise in the vice or pliers and straighten the knot as well as possible. Now using the wire, pull the knot into the socket and check to see that the socket swivels freely. The socket is now ready to be attached to the upper end of the stem.



(a) Grip button in vice and wrap wire approx 12 turns



(b) Heat generated during wraps assists in breaking the line when a sharp reverse twist is applied.



(c) The final knot must have a clean break.

Figure 4-3: Assembly of the Knot Type Rope Socket

4.2.1.2

No-Knot Rope Socket

The No-knot rope socket, also known as a teardrop or wedge rope socket, is designed for 0.108 in. and 0.125 in. slickline. While it can be also used for 0.092 in., the knot type rope socket is more common for the thinner wire.

The standard socket body has an internal taper to accept the thimble. However, a thimble eye is available to convert the older style of rope socket.

The end of the wire is bent to fit the curve at the bottom of the 'teardrop', with the 'short' side slightly shorter than the side of the thimble.

The groove in the thimble of these sockets is not deep enough to accommodate the total thickness of the slickline. As the security of the slickline depends upon its being 'pinched' between the thimble and body, care must be taken to ensure the correct size of socket is selected for the slickline in use.



Note

As the internal components of the teardrop rope socket do not permit the wire to rotate, it is essential to include a swivel immediately below the rope socket.

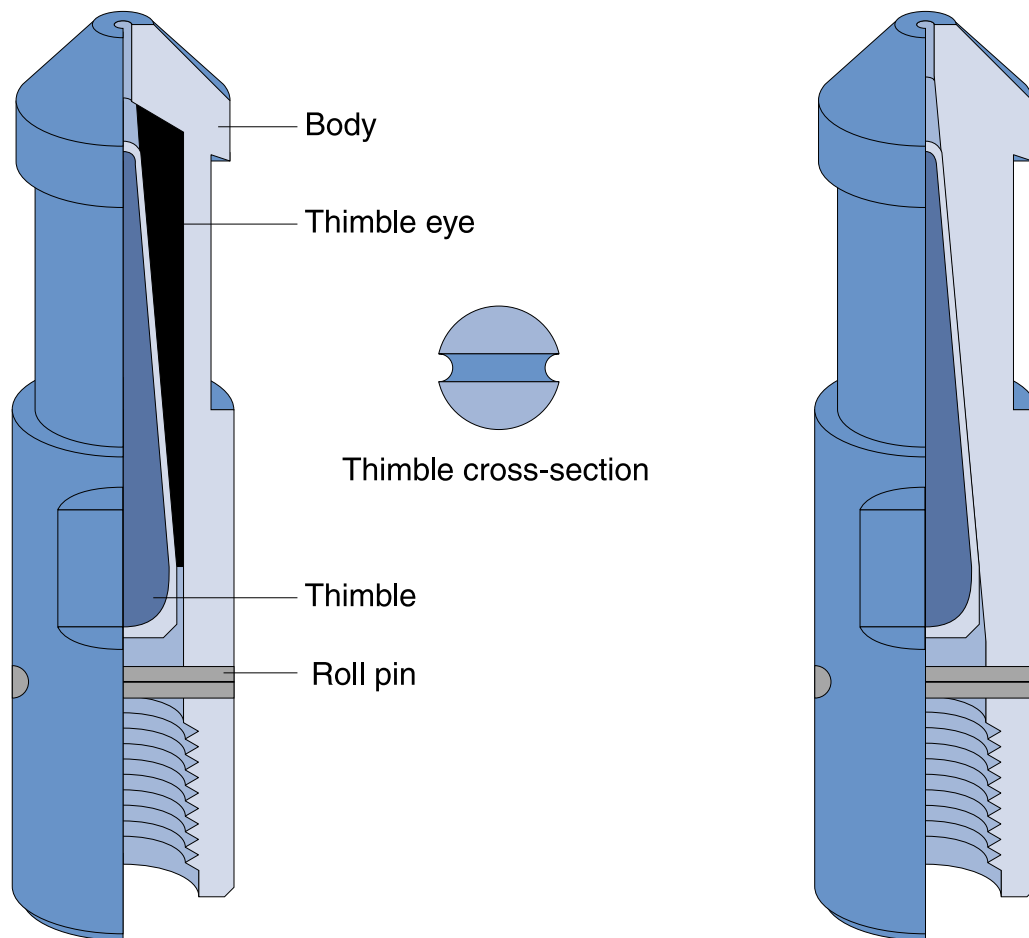
Do not substitute a knuckle joint in place of a swivel. A swivel has $1\frac{1}{2}^{\circ}$ to 5° of lateral movement, where a knuckle is not designed to rotate under load and has 15° of lateral movement. In the event of it being necessary to fish the rope socket, a knuckle joint will allow it to lay over against the side of the tubing wall at an angle which may make latching difficult or impossible.

Table 4-1: Rope Socket Sizes

Nominal Size (in.)	Fish Neck (in.)	Types Available	Length * (in.)	Pulling Tool Nominal Size (in.)	Minimum Tubing Diameter (in.)
1	0.875	K	6.0	1-3/16	1.380
$1\frac{1}{4}$	1.187	N/K	5.0 - 6.60	$1\frac{1}{2}$	1.610
$1\frac{1}{2}$	1.375	K, N/K, B	5.0 - 6.75	2	1.867
$1\frac{7}{8}$	1.750	K, N/K, B	5.0 - 8..90	$2\frac{1}{2}$	2.259
$2\frac{1}{4}$	1.750	N/K, B	6.6 - 10	$2\frac{1}{2}$	2.992
$2\frac{1}{2}$	2.312	N/K, B	6.8 - 10.125	3	2.992
[K= Knot N/K=No-Knot B=Braided]					

* - Approximate Camco sizes shown

1 - Otis $1\frac{1}{2}$ in. has a $1\frac{3}{8}$ in. body maximum OD



No-knot rope socket
(Converted from knot type
by installing a thimble eye)

No-knot rope socket

Figure 4-4: No Knot Rope Sockets

4.2.1.3

Braided Line Rope Socket

There are two types of rope sockets commonly used for braided line - the percentage slip type and the clamp type.

Clamp Type

Thread the wire through the rope socket and through the clamp. Leave $\frac{1}{4}$ in. of wire protruding from the clamp, tighten the hex-head screws diagonally ensuring that the two sides of the clamp remain even when finished, flair over the end that is protruding and slip clamp up into rope socket.

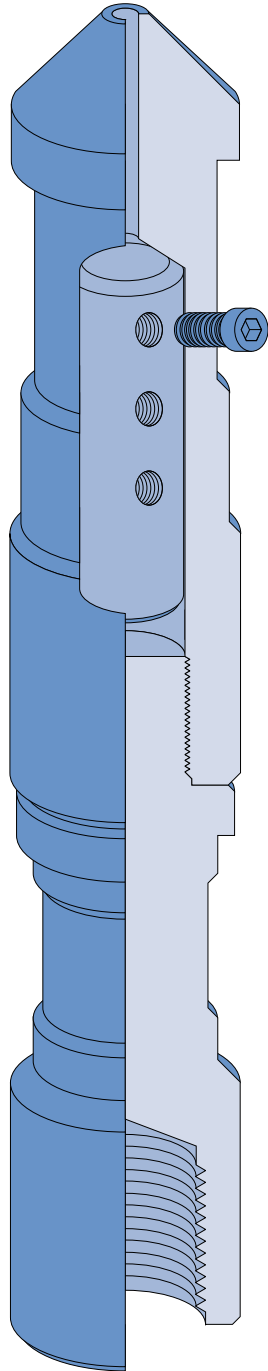


Figure 4-5: Clamp Type Rope Socket

4.2.2

Swivel

The slickline swivel is designed to permit the easy rotation of the tool string; even under relatively high loads as the tools are conveyed in and out of the well bore.

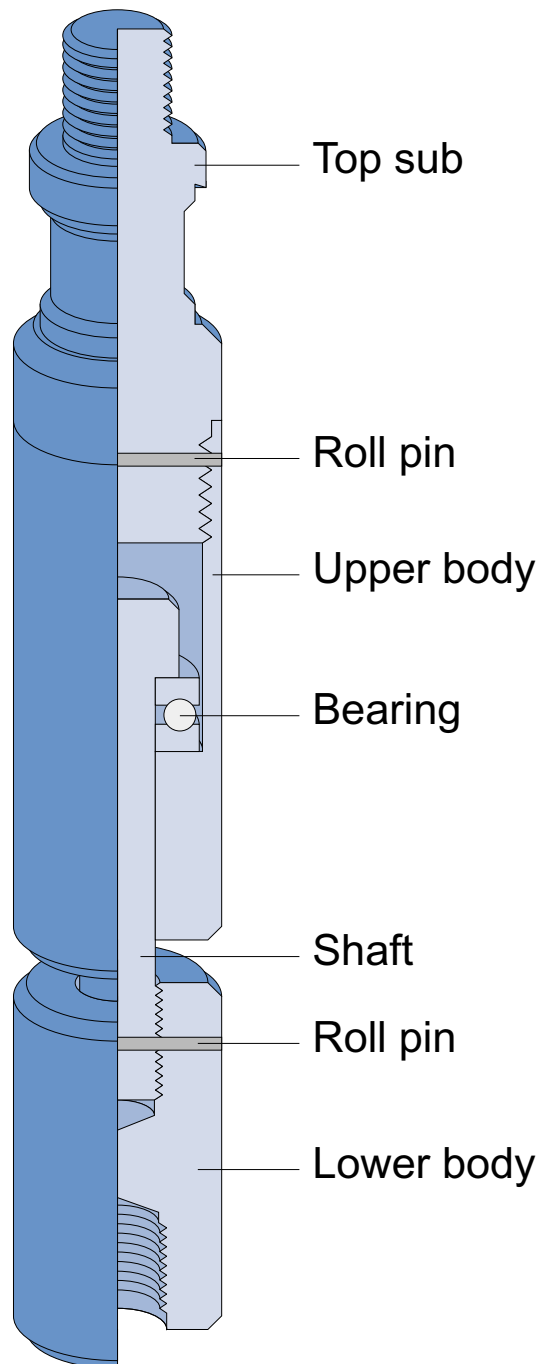


Figure 4-6: Slickline Swivel

It is essential to use a swivel between the rope socket and stem to protect the line from excessive twisting, especially when:

- Using a 'no-knot' type rope socket, since the socket design does not allow rotation of the components.

- Using a braided line rope socket. Twisting force on braided line can cause the braid to unwrap or open up, which can lead to broken strand or jamming in the flow tubes.

The sideways movement of a swivel varies from $1\frac{1}{2}^{\circ}$ to 5° , (depending on the manufacturer) unlike a knuckle joint, which has 15° of movement.

In the event of a line break, the swivel will keep the rope socket fishing neck near straight and make latching possible. If a knuckle joint has been used in place of a swivel, it allows the rope socket to 'fall over' making the latching difficult. Also, knuckle joints are not designed to rotate under load, therefore, swivels and knuckle joints are not interchangeable.

4.2.3 **Stem**

Sometimes referred to as sinker bar, stem is used to provide additional weight to the tool string which may be required to run into the well bore against high-pressure and stuffing box friction.

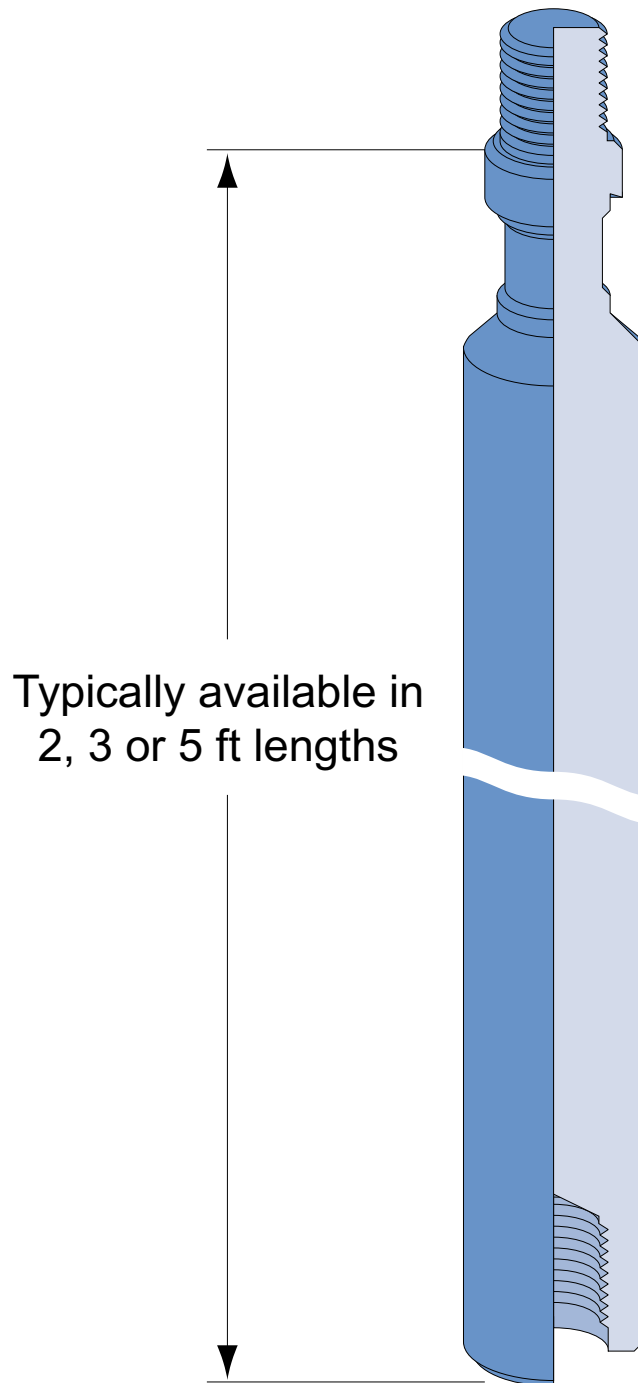


Figure 4-7: Slickline Stem

A rule of thumb commonly used to determine the weight of a solid steel stem is:

$$\text{Stem OD}^2 \times 8/3 = \text{weight lbm/ft}$$

Increasing the stem weight increases the impact force delivered by a jar. However, avoid placing too much weight in the tool string, since excessive mass dampens the feel and action of tools felt at surface and premature shearing can occur.

Flats for wrenches are provided and should be used, never grip on the fishing neck or this will damage the sharp edges.

All connections should be clean and dry. Do not lubricate down hole threads since they may unscrew down hole during extended jarring.

The stem is available in standard lengths of 2 ft, 3 ft and 5 ft.

Details of common stems specification are should in :

Table 4-2: Common Stem Specifications

Nominal Size	Thread Connection*	Fish Neck	Maximum OD	Approximate Weight per foot	
(in.)	OD	(in.)	(in.)	(ft)	(kg)
$\frac{3}{4}$	$\frac{5}{8}$ - 11	0.500	0.750	1.500	0.68
1	$\frac{5}{8}$ -11	0.750	1.000	2.660	1.21
$1\frac{1}{4}$	15/16 - 10	1.187	1.250	4.160	1.90
$1\frac{1}{2}$	15/16 - 10	1.375	1.500	6.000	2.73
$1\frac{7}{8}$	1-1/16 - 10	1.750	1.880	9.375	4.26
$2\frac{1}{8}$	1-1/16 - 10	1.750	2.125	12.040	5.47
$2\frac{1}{2}$	1-9/16 - 10	2.313	2.500	16.660	7.60

* - 'Quick' type connections are available on most of these sizes

4.2.4

Roller Stem

Roller stem is a useful, sometimes essential, addition to tool strings to be run in deviated wells. The rollers reduce the frictional losses as the tool string runs along the tubing wall.

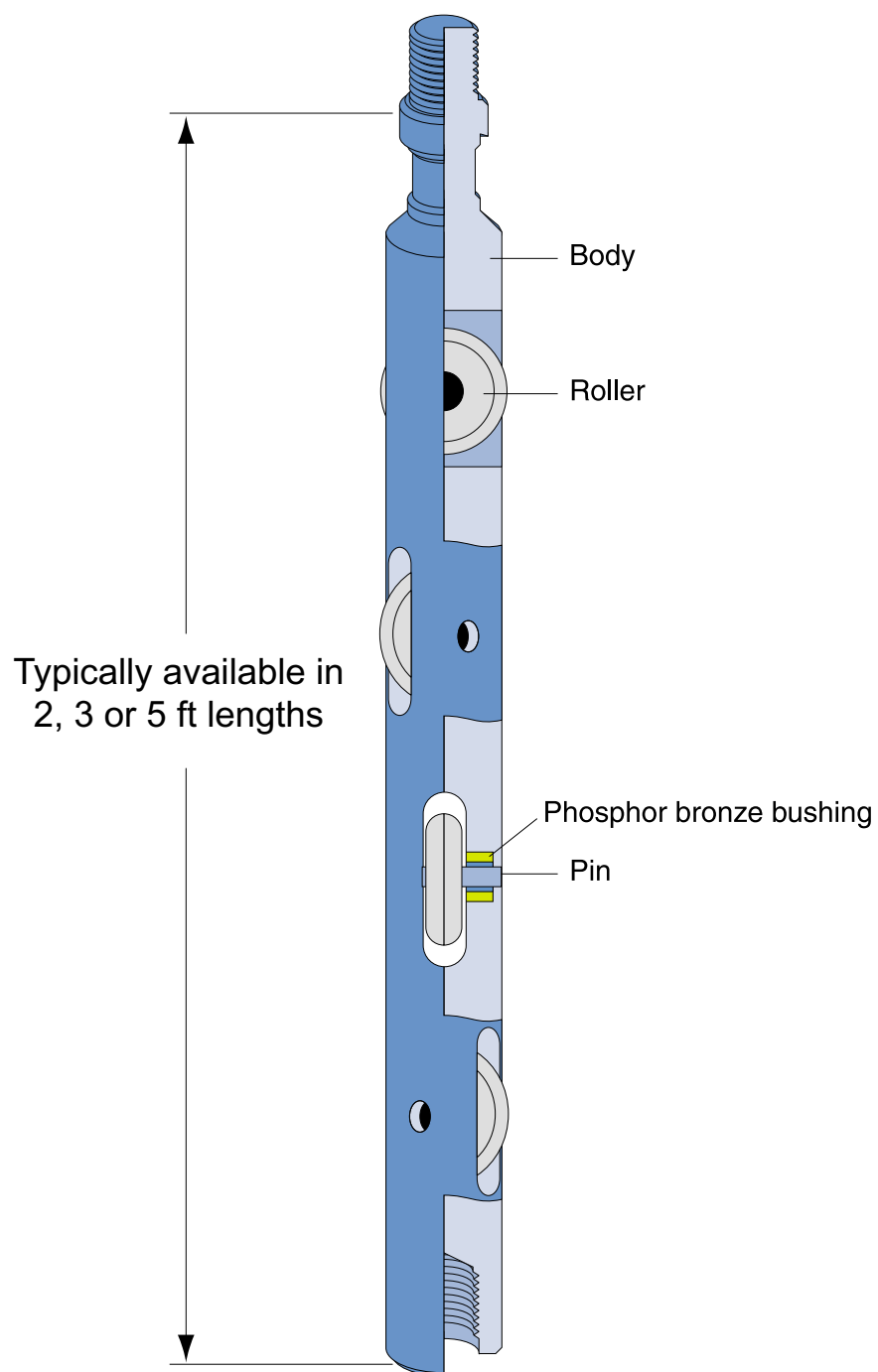


Figure 4-8: Roller Stem

4.2.5 **Lead Filled Stem**

To provide greater weight for the same diameter and length, lead filled stems can be used. This stem has a regular steel pin and box and a tubular steel outer barrel. The inside is filled with lead to provide maximum density. However, heavyweight stem containing tungsten is also available.

This stem is used primarily to run flowing pressure surveys to obtain maximum weight and minimum cross-sectional area, to protect against buoyancy effects or being blown up the hole by pressure surges.

Lead filled stem should not be used on jarring applications since the lead will tend to creep downwards and split the outer barrel.

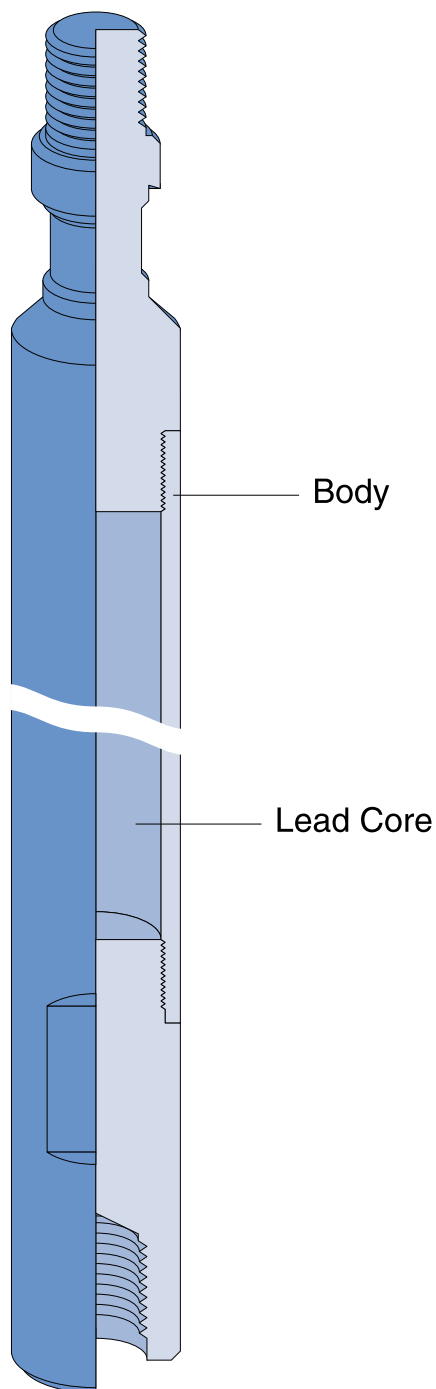


Figure 4-9: Lead Filled Stem

Table 4-3: Lead Filled Stem Specifications

OD (in.)	Connection	Fish Neck (in.)	Length (ft)	Approximate Weight	
				(lb)	(kg)
1 $\frac{1}{4}$	15/16 - 10	1.187	5	32.0	15.0

$1\frac{1}{2}$	15/16 - 10	1.375	5	41.7	19.0
$1\frac{7}{8}$	1-1/16 - 10	1.750	5	55.0	25.0
$2\frac{1}{8}$	1-1/16 - 10	1.750	5	68.0	31.0
$2\frac{1}{2}$	1-9/16 - 10	2.312	5	81.6	37.1

4.2.6 Jars

4.2.6.1 Tubular Jars

Tubular jars are designed with a perforated tube (for fluid bypass) and a telescoping rod that moves vertically within the tube. The telescoping rod has a fishing neck and a pin thread connection on the upper end and the tube has a box thread connection on the lower end. The telescoping rod is extended or collapsed within the tube by manipulating the slickline at the surface to produce upward or downward jarring. The intensity of the jarring impact depends on the weight of stem installed immediately above the jars, the stroke length of the jar and the density of the well fluid. Because of the tubular construction, these jars are especially effective for fishing, bailing and through tubing work.

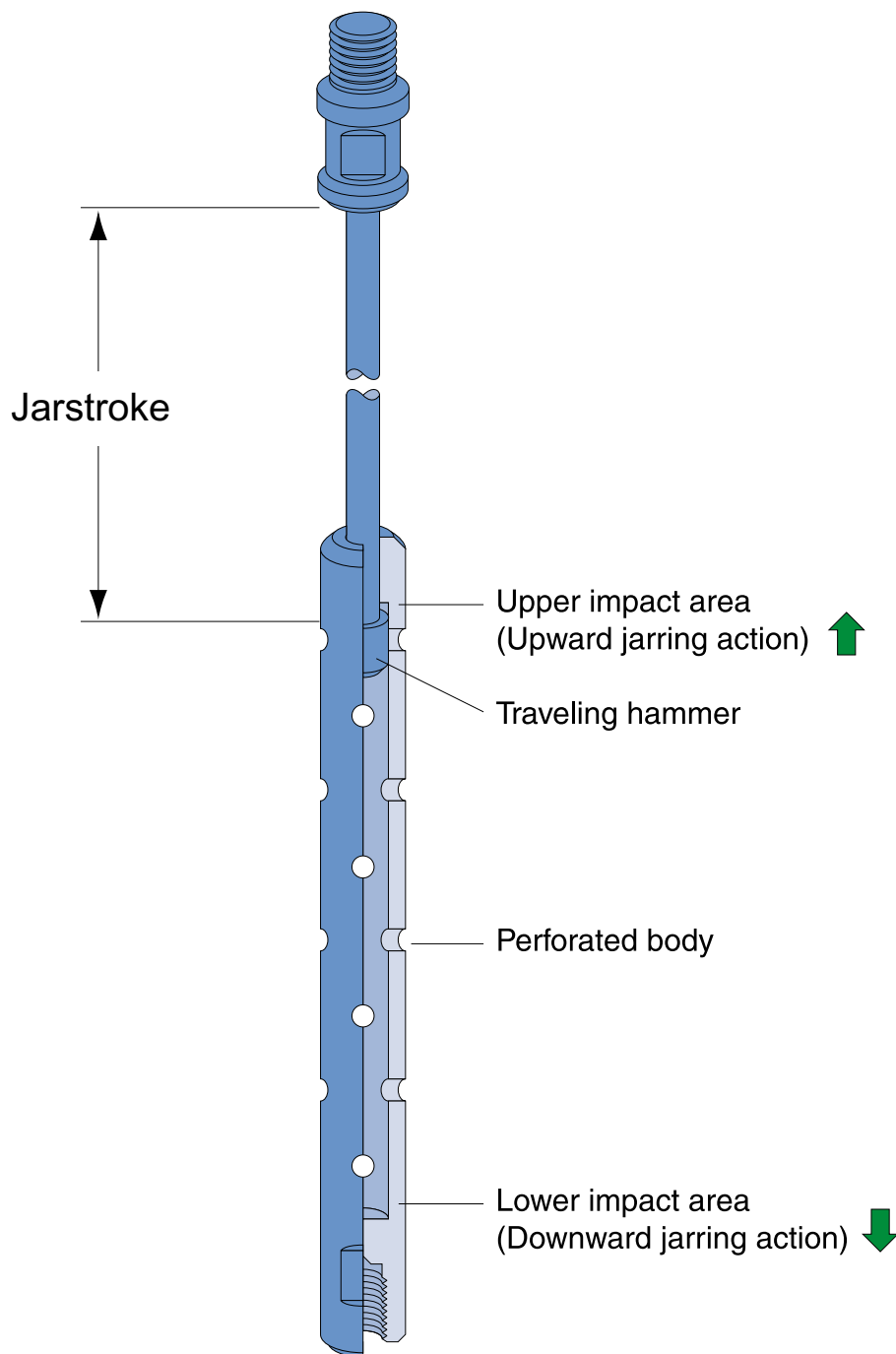


Figure 4-10: Tubular Jar

4.2.6.2

Mechanical Jars

Jars are a vital component in almost every slickline tool string (except when running pressure surveys).

For efficient operation, it is essential that the slickline unit operator can recognize the precise opening and closing point of the jars on the weight indicator at surface.

The force required downhole to manipulate tools and shear pins is generated by the impact of the jars. If the jars are not being operated correctly or if jar action is lost, then very little force can be exerted on the tools.

For the formula, $F = MA$ (Force = Mass x Acceleration), it can be seen that the impact force can be increased by increasing mass, through additional stem or speed at impact, through precise control.

The stem weight is fixed after the tools are run in the well, however, the impact speed can be varied.

Jar-down action is limited to maximum speed that gravity will close the jars. Consequently, in highly deviated wells or in well bores containing thick viscous fluid, the effect of downward jarring may be severely restricted.

Jar-up action is more effective (with the same stem weight) as speed can be increased by increasing the spooling speed at the slickline unit and by the use of long stroke jars. Hence it may be noticed that shear up tools have larger shear pins than shear down tools.

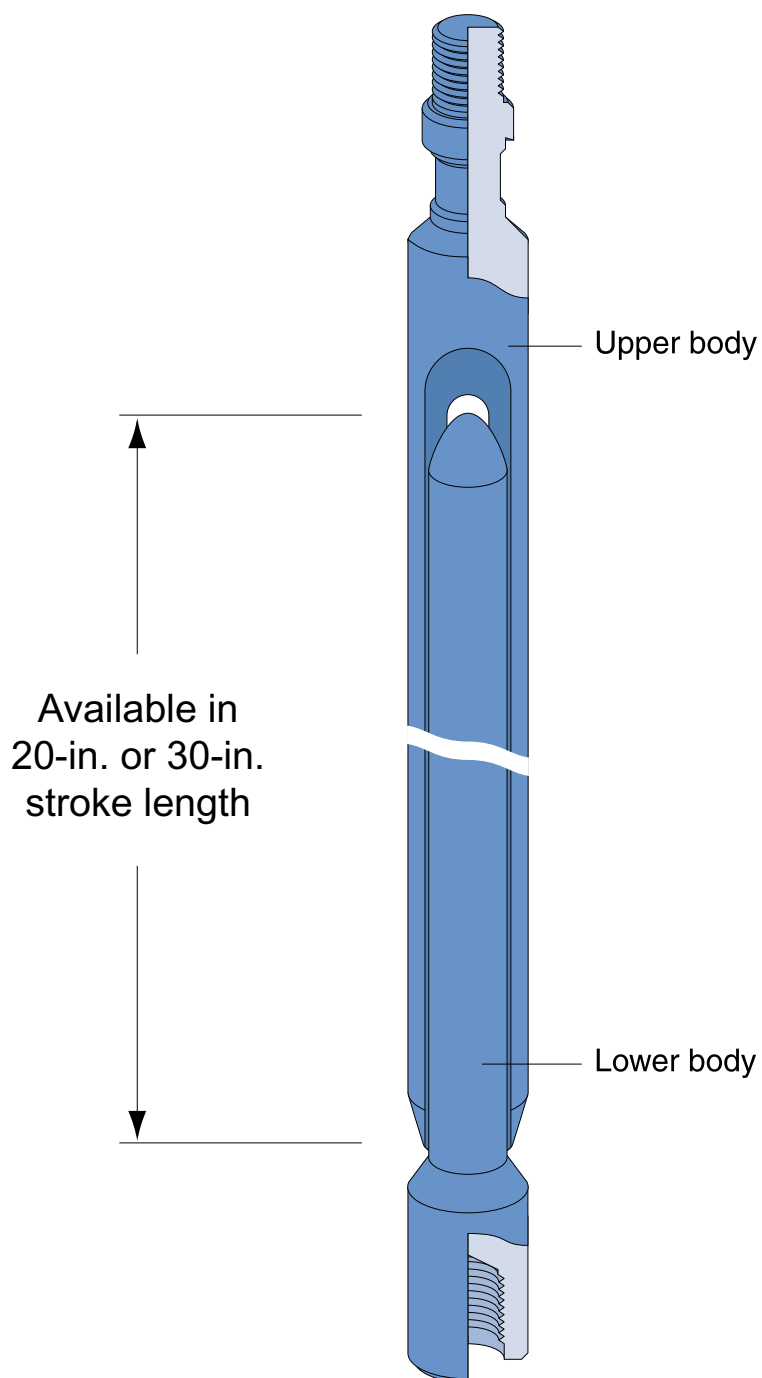


Figure 4-11: Mechanical Jar

Table 4-4: Mechanical Jar Specifications

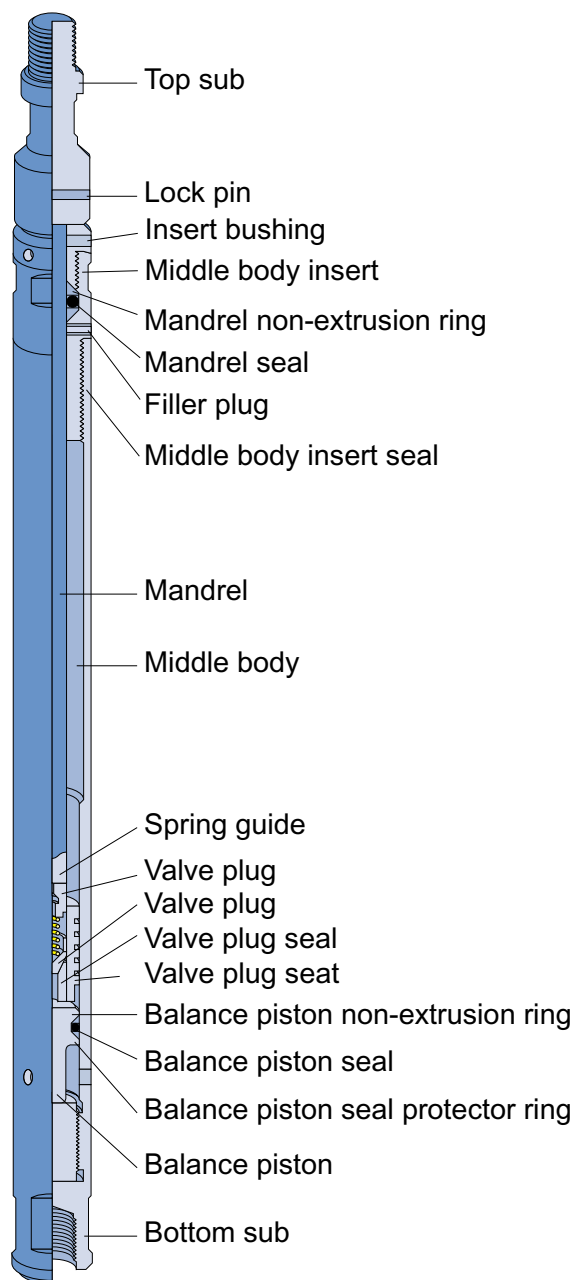
OD (in.)	Connection	Fish Neck (in.)	Closed Length (in.)	Stroke (ins)
1 $\frac{1}{4}$	15/16 - 10	1.187	38	20

$1\frac{1}{2}$	15/16 - 10	1.375	38	20
$1\frac{1}{2}$	15/16 - 10	1.375	48	30
$1\frac{7}{8}$	1-1/16 - 10	1.750	$38\frac{1}{8}$	20
$1\frac{7}{8}$	1-1/16 - 10	1.750	$38\frac{1}{8}$	30

4.2.6.3 Hydraulic Jars

Hydraulic upstroke jars are placed between the stem and mechanical jars in the tool string, when extra jar up action is required or anticipated. This is especially important when conventional jar up action is difficult because of deviation or high viscosity well fluid. Hydraulic jars are available in the following common sizes:

- $1\frac{1}{4}$ in.
- $1\frac{1}{2}$ in.
- $1\frac{3}{4}$ in.
- $2\frac{1}{8}$ in.
- $2\frac{1}{2}$ in.



Jar shown in closed or starting position

Figure 4-12: Hydraulic Jar Assembly

When the hydraulic jar is in the closed position, the piston in the lower end of the mandrel assembly is inside the restricted internal diameter (cylinder) of the body. When an upward strain is taken on the slickline, the mandrel assembly is pulled upward in relation to the body. The upward movement of the mandrel is impeded annular space between the outside diameter of the piston (on the mandrel) and restricted internal diameter (cylinder) in the body. As soon as the piston moves out of the restricted internal diameter (cylinder) of the body and into the enlarged

internal diameter the body, the fluid resistance ceases. At this point, the stretch that has been pulled in the slickline caused the mandrel subassembly to travel upward at a constantly accelerating velocity until the top shoulder on the piston strikes the stop in the upper end of the body. This transmits an upward jarring impact to the tool(s) that is below the hydraulic jar.

After the upward jarring impact has been completed, the wire is slacked off to allow the weight of the slickline stem to close the hydraulic jar. During closing, as the piston enters the cylinder, the valve assembly in the piston is moved off seat to permit rapid displacement of hydraulic fluid from below the piston to above. When the mandrel/piston assembly has completed its downward travel, the valve in the piston is closed by a small spring and the jar is ready for the next upward jarring impact.

The slickline operator can control the intensity of the upward jarring impact of the hydraulic jar by increasing or decreasing the amount of tension (and the resulting stretch) that is pulled on the slickline.

Hydraulic jars should not be run in conjunction with mechanical jars. In the event that gas infiltrates the hydraulic jar, the jar will act as a shock absorber rendering the shear down release difficult to achieve.

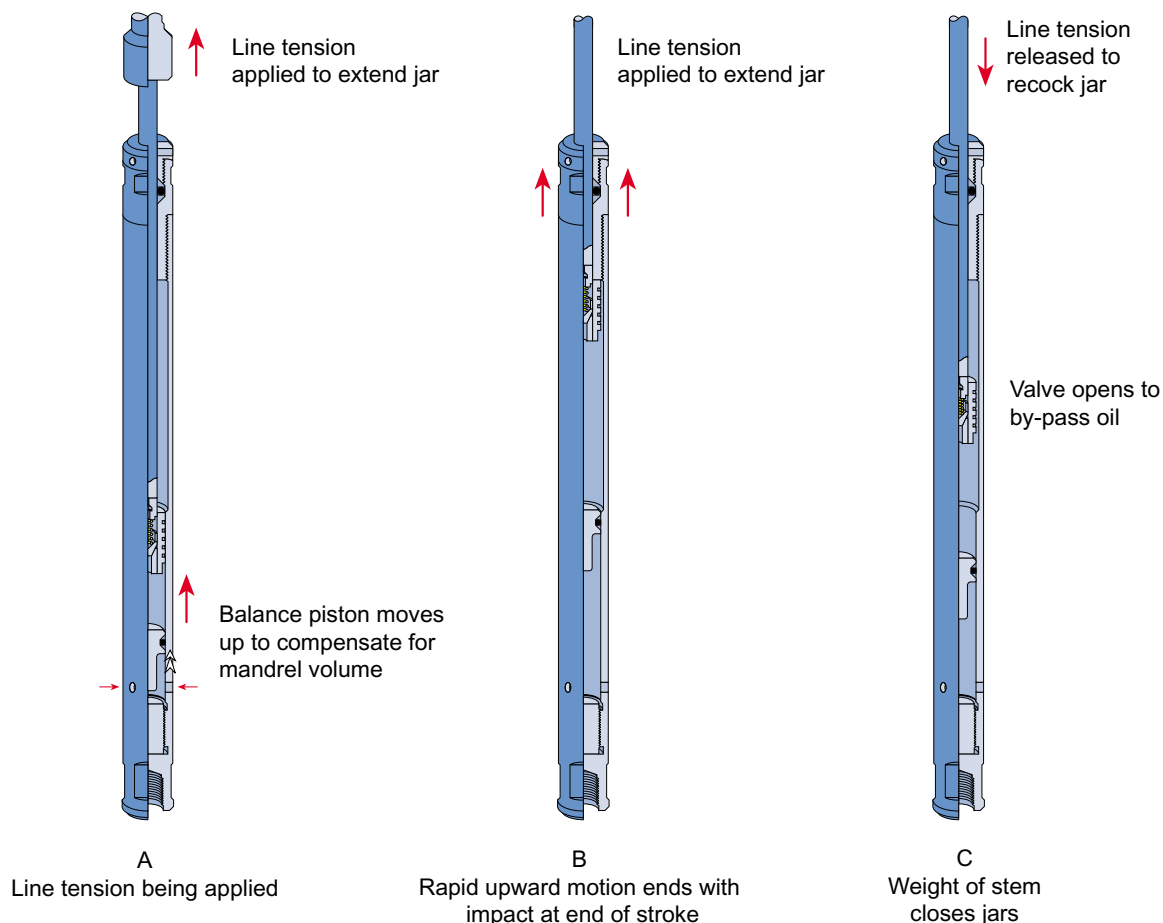


Figure 4-13: Hydraulic Jar Operating Sequence

4.2.6.4

Petrolin Spring Jars

Petrolin spring jars are considered an alternative to hydraulic jars to provide upward impact force. As with hydraulic jars, they are installed in the tool string between the stem and mechanical jars.

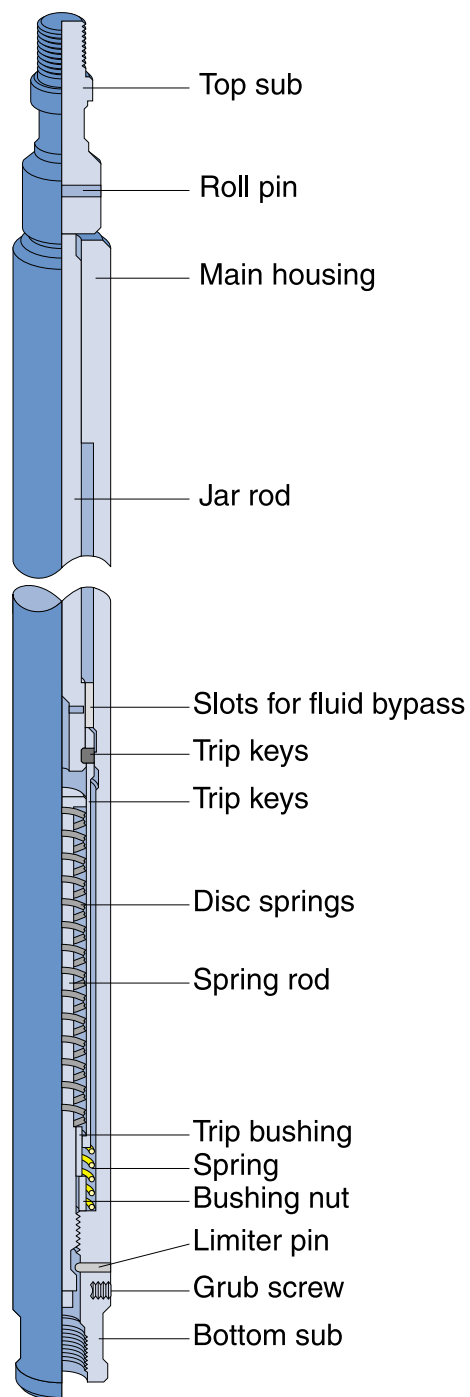


Figure 4-14: Petrolin Spring Jar

**Note**

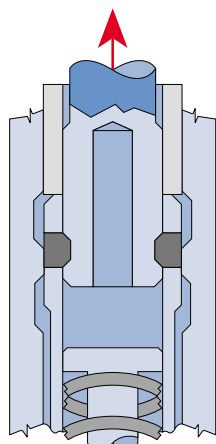
Mechanical jars should always be included to enable downward jarring to shear if upward jarring does not achieve the desired result.

An upward pull is applied via the slickline. With the pulling/fishing tool latched, the line tension is stored until a mechanical release mechanism retracts and permits the rapid upward movement that creates an impact force.

Some designs permit the adjustment of the release mechanism, which alters the amount of tension required to activate or fire the jars. Hence the magnitude of the resulting impact is variable.

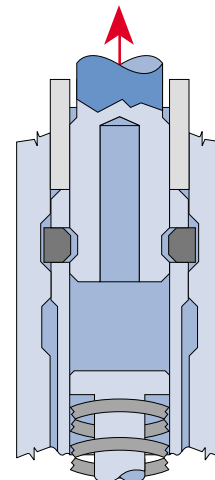
Sequence of Operation

- Increasing the line tension moves the jar rod upwards from its static position, slowly compressing the main disc spring via the trip keys and trip housing. The amount of tension required is adjustable by rotating the spring rod with the calibrating key. The jar rod and trip housing are gripped together by the trip keys.
- As the trip keys move upwards with increasing line tension, they move outwards (expand) into the recess in the main housing.
- The jar rod is released and moves rapidly upwards to strike the inside of the main housing, thus creating upward impact proportional to mass (stem weight) above the jars and velocity at impact. The trip housing is gripped together by the trip key.
- To reset the jars back to their original position, the weight of the stem forces the jar rod and trip housing down by compressing the cocking spring. This causes the trip keys to retract into the lower recess in the main housing. The trip keys relatch the groove on the jar rod and the jarring cycle can be repeated.

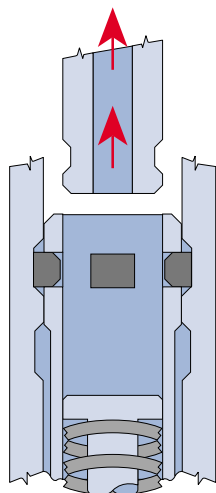


A

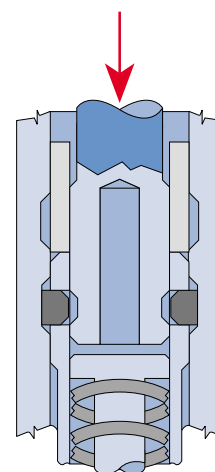
Line tension being increased



B

Trip keys about to retract
and release jar rod

A

Jar rod released
to accelerate upwards
to create upward impact force.

A

Resetting the jar using the weight of
stem to compress the cocking spring
to engage trip keys into groove in jar rod.**Figure 4-15: Petroline Spring Jar Sequence**

The advantages of spring jars include:

- No O-ring seals to leak and allow internal pressure build-up
- Fluid bypass permits free access of well fluids through the jars
- Generally greater upward impact than comparable hydraulic jars

**Note**

The use of fishing tools with a greater area of “dog to fishing neck” contact is advisable.

4.2.6.5 **Petroline 2 $\frac{1}{2}$ in. OD Easy Adjust Jar**

The Petroline easy adjust jar is an upgraded version of the Petroline adjustable upstroke jar with the following new features:

- The jar can be adjusted without removal from the tool string.
- A new locking feature makes it virtually impossible for the jar to back off while down hole.
- Friction is reduced between the jar rod and the housing by means of ball bearings, which have been incorporated around the jar rod. Thus giving increased impact forces.
- In order to give a wider range of settings on the tool, a secondary spring stack has been added which gives more control at the lower settings.
- Spring life is greatly increased, due to the fact that they are only under compression when being fired and they are also well protected from debris due to close tolerances between parts.

As a general guide to the impact force that can be achieved:

- 1.000 lb jar setting gives around 40,000 lb impact force
- 4.000 lb jar setting gives around 120,000 lb impact force

These figures were achieved during a surface test - downhole the figures would be reduced due to fluid damping and friction.

4.2.6.6 **Flopetrol Upstroke Jars**

Upstroke jars incorporate a ball locking mechanism and a compression spring tensioning system. The central shaft is abruptly unlocked when the compression force of the spring is reached. Pulling on the slickline, without acceleration, brings about jarring.

The advantages of upstroke jars over hydraulic jars are that they are fully mechanical and have no seals, enabling them to be used in gas wells. They can deliver more lifts in a given period of time.

A Schlumberger stretch simulator can be utilized when the slickline has insufficient elasticity (at or near the surface) to activate the jar.

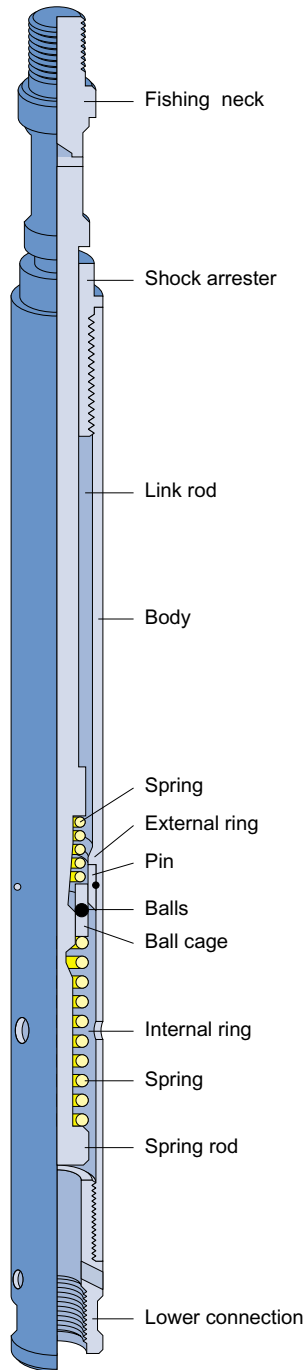


Figure 4-16: Flopetrol Upstroke Jar Assembly

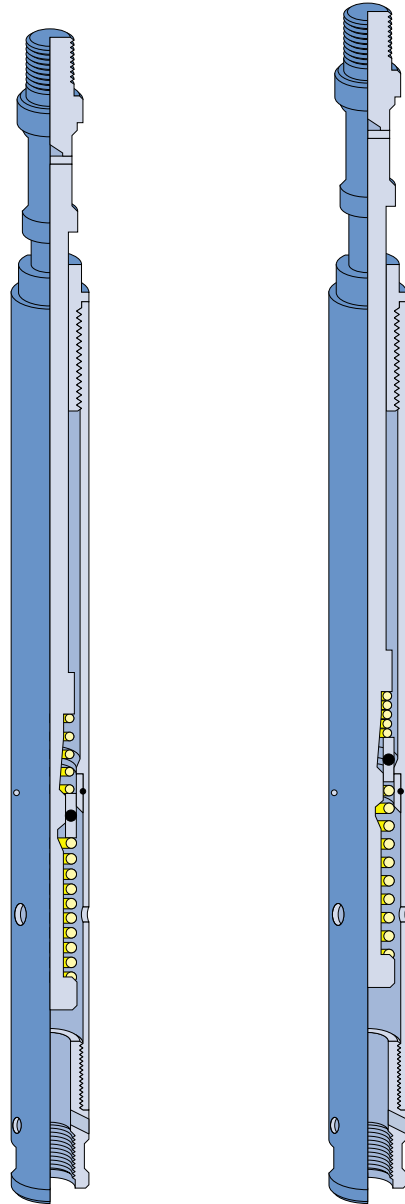
Table 4-5: Flopetrol Upstroke Jar - Technical Specifications

Technical Specifications		
Size	1.5 in.	2.125 in.
Part number	M-809695	M-807951
Maximum OD	1.5 in. (38.1 mm)	2.125 in. (54 mm)
Length	27.5 in. (69.85 cm)	35.14 in. (89.25 cm)
Standard spring tension*	400 lbm (180 kg)	1000 lb (450 kg)
Pin and box thread	0.937 in. (23.8 mm) - 10	1.0625 in. (27 mm) - 10
Fishing head	1.5 in. (38.1 mm)	1.75 in. (44.4 mm)

* - The weight of the string - cable -friction must be added to the spring tension.

Table 4-6: Flopetrol Upstroke Jar - Optional Parts

Optional Parts				
Size of Jar	1.5 in.		2.125 in.	
Adaptable simulator (Size)	M-812918 (2.25 in.)		M-810769 (2.625 in.)	
Spring tension	Jar 1.5 in.	Simulator 2.25 in.	Jar 2.125 in.	Simulator 2.625 in.
200 lbm (90 kg)	M-810645	M-812919		
400 lbm (180 kg)	M-810644			
700 lbm (320 kg)			M-810514	M-810759
1000 lbm (450 kg)			M-810374	



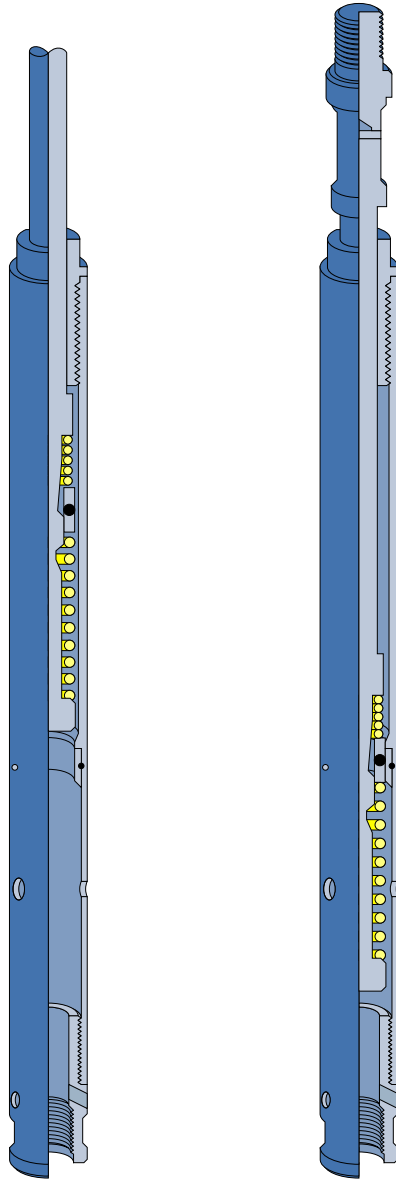
A

Line overpull
compresses lower
spring against balls

B

As ball cage moves
upwards balls move
out into groove.

Figure 1-2: Flopetrol Upstroke Jar Operating Sequence (A & B)



C
Link rod releases
and accelerates
upwards to create
impact

D
Stem weight resets
jars as balls retract
into space above
internal ring

Figure 4-18: Flopetrol Upstroke Jar Operating Sequence (C & D)

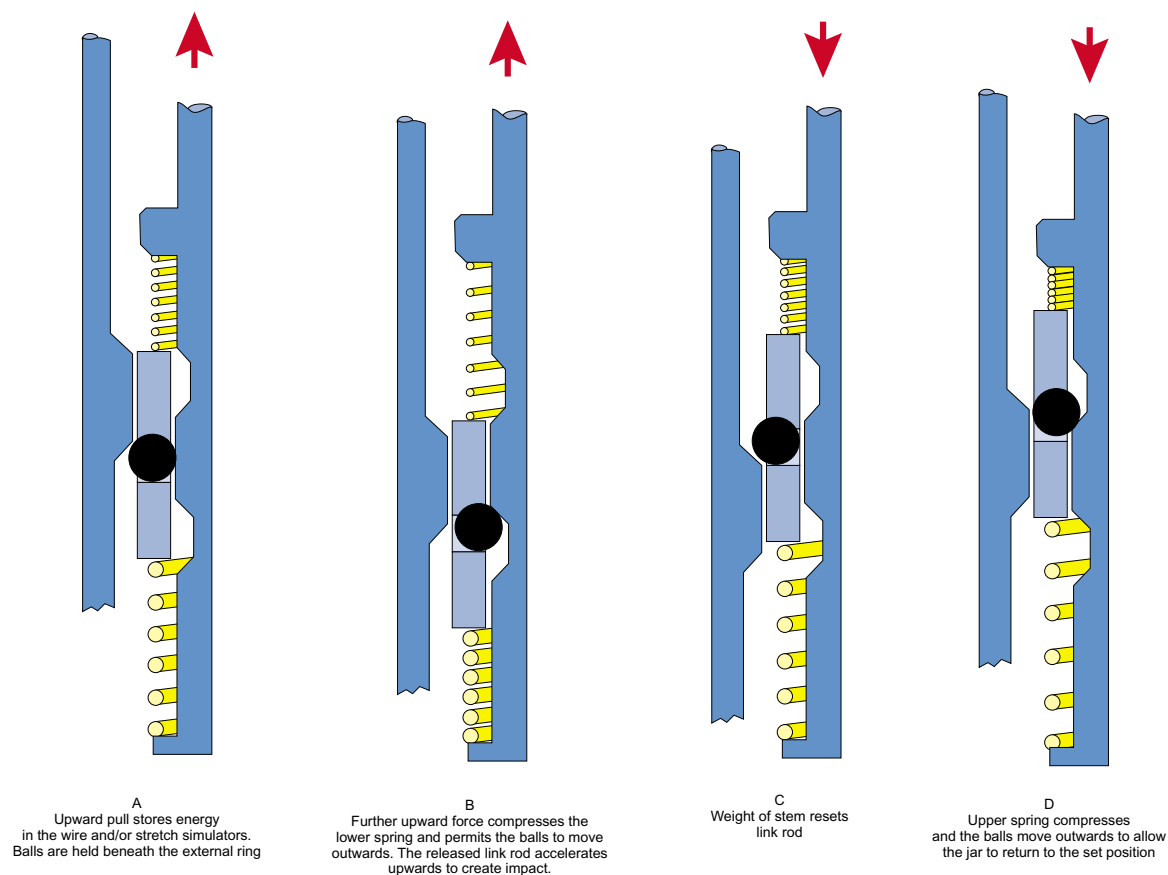


Figure 4-19: Flopetrol Upstroke Jar Operation

4.2.7

Accelerators

The accelerator is used in conjunction with the hydraulic or spring jar primarily, when unseating and retrieving heavy sub surface devices from shallow depths.

At shallow depths, the amount of stretch that could be pulled in the slickline to activate the hydraulic jar would be insufficient for good jar action. In addition, the resulting high load applied to the slickline at shallow depths may either break the slickline or pull it from the rope socket.

Installing an accelerator in the tool string between the rope socket and the stem (weight bars) allows the hydraulic jar to be used at shallow depths.

When a strain is pulled on the slickline, the spring in the accelerator is compressed over a given distance. The distance that the spring is compressed is greater than the distance that the mandrel and piston assembly of the hydraulic jar must travel when moving from the closed to open position. By maintaining a constant tension on the slickline, the compressed spring in the accelerator

tends to accelerate the upward speed of the mandrel and piston assembly of the hydraulic jar when it activates. This delivers an upward jarring impact to the tools below the hydraulic jar.

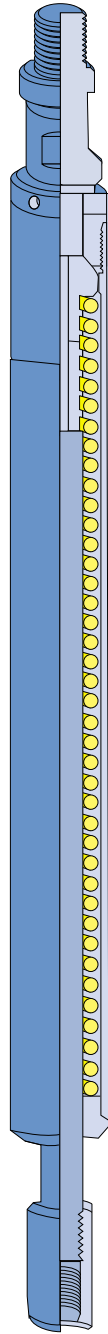
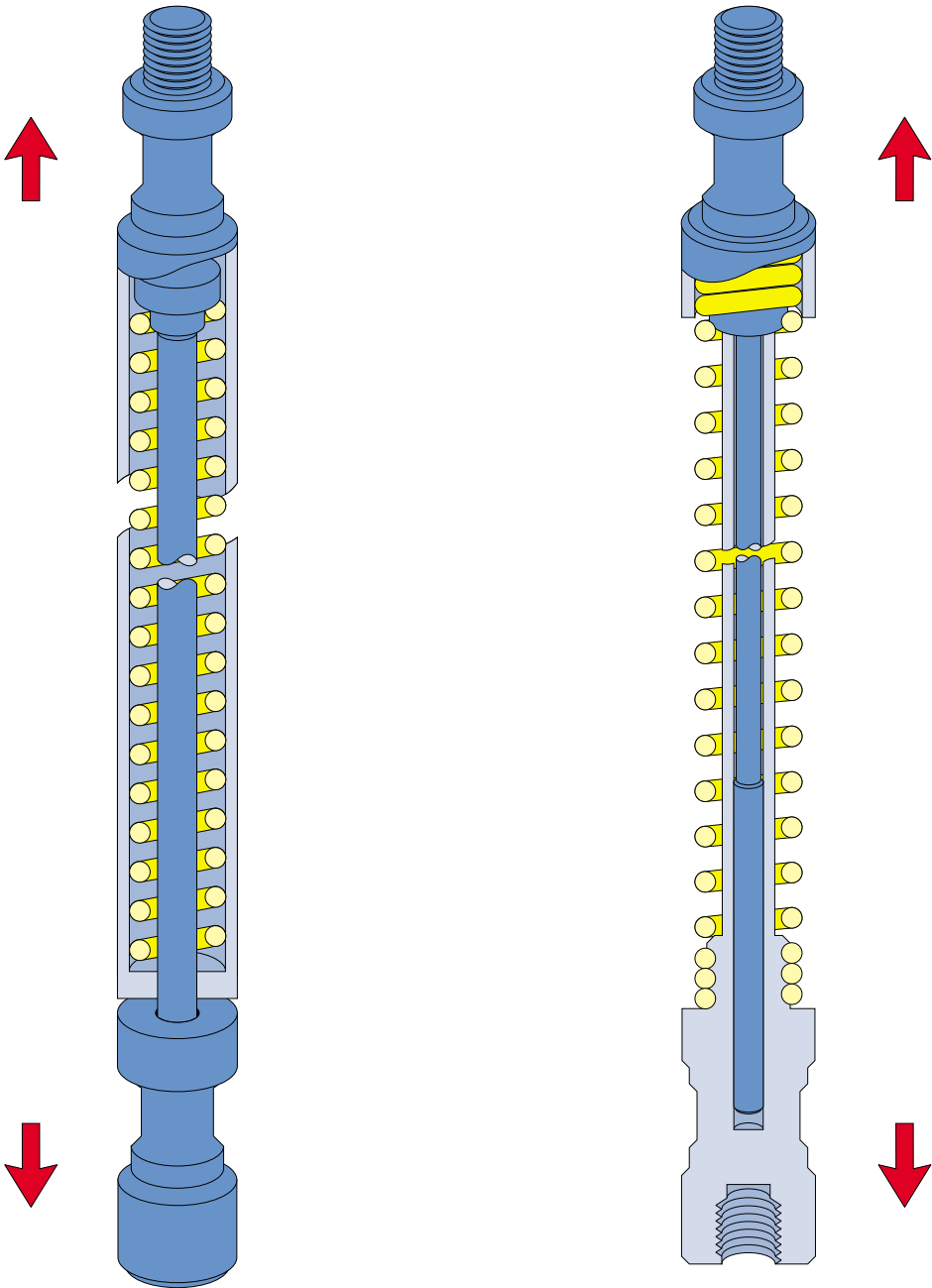


Figure 4-20: Otis Accelerator



2-3/8-in. Model

2-1/4-in. and 2-5/8-in. Models

Figure 4-21: Flopetrol Accelerators (Stretch Simulators)

Table 4-7: Flopetrol Accelerators - Technical Specifications

Technical Specifications			
	New Type Size External Spring	2 1/4 in. Internal Spring	2 3/8 in.** 2 5/8 in. External Spring

Part number	M-812918	M-807951	M-810769
Maximum OD	2.25 in.	2.36 in.	2.64 in.
Length	51.5 in.	59.8 in.	52.4 in.
Standard spring tension	400 lbf	400 lbf	1000 lbf
Pin/Box thread	15/16 in. - 10	1-1/16 in. - 10	1-1/16 in. - 10
Fishing head	1 $\frac{1}{4}$ in.	2-5/16 in.	1 $\frac{3}{4}$ in.
Adaptable upstroke jar	M-809695		M-810373

Table 4-8: Flopetrol Accelerators - Optional Parts

Optional Parts *			
	2 $\frac{1}{4}$ in.	2 $\frac{3}{4}$ in. *	2 $\frac{5}{8}$ in.
Size	External Spring	Internal Spring	External Spring
Assembling tool		M-807952	
Tension Spring			
200 lbf *	M-812919	M-810449	
Standard 400 lbf	M-812919	M-810336	
700 lbf *			M-810759
Standard 1000 lbf			M-810759
4-1** When combined with a Flopetrol upstroke jar, the stretch simulator 2 $\frac{3}{8}$ in. must be fitted with the appropriate spring.			

4.2.7.1

Heavy Duty Accelerators

A heavy-duty accelerator is recommended for use with spring jars when jarring at shallow depths.

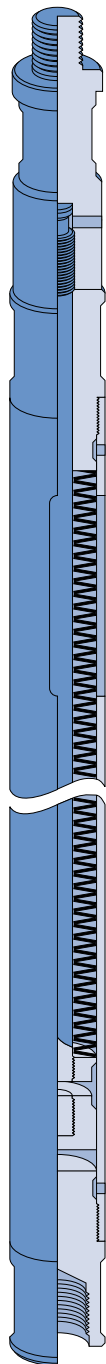
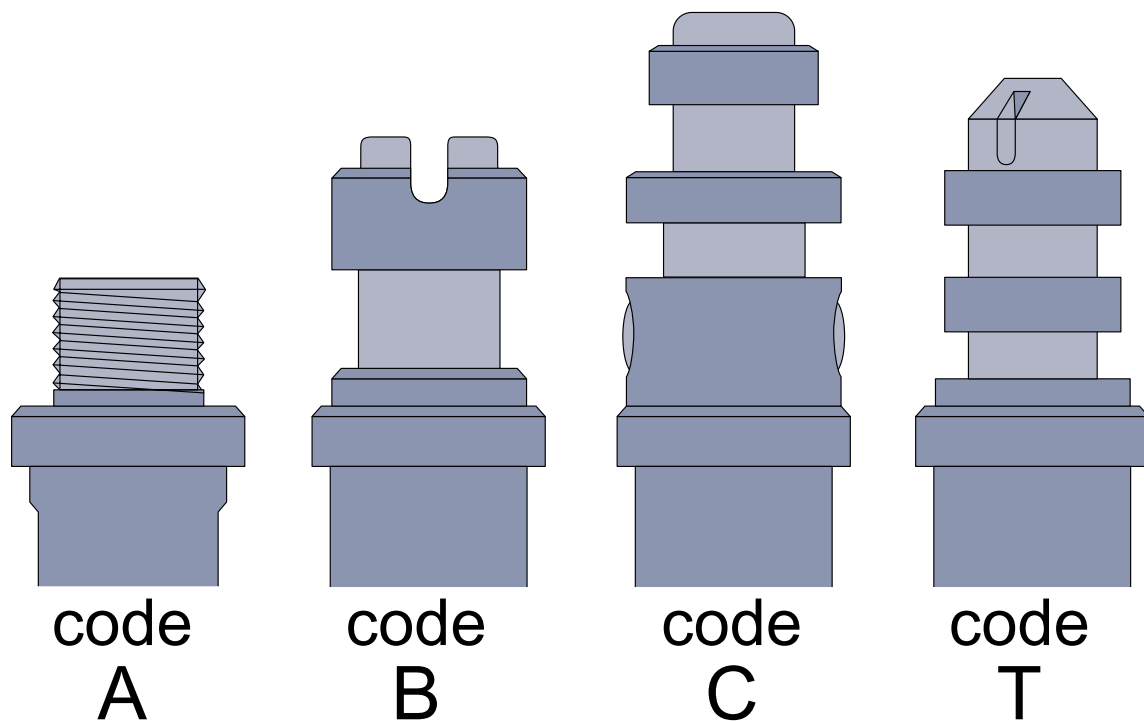


Figure 4-22: BDK Heavy Duty Accelerator



Connection options

Figure 4-23: BDK Heavy Duty Accelerator Connection Options

The slickline accelerator assembly is run just below the rope socket of the tool string. Upward tension on the slickline compresses the springs within the accelerator, storing energy. When the jar fires, the stored energy is released, increasing the impact of the jar at the fish.

Table 4-9: BDK Heavy-Duty Accelerator Basic Specifications

OD (in.)	Range (lbf)	Stroke (in.)	Assembly Number
1.500	160-1100	11.20	4748
1.875	400-3000	13.40	10722
2.125	400-3000	13.40	10908
2.500	1000-7000	16.00	10718

4.2.8 Tool String Connectors

4.2.8.1 Petroline Quick Lock Connector

The quick-lock connector provides a fast method of connecting tool string components. The components are pushed together and rotated 90°. Once engaged, the spring-loaded 'blade' prevents rotation and release. To release the connection, the blade is retracted by using a punch as shown or by hand on some designs and the male connection is then rotated 90° and released. The quick-lock provide several advantages:

- Speed of connecting the tool string assembly
- Rapid changing of the tools for each run
- Higher strengths than sucker rod connections
- Wrenches no longer needed to make up or break-out the tools, therefore no sharp burrs, damage to tools or risk of damage to hands
- Prevent possibility of unscrewing or release down hole

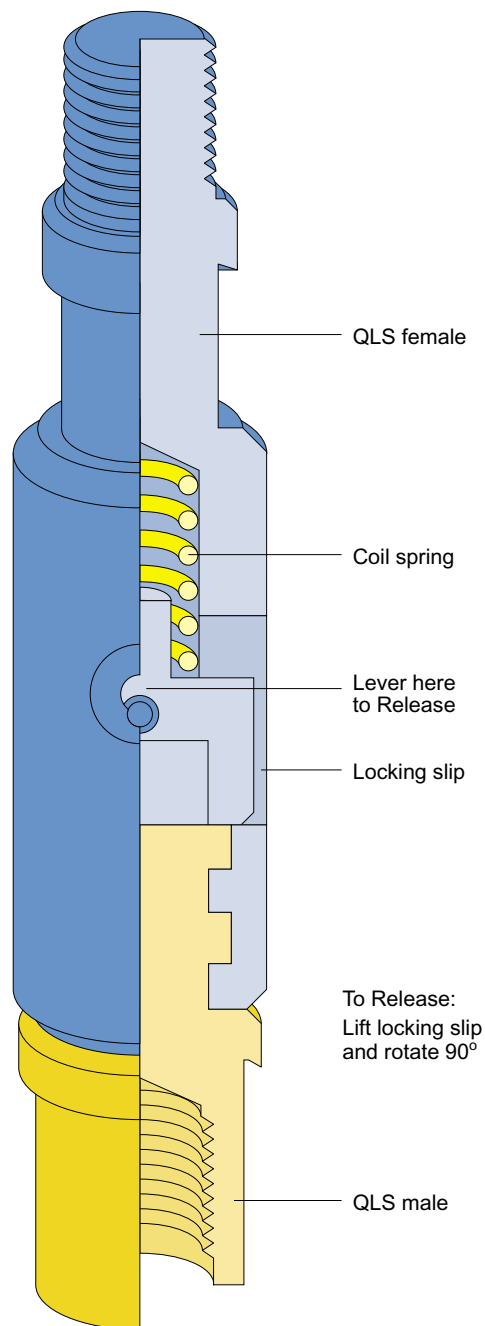


Figure 4-24: Petrolite Quick Lock Connector

4.2.8.2

BDK Quick Release Joint

The original BDK Quick Release Joint is a single shoulder contact connection designed as an alternative to a conventional threaded tool string. This offers the operator an increase in speed, efficiency and most of all, safety at the wellhead.

The QRJ is available to suit the following tool string sizes:

- $1\frac{1}{4}$ in.
- $1\frac{1}{2}$ in.
- $1\frac{7}{8}$ in.
- $2\frac{1}{8}$ in.
- $2\frac{1}{2}$ in.

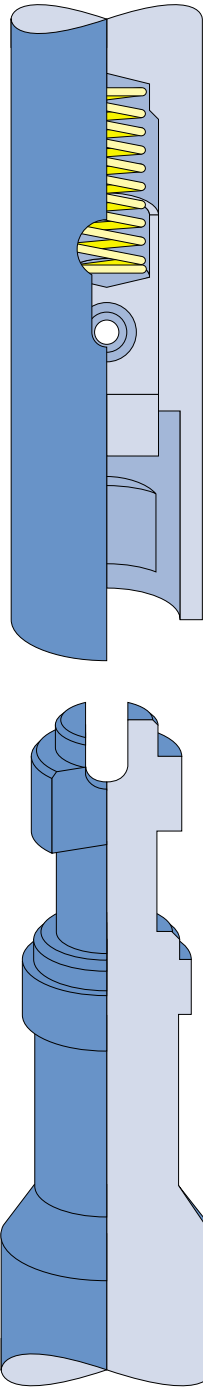


Figure 4-25: BDK Quick Release Joint

4.2.8.3 **BDK Trinity Quick Lock Connector**

The most striking feature of the Trinity quick lock connector is its unique triangular shape. The connection is held locked by the trigger plate and spring mounted perpendicular to the axis of loading, thereby protecting the mechanism from the effects of jarring.

The connector is very easily engaged due to its shape and requires only 60° of rotation to make up. Alignment marks are present to allow for easy disengagement.

The TQLC is available to suit the following tool string sizes:

- 1 $\frac{1}{2}$ in.
- 1 $\frac{7}{8}$ in.
- 2 $\frac{1}{8}$ in.
- 2 $\frac{1}{2}$ in.

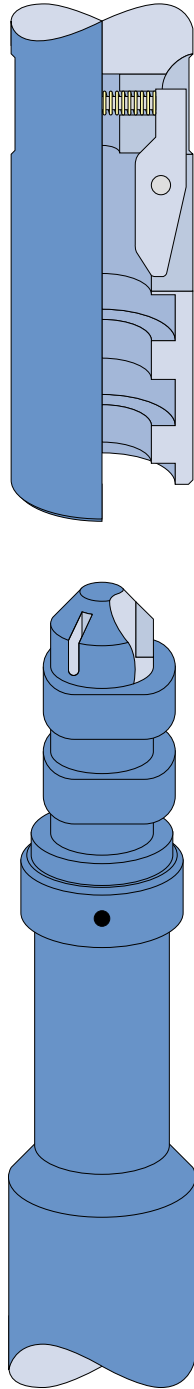


Figure 4-26: BDK Trinity Quick Lock Connector

4.2.8.4

BDK Heavy Duty Quick Release Joint

The BDK Heavy Duty Quick Release Joint is intended as an alternative to the original BDK Quick Release Joint. It has been developed for ultimate strength specifically for use in H₂S or CO₂ well environments.

The unique finger release feature eliminates the need for a release tool providing a connection, which is fast and simple to use.

The stepped double shoulder contact design is efficient and safe in comparison to the conventional threaded tool string, which can prove to be time consuming and sometimes hazardous during slickline operations, often leading to damaged tools or the possible risk of injury.

The HD QRJ is available in the following tool string sizes:

- $1\frac{1}{2}$ in.
- $1\frac{7}{8}$ in.
- $2\frac{1}{8}$ in.
- $2\frac{1}{2}$ in.

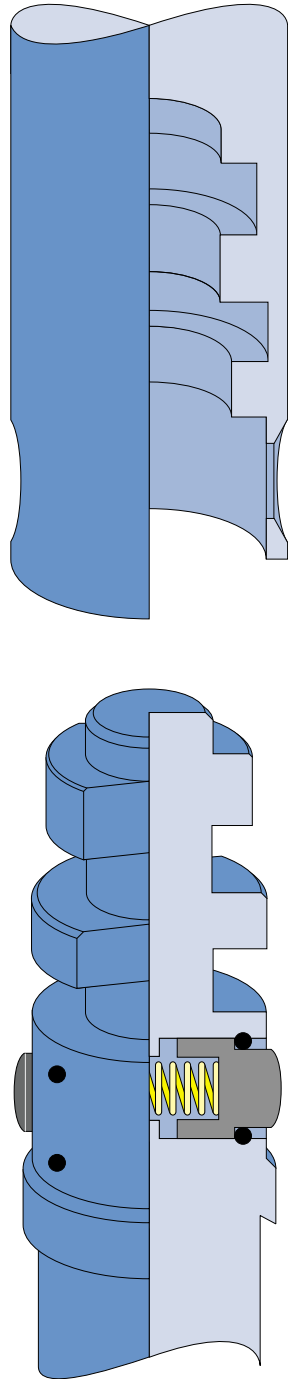


Figure 4-27: BDK Heavy Duty Quick Release Joint

4.2.9 Knuckle Joints

Knuckle joints are used to add flexibility to the tool string and are widely used in deviated wells. They are usually positioned immediately below the mechanical jars. However, if additional flexibility is required, a further knuckle joint can be included between the stem and jars.

Knuckle joints permit 15° of movement and should be used only when necessary. Excessive numbers of knuckle joints can reduce the effectiveness of downward jarring by allowing a sideways component of the force to be applied to the tubing wall.

Knuckle joints should be equipped with a fishing neck on the lower body to assist with recovery in the event the knuckle separates down hole.

The use of knuckle joints and swivels should not be confused. Swivels permit only limited movement and are equipped with a bearing to allow easy rotation even when under tension. Knuckle joints should not be used in place of swivels. If the line breaks, latching a rope socket with a knuckle joint leaning against the tubing wall can be very difficult.

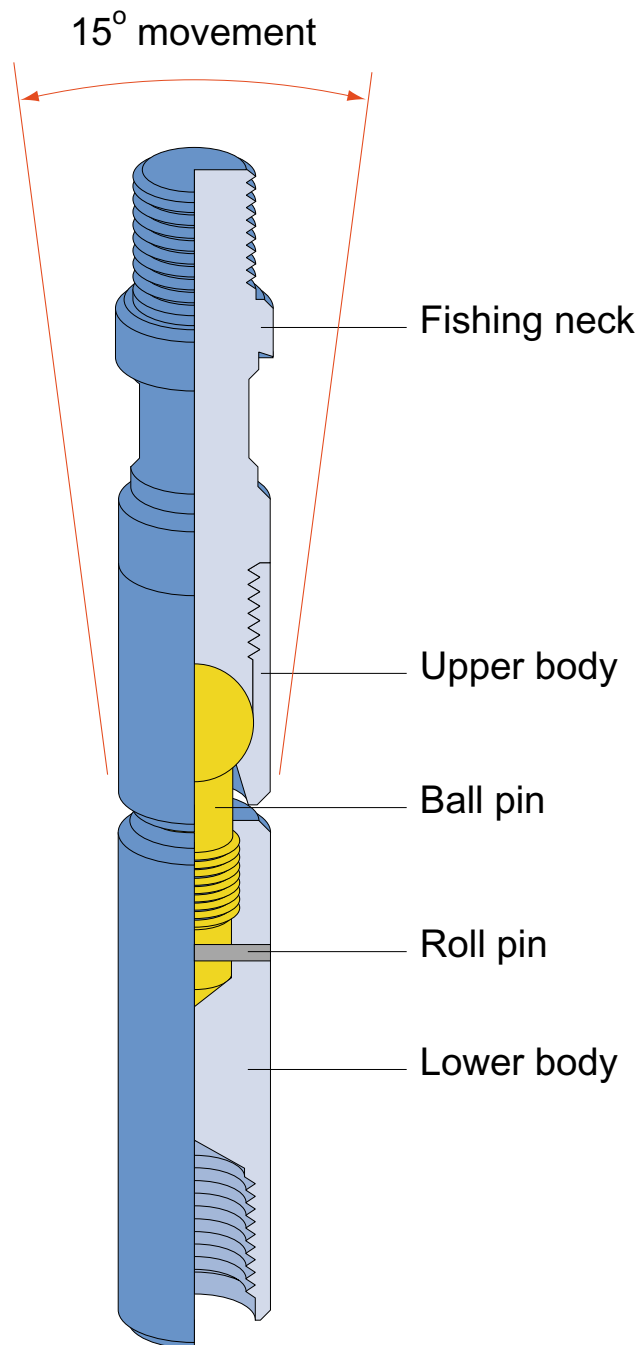


Figure 4-28: Knuckle Joint

4.2.10 Tool String Preparation

It is expected that slickline tools and equipment will sustain some wear or damage during use, however, it is essential that corrective action is taken to prevent any tools in a badly worn or damaged state being used. All tools and down hole equipment should be inspected and tested in base workshops before issue. However, they must also be thoroughly inspected on site before and after use.

Before assembling a tool string, the following checks should be carried out:

- Inspect the rope socket for burrs around the wire hole, which could damage the wire.
- Inspect all box and pin threads or quick connections for damage.
- Inspect the fishing neck profiles for burrs and wrench damage.
- Inspect the mechanical jars for buckling, bending, bowing, and check for smooth operation.
- Check the hydraulic jars for leaks and correct operation.
- Check the spring jars for operation (with hydraulic test sub) and set the release point required.
- Check the integrity of the roll pins in the knuckle joints, and freedom of movement of the ball in the socket.
- Check the swivel joint rotation action and any roll pins.
- Check all the tool operations on the surface, i.e., remove the shear pins and check the movement.

Intentionally Blank

5 Standard Service Tools

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5 STANDARD SERVICE TOOLS

5.1 Downhole Tools

5.1.1 Gauge Cutter

It is good operating practice to run a gauge cutter before starting any operation in a well. A gauge cutter run is used to:

- Check the tubing ID
- Tag and confirm the total depth
- Locate the nipple ID restrictions and no-gos
- Locate general restrictions in the completion string
- Cut sand, scale, paraffin and other deposits from the tubing wall
- Determine the profile of a bridge by successively running smaller cutters and plotting the depth, versus the size to establish the shape of restriction

When selecting the size of the gauge cutter, carefully consider the ID you wish to locate and the dimensions of any restrictions through which the cutter must pass.

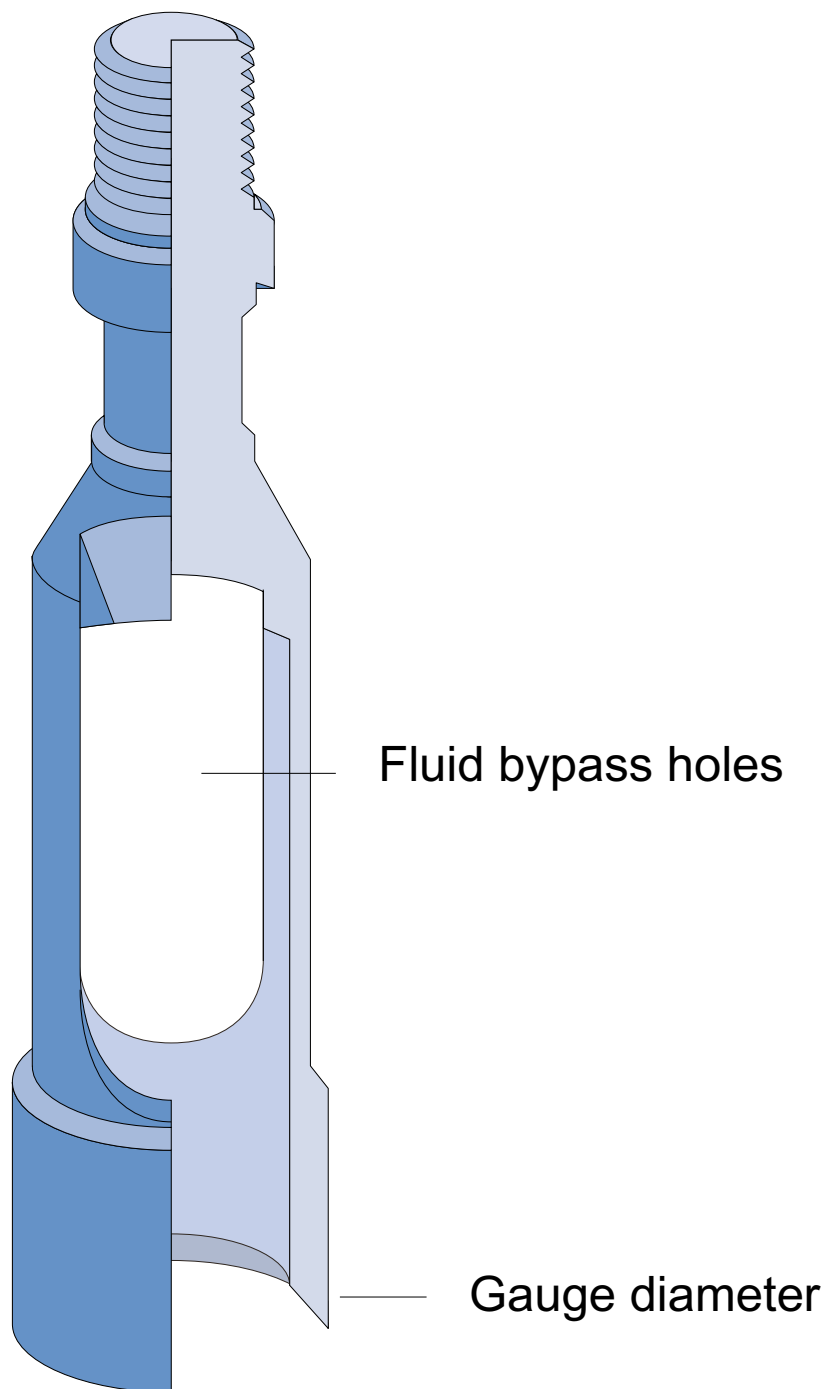


Figure 5-1: Gauge Cutter

5.1.2

Blind Box

The blind box is used when heavy downward jarring is required to dislodge a fish or push something down the hole. It is flat on the bottom and hardened to reduce wear and damage.

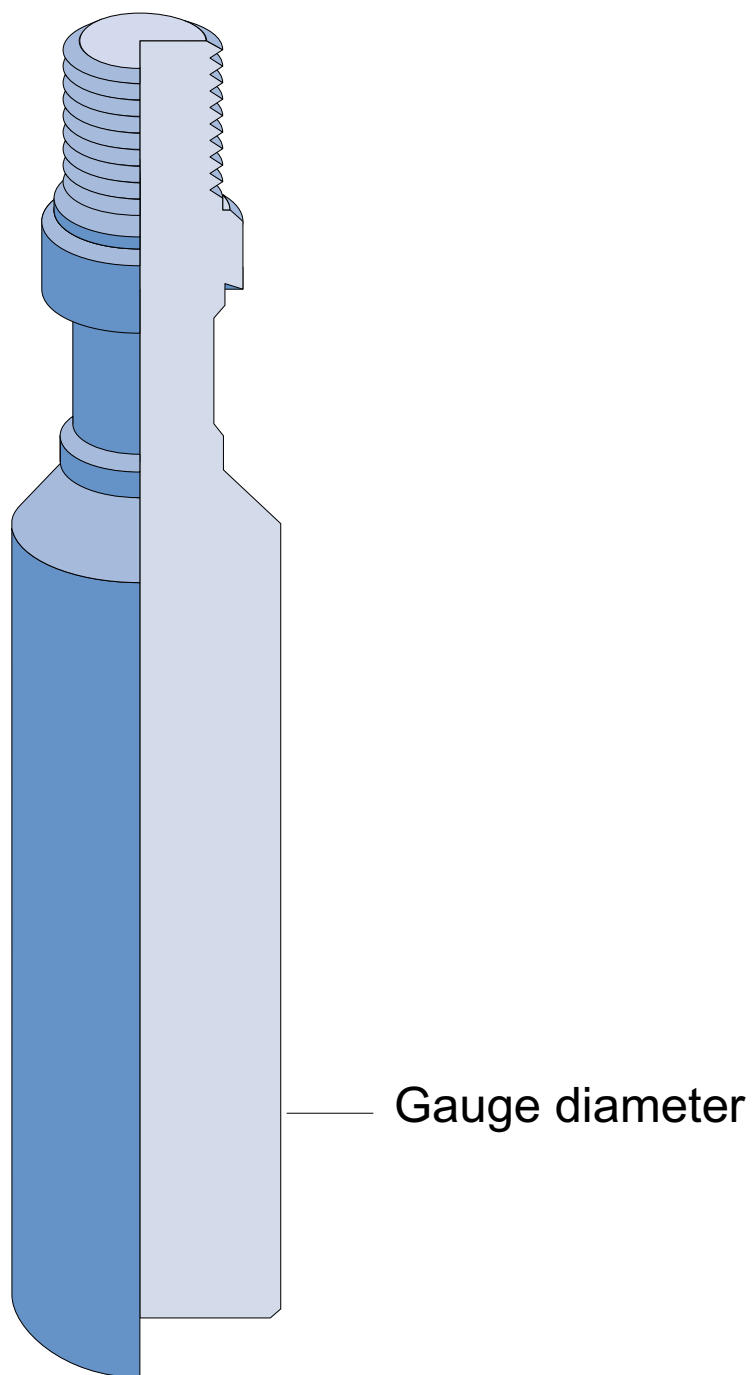


Figure 5-2: Blind Box

Blind boxes are available in a range of sizes to suit the application and dimensions of the completion through which it is to be run.

When used as a cutter bar, it is made up below some stem and a rope socket then dropped in the well bore to cut wire down hole.

5.1.3 Impression Block

The impression block or lead impression block (LIB) is similar in appearance to the blind box, but it is filled with lead. The lead is keyed in position by a roll pin or a hex headed bolt that is installed prior to pouring molten lead inside the housing.

The impression block is used to obtain a picture (impression) of the component creating the down hole blockage or obstruction. The information gained is used in selecting an appropriate fishing tool assembly.

To prepare the impression block, roughly flatten the lead face with a hammer, then smooth with a course rasp. Finish with a smooth file and a piece of steel shear stock rubbed across the face to give a polished surface.

There should be no indentations in the surface prior to running and a check should be made to ensure there are no overlapping edges that may hang up in the collars when pulling out and dislodge or distort the lead.

When refilling the impression block, always melt the previous lead out and replace in a continuous pour. Stopping and restarting will create a weak flaw, which could separate down hole.

In operation, the impression block should be positioned on the obstruction and one jar down only applied to obtain one clear image. Subsequent jarring may cause multiple impressions that will confuse the image.

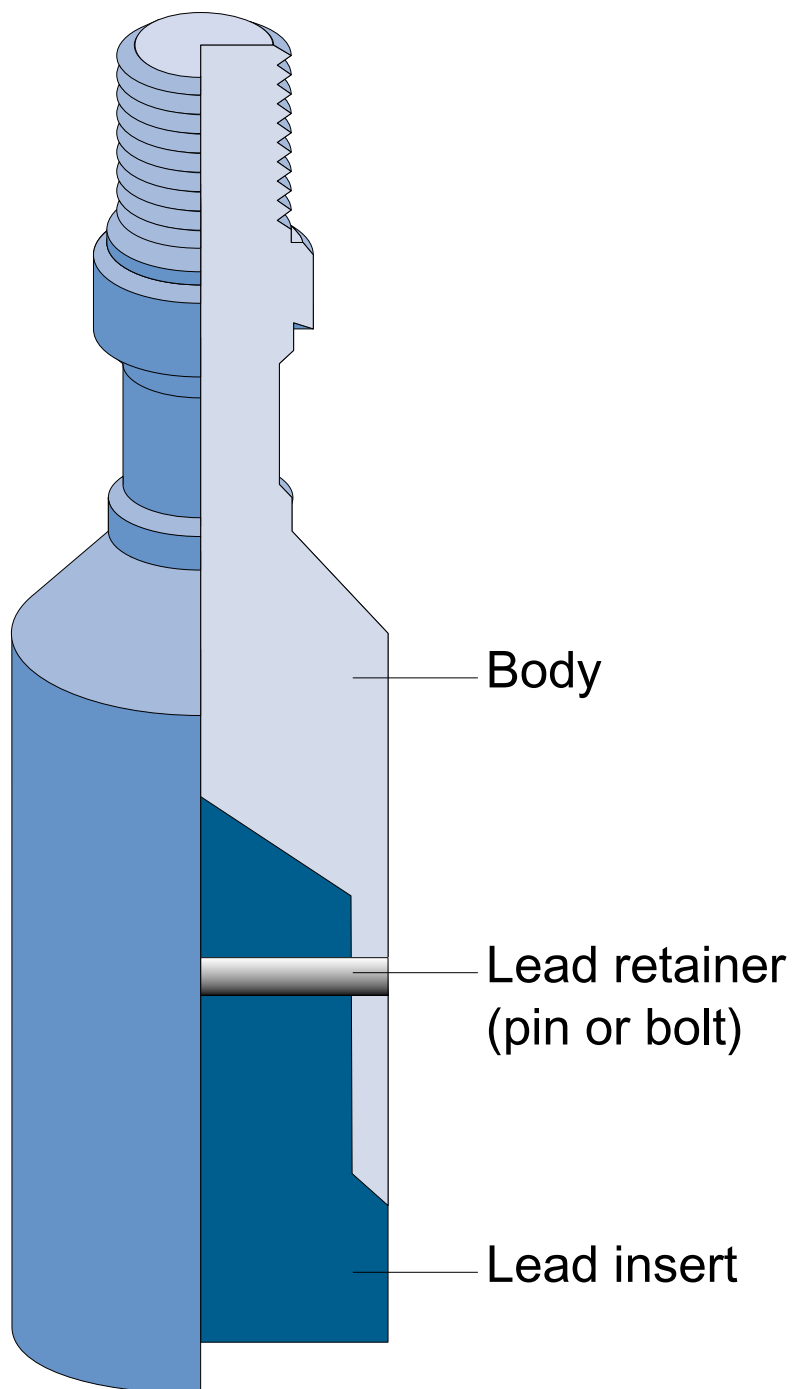


Figure 5-3: Impression Block

5.1.4 Swaging Tool

A swaging tool is used to restore lightly collapsed or distorted damage to the tubing string. The OD of the swage should be equal to the tubing drift. To operate the swage, down-jars are required to force the swage through the tubing damage. To ensure recovery of the tool string, up-jars should also be included in the event the swage becomes jammed.

The fluid bypass hole permits the passage of fluid when the OD of the swage fills the tubing ID.

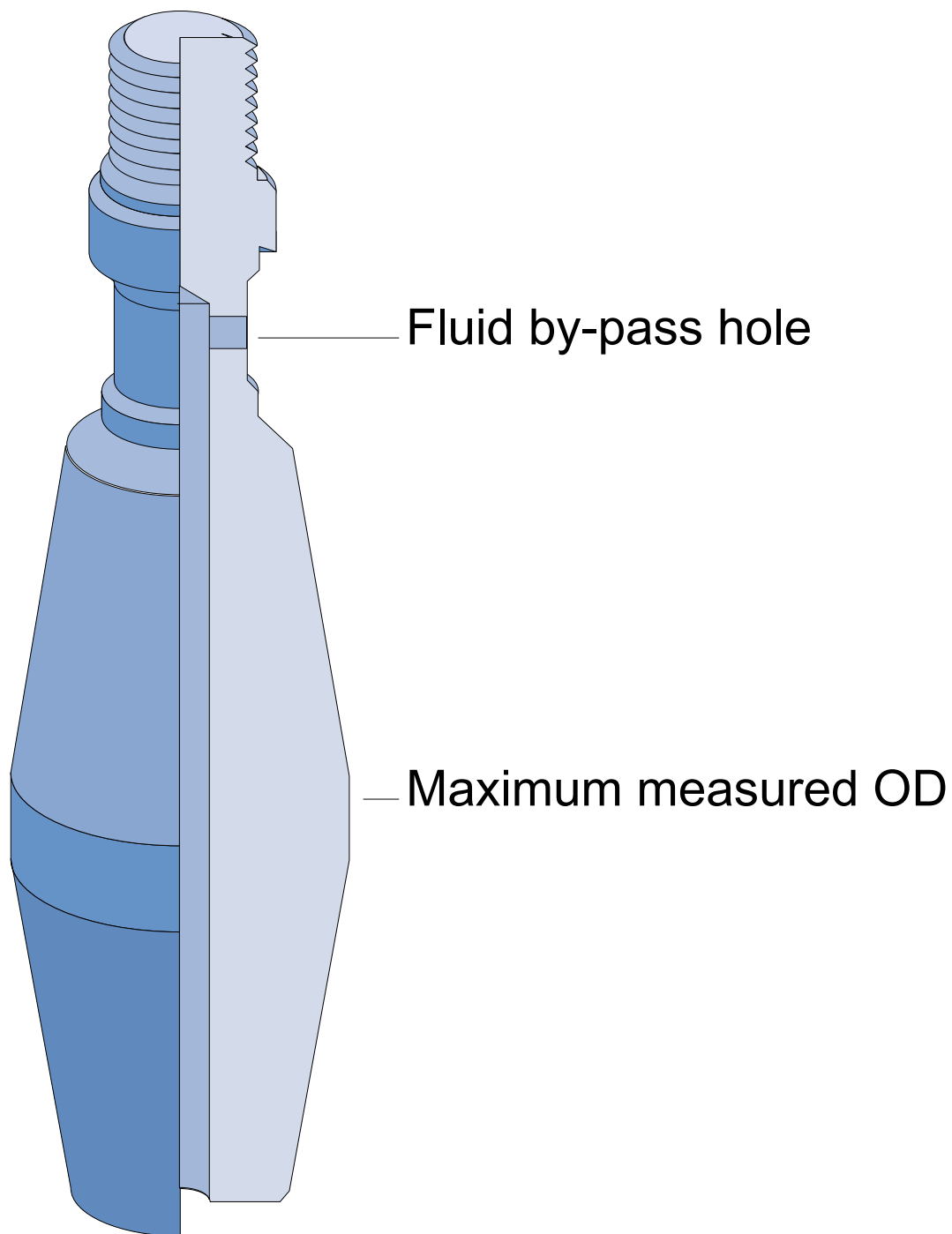


Figure 5-4: Swaging Tool

5.1.5

Wire Scratcher

A wire scratcher is used to remove soft paraffin or scale deposits from the ID of the tubing, nipple profiles or completion equipment.

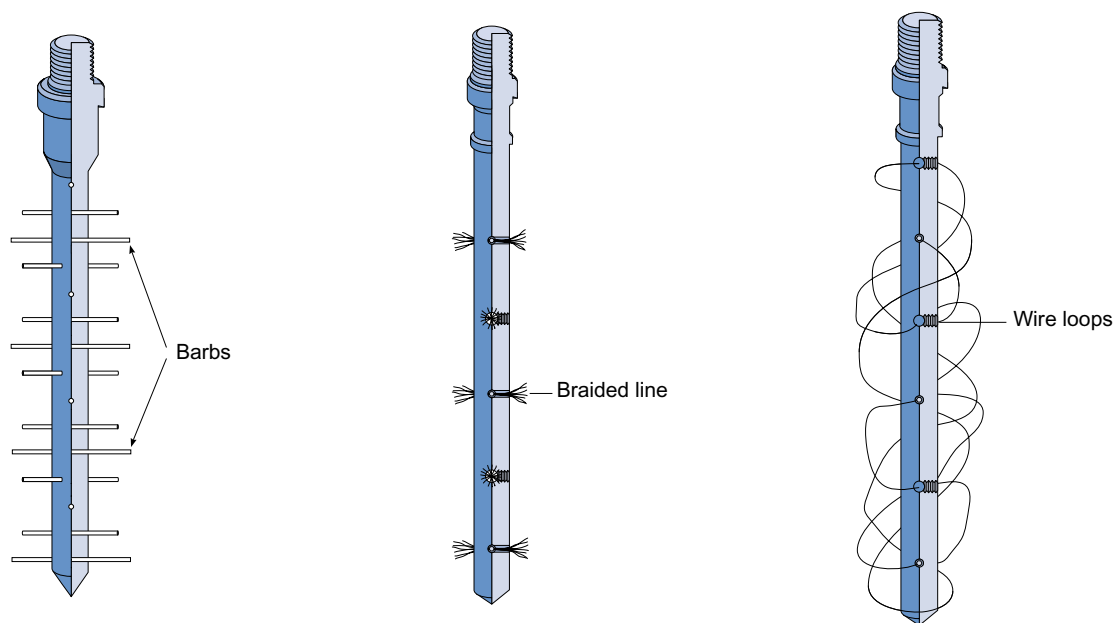


Figure 5-5: Wire Scratchers

5.1.6

Tubing End Locator

The tubing end locator is used to locate the end of the tubing string to provide a cross-reference or correlation check of the tool string depth against known tubing depth references. The end locator is also used to correlate the tag sand depth accurately from the bottom of the tubing (depth known from completion records).

The tool may be fitted with more than one shear pin position to enable the same tool to be run in different size tubing strings. Since the tool operates on a one-shot basis, care should be taken to ensure the pin is not accidentally sheared, e.g., take care pulling the tubing end locator up into the lubricator.

After the tubing end locator is started in the hole, it must be run out the bottom of the tubing string, so that the loaded finger trips to the horizontal position. Pick-up to tag the tubing end and obtain the tubing end depth reference. A subsequent jar-up action shears the 3/16 in. brass pin below the finger and allows the tool to be removed from the well bore.

**Note**

Run a gauge cutter first to ensure the tubing string is clear. If the tubing end locator has to be pulled up with the finger in the running position, it may catch in the tubing or a collar. Continued upward movement in this situation will shear the pivot pin and drop the finger and spring. In some cases, the finger has damaged or punctured the tubing.

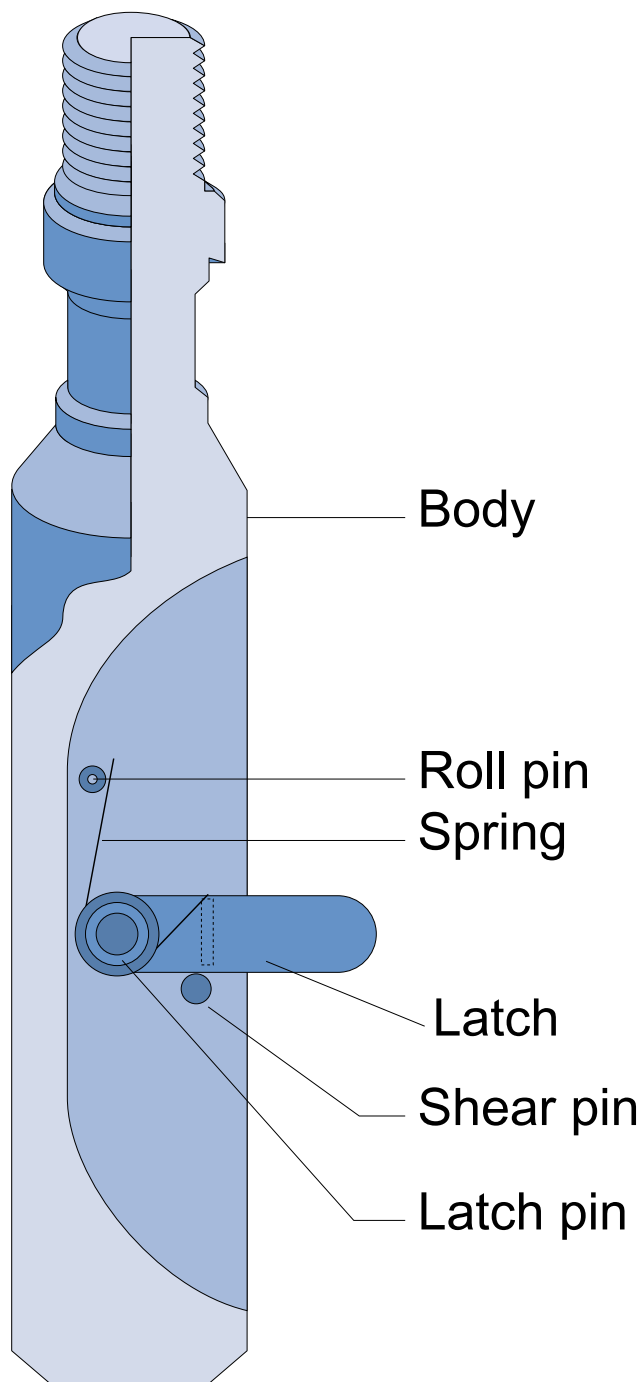


Figure 5-6: Tubing End Locator

5.2 Pulling Tools

Pulling tools are designed to remove various items of completion or subsurface equipment from the well bore.

A standard or compatible fishing neck profile is required for the pulling tool to engage properly on the tool or equipment to be removed. If it is impossible to retrieve the equipment, the pulling tool can be released by shearing a pin enabling the tool to be released and retrieved to surface.

Pulling tools may be designed for either external or internal fishing necks and may be equipped with jar up or down, release mechanisms. Tool configuration examples are shown in .

Table 5-1: Standard Pulling Tool Operation

Direction of Jar Action	Fishing Neck Profile	Compatibility
UP	External	Otis RB, RS/Camco JUC, JUS
DOWN	External	Otis SB, SS/Camco JDC, JDS
UP	Internal	Otis GR
DOWN	Internal	Otis GS/Camco PRS

Pulling tools have uniquely shaped dogs, therefore, a Camco pulling tool should not be used to fish Otis or Bowen equipment and vice versa. Damage to the fishing neck and pulling tool dog can result.

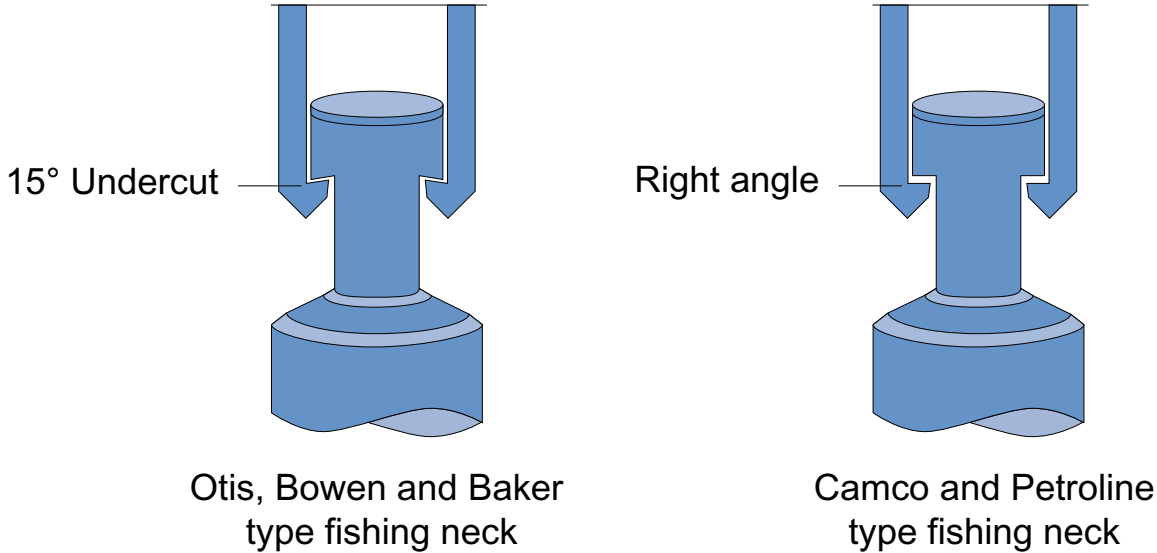
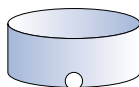


Figure 5-7: Common Fishing Neck Profiles

It is essential that the operator select a tool which shears in the direction opposite to which jarring is required, to achieve movement down hole. For example, if jar-down action is required to unlock the mandrel, so then a jar-up shear tool must be used.

Consequently, the slickline operator must be able to immediately identify a tool's shear direction. As an aid, these features should be remembered to differentiate between R and S series tools. The construction of pulling tools vary internally.

- **R Series Tools** - The core is attached to the top sub and the skirt is pinned to the core
- **S Series Tools** - The skirt is attached to the top sub and the core is pinned to the skirt



Ring on R series tools



Sleeve on S series tools

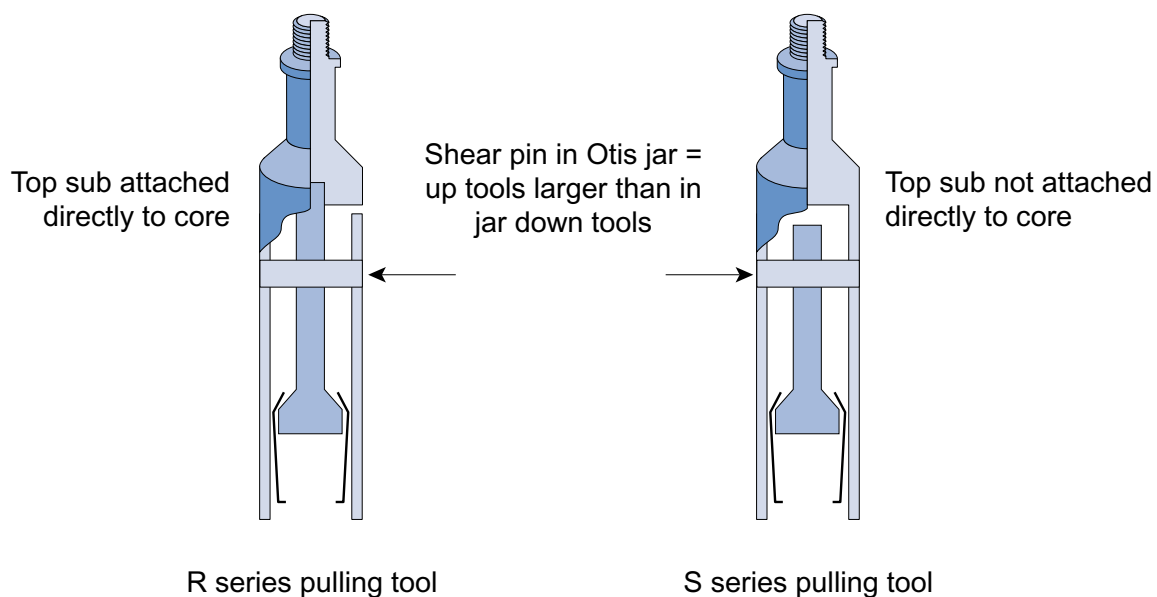


Figure 5-8: Type R and S Pulling Tool Configurations

5.2.1 R Series Pulling Tools

The R series of pulling tools are designed to engage an external fishing neck and shear to release by an upward jar action.

The R pulling tool is used in three different versions or types, which are types RB, RS and RJ. The difference in the three types is only in the length of the core, which is installed in the tool. The type RB used the longest core, the type RS uses the intermediate length core and the type RJ the shortest core.

The length of the core determines the reach of the pulling tool. Reach is the distance from the lower end or face of the core, down to the engaging shoulder at the lower end of the pulling tool dogs. Therefore the types RB pulling tool, which has the longest core, would have the shortest reach and the type RJ pulling tool with the shortest core would have the longest reach. Any one of these 3 tools (type RB, RS, or RJ) may be changed to either of the 2 other types simply by changing the core. All other parts of the 3 types of tools are identical and are completely interchangeable.

The type of lock mandrel or other down hole device to be retrieved will determine which type of pulling tool must be used. The required type of pulling tool will be shown in the relevant section for each type of equipment shown elsewhere in this book. Most of the locking mandrel will require a specific type of pulling tool and no other pulling tool should be used. Be sure of the proper type of pulling tool before attempting to latch and retrieve any lock mandrel.

All shear-up pulling tools have a larger shear pin than the equivalent shear down tool.

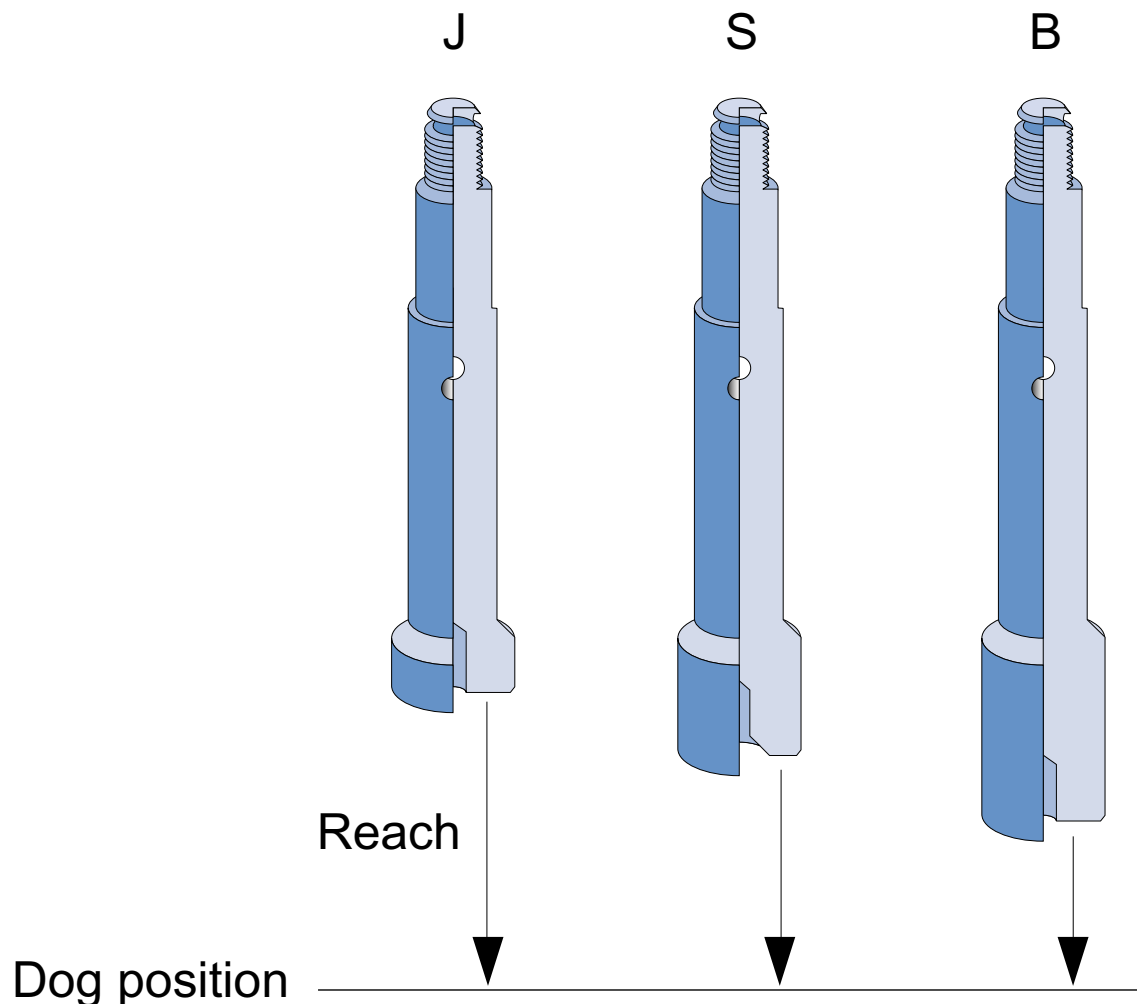


Figure 5-9: R Series Pulling Tool Core Configurations

5.2.1.1

Principle of Operation

The pulling tool is attached to a standard slickline tool string and lowered into the well. Upon contact with the control device, the lower portion of the cylinder passes over the fishing neck or pulling flange because of the force of the dog spring. Upward impact of the jar is utilized to pull the control device from the well.

The shear pin should withstand considerable jarring before shearing. When the pin shears, the force in the cylinder spring acts between the sub and cylinder then moves the core up in the cylinder. This moves the dogs upward against the force of the dog spring. As the dogs move upward their tapered upper ends move into the cylinder forcing the dogs inward, thereby forcing the dogs lower end outward. This causes the dogs to release their grip on the pulling flange.

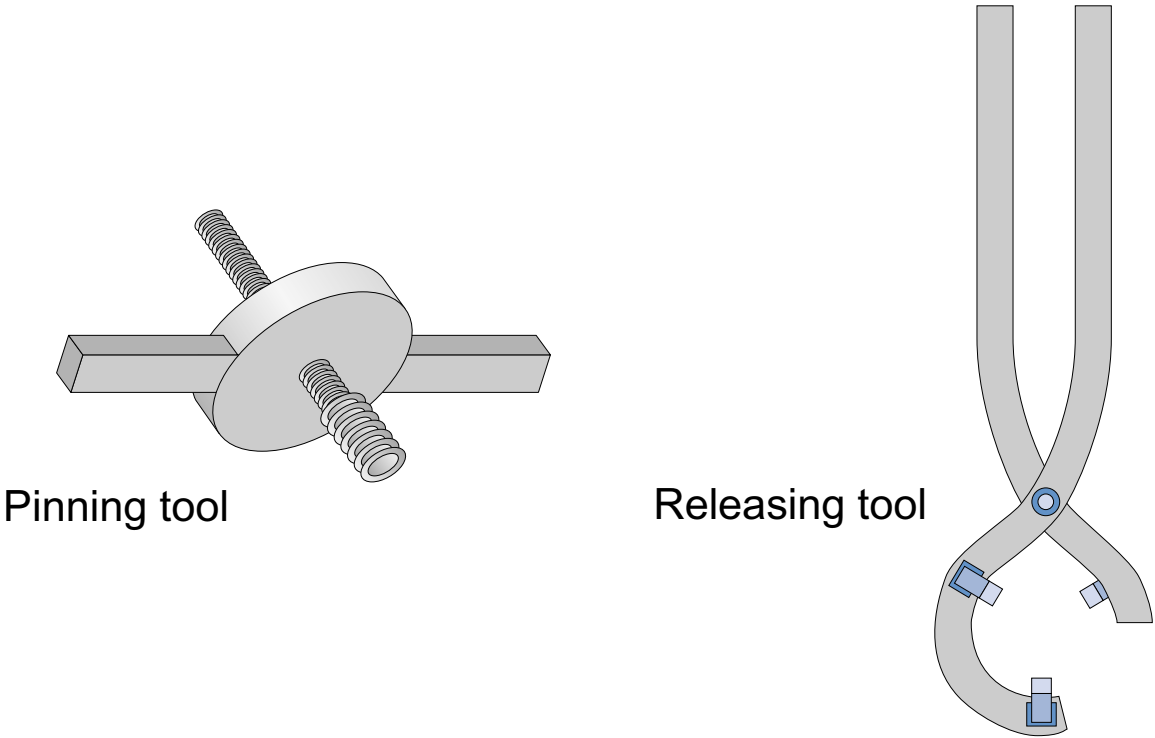
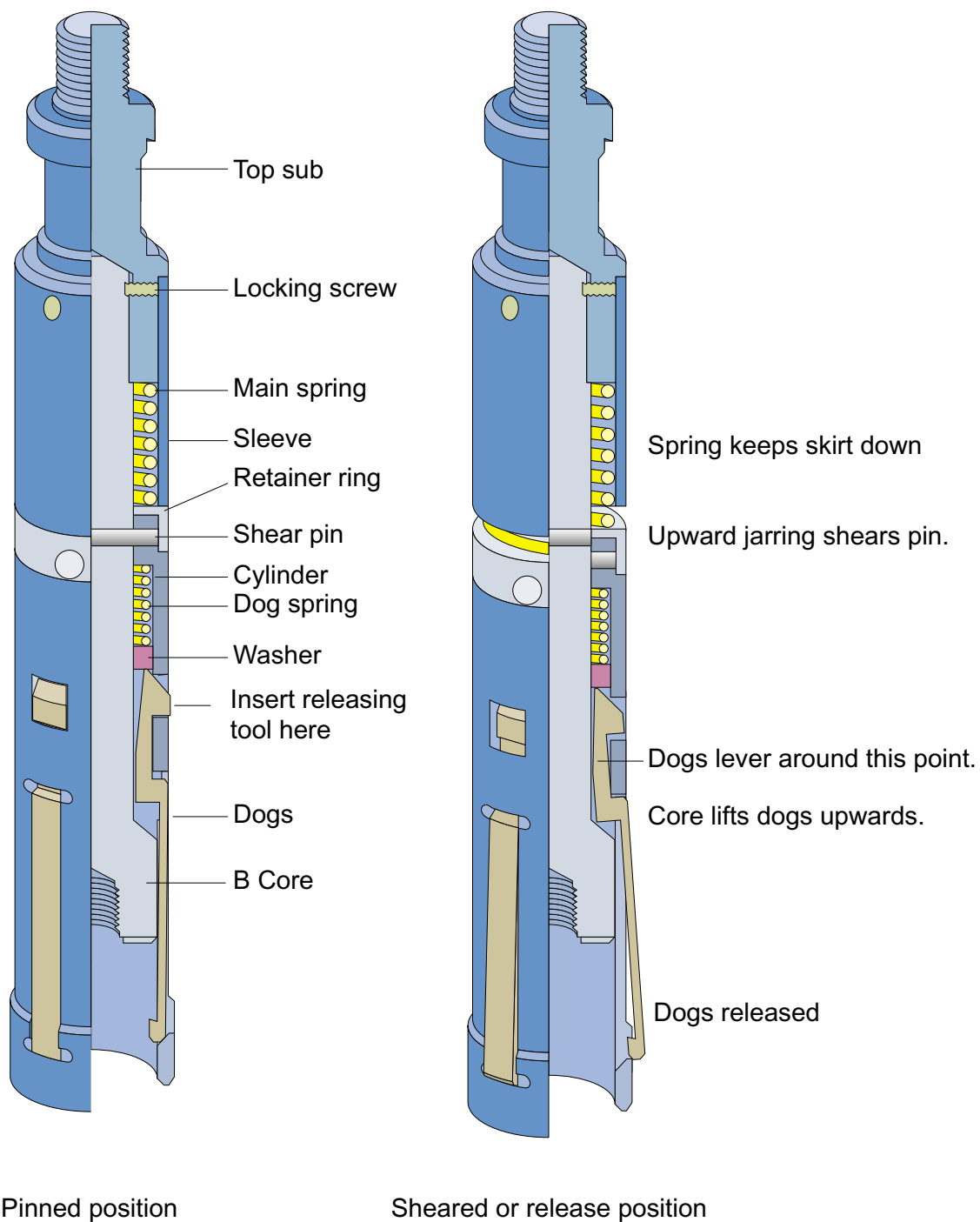


Figure 5-10: R Series Pulling Tool Pinning and Release Tools

Table 5-2: R Series Tool General Specification

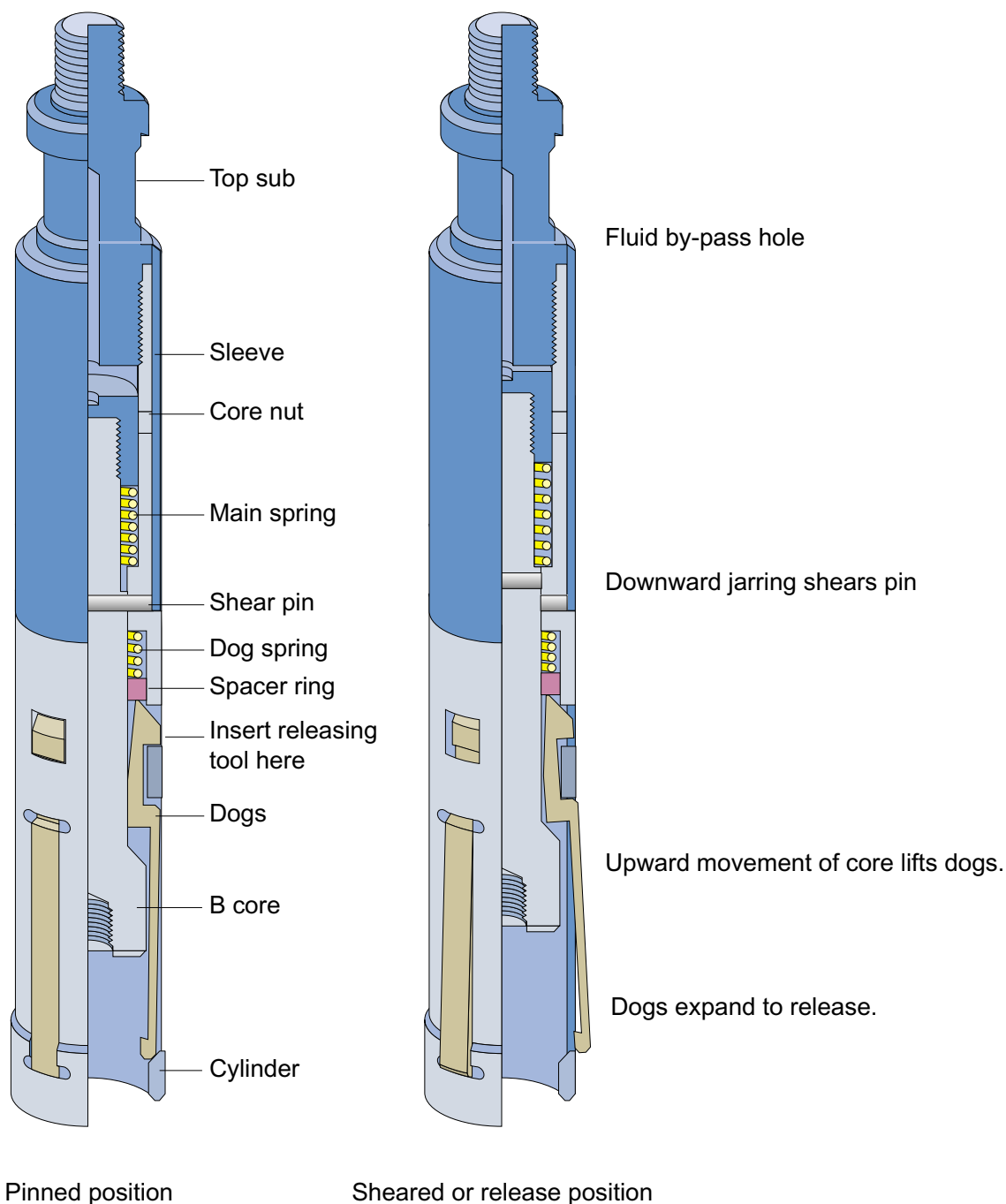
	Part No.	Size (in.)	OD (in.)	Fish Neck (in.)	Will Latch (in.)	Top Thread	Shear Pin (in.)	Reach (in.)
RB	40RB14	1½	1.430	1.187	1.187	15/16 - 10	¼	1.219
	40RB1	2	1.770	1.375	1.375	15/16 - 10	5/16	
	40RB18	2½	2.180	1.375	1.750	15/16 - 10	5/16	
	40RB19	3	2.740	2.313	2.313	1 15/16 - 10	¾	
RS	40RS5	1½	1.430	1.187	1.187	15/16 - 10	¼	1.797
	40RS6	2	1.770	1.375	1.375	15/16 - 10	5/16	1.984
	40RS7	2½	2.180	1.375	1.750	15/16 - 10	5/16	1.984
	40RS9	3	2.740	2.313	2.313	1-15/16 - 10	¾	1.190



Pinned position

Sheared or release position

Figure 5-11: RB Pulling Tool



Pinned position

Sheared or release position

Figure 5-12: SB Pulling Tool**5.2.2****S Series Pulling Tool**

The S series of pulling tools are jar-down to shear and are designed to pull equipment by jarring up or to run and release equipment by jarring down.

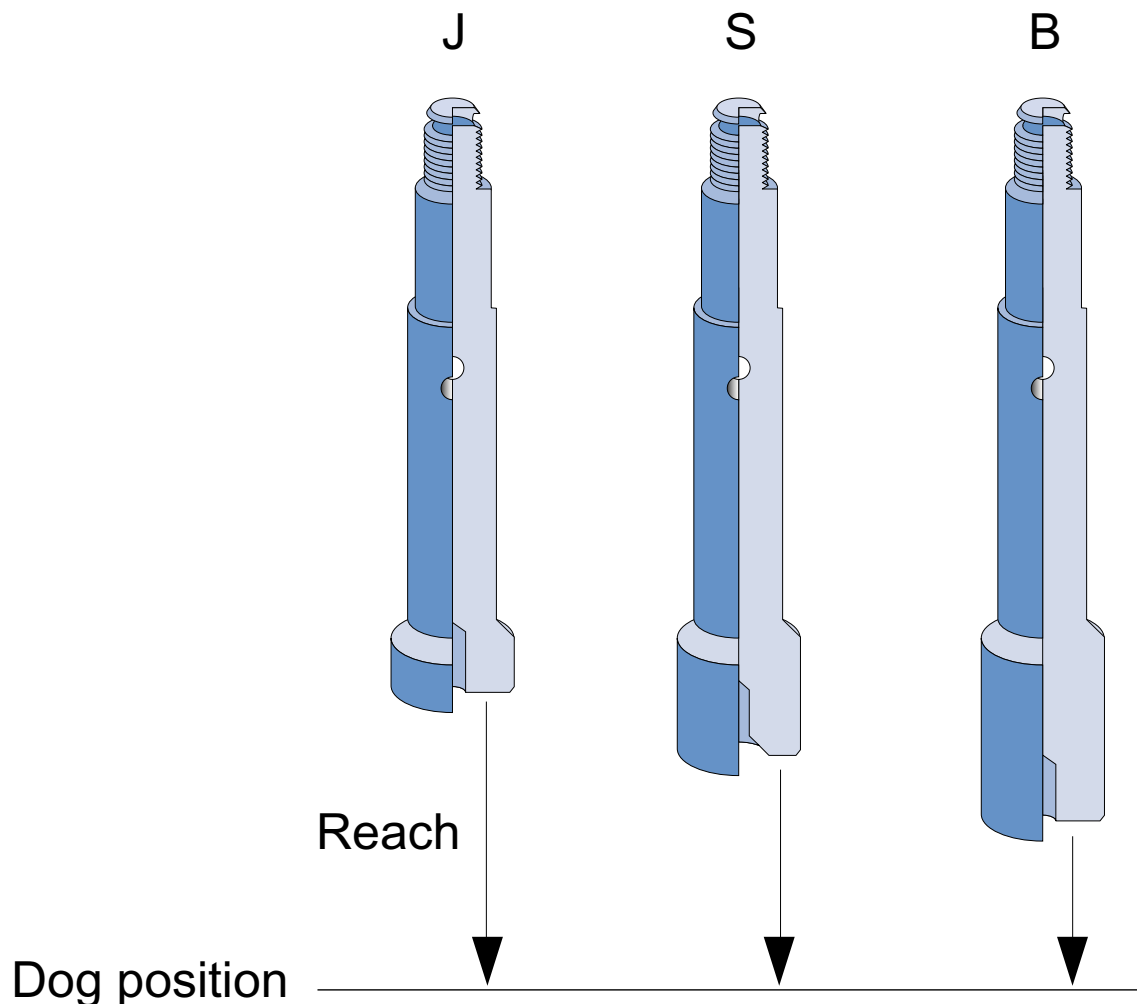


Figure 5-13: S Series Pulling Tool Core Options

Always check that the item to be released has sufficient clearance on the skirt to move the core upwards fully. Failure to check this may result in the tool not releasing fully.



Note

The shear pin in shear down tools is smaller than the equivalent in shear up tools.

The S series of tools uses the same releasing and pinning tools as the R series.

Table 5-3: S Series Pulling Tool General Specification

	Part No.	Size (in.)	OD (in.)	Fish Neck (in.)	Will Latch (in.)	Top Thread	Shear Pin (in.)	Reach (in.)
SB	40SB6	1 $\frac{1}{2}$	1.437	1.187	1.187	15/16 - 10	3/16	1.297
	40SB1	2	1.766	1.375	1.375	15/16 - 10	$\frac{1}{4}$	1.219
	40SB2	2 $\frac{1}{2}$	2.188	1.375	1.750	15/16 - 10	$\frac{1}{4}$	1.281
	40SB9	3	2.734	2.313	2.313	1-15/16 - 10	5/16	1.380
SS	40SS3	1 $\frac{1}{2}$	1.430	1.187	1.187	15/16 - 10	3/16	1.780
	40SS1	2	1.770	1.375	1.375	15/16 - 10	$\frac{1}{4}$	2.030
	40SS2	2 $\frac{1}{2}$	2.180	1.375	1.750	15/16 - 10	$\frac{1}{4}$	2.000
	40SS4	3	2.840	2.313	2.313	1-15/16 - 10	5/16	2.210
SM	40SM7	1.66	1.187	0.875	0.875	16/16 - 10	3/16	1.680

The SSJ double shear down adapter is designed to be added to an S series pulling tool when a J (long reach) core is fitted.

The SSJ combination is the correct running tool for the N and Q test tools, X selective tools and PX test tool, because:

- The long reach core permits the dart (fishing neck) of the test tool to float upwards off the scaling seal to provide fluid bypass. This is essential to permit the test tool to pass through the nipple seal bore of the same size as the V-packing.
- Downward jarring force is between the skirt and top sub of the test tool, and not absorbed against the dart or seal surface.

The SSJ adapter permits the S tool to be sheared by jarring downwards on either the core or skirt. The core on the SB and SS tools must have contact to enable the pin to be sheared.

The SSJ combination is easier to re-pin and can also be added to S series tools with B and S type cores, i.e., SSB and SSS combinations.

**Note**

It is essential to remove the shear pin from the S tool core. Failure to do this will prevent the tool from shearing.

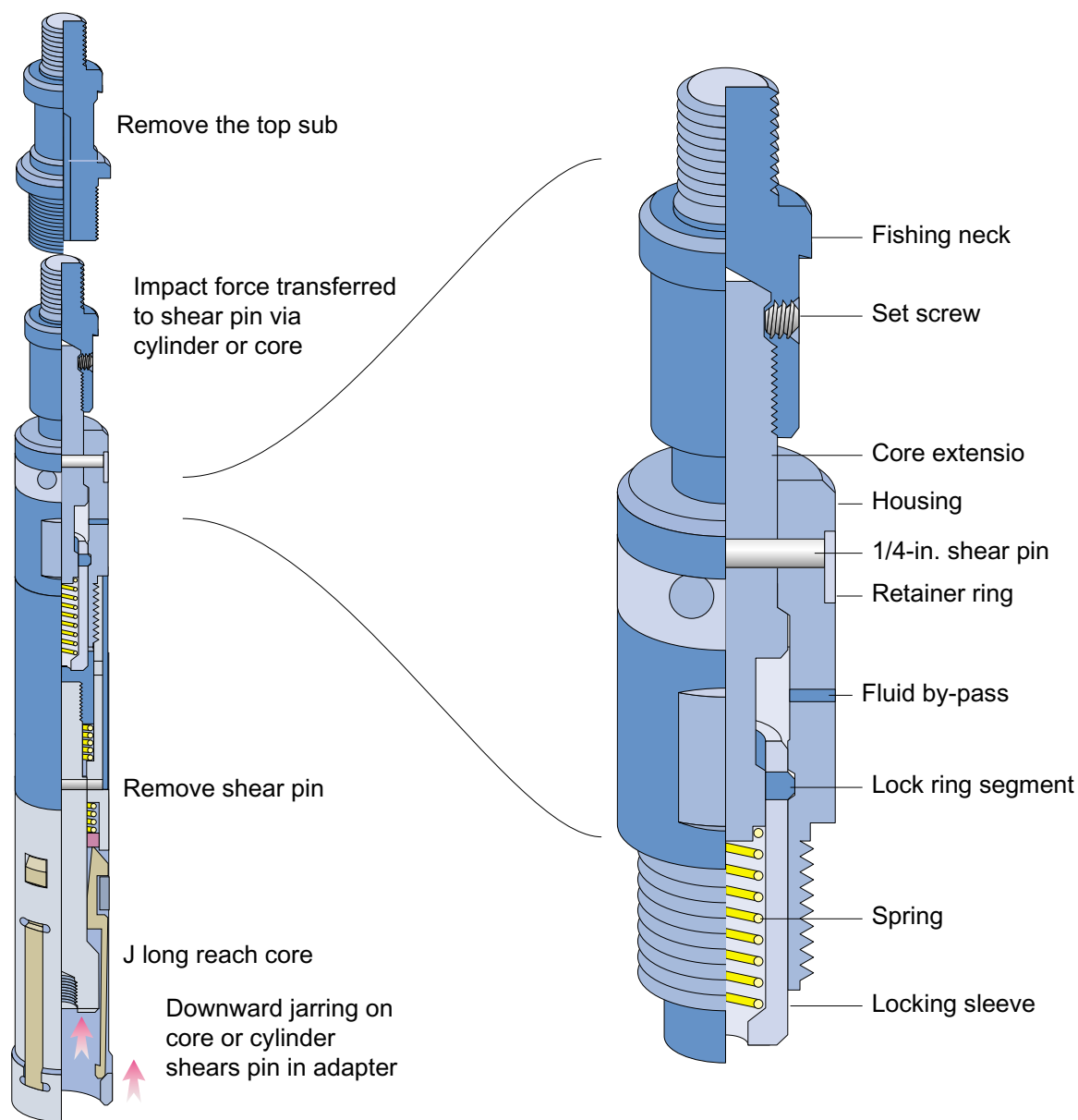


Figure 5-14: SSJ Tool Assembly

5.2.3

Camco Pulling Tools

The JU series is the standard Camco Jar Up (JU) to shear and release tool, and it is available with the following core and reach options:

Table 5-4: Camco Pulling Tools

Core	JU Assembly	Reach	JD Assembly	Otis Core Equivalent*
'C'	JUC	Short	JDC	'B'
'S'	JUS	Medium	JDS	'S'
'L'	JUL	Long	-	'J'

* Not interchangeable with Camco - This is for comparison only.

The JU can be converted to the JD by changing the top sub, core nut and retainer screw. The cores for JU and JD are identical.

In comparing the JU and JD tools, the JU is identified by the grub screw, which is visible in the top sub. The JD has no such screw visible. This difference is the only quick method of identifying the shear direction of the tools.

JU:	Jar Up to shear	JD:	Jar Down to shear
-	Core attached to the top sub	-	Skirt attached to the top sub
-	Screw hole in the top sub – ID feature	-	No hole in the top sub
-	Skirt pinned to the core	-	Core pinned to the skirt
-	Bigger shear pin than the JD	-	Smaller shear pin than the JU

**Note**

The dog profile on the Camco tool is right angle and the Otis tools and compatible equipment have 15° undercut.

The OD of the Camco tools is larger than the equivalent Otis tool and no releasing tool required for Camco.

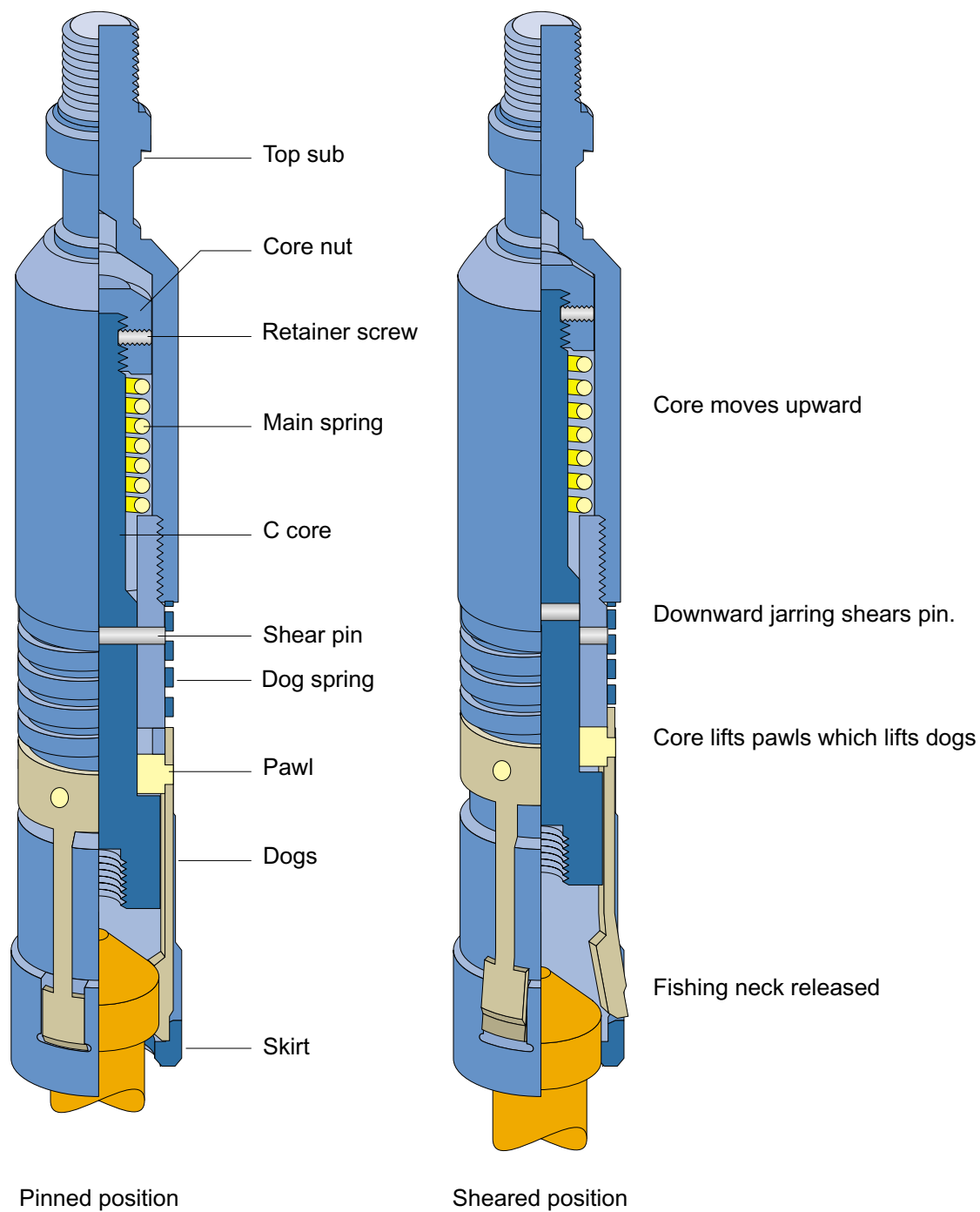


Figure 5-15: JDC Pulling Tool

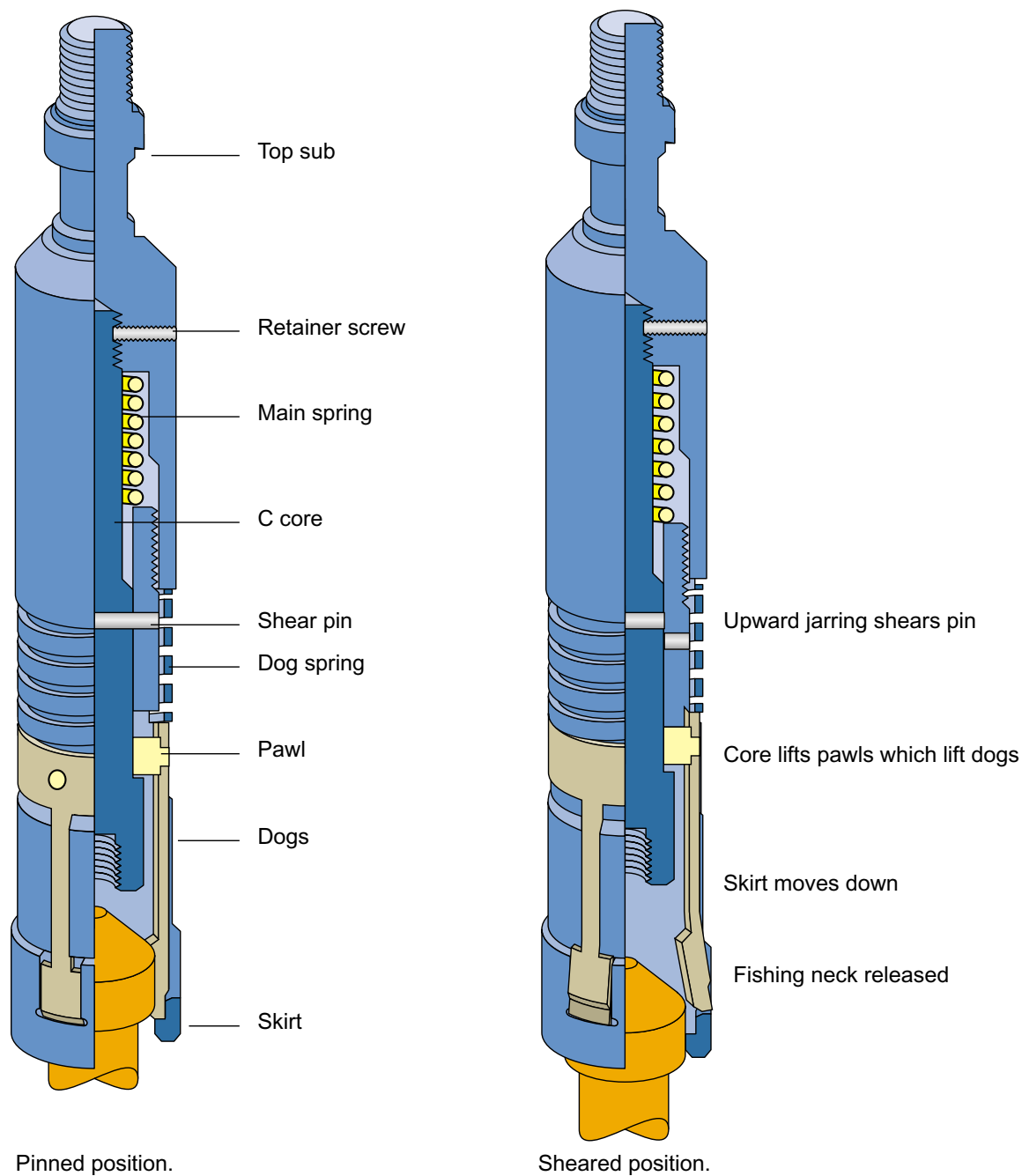


Figure 5-16: JUC Pulling Tool

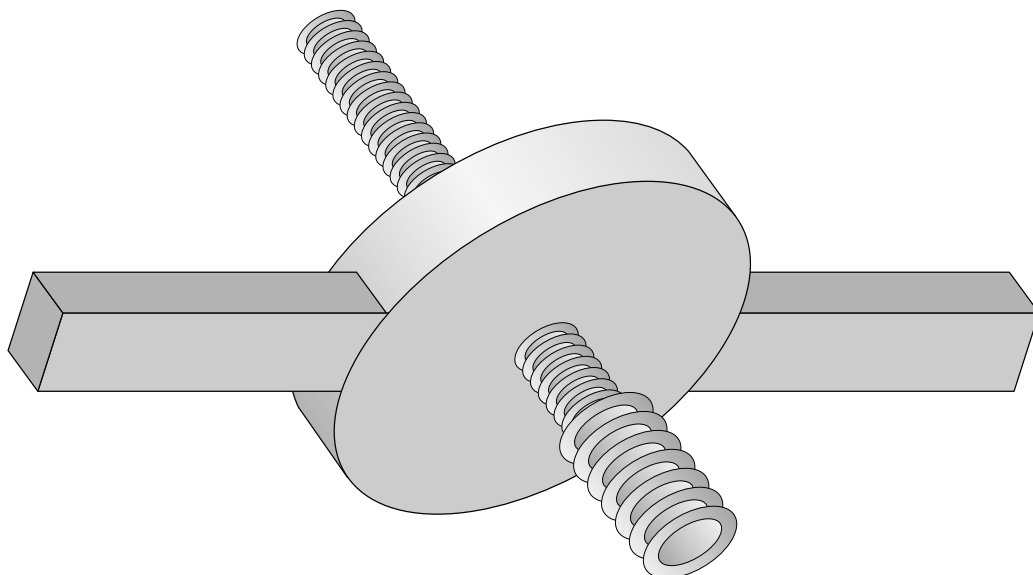
The JD series is the standard Camco Jar Down (JD) to shear and release tool. It can be used as a running tool when downward jar action is required to release equipment down hole. It is available with 2 core and reach options

- JDC Short reach option - to latch rope socket type fishing necks
- JDS Medium reach option - to latch fishing necks with thread, such as stem etc.

All Camco type pulling tools have dogs, which are machined from one piece of steel, as opposed to the Otis type, which have 3 independent dogs. The one-piece design ensures that the load is taken equally on all three dogs.

No releasing tool is required, as the dogs can be retracted manually and compresses the dog spring.

The pinning tool for all Camco tools is the same as for Otis and is screwed into the prong thread in the bottom end of the core. The main spring is compressed by rotating the plate against the skirt until the shear pinholes are aligned and the new pin is inserted.



Pinning tool

Figure 5-17: Pinning Tool

Table 5-5: Pulling Tool Data Sheet

CAMCO Type					OTIS Type					
Will Engage (in.)	Part #	Reach (in.)	OD (in.)	Camco Type	Size (in.)	Otis Type	OD (in.)	Reach (in.)	Part #	Will Engage (in.)
					1	RB	0.970	1.328	40RB12	0.750
					1	SB	0.927	1.000	40SB25	0.687
					1	RS	0.880	1.000	40R512	0.687
					1-3/16	SM	1.190	1.680	40SM4	0.875
					1-3/16	RB	1.190	1.300	40RB11	0.875
					1 1/4	SB	1.220	1.280	405B14	1.000

CAMCO Type						OTIS Type				
Will Engage (in.)	Part #	Reach (in.)	OD (in.)	Camco Type	Size (in.)	Otis Type	OD (in.)	Reach (in.)	Part #	Will Engage (in.)
					$1\frac{1}{4}$	RB	1.220	1.219	40RB10	1.000
					$1\frac{1}{4}$	RS	1.220	2.125	40R510	1.000
0.875	15151	1.937	1.281	JDC	$1\frac{1}{4}$					
0.875	15165	2.688	1.291	IDS	$1\frac{1}{4}$					
1.000	15153	1.875	1.375	JDC						
1.188	15174	1.094	1.422	JUC	$1\frac{1}{2}$	RB	1.430	1.265	40RB14	1.188
1.188	15194	1.844	1.422	JUS	$1\frac{1}{2}$	RS	1.430	1.797	40R55	1.188
					$1\frac{1}{2}$	RI	1.430	2.547	40RJ5	1.188
					$1\frac{1}{2}$	SB	1.437	0.688	405B3	1.188
1.188	15154	1.094	1.422	JDC	$1\frac{1}{2}$	SB	1.437	1.297	405B6	1.188
1.188	15166	1.844	1.422	IDS	$1\frac{1}{2}$	SS	1.430	1.780	40SS3	1.188
					$1\frac{1}{2}$	SM	1.380	1.578	405M4	0.875
					1.66	SM	1.188	1.680	405M7	0.875
1.188	15155	1.843	1.625	JDS	$1\frac{5}{8}$					
					$1\frac{3}{4}$	RS	1.562	1.797	40R514	1.188
1.375	15176	1.438	1.859	JUC	2	RB	1.770	1.219	40RB17	1.375
1.375	15196	2.125	1.859	JUS	2	RS	1.770	1.984	40R56	1.370
1.375	15156	1.438	1.859	IDC	2	SB	1.766	1.219	405M1	1.375
					2	SM	1.770	1.640	405M1	1.375
1.375	15168	2.125	1.859	105	2	SS	1.770	2.030	40SS1	1.375
1.750	15178	1.313	2.250	JUC	$2\frac{1}{2}$	RB	2.180	1.203	40RB18	1.750
1.750	15198	2.188	2.250	JUS	$2\frac{1}{2}$	RS	2.180	1.984	40RS7	1.750
					$2\frac{1}{2}$	RI	2.180	2.547	40RI2	1.750
1.750	15158	1.313	2.250	JDC	$2\frac{1}{2}$	SB	2.180	1.281	40SB2	1.750
1.750	15170	2.188	2.250	105	$2\frac{1}{2}$	SS	2.180	2.000	40SS2	1.750
2.310	15180	1.438	2.796	JUC	3	RB	2.740	1.297	40RB19	2.310
2.310	15200	2.125	2.796	JUS	3	RS	2.740	2.190	40R58	2.310
					3	SB	2.734	1.380	405B9	2.310
2.310	15160	1.438	2.796	JDC	3	SB	2.844	1.500	405B7	2.310
2.310	15172	2.125	2.796	JDS	3	SS	2.840	2.210	40SS4	2.310
					$3\frac{1}{2}$	RB	3.110	1.350	40RB30	2.750
					$3\frac{1}{2}$	RS	3.110	2.100	40R516	2.750

CAMCO Type						OTIS Type				
Will Engage (in.)	Part #	Reach (in.)	OD (in.)	Camco Type	Size (in.)	Otis Type	OD (in.)	Reach (in.)	Part #	Will Engage (in.)
					$3\frac{1}{2}$	SB	3.115	1.690	405B11	2.750
3.125	15182	3.375	3.750	JUC	4	RB	3.670	1.490	40RB20	3.125
					4	RS	3.718	2.156	40R59	3.125
					4	SB	3.670	1.500	40SB10	3.125
					4					
3.125	15162	2.313	3.750	JUC	4					

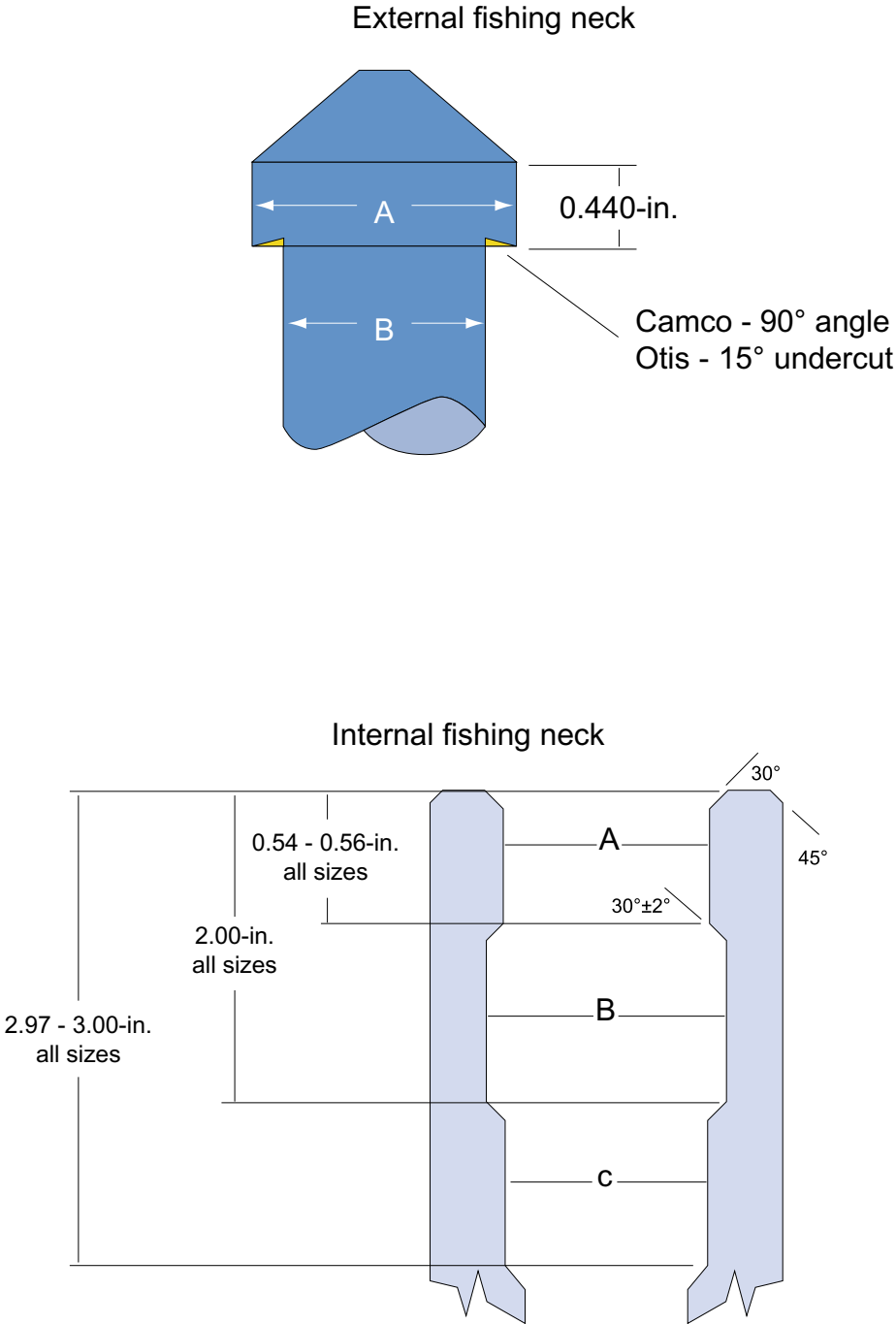


Table 5-6: Fishing Neck Dimensions

External Fishing Neck Chart				
Tool string Size (in.)	Diameter A (in.)		Diameter A (in.)	
	Maximum	Minimum	Maximum	Minimum

SophiaPublish-SRC-General\John Mayzel\Slickline\Release Date: Provisory\EDMS UID: /\Published: //

$\frac{3}{4}$	0.750	0.740	0.630	0.620
1	1.000	0.990	0.880	0.870
$1 \frac{1}{4}$	1.187	1.177	1.060	1.030
$1 \frac{1}{2}$	1.375	1.365	1.190	1.160
$1 \frac{7}{8}$	1.750	1.740	1.500	1.470
$2 \frac{1}{8}$	1.750	1.740	1.500	1.470
$2 \frac{1}{2}$	2.313	2.303	2.060	2.030
<i>Internal Fishing Neck</i>				
Tubing Size (in.)	Diameter A (in.)		Diameter B (in.)	
	Maximum	Minimum	Maximum	Minimum
2.062	1.06	1.08	1.22	1.24
$2 \frac{3}{8}$	1.38	1.40	1.57	1.59
$2 \frac{7}{8}$	1.81	1.83	2.00	2.02
$3 \frac{1}{2}$	2.31	2.33	2.50	2.52

5.2.4

G Series Pulling Tools

The tools described in this section are all designed to latch external fishing necks, e.g., rope sockets, stem etc. The GS and GR series are designed to latch internal fishing necks, e.g., X and XN locks, soft set bomb hanger's etc.

The basic tool is the GS, which shears down, but the addition of a GU adapter converts the total assembly to a GR shear-up tool.

A GRL version with an extended core nose is available and required to pull the model D collar locks.

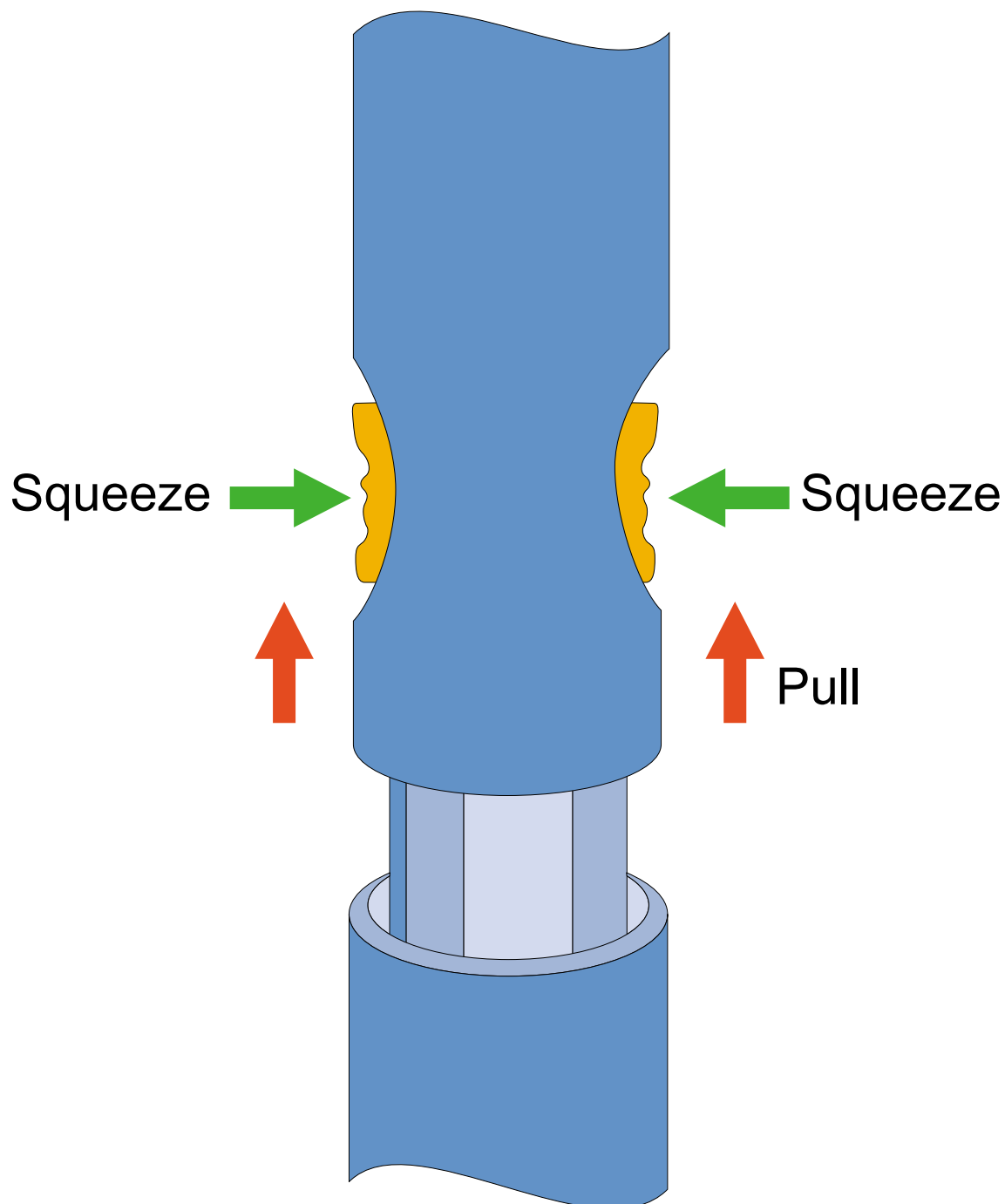


Figure 5-19: G Series Tool Release Method

To release the pulling tool from the lock mandrel, grasp the dog retainer with the thumb and forefinger then force it up to compress the spring. This should lift the dogs enough to allow them to retract against the smaller outside diameter of the core. Take the mandrel off the pulling tool.

5.2.4.1 **GS Operation**

The skirt must be moved up by the fishing neck of the equipment latched. If there is insufficient space for the GS to move down inside the internal fishing neck, it is not possible to shear off.

Latching

As the GS passes downwards into the fishing neck, the dogs move up and inwards to pass the ID of the fishing neck, then the dog spring forces them backwards.

Pulling

The upward movement is transmitted from the tool string through the core to the dogs, which are now firmly expanded beneath the fishing neck.

Shearing

Downward jar force is applied to move the core downwards, relative to the skirt. The skirt resting on the fishing neck, shears the pin in an upward direction.

Pinning

A GU adapter can be used as a pinning tool to realign the shear-pin holes by compressing the spring. If a GU adapter is not available, the spring can be compressed by levering the tool in a vice.

Uses

Running and pulling - G stops and G pack-offs

Running - Soft set bomb hangers

Pulling - Soft set bomb hangers

5.2.4.2 **GR Operation**

The GR jar-up to shear pulling tool is configured as a combination of a GS tool and GU adapter.

The pin must be removed from the GS or the tool will not shear in either direction. The operating sequence is the same as the GS, except the tool now shears in the opposite direction.

Shearing

Upward jar action is transmitted through the shear pin (a larger diameter than in the GS) until the pin is sheared. Downward jar action has no tendency to shear the pin, as the force is transmitted through the main GU body to the skirt of the GS and onto the fishing neck.

Pinning

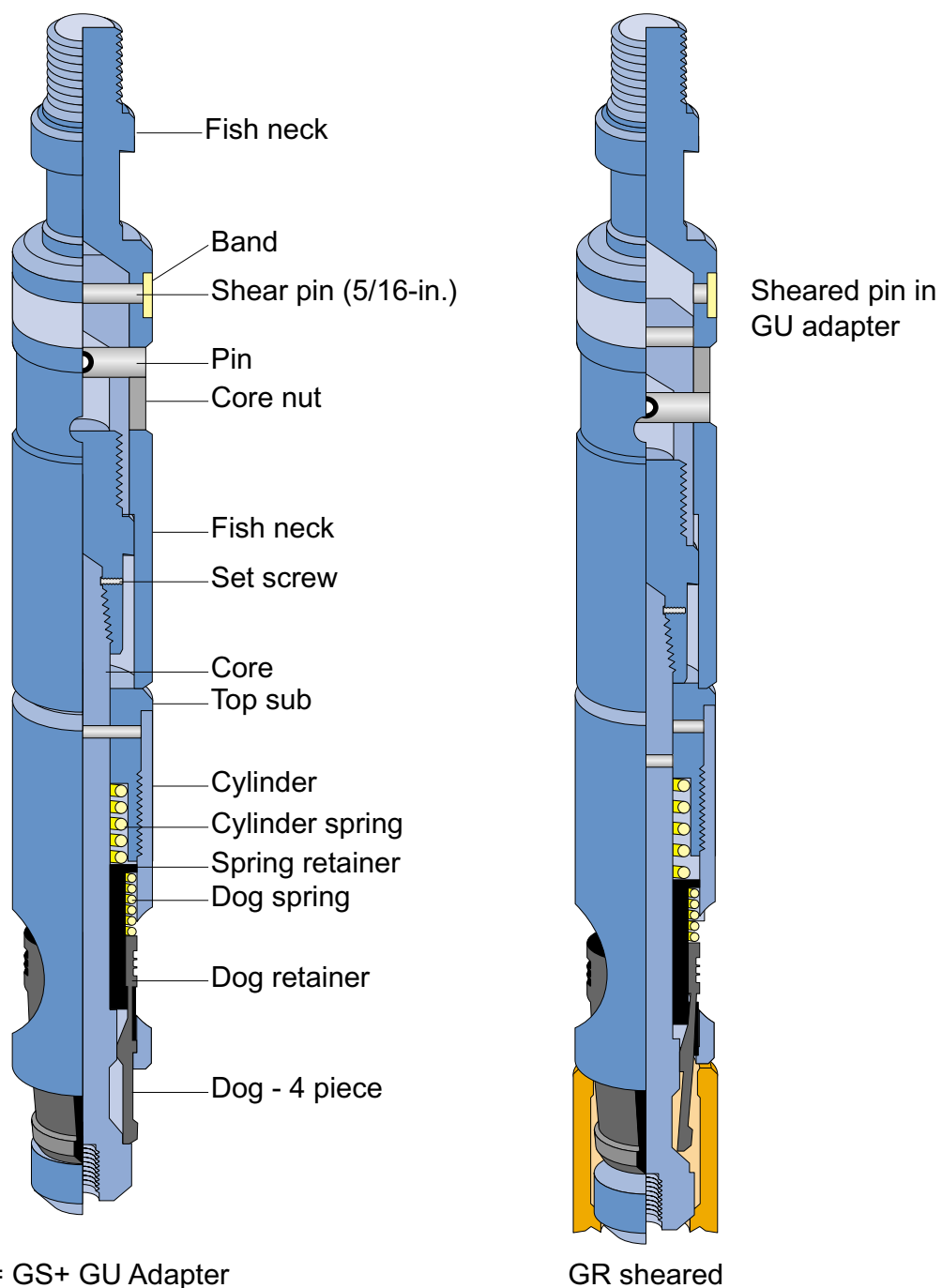
Back the GU adapter off the GS and re-pin the adapter. Screw the adapter back into position and the main GS spring will be returned to the pinned position. Check there is no shear pin in the GS body.

Uses

The GR is used to pull X and XN locks. The jar down side loosens the set on the keys and makes the lock easier to pull.

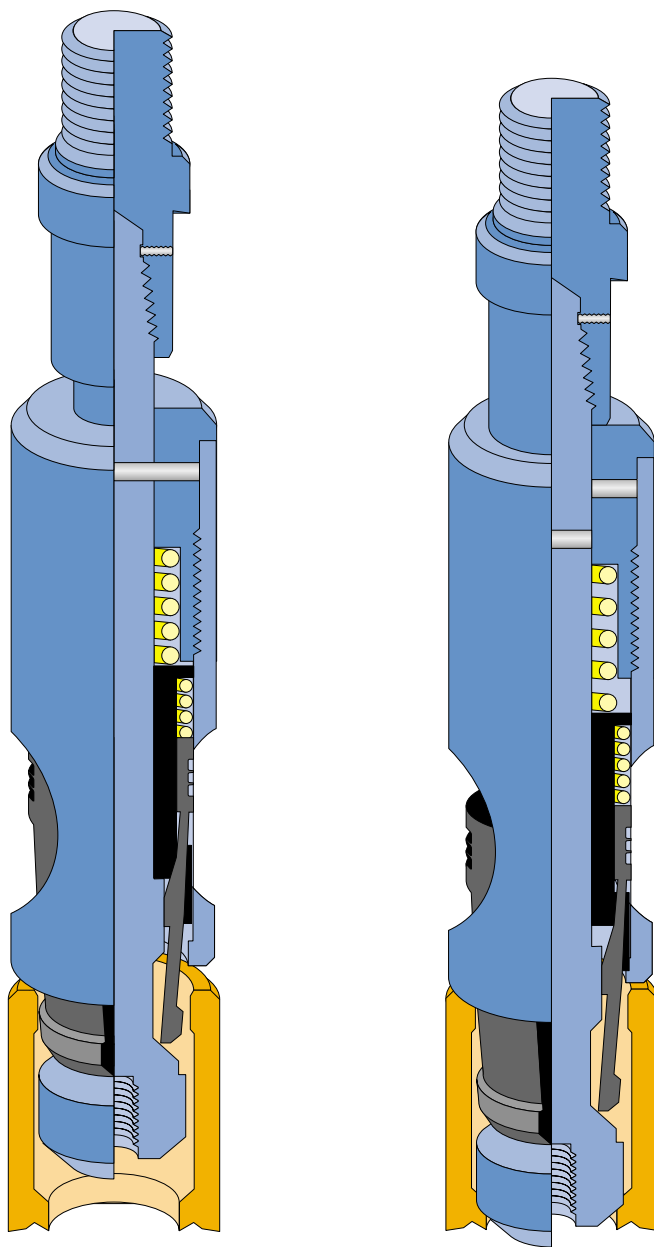
Table 5-7: Common GR Tool Specifications

Nom Size (in.)	Lock OD Ref	GR Part No.	GS Part No.	GU Part No.	Will Latch ID (in.)	Max OD (in.)	Top Thread	Tool Fish Neck (in.)
2	1.875	40GR18700	40GS18700	40GU18700	1.38	1.81	15/16 - 10	1.375
2½	2.313	40GR23100	40GS23100	40GU23100	1.81	2.25	15/16 - 10	1.750
3	2.750	40GR27500	40GS27250	40GU31200	2.31	2.72	1-1/16 - 10	2.313
5	4.562	40GR45600	40GS45600	40GU45600	4.00	4.50	1-1/16 - 10	3.125



GR = GS+ GU Adapter

Figure 5-20: GR Tool Assembly



GS tool latching

GS tool sheared

Figure 5-21: GS Tool Assembly

5.2.5

PRS Pulling Tool

The Camco PRS pulling tool is designed to latch internal fishing necks. This series includes the PRS, PRS-2 and PRS-3 types.

PRS - shears down to release (equivalent to the GS)

PRS-2 – incorporates a reversible shear-releasing feature (equivalent to the GS / GR)

PRS-3 - also has a reversible shear releasing feature, but are designed with an extended core to release the Otis type D lock (equivalent to GRL) This version will not be covered in this section as its use is restricted to pulling type D locks.

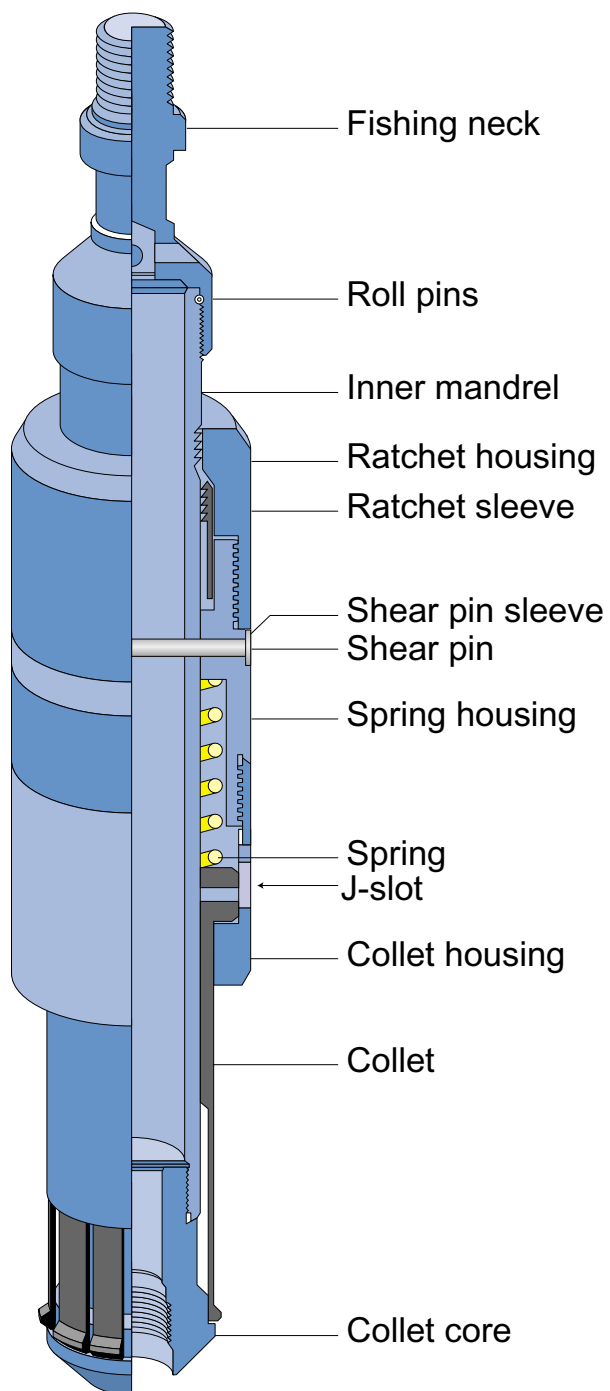


Figure 5-22: PRS Pulling Tool

5.2.5.1 Operation

As the PRS is lowered into the fishing neck, the collet moves upward against the spring and the collet fingers collapse to enter the fishing neck. Once fully engaged, the spring pushes the collet back down and the collet fingers are held in the expanded position by the collet core.

Upward jarring extends the fishing neck of the lock and releases the lock from the nipple profile.

In the event that the lock will not release, downward jarring (on the PRS) will shear the pin (brass or steel, depending on conditions). The collet collapses to release the fishing neck and the tool can be retrieved.

Once the tool is sheared, the ratchet sleeve holds the core in the downward position. The tool must always be redressed after shearing.

On the PRS-2, shearing can be achieved by upward or downward jarring. The required direction is set at the surface by changing the position of the sleeve and spring to the other side of the stop on the inner mandrel.



Note

This reversible feature is only available on tools of $3\frac{1}{2}$ in. nominal size and smaller.

All PRS series tools have threads in the nose of the core to attach the equalizing prongs.

Releasing Procedure

As the PRS is lowered into the fishing neck, the collet moves upward against the spring and the collet fingers collapse to enter the fishing neck. Once fully engaged, the spring pushes the collet back down and the collet fingers are held in the expanded position by the collet core.

Upward jarring extends the fishing neck of the lock and releases the lock from the nipple profile.

In the event that the lock will not release, downward jarring (on the PRS) will shear the pin (brass or steel, depending on conditions). The collet collapses to release the fishing neck and the tool can be retrieved.

Once the tool is sheared, the ratchet sleeve holds the core in the downward position. The tool must always be redressed after shearing.

On the PRS-2, shearing can be achieved by upward or downward jarring. The required direction is set at the surface by changing the position of the sleeve and spring to the other side of the stop on the inner mandrel.

**Note**

This reversible feature is only available on tools of $3\frac{1}{2}$ in. nominal size and smaller.

All PRS series tools have threads in the nose of the core to attach the equalizing prongs.

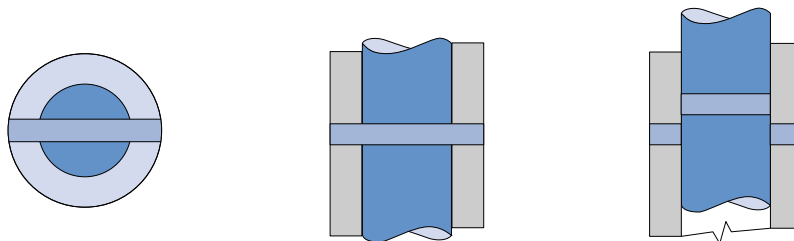
5.3

Shear Pins

The choice of brass or steel shear pins depends on the conditions in the well. Factors, which influence the decision, include:

- The amount of force required or is available, to shear the pin
- The amount of stem that can be included in the tool string
- The depth at which the tool is to be sheared
- The well deviation
- The well fluid – less acceleration available in heavy fluid wells than in gas
- The tool from which the running or pulling tool is to be released
- The type of jars in use on the tool string – mechanical only or upstroke jars

Radial shear pins

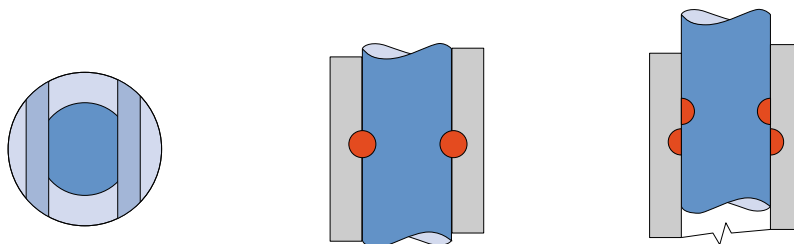


Shearing edges should be sharp and in good condition



Tangential shear pins

Usually of a relatively small diameter as there is an increased shear area over radial types



Shearing edges should be sharp and in good condition

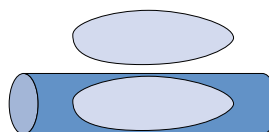


Figure 5-23: Radial and Tangential Shear Pin Detail

Table 5-8: Shear Stock Specifications

Material	Description	Ultimate Shear Strength (psi)
Yellow brass	$\frac{1}{2}$ hard – Rockwell B 70	40,500
Aluminum	2024 – T4	41,000
Naval Brass (Tobin Bronze)	$\frac{1}{4}$ hard – Rockwell B 80	43,000
Mild steel	1018	58,000

Material	Description	Ultimate Shear Strength (psi)
Low fuming bronze	Type RCUNZ – C Rockwell B 82 Anaconda welding Rod No. 997	58,000
Low fuming bronze	Type RCUNZ – C Rockwell B 80 Anaconda welding Rod No. 27	60,000
Drill rod	Oil hardened, polished & annealed Rockwell C 10	81,000

5.3.1 Shear Pin Nomographs

The following nomographs give the theoretical breaking force necessary to shear pins up to one inch OD or metal areas up to 0.7 in.².

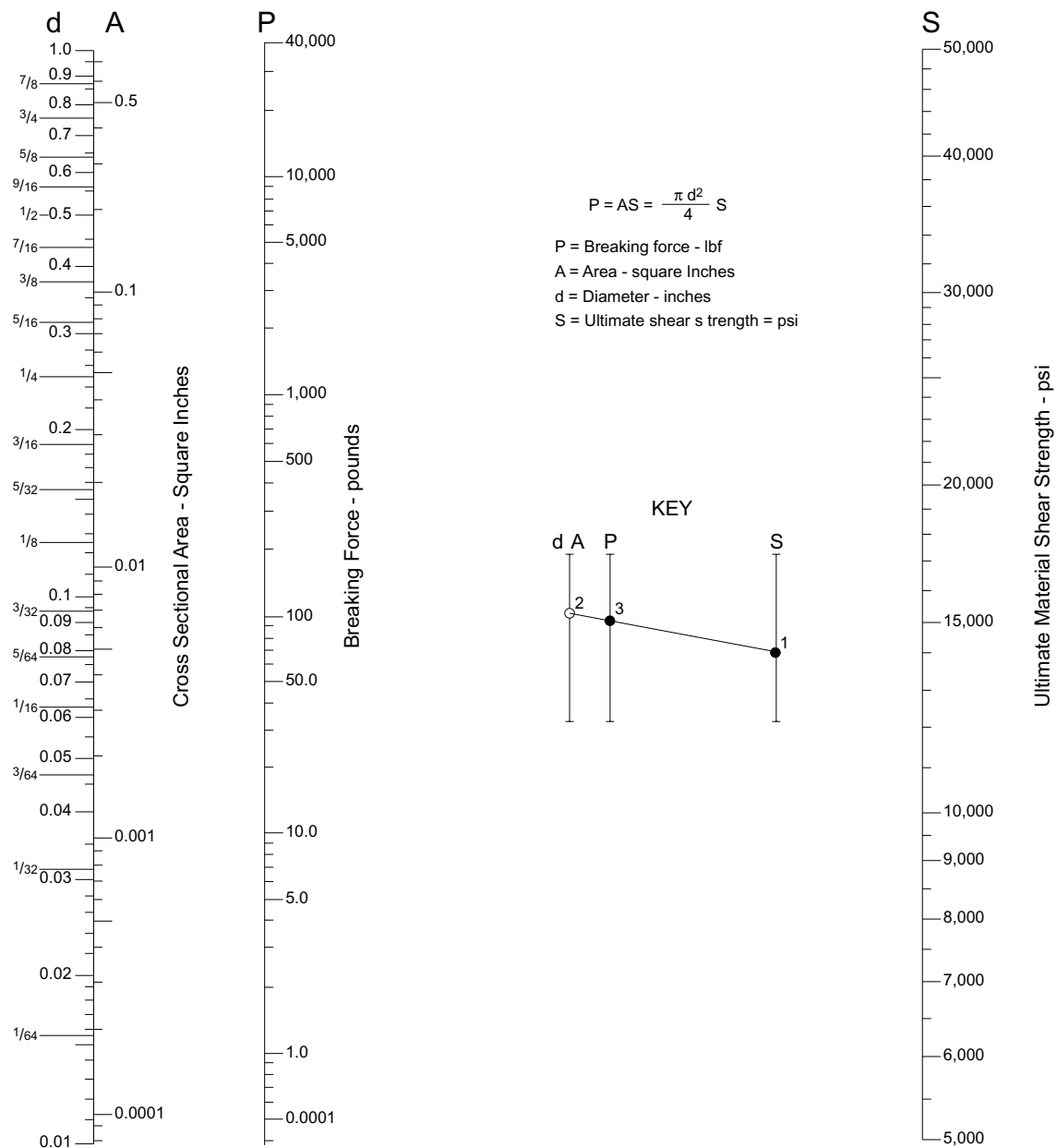


Figure 5-24: Shear Pin Nomograph

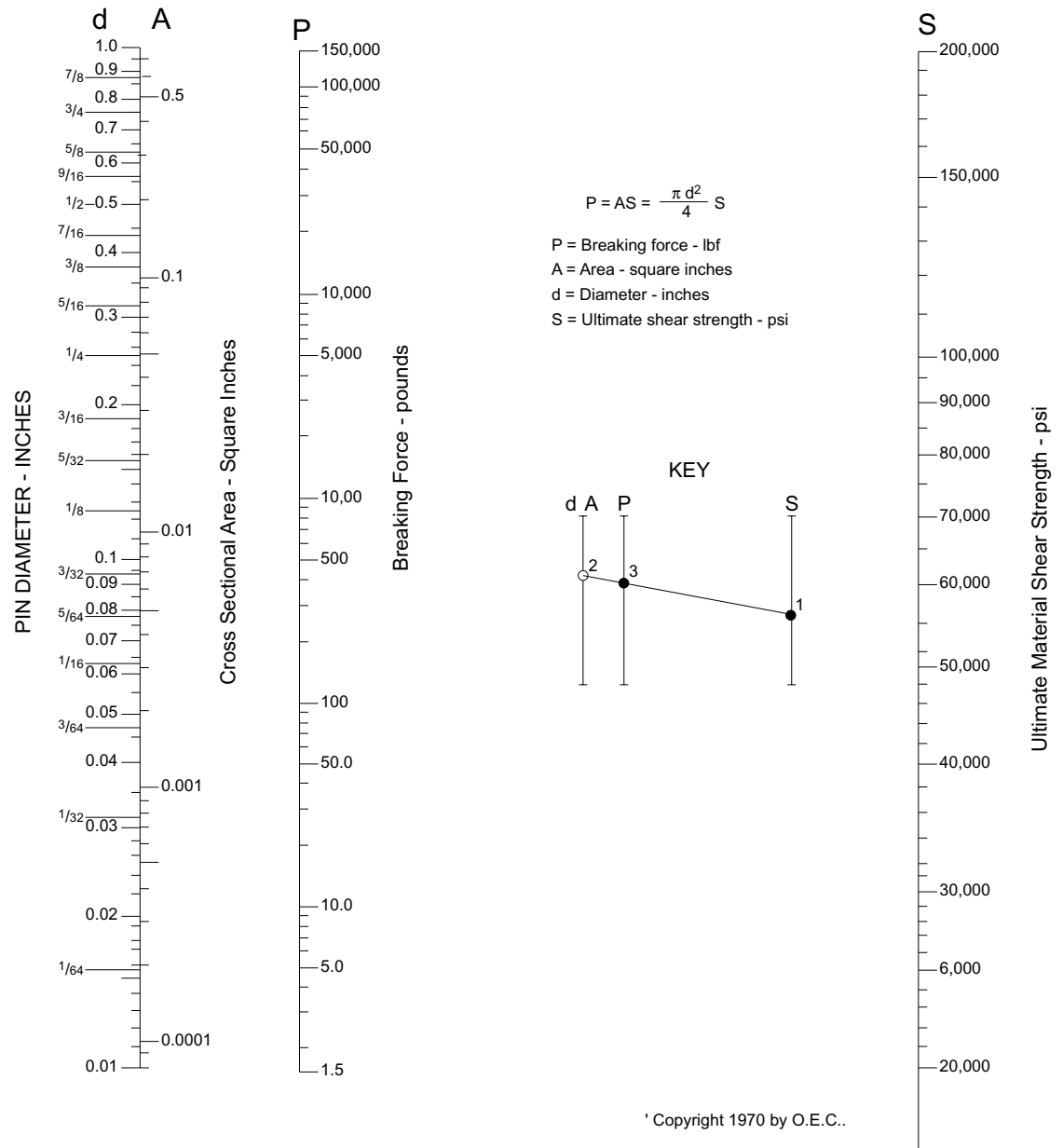


Figure 5-25: Shear Pin Nomograph

These are representative samples only and were tested under good conditions. The edges of the holes in the fixture were sharp, with 0.0005 in. clearance on each side of the core. The pins fit very snugly in the holes. Any conditions other than these would give different results.

To calculate the breaking force for round pins in a fixture such as this, draw a straight line from S (ultimate material shear strength – psi) to D (pin Diameter – inches) on the graph. Where this line crosses P (breaking force – pounds), read pounds. If the pin extends through the core to both outside edges of the sleeve, merely double P for double shear.

There are several factors involved, which will increase the actual breaking force, including:

- Cutting edges of holes in the core a cylinder rounded or dull.
- Holes in the core or cylinder larger than the shear pin.
- Increased clearance between the core and cylinder.

If the pin diameter is large in relation to the core diameter, it would be best to calculate the actual area sheared, rather than using the pin diameter scale.

It is very difficult to produce pure shear in metals. However, this condition can be approached if both cutting edges are sharp and move in the same plane, with very little clearance between each other. One example of this is a close fitting core and cylinder fixture with a hole drilled radially through both to receive a pin very slightly smaller in size than the hole. Either the core or the cylinder is fixed and the other moves axially to shear the pin.

5.3.1.1 Bar Stock Material Pins

The following table was compiled from a series of tests, which are conducted by Carl Ivey in 1971. (Reference test JA 003-001-1) The raw data has been verified a number of times over the years. However, please remember that there are many variables to consider in determining when a rod will shear. These tables should be used as a guide only.

The nominal size is given as a 3 place decimal. The actual diameter of each specimen was measured. Three shear tests were made on each sample so that the average shear strength could be determined. The average of these tests was the average double shear strength. The average single shear strength was calculated by dividing the average shear strength by two. The shear strength of the material was calculated by dividing the average shear strength by the actual area of the specimen. The calculated single shear strength was determined by dividing the shear strength by the nominal diameter. In order to simplify the table, only the calculated single shear strength and the shear strength of the material is included.

Table 5-9: Bar Stock Material Shear Strength Specifications

Material	Diameter (in.)	Shear Value (lbf)	Shear Strength (psi)
2024-T4	0.125	483	39361
Aluminum	0.188	1181	42782
	0.250	2210	45072

Material	Diameter (in.)	Shear Value (lbf)	Shear Strength (psi)
	0.313	3310	43153
	0.375	5007	45330
	0.500	9120	46447
	0.563	10133	40776
Free-Cut Yellow Brass	0.125	474	38598
	0.188	1307	47334
	0.250	2197	44750
	0.313	3392	44229
	0.375	4868	44072
	0.563	10706	43081
1018 Steel Rc 14Max.	0.125	670	54597
	0.156	1133	59059
	0.250	2812	57295
	0.313	4234	55205
	0.375	6872	62217
	0.500	10996	56003
303 Stainless Rc 14 Max.	0.094	690	99907
	0.125	1182	96291
	0.156	1860	96950
	0.188	2914	105530
	0.250	4800	97785
	0.313	6737	87834
	0.075	489	110612
R-Monel	0.125	825	67227
	0.188	1927	69787
	0.250	3333	69706
	0.375	7117	64442
	0.438	9137	60782
	0.500	13375	68118
	0.563	16024	64481

Shear pin numbers indicate material, diameter and length.

EXAMPLE: 9P21250 (1018, $\frac{1}{8}$ x $1\frac{1}{4}$)

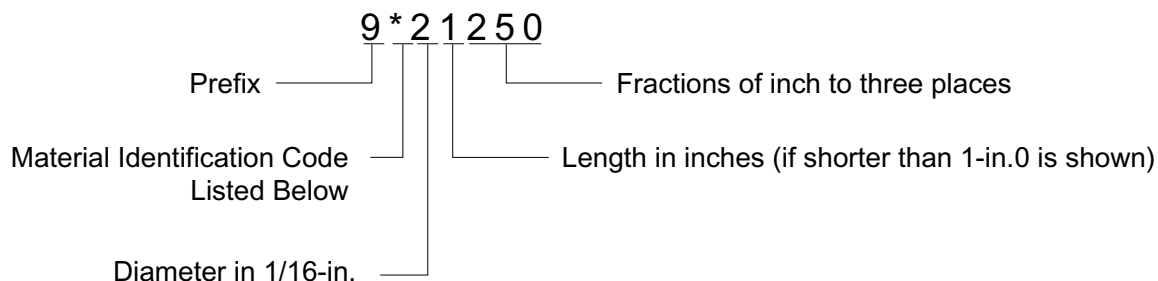


Figure 5-26: Shear Pin Identification

Material Code - *

9P	_____	= 1018 (ES-MA-9)
9PA	_____	= 2024-T4 or T351 Aluminum C.D.
9PB	_____	= Yellow Brass C.D. $\frac{1}{2}$ Hard
9PD	_____	= Drill Rod AISI 01 Hardened & Polished
9PH	_____	= 17-4PH (ES—H-I)
9PM	_____	= MONEL K-500 ANL
9PM	_____	= 410 Stainless ANL.
9PR	_____	= 1018 (ES-MA-22) ANL 1018
9P5	_____	= 303 Stainless C.D. & ANL. 30,000 PSI Min. 237 Max. 8HN
9PT	_____	= TOBIN BRONZE (Naval Brass)

**Note**

When the proper operation of a tool depends on consistent shear values, 1018 or Brass or Annealed 303 should be used (9P, 9PB, 9PS). Of the ten material codes listed above, only the 9P, 9PA, 9PB and 9PT are normally used for PULLING TOOL SHEAR PINS.

Intentionally Blank

6 Camco Plugs, Locks and Tools

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6 CAMCO PLUGS, LOCKS AND TOOLS

6.1 Introduction

Guides for the selection of Camco equipment are shown in the [Overview Tables](#) (a) through (e).

6.2 Nipples

6.2.1 Type A Seating Nipples

The Camco Type A seating nipple is a top no-go, reduced bore polished nipple. It is commonly used with an equalizing standing valve and does not contain a locking recess.

Tools such as the A or M equalizing standing valve shoulder against the reduced ID of the packing bore and seal in the polished section.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread type; bottom-hole pressure and temperature; required pressure rating; percent of H₂O, H₂S and CO₂.

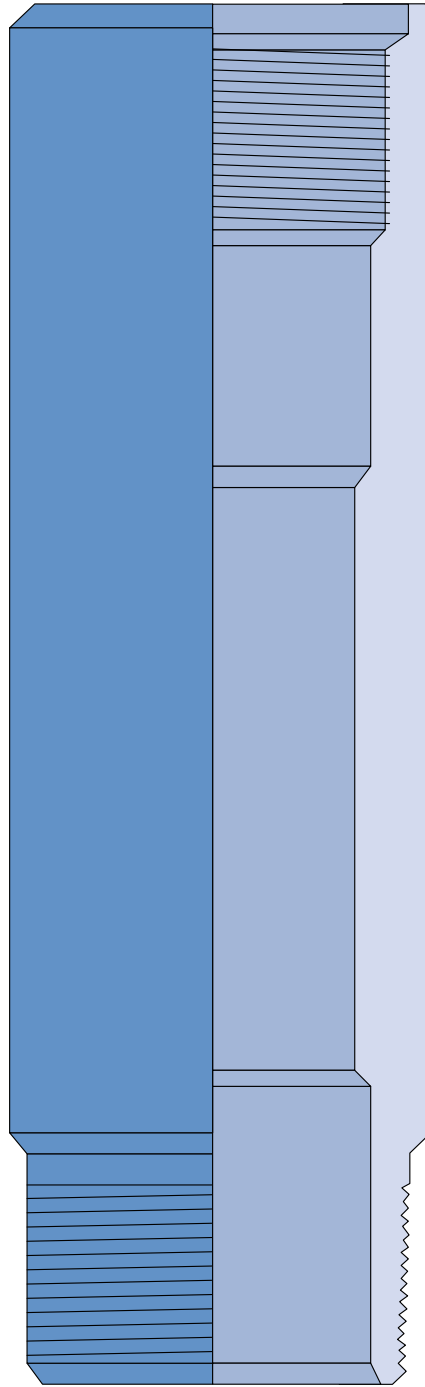


Figure 6-1: Type A Nipple

Table 6-1: Type A Nipple Specifications

Tubing		Assembly No.	OD (in.)	Packing Bore (in.)
OD (in.)	Weight (lb/ft)			
1.900 (1½)	2.9	33013	2.500	1.187
		33015		1.250
		33018		1.437
2.375 (2)	4.7	33048	3.063	1.187
		33047		1.250
		33049		1.437
		33070		1.562
		33053		4.625
		33056		4.812
		33061		1.875
2.875 (2½)	6.5	33078	3.668	1.187
		33077		1.437
		33080		1.812
		30803		2.250
		33084		2.312
3.500 (3)	9.3	33091	4.500	2.250
		33095		2.750
		33097		2.812
4.500 (4)	12.75	33088	5.562	3.625

6.2.2

D Series No-Go Landing Nipples

The Camco D series landing nipples are top no-go nipples utilized to permit the landing, locking and sealing of locks with attached flow control devices in the production tubing. The D nipple receives a C, CC or HPC-R series lock while the DS nipple, with a slightly larger ID, receives a CS, CSC or HPC-R series lock. The D-2 nipple, which receives a C or CC lock, is designed with a slickline re-entry guide and is installed as the bottom nipple on the end of the tubing string. The DN nipple is a bottom no-go nipple and receives a CBNS-R series lock.

The internal profile of these nipples includes a shoulder that engages the no-go of the lock and a locking recess. When installed, the locking dogs of the lock move out into the recess of the nipple and the lock packing seals in the polished bore section.

6.2.2.1 Operation

To install a no-go lock in these nipples, the lock and attached flow control device are run into the tubing using standard slickline methods. The assembly is lowered until the no-go of the lock contacts the nipple no-go shoulder. Downward jarring forces the locking dogs of the lock into the locking recess of the nipple, anchoring the assembly.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread type; bottom-hole pressure and temperature; required rating; percent of H₂O, H₂S and CO₂.

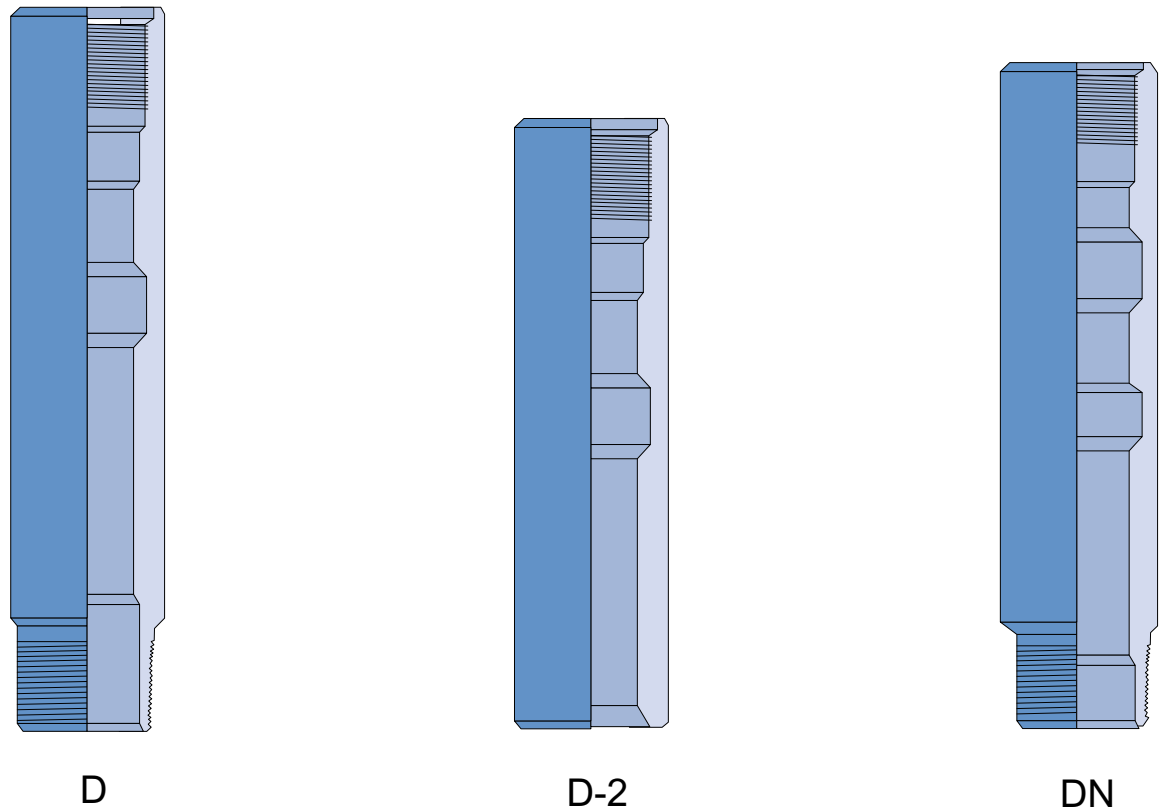


Figure 6-2: D Series No-Go Landing Nipple

Table 6-2: D Series Engineering Data

Tubing OD (in.)	Weight (lb/ft)	Type	Assembly Number	OD (in.)	Packing Bore (in.)
1.900 (1½)	2.9	D	33306	2.500	1.437
		D-2	33307		
2.063 (2-1/16)	3.25	D	33324**	2.330	1.437
			33326**		1.562
2.375 (2)	4.7	D	33334	3.063	1.437
		D-2	33321		1.562
		D	33336		
		D-2	33327		1.765
		DN	33843		1.812
		D	33340		1.875
		DS	33348		1.562
2.875 (2½)	6.5	D	33318	3.668	1.812
			33355		1.875
		DS	33366		1.937
		D	33295		2.000
			33294		2.062
			33293		2.125
			33868		2.188
			33292		2.203
		DN	33844		2.250
		D	33310		
		D-2	33320		2.312
		DS	33365		

Tubing OD (in.)	Weight (lb/ft)	Type	Assembly Number	OD (in.)	Packing Bore (in.)
3.500 (3)	9.3	DS	33433	4.500	1.875
		D	33869		2.125
			33291		2.188
			33374		2.250
		D-2	33328		2.312
		DS	33369		2.437
			33296		2.562
			33871		2.703
		DN	33845		2.750
		D-2	33106		2.812
		D	33373		2.875
		DS	33376		
			33377		

6.2.3

DB Series No-Go Landing Nipples

The Camco DB series landing nipples are large-bore top no-go nipples utilized to allow the landing, locking and sealing of locks with attached flow control devices in the production tubing. The DB nipples accept DB-6 series locks and are available in many sizes for multiple nipple applications.

The internal profile of these nipples includes a shoulder that engages the no-go of the lock and a locking recess. When installed, the locking dogs of the lock move into the recess of the nipple and the lock packing seals in the polished bore section.

6.2.3.1

Operation

To install a no-go lock in these nipples, the lock and attached flow control device are run into the tubing using standard slickline methods. The assembly is lowered until the no-go of the lock contacts the nipple no-go shoulder. Downward jarring forces the locking dogs of the lock into the locking recess of the nipple and anchors the assembly.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread connection; bottom-hole pressure and temperature; required pressure rating; percent of H₂O, H₂S and CO₂.

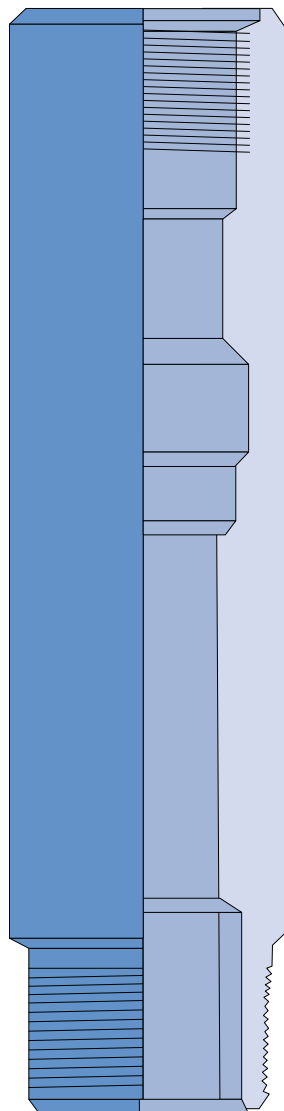
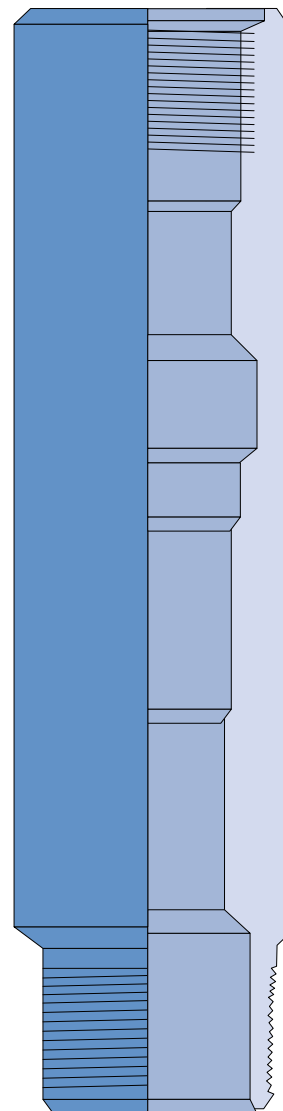
**DB-6****DB-6N****Figure 6-3: DB Series No-Go Landing Nipples**

Table 6-3: DB Series Engineering Data

Tubing		Assembly Number	OD (in.)	Packing Bore (in.)
OD (in.)	Weight (lb/ft)			
4.000 (3 $\frac{1}{2}$)	11.0	33437	5.000	3.125
		33426		3.187
		33438		3.250
		33439		3.312
4.500 (4)	12.75	33440	5.563	3.437
		33571		3.500
		33300		3.563
		33572		3.625
		33935		3.687
		33573		3.750
		33574		3.813
		33873		3.875
5.000	15.0	33407	5.562	3.813
		33830		3.875
		33833		3.937
		33832		4.000
		33831		4.063
		33829		4.125
5.500 (5 $\frac{1}{2}$)	17.0	33395	6.050	4.312
		33393		4.437
		33392		4.500
		33397		4.562
7.000	26.0	33803	7.656	5.750
		33800		5.813
		33801		5.875
		33802		5.937
		33805		6.000
		33432		6.000
7.625	26.4	33906	8.500	5.813

6.2.4 DB-HP Series No-Go Landing Nipple

The Camco DB-HP series landing nipples are high pressure, large-bore, no-go nipples utilized to allow the landing, locking and sealing of locks with attached flow control devices in the production tubing. The DB-HP nipples accept the DB-6-HP type locks and the DB-6N-HP lower no-go nipples accept the DB-6N-HP type locks. The DB-HP series locks are available in many bore sizes for multiple nipple installations.

The internal profile of these nipples includes a shoulder that engages the no-go of the lock and a locking recess. When installed, the locking dogs of the lock move into the recess of the nipple and the lock packing seals in the polished bore section.

6.2.4.1 Operation

To install a no-go lock in these nipples, the lock and attached flow control device are run into the tubing using standard slickline methods. The assembly is lowered until the no-go of the lock contacts the nipple no-go shoulder. Downward jarring forces the locking dogs of the lock into the locking recess of the nipple and anchors the assembly.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread type; bottom-hole pressure and temperature; required pressure rating; percent of H₂O, H₂S and CO₂.

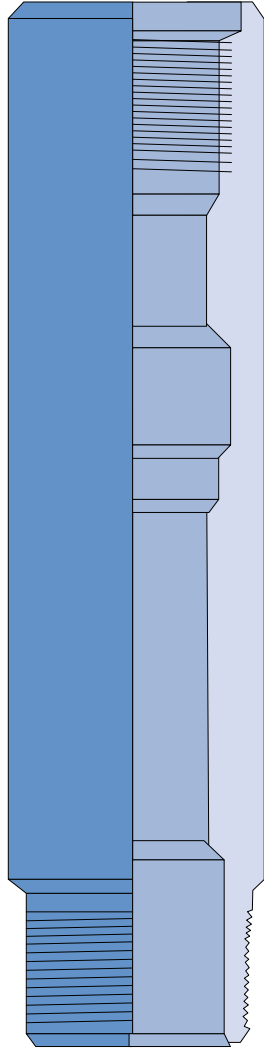
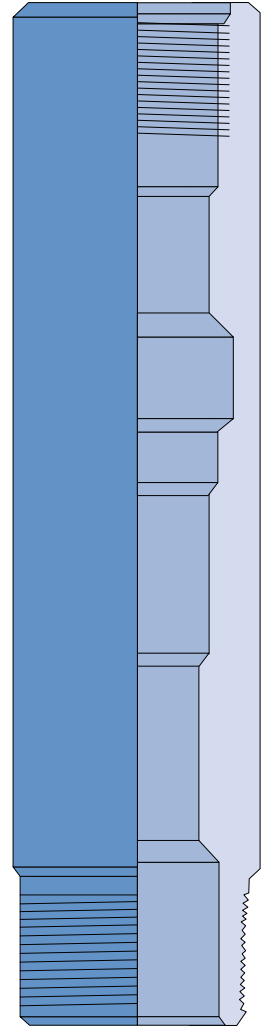
**DB-6-HP****DB-6N-HP****Figure 6-4: DB-HP Series No-Go Landing Nipples**

Table 6-4: DB-HP Series Engineering Data

Tubing		Assembly Number	OD (in.)	Packing Bore (in.)
OD (in.)	Weight (lb/ft)			
4.000 (3½)	11.0	33819†	5.000	3.125
		33818		
		33817		3.250
4.500 (4)	12.75	33689†	5.562	3.187
		33303		
		33304		3.312
		33686		3.437
		33688		3.562
		33687		3.687
5.000	15.0	33828	5.562	3.312
		33441		3.437
		33827		3.562
		33826		3.687
		33824		3.813
		33825		3.967
5.500 (5½)	17.0	33823†	6.050	3.937
		33822		
		33821		4.125
		33820		4.312
		33305		4.500

6.2.5

D-15 No-Go Landing Nipple

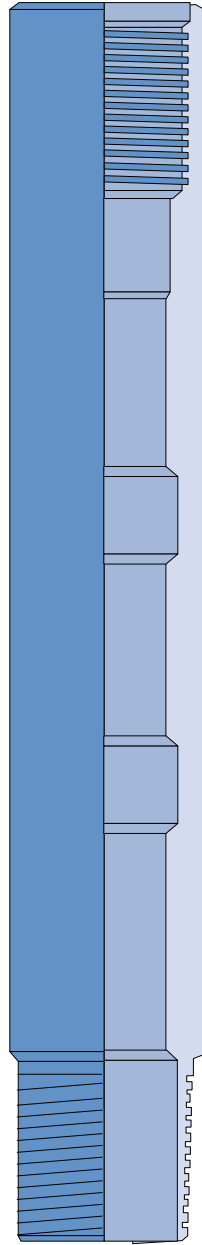
The Camco D-15 no-go landing nipples are utilized to allow the landing, locking and sealing of locks with attached flow control devices in ultra high-pressure production tubing. Designed to withstand up to 15,000 psi with the proper threaded connections, the D-15 nipple is unique in that it has two locking recesses. The D-15 nipple receives the HPC-R lock that engages in the upper recessed groove, and the 15-A, which locks in the lower recessed groove. The middle section has a polished bore for receiving the packing of the locks.

The internal profile of these nipples includes a shoulder that engages the no-go of the lock. When installed, the locking dogs of the lock move into the appropriate recess of the nipple and the lock packing seals in the polished bore section.

6.2.5.1 Operation

To install a no-go lock in these nipples, the lock and attached flow control device are run into the tubing using standard slickline methods. The assembly is lowered until the no-go of the lock contacts the nipple no-go shoulder. Downward jarring forces the locking dogs of the lock into the appropriate locking recess of the nipple and anchors the assembly.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂.



D-15

Figure 6-5: D-15 Series No-Go Landing Nipple

Table 6-5: D-15 Engineering Data

Tubing		Assembly Number	OD (in.)	Packing Bore (in.)
OD (in.)	Weight (lb/ft)			
2.875 (2 $\frac{1}{2}$)	8.7	33270	3.500	1.812
		33269		1.875
		33268		1.937
		33267		2.000
		33266		2.062
		33265		2.125
		33264		2.188
3.500 (3)	12.7	33263	4.250	2.125
		33262		2.188
		33261		2.250
		33260		2.312

6.2.6

W Series Selective Landing Nipples

The Camco W series landing nipples are selective nipples utilized to allow landing, locking and sealing of locks with attached flow control devices in the production tubing. The W-1 and WP-1 nipples are identical except that the WP-1 accepts premium threads and has an additional machined shoulder that positions the selective running tool. All W series nipples receive M series locks. Since these W series landing nipples are selective, they do not require position coding or sequential ordering during installation. Therefore, there is no limit to the number of these nipples that can be run in a live well.

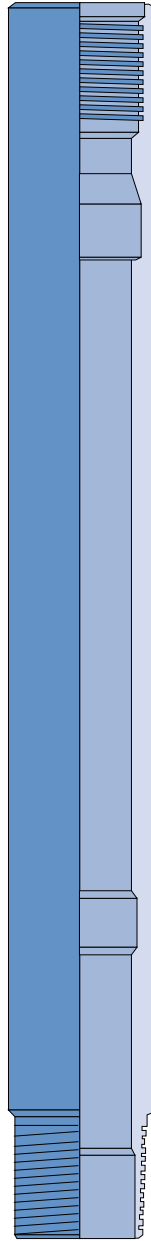
When installed, the locking dogs of the lock move out into the recess of the nipple and the lock packing seals in the polished bore section of the nipple.

6.2.6.1

Operation

To install a selective lock in these nipples, the M series lock and attached flow control device are run into the tubing using standard slickline methods. The assembly is run below the desired landing nipple. The control device and running tool are then pulled back up through the nipple, tripping the running tool. The running tool and control device is then lowered back into the nipple. Downward jarring drives the locking dogs out into the nipple locking recess, anchoring the assembly.

When specifying the product, the following factors should be included; assembly number; casing weight and size; tubing weight, grade, size and thread type; bottom-hole pressure and temperature; required pressure rating; percent of H₂O, H₂S and CO₂.



WP-1

Figure 6-6: W Series Selective Landing Nipple

Table 6-6: W Series Engineering Data

Tubing		Type	Assembly Number	OD (in.)	Packing Bore (in.)
OD (in.)	Weight (lb/ft)				
1.900 (1½)	2.9	W-1	33550	2.500	1.500
2.375 (2)	4.7	W-1	33557	*	1.875
		W-1	33555	3.063	
		W-1	33600		1.906
2.875 (2½)	6.5	W-1	33590	*	1.875
		W-1	33570		2.312
		W-1	33585	3.668	
3.500 (3)	9.3	W-1	33836	*	2.750
		W-1	33565		2.812
		W-1	33563	4.500	

6.3

Locks

See [“Guide to Camco Locks and Running Tools”](#) Tables.

6.3.1

M Series Selective Slickline Locks

The M series lock is attached to subsurface control devices and anchors them in place in the tubing string. M series locks are designed to land in Camco type W selective landing nipples. This series of lock is used in applications involving differential pressures up to 5000 psi above or below the lock assembly.

Each M series lock features an external running and fishing neck which enables use of the most common types of running and pulling tools. The M series includes the MC lock which contains the same components as the M series lock except a collet locking assembly replaces a ratchet locking assembly.

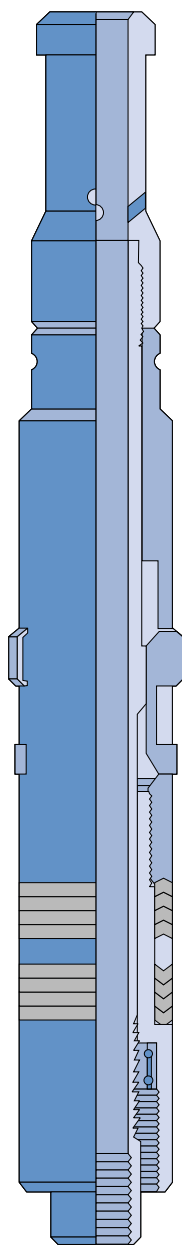
The packing assembly on each M series lock seals in the polished bore of the landing nipple. The M series lock is designed so that whenever pressure differential from above or below is experienced, all force will be supported by the locking dogs. Optional high temperature packing stacks for temperatures above 300° are available for the M locks.

6.3.1.1 Operation

When installing an M series lock in the appropriate nipple, the lock and attached flow control device are attached to the appropriate W series running tool and lowered into the tubing using standard slickline methods. The lock assembly is run below the desired landing nipple. The control device and running tool are then pulled back up through the nipple, tripping the running tool. The running tool and control device are then lowered back into the nipple. Downward jarring moves the expander tube downward, forcing the locking dogs out into the nipple locking recess, anchoring the assembly.

When removing the lock after pressure equalization, upward jarring is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.



M
(Locked Position)

Figure 6-7: M Series Selective Slickline Lock

Table 6-7: M Series Engineering Data

Type	Assembly Number	Packing OD (in.)	Bore (in.)	Fishing Neck (in.)	Redress Kit No.
M	10600	1.500	0.562	1.188	16550
	10603	1.625			16551
	10602	1.825	0.875	1.375	16552
	10604	1.906			16763
	10607	2.312	1.125	1.750	16553
MC	10640	2.750	1.531	2.312	16981
M	10609	2.812	1.546	2.312	16554

6.3.2

C SERIES No-Go Slickline Lock

The type C series lock is attached to subsurface control devices and accessories and anchors them in place in the tubing string. The C series of lock is designed to be landed in a Camco type D or DS non-selective no-go landing nipple and is used in applications involving differential pressures up to 5000 psi from either above or below the lock assembly.

The C series includes type C, CS, CC and CSC locks. These locks are of the same design except the C and CS types feature a ratchet locking assembly, while the CC and CSC locks feature a collet locking assembly, while the CC and CSC locks feature a collet locking assembly. The CS and CSC locks feature a slightly larger OD. All CS series locks feature an external running and fishing neck, which enables use of the most common types of running and pulling tools. Optional high temperature packing stacks for temperatures above 300° are available for the C series locks.

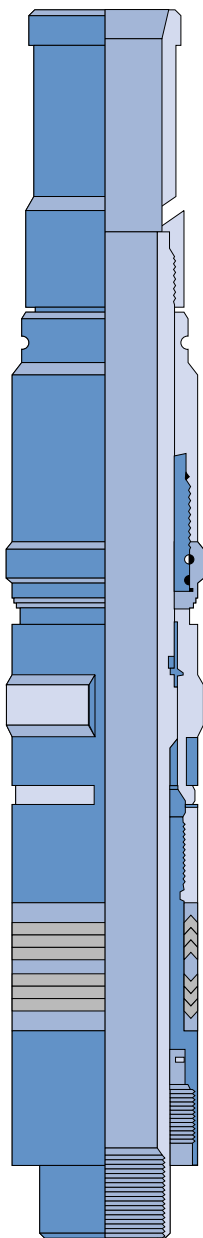
6.3.2.1

Operation

When installing a C series lock in the appropriate landing nipple, the lock and attached flow control device are attached to the appropriate D series running tool and run into the tubing using standard slickline methods. This assembly is lowered until the no-go ring of the lock lands on the nipple no-go shoulder. Downward jarring moves the no-go ring upward and releases the expander tube to move downward, forcing the locking dogs of the lock into the locking recess of the nipple, anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate Camco J series pulling tool is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.



C
(Locked Position)

Figure 6-8: C Series No-Go Slickline Lock

Table 6-8: C Series Engineering Data

Type	Assembly Number	No-Go (in.)	Packing OD (in.)	Bore ID (in.)	Fishing Neck (in.)	Redress Kit Number
C	10200	1.484	1.437	.562	1.188	16560
CC	10214	1.484	1.437	.562	1.188	16762
C	10206	1.609	1.562	.562	1.188	16562
CC	10201	1.609	1.562	.562	1.188	16980
C	10204	1.859	1.812	.875	1.375	16563
CC	10226	1.859	1.812	.875	1.375	16575
CS	10230	1.910	1.875	.875	1.375	16570
CSC	10225	1.910	1.875	.875	1.375	16580
C	10208	2.296	2.250	1.125	1.750	16564
CC	10227	2.296	2.250	1.125	1.750	16576
CS	10232	2.345	2.312	1.125	1.750	16571
CSC	10223	2.345	2.312	1.125	1.750	16581
C	10210	2.795	2.750	1.546	2.312	16565
CC	10212	2.795	2.750	1.531	2.312	16577
CS	10236	2.856	2.812	1.546	2.312	16572
CSC	10229	2.856	2.812	1.531	2.312	16582
CS	10234	2.906	2.875	1.546	2.312	16584

6.3.3

DB-6 No-Go Slickline Lock

The DB-6 lock is a non-selective no-go locking device designed to be landed in a Camco type DB-6 series landing nipple and Camco B-6 hydraulic safety valve landing nipples. The lock anchors and seals an attached pressure control device in position in the tubing string. This lock is used in applications involving differential pressures up to 5000 psi from below the lock assembly. Pressure ratings for differential pressures from above vary with each assembly.

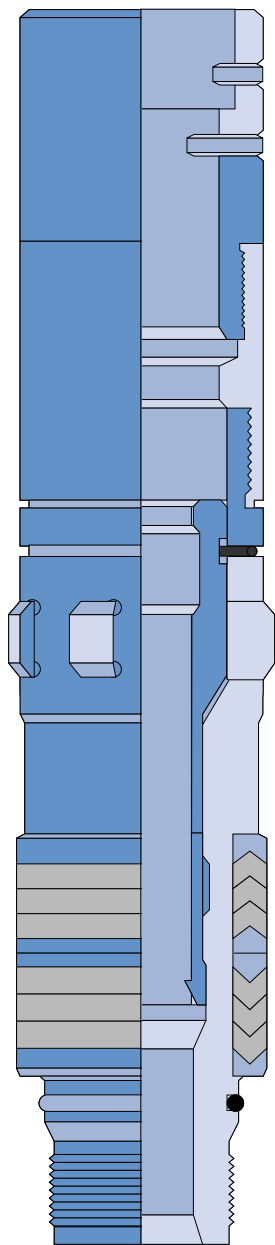
Each lock features an internal fishing neck that allows a large bore through the lock. When set in position, an internal sleeve (expander tube) is held in the locked position by both a collet type latch and shear pins, preventing the possibility of unlocking at high flow rates. The DB-6 lock is also designed to allow the use of tattle-tale type running tools. These tools give the slickline operator clear indication that the assembly is in the locked position. Optional high temperature packing stacks for temperatures above 300°F are available for the DB-6 locks.

6.3.3.1 Operation

The DB-6 lock is installed in the appropriate landing nipple using standard slickline methods. The lock and attached flow control device are attached to the appropriate Z-6 series running tool and lowered into the tubing until the no-go of the lock lands on the nipple no-go shoulder. Downward jarring moves the expander tube downward, forcing the locking dogs of the lock into the locking recess of the nipple, anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate PRS series pulling tool is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.



DB-6
(Locked Position)

Figure 6-9: DB-6 No-Go Slickline Lock

Table 6-9: DB-6 Engineering Data

Assembly Number	No-Go OD (in.)	Packing OD (in.)	Bore ID (in.)	Redress Kit No.
10320	3.172	3.125	1.875	16613
10325	3.234	3.187	1.875	16611
10321	3.296	3.250	1.875	16608
10322	3.360	3.312	1.875	16609
10323	3.484	3.437	1.875	16610
10255	3.547	3.500	2.250	16555
10259	3.609	3.562	2.250	16557
10258	3.657	3.625	2.250	16533
10260	3.735	3.687	2.250	16532
10257	3.785	3.750	2.250	16531
10254	3.843	3.813	2.250	16530
10351	3.910	3.875	2.250	16738
10345	3.975	3.937	2.250	16663
10344	4.046	4.000	2.250	16662
10343	4.110	4.063	2.250	16661
10341	4.172	4.125	2.250	16660
10261	4.360	4.312	2.781	16537
10274	4.482	4.437	2.781	16536
10263	4.545	4.500	2.781	16535
10252	4.610	4.562	2.781	16534
10390	5.732	5.687	4.000	18138
10269	5.795	5.750	4.000	16542
10287*	5.740	5.750	4.000	16556
10268	5.858	5.813	4.000	16541
10253	5.890	5.813	4.000	16543
10267	5.920	5.875	4.000	16540
10266	5.982	5.937	4.000	16539
10265	6.045	6.000	4.000	16538

6.3.4

DB-6-E No-Go Slickline Lock

The DB-6-E lock is an non-selective no-go locking device designed to be landed in a Camco type DB series landing nipple and Camco B-6 hydraulic safety valve landing nipples. The lock anchors and seals the attached pressure control device in position in the tubing string. This lock is used in applications involving

differential pressures up to 5000 psi from either above or below the lock assembly. The DB-6-E lock features a unique expendable no-go ring that deforms when high differential pressure is experienced from above the lock. This means that all setting force is supported by the locking dogs of the lock. This configuration prevents possible deformation of the lock mechanisms or the landing nipple since the expendable no-go ring is replaced with each trip into the hole.

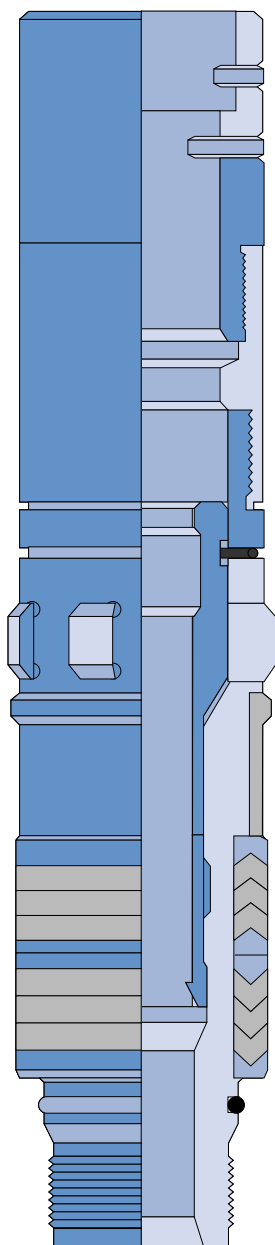
Each lock features an internal fishing neck that allows a large bore through the lock. When set in position, an internal sleeve (expander tube) is held in the locked position by both a collet type latch and shear pins, preventing the possibility of unlocking at high flow rates. The DB-6 -E lock is also designed to allow the use of tattletale type running tools. These tools give the slickline operator a clear indication that the assembly is in the locked position. Optional high temperature packing stacks for temperatures above 300° are available for the DB-6-E locks.

6.3.4.1 Operation

The DB-6-E lock is installed in the appropriate landing nipple using standard slickline methods. The lock and attached flow control device are attached to the appropriate Z-6 series running tool and lowered into the tubing until the no-go of the lock lands on the nipple no-go shoulder. Downward jarring move the expander tube downward, forcing the locking dogs of the lock into the locking recess of the nipple, thereby anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate PRS series pulling tool is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.



DB-6-E
(Locked Position)

Figure 6-10: DB-6-E No-Go Slickline Lock

6.3.5

DB-6-HP Series No-Go Slickline Locks

The DB-6-HP series lock is a non-selective no-go locking device designed to be landed in a Camco type DB-6-HP series landing nipple and Camco B-6 hydraulic safety valve landing nipples. The lock anchors and seals an attached

pressure control device in position in the tubing string. The DB-6-HP series lock can withstand differential pressures up to 10,000 psi from below the assembly. Pressure ratings for differential pressures from above vary with each assembly.

Each lock features an internal fishing neck that allows a large bore through the lock. When in the set position, an internal sleeve (expander tube) is held in the locked position by both a collet type latch and shear pins, preventing the possibility of unlocking at high flow rates. The DB-6 lock is also designed to allow the use of tattletale type running tools. These tools give the slickline operator a clear indication that the assembly is in the locked position. Optional high temperature packing stacks for temperatures above 300°F are available for the DB-6-HP locks.

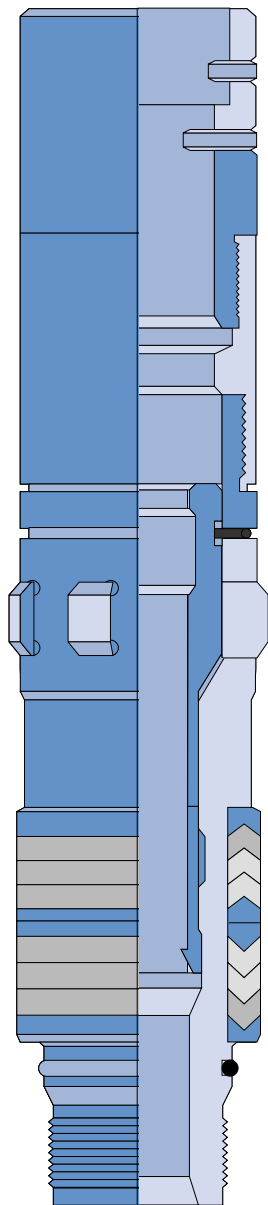
The DB-6-HP series includes the DB-6N-HP lock, which features a substantially larger no-go area than the DB-6-HP lock. The DB-6N-HP is a bottom no-go lock designed to be installed in a bottom no-go DB-6N-HP landing nipple and is normally used as the bottom nipple in the tubing string.

6.3.5.1 Operation

The DB-6-HP series lock is installed in the appropriate landing nipple using standard slickline methods. The lock and attached flow control device are attached to the appropriate Z-6 series running tool and lowered into the tubing until the no-go of the lock lands on the nipple no-go. Downward jarring moves the expander tube downward, forcing the locking dogs of the lock into the locking recess of the nipple and anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate PRS series pulling tool releases the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.



DB-6-HP
(Locked Position)

Figure 6-11: DB-6-HP Series No-Go Slickline Lock

6.3.6 HPC-R No-Go Slickline Lock

The HPC-R lock is a non-selective no-go locking device designed to be landed in a Camco D, DS or D-15 type landing nipple. The HPC-R lock anchors and seals an attached pressure control device in position in the tubing string. Each lock features an internal fishing neck that allows the maximum bore possible through the lock.

When installed in a D or DS nipple, the HPC-R lock is used in applications involving differential pressures up to 10,000 psi from above or below the lock assembly. When the lock is installed in a D-15 nipple, the assembly can withstand 15,000 psi from below and 10,000 psi from above. The design of the HPC-R lock is such that whenever pressure differential from above or below is experienced, all force will be supported by the locking dogs and not the no-go ring or no-go release ring.

The HPC-R locks are held in the locked position with a proven ratchet locking assembly. Optional high temperature packing stacks for temperatures above 300°F are available for the HPC-R locks.

6.3.6.1 Operation

When installing an HPC-R lock in the appropriate nipple, the lock and attached flow control device are attached to the appropriate D series running tool and run into the tubing using standard slickline methods. This assembly is lowered until the no-go of the lock lands on the nipple no-go shoulder. Downward jarring move the no-go ring upward, releasing and enabling the expander tube to move downward, forcing the locking dogs of the lock into the locking recess of the nipple and anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate PRS series pulling tool is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.

6.3.7 CBNS-R No-Go Slickline Locks

The type CBNS-R lock is attached to subsurface control devices and anchors them in place in the tubing string. The CBNS-R is a bottom no-go substitute lock designed to be used as the only or bottom lock in the tubing string. CBNS-R

locks are landed in Camco type DN non-selective no-go landing nipples. This lock is used in applications involving differential pressure up to 10,000 psi from either above or below the lock assembly.

The CBNS-R features an internal fishing neck that allows a large bore through the neck. The CBNS-R locks are held in the locked position with a proven ratchet locking assembly. The CBNS-R lock is designed so that whenever pressure differential from above or below is experienced, all force will be supported by the locking dogs and not the no-go ring or no-go release ring. Optional high temperature packing stacks for temperatures above 300°F are available for the CBNS-R locks.

When installing a CBNS-R lock in the appropriate landing nipple, the lock and attached flow control device are attached to the appropriate D running tool and run into the tubing using standard slickline methods. This assembly is lowered until the no-go of the lock locates on the nipple no-go shoulder. Downward jarring moves the no-go ring upward, releasing and enabling the expander tube to move downward, forcing the locking dogs of the lock into the locking recess of the nipple and anchoring the assembly.

When removing the lock after pressure equalization, upward jarring with the appropriate PRS series-pulling tool is applied to unlock the assembly. The lock can then be pulled to the surface.

When specifying the product, the following factors should be included; assembly number; tubing weight, size and thread type; bottom-hole pressure and temperature; percent of H₂O, H₂S and CO₂; landing nipple type and ID.

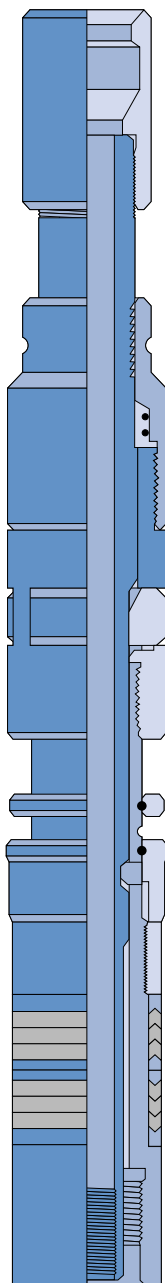


Figure 6-12: CBNS-R No-Go Slickline Lock

Intentionally Blank

Overview of Camco Nipples, Locks and Accessory Control Devices (a)

Tubing OD (Nom.) (in.)	Nipples			Locks		Blanking Plugs			Standing Valves		Circulating Plugs		Shock Absorbers	
	Type	Assy Number	Packing Bore ID	Type	Assy Number	Type	Assy Number	Use Adapter Number	Type	Assy Number	Type	Assy Number	O Sub #	Assy Number
1.900 (1½)	A	33013	1.187	*	*	*	*	*	A-2	20455	*	*	*	*
	A	33015	1.250	*	*	*	*	*	A-2	20450	*	*	*	*
									M	20470				
	A	33018	1.437	*	*	*	*	*	A-2	20477	*	*	*	*
									M	20475				
	D	33306	1.437	C	10200	A	20002	N/R	M-1	22065	C	20911	20150	20327
				CC	10214									
2.063 (2⅛)	D-2	33307	1.437	C	10200	A	20002	N/R	M-1	22065	C	20911	20150	20327
				CC	10214									
	W-1	33550	1.500	M	10600	A	20002	N/R	*	*	C	20911	20150	20327
	D	33324	1.437	C	10200	A	20002	N/R	M-1	22065	C	20911	20150	20327
2.375 (2)				CC	10214									
	D	33326	1.562	C	10206	A-2	20015	N/R	M-1	20363	C	20911	20162	21214
				CC	10201									
	A	33048	1.187	*	*	*	*	*	A-2	20455	*	*	*	*
	A	33047	1.250	*	*	*	*	*	A-2	20450	*	*	*	*
									M	20470				
	A	33049	1.437	*	*	*	*	*	A-2	20477	*	*	*	*
									M	20475				
	D	33334	1.437	C	10200	A	20002	N/R	M-1	22065	C	20911	20150	20327
				CC	10214									
	D-2	33321	1.437	C	10200	A	20002	N/R	M-1	22065	C	20911	20150	20327
				CC	10214									
	A	33070	1.562	*	*	*	*	*	A-2	20476	*	*	*	*
	D	33336	1.562	C	10200	A-2	20015	N/R	M-1	20363	C	20911	20162	21214
				CC	10214									
	D-2	33327	1.562	C	10200	A-2	20015	N/R	M-1	20363	C	20911	20162	21214
				CC	10214									
	A	33053	1.625	*	*	*	*	*	A-2	20461	*	*	*	*
	DN	33843	1.765	CBNS-R	10347	HP-A	20275	N/R	HP-SV	20296	HP-C	20311	N/R	20351
	A	33056	1.812	*	*	*	*	*	A-2	20458	*	*	*	*
									M	20472				
2.875 (2½)	D	33340	1.812	HPC-R	10520	HP-A	20298	N/R	HP-SV	20285	HP-C	20308	N/R	*
				C	10204	A-2	20002		M-1	22066	C	20910	20153	20656
				CC	10226									
	A	33061	1.875	*	*	*	*	*	M1-DS	20447	*	*	*	*
	DS	33348	1.875	HPC-R	10521	HP-A	20298	N/R	HP-SV	20285	HP-C	20308	N/R	*
				CS	10230	A-2	20002		M1-DS	20447	C	20910	20153	20656
				CSC	10225									
	WP-1	33557	1.875	M	10602	A-2	20002	N/R	*	*	C	20910	20153	20656
	W-1	33555	1.875	M	10602	A-2	20002	N/R	*	*	C	20910	20153	20656
		33600	1.906		10604									
	A	33078	1.187	*	*	*	*	*	A-2	20455	*	*	*	*
	A	33077	1.437	*	*	*	*	*	A-2	20477	*	*	*	*
2.875 (2½)	D	33318	1.562	C	10206	A-2	20015	N/R	M-1	20363	C	20911	20162	21214
				CC	10201									
	A	33080	1.812	*	*	*	*	*	A-2	20458	*	*	*	*
									M	20472				
	D	33355	1.812	HPC-R	10520	HP-A	20298	N/R	HP-SV	20285	HP-C	20308	N/R	*
				C	10204	A-2	20020		M-1	22066	C	20910	20153	20656

Overview of Camco Nipples, Locks and Accessory Control Devices (b)

	Nipples	Locks	Blanking Plugs	Standing Valves							Circulating Plugs		Shock Absorbers		
Tubing OD (in.)	Type	Assy Number	Packing Bore ID	Type	Assy Number	Type	Assy Number	Use Adapter Number	Type	Assy #	Type	Assy No.	Use O Sub Number	Assy Number	
2.875 (2 ¹ / ₂)	D-15	33270	1.812	HPC-R	10520	HP-A	20298	N/R	*	*	HP-C	20308	N/R	*	
	WP-1	33590	1.875	M	10602	A-2	20020	N/R	*	*	C	20910	20153	20656	
	DS	33366	1.875	HPC-R	10521	HP-A	20298	N/R	HP-SV	20285	HP-C	20308	N/R	*	
				CS	10230	A-2	20020		M1-DS	20447	C	20910	20153	20656	
				CSC	10225										
	D-15	33269	1.875	HPC-R	10521	HP-A	20298	N/R	*	*	HP-C	20308	N/R	*	
	D	33295	1.937	HPC-R	10522	HP-A	20303	N/R	HP-SV	20299	HP-C	20306	N/R	20332	
	D-15	33268	1.937	HPC-R	10522	HP-A	20303	N/R	HP-SV	20299	HP-C	20306	N/R	20332	
	D	33294	2.000	HPC-R	10523	HP-A	20303	N/R	HP-SV	20299	HP-C	20306	N/R	20332	
	D-15	33267	2.000	HPC-R	10523	HP-A	20303	N/R	HP-SV	20299	HP-C	20306	N/R	20332	
	D	33293	2.062	HPC-R	10524	HP-A	20302	N/R	HP-SV	20313	HP-C	20305	N/R	*	
	D-15	33266	2.062	HPC-R	10524	HP-A	20302	N/R	HP-SV	20313	HP-C	20305	N/R	*	
	D	33868	2.125	HPC-R	10525	HP-A	21973	N/R	HP-SV	20326	HP-C	20290	N/R	*	
	D-15	33265	2.125	HPC-R	10525	HP-A	21973	N/R	HP-SV	20326	HP-C	20290	N/R	*	
	D	33292	2.188	HPC-R	10526	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
	D-15	33264	2.188	HPC-R	10526	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
	DN	33844	2.203	CBNS-R	10533	HP-A	20273	N/R	HP-SV	20271	HP-C	20309	N/R	20352	
	A	33081	2.250	*	*	*	*	*	A-2	20464	*	*	*	*	
									M	20474					
	D	33310	2.250	HPC-R	10527	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
				C	10208	A-2	21984		M-1	22042	C	20912	20155	20658	
				CC	10227										
D-2	33320	2.250	C	10208	A-2	21984	N/R	M-1	22042	C	20912	20155	20658		
			CC	10227											
A	33084	2.312	*	*	*	*	*	MI-DS	20448	*	*	*	*		
DS	33365	2.312	HPC-R	10528	HP-A	20269	N/R	HP-SV	20317	HP-C	20308	N/R	*		
			CS	10232	A-2	21984		MI-DS	20448	C	20912	20155	20658		
			CSC	10223											
WP-1	33570	2.312	M	10607	AS	21423	N/R	*	*	C	20912	20155	20658		
W-1	33585	2.312	M	10607	AS	21423	N/R	*	*	C	20912	20155	20658		
3.5 00(3)	DS	33433	1.875	HPC-R	10521	HP-A	20298	N/R	HP-SV	20285	HP-C	20308	N/R	*	
				CS	10230	A-2	20020		MI-DS	20447	C	20910	20153	20656	
				CSC	10225										
	D	33869	2.125	HPC-R	10525	HP-A	21973	N/R	HP-SV	20326	HP-C	20290	N/R	*	
	D-15	33263	2.125	HPC-R	10525	HP-A	21973	N/R	HP-SV	20326	HP-C	20290	N/R	*	
	D	33291	2.188	HPC-R	10526	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
	D-15	33262	2.188	HPC-R	10526	HPA	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
	A	33091	2.250	*	*	*	*	*	A-2	20464	*	*	*	*	
									M	20474					
	D	33374	2.250	HPC-R	10527	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
				C	10208	A-2	21984		M-1	22042	C	20912	20155	20658	
				CC	10227										
	D-2	33328	2.250	C	10208	A-2	21984	N/R	M-1	22042	C	20912	20155	20658	
				CC	10227										
	D-15	33261	2.250	HPC-R	10527	HP-A	20301	N/R	HP-SV	20315	HP-C	20304	N/R	20339	
	DS	33369	2.312	HPC-R	10528	HP-A	20269	N/R	HP-SV	20317	HP-C	21640	N/R	*	
				CS	10232	A-2	21984		M1-DS	20448	C	20912	20155	20658	
				CSC	10223										
D-15	33260	2.312	57	HPC-R	10528	HP-A	20269	N/R	HP-SV	20317	HP-C	21640	N/R	*	
DS	33296	2.437	52	HPC-R	10529	HP-A	20307	N/R	HP-SV	20317	HP-C	20294	N/R	*	
	33871	2.562			20530		21772							20353	
DN	33845	2.703	52	CBNS-R	10534	HP-A	21772	N/R	HP-SV	20297	HP-C	20294	N/R	20353	

Overview of Camco Nipples, Locks and Accessory Control Devices (c)

	Nipples			Locks		Blanking Plugs			Standing Valves		Circulating Plugs		Shock Absorbers		
Tubing size OD (Nominal) (in.)	Type	Assy Number	Packing Bore ID	Type	Assy Number	Type	Assy Number	Use Adapter Number	Type	Assy Number	Type	Assy Number	Use O Sub Number	Assy Number	
3.500 (3)	A	33095	2.750	*	*	*	*	*	A-2	20463	*	*	*	*	
	D-2	33106	2.750	C	10210	A-2	20009	N/R	M-1	22036	C	20913	20156	20335	
				CC	10212										
	D	33373	2.750	HPC-R	10531	HP-A	21772	N/R	HP-SV	20.17	HP-C	20294	N/R	20353	
				C	10210										A-2
				CC	10212										
	WP-1	33836	2.750	MC	10640	A-2	20008	N/R	*	*	C	20913	20156	20335	
	A	33097	2.812	*	*	*	*	*	M1-DS	20449	*	*	*	*	
	DS	33376	2.812	CS	10236	A-2	20009	N/R	M1-DS	20449	C	20913	20156	20335	
				CSC	10229										
WP-1	33565	2.812	M	10609	A-2	20008	N/R	*	*	C	20913	20156	20335		
W-1	33563	2.812	M	10609	A-2	20008	N/R	*	*	C	20913	20156	20335		
DS	33377	2.875	CS	10234	A-2	20009	N/R	*	*	C	20913	20156	20335		
4.000 (3½)	D8	33437	3.125	D8-6	10320	D8-HP	20227	N/R	*	**	*	***	*	20336	
						D8-P	20218	10481		*		*			
						D8-1-WLP	20216			**		***			
	D8-HP	33819	3.125	D8-6N-HP	10319	D8-HP	20341	N/R	*	**	*	***	*	20336	
						D8-P	20235			*		*			
						D8-1-WLP	20234			**		***			
	D8-HP	33818	3.125	D8-6-HP	10314	D8-HP	20227	N/R	*	**	*	***	*	20336	
						D8-P	20218	10481		*		*			
						D8-1-WLP	20216			**		***			
	D8	33426	3.187	D8-6	10325	D8-HP	20227	N/R	*	**	*	***	*	20336	
						D8-P	20218	10481		*		*			
						D8-1-WLP	20216			**		***			
	D8	33438	3.250	D8-6	10321	D8-HP	20260	N/R	*	**	*	***	*	20336	
						D8-P	20218	10482		*		*			
						D8-1-WLP	20216			**		***			
	D8-HP	33817	3.250	D8-6-HP	10312	D8-HP	20260	N/R	*	**	*	***	*	20336	
						D8-P	20218	10482		*		*			
						D8-1-WLP	20216			**		***			
	D8	33439	3.312	*	*	*	*	*	A-2	21758	*	*	*	*	20336
				D8-6	10322	D8-HP	20260	N/R	*	**		***			
						D8-P	20218	10482		*		*			
						D8-1-WLP	20216			**		***			
4.500 (4)	D8-HP	33689	3.187	D8-6N-HP	10335	D8-HP	20342	N/R	*	**	*	***	*	20336	
						D8-P	20218	10484		*		*			
						D8-1-WLP	20216			**		***			
	D8-HP	33303	3.187	D8-6-HP	10317	D8-HP	20227	N/R	*	**	*	***	*	20336	
						D8-P	20218	10481		*		*			
						D8-1-WLP	20216			**		***			
	D8-HP	33304	3.312	D8-6-HP	10318	D8-HP	20260	N/R	*	**	*	***	*	20336	
						D8-P	20218	10482		*		*			
						D8-1-WLP	20216			**		***			
	D8	33440	3.437	*	*	*	*	*	A-2	20231	*	*	*	*	20336
				D8-6	10323	D8-HP	20343	N/R	*	**		***			
						D8-P	20218	10485		*		*			
						D8-1-WLP	20216			**		***			
D8-HP	33686	3.437	D8-6-HP	10324	D8-HP	20260	N/R	*	**	*	***	*	20336		
					S8-P	20218	10485		*		*				
					S8-1-WPL	20216			**		***				

* Not Applicable

** D8-1-WPL kit assembly number 20217 and D8-HP kit assembly number 202250 will convert blanking plug to a standing valve.

*** D8-1-WPL kit assembly number 20215 abd D8-HP kit assembly number 20325 will convert blanking plug to a circulating plug.

Overview of Camco Nipples, Locks and Accessory Control Devices (d)

	Nipples			Locks		Blanking Plugs			Standing Valves		Circulating Plugs		Shock Absorbers	
Tubing size OD (Nominal) (in.)	Type	Assy No	Packing Bore ID	Type	Assy No	Type	Assy Number	Use Adapter Number	Type	Assy No.	Type	Assy No.	O Sub #r	Assy No
4.50 (4)	D8	33571	3.500	D8-6	10255	D8-HP	20344	N/R	*	**	*	***	*	20446
						D8-P	20218	10486		*		*		
						D8-1-WLP	20216			**		***		
	D-8	33300	3.562	D8-6	10259	D8-HP	20261	N/R	*	**	*	***	*	20446
						D8-P	20218	10326		*		*		
						D8-1-WLP	20216			**		***		
	D8-HP	33688	3.562	D8-6-HP	10334	D8-HP	20261	N/R	*	**	*	***	*	20446
						D8-P	20218	10326		*		*		
						D8-1-WLP	20216			**		***		
	A	33088	3.625	*	*	*	*	*	A-2	20233	*	*	*	*
	D8	33572	3.625	D8-6	10258	*	*	*	A-2	20233	*	*	*	20446
						D8-HP	20261	N/R	*	**		***		
						D8-P	20218	10326		*		*		
	D8-1-WLP	20216	**	***										
	D8-HP	33687	3.687	D8-6-HP	10333	D8-HP	20017	N/R	*	**	*	***	*	20446
						D8-P	20218	10350		*		*		
						D8-1-WLP	20216			**		***		
	D8	33935	3.687	D8-6	10260	*	*	*	A-2	20226	*	*	*	22138
						D8-HP	20017	N/R	*	**		***		
						D8-P	20218	10350		*		*		
	D8-1-WLP	20216	**	***										
	D8	33573	3.750	D8-6	10257	*	*	*	A-2	20276	*	*	*	20336
						D8-HP	20017	N/R	*	**		***		
						D8-P	20218	10350		*		*		
D8-1-WLP	20216	**	***											
D8	33574	3.813	D8-6	10254	*	*	*	A-2	20277	*	*	*	20336	
					D8-HP	20345	N/R	*	**		***			
					D8-P	20218	10487		*		*			
D8-1-WLP	20216	**	***											
D8	33873	3.875	D8-6	10351	*	*	*	A-2	20278	*	*	*	20446	
					D8-HP	20345	N/R	*	**		***			
					D8-P	20218	10487		*		*			
D8-1-WLP	20216	**	***											
5.000	D8-HP	33828	3.312	D8-1-HP	10318	D8-HP	20260	N/R	*	**	*	***	*	20446
						D8-P	20218	10482		*		*		
						D8-1-WLP	20216			**		***		
	D8-HP	33441	3.437	D8-6-HP	10324	D8-HP	20343	N/R	*	**	*	***	*	20446
						D8-P	20218	10485		*		*		
						D8-1-WLP	20216			**		***		
	D8-HP	33827	3.562	D8-6-HP	10334	D8-HP	20261	N/R	*	**	*	***	*	20446
						D8-P	20218	10326		*		*		
						D8-1-WLP	20216			**		***		
	D8-HP	33826	3.687	D8-6-HP	10333	D8-HP	20017	N/R	*	**	*	***	*	20446
						D8-P	20218	10350		*		*		
						D8-1-WLP	20216			**		***		
	D8	33407	3.813	D8-6	10254	*	*	*	A-2	20277	*	*	*	20446
						D8-HP	20345	N/R	*	**		***		
						D8-P	20218	10487		*		*		
	D8-1-WLP	20216	**	***										
D8-HP	33824	3.813	D8-6-HP	10340	D8-HP	20345	N/R	*	**	*	***	*	20446	
					D8-P	20218	10487		*		*			
					D8-1-WLP	20216			**		***			

* Not Applicable

** D8-1-WLP kit assembly number 20217 and D8-HP kit assembly 20225 will convert blanking plug to a standing valve.

*** D8-1-WLP kit assembly number 20215 and D8-HP kit assembly 20325 will convert blanking plug to a circulating plug.

Overview of Camco Nipples, Locks and Accessory Control Devices (e)

	Nipples			Locks		Blanking Plugs			Standing Valves					
Tubing size OD (Nominal Inches)	Type	Assy. Number	Packing Bore ID	Type	Assy. Number	Type	Assy. Number	Use Adapter Number	Type	Assy Number	Type	Assy Number	O Sub Number	Assy. Number
5.000	D8	33830	3.875	*	*	*	*	*	A-2	20278	*		*	*
				D8-6	10351	D8-HP	20345	10487	*	**		***		22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33833	3.937	D8-6	10345	D8-HP	20347	10346	*	**	*	*	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8-HP	33825	3.937	D8-6-HP	10338	D8-HP	20347	10346	*	**	*		*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33832	4.000	D8-6	10344	D8-HP	20347	10346	*	**	*	***	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33831	4.063	D8-6	10343	D8-HP	203147	10346	*	**	*	***	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33829	4.125	D8-6	10341	D8-HP	20348	10354	*	**	*	***	*	22138
						D8-P	20218		*	*				
D8-1-WLP						20216	*		***					
5.500 (5 ¹ / ₂)	D8-HP	33823	3.937	D8-6N-HP	10339	D8-HP	20346	10488	*	**	*	***	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8-HP	33822	3.937	D8-6-HP	10338	D8-HP	20347	10346	*	**	*	***	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8-HP	33821	4.125	D8-6-HP	10337	D8-HP	20348	10354	*	**	*	***	*	22138
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33395	4.312	D8-6	10261	D8-HP	20011	10329	*	**	*	***	*	20329
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8-HP	33820	4.312	D8-6-HP	10336	D8-HP	20263	10489	*	**	*	***	*	20337
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33393	4.437	D8-6	10274	D8-HP	20213	10328	*	**	*	***	*	20338
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
D8	33392	4.500	D8-6	10263	*	*	*	A-2	21674	*	*	*	*	
					D8-HP	20018	10327	*	**		***	20337		
					D8-P	20218		*	*					
					D8-1-WLP	20216		*	***					
D8-HP	33305	4.500	D8-6-HP	10316	D8-HP	20018	10327	*	**	*	***	*	20337	
					D8-P	20218		*	*					
					D8-1-WLP	20216		*	***					
D8	33397	4.562	D8-6	10252	D8-HP	20018	10327	*	**	*	***	*	20337	
					D8-P	20218		*	*					
					D8-1-WLP	20216		*	***					
7.000	D8	33803	5.750	D8-6	10269	D8-HP	20019	10331	*	**	*	***	*	20334
						D8-P	20218		*	*				
						D8-1-WLP	20216		*	***				
	D8	33800	5.750	D8-6N	10287	D8-HP	20349	10490	*	**	*	***	*	20334
D8-P						20218	*		*					
D8-1-WLP						20216	*		***					

* Not Applicable

** D8-1-WLP kit assembly number 20217 and D8-HP kit assembly number 20225 will convert blanking plug to a standing valve.

*** D8-1-WLP kit assembly number 20215 and D8-HP kit assembly number 20325 will convert blanking plug to a circulating plug.



Intentionally Blank

Guide to Camco Locks and Running Tools (a)

LOCKS					BLANKING PLUGS							STANDING VALVES					CIRCULATING PLUGS				
Type	Assy. Number	OD Packing	Type	Plug Assy. Number	Lock with Plug Running Tool	Prong	Pulling Tool	Equal Prong for Lock Pulling Tool	Pulling Tool Equal. Prong	Pulling Tool for Equal Insert	Equal. Prong for Insert Pulling Tool	Valve Assy Number	Running Tool	Running Prong	Lock Pulling Tool	Equal. Prong	Plug Assy. No.	Running Tool	Running Prong	Lock Pulling Tool	Equal. Prong
C	10200	1.437	A	20002	15021	**	15154	**	15151	**	**	**	**	**	**	**	20911	15024	15974	15154	15646
CC	10214	1.437	A	20002	15021	**	15154	**	15151	**	**	**	**	**	**	**	2011	15024	15974	15154	15646
M	10600	1.500	A	20002	15139	**	15154	**	15151	**	**	**	**	**	**	**	20911	15139	15973	15154	15646
C	10206	1.562	A-2	20015	15021	**	15154	**	15151	**	**	**	**	**	**	**	20911	15024	15974	15154	15643
CC	10201	1.562	A-2	20015	15021	**	15154	**	15151	**	**	**	**	**	**	**	20911	15024	15974	15154	15643
CBNS-R	10347	1.765	HP-A	20275	13064	**	15111	**	15111	**	**	20296	13063	**	15111	13081	20311	10363	10393	15111	13081
C	10204	1.812	A-2	20020	15035	**	15156	**	15156	**	**	**	**	**	**	**	20910	15017	15964	15156	13101
CC	10226	1.812	A-2	20020	15035	**	15156	**	15156	**	**	**	**	**	**	**	20910	15017	15964	15156	13101
HPC-R	10520	1.812	HP-A	20298	13064	**	15111	**	15111	**	**	20285	13063	**	15111	13082	20308	13063	13087	15111	13082
CS	10230	1.875	A-2	20020	15035	**	15156	**	15156	**	**	**	**	**	**	**	20910	15017	15963	15156	13101
CSC	10225	1.875	A-2	20020	15035	**	15156	**	15156	**	**	**	**	**	**	**	20910	15017	15963	15156	13101
M	10602	1.875	A-2	20020	15890	**	15156	**	15156	**	**	**	**	**	**	**	20910	15140	15962	15156	15646
HPC-R	10521	1.875	HP-A	20298	13064	**	15111	**	15111	**	**	20285	13063	**	15111	13082	20308	13063	13087	15111	13082
M	10604	1.906	A-2	20020	15890	**	15156	**	15156	**	**	**	**	**	**	**	20910	15140	15962	15156	15646
HPC-R	10522	1.937	HP-A	20303	13064	**	15211	**	15211	**	**	20299	10363	**	15111	13083	20306	13063	13088	15111	13083
HPC-R	10523	2.000	HP-A	20303	13066	**	15211	**	15211	**	**	20299	10365	**	15211	13083	20306	13065	13088	15111	13083
HPC-R	10524	2.062	HP-A	20302	13066	**	15211	**	15211	**	**	20313	13065	**	15211	13084	20305	13065	13089	15211	13084
HPC-R	10525	2.125	HP-A	21973	15055	**	15211	**	15211	**	**	20326	15057	**	15211	13022	20290	15057	13021	15211	13022
HPC-R	10526	2.188	HP-A	20301	15055	**	15211	**	15211	**	**	20315	15057	**	15211	13085	20304	15057	13090	15211	13085
CBNS-R	10533	2.203	HP-A	20273	15055	**	15211	**	15211	**	**	20271	15057	**	15211	13080	20309	15057	13092	15211	13080
C	10208	2.250	A-2	21984	15037	**	15158	**	15158	**	**	**	**	**	**	**	20912	15019	15966	15158	15968
CC	10227	2.250	A-2	21984	15037	**	15158	**	15158	**	**	**	**	**	**	**	20912	15019	15966	15158	15968
HPC-R	10527	2.250	HP-A	20301	15055	**	15211	**	15211	**	**	20315	15057	**	15211	13085	20304	15057	13090	15211	13085
CS	10232	2.312	A-2	21984	15037	**	15158	**	15158	**	**	**	**	**	**	**	20912	15019	15967	15158	15595
CSC	10223	2.312	A-2	21984	15037	**	15158	**	15158	**	**	**	**	**	**	**	20912	15019	15967	15158	15595
M	10607	2.312	AS	21423	15891	**	15158	**	15158	**	**	**	**	**	**	**	20912	15142	15965	15158	15968
HPC-R	10528	2.312	HP-A	20269	15055	**	15211	**	15211	**	**	20317	15057	**	15211	13086	21640	15057	13091	15211	13086
HPC-R	10529	2.437	HP-A	20307	15055	**	15211	**	15211	**	**	20317	15057	**	15211	13086	20294	15057	15092	15211	15087
HPC-R	10530	2.562	HP-A	21772	15083	**	15213	**	15213	**	**	20317	15101	**	15213	13086	20294	15101	15092	15213	15087
CBNS-R	10534	2.703	HP-A	21772	15083	**	15213	**	15213	**	**	20297	15101	**	15213	15087	20294	15101	15092	15213	15087
C	10210	2.750	A-2	20009	15026	**	15160	**	15158	**	**	**	**	**	**	**	20913	15026	15972	15160	15969
CC	10212	2.750	A-2	20009	15026	**	15160	**	15158	**	**	**	**	**	**	**	20913	15026	15972	15160	15969
MC	10640	2.750	A-2	20008	15917	**	15160	**	15158	**	**	**	**	**	**	**	20913	15917	15972	15160	15969
HPC-R	10531	2.750	HP-A	21772	15083	**	15213	**	15213	**	**	20317	15101	**	15213	13086	20294	15101	15092	15213	15087
CS	10236	2.812	A-2	20009	15026	**	15160	**	15158	**	**	**	**	**	**	**	20913	15026	15972	15160	15969
CSC	10229	2.812	A-2	20009	15026	**	15160	**	15158	**	**	**	**	**	**	**	20913	15026	15972	15160	15969
M	10609	2.812	A-2	20008	15892	**	15160	**	15158	**	**	**	**	**	**	**	20913	15144	15971	15160	15970
CS	10234	2.875	A-2	20009	15026	**	15160	**	15158	**	**	**	**	**	**	**	20913	15026	15972	15160	15969
D8-6	10320	3.125	D8-HP	20227	15096	15777	15231	**	**	15156	15778	D8-HP kit assembly number 20225 and D8-1-WLP kit assembly number 20217 will convert blanking plug to a standing valve. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.					D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.				
			D8-P	20218		**		N/R	15231***	**	**										
			D8-1-WLP	20216		15874		15875	**	**	**										
D8-6N-HP	10319	3.125	D8-HP	20341	15096	15777	15238	**	**	15156	15778										
			D8-P	20235		**		N/R	15231***	**	**										
			D8-1-WLP	20234		15874		15875	**	**	**										
D8-6-HP	10314	3.125	D8-HP	20272	15096	15777	15231	**	**	15156	15778										
			D8-P	20218		**		N/R	15231***	**	**										
			D8-1-WLP	20216		15874		15875	**	**	**										
D8-6N-HP	10335	3.187	D8-HP	20342	15096	15777	15231	**	**	15156	15778										
			D8-P	20218		**		N/R	15231***	**	**										
			D8-1-WLP	20216		15874		15875	**	**	**										

* For running and pulling tool specifications, see Camco's Slickline Tools and Units Catalog.

** Not applicable.

*** For internal fishing neck type prong. Also prong running tool.

Guide to Camco Locks and Running Tools (b)

LOCKS					BLANKING PLUGS						STANDING VALVES						CIRCULATING PLUGS																																																																																																																																																																																																	
Type	Assy #	OD (in.)	Type	Plug Assy #	Lock with Plug Running Tool	Run Prong	Lock Pulling Tool	Equal Prong for Lock Pulling Tool	Pulling Tool for Integral Equal. Prong	Pulling Tool for Equal Insert	Equal. Prong Pulling Tool	Valve Assy #	Running Tool	Running Prong	Lock Pulling Tool	Equal. Prong for Lock Pulling Tool	Plug Assy #	Running Tool	Running Prong	Lock Pulling Tool	Equal. Prong for Lock Pulling Tool																																																																																																																																																																																													
D8-6	10325	3.187	D8-HP	20227	15096	15777	15231	**	**	15156	15778	D8-HP kit assembly number 20225 And D8-1-WLP kit assembly number 20217 will convert blanking plug to a standing valve. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																																																																						
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6-HP	10317	3.187	D8-HP	20227	15096	15777	15231	**	**	15156	15778											D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																																																												
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6-HP	10312	3.250	D8-HP	20260	15096	15777	15231	**	**	15156	15778																					D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																																																		
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6	10321	3.250	D8-HP	20260	15096	15777	15231	**	**	15156	15778																																D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																																							
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6	10322	3.312	D8-HP	20260	15096	15777	15231	**	**	15156	15778																																												D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																											
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6-HP	10318	3.312	D8-HP	20260	15096	15777	15231	**	**	15156	15778																																																									D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																														
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6	10323	3.437	D8-HP	20343	15096	15777	15231	**	**	15156	15778																																																																						D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																	
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6-HP	10324	3.437	D8-HP	20260	15096	15777	15231	**	**	15156	15778																																																																																			D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																				
			D8-P	20218		**		N/R	15231***	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15874		15875	**																																																																																																																																																																																																									
D8-6	10255	3.500	D8-HP	20344	15098	15733	15203	**	**	15156	15723																																																																																																D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																							
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6	10259	3.562	D8-HP	20261	15098	15733	15203	**	**	15156	15723																																																																																																													D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																										
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6-HP	10334	3.562	D8-HP	20261	15098	15733	15203	**	**	15156	15723																																																																																																																										D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																													
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6	10258	3.625	D8-HP	20261	15098	15733	15203	**	**	15156	15723																																																																																																																																							D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6	10260	3.687	D8-HP	20017	15098	15733	15203	**	**	15156	15723																																																																																																																																																				D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																			
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6-HP	10333	3.687	D8-HP	20017	15098	15733	15203	**	**	15156	15723																																																																																																																																																																	D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																						
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6	10257	3.750	D8-HP	20017	15098	15733	15203	**	**	15156	15723																																																																																																																																																																														D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																									
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									
D8-6	10254	3.813	D8-HP	20345	15098	15733	15203	**	**	15156	15723																																																																																																																																																																																											D8-HP kit assembly number 20325 and D8-1-WLP kit assembly number 20215 will convert blanking plug to a circulating plug. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.												
			D8-P	20218		**		N/R	15203	**	**																																																																																																																																																																																																							
			D8-1-WLP	20216		15897		15898	**																																																																																																																																																																																																									

* For running and pulling tool specifications, see Camco's Slickline Tools and Units Catalog.

** Not applicable.

*** For internal fishing neck type prong. Also prong running tool.

Guide to Camco Locks and Running Tools (c)

LOCKS				BLANKING PLUGS								STANDING VALVES					CIRCULATING PLUGS																																																																																																																																																										
Type	Assy #	OD Packing	Type	Plug Assy #	Lock with Plug Running Tool	Running Prong	Lock Pulling Tool	Equal Prong for Lock Pulling Tool	Pulling Tool for Integral Equal. Prong	Pulling Tool	Equal. Prong	Valve Assy.	Run Tool	Running Prong	Lock Pulling Tool	Equal. Prong	Plug Assy	Running Tool	Running Prong	Lock Pulling Tool	Equal. Prong Lock Pulling Tool																																																																																																																																																						
D8-6-HP	10340	3.813	D8-HP	20345	15098	15733	15203	**	**	15156	15723	D8-HP kit assembly number 20225 And D8-1-WLP kit assembly number 20217 will convert blanking plug to a standing valve. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.																																																																																																																																																															
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6	10351	3.875	D8-HP	20345	15098	15733	15203	**	**	15156	15723																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6	10345	3.937	D8-HP	20347	15098	15733	15203	**	**	15156	15723																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6-HP	10339	3.937	D8-HP	20346	15098	15733	15203	**	**	15156	15706																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6-HP	10338	3.937	D8-HP	20347	15098	15733	15203	**	**	15156	15706																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6	10344	4.000	D8-HP	20347	15098	15733	15203	**	**	15156	15723																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6	10343	4.063	D8-HP	20347	15098	15733	15203	**	**	15156	15723																																																																																																																																																																
			D8-P	20218		**		N/R	15203 ***	**	**																																																																																																																																																																
			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6	10341	4.125	D8-HP	20348	15098	15733	15203	**	**	15156	15723																																																																																																																																																																
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			D8-1WLP	20216		15897		15898	**																																																																																																																																																																		
D8-6-HP	10337	4.125	D8-HP	20348	15093	15605	15204	**	**	15156	15606																																																																																																																																																																
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* For running and pulling tool specifications, see Camco's Slickline Tools and Units Catalog.

** Not applicable.

*** For internal fishing neck type prong. Also prong running tool.

Guide to Camco Locks and Running Tools (d)

LOCKS					BLANKING PLUGS							STANDING VALVES					CIRCULATING PLUGS				
Type	Assy #	OD Packing	Type	Plug Assy #	Lock with Plug Running Tool	Running Prong	Lock Pulling Tool	Equal Prong for	Pulling Tool Integral Equal. Prong	Pulling Tool	Equal. Prong	Valve Assy #	Running Tool	Running Prong	Pulling Tool	Equal. Prong	Plug Assy #	Running Tool	Running Prong	Pulling Tool	Equal Prong
D8-6N	10287	5.750	D8-HP	20349	15094	15722	15205	**	**	15156	15723	D8-HP kit assembly number 20225 and D8-1-WLP kit assembly number 20217 will convert blanking plug to a standing valve. Use same running tools, pulling tools and prongs as blanking plug. See pp. 104 and 106.									
			D8-P	20218		**		N/R	15205**	**	**										
			D8-1-WLP	20216		15921		15922	**												
D8-6	10268	5.813	D8-HP	20019	15094	15722	15205	**	**	15156	15723										
			D8-P	20218		**		N/R	15205**	**	**										
			D8-1-WLP	20216		15921		15922	**												
D8-6	10253	5.813	D8-P	20218	15094	**	15205	N/R	15205**												
			D8-1-WLP	20216		15921		15922	**												
D8-6	10267	5.875	D8-HP	20350	15094	15722	15205	**	**	15156	15723										
			D8-P	20218		**		N/R	15205**	**	**										
			D8-1-WLP	20216		15921		15922	**												
D8-6	10266	5.937	D8-HP	20350	15094	15722	15205	**	**	15156	15723										
			D8-P	20218		**		N/R	15205**	**	**										
			D8-1-WLP	20216		15921		15922	**												
D8-6	10265	6.000	D8-HP	20350	15094	15722	15205	**	**	15156	15723										
			D8-P	20218		**		N/R	15205**	**	**										
			D8-1-WLP	20216		15921		15922	**												

* For running and pulling tool specifications, see Camco's Slickline Tools and Units Catalog.

** Not applicable.

*** For internal fishing neck type prong. Also prong running tool.

7 Petroline Plugs, Locks and Tools

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7 PETROLINE PLUGS, LOCKS AND TOOLS

7.1 Retractable No-Go Standing Valve

The prime criteria for the development of this tool was to significantly reduce the number of slickline runs required during the completion of a well. The retractable no-go standing valve provides a high-pressure test capability with a single slickline run. The standing valve can be used both in Petroline's QN nipple profiles and in other manufacturer's profiles.

The valve design and operating features include:

- 5000 to 10,000 psi pressure ratings as standard
- Single run to set and retrieve
- Hydraulic set capability (no downward jarring required for high deviation wells)
- Not reliant on operator ability
- Flow through capability

The standing valve is designed to be set in the nipple profile by hydraulic means, and no downward jarring is required. The tool is therefore ideal for high deviation applications and has been successfully run in wells up to 79° deviation.

The equalization section can be provided with a spring and ball retainer to ensure a positive seat of the sealing ball if required.

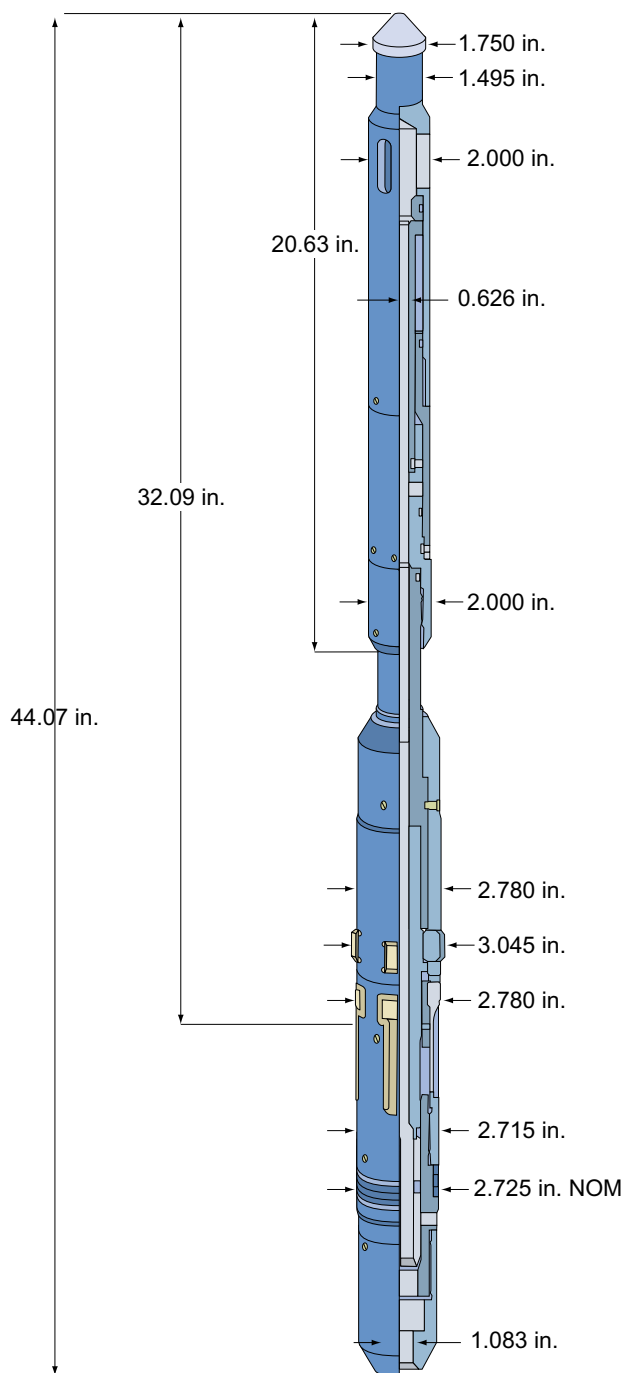


Figure 7-1: Retractable No-Go Standing Valve

Table 7-1: Retractable No-Go Standing Valve Components

Item	Description	Qty	Part No
001	2.000 in. Std. Valve Sub Assembly	1	218-2000-00-05
002	Plunger	1	625-2635-02-45

Item	Description	Qty	Part No
003	Main Body	1	625-2725-01-45
004	Lock Out Keys	4	625-2725-03-45
005	Finger Sleeve	1	625-2635-05-45
006	Lock Down Collet	1	625-2635-04-45
007	Packing Barrel	1	625-2725-02-45
008	Bottom Sub	1	625-2635-07-45
009*	Grub Screw ($\frac{1}{4}$ in.-20UNC x $\frac{1}{4}$ in.)	2	GS-020
010a*	Elastomer (O-ring)	1	OV-123-075
010b*	Elastomer (Parbak Ring)	2	PB-123-N90
011a*	Elastomer (O-ring)	1	OV-218-075
011b*	Elastomer (Parbak Ring)	2	PB-218-N90
012a*	Elastomer (O-ring)	1	OV-122-075
012b*	Elastomer (Parbak Ring)	2	PB-122-N90
013*	ShearScrew ($\frac{1}{4}$ in.-20UNC)	4	SS-011
014*	Shear Screw (5/16 in.-18UNC)	3	SS-010
015*	Shear Screw ($\frac{1}{4}$ in.-20UNC)	4	SS-005
016*	2.725 in. Chevron Packings	3	243-2725-BI-OI
017	Male End Adaptor	1	245-2725-02-45
018	Female End Adaptor	1	245-2725-01-45

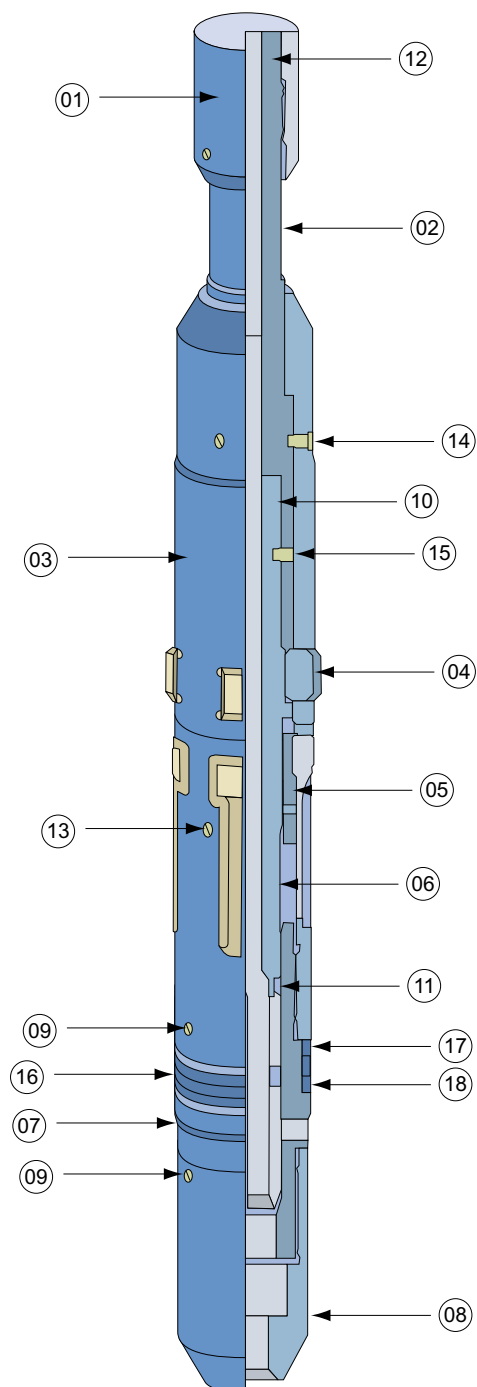


Figure 7-2: RNQN Standing Valve - Technical Illustration

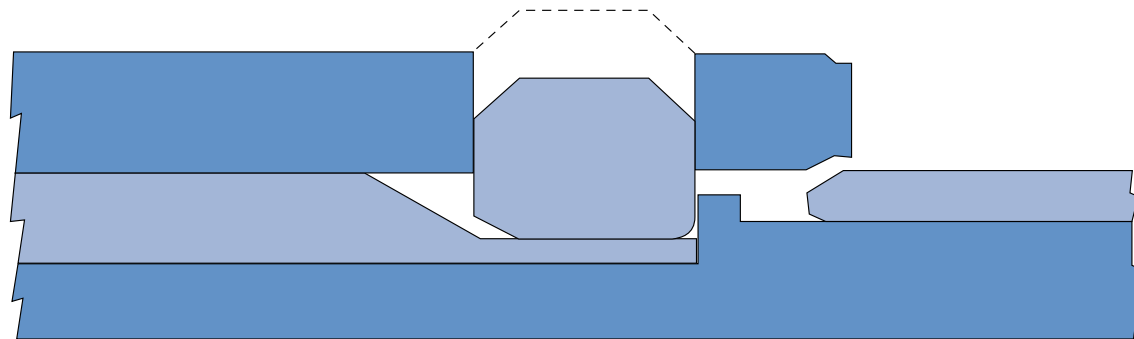


Figure 7-3: RNQN Standing Valve - Assembly Illustration

Table 7-2: RNQN Standing Valve

Item	Description	Qty	Part No
001	Top Sub	1	218-2000-06-45
002	Inner Mandrel	1	218-2000-13-45
003	Connector	1	218-2000-12-45
004	Shear Sleeve	1	218-2000-11-45
005	Ball Seat	1	218-2000-10-45
006a*	Elastomer (O-ring)	3	OV-125-090
006b*	Elastomer (Parbak Ring)	6	PB-125-N90
007*	Grub Screw ($\frac{1}{4}$ in.-20 UNC x $\frac{1}{4}$ in.)	3	GS-020
008*	Shear Screw	4	SS-005
009	1 in. Steel Ball	1	SB-002

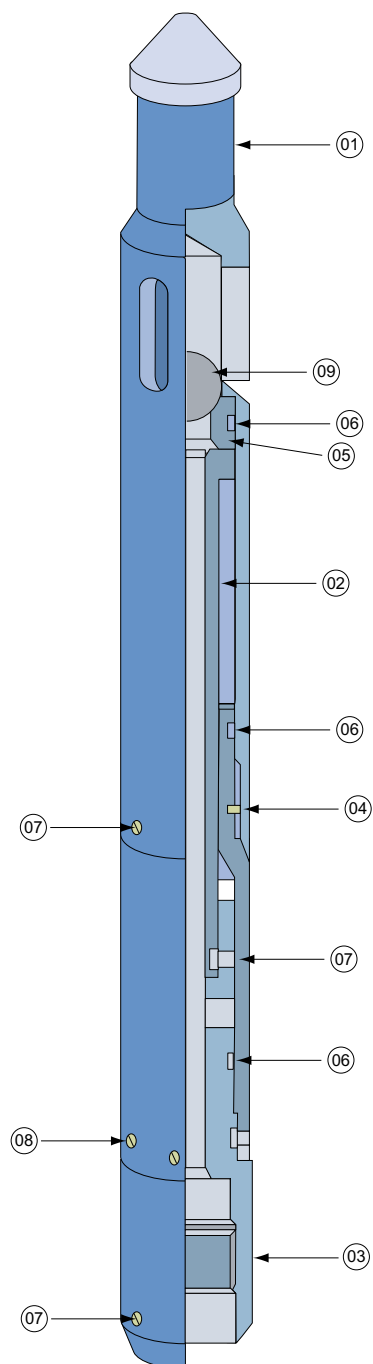


Figure 7-4: RNQN Standing Valve

7.1.1 Assembly - Disassembly

7.1.1.1 Assembly

1. Install elastomers into the lock down collet then slide lock down collet into the plunger, secure by installing required number of shear screws.
2. With the box thread facing upwards, install the lock out keys into the windows on the main body.



Tip

A small amount of grease on the keys will help retain them in the windows. Ensure keys are fitted the correct way round with the 30 internal taper face matching 30 taper on the plunger assembly.

3. Place the plunger assembly (plunger first) down into the main body and lift the body until it bottoms out on the inner assembly. The shear screw holes should be lined up with the track, then install the required number of the shear screws.
4. Insert elastomer into the plunger. Make up the sub-assy to the plunger utilizing a screw driver through the equalizing ports and then secure with grub screw.
5. Slide the finger sleeve down into the main body until the shear screw holes line up with the groove. Install shear screws.
6. Install the packing stack, onto the packing barrel. Thread the packing barrel into the main body and secure with grub screw.
7. Thread the bottom sub onto the packing barrel and secure with grub screw.

7.1.1.2 Disassembly

1. Remove all grub screws.
2. Remove bottom sub and using the lead in angle on the lower end push against the packing barrel end face to hence collapse the internal fingers of the lock down collet back inside the body.
3. The remainder of the tool should be disassembled opposite to the assembly instructions.
4. All parts should be inspected for damage and replaced as necessary.

7.1.1.3 Assembly Instructions for Standing Valve Sub Assembly

1. Install elastomers into the connector and shear sleeve respectively. Slide the shear sleeve onto the inner mandrel.
2. Thread the inner mandrel onto the connector. The notch on the connector OD should be covered when the inner sleeve is fully made up. If this notch is visible continue threading until it disappears under the shear sleeve, secure with grub screw.
3. Slide the shear sleeve down over the connector until it locates on the square shoulder, install shear screw.
4. Install elastomers into the ball seat. Install steel ball into the top sub. Thread the top sub onto the shear sleeve. This will automatically locate the steel ball and ball seat in the correct position. Install grub screw.
5. The standing valve sub assembly can now be made up to the main assembly.

Disassembly

1. Remove all grub screws.
2. Disassembly should be opposite to the assembly instructions.
3. On disassembly, inspect all parts for damage and replace as necessary.

7.1.2 Operating Procedures

The Petroline retractable no-go standing valve is run using standard slickline methods and can be set either mechanically or hydraulically.

When seating the retractable no-go standing valve mechanically, make-up the standing valve to the appropriate JDC or SB type pulling tool complete with brass pin. Lower the assembly into the well bore until the no-go fingers on the standing valve make contact with the no-go on the nipple profile.

Downward jarring will cause the shear screws to shear and in turn will move the inner mandrel down locking out the locking dogs and remove the support from the retractable no-go fingers. Further downward jarring will cause the shear pin in the pulling tool to shear. The tool string can now be retrieved from the well bore.

When retrieving the retractable no-go standing valve, lower the tool string complete with the appropriate JDC or SB type pulling tool into the well bore and latch the retractable no-go standing valve (an upward pull on the slickline will confirm latching).

Upward jarring will cause the equalization screws and inner mandrel screws to shear and the standing valve can now be retrieved from the well bore.

If pressure testing is required in one run without shearing the setting tool, we recommend that the standing valve is set hydraulically as follows:

Lower the standing valve in the well bore, this should be done at a relatively steady speed and care should be taken when passing through restrictions or when opening the spang jars to prevent premature equalization.

Once the nipple is encountered 1 or 2 light downward taps should be applied to ensure the seals have entered the seal bore then pressure can be applied.

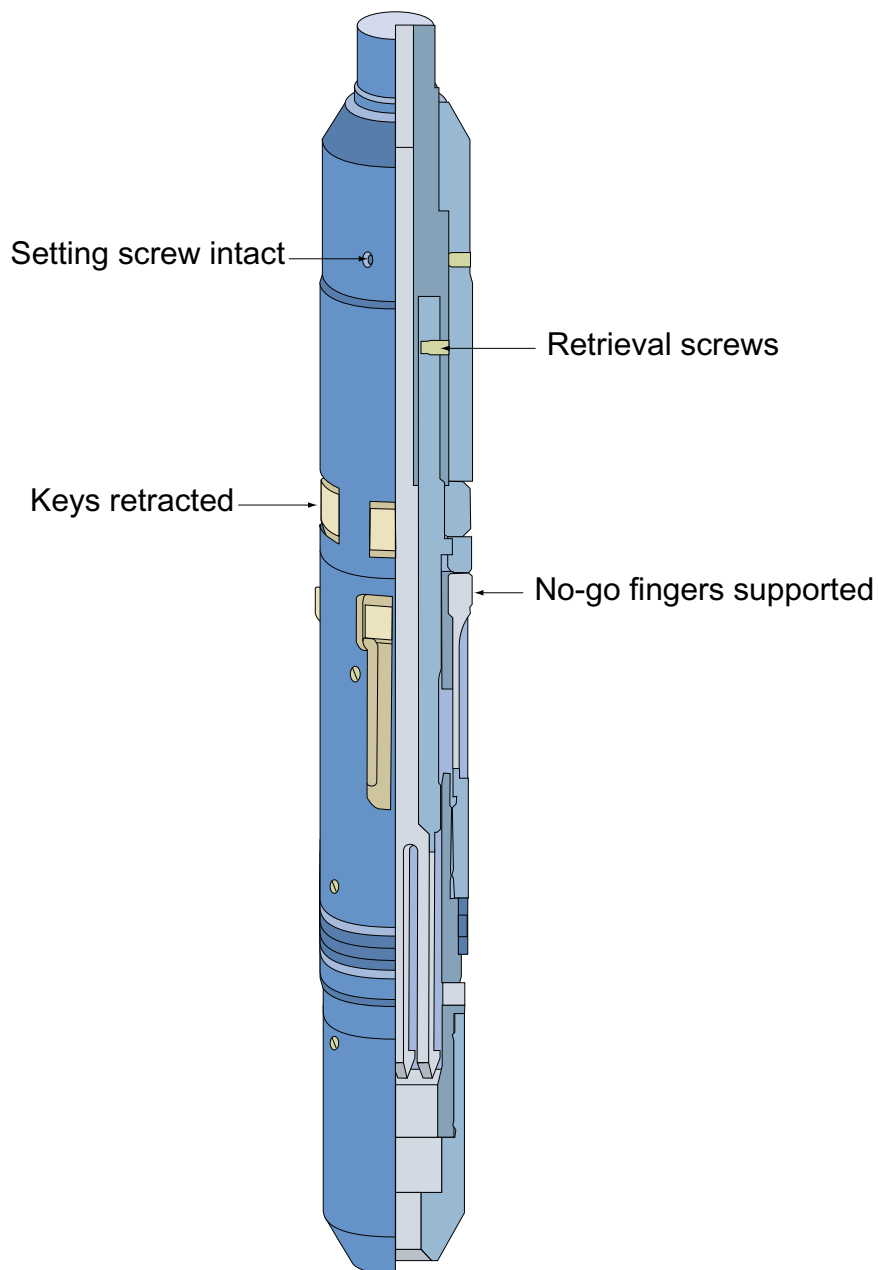
If you are required to stay on the device, slack off 10 ft of wire approximately and apply the nominal shear out value of the valve. Monitor the pressure for a few minutes then increase up to the required test level. When the standing valve sets a slight reduction in pressure will be seen at surface. On completion of test, jar upwards to equalize and unlock the standing valve which can then be retrieved to surface.

If you are required to leave the standing valve in the nipple, slack off 10 ft wire apply the nominal shear out value of the Valve. Monitor the pressure for a few minutes then commence to jar downwards, if during jarring the valve is accidentally equalized pressure will be lost.

Monitor at all times when seating and if pressure does drop attempt to apply again. If indications are that the valve has been equalized jar up to retrieve.

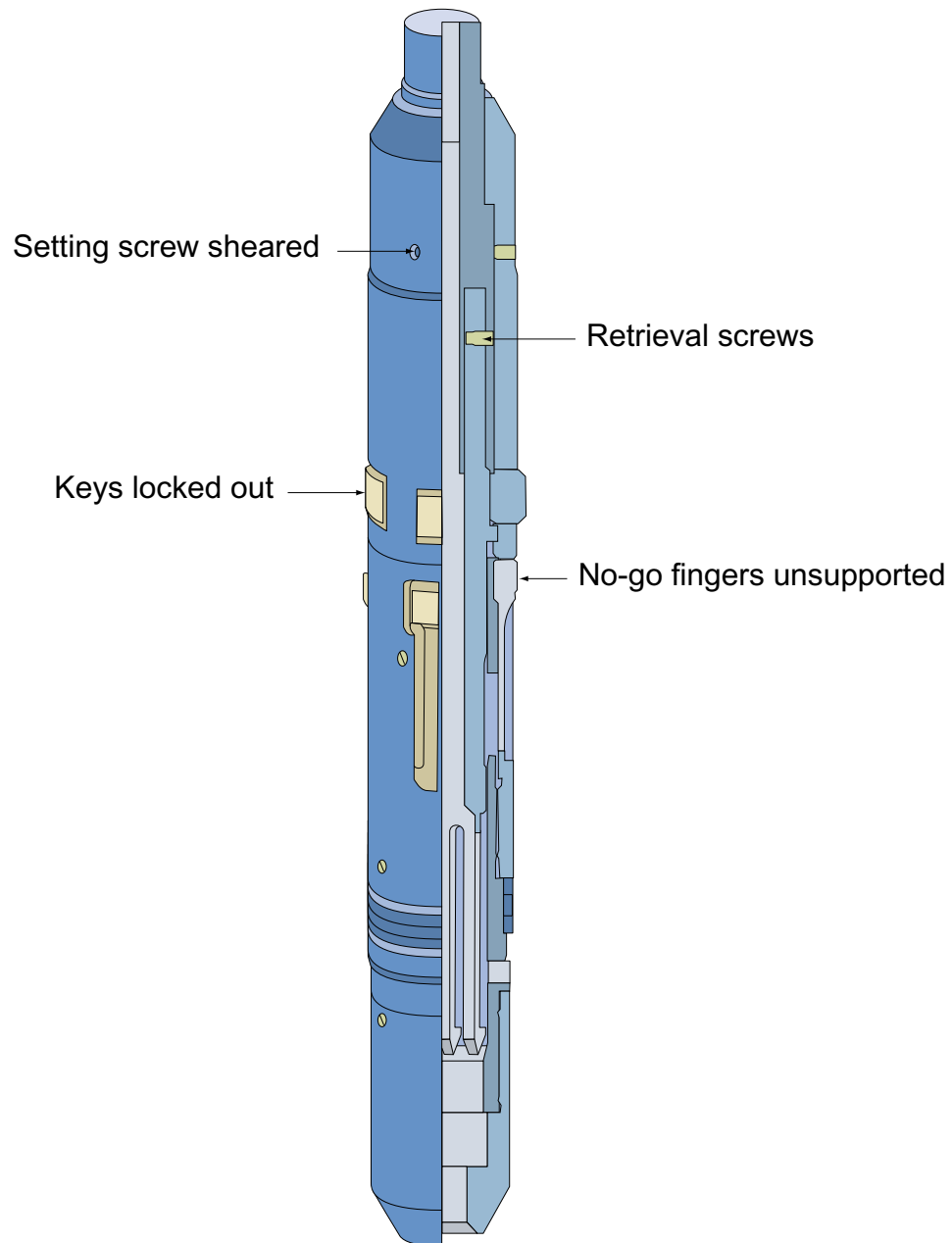
**Note**

If pressure is lost, cease downward jarring, this may be in time to prevent release of the running tool and will save unneeded slickline runs to retrieve and reinstall the Valve.



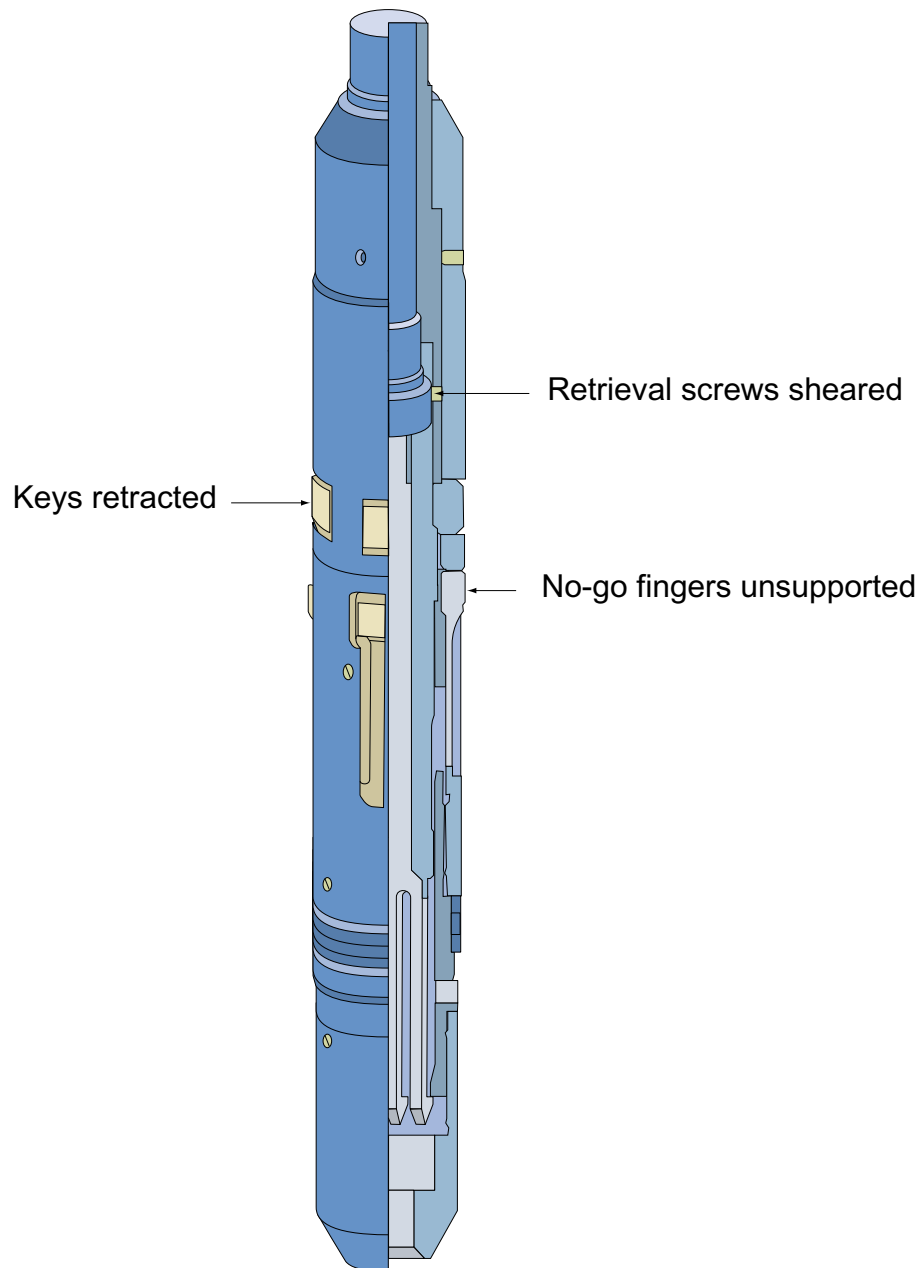
Retractable no-go standing valve
shown in the run position

Figure 7-5: RNQN Standing Valve - Run Position



Retractable no-go standing valve
shown in the set position

Figure 7-6: RNQN Standing Valve - Set Position



Retractable no-go standing valve
shown in the retrieval position

Figure 7-7: RNQN Standing Valve - Retrieval Position

7.2

Releasable Rope Socket

The releasable rope socket can be utilized with either slick or braided type slickline and is designed to release only in the event that the tool string becomes stuck down hole.

The device is activated by a drop bar, which is dropped down the wire in a similar manner to a go-devil or snipper.

When the drop bar contacts the release trigger, the collet releases the lower fishing neck. The upper housing and drop bar are retrieved to surface leaving a clean fishing neck. The releasable rope socket is multifunctional in that it can be used with both slickline and braided line merely by changing the internal clamping mechanism.

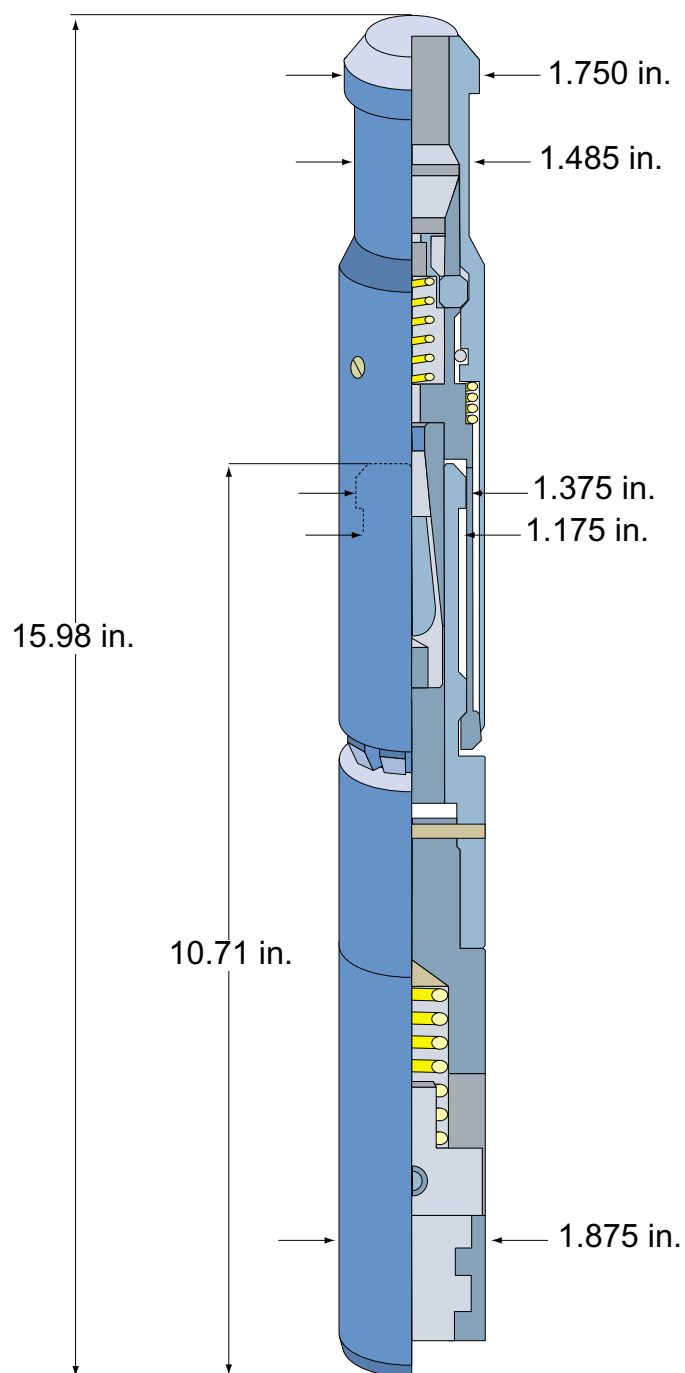


Figure 7-8: Releasable Rope Socket

Table 7-3: Releasable Rope Socket - Part List

Item	Description	Qty	Part Number
001	0.108/0.092 in. Wire Guts Assembly	1	405-1500-00-01
002	Fishing Neck	1	460-1875-02-11

Item	Description	Qty	Part Number
003	Locking Mandrel	1	460-1875-03-45
004	Finger Mandrel	1	460-1875-04-45
005	Trigger Assembly	1	460-1875-00-14
006	Operating Key	3	460-1875-06-45
007	1- $\frac{7}{8}$ in. QLS Female	1	444-1875-00-03
008	Roll Pin (3/16 in. dia.)	1	RP-005
009	Coil Spring	1	CS-167
010	Coil Spring	1	CS-168
011	Grub Screw (5/16 in. UNC)	1	GS-023
012	Stainless Steel Ball	20	SB-015

7.2.1 Assembly - Disassembly

7.2.1.1 Assembly

1. Locate the trigger spring and the trigger into the top of the finger mandrel.
2. Insert the operating keys into the windows in the finger mandrel.



Note

A small amount of grease will help retain them in place. Ensure the keys are in the correct way round with the 45° angle on the keys matching the 45° angle on the trigger.

3. Locate the coil spring over the keys and onto the plunger mandrel.
4. Load the above assembly up into the locking mandrel. Push the trigger down to retract the keys and allow full entry of the finger mandrel assembly. The trigger can now be released allowing the keys to lock out in the recess.
5. Install the stainless steel balls into the locking mandrel through the grub screw hole. Hence insert the grub screw. Ensure no steel balls are trapped under the grub screw.
6. Push the trigger down to retract the Keys. The tool is now in the released position.
7. Install the pear drop retainer into the main assembly.

8. Make-up the relevant wire to the pear drop assembly and pull back up into the main assembly.
9. The fishing neck, QLS and Roll Pin will be made up at Petroline and should not need to be disassembled.
10. Install the fishing neck up into the bottom of the finger mandrel. Pushing the two assemblies together will lock them in the run position.

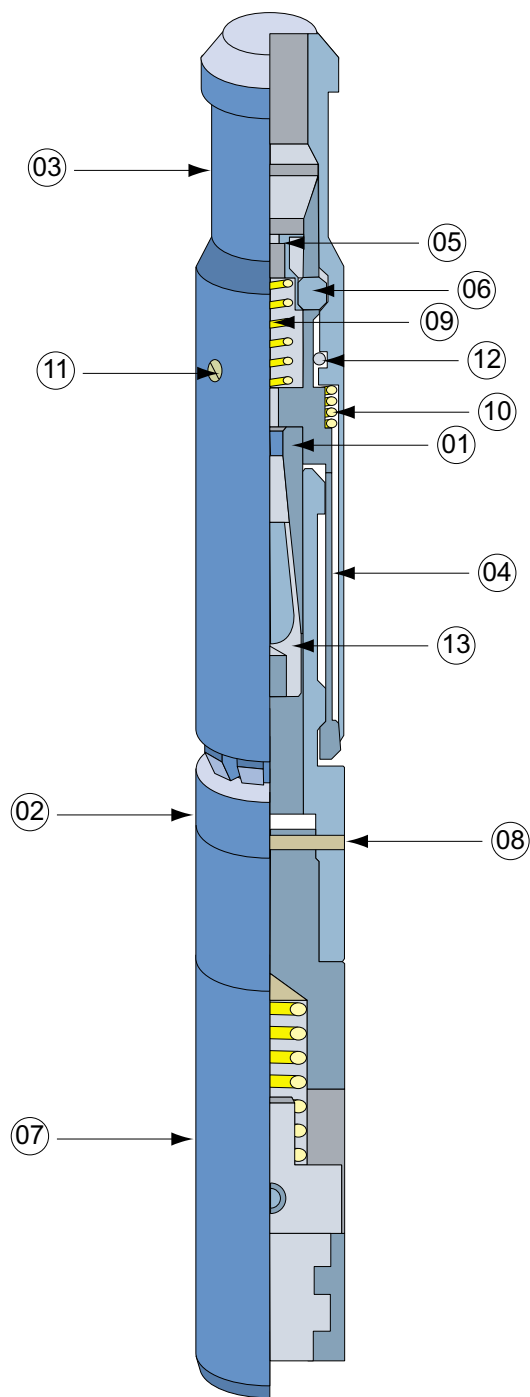


Figure 7-9: Assembly Instructions for Releasable Rope Sockets

7.2.1.2

Disassembly

1. Disassembly should follow the reverse of the assembly instructions.
2. Check all parts for any damage and replace as necessary.

7.2.2 Operating Procedures

Prior to attaching the Petroline releasable rope socket to slickline the following steps should be taken.

1. The RRS should be visually checked on ensure that the finger mandrel is properly engaged onto the fishing neck.
2. The release mechanism should now be tested by tapping downwards with the drop bar onto the operating keys.
3. The upper housing assembly will then be released from the fish neck.
4. To reconnect the upper housing assembly to the fish neck, simply slide components together and apply pressure on top of the upper housing. The finger mandrel will become fully covered and the RRS is now again locked.
5. Release and lock sequence should be repeated at least 3 times.

In order to activate the rope socket down hole, it will be necessary to attach the drop bar onto the slickline above closed slickline valves.

After equalizing and opening the slickline valves, the drop bar will be allowed to travel down the wire. On contact with the RRS, the trigger mechanism will be activated allowing the release of fishing neck assembly from the upper housing, therefore allowing wire, drop bar and upper housing to be retrieved to surface.

Please note that the release mechanism is designed not to activate under tension. Prior to releasing the drop bar only wire weight should be taken up. If the tool string is not lifted this will optimize the chance of first time release. In the event this does not occur, the wire should be worked to assist placement of the drop bar within the trigger assembly. In high deviation wells if there is insufficient energy to activate the release mechanism, it can be augmented by operating the mechanical jars within the tool string. A roller drop bar would also help in this instance.

7.3 Spring Roller Centralizer

The spring roller centralizer designed to meet the increasing need for devices, which improve slickline operations in high deviations wells, the S.R.C. is widely used in wells up to 80° deviation.

Designed to be run directly above the flow control device to be installed/retrieved the S.R.C. offers many benefits.

- Roller arms reduce frictional resistance
- High-energy spring stack gives high lift capability while centralized stack and arm leverage requires minimal force for full collapse through restrictions.
- High integrity design suitable for high velocity or impact operations
- Can be supplied with integral QLS connections or sucker rod threads
- Triple roller arm expanders
- Maximum circumferential coverage gained for minimal strength loss
- Can be adapted for coiled tubing operations

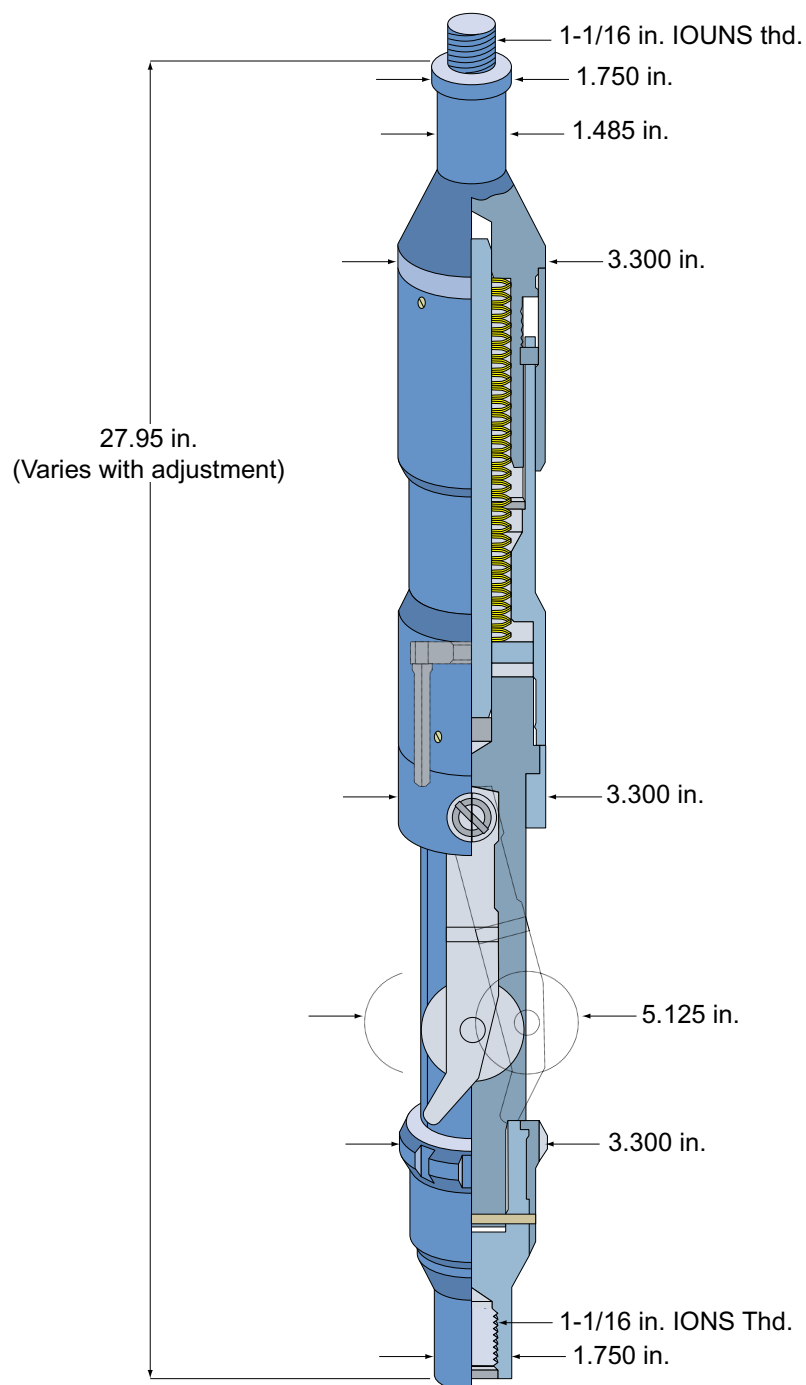


Figure 7-10: Spring Roller Centralizer

Table 7-4: Spring Roller Centralizer – Part List

Item	Description	Qty	Part No
001	Petroline X-Over Sub	1	486-3300-02-15
002	Bottom X-Over Sub	1	415-3300-17-11

Item	Description	Qty	Part No
003	Roll Pin (3/16 in. Dia x 3 in.)	1	RP-006
	S.R.C Sub Assembly		486-3300-00-30
004	Main Body	1	486-3300-06-45
005	Lower Body	1	486-3300-01-45
006	Disc Spring	80	DS-017
007	Bottom Sub	1	415-3300-04-45
008	Locking Sleeve	1	486-3300-03-45
009	Locking Segment	1	486-3300-05-09
010	Pusher Plate	1	415-3300-07-45
011	Sliding Rod	3	415-3300-08-45
012	Spring Rod	1	486-3300-04-45
013	Pivot Pin	3	415-3300-12-45
014	Locking Ring	1	415-3300-15-45
015	Grub Screw (3/16 in. BSF x $\frac{1}{4}$ in.)	3	GS-001
016	Grub Screw ($\frac{1}{4}$ in.-20UNC x 3/16 in.)	2	GS-023
017	Roller Arm Sub Assembly		415-3300-00-17
018	Bush	3	415-3300-11-02
019	Arm	3	415-3300-18-14
020	Roller Pin	3	415-3300-13-11
021	Roller Bush	3	415-3300-16-09
022	Roller	3	415-3300-14-11

7.3.1 Assembly - Disassembly

7.3.1.1 Disassembly

1. Remove the grub screw from locking sleeve and back-off locking sleeve.
2. Remove locking segment from slot in main body and unscrew top sub anti-clockwise along with integral tool string connector.
3. The bottom sub and tool string connector can be removed from the lower body at the same time, having previously removed roll pin. Once removed from the lower body, the bottom sub and tool string connector can be separated from each other.

4. Grub screws are removed from locking ring in order to allow pivot pins to be backed off anti-clockwise and removed to free the lever arms from the lower body. This procedure is repeated for each of the 3 arms.
5. Once all arms are free, the Locking Ring can now be freed from the Lower Body.
6. The grub screw is removed from the main body in order to allow the lower body along with the disc springs the spring rod the pusher plate and the sliding rods to be unscrewed from the main body.
7. Once the spring stack and spring rod have been removed, the pusher plate and the sliding rods to be unscrewed from the main body.
8. The locking sleeve, which is threaded to the main body, can be fully unscrewed for cleaning and inspection.
9. All parts should be checked for damage, careful scrutiny being given to all threads and bearing surfaces. Replace any damaged parts if necessary.
10. The pins for the rollers are welded in position and should not need replacement unless excessive wear is evident. These should be returned to Petroline for repair.

7.3.1.2

Assembly

- The crossover sub, roll pin and bottom sub are made up to the lower body.
- Make-up the sliding rod to the pusher plate. Slide the locking ring over the lower body, slide the pusher plate/rod assembly into the lower body and make-up the lower body to the main body. Install grub screw.
- Locate the bush into the pre-assembled roller arm assembly consisting of arm, roller pin, roller bush and roller, locate the arm onto the lower body and pin with pivot pin through the locking rings. Fix pivot pins in place with grub screw.
- Locate spring rod down through the main body into the lower body. Load the disc springs onto the spring rod.
- Slide the locking sleeve down over the main body, make-up the top sub assembly to the main body. Install locking segment through the main body onto the top sub. Ensure teeth are fully located.
- Make-up locking sleeve to the top sub and install grub screw.

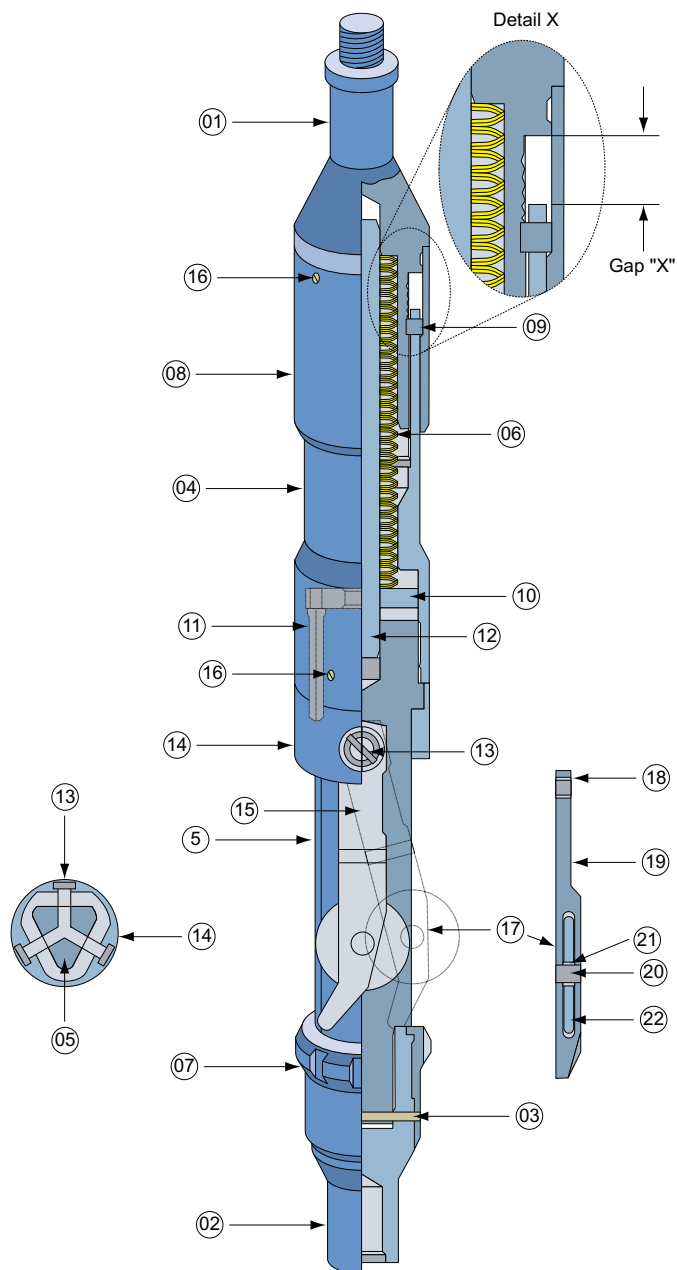


Figure 7-11: Assembly Detail for Spring Roller Centralizer

7.3.2 Operating Procedures

7.3.2.1 Running and Retrieving

- The centralizer is run immediately above the plug to be centralized. No shearing of pins or the like is required within the centralizer, therefore running/retrieving operations of the plug being centralized are not affected.
- The centralizer pre-load is adjusted to the required setting.
- The plug is run, with the centralizer above, into the desired tubing/casing string.
- Tool string should now be lowered until the first restriction is approached, at which point care should be taken upon entry into restriction. Downward jarring may be required in order to aid centralizer through the restriction. At any subsequent restrictions the above procedure should be repeated.
- After locating the plug in the correct nipple profile, it is set as normal.
- Retrieval of centralizer and plug running tool is carried out as normal except when passing through the restrictions. Upward jarring may be required at this point.

Standard Spring Force Setting

- The force exerted by the spring stack can be altered in two ways. Firstly, the pre-load can be changed using the adjuster and secondly, the spring configuration itself can be altered to give different operating characteristics.
- Although, the spring configuration can be varied, one, which is considered to be optimum for the circumstances, is used. In the case of the 3.3 in. to 5.125 in. the configuration is:
20 SETS OF DOUBLES & 23 SINGLES = 63 SPRINGS
 Springs used have the following dimensions: OD 45.0 mm, ID 22.4 mm thickness 2.5 mm
- The gap can be adjusted whether or not the centraliser is connected into the tool string. Firstly, remove grub screw and back off locking sleeve. The locking segment is now free to move over the machined grooves in the top sub.

- The top sub is screwed in or out until the required gap is achieved. The segment may sit slightly above the internal diameter of the locking sleeve. To allow it to pass below, a further small adjustment of the top sub will be required. Once flush, the locking sleeve can be screwed back over the segment and shouldered against the top sub.
- The grub screw is replaced in the locking sleeve and the adjuster is now prevented from backing off.

High Load Spring Setting

Some applications may require a higher spring load acting on the arms. For example, the SRC can be used as a depth indicator where the SRC is used to locate in a profile at a set depth. To help locate and hold the SRC in the profile, it may be necessary to increase the force required to collapse the SRC arms. For a High Load Spring Configuration in the case of the 3.3 in. to 5.125 in. range, the configuration is:

32 SET OF DOUBLE & 2 SINGLES = 66 SPRINGS



Note

Due to increased load, the Arms will not collapse through restrictions below 3.50 in. ID. Therefore do not use tool with high load spring set up in applications with a minimum ID less than 3.500 in..

7.4

Easy Adjust Jar

The Petroline easy adjust jar (EAJ) was developed in response to an industry demand for higher down hole impact forces. The original Power jars utilized a hydraulic by-pass system to create an instantaneous release of wire tension resulting in an upward impact (jar).

However, the effective stroke of these jars limited the impacts available and the tendency for seal failure during prolonged use often resulted in serious down hole problems if the jar 'gassed up'.

Using a stack of disc spring washers, which is fully adjustable, gives the ability to simulate the function of a hydraulic jar but without the associated risk. The jar stroke has been lengthened to give an improvement in impact force of up to 300% over hydraulic jars.

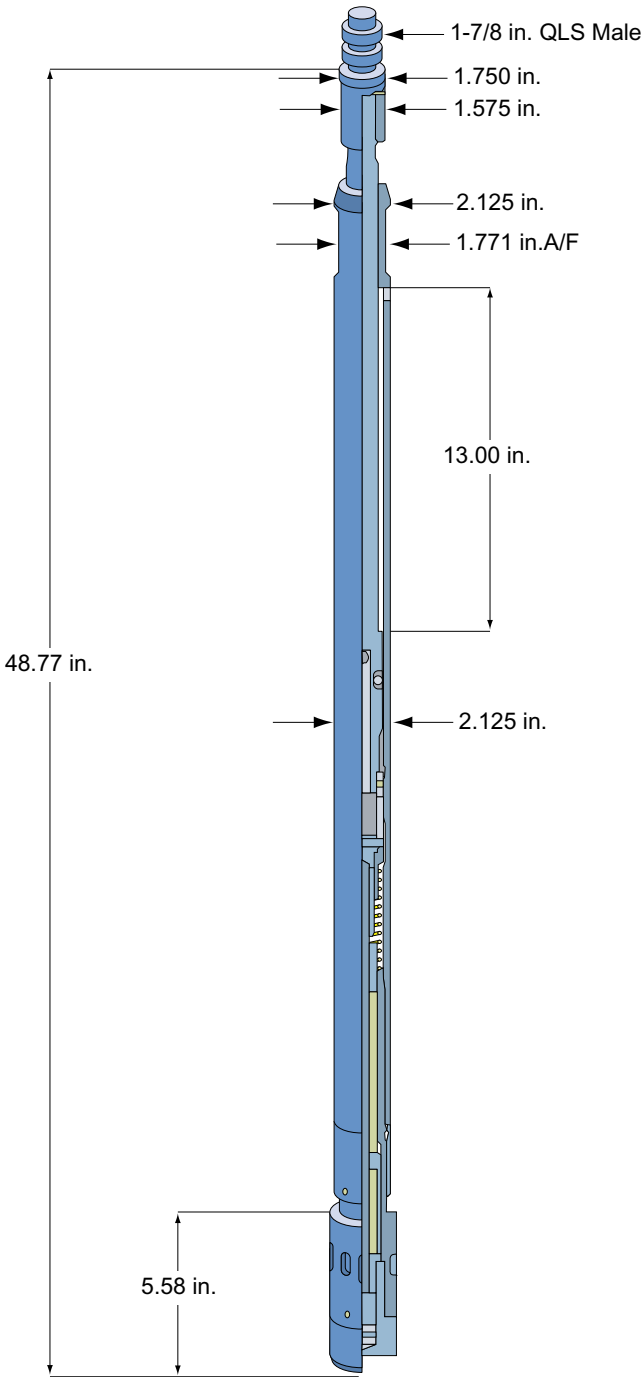


Figure 7-12: Easy Adjust Jar

Table 7-5: Easy Adjust Jar - Technical Information

Assembly Number	401-2125-00-09
Overall Length (closed)	48.77 in.
(open)	61.77 in.
Metallic Material	ALSI 4140 (30-36 Rc)

Metallic Material (Coil & Disc Springs) Carbon Steel

Connections 1- $\frac{7}{8}$ in. QLS Male

Coatings Parkerize / Q.P.Q.

Max Tensile Strength 73,000 lb @ QLS Connection

Setting Range 350 – 2000 lb *

Jar Stroke 13.0 in.

7.4.1 Operating Procedures

7.4.1.1 Calibration

For accurate setting of the jar, it is recommended that a calibrator sub be used.

7.4.1.2 Spring Stack

The EAJ contains two spring stacks to give greater control at the lower settings. Spring life in the EAJ has been greatly increased due to the fact that the springs are only under load when the jar is fired.

If the spring stacks are disassembled for any reason they should be carefully and correctly reassembled. Should the used springs be exchanged with brand new springs the jar should be assembled and fired off several times at its maximum setting in order to bed the new springs in. This is normally done for every new jar at time of manufacture/assembly.

After this bedding in procedure a check should be carried out using the calibrator sub to establish that calibration settings stamped on the housing still correspond with values obtained by firing the jar with calibrator sub. If it proves difficult to obtain lower settings, after having replaced the spring stack, then single springs should be removed from the top of the large stack.

7.4.1.3 Lock Segment

The lock segment is purposely machined from aluminum alloy and is designed such that should problems be encountered in disassembling the tool, the lock segment will shear thus allowing free and easy disassembly. This prevents any damage occurring to the more complex components of the jar. These lock segments are included as part of the redress kit and are also available separately from Petroline.

7.4.1.4 Spring Stack Configurations

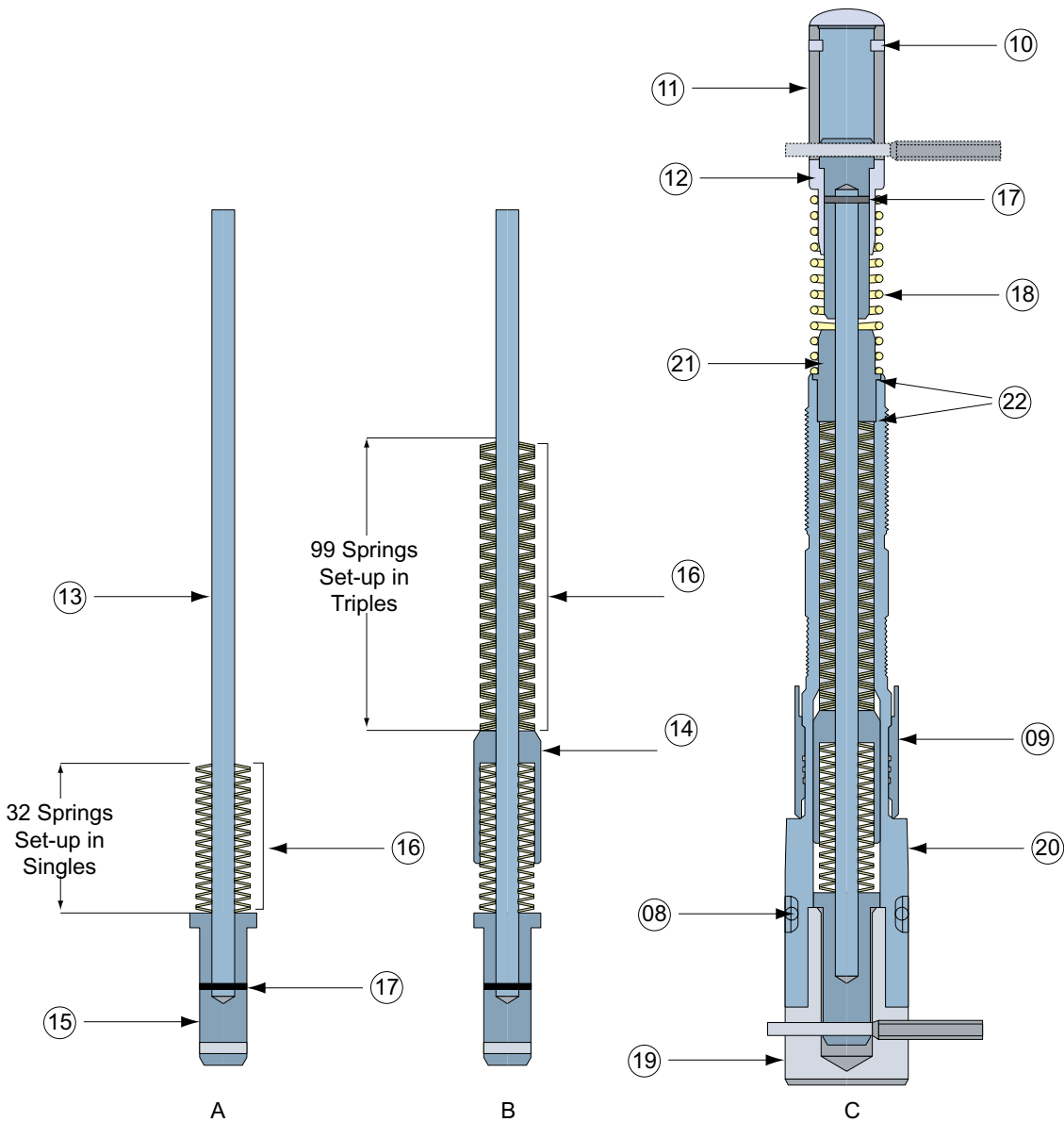


Figure 7-13: Spring Stack Configuration

Table 7-6: Easy Adjust Jar - Parts List

Item	Description	Qty	Part No
001	Jar Rod	1	401-2125-02-11
002	Main Housing	1	401-2125-28-11
003*	Lock Segment	1	401-2125-04-01

Item	Description	Qty	Part No
004	1- $\frac{7}{8}$ in. QLS X-Over	1	444-1875-26-11
005*	Grub Screw ($\frac{1}{4}$ in. -20UNC x $\frac{3}{8}$ in. L)	1	GS-007
006*	Grub Screw ($\frac{1}{4}$ in.-20UNC x 3/16 in. L)	1	GS-019
007*	Roll Pin (3/16 in. dia x 1 $\frac{1}{2}$ in. L)	1	RP-004
008*	Steel Ball (5/16 in. dia.)	12	SB-009
	EAJ Sub Assembly	1	401-2125-00-10
009	Lock Ring	1	401-2125-05-11
010	Trip Keys	3	401-2125-07-11
011	Trip Sleeve	1	401-2125-08-11
012	Upper Spring Stop	1	401-2125-09-11
013	Spring Rod	1	401-2125-10-11
014	Stack Regulator	1	401-2125-11-11
015	Lower Spring Stop	1	401-2125-12-11
016*	Disc Springs	131	DS-004
017*	Roll Pin ($\frac{1}{8}$ in. dia x $\frac{7}{8}$ in. L)	2	RP-014
018	Coil Spring	1	CS-107
019	Bottom Sub	1	401-2125-27-11
	Spring Housing Sub Assembly	1	401-2125-00-71
020	Jar Rod Housing	1	401-2125-26-11
021	End Piece	1	401-2125-13-11
022*	Elastomer (O-Ring)	2	OV-024-075

7.4.2 Assembly - Disassembly

7.4.2.1 Assembly

1. Thread the lower spring stop onto the spring rod. Then secure with roll pin. Apply copper slip to the rod and assemble the lower spring Stack (32 disc springs, set-up in singles). Coat springs with copper slip.
2. Locate the spring protector followed by the upper spring stack (99 disc springs, set-up in triples)
3. The spring housing sub assembly should be made-up as follows: Place one elastomer into the groove at the back end of the thread on the end piece and the second at the back end of the thread in the jar rod housing. Then thread the end piece to the jar rod.

4. Place assembled spring rod through the spring housing sub-assembly. Place the coil spring down over the spring rod, then locate the trip sleeve over the upper spring stop then temporarily hold together with a punch. With the use of a second punch through the hole in the lower spring stop, thread the upper spring stop to the spring rod. Align and secure with roll pin.
5. Remove both punches. Install $\frac{1}{4}$ in. x 1.500 in. L shear stock through the trip sleeve and into the upper spring stop. Ensure that the shear stock is centralized within the trip sleeve. Thread the bottom sub to the jar rod housing. Slip the lock ring down over the above assembly and thread fully onto the jar rod until it butts out. Note: Do not tighten.
6. Slip the jar rod part way up into the main housing. Apply clean grease into each of the six pockets, then install one steel ball into each pocket. Continue to push the jar rod into the main housing until the top end is visible. Thread the QLS crossover onto the jar rod and secure with the roll pin.
7. With a little clean grease, install the three trip keys into the trip sleeve and then thread the jar rod housing assembly up into the main housing until the required spring force setting is reached. Install the lock segment through the pocket in the main housing and into the jar rod housing ensuring that the teeth are fully engaged. Thread the lock ring back over the lock segment and secure with grub screw.
8. To activate the EAJ, simply push down on the QLS crossover/jar rod to latch onto the trip keys inside the trip sleeve.

7.4.2.2

Disassembly

1. Remove grub screw from the lock ring. While gripping the jar rod housing to prevent it from turning, attempt to back off the lock ring if it should prove to be tight do not force it. If the lock ring does not come free, grip both the main housing and lock ring together, to prevent them turning relative to each other, now gripping the jar rod housing, turn it slightly in both directions until a slackness is felt and/or lock ring becomes free. Once a slackness is felt do not turn the jar rod housing any further, hold it in that position relative to the main housing and back off the lock ring.

2. Should for any reason it becomes difficult to back-off the jar rod housing from the main housing, without having first removed the lock segment, simply grip the main housing securely, i.e., in a vice and with a strap wrench or similar back-off jar rod housing anti-clockwise. The teeth of the lock segment are designed to shear off in this situation, thus allowing disassembly, without causing damage to jar components.

**Note**

New lock segments are contained in every redress kit and are also available separately.

3. Unscrew the bottom section of the jar from the main housing. Remove the trip keys.
4. Remove the roll pin p from the QLS crossover and unscrew from the jar rod. The jar rod can now be removed from the main housing (take care at this stage as the steel may fall from the jar rod. Remove the steel balls.
5. Using a $\frac{1}{4}$ in. diameter punch, remove the shear stock from the trip sleeve and upper spring stop. Keeping the punch in place, remove the bottom sub. Place another $\frac{1}{4}$ in. diameter punch through the lower spring stop and back off and remove the trip sleeve and upper spring stop along with the coil spring.
6. The spring rod assembly along with the disk springs and stack regulator can now be removed from the spring jar housing assembly.
7. The spring stack at this point should be checked and replaced as required.

7.5 Adjustable Upstroke Jar (1-7/8 in.)

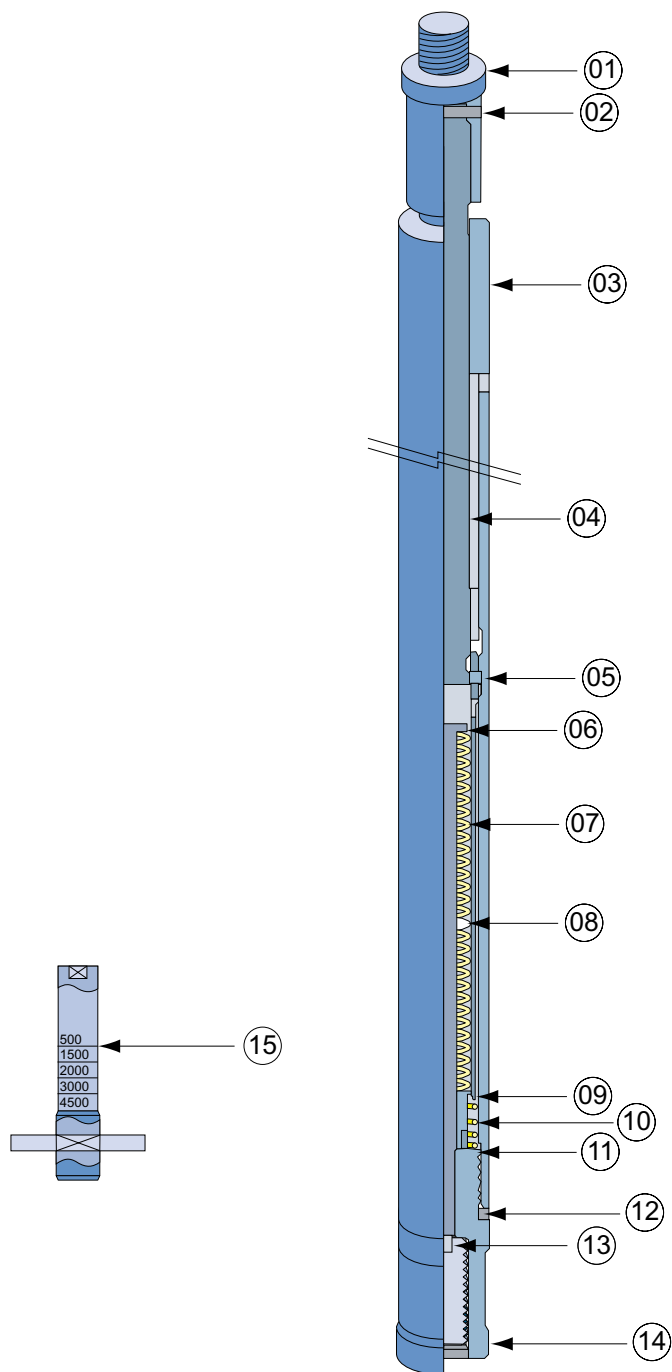


Figure 7-14: Assembly Illustration

Table 7-7: Adjustable Upstroke Jar (H₂S) - Parts List

Item	Description	Qty	Part No
001	Fishing Neck	1	400-1875-03-11
002*	Roll Pin	1	RP-004
003	Main Housing	1	400-1875-01-11
004	Jar Rod	1	400-1875-02-11
005	Trip Keys	2	400-1875-11-11
006	Trip Housing	1	400-1875-04-11
007*	Disc Spring	110	DS-004
008	Spring Rod	1	400-1875-13-11
009	Trip Bushing	1	400-1875-06-11
010*	Coil Spring	1	CS-004
011	Bushing Nut	1	400-1875-07-11
012*	Grub Screw	1	GS-002
013*	Limiter Pin	1	400-1875-10-03
014	Bottom Sub	1	400-1875-09-11
015	Calibration key	1	400-1875-00-08

7.5.1 Assembly - Disassembly

7.5.1.1 Assembly

1. Slide the trip bushing down into the trip housing until it locates at 90 shoulder.
2. Make-up bushing nut to trip bushing.
3. Load disc springs onto the spring rod Note: springs can be built in singles, doubles or triples. Refer to Technical Information for details.
4. Slide the spring stack into the trip housing and place coil spring onto bushing.
5. Make-up assembly to the bottom sub.
6. Insert calibrated key into bottom sub and rotate counter-clockwise for $2\frac{1}{8}$ in. Jar (clockwise for $1\frac{1}{2}$ in., $1\frac{7}{8}$ in. & $2\frac{11}{16}$ in. sizes) until spring tension starts to build up. Ensure that shoulder on spring rod is past hole for limiter pin.
7. Limiter pin, P, can now be easily inserted.

8. Stand assembly up on the bottom sub, insert trip keys into the trip housing (a small amount of grease will help retain them in place).
9. Locate the jar rod into the main housing and make-up top sub and hence install roll pin.
10. Slide pre-assembled bottom sub and trip housing into main housing. The jar rod can then slide through main housing and locate into trip housing via keys.
11. Calibrate spring setting by inserting calibrated key into the bottom sub and rotating as before until end of bottom sub is in line with notch on key at required load setting.
12. Make-up QLS female if required and install roll pin.

7.5.1.2

Disassembly

1. Remove grub screw.
2. Back-off bottom sub and unscrew by hand approximately $\frac{1}{2}$ in. The jar rod should then pull out. Do not unscrew or force the bottom sub any further until the jar rod is loose.
3. Remove the bottom sub, with tripping mechanism attached.
4. Care should be taken to ensure all trip keys are retained.
5. Insert calibrated key into bottom sub and turn clockwise for $2\frac{1}{8}$ in. Jar (counter-clockwise for $1\frac{1}{2}$ in., $1\frac{7}{8}$ in. and $2\frac{11}{16}$ in. Jars) until it stops. Now rotate a half turn in the opposite direction and push out limiter pin.
6. Insert calibrated key into bottom sub and unscrew as this will aid removal of spring rod from bottom sub.
7. Inspect all parts and replace as necessary.
8. If you wish to inspect the jar rod, knock out the roll pin from the fish neck/QLS and the jar rod will come free.

7.6

Uniset Lock and Nipple System

The system was developed to meet the need for a reliable, strong, simple slickline lock and nipple range. The Petroline Uniset lock & running tool is of a top no-go configuration. However, the design is such that a bottom no-go configuration can be manufactured if specifically required.

The range available covers all the standard oilfield sizes for $3\frac{1}{2}$ in. to $5\frac{1}{2}$ in. tubing.

7.6.1 System Features

All loading is taken on high strength keys, which means the ability to withstand high pressures both from above and below the lock.

- Large, uninterrupted, smooth bore of lock allows maximized flow area and minimal turbulence.
- Simple, positive lock design eliminates the need for collets or snap rings.
- Design is such that flow will assist in maintaining the lock in the set position.
- Standardization means that one running tool can be used on various sizes of locks.
- Telltale feature on each running tool allows positive indication at surface of correct setting.
- Running tool can be supplied with integral QLS connection.
- Wide range of nipple sizes available.
- Simple lock/running tool design for ease of use and trouble free operation.
- Lock is retrieved on a standard GS Pulling Tool in conjunction with the correct Petroline Pulling Probe.

Table 7-8: QX Locks and QN nipple Specifications

Tubing Data				Nipple Data		Lock Data		Running Tool	Pulling Tool
OD (in.)	WT. (lb/ft)	ID (in.)	Drift (in.)	Nom Bope. (in.)	ID (in.)	NoGo (in.)	ID (in.)		
3 1/2	9.3	2.992	2.867	2.812	2.872	2.862	1.575	3.5A R/T	3 in. GS
				2.750	2.810	2.800	1.575		
	12.7	2.750	2.625	2.562	2.622	2.612	1.417	3.58 R/T	2 1/2 in. GS
	15.8	2.548	2.423	2.312	2.372	2.362	1.417		
4	9.5	3.548	3.423	3.312	3.312	3.362	1.850	4.0 R/T	3 in. GS
	11.0	3.476	3.351	3.250	3.310	3.300	1.850		
	11.6	3.425	3.303	3.125	3.185	3.175	1.850		
	13.4	3.340	3.215	3.125	3.185	3.175	1.850		
	16.5	3.140	3.015	2.812	2.872	2.862	1.575	3.5A R/T	

Tubing Data				Nipple Data		Lock Data		Running Tool	Pulling Tool
4 $\frac{1}{2}$	11.6	4.000	3.8475	3.812	3.872	3.862	2.165	4.5 R/T	4-in. GS
	12.7	3.958	3.833	3.750	3.510	3.600	2.165		
	13.5	3.920	3.795	3.688	3.748	3.738	2.165		
	16.9	3.724	3.679	3.625	3.685	3.675	2.165		
	18.8	3.640	3.515	3.437	3.497	3.487	1.850	4.0 R/T	
	21.6	3.500	3.375	3.312	3.572	3.362	1.850		
5	11.5	4.560	4.435	4.312	4.382	4.3752	2.862	5.0A R/T	4 in. GS
	15.0	4.408	4.283	4.125	4.195	4.185	2.500	5.0B R/T	
	18.0	4.276	4.151	4.000	4.070	4.060	2.50		
	20.8	4.156	4.031	3.875	3.945	3.935	2.500		
	23.6	4.044	3.919	3.812	3.872	3.862	2.165	4.5 R/T	
5 $\frac{1}{2}$	10.5	4.950	4.825	4.750	4.830	4.820	3.012	5.5 R/T	5 in. GS
	17.0	4.892	4.767	4.562	4.642	4.632	3.012		
	20.0	4.778	4.653	4.562	4.642	4.632	3.012		
	23.0	4.670	4.545	4.437	4.517	4.507	3.012		
		26.0	4.548	4.423	4.312	4.382	4.372	2.862	5.0A R/T

7.6.2

Uniset QN Nipple

The QN nipple is a down hole tubing nipple, which is used to locate, seal and retain Uniset QX locks and Petroline retractable no-go standing valves. The QN Nipple is used with top no-go equipment. It is one-piece manufacture consists of a locking groove, locating no-go shoulder and a seal bore.

7.6.2.1

Features

- QN nipple material will be the same or equivalent to the tubing string material (or to a particular customer specification).
- QN nipple OD will be compatible with tubing coupling OD, as will nipple threads.
- QN nipple burst/collapse ratings will be equal to or better than tubing connection tensile strengths.
- Tight tolerance dimensions ensure correct position of locking keys when lock hits locating no-go.

- Small no-go acts as positive locating device without the need for a highly tapered string as is normally associated with no-go nipple type completions.

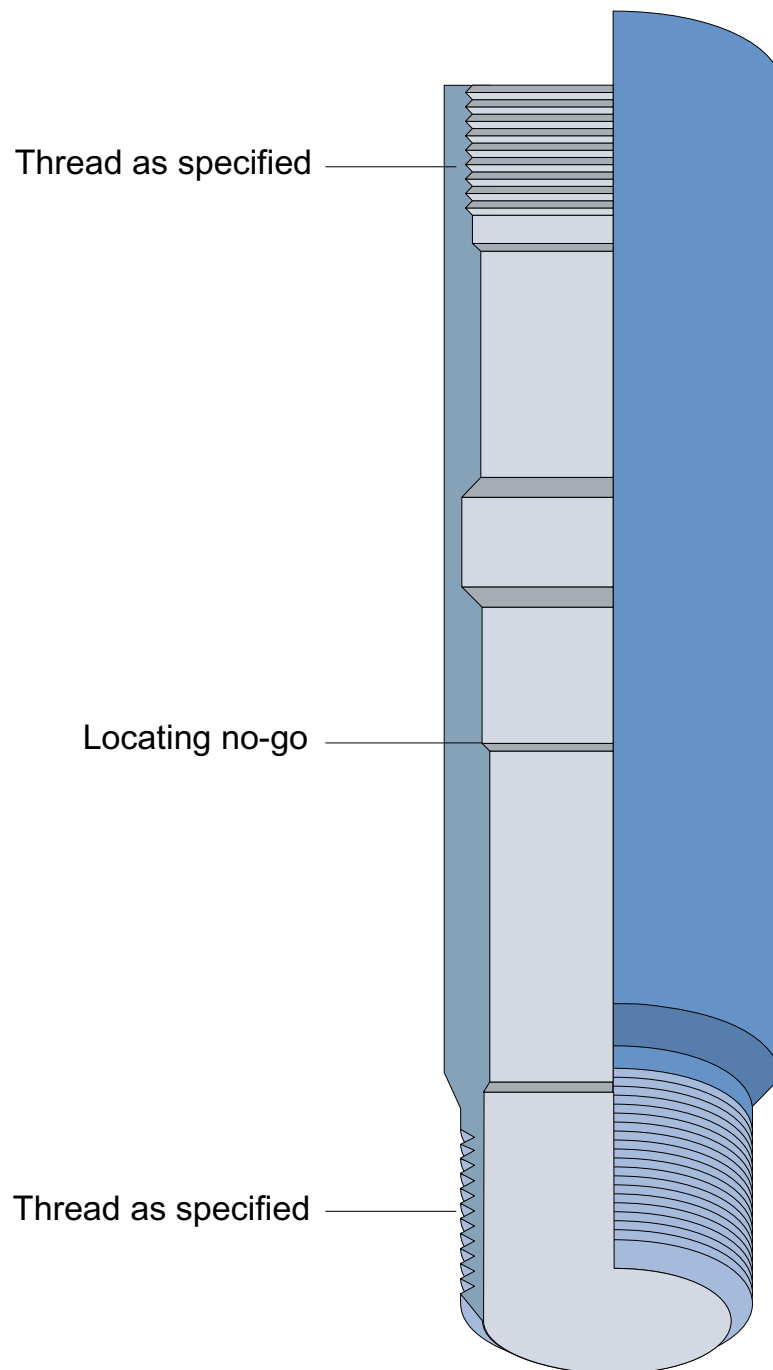


Figure 7-15: QN Nipple

7.6.3 Uniset QX Lock

The Uniset QX lock is a top no-go style lock, which is used to run, locate and then retain various flow control devices (pump-open plugs, safety valves, etc.). The QX lock consists of only five different parts:

- fishing neck
- main body
- inner mandrel
- spring
- locking keys

The QX lock is of a lift-off no-go design and the high strength locking keys facilitate high-pressure ratings.

7.6.3.1 Features

- QX locks are designed to have a pressure rating of 10,000 psi above and below the lock.
- QX Locks are designed to have a minimum tensile strength of 100,000 lb.
- QX Locks have a large flush ID to maximize production flow area and reduce flow turbulence.
- Flush ID helps to prevent sand, grit etc. from entering lock internal parts hence helping to eliminate potential “jarring problems”.
- All QX locks manufactured from a high strength stainless steel that conforms to NACE specifications.
- A simple and easy to understand design eliminates the use of collets or snap rings and their potential problems.

At the point where the keys aligned with the locking groove the upward travel of the inner mandrel is such that in the locked-out position the Inner mandrel fingers are lined up with the top groove in the lock mandrel. As they are the unsupported they can expand outwards and release the QX running tool collet. A sustained upward pull against the top shear pins will confirm that the lock is securely installed after which upward jarring will shear the pins allowing the QX running tool to be retrieved.

In the event that it is not possible for the keys to expand fully into the locked-out position, the inner mandrel fingers will not release the QX running tool collet. To allow retrieval of the QX running tool and to indicate incorrect setting, the QX running tool collet is pinned and in the event that the QX lock is incorrectly set the pin may be sheared by upward jarring. This allows the collet to collapse and the QX running tool to be retrieved.

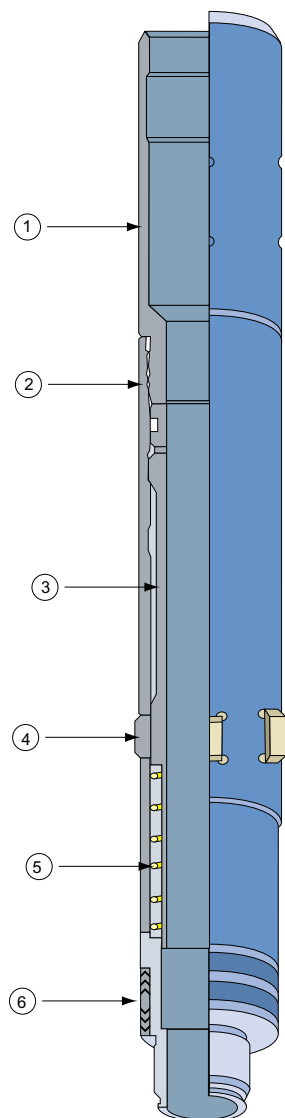
The Uniset QX lock mandrel is the only one available, which is positively removed from the no-go by applying force in the direction of travel required.

The design is such that should any problems be encountered during setting it is always possible to retrieve the tool string in every eventuality, whereas, certain other systems require the lock to be retrieved and have no safety release feature.

In the event that the lock pre-sets above the nipple due to scale or some other restriction, the keys cannot expand fully in the ID of the tubing, ensuring that incorrect setting is indicated. This feature applies to virtually all weights of tubing and further details can be supplied as requested.

The Uniset QX lock is run into the well with the locking keys retracted. It is then positioned in the QN nipple by use of the no-go shoulder. Downward jarring shears the lower set of shear pins and allows the collet on the QX running tool to travel downwards past the inner mandrel fingers. The coil spring then acts to move the inner mandrel towards the set position; however, the design is such that the locking keys can only partially expand into the locking groove.

An upward pull is then taken on the line causing the QX running tool to be lifted until its collet contacts the inner mandrel fingers. The upward pull is then transferred to the lock mandrel causing it to lift until the locking keys are aligned with the locking groove in the QN nipple. Due to the spring force applied to the inner mandrel, the locking keys then expand into the fully locked-out position. This ensures any loading will not be placed on the no-go shoulder of the lock since due to the upward movement; it is no longer in contact with the QN nipple.



ITEM	DESCRIPTION
1	FISHING NECK
2	MAIN BODY
3	INNER MANDREL
4	LOCKING KEYS
5	SPRING
6	CHEVRON PACKING STACK

Figure 7-16: Uniset Lock Assembly

7.6.4 Uniset QX Running Tool

The QX running tool is a specially designed tool, which is used to run and set a Petroline Uniset QX lock. It's simple design combines strength with ease of operation. The QX running tool consists of a top sub, shear off sub, main body, telltale collet and bottom sub. It has a unique Telltale collet feature, which provides positive indication, at surface, of correct QX lock setting.

7.6.4.1 Features

- Unique Telltale Collet gives a positive indication, at surface, of a correctly set Petroline Uniset QX lock.
- One size QX running tool can be used with a wide range of Uniset QX lock sizes.
- Each QX running tool can be supplied with integral Petroline QLS male connection.

When the Uniset QX lock is run in the well the Telltale collet forces the fingers on the inner mandrel out into the lower internal groove in the lock body. This keeps the inner mandrel in position, keeping keys retracted.

When first down shear occurs in the QX running tool the telltale collet is forced down allowing the inner mandrel fingers to collapse and hence mandrel moves up. Now, in order for the telltale collet to be removed correctly (without shearing) the inner mandrel has to be fully up hence allowing fingers to be forced out into the upper internal groove in lock body. With the inner mandrel in this position, the lock has to be correctly set.

If the Uniset QX lock has not set correctly, the inner mandrel can't travel far enough to reach the upper internal groove, hence fingers can't be forced out and the telltale collet will shear off.

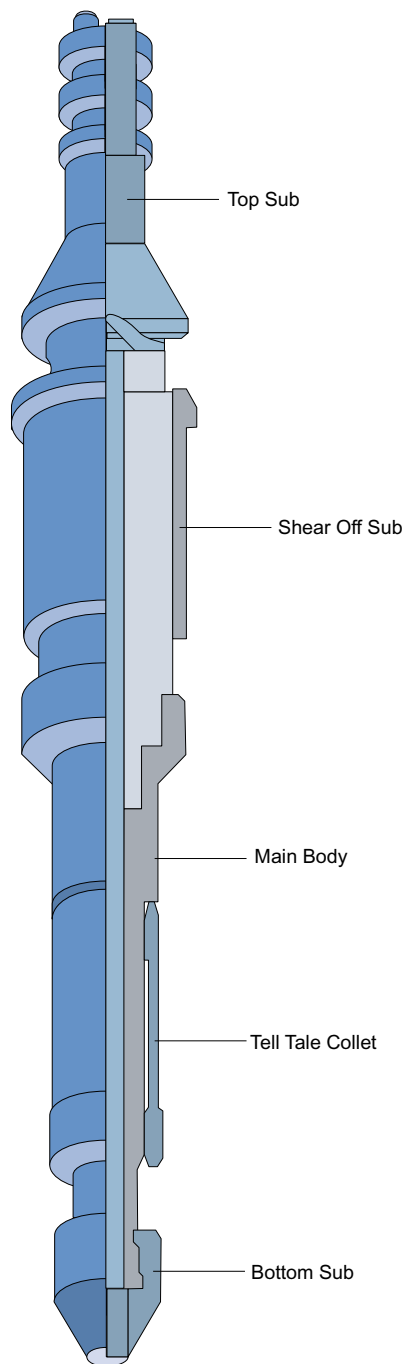


Figure 7-17: QX Running Tool

7.6.5

Uniset Retractable No-Go Standing Valve

The Petrolin retractable no-go standing valve was developed for use in conjunction with the QN nipples range. Due to the fact that the latest generation of QN nipples utilize a small diameter no-go Shoulder purely as a locating device and not for load bearing, it has previously not been possible to carry out tubing

tests without shearing off the tool. As this meant extra slickline runs, it was decided to address the problem and this has resulted in the design of Petroline's retractable no-go standing valve.

The tool consists of a standard standing valve-equalizing assembly in conjunction with a lock mandrel. In the running position, the locking dogs are collapsed and the no-go fingers are supported by the profile of the inner mandrel. It is lowered into the well until the no-go shoulder locates in the QN nipple.

Downward jarring shears a set of screws allowing the inner mandrel to travel downwards and lock the keys into the locking profile of the nipple. Due to the profile of the inner mandrel, further downward travel then removes the support from the no-go fingers allowing them to collapse and ensuring all the loading is on the keys.

In the event that insufficient jarring is applied to shear the screws and lock the keys out, as soon as pressure is applied from above this would be transferred to the shear screws causing them to shear long before damage could be done to the no-go of the QN nipple. This safety feature ensures that the no-go of the 'QN' Nipple is protected at all times and allows very high test pressures to be achieved. Due to the locking collet on the inner mandrel, it is possible to flow through the standing valve without fear of it becoming unlatched.

To retrieve the tool, upward jarring will equalize the valve then shear the screws, which hold the two piece inner mandrel in position. The top section travels upwards unlocking the keys from the profile while the lower section is retained in the set position by its collet. This ensures that the no-go Fingers remain in the collapsed position allowing trouble free retrieval.

7.6.5.1

Features

- Locking keys take the entire load hence 10,000 psi pressure rating.
- Lock Down Collet prevents flow from unsetting lock.
- Flush ID helps reduce flow turbulence.
- Design allows high-pressure tests to be carried out with only one run.
- All load taken on locking keys.

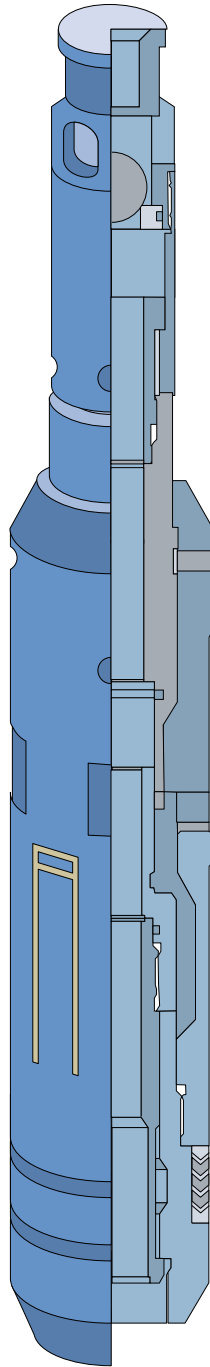


Figure 7-18: Retractable Standing Valve Assembly

7.7 Petroline $4\frac{3}{8}$ in. Standing Valve

The prime criteria for the development of this tool was to significantly reduce the number of slickline runs required during the completion of a well.

The retractable no-go standing valve provides a high-pressure test capability with a single slickline run. The standing valve can be used both in Petrolite's QN nipple profiles and in other manufacturer's profiles.

7.7.1 Features

- 5000 to 10,000 psi pressure ratings as standard
- Single run to set and retrieve
- Hydraulic set capability (no downward jarring required for high deviation wells)
- Not reliant on operator ability
- Flow through capability

The standing valve is designed to be set in the nipple profile by hydraulic means, and no downward jarring is required. The tool is therefore ideal for high deviation applications and has been successfully run in wells up to 79° deviation.

The equalizing section can be provided with a spring and ball retainer to ensure a positive seal of the sealing ball if required.

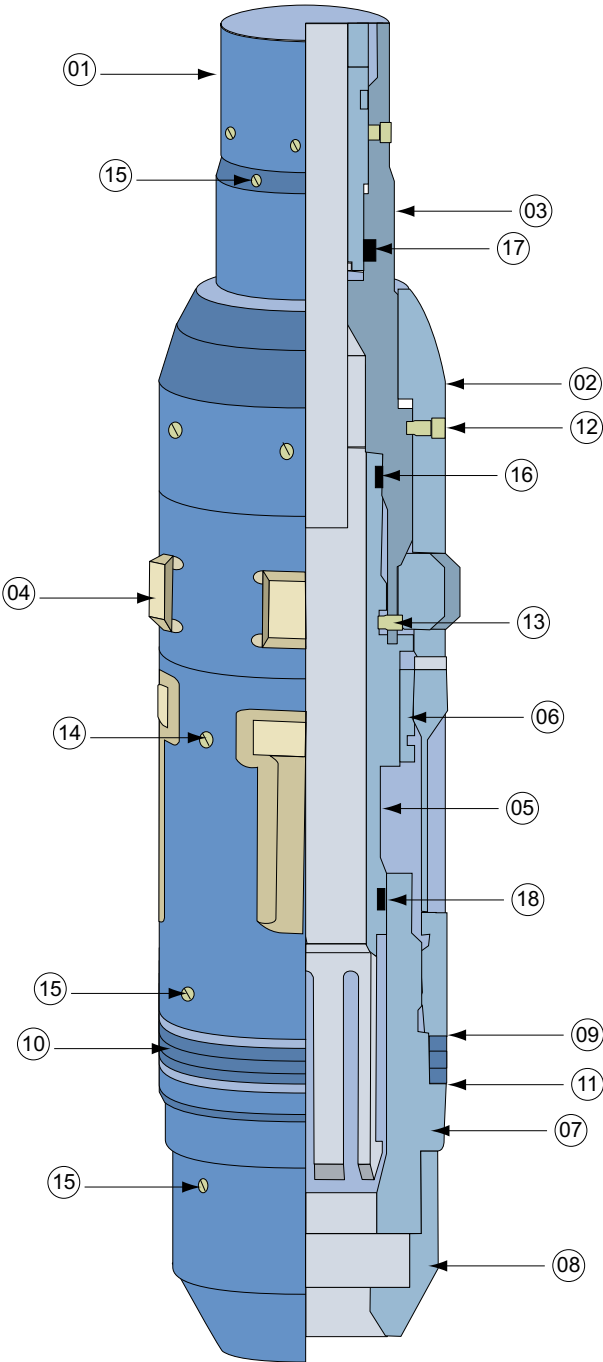


Figure 7-19: RNQN Standing Valve

Table 7-9: RNQN Standing Valve Parts List

Item	Description	Qty	Part No
001	2.875-in. Std. Valve Sub Assembly	1	218-2875-00-03
002	Main Body	1	625-4437-01-45
003	Plunger (Inner Mandrel)	1	625-4437-09-45

Item	Description	Qty	Part No
004	Lock Out Keys	4	625-4437-02-45
005	Lock Down Collet	1	625-4500-10-45
006	Finger Sleeve	1	625-4500-07-45
007	Packing Barrel	1	625-4437-03-45
008	Bottom Sub	1	625-4500-06-45
009	Male End Adaptor	1	245-4437-02-45
010*	4.437 in. Chevron Packings	3	243-4437-BI-OI
011	Female End Adaptor	2	245-4437-01-45
012*	Shear Screw (5/16 in. -28UNC)	4	SS-030
013*	Shear Screw ($\frac{1}{4}$ in. -20UNC)	4	SS-005
014*	Shear Screw ($\frac{1}{4}$ in. -20UNC)	4	SS-011
015*	Grub Screw ($\frac{1}{4}$ in. -20UNC)	3	GS-020
016a*	Elastomer (O-ring)	1	OV-140-075
016b*	Elastomer (Parbak Ring)	2	PB-140-N90
017a*	Elastomer (O-ring)	1	OV-225-075
017b*	Elastomer (Parbak Ring)	2	PB-225-N90
018a*	Elastomer (O-ring)	1	OV-228-075
018b*	Elastomer (Parbak Ring)	2	PB-228-N90

7.7.2

Assembly - Disassembly

7.7.2.1

Assembly

1. Assemble standing valve sub assembly as outlined in relevant instructions in this manual.
2. Install elastomers onto the lock down collet and slide lock down collet into and install shear screws.
3. Stand the main body up on end, with the box thread facing upwards; install the lock out keys into the windows in the main body. A small amount of grease will help retain the keys in the windows. Ensure keys are fitted the correct way round with the 30° internal taper face matching 30° taper on mandrel.

4. Place the inner assembly down into the main body then lift then body until it bottoms out on the inner assembly. The shear screw holes should be lined up with the track, hence insert shear screws. If the quantity of shear screws is different from number of holes in main Body, this will be stated on Technical Information Sheet.
5. Slide the finger sleeve down into the main assembly align and install shear screw .
6. Assemble the packing stack respectively, onto the packing barrel. Thread the packing barrel to the main body and secure with grub screw. Thread the bottom sub to the packing barrel and secure with grub screw.
7. Install elastomers into the inner mandrel. The standing valve sub assembly should now be made-up to the main assembly. Using a screwdriver through the portholes, make-up the sub assembly and inset grub screws.

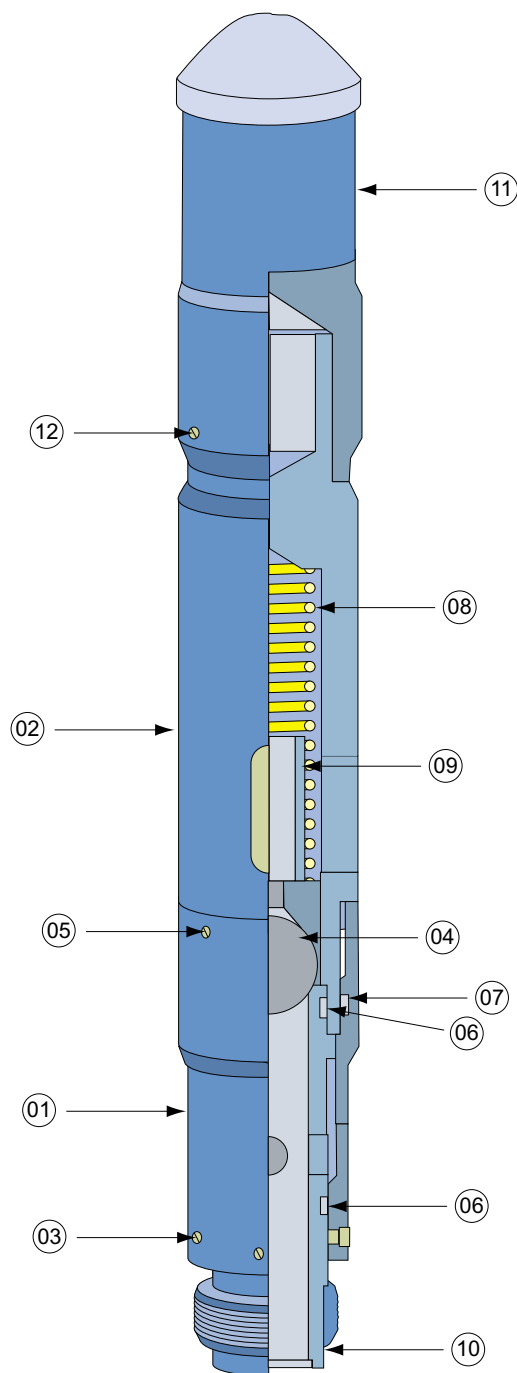


Figure 7-20: RNQN Standing Valve Assembly Detail

7.7.2.2

Disassembly

- Remove all grub screws.

- Remove bottom sub and using the lead in angle on the lower end push against the packing barrel end face to hence collapse the internal fingers of the lock down collet back inside the body.
- The remainder of the tool should be disassembled opposite to the assembly instructions.
- All parts should be inspected for damage and replaced as necessary.

Table 7-10: Standing Valve Sub Assembly – Parts List

Item	Description	Qty	Part No
001	Equalising Housing	1	218-2875-05-45
002	Top Sub	1	218-2875-15-45
003*	Shear Screw (1/4 in. -20UNC)	4	SS-026
004	Steel Ball (1 - 1-1/16 in. Dia.)	1	SB-001
005*	Grub Screw (1/4 in.-20UNC x 3/16 in.)	1	GS-023
006a*	Elastomer (O-ring)	2	OV-224-090
006b*	Elastomer (Parbak Ring)	4	PB-224-N90
007a*	Elastomer (O-ring)	1	OV-229-090
007b*	Elastomer (Parbak Ring)	2	PB-229-N90
008	Coil Spring	1	CS-226
009	Ball Retainer	1	218-2670-15-45
010	Equalising Mandrel	1	218-2875-14-45
011	Fish Neck (3.125 in. Rope Socket)	1	464-3125-01-45
012*	Grub Screw ($\frac{1}{4}$ in.-20UNC x $\frac{1}{4}$ in.)	1	GS-020

7.7.2.3

Assembly - Disassembly of Standing Valve Subassembly

1. Install elastomers into the equalizing housing and elastomers into the equalizing mandrel respectively. Slide the equalizing mandrel onto the equalizing housing.
2. Make-up the equalizing mandrel to the plunger on the main standing valve assembly. Hold in place with grub screw.
3. Place the coil spring followed by the ball retainer and the stainless steel ball into the top sub. Push the ball down past the flow ports and place a screwdriver through the ports to hold the ball back against the spring force.
4. Thread the top sub assembly to the equalizing housing. Install the grub screw.

5. Slide the equalizing assembly up, to line up shear screw hole in equalizing housing with track in equalizing mandrel, install the shear screws.
6. Carefully remove screwdriver from flow ports to allow steel ball to seat up against the ball seat.
7. Thread the required fish neck onto the top sub and secure with grub screw.

Disassembly

- Remove all grub screws.
- Disassembly should be opposite to the assembly instructions.
- On disassembly, inspect all parts for damage and replace as necessary.

7.7.3 Operating Procedures

The Petroline retractable no-go standing valve is run using standard slickline methods and can be set either mechanically or hydraulically.

When using the retractable no-go standing valve mechanically, make-up the standing valve to the appropriate JDC or SB type pulling tool complete with brass pin. Lower the assembly into the well bore until the no-go fingers on the standing valve make contact with the no-go on the nipple profile.

Downward jarring will cause the shear screws to shear and in turn will move the inner mandrel down locking out the locking dogs and remove the support from the retractable no-go on the nipple profile.

When retrieving the retractable no-go standing valve lower the tool string complete with the appropriate JDC or SB type pulling tool into the well bore and latch the retractable no-go standing valve (an upward pull on the slickline will confirm latching).

Upward jarring will cause the equalization screws and inner mandrel screws to shear and the standing valve is set hydraulically as follows:

Lower the standing valve in the well bore, this should be done at a relatively steady speed and care should be taken when passing through restrictions or when opening the spang jars to prevent premature equalization.

Once the nipple is encountered one or two light downward taps should be applied to ensure the seals have entered the seal bore then pressure can be applied.

- If it is required to stay on the device, slack off 10 ft of wire approximately and apply the nominal shear out value of the valve. Monitor the pressure for a few minutes then increase up to the required test level. When the standing valve sets a slight reduction in pressure will be seen at surface. On completion of test, jar upwards to equalize and unlock the standing valve which can then be retrieved to surface.
- If you require leaving the standing valve in the nipple, slack off 10 ft wire apply the nominal shear-out value of the valve. Monitor the pressure for a few minutes then commences to jar downwards, if during jarring the valve is accidentally equalized pressure will be lost.

Monitor at all times when setting and if pressure does drop, attempt to apply again. If indications are that the valve has been equalized jar up to retrieve.



Note

If pressure is lost cease downward jarring immediately, this may be in time to prevent release of the running tool and will save unneeded slickline run to retrieve and reinstall the valve.

7.8

DU Pulling Tool

The DU Adaptor was designed to be used with conventional GS pulling tools to enhance the performance and give a greater degree of operational flexibility.

When releasing many down hole flow control devices and valves, it is necessary to jar downward to free off the relative motion of the keys, then jar upwards to retrieve the device in question.

This causes two problems:

- Downward jarring will shear a GS pulling tool
- Upward jarring will shear the alternative shear-up GR pulling tool.

This often means that a one-run device requires at least two runs.

The DU adapter operates in a manner, which allows jarring force to be effectively applied in both directions.

Downward jarring at first will not affect the DU pulling tools no matter how prolonged or severe.

Subsequent upward jarring can also be indefinitely. During upward jarring the shear screws will shear moving the tool into the pre-release second position.

Final downward jarring will shear the pin in the pulling tool allowing it to be retrieved to surface.

With a conventional GS, if there is debris in the flow control device or if the equalizing prong spacing is such that the GS does not shoulder out on the internal fishing neck, it will NEVER shear and in all likelihood a fishing job will result.

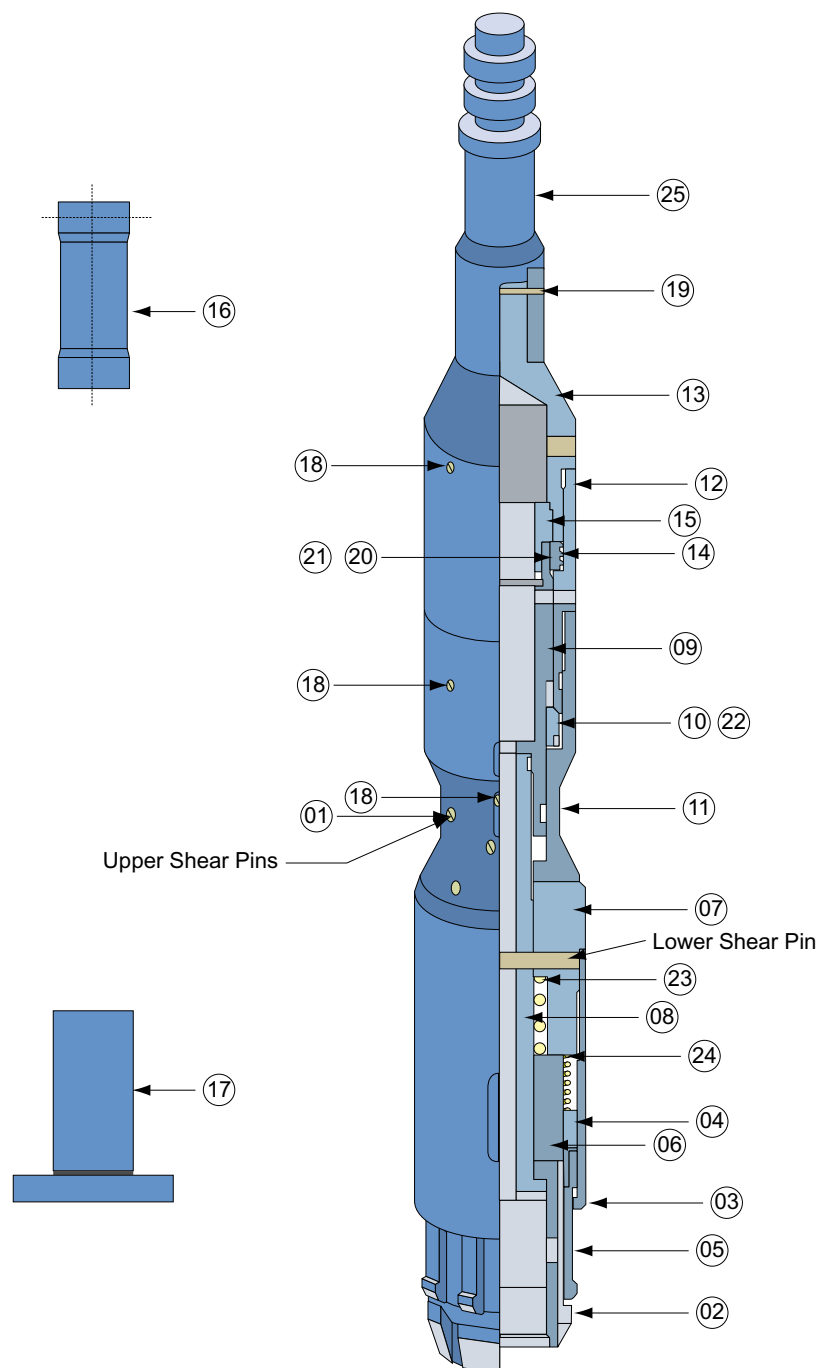


Figure 7-21: DU Pulling Tool

Table 7-11: DU Pulling Tool Parts List

Item	Description	Qty	Part No
001	Shear Screw	8	SS-030
002	Core Bottom Half	1	435-4000-08-15
003	Outer Sleeve	1	435-4000-13-15
004	Dogs Retainer	4	435-4000-16-15
005	Dogs	1	435-4000-17-15
006	Spring Retainer	1	435-4000-15-15
007	Shear Pin Retainer	1	435-4000-14-15
008	Core Top Half	1	435-4000-07-11
009	Ratchet Mandrel	1	435-4000-06-11
010	Ratchet	4	435-4000-09-11
011	Lower Body	1	435-4000-04-15
012	Upper Body	1	435-4000-03-15
013	Top Sub	1	435-4000-01-15
014	Lock Down Keys	3	435-4000-05-11
015	Inner Ring	1	435-4000-02-11
016	Assembly Tool	1	435-4000-10-11
017	Dis-Assembly Tool	1	435-4000-11-11
018	Grub Screw ($\frac{1}{4}$ in.-20UNC)	3	GS-020
019	Roll Pin	1	RP-005
020	Steel Spring Belt Coupling	1	MC-009
021	Steel Spring Belt Connector	6.1 in.	MC-010
022	Split Ring	2	SR-003
023	Coil Spring (Small GD)	1	CS-179
024	Coil Spring (Large GD)	1	CS-180
025	$1\frac{7}{8}$ in. QLS Male	1	444-1875-21-11

7.8.1 Assembly - Disassembly

7.8.1.1 Assembly

1. Stand the core bottom half with the core top half inserted, on the assembly tool vertically in a vice.
2. Install the dog's retainer, and latch dogs into outer sleeve. Slide outer sleeve/dogs retainer and latch dogs over bottom core.

3. Install large OD coil spring, spring retainer followed by small OD coil spring and shear pin retainer. At this point, all items should be free to move against the spring and be in the vertical position.
4. Connect the assembly tool on the thread on the core top half. Wind on the assembly tool until the outer sleeve can be threaded by 2 - 3 turns onto the shear pin retainer. Ensure the spring is free to move. Thread down assembly tool until the shear pin hole in the shear pin retainer and inner mandrel line up. Note the disassembly tool is always in line with the holes on the inner mandrel. Install shear stock and unthread assembly tool. Continue to make-up outer sleeve to the shear pin retainer until sleeve butts out on square shoulder on retainer.
5. Line up the ratchet segments in order ensuring that the numbers stamped on them run consecutively from 1-4 in a clockwise direction. Install the split wire rings in order to assist in holding the segments where assembling to the threads on the ratchet mandrel. Slip the ratchet segments over the mandrel and thread segments to start of thread on ratchet mandrel.
6. Slip ratchet mandrel inside lower main body and thread onto the core top half. Install grub screw through access hole in the lower body. Using a screwdriver through the access hole on the lower body wind ratchet forwards until it butts out on inside face of lower body. Insert the upper shear screws into the ratchet mandrel through the lower main body.
7. Thread the upper main body into the lower body, install grub screw.
8. Assemble the three parts of the spacer keys with steel spring belt and connector and slide over the end of the ratchet mandrel.
9. Thread top sub with QLS integral part into the upper body. Install grub screw. Finally ensure ratchet is butting out on inside face of lower body. Adjust with screwdriver through slot if necessary.

7.8.1.2

Disassembly

1. Grip DU pulling tool in vice. Remove grub screw, remove top sub and QLS integral part. Remove grub screw and upper body. Retain split ring and garter spring when removing body.
2. Remove grub screw from core top half.
3. Install punch in hole in ratchet mandrel. Locate disassembly tool in slot in core top half. Back off ratchet mandrel from core top half.

4. After disassembly inspect all parts for damage and replace if necessary before re-assembly. Ensure the ratchet segments, split wire rings and the threads on the mandrel are fully inspected for any damage. If any damage is seen, replace the damaged items. It is essential to the correct operation of the tool that these items are checked.

7.8.1.3 Disassembly

If Only the Upper Pin has been Sheared Out

If the tool is being used for workshop or surface testing, then it can be used for multiple operations without shearing the lower shear pin (as per standard GS pulling tool). The tool will function satisfactorily in the workshop with the upper pin sheared out. The tool is used in this manner must be fully disassembled prior to using in the field. To complete the disassembly, knock out the lower shear pin and disassemble as outlined in the instructions above.

7.8.2 Operating Procedures

Running and retrieving is carried out as per a standard GS pulling tool.

The tool is run in the pinned up position.

After locating into the correct fishing neck, upward jarring will shear pin A and activate tool to pulling position by opening a gap between the lower section (based on standard GS pulling tool design) and the upper section. This will not allow continuous upward jarring to the tool without any effect on the tool facilitating removal of lock, fish, etc. from well bore.

If the DU pulling tool is to be retrieved from the fishing neck, then downward jarring will allow shear out of pin B allowing retraction of the fingers from fishing neck. DU pulling tool can now be retrieved from well bore.

Internal gap C in the DU pulling tool allows the tool to be retrieved even if a prong attached to the tool is prevented from further downward travel for any reason i.e., shear pin B can always be sheared out.

For workshop or surface operations, the DU pulling tool can be released from the fish neck by applying force to the finger retaining sleeve collapsing the fingers to allow retrieval. This will negate the requirements to shear out pin B and save time on redress for multiple surface/workshop tests. (This is done in the same manner as is current practices with standard GS pulling tool).

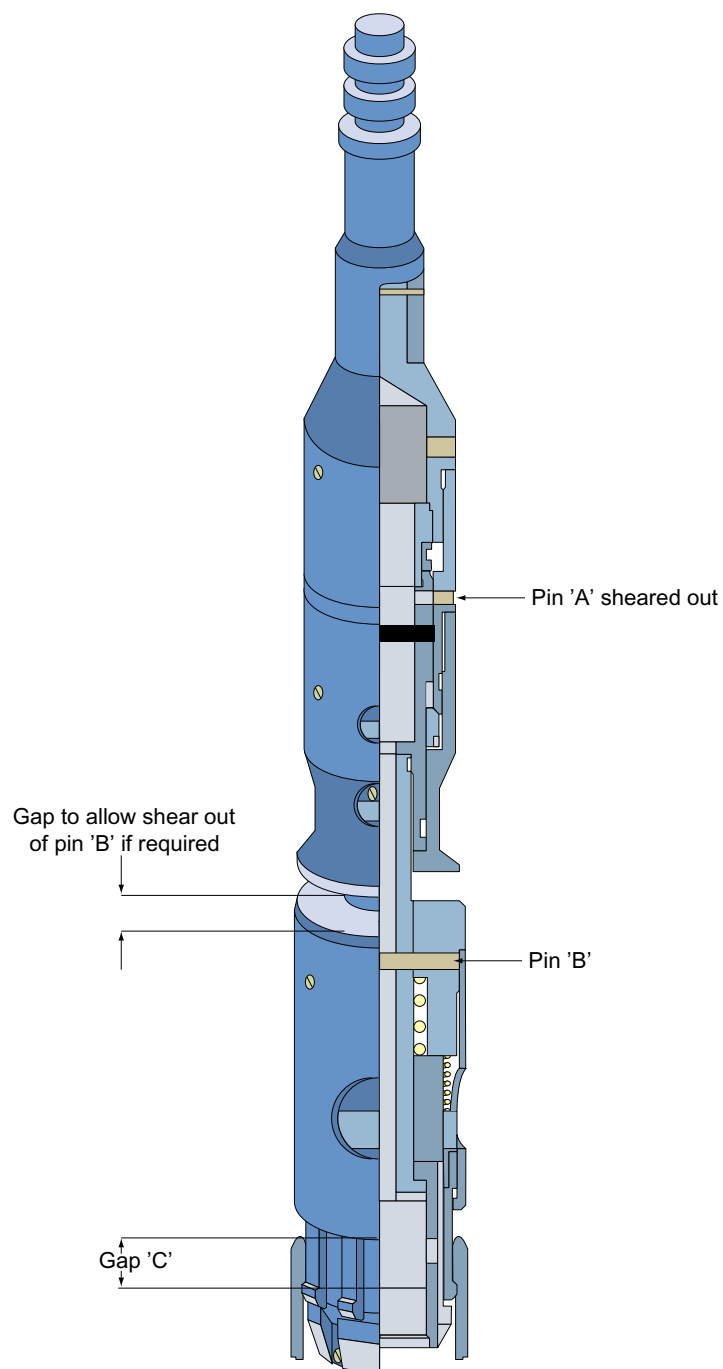


Figure 7-22: DU Pulling Tool - Pulling Position

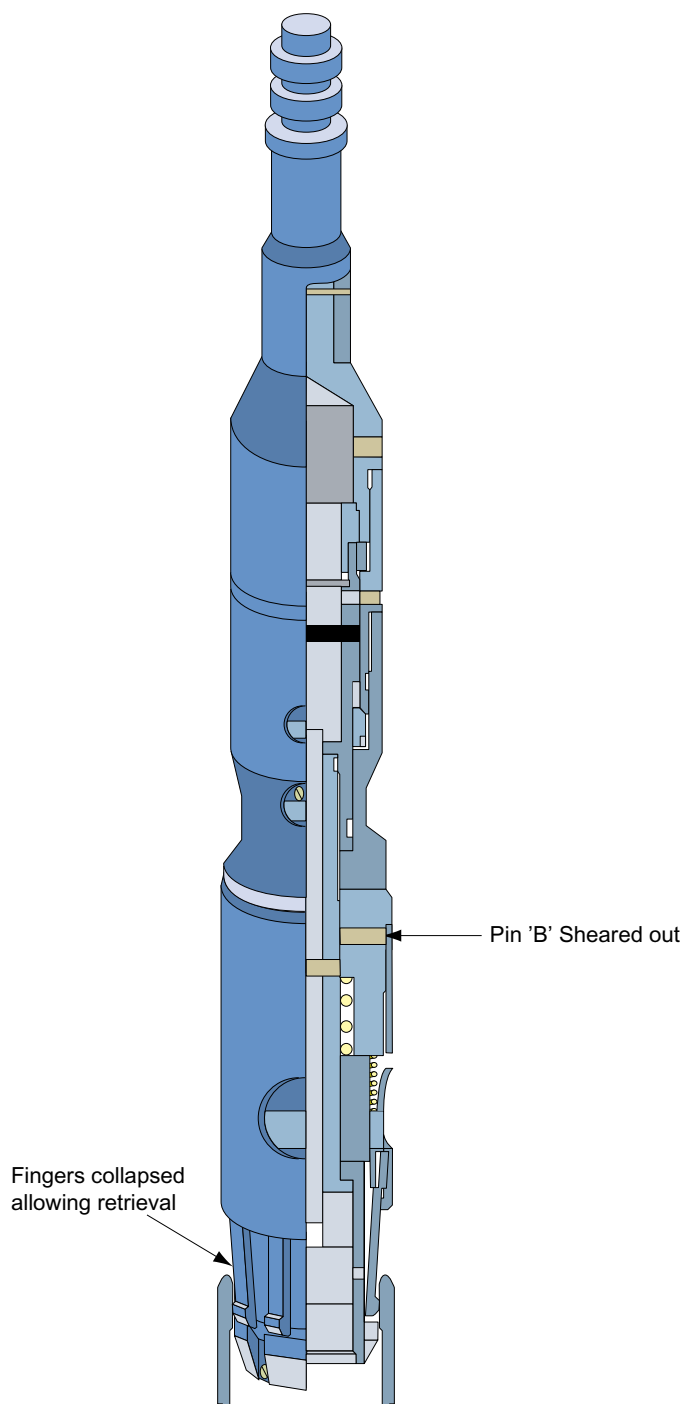


Figure 7-23: DU Pulling Tool - Shear-Off Position

7.9

H-Style Equalizing Assembly

The Petrolite H-Style equalizing assembly is a conventional two run equalizing system comprising of a housing and equalizing prong.

The equalizing prong can incorporate dual centralizers, the upper is fixed permanently and the lower is shear pinned in place. This both assists centralization into the housing and protects the elastomer seals from wear and damage as they are lowered into the well bore. When the plug body is encountered, light downward jarring shears the lower retaining pin allowing the sealing prong to move downward, through the centralizer to the sealed position. The use of the lower centralizer is dependent upon the length of the plug.

All sealing prongs are supplied with dummy rope socket top subs with sucker rod threads, which allow the insertion of spacer bars (stem) to extend the prongs when required for high debris conditions.

As an option the dummy rope socket top subs can be replaced by a junk or valve catcher sub with an internal fishing neck on request.

The anti-vibration prong ensures that the sealing prong cannot be removed other than by slickline methods, and plug integrity is maintained. The prong is held in place by means of a locking collet.

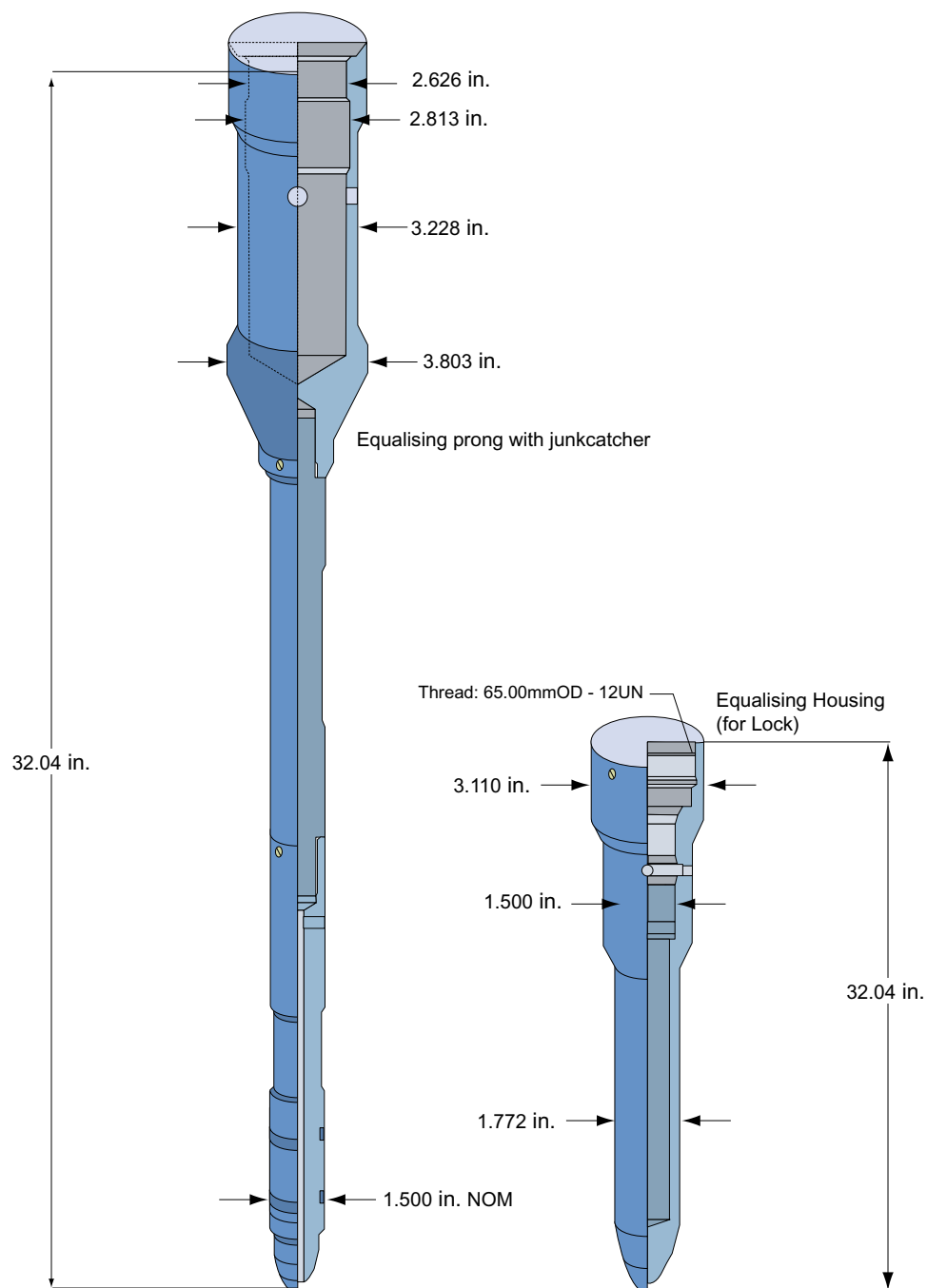


Figure 7-24: H-Style Equalizing Assembly

Table 7-12: H-Style Equalizing Assembly – Part List

Item	Description	Qty	Part No
001	Equalizing Prong	1	205-3310-51-45
002	Top Sub	1	205-3813-06-10
003	Connector Prong	1	205-3813-07-10

Item	Description	Qty	Part No
004	Equalising Housing	1	205-4000-06-45
005*	Grub Screw ($\frac{1}{4}$ in. -20UNC)	2	GS-019
006a*	Elastomer (O-ring)	2	OV-218-075
006b*	Elastomer (Parbak Ring)	4	PB-218-090
007*	Grub Screw ($\frac{1}{4}$ in. -20UNC)	1	GS-020

7.9.1 Assembly - Disassembly

7.9.1.1 Assembly

1. The equalizing housing should be made up to the bottom of the relevant lock assembly and secured with grub screw prior to the lock being run down hole.
2. Make-up the top sub/fish neck to the connector prong and secure with grub screw.
3. Make-up the equalizing prong to the connector prong and secure with grub screw.
4. Install elastomers into the equalizing prong.

7.9.1.2 Disassembly

1. Remove all grub screws.
2. Disassemble in opposite manner to assembly instructions.
3. Inspect all parts for damage and replace where necessary.

7.9.2 Operating Procedures

1. Run in assembly as per the Uniset Lock Running Procedure.
2. When preparing the equalizing prong, if debris is likely in the well insert the required length of spacers between seals and fishing neck. This is done by attaching lengths of stem bar.
3. The prong is run using conventional SB/GS pulling tools (dependent on top sub) and should be lowered until the plug is encountered. Light downward jarring should overcome frictional resistance and move the prongs into the sealed position.

4. It is then advisable to apply some pressure from surface and then once indications are that the plug is set, continue to jar downward to release the SB/GS. If the prong is accidentally unseated while jarring a pressure drop will be seen and it may possible to re-set the prong.

7.9.2.1

Pulling Procedure**For QX Lock with H-Style Bottom and Equalizing Prong**

- Ensure whenever possible, that the pressure across the plug is equalized. Attach the relevant SB or JDC pulling tool to the tool string, lower into the well bore, latch equalizing prong and jar upwards to retrieve equalizing prong.
- Make-up the correct pulling probe to the relevant GS/DU pulling tool.
- Lower the tool string with GS assembly into the well bore and locate the lock assembly. If the GS pulling tool is then latched, upward jarring should be applied to overcome seal friction.
- At this point the keys are unsupported and therefore the lock should be easily retrieved.

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8 BAKER PLUGS, LOCKS AND TOOLS

8.1 Introduction

A summary of the tools and equipment described in this section is shown on the summary and compatibility charts.

Table 8-1: Baker Lock Mandrel Running and Pulling Summary

Lock	Running Tool	Running Accessory	Pulling Tool	Pulling Accessory
	'G' Selective	-	RB	
Selective 'S'	E' Selective	-	JUC SB JDC	'A' Probe
	C-1	Locator Ring + 'A' Shank		
Top No-Go 'W'			RB	'B' Probe
	C-1 (or Soft Set)	Protector + 'A' Shank	JUC	
'G'	C-1	Protector + N-1 Shank	SB JDC	N-1 Probe
'F'	'M'	'M' Probe	'M'	M-1 Probe
'M'				
M-1				
F-1				
'B'				
M-2	GS	M-1 Probe	GS	
		BT+'X' to suit		BT + 'X'
		MA adjustable		MA + adjustable Probe
'Z'	Soft Set	-	RB	
	C-1	Protector + 'A' Shank	JUC	'B' Probe
'R'		Protector + N-1 Shank	SB JDC	N-1 Probe
'K'	'M'	'M' Probe	'M'	'M' Probe
'E'				
E-1	GS	M-1 Probe	GS	M-1 Probe

8.2 Seating Nipples

The Baker top no-go or selective nipple is the F nipple. This same profile is cut into the top sub of the model L sliding side door. Consequently, the same lock mandrels fit in both devices. The bottom no-go alternative is the R nipple.

The lock positioning method will be one of the following:

8.2.1 Top No-Go

An enlarged OD above the V-packing assembly on the lock. This should be located on a shoulder above the seal bore of the F nipple and L sliding side-door.

8.2.2 Bottom No-Go

A reduced OD below the V-packing assembly on the lock. This shoulder is located on a reduced ID below the seal bore of the R nipple.

8.2.3 Selective

This is for top no-go equipment only. Positioning and locking is achieved by the use of various sized locating rings on the running tools (C-1) or by using the selective (G and E) running tools to selectively expand the locking dogs.

Running and pulling tools are specified by their Baker, Otis and Camco designations.

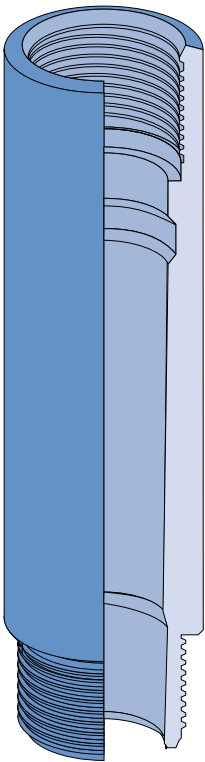


Note

It should be remembered that Baker fishing necks have a 20° undercut which matched the Otis pulling tool dogs. Camco dogs have a 90° shoulder. The use of Camco tools in this application will place additional stress on the outer fishing neck profile. For this reason, Camco tool references have been provided only as alternatives to the recommended Otis or Baker tools.

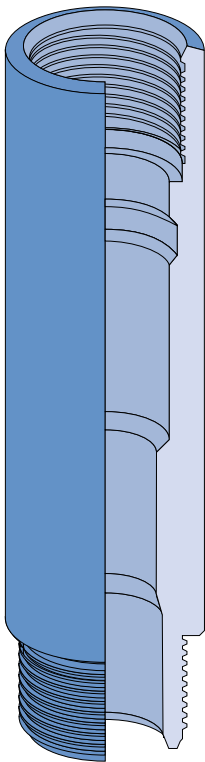
It should also be noted the Petrolin DU Pulling Tool offers a good alternative to the Baker M and Otis GS. The DU permits downward jarring to loosen the lock mandrel before jarring upwards to retrieve the lock.

8.2.4 F Nipple - Top No-Go Selective



F Nipple

Sizes 1.18 in. to 3.81 in.
(excl. 3.12 in. and 3.31 in.)



F Nipple

Sizes 3.12 in., 3.31 in. and
4.00 in. - 5.95 in.

Figure 8-1: Model F Nipple Configuration

Table 8-2: Model F Nipple Specifications

Tubing		Nipple			Tubing		Nipple			Tubing		Nipple		
OD (in.)		Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm		Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm		Seal Bore (in.) mm	Size* (in.)	Min OD** (in.)
1.660		1.187	1.18				2.250	2.25				4.000	4.00	
		30.15		1.875	2 ⁷ / ₈		57.15		3.109					
42.16		1.250	1.25	47.63	73.02		2.312	2.31	78.97		5	4.125	4.12	
		31.75					58.72				127.00	104.78		
		1.437	1.43				2.562	2.56				4.312	4.31	
1.900		36.50		2.109			65.07					109.52		

Tubing				Nipple				Tubing				Nipple				Tubing				Nipple			
OD (in.)	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm	OD (in.) mm	Seal Bore (in.) mm	Size* (in.)	Min OD** (in.) mm
48.26	1.500	1.50	53.57	3 1/2	2.750	2.75	3.687	5 1/2	4.562	4.56		139.70	115.87	4.75		6 5/8	5.250	5.25		168.28	133.35	5.50	
	38.10			88.90	69.85	115.87	93.65		4.750	4.75			120.65				5.500	5.50			139.70		
2 1/16	1.562	1.56	2.250		2.812	2.81			5.750	5.75		7	146.05			7 5/8	6.125	6.12		193.68	155.58	6.37	
52.37	39.67				71.42				5.953	5.95			151.21				6.375	6.37			161.92		
	1.625	1.62	57.15																				
	41.28																						
2 3/8	1.781	1.78		4	3.125	3.12			5.750	5.75													
60.33	45.24			101.60	82.55				5.953	5.95													
	1.812	1.81	2.560		3.312	3.31			6.125	6.12													
	46.02		65.02		84.12				6.375	6.37													
	1.875	1.87																					
	47.63																						
2 7/8	2.062	2.06	3.109	4 1/2	3.750	3.75			6.375	6.37													
73.02	52.37		78.97	144.30	97.25	155.58			6.375	6.37													
					3.812	3.81																	
					96.82																		

* Other sizes for heavy weight tubing are available on request.

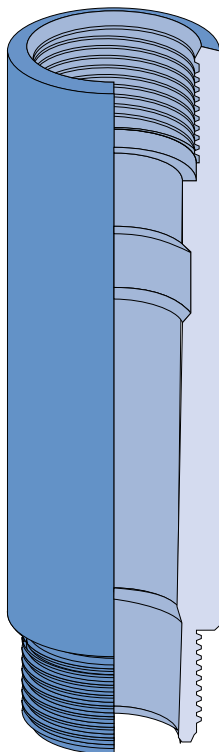
** Nipples are normally manufactured to the tubing joint or coupling OD. Nipples cannot be manufactured with smaller ODs than indicated above.

Table 8-3: W Nipple Specifications

Tubing OD	Seal Bore		Size	Minimum OD			
				801-70		801-74	
	in.	mm		in.	mm	in.	mm
	1.500	38.10	1.50	-	-	1.900	48.26
	1.625	41.28	1.62	-	-	2.630	66.80
2 7/8	1.781	45.24	1.78	-	-	3.375	85.73
73.02	1.875	47.63	1.87	-	-		
	2.000	50.80	2.00	3.663	93.04	3.750	95.25
	2.125	53.98	2.12				

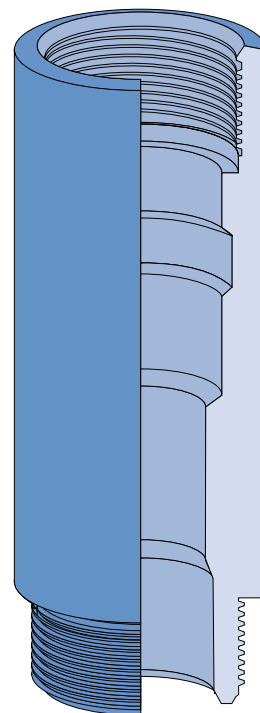
The W nipple is a high-pressure version of the F profile which accepts the M-2 lock mandrel.

8.2.5 R Nipple



R Nipple

Sizes 1.18 in. to 3.81 in.
(excl. 3.12 in. and 3.31 in.)



R Nipple

Sizes 3.12 in., 3.31 in. and
4.00 in. - 5.95 in.

Figure 8-2: Model R Nipple Configuration

R nipples accept the following bottom no-go locks:

- Z
- R
- E
- E-1
- K

The location, size and number of the R nipples can be varied to provide optimum versatility in any given well completion.

Table 8-4: Model R Nipple Specifications

Tubing OD		Nipple						
		Seal Bore		Size*	No-Go ID		Minimum OD**	
in.	mm	in.	mm			in.	mm	in.
1.660	42.16	1.187	30.15	1.18	1.135	28.83	1.875	47.63
1.900	48.26	1.437	36.50	1.43	1.385	35.18	2.109	53.57
		1.500	38.10	1.50	1.447	36.75		
2-1/16	53.37	1.562	39.67	1.56	1.510	38.35	2.250	57.15
2 ³ / ₈	60.33	1.781	45.24	1.78	1.728	43.89	2.560	65.02
		1.812	46.02	1.81	1.760	44.70		
		1.875	47.63	1.87	1.822	46.28		
2 ⁷ / ₈	73.02	2.062	52.37	2.06	1.978	50.24	3.109	78.97
		2.125	53.97	2.12	2.035	51.68		
		2.250	57.15	2.25	2.197	55.68		
		2.312	58.72	2.31	2.259	57.37		
3 ¹ / ₂	88.90	2.562	65.07	2.56	2.442	62.03	3.687	93.65
		2.750	69.85	2.75	2.697	68.50		
		2.812	71.42	2.81	2.759	70.07		
4	101.60	3.125	79.38	3.12	3.072	78.03	Coupling OD	
		3.312	84.12	3.31	3.242	82.35		
4 ¹ / ₂	114.30	3.688	93.68	3.68	3.625	92.08		
		3.750	95.25	3.75	3.700	93.98		
		3.812	96.82	3.81	3.759	95.48		
5	127.00	4.000	101.60	4.00	3.910	99.31		
		4.125	104.78	4.12	4.035	102.49		
		4.312	109.52	4.31	4.223	107.26		
5 ¹ / ₂	139.70	4.562	115.87	4.56	4.472	113.59		
		4.750	120.65	4.75	4.660	118.36		
6 ⁵ / ₈	168.28	5.250	133.35	5.25	5.150	130.81		
		5.500	139.70	5.50	5.400	137.16		
7	177.80	5.750	146.05	5.75	5.625	142.88		
		5.953	151.21	5.95	5.828	148.03		
7 ⁷ / ₈	193.68	6.125	155.58	6.12	6.000	152.40		
		6.375	161.92	6.37	6.257	158.93		

* Other sizes for heavy weight tubing are available on request.

** Nipples are normally manufactured to the tubing joint OD or coupling OD. Nipples cannot be manufactured with smaller ODs than indicated in the chart above.

Table 8-5: Tool Sizes Specified in Baker Charts

Otis	OD (in.)	Camco	GD (in.)	Nominal Size (in.)	Will Engage (in.)
40RB11	1.177			13/16	0.875
40RB14	1.427	JUG 15174	1.422	1 $\frac{1}{2}$	1.187
40RB21	1.484	JUG 15174	1.422	1 $\frac{1}{2}$	1.187
40RB17	1.770	JUG-TD 15185	1.775	2	1.375
40RB18	2.180	JUC-TD 15189	2.240	2 $\frac{1}{2}$	1.750
40RB19	2.740	JUC-TD 15191	2.740	3	2.313
40SM4	1.177	-	-	1 $\frac{1}{4}$	0.875
40SB6	1.427	JDC 15154	1.422	1 $\frac{1}{2}$	1.187
40SB8	1.484	JDG 15154	1.422	1.9	1.187
40SB1	1.771	JDC-TD 15169	1.775	2	1.375
40SB2	2.240	JDC 15171	2.240	2 $\frac{1}{2}$	1.750
40SB9	2.734	JDC-TD 15181	2.740	3	2.313
40SB10	3.670	JDC-TD 15183	3.678	4	3.125

Table 8-6: Lock Mandrel Classification

	Non-Flowing Applications (e.g. Plugs)	Flowing Applications (e.g. Safety Valves)
Top No-Go	'W'	'G', 'F', 'M'
Bottom No-Go	'Z'	'R' 'E' 'L' 'K'
Selective	'S'	
⁸⁻¹ Variations such as F1 and M-1 denote variations on the basic lock design. ⁸⁻² Refer to the individual lock explanations for details.		

The nipple profile, lock and flow control device combinations are generally described by using the letter for each device in the order shown below (there are some exceptions to this general rule).

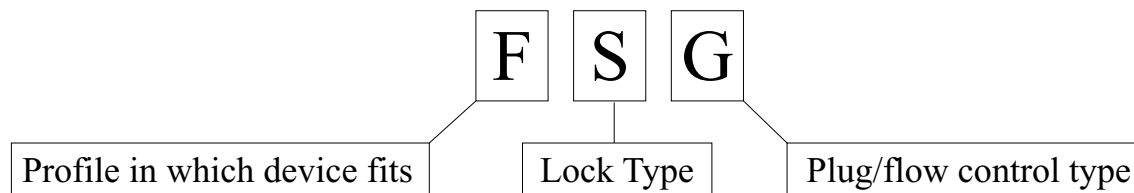


Figure 8-3: Nipple, Profile and Lock Identifiers

For example:

- FSB - the F nipple profile is set with an S-type lock and a B circulating blanking plug.
- RZG - the R nipple profile is set with a Z-type lock and a G bypass blanking-plug.

8.3 Plugs

8.3.1 FSG Plug

Run as the FSG, with the equalizing prong held in the fluid bypass position by the running tool to permit fluid bypass as the V-packing passes through the nipple bores of the same ID.

8.3.1.1 Running and Pulling

Running into a F nipple profile:

- No-Go – use a model C-1 running tool - use locator rings to suit the nipple bore.
- Selective – use a model G running tool and remove the core of the running tool to make space for the equalizing prong.
- Upward jarring shears the running tool off the lock, shifts the inner prong to the plugging position and the running tool shears off the inner prong.

Pulling

- SB pulling tool used to recover the equalizing prong (Alternate – JDC)
- RB (or SB) + A probe to recover the lock – the A-probe retracts the upward facing dogs.

Table 8-7: Model FSG Plug Dimensions

Tubing OD in. mm	Seal Bore in. mm	Size	To Run			To Pull	
			No-Go		Selective	Removable Mandrel	Plug
			Locating Ring OD in. mm	C-1 Running Tool Product #811-06	'G' Running Tool Product # 811-08	Pulling Tool*	'A' Probe Product #812-06
1.900 48.26	1.437 36.50	1.43	1.468 37.29	1.900 48.26		40RB14 JUC1S174 40SB6 JDC1S1S4	1.900** 48.26
	1.500 38.10	1.50	1.520 38.61				
	1.562	1.56	1.593			40R.B14, 40RB21	
2 3/16	39.67		40.46			40SB6, 40SB8	
52.37	1.625	1.62	1.656			JUC 15174	
	41.28		42.06			JDC 15154	
2 3/8 60.33	1.781 45.24	1.78	1.807 45.90	2 3/8 60.33		40RB14 40SB1 JUC-TD1S18S JDC-TD15169	2 3/8 60.33
	1.812 46.02	1.81	1.843 46.81				
	1.875	1.87	1.906				
	47.63		48.41				
2 7/8 73.03	2.250 57.15	2.25	2.281 57.94	2 7/8 73.03		40RB18 40SB2 JUC-TD15189 JDC-T015171	2 7/8 73.03
	2.312	2.31	2.343				
	58.72		59.51				
3 1/2 88.90	2.750 69.85	2.75	2.781 70.64	3 1/2 88.90		40RB19 40SB9 JUC-TD15191 JDC-TD15181	88.90
	2.812	2.81	2.843				
	71.42		72.21				
4 1/2 3.812	3.688 93.68	3.68	3.717 94.41	4 1/2 114.30		40RB20 40SB10 JUC-TD15193 JDC-TD15183	4 1/2 114.30
	3.81	3.835	114.30				
	96.82		97.41				

* See the running and pulling tool specification guide for the required ODs.

** When ordering, specify the pin thread: $\frac{3}{8}$ - 16N pin for SB and RB tools, $\frac{1}{2}$ - 13N pin for JDC and JUC tools.

8.3.2 **FSR Plug**

Run as the FSR, on the S lock to set selectively in an F nipple profile.

Fluid bypass during running is achieved by holding the bypass valve open with the model B running prong.

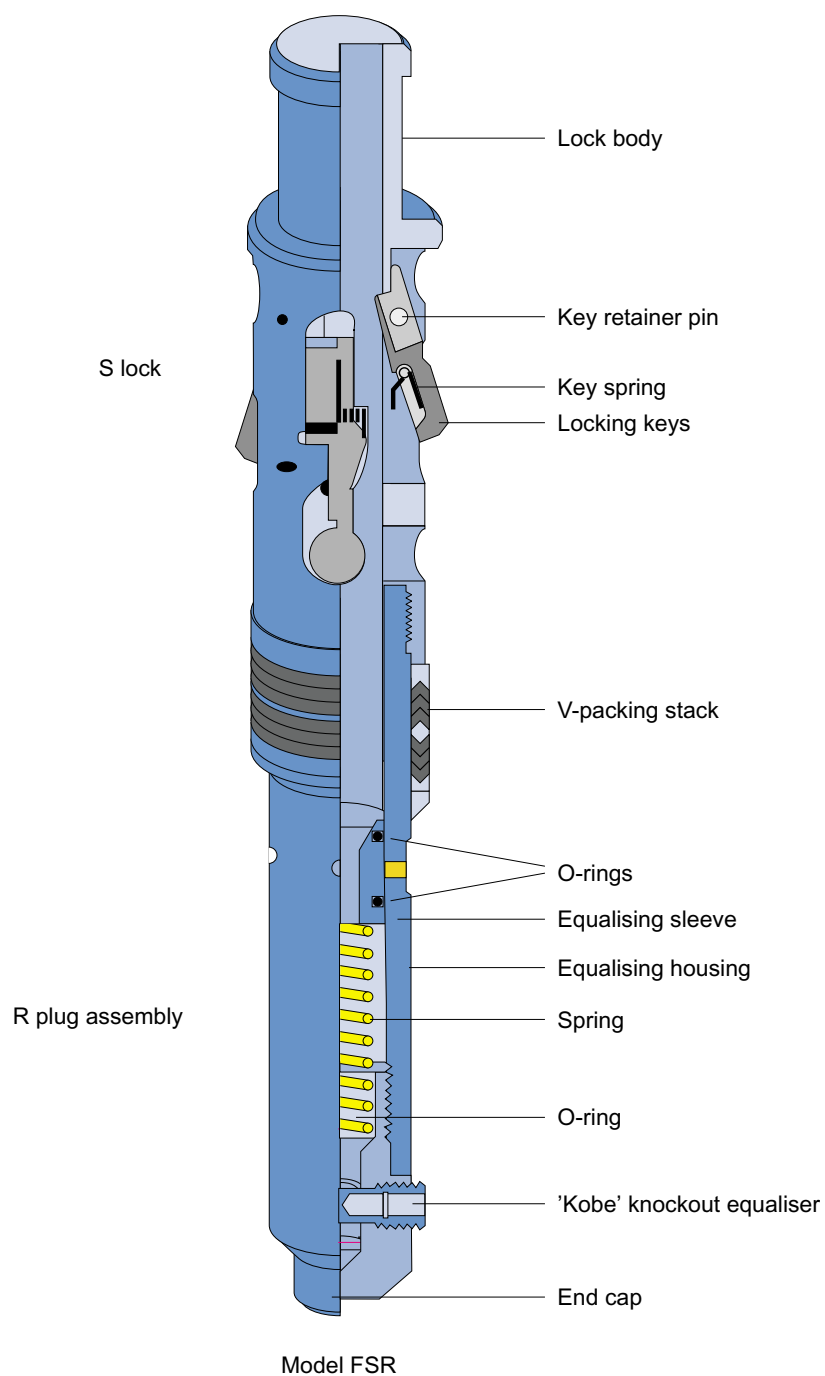


Figure 8-4: Model FSR Plug

Table 8-8: Model FSR Plug Dimensions

Tubing OD in. mm	Seal Bore in. mm	Size	To Run						To Equalize		To Pull	
			No-Go				Selective					
			Loc. Ring OD in. mm	C-1 Running Tool 811-06	'A' Shank 811-80	'B' Prong 811-72	'E' Selective Running Tool 811-17	'B' Prong 811-72				
1.660	1.187 30.15	1.187	1.240 31.50	1.660	1.660 x	$\frac{1}{4}$ x	1.660	$\frac{1}{4}$ x	1.660	$\frac{1}{4}$ x	40RB11	1.660
42.16	1.250 41.75	1.250	1.281 32.54	42.16	4 $\frac{3}{8}$	11 $\frac{7}{8}$	42.16	10 $\frac{7}{8}$	42.16	20 $\frac{3}{8}$	40SM4	42.16

* See the running and pulling tool specifications for the required ODs.

8.3.2.1 Running and Pulling

No-go - C-1 Running Tool

- Plus - A shank (No. 811-80)
- Plus - B prong (No. 811-72)

Use the seal bore locator ring to suit the nipple bore.

Selective - E Selective or G Selective

- Plus - B prong (No. 811-72)

Pulling

- SB pulling tool used to recover the equalizing prong (Alternate – JDC)
- RB (or SB) + A probe to recover the lock – the A-probe retracts the upward facing dogs.

Table 8-9: Model FSG Plug Dimensions

Tubing OD in. mm	Seal Bore in. mm	Size	To Run			To Pull	
			No-Go		Selective	Removable Mandrel	Plug
			Locating Ring OD in. mm	C-1 Running Tool Product #811-06	'G' Running Tool Product #811-08	Pulling Tool*	'A' Probe Product #812-06
1.900 48.26	1.437 36.50	1.43	1.468 37.29	1.900 48.26		40RB14 JUC1S174 40SB6 JDC1S1S4	1.900** 48.26
	1.500 38.10	1.50	1.520 38.61			40R.B14, 40RB21 40SB6, 40SB8	
	1.562	1.56	1.593			JUC 15174	
	2 3/16		40.46			JDC 15154	
	52.37	1.625	1.656				
		41.28	42.06				
2 3/8 60.33	1.781 45.24	1.78	1.807 45.90	2 3/8 60.33		40RB14 40SB1 JUC-TD1S18S JDC-TD15169	2 3/8 60.33
	1.812 46.02	1.81	1.843 46.81				
	1.875	1.87	1.906				
	47.63		48.41				
2 7/8 73.03	2.250 57.15	2.25	2.281 57.94	2 7/8 73.03		40RB18 40SB2 JUC-TD15189 JDC-T015171	2 7/8 73.03
	2.312 58.72	2.31	2.343 59.51				
3 1/2 88.90	2.750 69.85	2.75	2.781 70.64	3 1/2 88.90		40RB19 40SB9 JUC-TDI5191 JDC-TD15181	88.90
	2.812 71.42	2.81	2.843 72.21				

Tubing OD in. mm	Seal Bore in. mm	Size	To Run			To Pull	
			No-Go		Selective	Removable Mandrel	Plug
			Locating Ring OD in. mm	C-1 Running Tool Product #811-06	'G' Running Tool Product #811-08	Pulling Tool*	'A' Probe Product #812-06
4 $\frac{1}{2}$ 3.812	3.688	3.68	3.717	4 $\frac{1}{2}$ 114.30		40RB20	4 $\frac{1}{2}$ 114.30
	93.68		94.41			40SB10	
	3.81	3.835	114.30			JUC-TD15193	
	96.82		97.41			JDC-TD15183	

* See the running and pulling tool specification guide for the required ODs.

** When ordering, specify the pin thread: $\frac{3}{8}$ - 16N pin for SB and RB tools, $\frac{1}{2}$ - 13N pin for JDC and JUC tools.

8.3.3 FWG/RZG Plugs

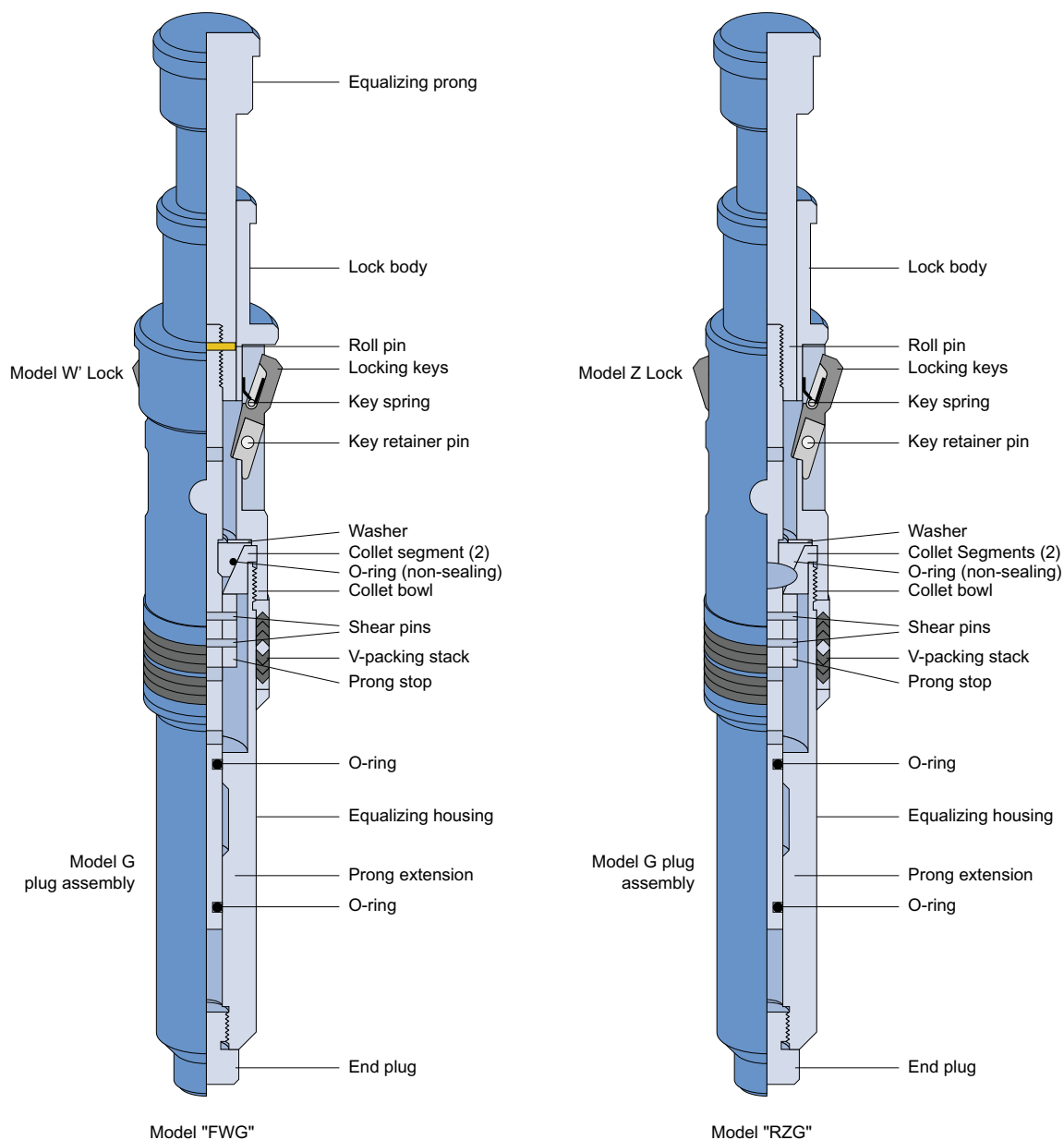


Figure 8-5: Model FWG and RZG Plugs

8.3.3.1 Model G Bypass Blanking Plug

Run as the FWG, on the W top no-go lock to set in an F nipple profile.

Fluid bypass during running is achieved by the running tool holding the equalizing prong in the open position.

8.3.3.2 Running and Pulling - FWG

- C-1 Running Tool - The lock no-go locates in the nipple bore.

Pulling

- Pull the equalizing prong with an SB.
- Pull the lock with the RB (or SB) + B probe.

Table 8-10: Model FWG and RZG Plug Dimensions

Tubing OD in. mm	Seal Bore in. mm	Size		Maximum OD in. mm		To Run	To Pull	
						C-1 Running Tool #811-06 Tool*	Removable Mandrel	Plug
		FWG	RZG	FWG	RZG		Pulling	'B' Probe #812-07
1.900	1.437	1.43		1.490	1.427	1.900 48.26	40SB6	1.900**
48.26	36.50			37.50	36.25		40RB14	
2 1/16	1.562	1.56		1.615	1.552		JUC1S174	
52.37	39.67			41.02	39.42		JDC151S4	48.26
2 3/8 60.33	1.781	1 7/8			1.771	2 3/8 60.33	40RB17	2 3/8 60.33
	45.24			1.865	44.98		40SB1	
	1.812	1.81		47.37	1.802		JUC-TD15185	
	46.02				45.77		IDC-TD15169	
2 7/8 73.03	1.875	1.87		1.928	1.865	2 7/8 73.03	40RB18	2 7/8 73.03
	47.63			48.97	47.37		40SB2	
	2.250	2.25		2.302	2.240		JUC-TD15189	
	57.15			58.47	56.90		JDC-TDIS171	
	2.312	2.31		2.365	2.301			
	58.72			60.07	58.47			

* See the running and pulling tool specification guide for the required ODs.

** When ordering, specify the pin thread: $\frac{3}{8}$ - 16N pin for SB and RB tools, $\frac{1}{2}$ - 13N pin for JDC and JUC tools.

Model G Bypass Blanking Plug

Run as the RZG, on the Z bottom no-go lock to set in an R nipple profile.

8.3.3.3 Running and Pulling - RZG

C-1 Running Tools - The lock no-go locates in the nipple bore.

Pulling

- Pull the equalizing prongs with an SB
- Pull the lock with the RB (or SB) + B probe.

8.4

Equalizing Check Valve

These standing/check valves prevent downward flow while allowing upward flow and are used for testing tubing, setting hydraulic packers and non-return of fluid in electric submersible pump completion.

Running	C-1, SB, JDC
Pulling	Otis RB, SB, Camco JUC or JDC

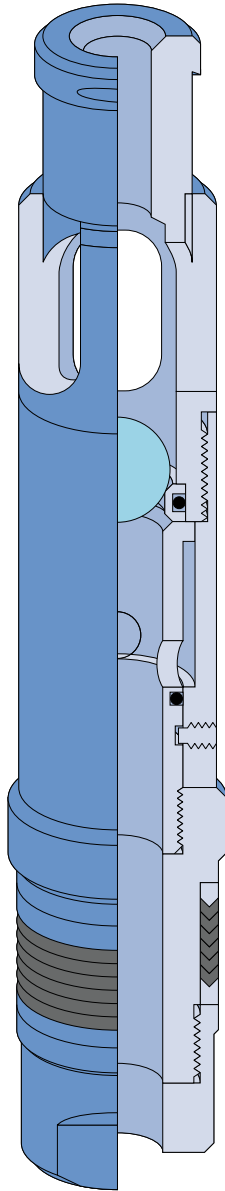
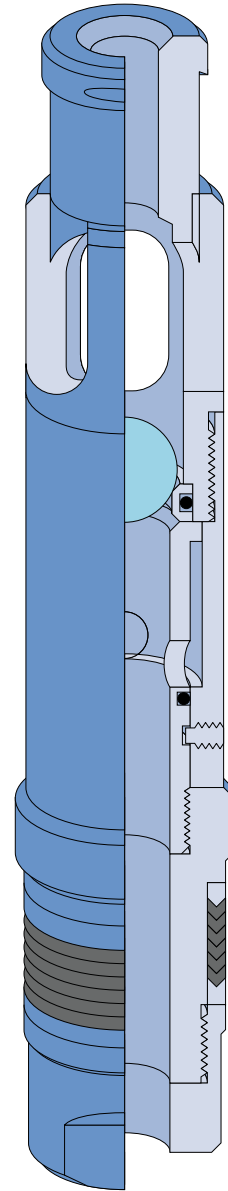
**FB-2****For F nipples****RB-2****For R nipples****Figure 8-6: Model FB-2 and RB-2 Equalizing Check Valves**

Table 8-11: Equalizing Check Valve Specifications

Tubing OD in. mm	Seal Bore in. mm	Size		Maximum OD in.		To Run	To Pull*
		FB-2	RB-2	FB-2	RB-2	C-1 Running Tool	Pulling Tool
1.660 42.16	1.187 30.15	1.18		1.240 31.50	1.177 29.90	1.660 42.16	40RB11 40SM4
	1.250 31.75	1.25	-	1.302 33.07			
1.900 48.26	1.437 36.50	1.43		1.495 37.97	1.427 36.25	1.900	40RB14 JUC15174 40SB6 JDC15154
	1.500 38.10	1.50		1.552 39.42	1.490 37.85		
2 1/16 52.37	1.562 39.67	1.56		1.615 41.02	1.552 39.42	48.26	40RB14, 40RB21 40S86,40SB8 JUC15174 JDC15154
	1.625 41.28	1.62		1.672 42.47			
2 3/8 60.33	1.781 45.24	1.78		1.803 45.80	1.771 44.98	2 3/8 60.33	40R.B17. 40SBI JUC-TD15185 JDC-TD15169
	1.812 46.02	1.81		1.865 47.37	1.802 45.77		
	1.875 47.63	1.87		1.905 48.39	1.865 47.37		
2 7/8 73.02	2.062 52.37	2.06		2.115 53.72	2.052 52.12	2 7/8 73.02	40RR18 40SB2 JUC-TD15189 JDC-TD15171
	2.250 57.15	2.25		2.302 58.47	2.240 56.90		
	2.312 58.72	2.31		2.364 60.05	2.302 58.47		
3 1/2 88.90	2.562 65.07	2.56		2.625 66.68	2.552 64.82	3 1/2 88.90	40R.B19 40SB9 JUC-TD15191 JDC-TD15181
	2.750 69.85	2.75		2.802 71.17	2.740 69.60		
	2.812 71.42	2.81		72.77	2.865		
	3.125	3.12		3.175	3.115		40RB19

Tubing OD in. mm	Seal Bore in. mm	Size		Maximum OD in.		To Run	To Pull*
		FB-2	RB-2	FB-2	RB-2	C-1 Running Tool	Pulling Tool
4 101.60	79.38			80.65	79.12	3½ 88.90	40SB9
	3.312	3.31		3.406	3.302		JUC-TD15191
	84.12			96.51	83.87		JDC-TD15181
4½ 114.30	3.688	3.68		3.740	3.678	4½ 114.30	40R820 40SB10 JUC-TD15193 JDC-TD15183
	93.68			95.00	93.42		
	3.750	3.75		3.802	3.740		
	95.25			95.57	95.00		
	3.812	3.81		3.875	3.802		
	96.82			98.43	96.57		
5 127.00	4.000	4.00		4.090	3.990		
	101.60			103.89	101.35		
	4.125	4.12		4.215	4.115		
	104.78			107.06	104.52		
	4.312	4.31		4.385	4.302		
5½ 139.70	109.52			111.38	109.27		
	4.562	4.56		4.653	4.552		
	115.87			118.19	115.62		
	4.750	4.75		4.840	4.740		
	120.65			122.94	120.40		

* See the running and pulling tool specifications for the required ODs.

8.5

Instrument Hanger

The RZB can be set directly into an R nipple of the correct size, or a nipple insert can be run to reduce the R nipple bore to suite the RZB. This is important where:

- Maximum ID through the R nipple is required for maximum flow.
- If the bottom hole recorders and RZB hanger are to be run through a retrievable safety valve. In this case, the nipple insert is installed during the completion or by slickline before running the safety valve. The valve must be pulled to recover the nipple insert.

The RZB is run on the soft release tool. This permits setting without jarring by pulling upwards, closing the jars gently and picking up to release. Ensure the sufficient stem weight is used to force the inner taper downwards and that the

inner taper is well greased and free from burrs or corrosion, which may prevent the tool from releasing. Difficulties in obtaining a smooth release are most often due to insufficient weight.

8.5.1 Releasing

1. Take a pick-up weight prior to landing in the nipple.
2. Locate the hanger in the nipple profile. The upward facing dogs will lock in the profile.
3. Pull upwards with the line to 150 – 200 lb over the tool string pick-up weight.
4. Sit down gently and pick-up. The tool should have released.
5. If not released, repeat the above steps but increase the line strain (over pull) until the tool releases.
6. Only apply jarring force if the tool fails to release.



Note

While the RZB can also be run on the C-1 running tool, upward jarring is then required which may affect instrument performance.

The model B instrument hanger can also be used in the W or S profiles.

If running the RZB or FWB on the soft release tool with up facing dogs trailing, these dogs should be taped in to avoid catching in the lubricator or BOP and prematurely cocking the soft release tool.

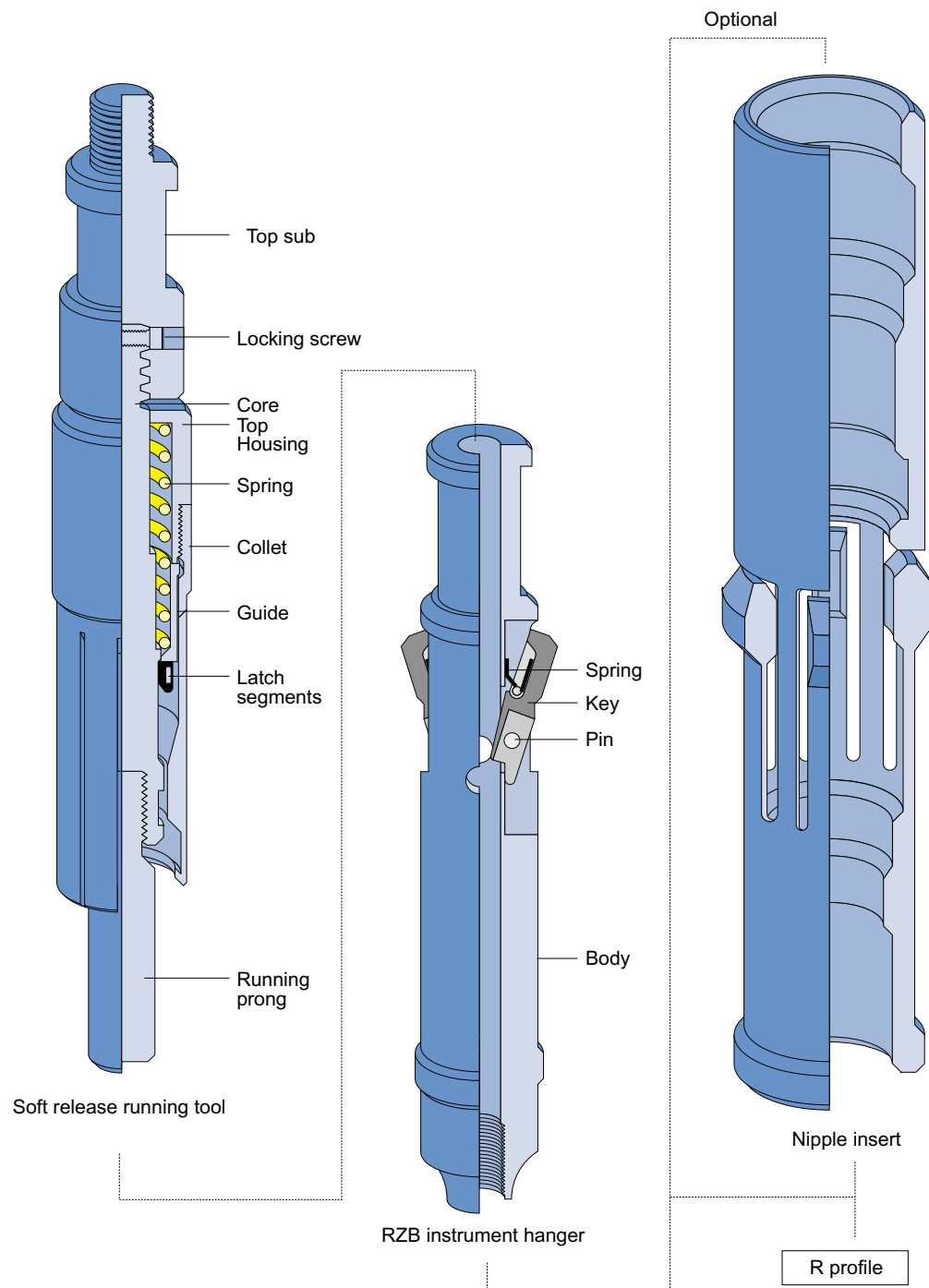


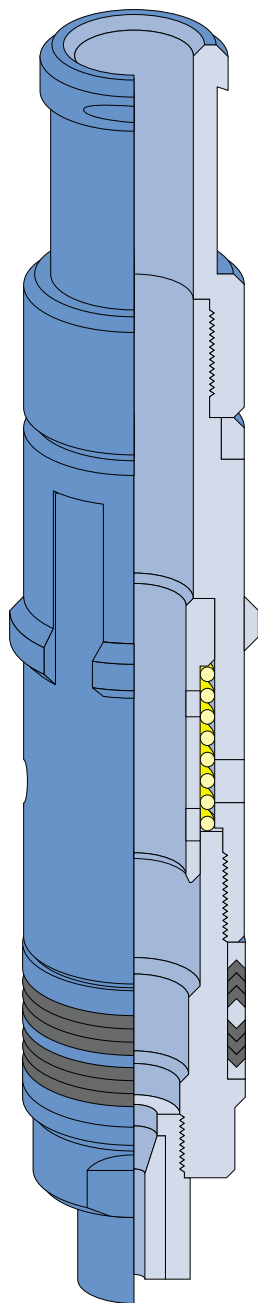
Figure 8-7: Model RZB Instrument Hanger

8.6 Downhole Chokes

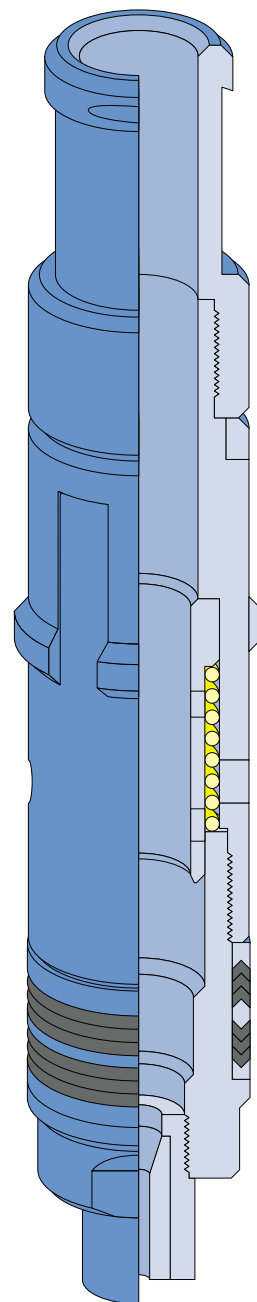
8.6.1 FGD Choke

Slickline retrievable chokes are used to restrict the flow in the tubing when required. The FGD choke is designed for use with an F-nipple profile.

Available with orifices 4/64 in. to 28/64 in. (1.180 in. and 1.225 in. – 15/64 in. maximum)



FGD choke



RRD choke

Figure 8-8: Model FGD and RRD Chokes

Table 8-12: Downhole Choke Specifications

Tubing OD in. mm	Seal Bore in. mm	Size		Maximum OD in. mm		To Run		To Pull	
		FGD	RRD	FGD	RRD	C-1 Running Tool 811-06	N-1 Shank 811-85	Pulling Tool*	N-1 Probe #812-13
2-1/16 52.37	1.562 39.67	1.56		1.615 41.02	1.552 39.42	2-1/16 52.37		40RB14, 40RB21, 40SB6, 40SB8, JUC15174, JUC15154	2-1/16** 52.37
2 ³ / ₈ 60.33	1.781 45.24	1.78		1.865 44.98	1.771 44.98	2 ³ / ₈ 60.33		40RB17	2 ³ / ₈ 60.33
	1.812	1.81		47.37 46.02	1.802 45.77			40SB1	
	1.875 47.63	1.87	-	1.928 48.97	-			JUC-TD15185 JDC-TD15169	
2 ⁷ / ₈ 73.03	2.250 57.15	2.25		2.302 58.47	2.240 56.90	2 ⁷ / ₈ 73.03		40RB18	2 ⁷ / ₈ 73.03
	2.312	2.31	-	2.365 66.93	-			40SB2	
	58.72							JUC-TD15189 IDC-TD15171	

* See the running and pulling tool specification guide for the required ODs.

** When ordering, specify the pin thread: $\frac{3}{8}$ - 16N pin or SB and RB tools, $\frac{1}{2}$ - 13N pin for JDC and JUG tools.

Running Tool C-1 + N-1 shank

Pulling Tool RB or SB + N-1 probe (or Camco equivalent)

8.6.2 RRD Bottom No-Go Choke

The RRD choke is designed for use with an R-nipple profile and uses the same running and pulling tools as the FGD assembly described above.

8.7 Running Tools

8.7.1 C-1 Running Tool

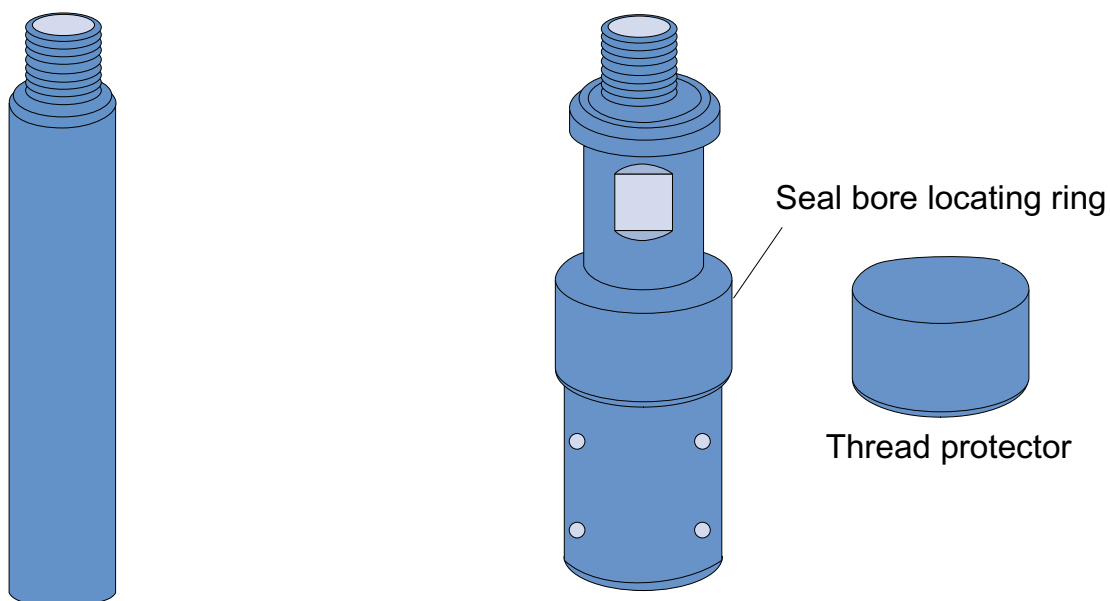
The Baker C-1 running tool is used to run flow control devices, which are run attached to locks with external fishing necks.

Tangential shear pins are inserted through the running tool to attach it to the lock.

A seal bore locator ring provides the top no-go location and setting.

The thread protector of the same OD as the running-tool body, replaced the locator ring if the top no-go location is not required.

A female thread inside the C-1 running tool accepts the A or N-1 shank.



Model A shank

Model C-1 running tool

Figure 8-9: Model C-1 Running Tool and Model A Shank

8.7.1.1 A-Shank

Used with the C-1 running tool to run S, W and Z locks (with dogs retracted) during running.

It can also be used as a prong carrier.

8.7.2 Model M Running and Pulling Tool

The Baker model M running and pulling tool is a jar-down-release device used to run and pull slickline equipment equipped with internal fishing necks.

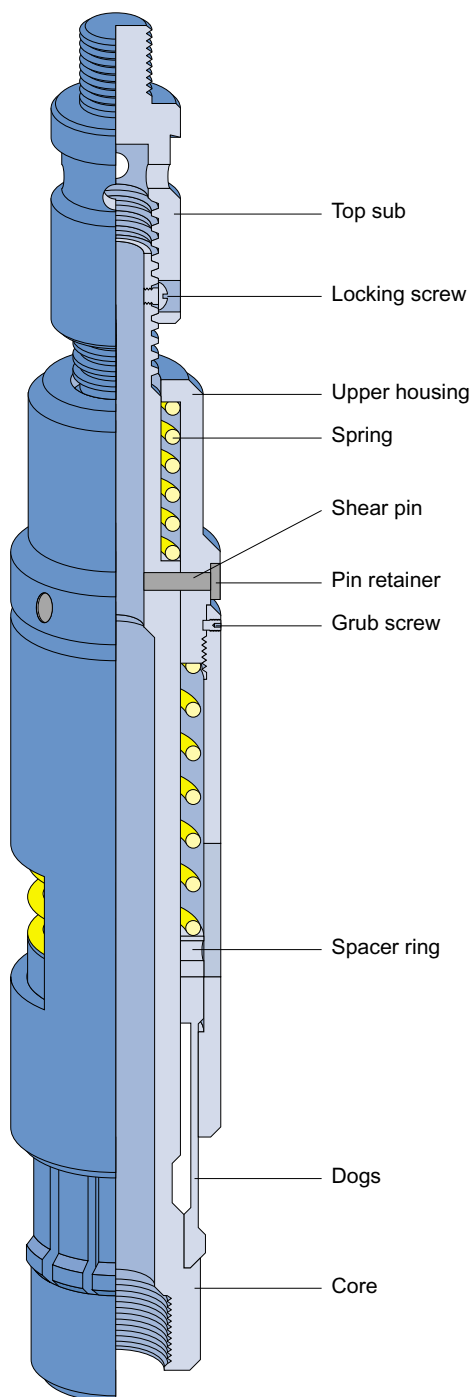


Figure 8-10: Model M Running and Pulling Tool

8.7.3 Model G Running Tool

The Model G running tool is used to run slickline accessories equipped with model S selective locks (up facing locks trailing) in selective model F seating nipples.

8.7.3.1 Operation

- The S lock is attached to the running tool with tangential shear pins.
- As the running tool/lock assembly moves up against the top spring, the collet collapses and the tools pass the profile. The collet then springs back to its original position.
- After passing through the target nipple bore, the tools are picked up. The collet cannot pass the profile and the pin in the running tool is sheared. The main body moves down relative to the inner core and the downward dogs are released to enter the profile.
- Upward jarring shears the pin to recover the running tool.

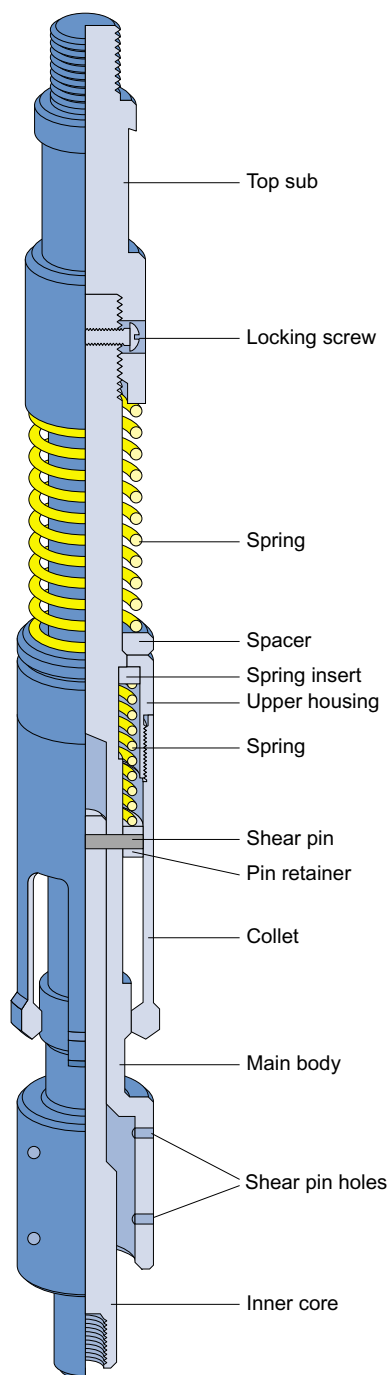


Figure 8-11: Model G Running Tool

8.7.4

Model E Selective Running Tool

The model E selective running tool is used to selectively run and land flow control devices with model S locks (all locks retracted).

8.7.4.1 Operation

- The S lock is attached to the running tool with tangential shear pins.
- As the running tool/lock assembly moves up against the top spring, the collet collapses and the tools pass the profile. The collet then springs back to its original position.
- After passing through the target nipple bore, the tools are picked up. The collet cannot pass the profile and the pin in the running tool are sheared. The outer housing moves down relative to the core and the upward facing dogs enter the nipple profile.
- Upward jarring shears the pins and sets the lock.

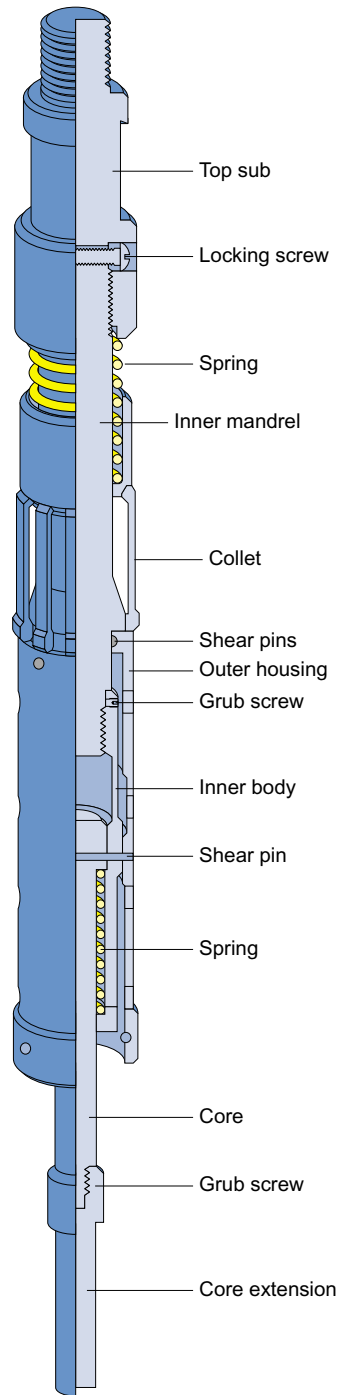


Figure 8-12: Model E Selective Running Tool

8.7.5

Running Tool Accessories

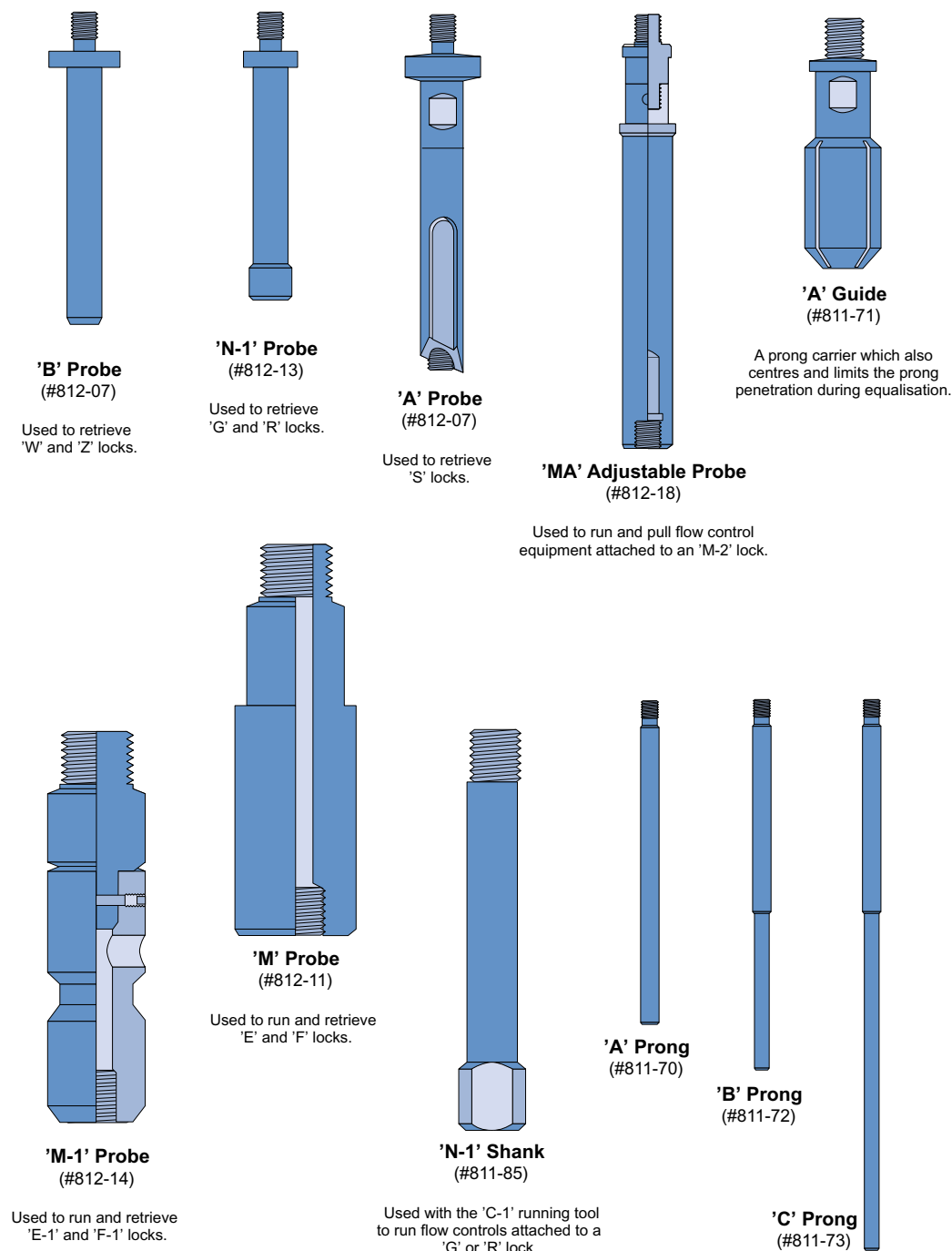
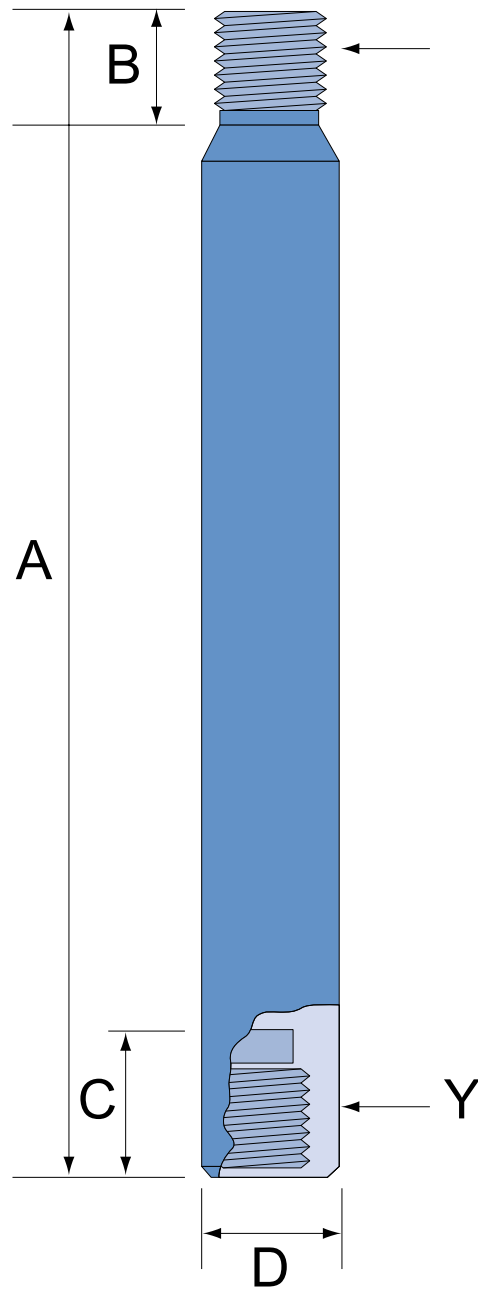


Figure 8-13: Running Tool Accessory Range

8.7.5.1 **Model A Shank**

In certain lengths, the model A shank is a lock retention device which, when made up to the running tool (type C), keeps the keys of down-facing S, TS, W and Z type locks retracted while running in.

In certain other lengths, it serves merely as a crossover from the running tool to the model A and B prongs.



A Shank

Figure 8-14: Model A Shank

Table 8-13: Model A Shank Dimensions

Dimensional Data (in.)									
Accessory Size	Shank Size				‘B’	‘C’	‘D’	‘X’	‘Y’
	Dia. *	Length Dimension ‘A’							
		‘W’ / ‘Z’ Locks		‘S’ / TS Locks					
		Retracted	Trailing	Trailing					
1.18 - 1.25	1.660	5.62	4.00	4.62	0.88	1.31	0.490	7/16 - 14	$\frac{1}{4}$ - 20
1.43 - 1.62	1.900 - 2-1/16	5.88		4.75	1.00	1.62	.0693	$\frac{5}{8}$ - 11	7/16 - 14
1.78 - 1.87	2 $\frac{7}{8}$	6.12		5.00	1.00	1.25	0.827	$\frac{3}{4}$ - 16	$\frac{1}{2}$ - 13
2.25 - 2.31	2 $\frac{7}{8}$	6.09		4.69	1.00	0.97	1.156	1 - 14	$\frac{1}{2}$ - 13
2.75 - 2.81	3 $\frac{1}{2}$	6.69		5.31	1.25	1.00	1.406	1 - 14	$\frac{5}{8}$ - 11
3.68 - 3.81	4 $\frac{1}{2}$	-	4.75	-	1.31	1.00	2.031	1 - 14	$\frac{5}{8}$ - 11

* Also the size of the TS type accessories.

8.7.5.2

Model A and AC Probes

The model A probe can carry a prong made up to its lower end, in place of the set screws.

The model AC probe, not being equipped to carry a prong, should be run in all areas where the prong is not required.

The model A or AC probe is used to close the up facing locks on any flow control device having S or TS selective locks.

As it penetrates the fishing neck, the blade automatically swivels by passing the down facing locks and retracting the up facing locks before the pulling tool latches on. The core extension shoulders against the fishing neck of the accessory when setting or jarring down.

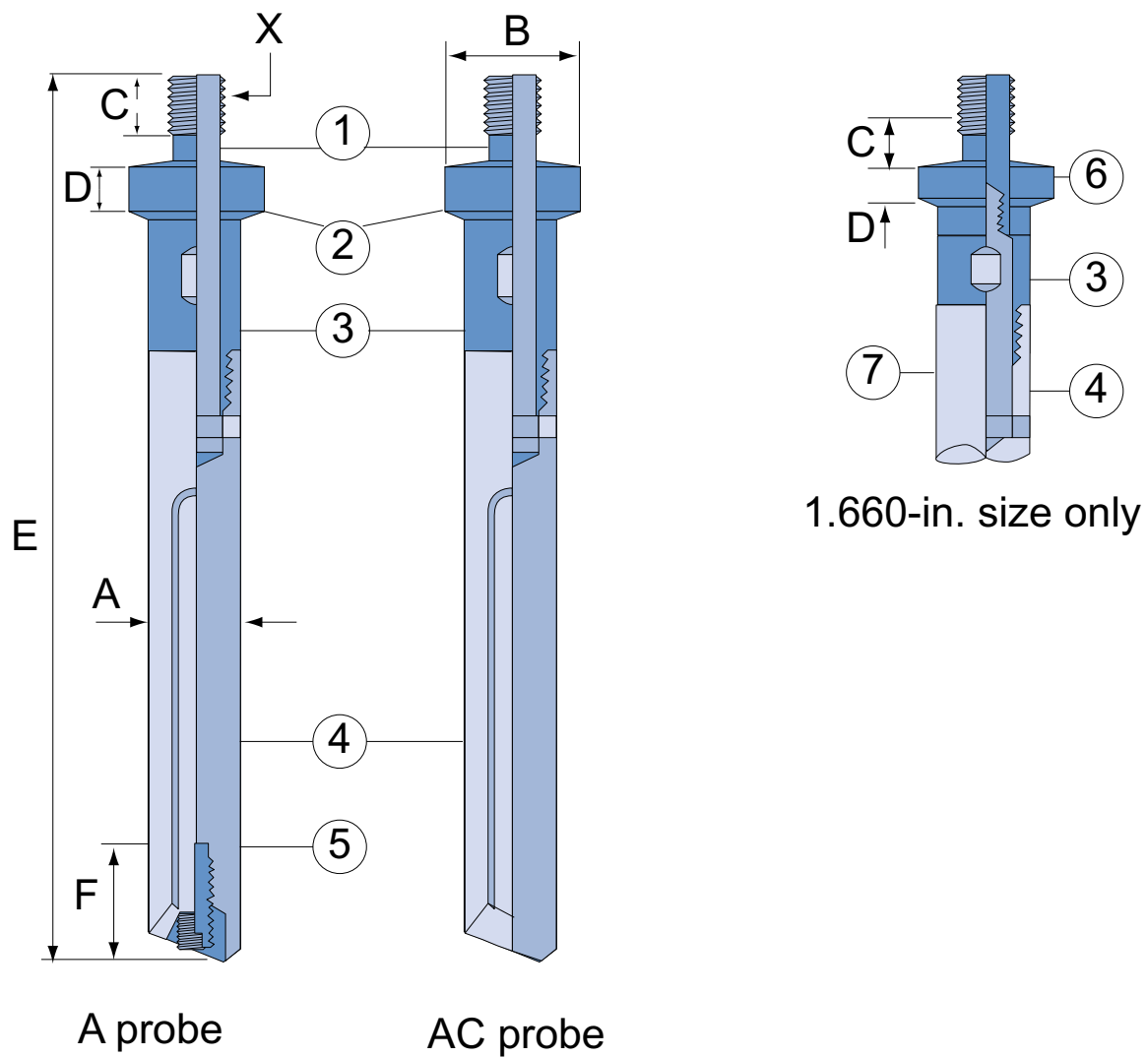


Figure 8-15: Model A and AC Probe

Table 8-14: Model A and AC Probe Dimensional Data

Dimensional Data (in.)									
Lock Size	Probe Size	'A'	'B'	'C'	'D'	'E'	'F'	'X'	'Y'
1.18 - 1.25	1.660	0.490	0.688	1.00	0.53	7.38	1.50	$\frac{3}{4}$ - 16	$\frac{1}{4}$ - 20
1.43 - 1.62	1.900 - 2-1/16	0.718	0.938		0.41	7.47	1.53	$\frac{3}{4}$ - 16* or $\frac{1}{2}$ - 13	7/16 - 14
1.78 - 1.87	2 $\frac{3}{8}$	0.827	1.188		0.53	9.06	1.88	$\frac{1}{2}$ - 13	
2.25 - 2.31	2 $\frac{7}{8}$	1.132	1.500		0.50	10.66	2.00	$\frac{5}{8}$ - 11	
2.75 - 2.81	3 $\frac{1}{2}$	1.382	2.062						
3.68 - 3.81	4 $\frac{1}{2}$	2.031	2 $\frac{7}{8}$	1 $\frac{1}{8}$	1 $\frac{1}{8}$	12 7/16	1 $\frac{1}{2}$	1 $\frac{1}{4}$ - 12N	$\frac{5}{8}$ - 11

* When ordering, specify pin up for pulling tool: $\frac{1}{8}$ in. - 16N for Otis, $\frac{1}{2}$ in. - 13N for Camco.

Table 8-15: Model A and AC Probe Parts List

Parts List									
Item #	Part Name		# Req	Size and Commodity Number					
				1.660 in.	1.900 - 2-3/16 in.	2 ³ / ₈ in.	2 ⁷ / ₈ in.	3 ¹ / ₂ in.	4 ¹ / ₂ in.
-	Model 'A' probe		1	812-06-4630	813-06-4635* 812-08-4631*	812-08-4621	812-08-4622	812-08-4623	812-08-4638
-	Model 'AC' probe		1	812-08-4619	812-08-4620* 812-08-4624**	812-08-4621	812-08-4622	812-08-4623	812-08-4638
1	Spindle		1	-	01-70820-00* 01-95975-00**	01-95975-00		01-95985-00	02-10828-00
2	Spacer		1	-	01-95976-00	01-95979-00	01-95982-00	01-95986-00	02-10829-00
3	Retaining Nut		1	01-05072-00	01-05077-00	01-95980-00	01-95983-00	01-95987-00	02-10827-00
4	Blade	Model 'A'	1	01-95973-00	01-95973-00	01-95978-00	01-95984-00	01-95988-00	02-10826-00
		Model AC		01-80867-00	01-80863-00	01-80869-00	01-80870-00	01-80871-00	02-11874-00
5	Socket set screw		1	WW-G71H-1H0	WW-G71F-1S0	WW-G71H-1S0		WW-G71M-1W0	
	Half dog			(¹ / ₄ - 20 x 1 ¹ / ₂ in.)	(7/16 - 14 x 1 ³ / ₄ in.)	(¹ / ₂ - 13 x 1 ³ / ₄ in.)		(1/3 - 11 x 1 ⁷ / ₈ in.)	(¹ / ₈ - 11 x 1 ¹ / ₈ in.)

Parts List							
Item #	Part Name	# Req	Size and Commodity Number				
			1.660 in.	1.900 - 2-3/16 in.	2 $\frac{3}{8}$ in.	2 $\frac{7}{8}$ in.	3 $\frac{1}{2}$ in. 4 $\frac{1}{2}$ in.
6	Core extension	1	01-70445-00				
7	Spindle nut	1	01-95971-00				

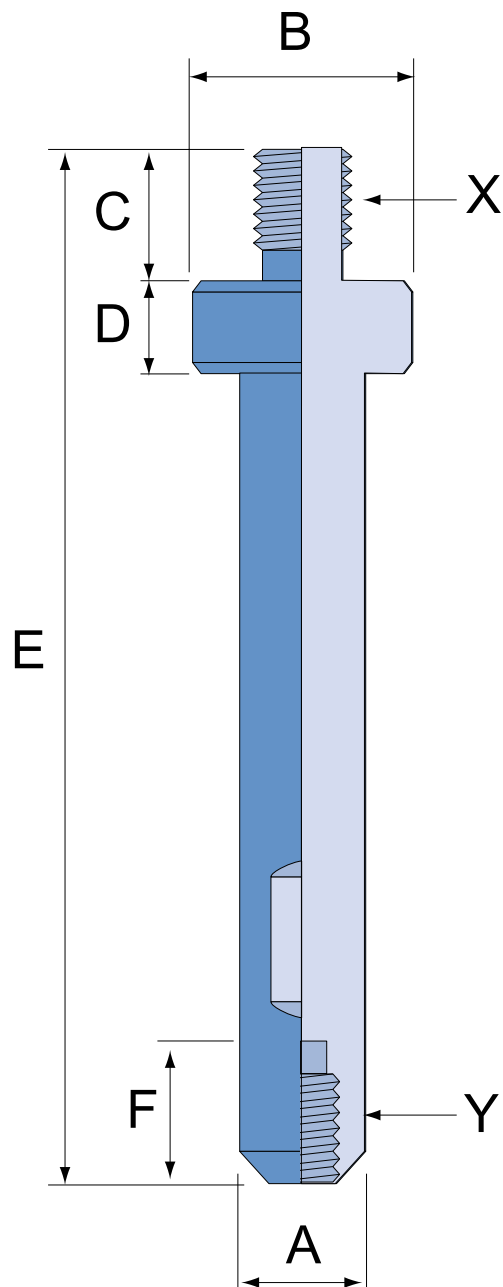
* $\frac{3}{8}$ in. - 16N pin up for Otis pulling tool.

** $\frac{1}{2}$ in.- 13N pin up for Camco pulling tool.

8.7.5.3 Model B Probe

The B probe is used to close the locks on any flow control device having a W or Z (top or bottom no-go) lock.

The model B probe retracts the locks before the pulling tool latches on. The flange shoulders against the fishing neck when setting or jarring down.



B probe

Figure 8-16: Model B Probe

Table 8-16: Model B Probe – Parts List

Size and Commodity Number					
1.660 in.	1.900 - 2-1/16 in.	2 $\frac{3}{8}$ in.	2 $\frac{7}{8}$ in.	3 $\frac{1}{2}$ in.	4 $\frac{1}{2}$ in.
812-07-4619	812-07-4624* 812-07-4620**	812-07-4621	812-07-4622	812-07-4623	812-07-4626

* $\frac{3}{8}$ in. - 16N pin up for Otis pulling tool

** $\frac{1}{2}$ in. - 13N pin up for Camco pulling tool

Table 8-17: Model B Probe – Dimensional Data

Dimensional Data (in.)									
Lock Size	Probe Size	'A'	'B'	'C'	'D'	'E'	'F'	'X'	'Y'
1.18 - 1.25	1.660	0.490	0.688	0.69	0.53		0.50	$\frac{3}{8}$ - 16	$\frac{1}{4}$ - 20
1.43 - 1.62	1.900 - 2-1/16	0.693	0.938		0.41	6.28	0.69	$\frac{3}{8}$ - 16 or $\frac{1}{2}$ - 13	7/16 - 14
1.78 - 1.87	2 $\frac{3}{8}$	0.827	1.062		0.53	7.09	0.88	$\frac{1}{2}$ - 13	
2.25 - 2.31	2 $\frac{7}{8}$	1.132	1.500			7.22			
2.75 - 2.81	3 $\frac{1}{2}$	1.382	2.000		0.50	7.75	1.00	$\frac{5}{8}$ - 11	
3.68 - 3.81	4 $\frac{1}{2}$	2.031	2 $\frac{7}{8}$	1 $\frac{1}{8}$	1 $\frac{1}{8}$	8 $\frac{1}{2}$	1.00	1 $\frac{1}{4}$ - 12N	$\frac{5}{8}$ - 11
8-1 When ordering, specify pin up for pulling tool: $\frac{3}{8}$ in. - 16N for Otis, $\frac{1}{2}$ in. - 13N for Camco.									

8.7.5.4

Model N Shank and N Probe

The model N shank is used to run the model N lock with the type C-1 running tool.

The model N probe is used to pull the model N lock with the Otis RB pulling tool.

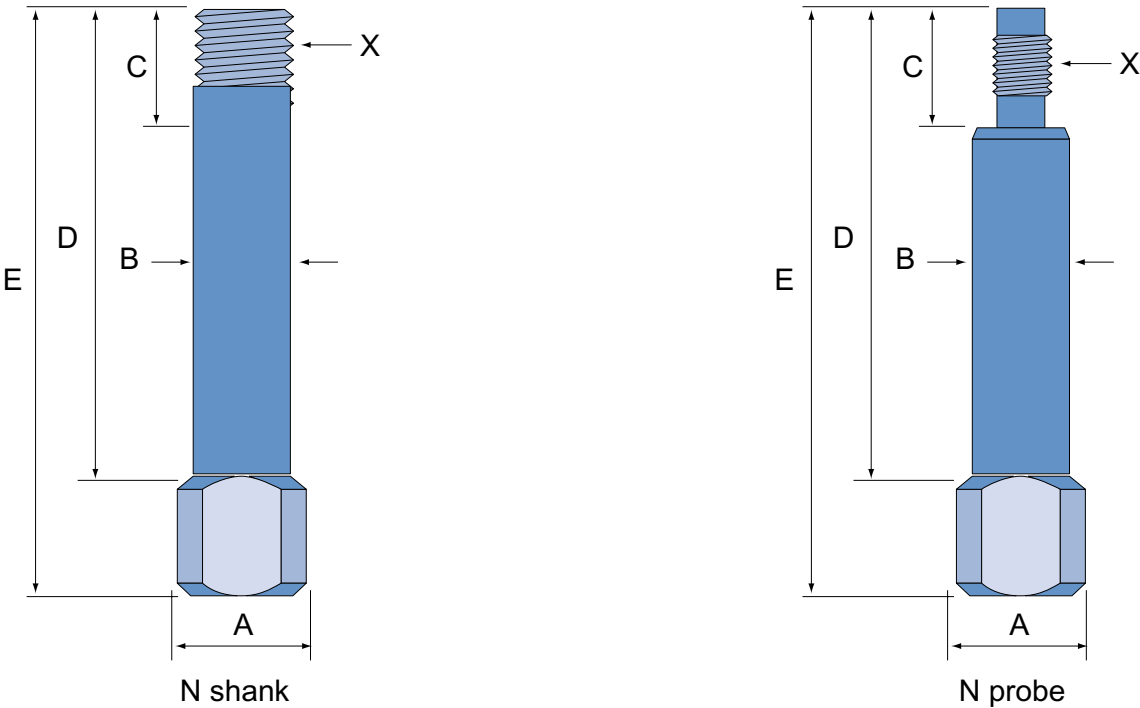


Figure 8-17: Model N Shank and Probe

Table 8-18: Model N Shank and Probe Parts List

Size	Commodity Number	
(in.)	Shank	Probe
$2\frac{3}{8}$	811-82-2300	812-09-2300
$2\frac{7}{8}$	811-82-2700	812-09-2700
$3\frac{1}{2}$	811-82-3200	812-09-3200
$4\frac{1}{2}$	811-824200	812-094200

Table 8-19: Model N Shank and Probe – Dimensional Data

Dimensional Data (in.)							Dimensional Data (in.)						
Tool Size	'A'	'B'	'C'	'D'	'E'	'X'	Tool Size	'A'	'B'	'C'	'D'	'E'	'X'
1.900	-	-	-	-	-	-	1.900	-	-	-	-	-	-
2-1/16	-	—	-	—	—	—	2-1/16	—	—	—	—	—	—
$2\frac{3}{8}$	0.938	$\frac{3}{4}$	$1\frac{1}{8}$	$9\frac{11}{16}$	$10\frac{11}{16}$	$\frac{3}{4} - \frac{1}{16}$	$2\frac{3}{8}$	0.938	$\frac{3}{4}$	15/16	10-1/16	11-1/16	$\frac{1}{2} - \frac{1}{13}$
$2\frac{7}{8}$	1.235	1	1	$9\frac{1}{2}$	$10\frac{9}{16}$	$1 - \frac{1}{14}$	$2\frac{7}{8}$	1.235	1	15/16	10	11	$\frac{1}{2} - \frac{1}{13}$

Dimensional Data (in.)							Dimensional Data (in.)						
Tool Size	'A'	'B'	'C'	'D'	'E'	'X'	Tool Size	'A'	'B'	'C'	'D'	'E'	'X'
3 $\frac{7}{8}$	1.614	1	1	9 $\frac{7}{8}$	10 $\frac{7}{8}$	1 - $\frac{1}{4}$	3 $\frac{1}{2}$	1.614	1	15/16	9 $\frac{3}{8}$	10 $\frac{3}{8}$	$\frac{5}{8}$ - $\frac{1}{11}$
4 $\frac{1}{2}$	2.297	2	1-3/16	11-3/16	12-3/16	1 - $\frac{1}{4}$	4 $\frac{1}{2}$	2.297	2	1 $\frac{1}{8}$	11-1/16	12 $\frac{7}{8}$	1 $\frac{1}{2}$ - $\frac{1}{12}$

8.8 Sur-set System

The Baker Sur-Set System is named after the feature of its running tool not releasing from the lock mandrel, unless it is completely set in the profile.

The Sur-Set range of lock mandrels is of the no-go design, with the top no-go and bottom no-go variations available in 10,000 and 15,000 psi pressure ratings.

The 10,000 psi locks will not fit into 15,000 psi nipples. However, high-pressure locks will fit into lower pressure nipples. This ensures no critical errors are made, but reduces the inventory required.

The 10,000 psi locks and profiles are designated A – AF (top no-go) and AR (bottom no-go).

The 15,000 psi locks and profiles are designated H – HF (top no-go) and HR (bottom no-go).

For applications in excess of 15,000 psi, a V designated series of locks are available (VF and VR).

The nipple profile and compatible lock have the same model identification (i.e., AF locks fit the AF nipple). Selective nipples (A, H and V) in 3 $\frac{1}{2}$ in. OD and smaller sizes will also accept top no-go locks (AF, HF and VF) of the same size.

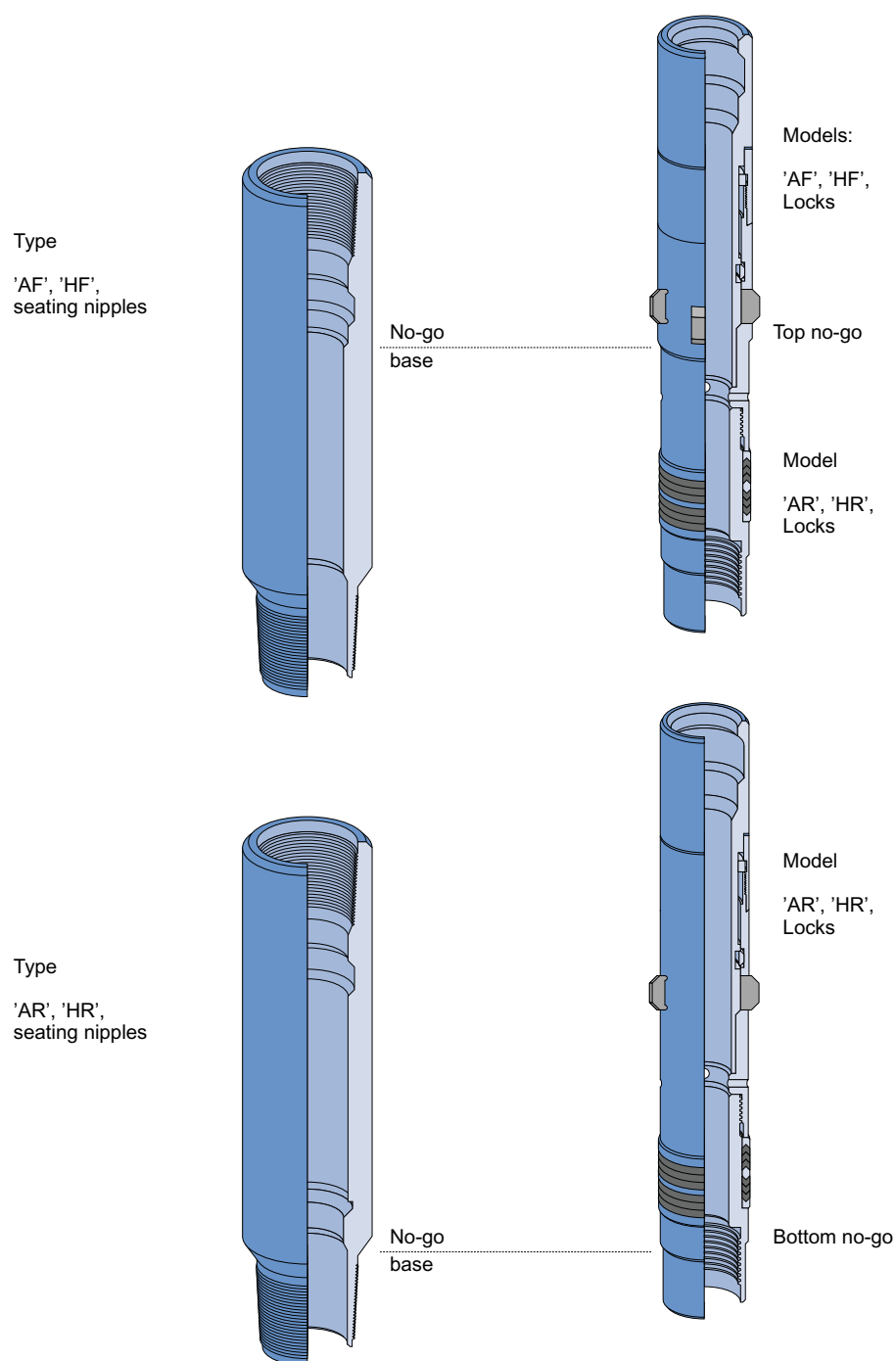


Figure 8-18: Sur-Set System Components

8.8.1 Seal Options

Standard seals can be used up to 350°F (176°C).

For high temperature applications up to 450°F (232°C) and 15,000 psi, PT-3 (Peak and Teflon) seals can be used. The design of the ET (Extreme Temperature) plugs has eliminated all the elastomers. The sealing is achieved by thermoplastic chevron seal stacks.

Table 8-20: Sur-Set Nipple and Lock Options

	Selective	Top No-Go (F)	Bottom No-Go (R)	Maximum Pressure
Model	'A'	AF	AR	10,000 psi
Model	'H'	HF	HR	15,000 psi
Model	'V'	VF	VR	Over 15,000 psi

8.8.2 Operating Principle

The locking dogs have an expanded OD greater than the tubing ID and therefore can only be set in the nipple profile. When the dogs are fully set, the lock is raised off the no-go shoulder to prevent any possible damage/distortion of the no-go shoulder. The dogs are made from Inconel 718 (40 Rc). This is stronger than the material of the lock and nipple to prevent any damage to the keys, which could prevent their ability to retract.

Once locked into the profile, an Inconel 718 snap ring prevents the dog expander from moving upwards with the flow.

This lock is of a jar down to set design, which move the dog expander mandrel down and provide a smooth internal bore, that minimizes flow turbulence. This feature also reduces the possibility of debris collecting, which may impede the recovery of the lock.

8.8.2.1 Lock Design Variations

In flowing applications, such as for safety valves, it is possible to have additional retaining forces on the expander mandrel. This is achieved by using an additional locking ring and shear pin configuration which hold the expander mandrel in the locked position. The additional locking ring requires a 10,000 lbf upward impact force to release. This jarring force also shears the pins holding the expander mandrel.

One extra feature is a debris barrier above the dogs to help exclude sand other debris.

These features can be adapted to any standard sur-set lock.

Table 8-21: Sur-Set System Dimension Summary

Seal Bore Fishing Neck ID	Model 'A' ID	Probe for Type Running Tool	Probe for Type 'A' Lock	Model 'D' GS Type 'H' Lock	Model 'D' Pulling Tool
1.562	1.06	811-55-1300	N/A	Built-in with running tool	
1.710		811-55-0302			40GS15000
1.781					811-42-1555
1.812					
1.875 HF					
1.875AF	1.38	811-55-0304	811-56-2300	N/A	400S18700 811-42-1875
2.062		811-55-3000	N/A	811-56-3000	
2.125				811-56-3200	
2.188					
2.250	1.81	811-55-3500	811-56-3500	N/A	40GS27500 811-42-285
2.312			811-56-3701	811-56-3704	
2.562			N/A	811-56-4101	
2.750	2.31	811-55-0701	811-56-4300	N/A	40GS27500 811-42-2755
2.812					40G53 1200 811-42-3125
3.125	2.62	811-55-4601	811-56-4800		
3.250			811-56-5000		
3.312		811-55-5200	811-56-5200		
3.437	3.12		811-55-6002		811-56-5401
3.625		811-56-5800			
3.688		811-55-6003	811-55-6000		
3.750					
3.812					
3.875					
4.000					
4.125					
4.250					
4.312					

Seal Bore Fishing Neck ID	Model 'A' ID	Probe for Type Running Tool	Probe for Type 'A' Lock	Model 'D' GS Type 'H' Lock	Model 'D' Pulling Tool
4.562	4.00	811-56-1701	811-56-6700	N/A	400845600
4.750			811-56-6900		811-42-4565
5.312		811-56-7400	811-56-7300		811-50-5250
5.625			811-56-7400		
5.750		811-55-1700	811-56-7500		
5.810			811-56-8500		
5.812					
5.593	5.40	811-55-7800	811-56-9002		811-42-7002
6.000	4.25	811-55-6900	811-56-9000		811-50-5250

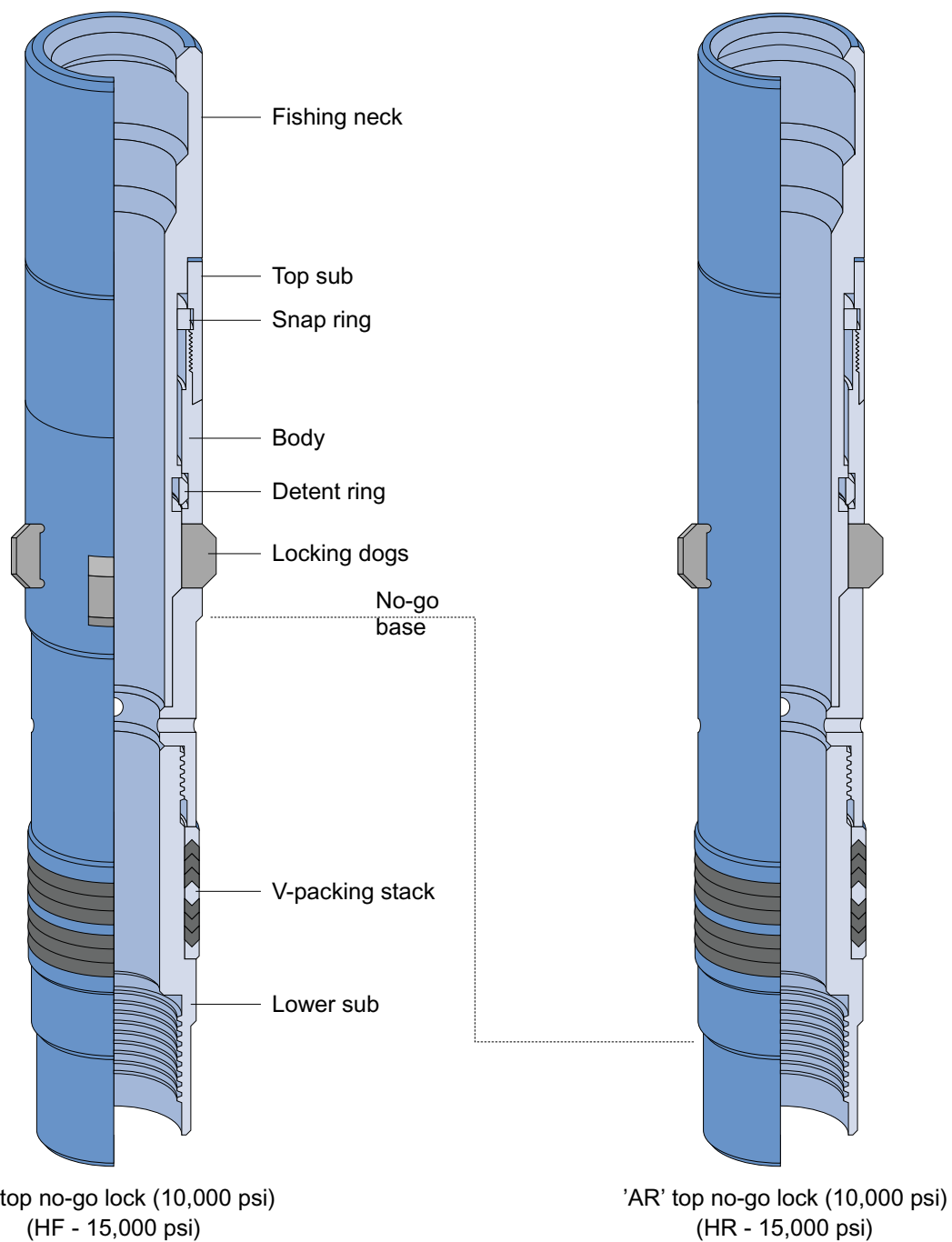


Figure 8-19: Model AF and AR Top No-Go Lock

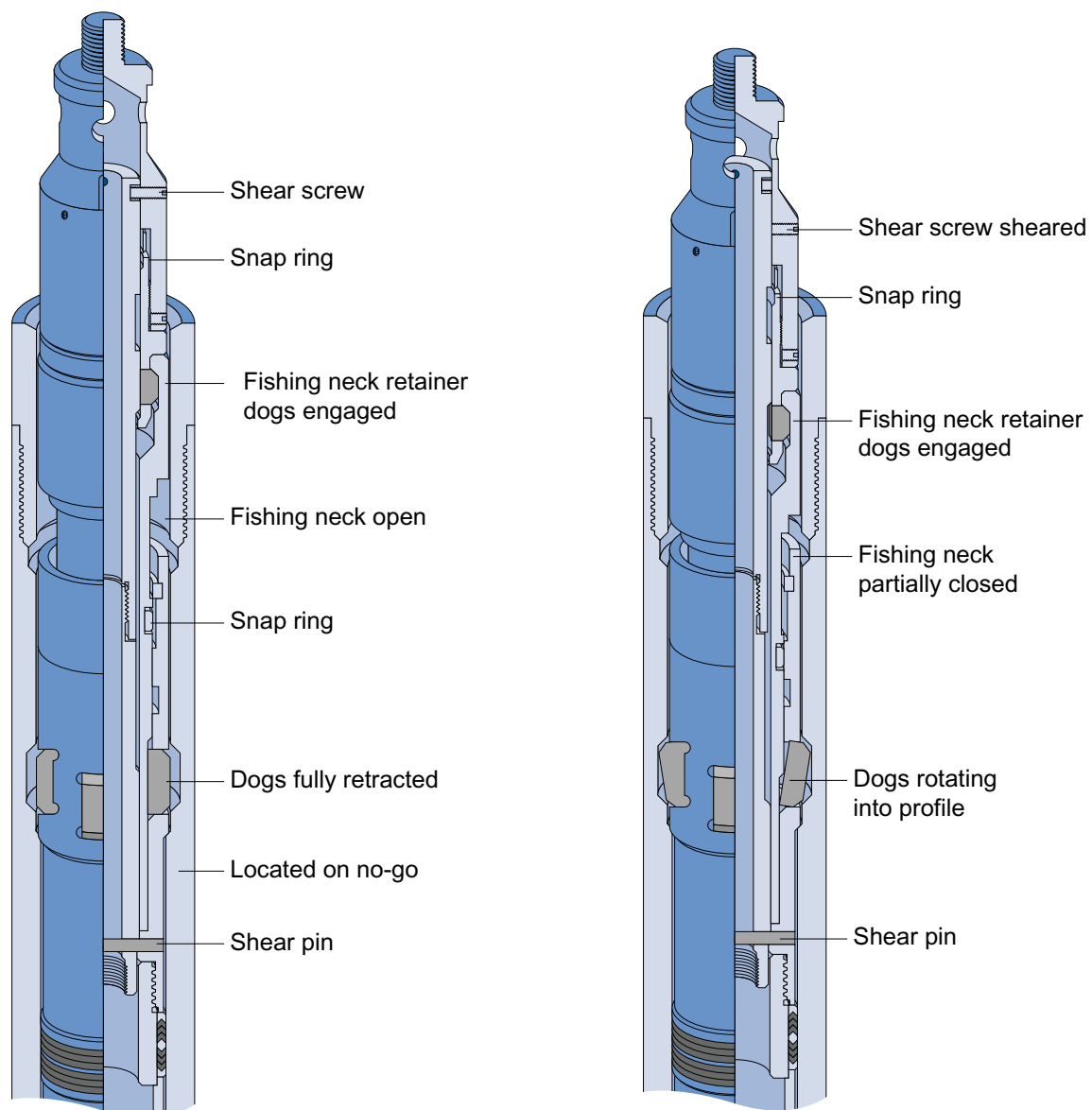


Figure 8-20: Sur-Set Running Sequence 1

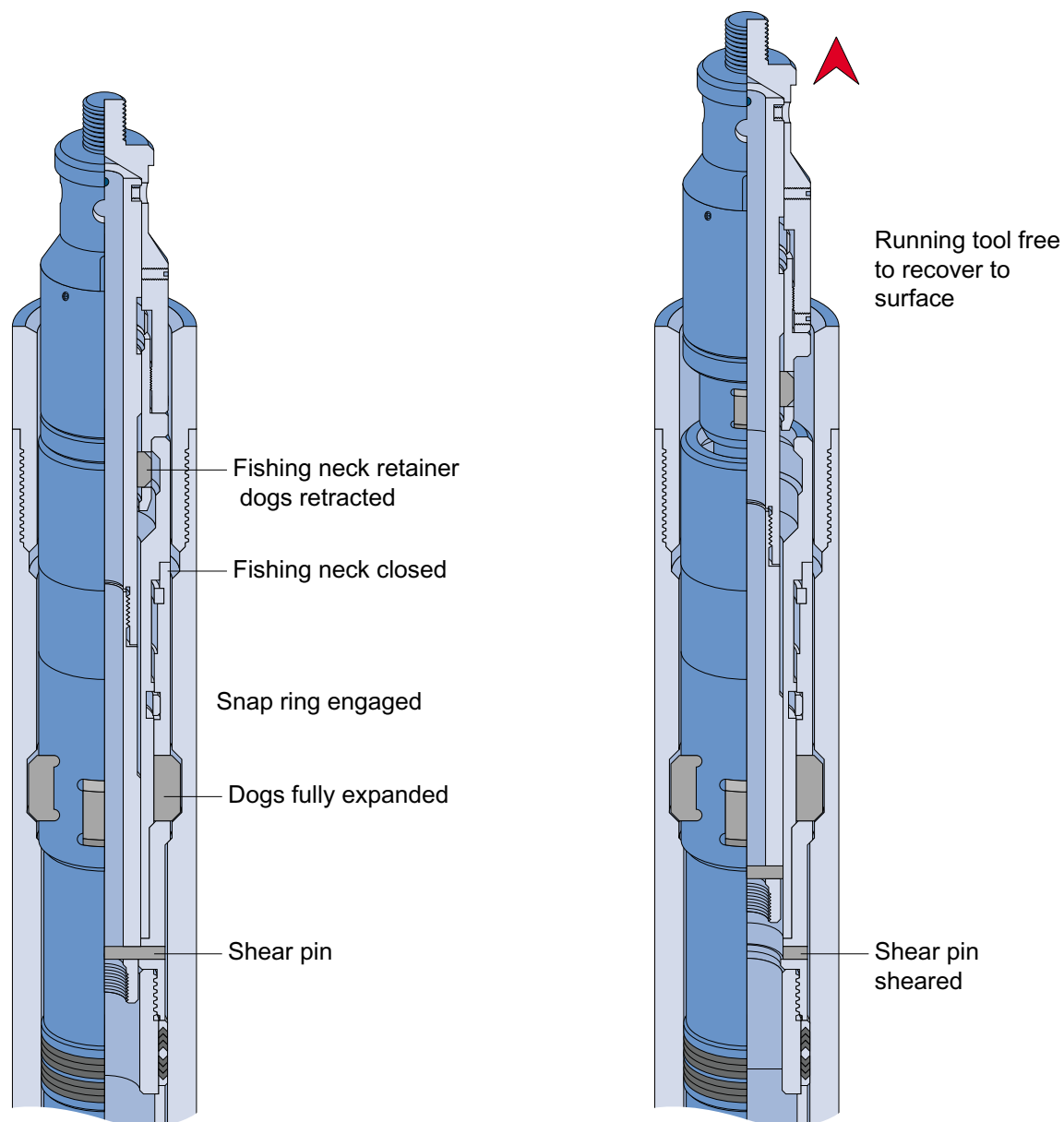


Figure 8-21: Sur-Set Running Sequence 2

8.8.3

Sur-Set Lock Running Tool

8.8.3.1

Model A Running Tool Plus D Probe

A small set of retaining dogs remain expanded within the fishing neck until the lock sets fully. It is this feature, which returns the lock to the surface on the running tool, if it is not fully into the profile.

8.8.3.2 Pinning Procedure

1. Remove all old shear pins and shear screws from the running tool.
2. With the core in the up position, the running tool is inserted into the lock.
3. With the tools in the vertical position, lift the lock expander mandrel. This may not be possible with the larger size locks.
4. The core should now be down and the upper shear screws can be inserted to lock the core.
5. Insert the lower shear pin through the lock and D probe.

**Note**

Usually brass – although steel can be used on bigger diameters, especially if setting in gas.

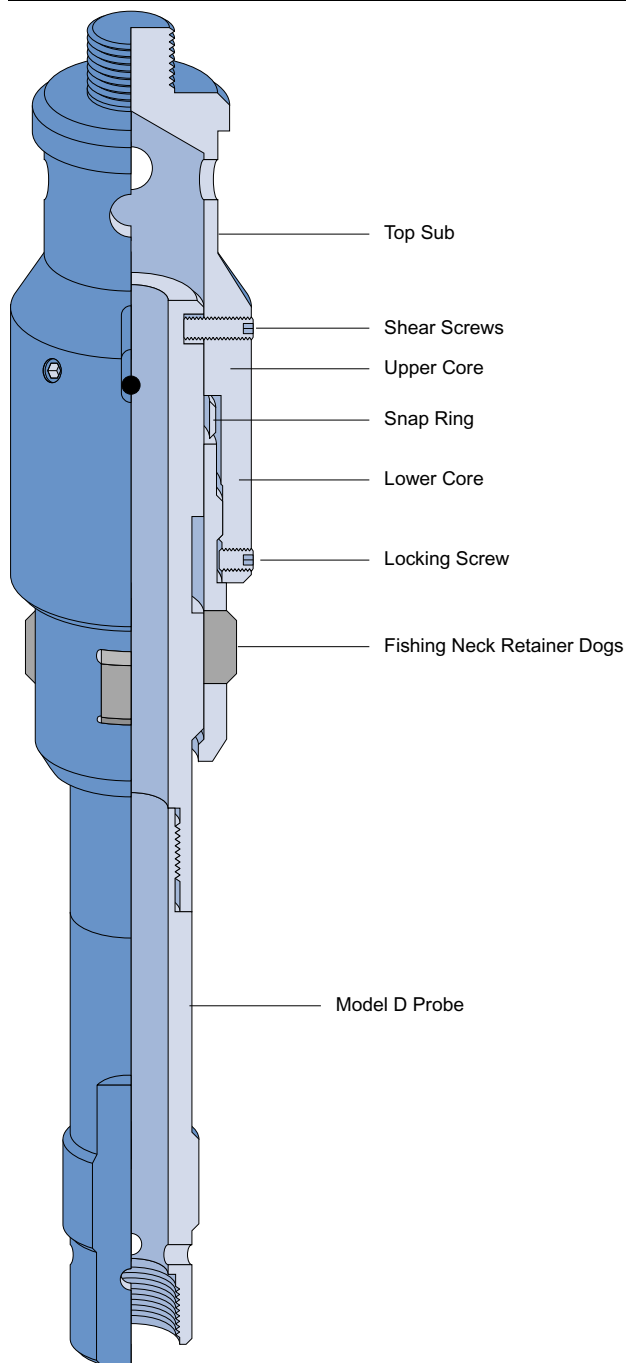


Figure 8-22: Sur-Set Running Tool

8.8.3.3 Running Procedure

The running tool and lock assembly is lowered onto the well bore until the lock stops at the no-go. Gentle downward jarring may be necessary to ensure the seals fully enter the seal bore.

Downward jarring shears the upper shear screws and expands the locking dogs into the nipple profile.

If the dogs do not fully expand into the profile or the expander mandrel does not fully move downwards, the fishing neck retainer dogs will retain the lock attached to the running tool and return the complete assembly to the surface. Upward jarring will shear the lower shear pin permitting recovery of the running tool.

8.8.3.4 Running Tool Variations

The Baker pre-sur-set running tool assists the setting of locks in wells deviated up to 70°. After locating the nipple, pressuring up on the tubing acts on the running tool to set the lock.

The same design feature ensures the lock is fully set prior to releasing from the running tool.

The pulling tool recommended by Baker is the Otis type GS.

An alternative pulling tool is the Petrolite DU, which provides the additional benefit of initial downward jarring to loosen the lock before jarring upwards to recover the lock/plug assembly. (The DU is sheared by further downward jarring if necessary).

8.8.3.5 Pulling Procedure

The pulling tool and appropriate equalizing prong is lowered into the lock.

After equalizing the pressure, upward jar action releases the snap ring and pulls the expander mandrel upwards so that the dogs can retract. Approximately 200 lbf of upward impact force is required to expand the mandrel.

8.8.4 Sur-Set T-2 Check Valve

Top No-Go	AFT-2 and HFT-2 (10,000 psi)
Bottom No-Go	ART-2 and HRT-2 (15,000 psi)

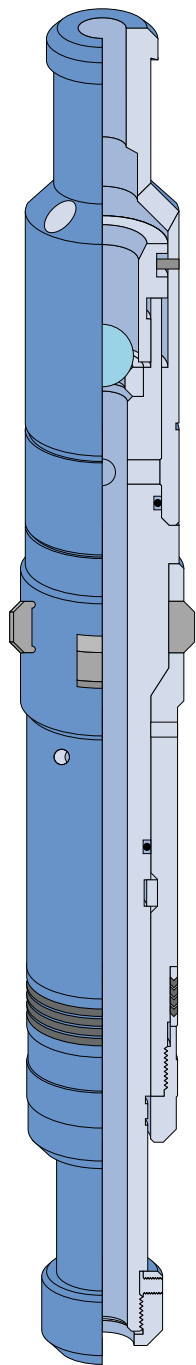


Figure 8-23: Sur-Set T2 Check Valve Assembly

These check valves hold pressure from above. As for the standard locks, the locking dogs lift the load off the no-go. The internal equalizing feature ensures that the fluid column exerting pressure from above is relieved prior to pulling the check valve.

8.8.5 **Sur-Set Model H Blanking Plug**

This plug hold pressure from both directions, and is design for use in well with the potential of sand or sediment being deposited on the plug. It is run in two trips and recovered in two trips.

The ports in the plug provide fluid bypass during running. When the plug mandrel is run, the ports are sealed off.

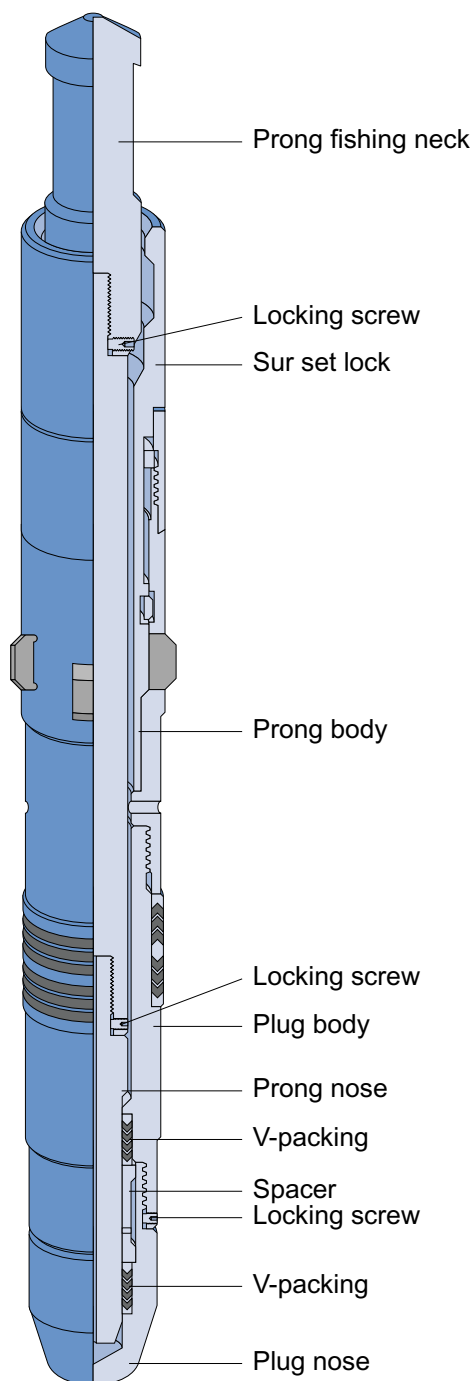


Figure 8-24: Sur-Set Model H Blanking Plug

8.8.5.1

Running

The lock assembly is run first on the Baker model A running tool.

The plug mandrel is then run on a type SB.

8.9

Sur-Set Model M Blanking Plug

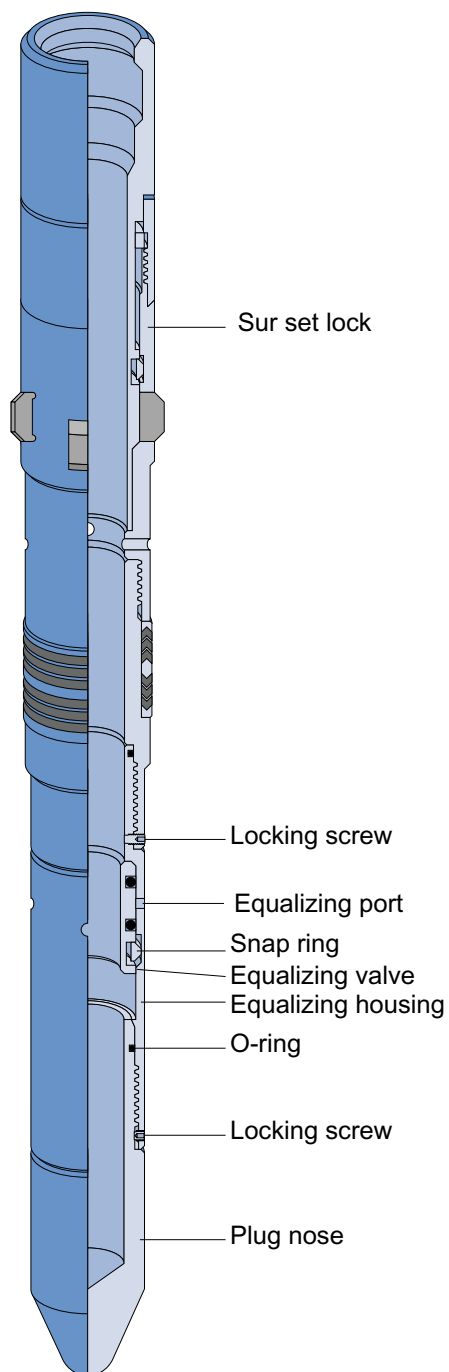


Figure 8-25: Sur-Set Model M Blanking Plug

8.9.1 Pulling

The plug mandrel is pulled with a model SB tool.

The lock mandrel is pulled with a GS (or DU) pulling tool.

This positive plug holds pressure from both directions and is designed for use in clean wells. It is run in one trip and recovered in one trip.

During running, the ports in the plug are held open by a running prong to provide fluid bypass. As the running tool is sheared upwards, the ports are sealed as the inner mandrel (valve body) is moved up by the running prong.

8.9.2 Pulling Option

A pump open plug bottom can be attached so that the assembly can be equalized from the surface and recovered in one trip.

8.9.3 Running

The lock/plug assembly is run on the Baker model A running tool, with a running prong to hold the valve off the seat for fluid bypass.

8.9.4 Pulling

The plug is equalized with a model A guide and equalizing prong.

The lock/plug mandrel is then pulled with a GS (or DU).

Intentionally Blank

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9 HALLIBURTON PLUGS, LOCKS AND TOOLS



Note

The pressure rating of many plugs and locks have been revised as a result of API testing processes. Consequently, manufacturer data should be consulted to obtain the current operating limits and requirements.

9.1 Locks

A lock mandrel is a device, which will grip in the well to provide an anchor for various flow control devices such as plugs, safety valves, separation tool etc. The lock mandrel grips either by utilizing slips, dogs or keys. The lock mandrel also has a means of sealing around its OD to hold pressure.

There are three main groups of lock mandrels:

Slip Locks

Can be set at any depth in any tubing except. With the exception of tubing that has been internally plastic coated.

Slip locks were the first type of lock to be designed. They have limitations, which make them less useful than the other types of lock mandrels.

- Maximum pressure differential 1500 psi.
- Will hold pressure from below only.
- Will not pass the nipple bore (of the same nominal size as the tubing).
- Can be unlocked by excessive flow from above.

Collar Locks

Collar locks are securely locked in the tubing collar recess by dogs, which extend downwards.

- Collar locks have the following features and limitations:
- Will hold 5000 psi - from ABOVE and BELOW.
- The G seal element is more effective than the W used on slip locks.
- Will not pass the nipple ID.

Nipple Locks

Positioned in a nipple run in the tubing string during completion. Nipple locks can be divided into the following categories:

- Selective -due to nipple profile -S locks
- Selective -due to running tool -X locks
- No-go -due to no-go ring in the nipple - XN locks

Nipple locks offer greater versatility, reliability and pressure rating than either slip or collar type locks.

9.1.1 Slip Locks

9.1.1.1 W Slip Locks

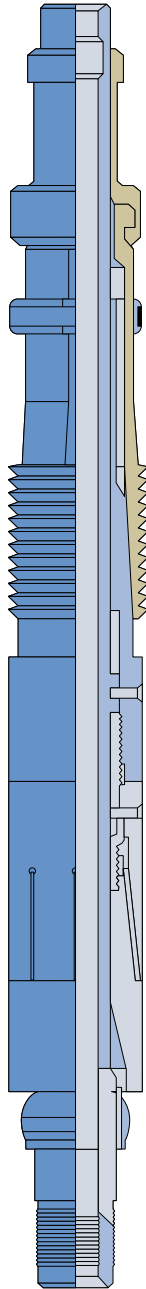


Figure 9-1: Type W Slip Lock

Description

The type W Lock Mandrel has three serrated slips mounted around the tapered slip mandrel. The slips are suspended from the slip carrier and are retained on the slip mandrel by the mandrel band. The upper end of the slip carrier provides a fishing neck (pulling flange B), which allows the lock assembly to be engaged by a pulling tool in order to retrieve the assembly from the well.

The element assembly is threaded onto the lower end of the slip mandrel. The above items are mounted on the main mandrel. The internal groove (A) near the upper end of the main mandrel provides an external thread to which equalizing subs and control devices such as plugs, safety valves, pressure regulators, etc. can be attached. The internal thread in the lower end of the element expander is provided for installation of a choke bean.

The port or slot (C) in the element expander provides an escape route for any fluid or gas that may be present between the element and element expander when the expander is moved up to expand the element. It also provides for equalization across the expander so that the expander cannot become pressure locked against the element.

The shear pin(s) hold the main mandrel stationary in relation to the element assembly to prevent premature expansion of the element during the running procedure.

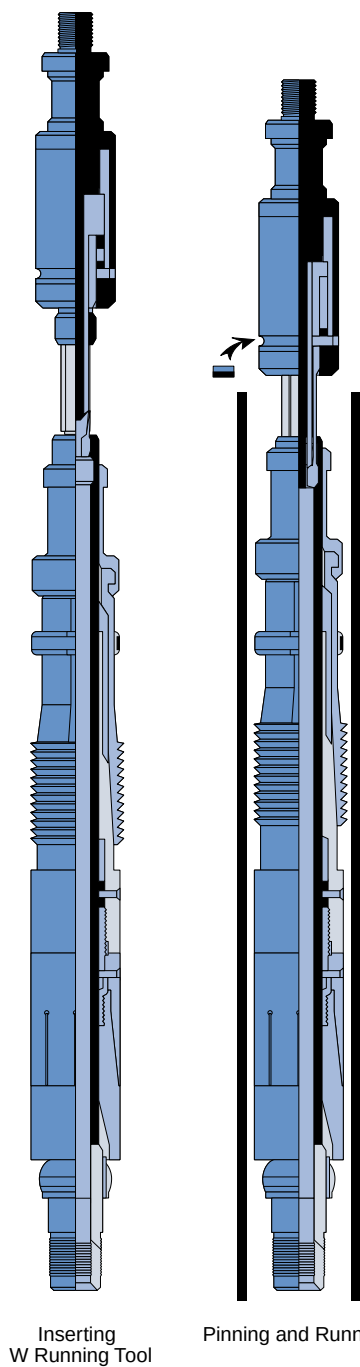


Figure 9-2: Type W Slip Lock Running Sequence

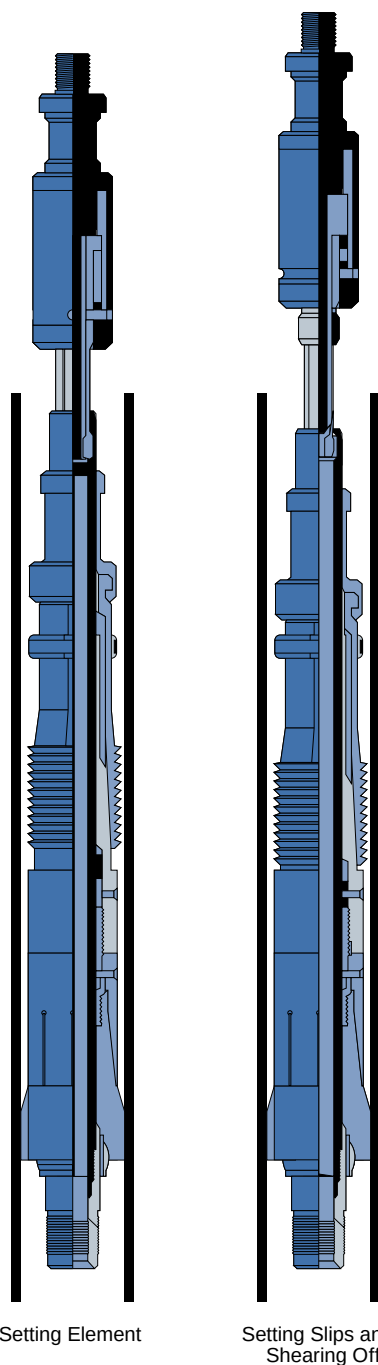


Figure 9-3: Type W Slip Lock Running Sequence

Application

The lock mandrel alone, serves no useful purpose if installed in a well. Equalizing subs and control devices such as pressure regulators, safety valve, plugs and bottom hole chokes may be attached to the lower, threaded end of the lock

mandrel assembly. These devices, when used must be anchored (locked) in place in the well tubing. The well fluid flow (liquid or gas) must be directed through these control devices in order for them to be effective.

This purpose is accomplished by the Type W lock mandrel in the following manner:

When installed (set) in the tubing, the slip mandrel is moved upward in relation to the slips, forcing the slips outwardly to engage the tubing wall. In effect, the tapered slip mandrel simply wedges the slips against the internal diameter of the tubing, preventing upward movement of the main mandrel. This upward movement pulls the element expander up into the element, forcing the resilient element outwardly and into positive contact with the tubing wall. This creates a seal, which now forces the well fluid flow (liquid or gas) through the control device, which is attached to the lower end of the lock mandrel (safety valve, pressure regulator, etc).

Running Procedure

1. The slips slide along the tube wall during running in.
2. When the anchoring depth is reached, pull up; then JAR UP.
3. The taper forces the slips to grip the tubing wall.
4. Continued jarring up shears the pins, which fix the mandrel body and taper together. The body moves up and the lower conical shoulder expands the packing, sealing against the tubing.
5. Further upward jarring shears the pins of the running tool.
6. Pull out of the well.



Caution

Potential Severity:	Light
Potential Loss:	Information
Hazard Category:	machinery equipment hand tools

Do not sit down on the lock after setting, as it may release.

Pulling Procedure

1. Attach the correct pulling prong to thread in the RB core.
2. The prong size depends on the plug type.
3. The core strikes the mandrel. JAR DOWN to release the taper behind the slips.

4. As the mandrel moves down, the RB dogs simultaneously latch the neck.
5. The element is also reached by this action.
6. The lock is pulled out of the well hanging by the fishing neck, which ensures the slips remain retracted.



Note

The tendency to pull the W lock using an RS pulling tool must be avoided. The reach of the RS is such that the skirt may push downward on the fishing neck, tightening the slips.

The mandrel must have room to move downward to release the taper behind the slips. For this reason it is NOT advisable to run a collar stop or any other restriction below the slip lock, as this will impede the downward movement.

9.1.1.2

W Running Tool

The W Running Tool is prepared in the following manner:

- Check the collet is free to move - Remove old shear pins.
- Install the collet in the W lock running neck.
- Insert two pieces of shear stock.
- Rotate the shear pin cover to prevent pieces of shear stock falling on top of the lock.

The upward jarring action shears the pins and retracts the core from the collet, releasing the W lock.

Table 9-1: Type W Lock Running Options

Part No.	Tubing OD (in.)	OD Slips Expand (in.)	OD Slips Retract (in.)	Min. ID (in.)	Fishing Neck (in.)	Running Tool	Pulling Tool	Thread Connection
10W018	2.375	2.062	1.859	0.687	1.375	41W013	40RB17	1-3/16 x 14
10W022	2.875	2.530	2.296	0.875	1.750	41W014	40RB18	1-9/16 x 12
10W023	3.500	3.080	2.843	1.375	2.312	41W022	40RB19	2 x 12
10W034	4.500	3.500	3.281	1.750	2.750	41W030	40RB30	2 ¹ / ₄ x 12

9.1.2 Collar Locks

9.1.2.1 D Collar Lock

Description

The type D collar lock mandrel is designed to locate, lock and seal various control devices into the coupling (collar) recess of either API externally upset tubing or API non-upset tubing. The same lock mandrel assembly (of a given size) may be used in EU or NU tubing without any part changes being made.

The advantages of the type D collar lock mandrel, when compared to the types B and W slip lock mandrels, are:

- The type D collar lock mandrel has a much higher differential working pressure rating (some sizes up to 5000 psi differential).
- The type D collar lock mandrel will support this higher differential pressure from BELOW and ABOVE.
- The type D collar lock mandrel has a larger bore (ID), which provides a greater flow area than can be obtained through the slip type lock mandrels.

The major limitation (or disadvantage) of the type D collar lock mandrel is that it can locate and lock ONLY in API, EU or NU threaded and coupled tubing. It CANNOT be used in tubing other than API, EU or NU.

The type D collar lock mandrel is designed for use in standard weight ranges of tubing and will pass through the type S or type X landing nipples which are normally used in standard weight tubing.



Caution

Potential Severity:	Light
Potential Loss:	Assets
Hazard Category:	temperature

Any temperature over 200°F the Nitrile element pressure rating should be cut by half. Contact manufacturer for recommended element with well temperature above 200°F.

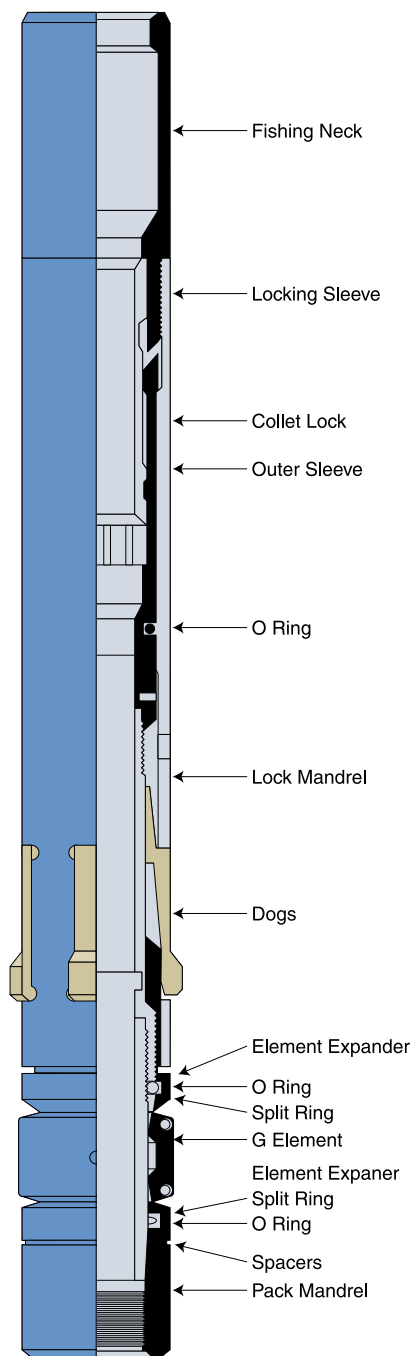


Figure 9-4: Type D Collar Lock

The illustration in shows the type D collar lock mandrel in the unlocked (running) position. The internal fishing neck is threaded into the upper end of the outer sleeve. The locking dogs are positioned in windows, which are machined in the outer sleeve. The three items, (the fishing neck, the outer sleeve and the dogs) are linked together and can move up or down as a unit in relation to all other parts of the assembly. The dog-outer sleeve-fishing neck unit is in its uppermost

position. Note that the locking dogs are recessed inwardly against the smaller diameter of the lock mandrel and are flush with the diameter of the outer sleeve. This allows the assembly to pass through the tubing.

The collet lock, the lock mandrel and the packing mandrel are threaded together and must move as a single unit. This unit can move up or down in relation to the fishing neck-outer sleeve-dog unit.

The locking sleeve is installed inside the upper, colleted end of the collet lock. Note that the collets of the collet lock are latched into a groove near the upper end of the locking sleeve.

In the unset (running) position the collet lock cannot release from the groove in the locking sleeve due to the internal diameter of the outer sleeve.

The O-Ring cage, the element and the element expander are mounted on the packing mandrel. These items and their functions will be discussed later in this section.

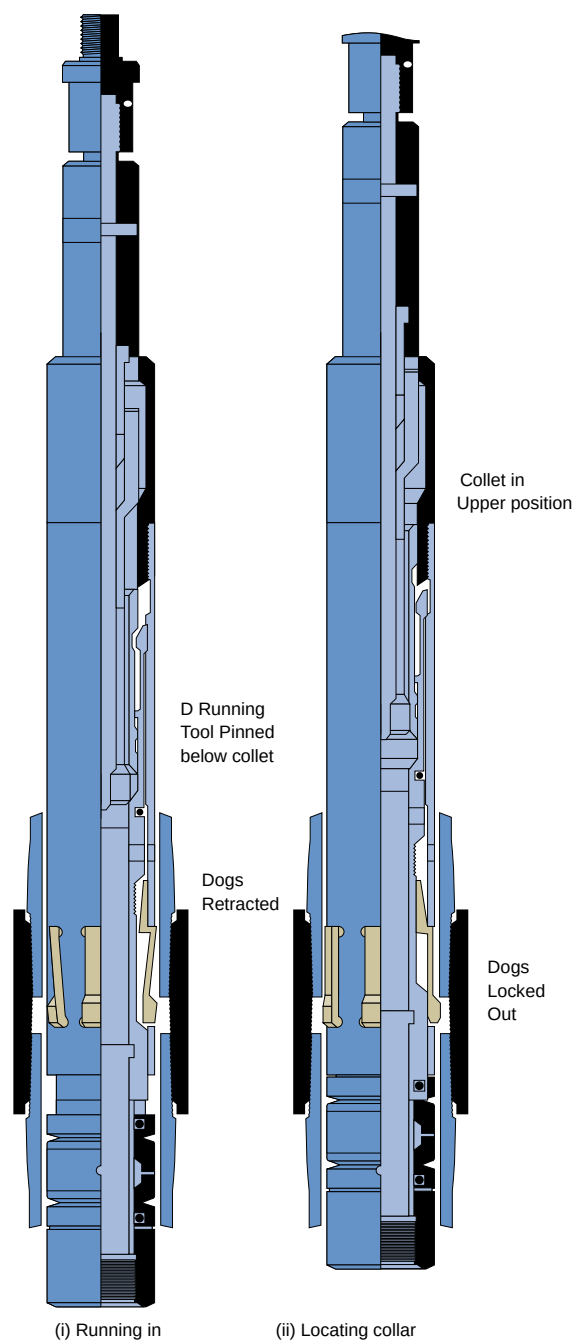


Figure 9-5: Type D Collar Lock Running Sequence

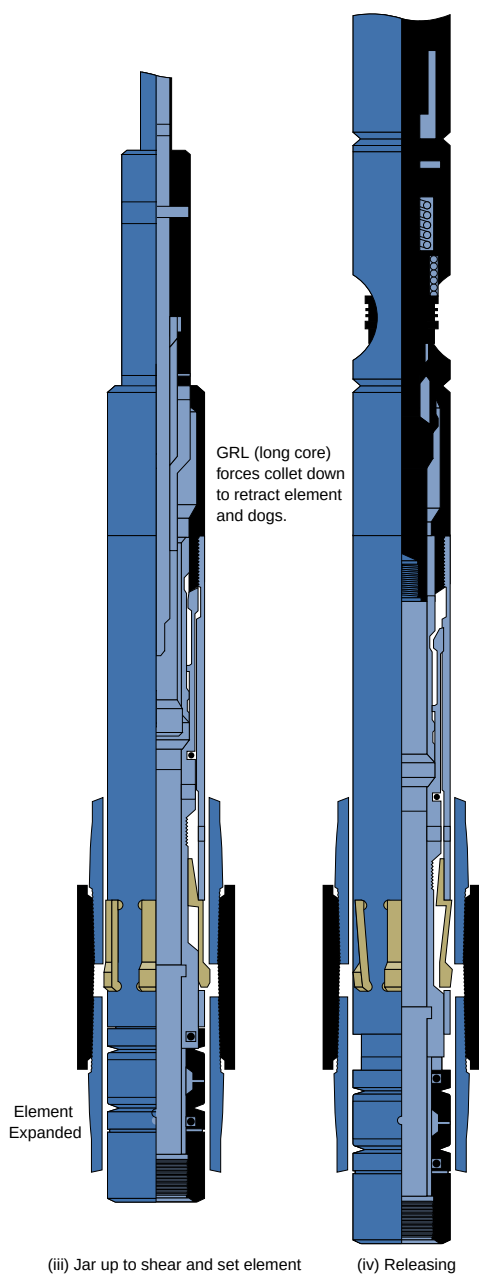


Figure 9-6: Type D Collar Lock Running Sequence

Preparing the Running Tool

Pin the D running tool so that the collet is expanded below the locking sleeve in the recess in the D collar lock. Select brass or steel shear pins as per the setting depth and jar force available.

Running

1. Lower the assembly into the hole and stop approximately one joint above the desired setting point.
2. Pull the assembly up slowly until a collar recess is located. DO NOT PULL MORE THAN 200 lbf (100 kg) AT THIS POINT. Note the slickline measurement at this point and check again at the target collar. This ensures you are correctly located in the collar - if you are one joint lower than the reference point.
3. To move downward again tap downward slightly, then move down the hole to approximately 10 ft below the desired collar recess.
4. Pull the assembly up until the collar recess is encountered and place approximately 300 lbf pull in the wire.
5. Close the jars slowly without any downward jarring.
6. A hard jar upward now is used to expand the element and fully lock the collet.
7. Prior to shearing the pin in the running tool, jar down slightly to check if the assembly is set. If the plug moves downward, repeat steps 5 and 6.
8. If the assembly does not move downwards, jar upwards until the shear pin is sheared and the running tool is freed. After the shear pin is sheared, do not tag the assembly again as this may release the lock.

Pulling

Pulling Tool = GRL + equalizing prong.

- Choose the equalizing prong to suit the plug attached to the lock
- As the GRL engages, the fishing neck prong activates the equalizing device. WAIT FOR THE PRESSURE TO EQUALIZE.
- JAR DOWN - The core extension on the GRL pushes the locking sleeve down, releasing the element and dogs.
- Pick-up and pull out of the hole.

Table 9-2: Type D Collar Lock Options

Tubing OD (in.)	Max. OD (in.) Dogs Retracted	Lock Dog Assembly #	Element Assembly #	Thread Down	Running Tool	Pulling Tool
2.375	1.843	310D037	310D047	1-3/16 - 14 Pin	41D010	40GRLI
2.875	2.281	310D030	310D049	1-9/16 - 12 Pin	41D011	40GRL4
3.500	2.844	310D058	310D057	2 - 12 Pin	41D09	40GRLI4
4.500	3.800	310D067	310D068	3-1/16 - 12 SLB Pin	41D015	40GRL26

Element Detail

The D collar lock uses a Type G element. By varying the number of spacers beneath the expander element, the amount of expansions can be controlled to seal in various tubing weights.

Pressure set and pressure balanced design refers to the split ring installed in the O-ring grooves either side of the element.

THESE RINGS MUST BE ON THE ELEMENT SIDE OF THE O-RING.

The pressure is permitted to act behind the element to energize the seal. As this pressure reaches the second O-ring, it will be contained. A reversal of pressure causes the bypass to be effective from the opposite direction.

This feature ensures the optimum sealing against the tubing well.

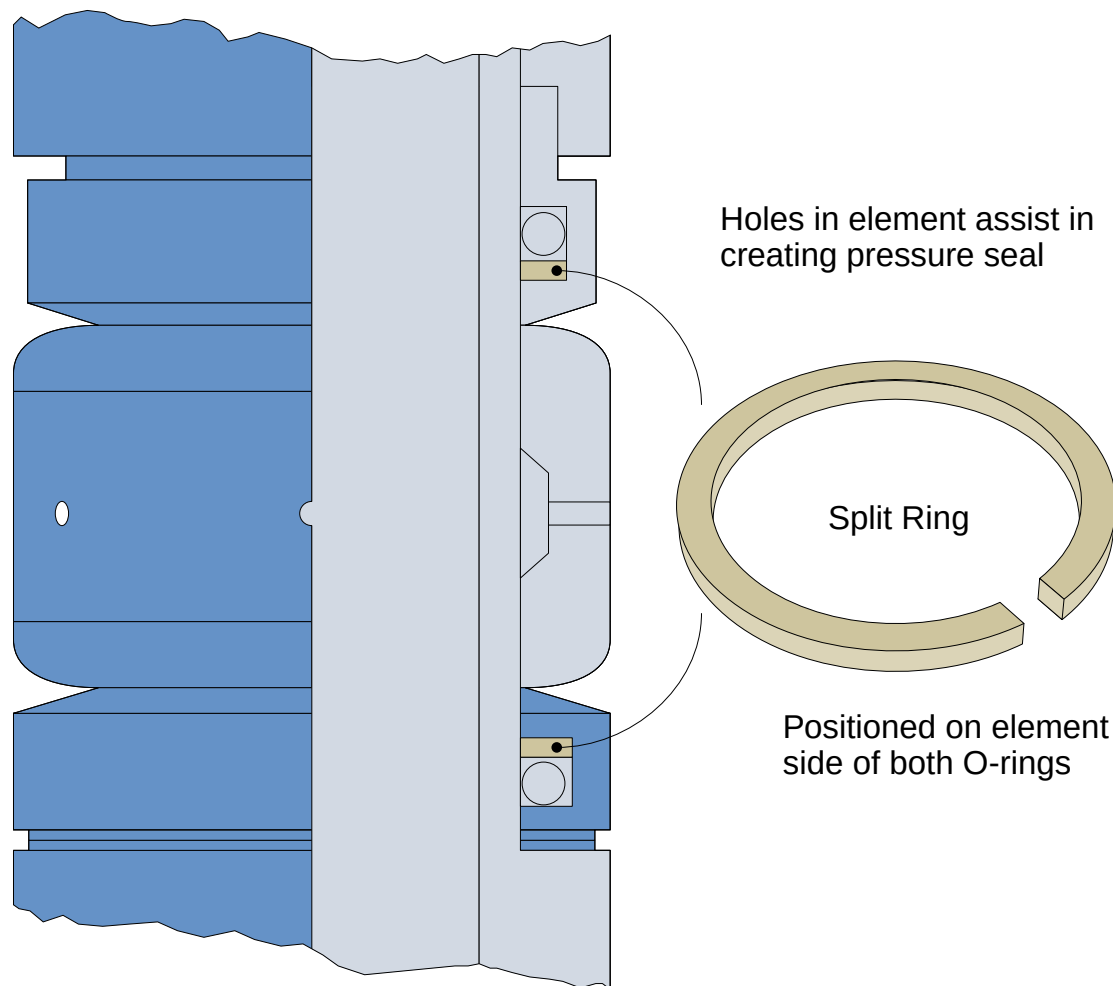


Figure 9-7: Type G Packing Element Detail

9.1.3

Nipple Locks

The X and XN lock mandrels designed by Otis set the standard for selective locks and are in common use worldwide.

There are 3 types of nipple locks:

- Selective - Due to nipple profile utilizing S Locks
- Selective - Due to running tool utilizing X Locks
- No-Go- Due to restriction in nipple utilizing XN Locks

9.1.3.1 S Lock System

The S Lock system relies on varying profiles in each nipple, starting with the S-1 at the bottom to an S-5 near the surface. The operator installs the keys below the lock that matches the nipple profile in which the lock is to be positioned.

9.1.3.2 X Lock System

The X Lock system uses identical nipples in each respective tubing size. The operator can select nipple the lock is to be set in, by the use of a selective running tool. The advantages over previous designs of lock include:

- V-packing seal in the polished bore of the nipple.
 - This method of sealing also applies to the S lock.
- Holds pressure from both directions (high pressure R/RN system available)
- Identical nipples simplify installation and ordering.
- Can be set in the X profile of sliding side doors.
- Simple lock designs reduces maintenance.
 - Running Tool - X
 - Pulling Tool - GR

9.1.3.3 XN Lock

The XN lock is an X lock with the keys changed to XN. All other components are identical, including the running and pulling tools.

The OD of the equalizing sub is too large to pass the no-go nipple ID, so it serves as a positive stop to locate the nipple keys.

**Note**

An Interference Lock in the X and XN style is now available from Otis. The only difference is a small, slightly raised band on the packing mandrel near the small holes behind the keys. When the expander mandrel is in the locked position, the interference fit between this raised band and the inside of the expander mandrel ensures the lock remains in the locked position until upward jarring is applied to the fishing neck.

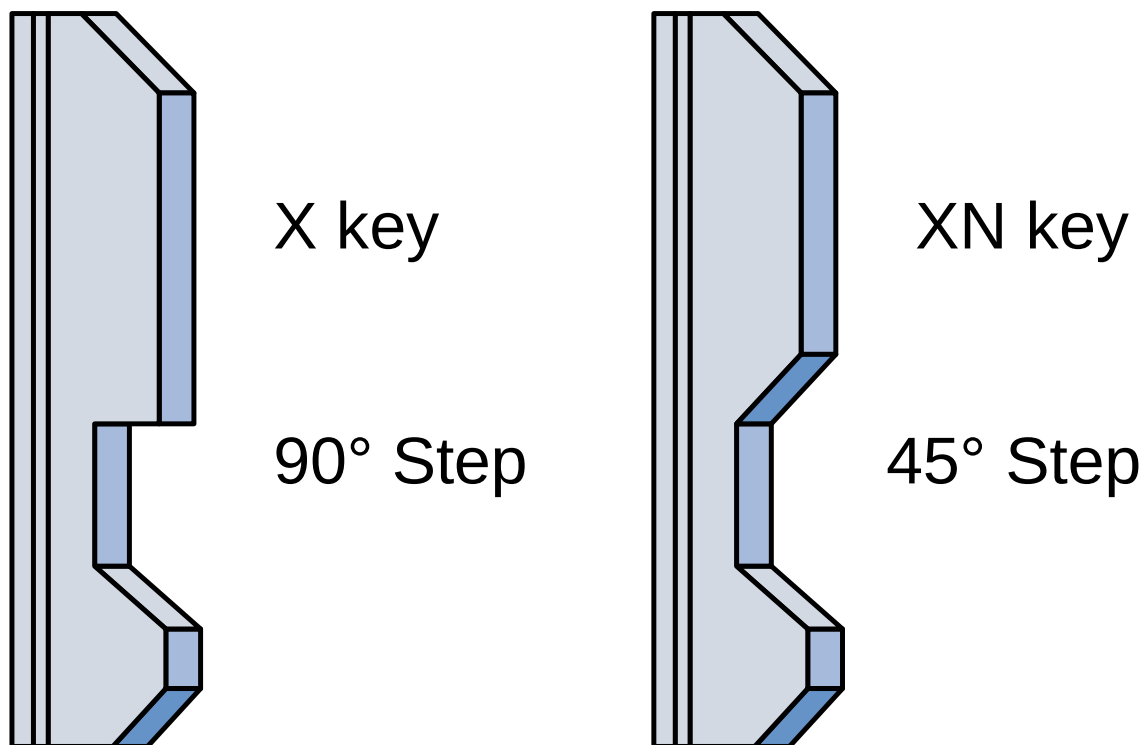


Figure 9-8: Type X and XN Keys

Prior to running an X (or XN) lock the following should be checked:

- All threads are tight - Note the hole in the expander mandrel for a bar.
- Correct profile keys - X or XN.
- Key spring tension - Keys should be fully retracted in selective and sprung forward evenly in nonselective
- Check the internal fishing neck for wear or damage.
- Check the serrations on the expander mandrel and keys. Replace if worn.

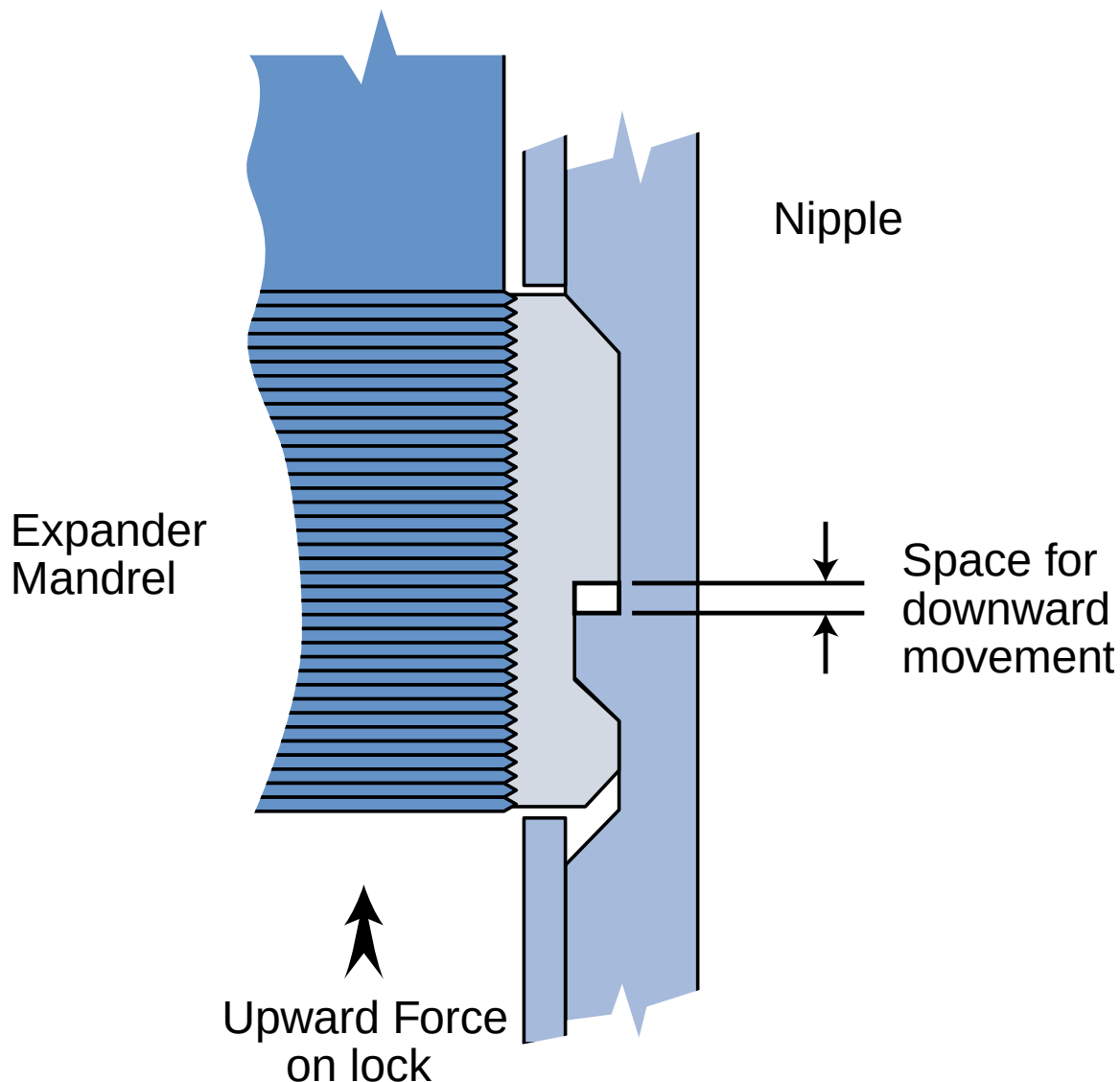


Figure 9-9: Expander Mandrel Detail

The greater the upward force created by the pressure differential, the greater the squeeze by the keys onto the packing mandrel. This grips the serrations to prevent the expander mandrel moving upwards and unlocking. This can be observed by opening and closing a lock mandrel and comparing the effort needed to repeat the opening sequences while squeezing the keys inwards by hand.

Assembly - Disassembly

Disassembly

1. Place the assembly horizontally in a vice. Grip on the fish neck and remove the packing from the packing mandrel.
2. Insert a steel rod through the shear pinholes in the packing mandrel.
3. Using the rod as a handle, pull the packing mandrel away from the vice. This removes the key retainer sleeve away from the fish neck and exposes the expander sleeve.
4. Insert a rod through the holes in the expander sleeve. Using the rod as a handle, remove the expander sleeve from fish neck.



Caution

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

Do not use a wrench on the expander sleeve. This could damage the special finish on the upper end of the expander sleeve. Also do not use a wrench on the packing mandrel or key retainer sleeve when removing them from the fish neck. This would twist the key springs and damage the grooves in the expander sleeve.

5. Remove the packing mandrel from the key retainer sleeve.



Caution

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

Do not use a wrench on the packing of the packing mandrel. This could cause premature wear of the packing ID and cause the packing to leak.

6. With the expander sleeve in the up or unlocked position, the keys may be removed from the slots.
7. Pull the expander sleeve out through the bottom of the key retainer sleeve. This allows the springs to fall free.
8. Clean and inspect all parts thoroughly for wear and damage.

**Caution**

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

Never grip the key retainer sleeve in the vice or wrench, since the thin wall can be easily damaged.

Assembly

1. Install the expander sleeve (small end first) into the lower end of the key retainer sleeve. Leave sufficient room to install the key springs.
2. Align the spring grooves in the expander sleeve with the slots in the key retainer sleeve.
3. Insert the springs through the top of the key retainer sleeve and into the spring grooves in the expander sleeve. Check that the hooked ends of the springs are in the holes in the key retainer sleeve. Hold in place with grease. (On big size locks with a shear pin retainer, check that the pinhole in the expander sleeve is aligned with the pin slot in the key retainer sleeve).
4. Push the expander sleeve through the key retainer sleeve until it engages and stops.
5. Install the keys through the bottom of the key retainer sleeve and onto the springs. The keys must be properly installed on the springs.
6. Push the expander sleeve down, moving the keys out into the windows of the key retainer sleeve.
7. Insert the packing mandrel into the expander sleeve and make up by hand.
8. Grip the upper end of the key retainer sleeve in a vice. Tighten the packing mandrel.

**Caution**

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

Do not use a wrench on the key retainer sleeve. This may twist the key springs and damage the grooves in the expander sleeve.

9. Remove this assembly from the vice and place the fish neck in the vice.

10. Make up the expander sleeve into the fish neck by hand.
11. Insert a steel rod through the shear-pin holes in the packing mandrel. Using the rod as a handle, pull the packing mandrel away from the fish neck to expose the expander sleeve.
12. Insert the rod through holes in the expander sleeve. Using the rod as a handle, make up the expander sleeve into the fish neck.

**Caution**

Potential Severity: Light
Potential Loss: Assets
Hazard Category: machinery equipment hand tools

Do not use a wrench on the key retainer sleeve. This would twist the key spring and damage the grooves in the expander sleeve.

13. Do not try to force the fish neck downwards. This may place the tool in a locked position.
14. Install the new packing onto the packing mandrel.
15. Install a new O-ring onto the lower end of the packing mandrel on locks $3\frac{1}{2}$ in. and larger.

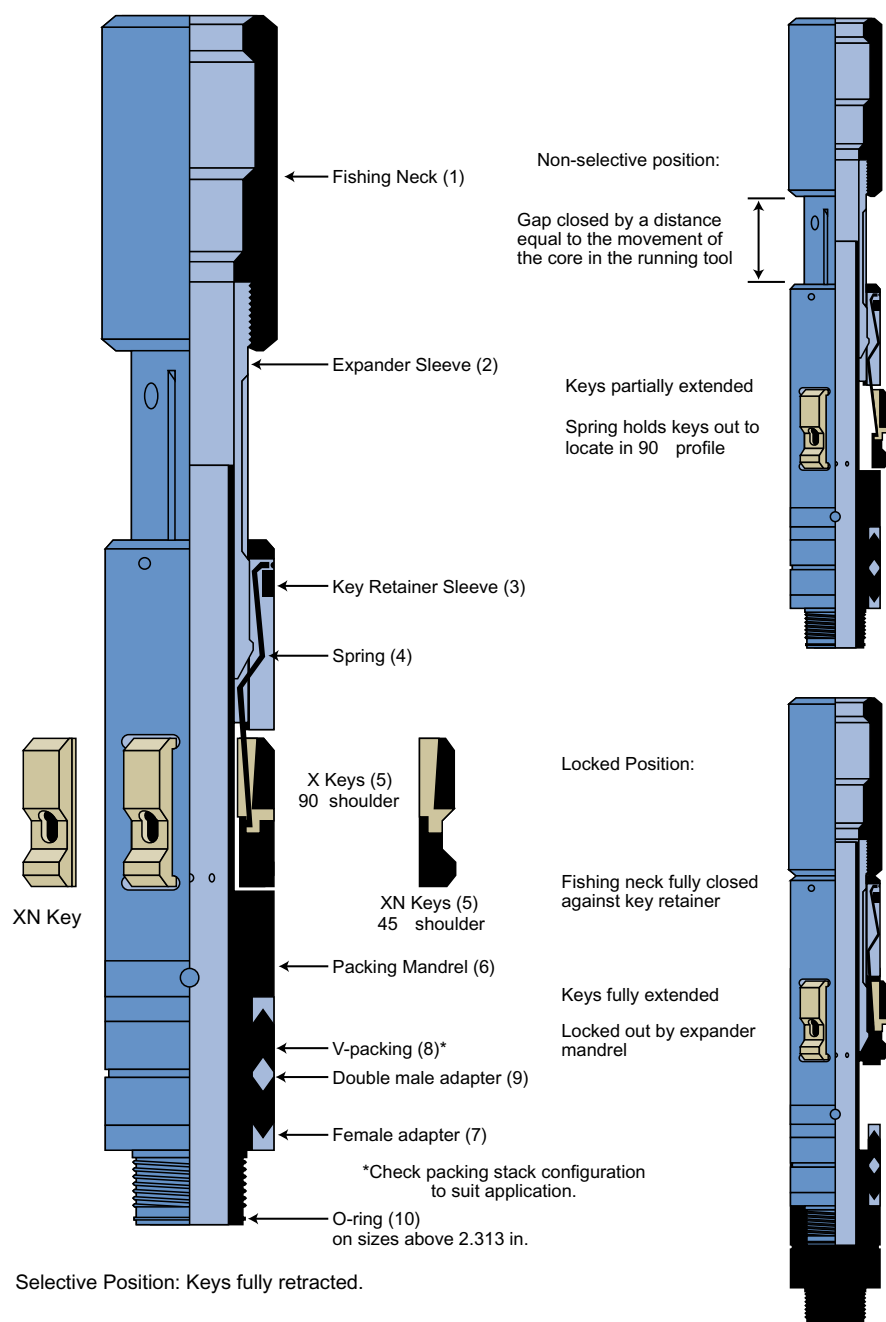


Figure 9-10: X Lock Positions — Selective, Non-Selective and Locked

9.1.3.4 X Running Tool

The X Running Tool is to enable the X lock to run selectively into the profile required.

The running tool has two positions which must be manually set at the surface:

- **Selective** - Used when setting in any profile except a top one or no-go (XN) profile.
- **Non-Selective** - Used when setting the lock in a top profile or no-go (XN) profile.

**Note**

When an XN is below several X profiles of the same size, it is advisable to run in SELECTIVE (to protect the top shear pin while jarring the packing through the profiles) and trip to NON-SELECTIVE in the last X profile above the XN.

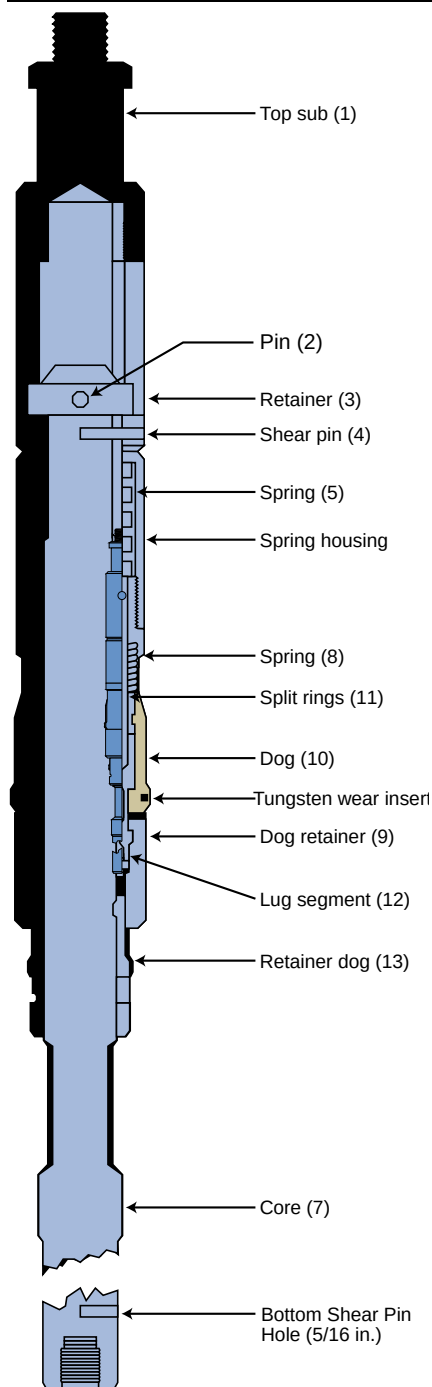


Figure 9-11: X Lock Running Tool

Selective Position

- Lock Mandrel
 - Keys are fully retracted with the running tool holding the lock fully extended.
- Running Tool
 - Nipple locator dogs OUT.
 - Lug segments LOCKING the core to the main mandrel.
 - No GAP between the fishing neck and spring housing.

Nonselective Position

- Lock Mandrel
 - Keys are SPRUNG forward to permit the 90° shoulder to locate in the nipple.
- Running Tool
 - Nipple locator dogs IN - now holding the inner mandrel in the up position.
 - Lug segments FREE to permit the core to move when the top pin shears.
 - GAP between the fishing neck and spring housing.

Checking the Running Tool

Prior to pinning to the lock, the running tool should be checked to ensure it trips freely from SELECTIVE to NON-SELECTIVE. Place the tool in NON-SELECTIVE (as it would be after pulling out of the hole), then:

Place the tool in the vice horizontally and grip GENTLY on the dog retainer. Using a square shank screwdriver (or other suitable tool) in the gap between the spring housing and fishing neck, increase the tension on the mainspring. At the same time, place the thumb and forefinger on the upper end of the nipple locator dogs, then squeeze inwards and upwards against the small spring. Release the screwdriver and the tool should spring into the SELECTIVE position. If not;

1. Check the nipple locator dogs were fully outwards when you released the tension.
2. Gently tap the spring housing in case the spring is binding inside the deformed housing. If too tight - replace prior to running.

Pinning Procedure

With the tool in selective, place the tool in a vice horizontally and grip GENTLY on the dog retainer. Push the nipple locator dogs up (towards the fishing neck). They should move inwards when at the upper end of travel, and return freely to the extended position. If they are not free, the spring is binding and the tool needs redressing.

Pull the fishing neck outwards against the spring tension. A bar or screwdriver can be placed through the slot above the core to provide handles to exert the necessary force.

The tool should trip into NON-SELECTIVE and remain in this position when the tension is released.

Check the running tool is in the NON-SELECTIVE position - otherwise the core will be locked.

1. Place the lock mandrel fishing neck in the vice firmly. Close the lock and insert the running tool. Push the core downwards and hold in place with the punch in the top shear pinhole. Extend the lock mandrel and move the running tool to line up the bottom shear pinhole. Pin with 5/16 in. brass.
2. Insert a $\frac{1}{4}$ in. steel pin in the top hole. Cross punch (through the center hole) and/or center punch the shear pins to ensure they do not drop out.
3. Check that the tool will trip from SELECTIVE to NON-SELECTIVE.
4. Check the lock mandrel key in:
 - SELECTIVE — Fully retracted
 - NON-SELECTIVE — Spring forward

Running Procedure (to SELECTIVELY set the X Lock)

1. Set the running tool in SELECTIVE.
2. Run into the well and JAR DOWN GENTLY to pass the packing through the upper nipple profiles.

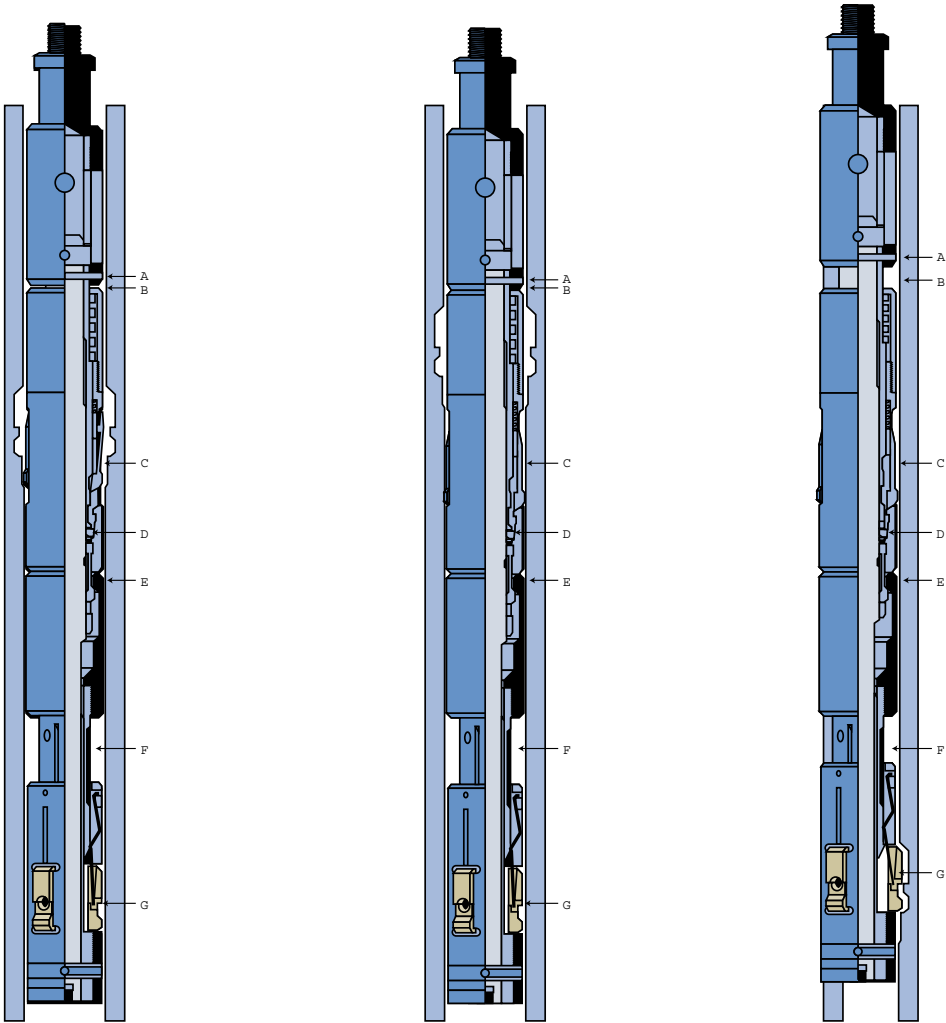


Note

In the SELECTIVE position, the lug segments are protecting the top shear pin.

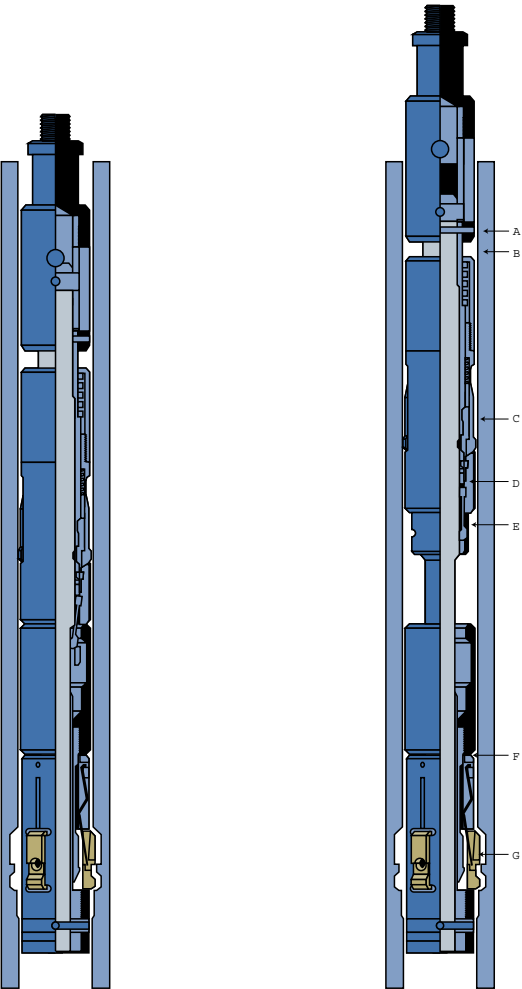
3. Pass through the nipple in which the lock is to be set - approximately 30 ft. The nipple locator dogs move up and inwards, then return to the selective position.

4. Take a pick-up weight reading and note the amount for later reference.
5. Pull up. The nipple locator dogs will not allow the tool to pass backup through the nipple.
6. Pull over the pick-up weight by approximately 200 to 400 lbf.
7. This will trip the running tool from SELECTIVE to NON-SELECTIVE.
Now the following points have occurred:
 - Lug segments retracted so the top shear pin unprotected.
 - There is a gap between the fishing neck and spring housing.
 - Nipple locator dogs retracted and holding the tool in NON-SELECTIVE.
 - Lock keys partially extended.
8. Lower down until the X keys locate the 90° shoulder in the nipple.
9. Jar down GENTLY to position the lock fully in the nipple.
10. JAR DOWN to shear the TOP pin. Provided the keys are fully locked in the nipple by the expander mandrel, the fishing neck retainer dogs will retract. This occurs when the expander mandrel has traveled a minimum of 80% of its full movement.
11. Pick-up approximately 100 kg over the pick-up weight. If the weight drops off, the lock was not fully set. Repeat from step 8.
12. If the lock is fully set, JAR UP to shear the BOTTOM pin and pull out of the hole
13. Run check set tool to confirm proper set.



A	Shear pin protected by lug segments		Shear pin unprotected	Pin sheared	
B	No gap.	No gap	Gap	Gap	Gap
C	Dogs moving up and in.	Dogs locating	Dogs holding inner mandrel in non-selective position		
D	Lug segments locking core to main mandrel		Lug segments release core by moving into recess in key retainer		
E	Retainer dogs hold fishing neck until core has moved 80% of full travel.			Released fishing neck - core fully moved	
F	Fully extended.		Partially compressed	Closed	Closed
G	Keys fully retracted		Sprung forward to locate	Locked	Locked

Figure 9-12: X Lock Running Sequence



A	Shear pin protected by lug segments		Shear pin unprotected	Pin sheared	
B	No gap.	No gap	Gap	Gap	Gap
C	Dogs moving up and in.	Dogs locating	Dogs holding inner mandrel in non-selective position		
D	Lug segments locking core to main mandrel		Lug segments release core by moving into recess in key retainer		
E	Retainer dogs hold fishing neck until core has moved 80% of full travel.			Released fishing neck - core fully moved	
F	Fully extended.		Partially compressed	Closed	Closed
G	Keys fully retracted		Sprung forward to locate	Locked	Locked

Figure 9-13: XN Lock Running Sequence

XN Lock

To run XN lock, run in NON-SELECTIVE as the XN lock WILL NOT pass the XN nipple to permit the running tool to trip.

XN Running Procedure

As for X, but omit steps 3, 5, 6 and 7.

Take the pick-up weight above the XN.



Note

If the XN is below several X nipple profiles, it is advisable to run in SELECTIVE to protect the top shear pin while jarring the packing through the nipple bores.

Trip to NON-SELECTIVE in the last X nipple above the XN.

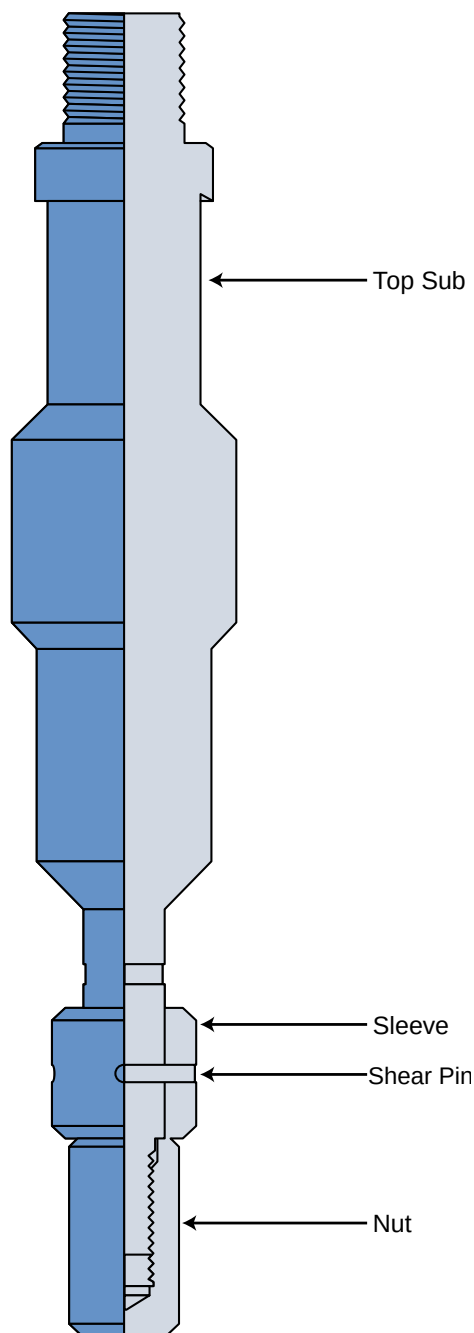


Figure 9-14: Check Set Tool Assembly

Disassembly

Ensure the tool is in the NON-SELECTIVE position, i.e., the core free to move.

1. Remove the locking pin and upper cross pin.

2. Withdraw the core.
3. Remove the fishing neck retainer dogs.
4. Hold the tool in the vice by the fishing neck - vertically.
5. Back off the key retainer housing from the mainspring housing. (The use of strap wrenches advisable to prevent deformation.)
6. Remove the key retainer housing, manipulating the dogs to permit removal.
7. Take care not to lose components, as there is a tendency for them to fly apart.
8. Remove the lug segments from the main mandrel slot.
9. Unscrew the main mandrel from the fishing neck.

**Note**

These are a matched pair - NOT INTERCHANGEABLE. If the tool is not going to be reassembled immediately, store these 2 components screwed together.

10. Remove the spring housing and mainspring.
11. Remove the dog spring by squeezing flat between 2 hacksaw blades and withdrawing through the slots in the retainer housing.
12. Check all parts for wear and grease slightly.

Assembly

1. Put the fishing neck in the vice - pin thread down.
2. Place the spring housing and mainspring on the fishing neck - Just sit them in position (thread upwards).
3. Insert the main mandrel and make-up - ensuring the milled slots are lined up. The mainspring is now compressed. The main mandrel and fishing neck are a matched pair and care must be taken to be certain they do not become mixed.
4. Insert two lug segments - 45° chamber up (i.e., towards the bottom of the tool).
5. Insert the spring into the dog retainer. Sandwich the spring between two hacksaw blades, insert through the slot, turn 90° and release the blades. Manipulate the spring into position and check that the ends of the springs are not crossed.

6. Slide the dog retainer housing over the main mandrel - thread downwards.
7. Insert the hacksaw blade through the slot in the dog retainer housing above the spring and right through the slots in the main mandrel.
8. Lift the housing to compress the spring against the hacksaw blade, and insert the file through the main mandrel to hold the housing up.
9. Insert one split ring in the lower inside of the dog retainer housing - Install with the slot towards the upper edge. (Grease on the back of the split ring will hold it in place).
10. Insert one nipple locator dog.
11. Insert the second split ring.
12. Insert the second dog - from inside at a steep angle to locate the fingers in the slots in the split rings.
13. Hold the dogs firmly while picking up gently on the dog retainer housing to remove the file from the slot.
14. Lower the complete assembly until the hacksaw blade is at the end of the slot. Remove the blade while gently supporting the dogs with the fingertips.
15. Turn the dog retainer housing 90° - to avoid the fishing neck retainer dog slots.
16. Manipulate the assembly gently down over the profiles on the main mandrel and thread into the spring housing.
17. Tighten the spring housing to the dog retainer. DO NOT OVERTIGHTEN as this can deform these thin section components.
18. Pull upwards to the dog retainer housing, and trip the tool into CONTROL.
19. Insert two fishing neck retainer dogs - using grease to hold in place.
20. Insert the core - which cannot be inserted if the tool is in the SELECTIVE position.
21. Install the cross pin.
22. Lift the core upwards and insert the locking pin through the hole in the fishing neck. BRAD both ends to ensure this pin will not fall out.
23. CHECK THE TOOLS OPERATION - i.e., Trip from NON-SELECTIVE to SELECTIVE and back to NON-SELECTIVE.

9.1.3.5 X and XN Lock Pulling Procedure



Note

The correct pulling tool is the model GR

1. Check the correct prong is attached to the GR core. The prong must match the plug and equalizing sub which is attached to the lock. (Check the shear pin in the GU adapter ONLY)
 2. Run into the well with the GR pulling tool. Reasons for using GR instead of GS include:
 - To enable downward jarring to loosen the lock.
 - To ensure we can shear off if the lock is full of sand.
-



Note

The GS core must be able to move down to shear. If the lock is packed with debris or sand, it will not be possible for the prong to reach the equalizing sub and bailing may be necessary.

3. Latch the lock fishing neck - wait for equalization if necessary.
4. Jar DOWN - to release the set on the keys.
5. Jar UP to expand the fishing neck and pull lock.
6. Pull out of the hole.

If the lock is extremely difficult to recover, consider the use of the GH pulling tool (hydrostatic version of the GS).

Table 9-3: Type X and R Otis Landing Nipple Specifications

Tubing Size				For Standard Tubing Weights (inches)				For Heavy Tubing Weights	
OD (in.)	Weight per foot	ID (in.)	Drift (in.)	X Nipple Bore		XN No-Go ID		‘R’ Packing Bore (in.)	‘RN No-Go ID (in.)
				Standard	Optional	Standard	Optional		
2.063	3.25	1.751	1.657	1.625		1.536			
	3.4	1.750	1.657						
2.375	4.6	1.995	1.901	1.875	1.905	1.791			
	4.7	1.995	1.901						
	5.3	1.939	1.845					1.781	1.640
	5.95	1.867	1.775					1.710	1.560
	6.2	1.853	1.759					1.500	1.345
	7.7	1.703	1.609						
	6.4	2.441	2.347	2.313	2.380	2.205			
	6.5	2.441	2.347						
2.875	7.9	2.323	2.229					2.188	2.010
	8.7	2.259	2.165					2.125	1.937
	8.9	2.243	2.149						
	9.5	2.195	2.101					2.000	1.881
	10.4	2.151	2.057						
	10.7	2.091	1.997					1.875	1.716
	11.0	2.065	1.971						
11.65	1.995	1.901							
3.500	9.3	2.992	2.867	2.813	2.875	2.635	2.760		
	10.3	2.922	2.797	2.750	2.813				
	12.8	2.764	2.639					2.562	2.329
	12.95	2.750	2.625					2.313	2.131
	15.8	2.548	2.423						
	16.7	2.480	2.355					2.188	2.010
17.05	2.440	2.315							
4.000	10.9	3.476	3.351	3.313		3.135			
	11.0	3.476	3.351						
	11.6	3.428	3.303					3.250	3.088
	13.4	3.340	3.215					3.125	2.907

Tubing Size				For Standard Tubing Weights (inches)				For Heavy Tubing Weights	
OD (in.)	Weight per foot	ID (in.)	Drift (in.)	X Nipple Bore		XN No-Go ID		'R' Packing Bore (in.)	'RN No-Go ID (in.)
				Standard	Optional	Standard	Optional		
4.500	12.75	3.958	3.833	3.813	3.725	3.813			
	13.5	3.920	3.795					3.688	3.456
	15.5	3.826	3.701						
	16.9	3.754	3.629					3.437	3.162
	19.2	3.640	3.515						
5.000	13.00	4.494	4.369	4.313				4.125	3.913
	15.00	4.408	4.283					4.125	3.912
	18.00	4.276	4.151					4.000	3.748
5.500	15.50	4.950	4.825	4.562		4.455		4.562	4.455
	17.00	4.892	4.767						
	23.00	4.670	4.545					4.313	3.987
7.000	17.32	-	-					5.962	5.750
¹⁻¹ The above dimensions apply to sliding side doors and other Otis equipment having integral landing nipple profiles.									

9.1.4 Type R and RN Lock Mandrels

The R/RN system was developed by Otis as high pressure version of the X/XN system. While actual pressure ratings vary with the lock diameter, the nominal rating on R/RN locks is 20,000 psi compared to the 10,000 psi rating on X or XN locks.

Check these pressure ratings with supplier for the sizes of locks and material type in use in your area.

The R/RN locks are of heavier construction with thicker wall sections. The OD is reduced which gives a considerable reduction in the ID. This is not of concern unless the well is to be flowed through the lock.

The key profiles have double 90° (R) and double 45° (RN) shoulders as shown below:

The key profile have double 90 (R) and double 45° (RN) shoulders as shown below:

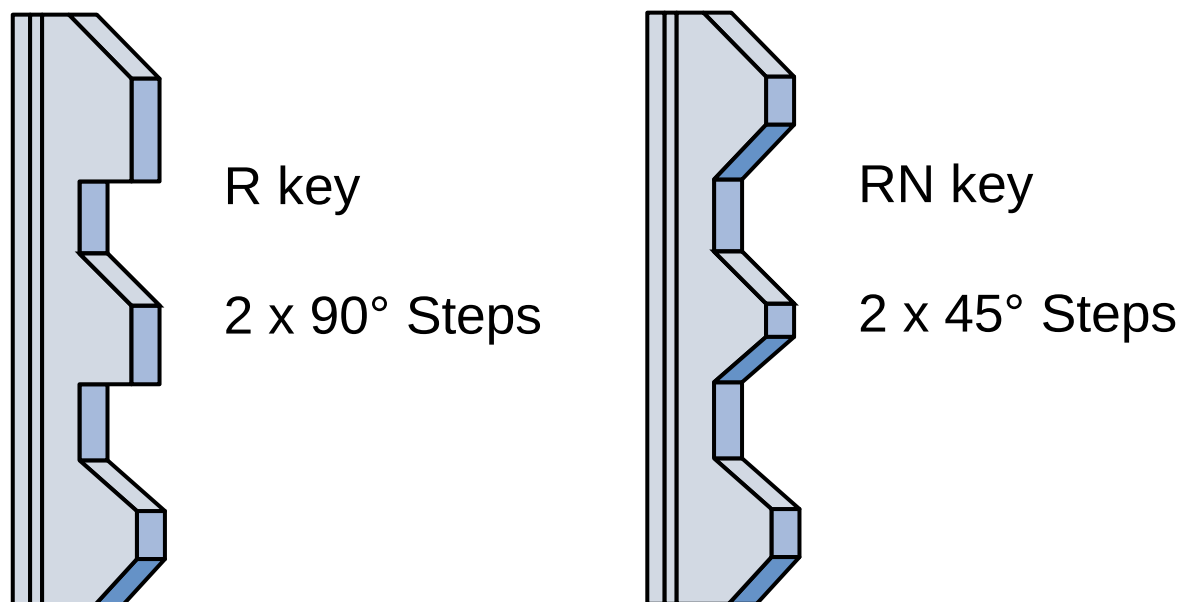


Figure 9-15: Type R and RN Key Profiles

Fishing neck IDs are the same for X/XN and R/RN equipment.

The running and pulling procedure and the redress, pinning and maintenance of R/RN items is the same as for the X/XN equipment.

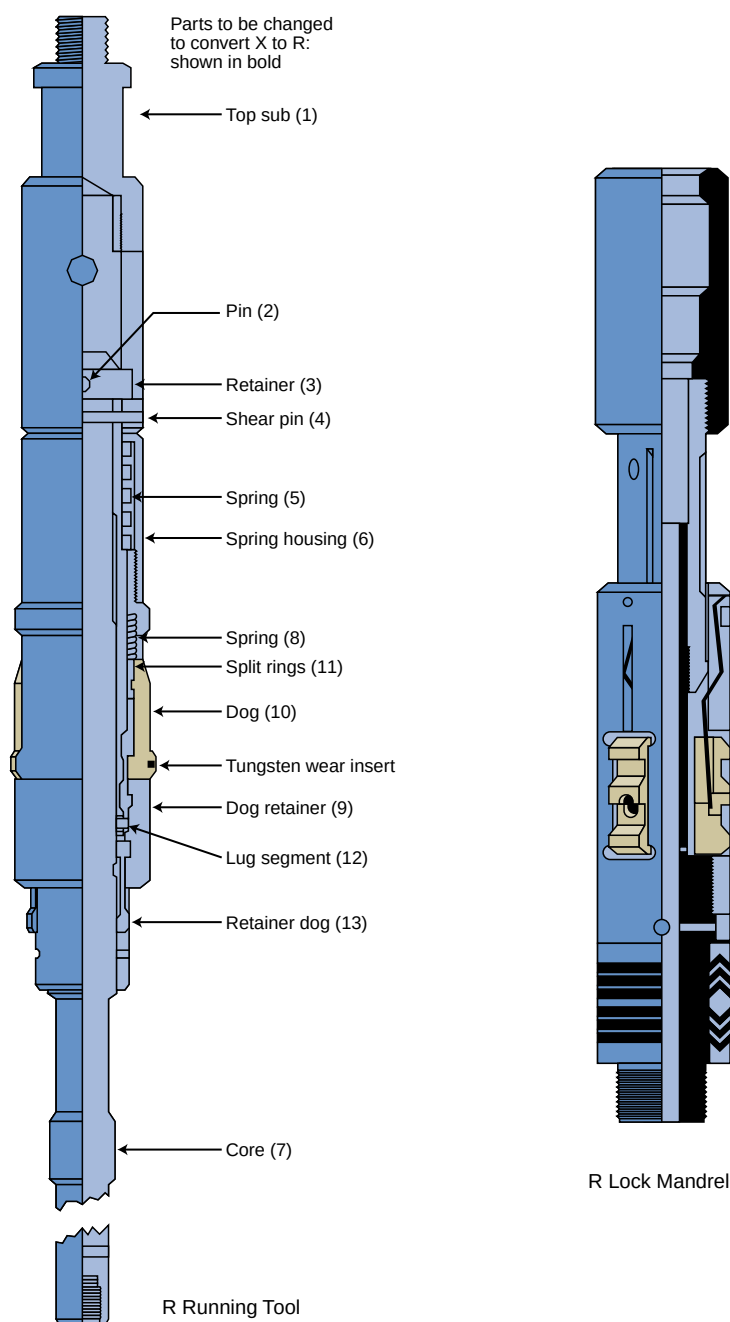


Figure 9-16: Type R Running Tool and Mandrel

9.2

Safety Set System

The running tool for the safety set lock mandrel is designed to minimize any operator guesswork at the surface, by requiring two independent conditions to occur in a specified sequence before the running tool will leave the lock and valve down hole. The safety valve must be pressured open in order for the running tool

to pull the locking sleeve upward. Then, only when the locking sleeve is locked into place, will the running tool release from the lock and valve. Should either of these two conditions not occur, the running tool would retrieve the lock and valve. A running tool retrieved to the surface without the lock and valve assures it to be functional and securely locked into the landing nipple. The running tool achieves this through simple reliable mechanical logic and without shear pins. The safety valve does not require a running prong when installed with the safety set locking system. The running tool core has an adjustable extension to serve this purpose and only requires a simple adjustment to run a variety of valves with no additional hardware.

9.2.1 □ **Design Features**

The running tool is attached to the lock and safety valve. The core of the running tool displaces the piston of the valve. The spring force from the displaced piston is transferred to the dog retainer through a pin, which ties the core and dog retainer together. The dog retainer is held in place by the retaining dogs engaged in the lock mandrel fish neck profile. The retaining dogs are maintained in the profile by the support of the lower setting sleeve.

The tool string is attached to the running tool through the top sub. The top sub is connected to the lower setting sleeve by a set of transfer lugs, which only lock the two together when the valve is pressured, open. This is accomplished by a receiving groove on the core located such, that when the core is in its uppermost position (no control line pressure) the lugs are free to move inward and do not lock the top sub to the lower setting sleeve. When the core moves down (valve pressured open) this receiving groove moves down from the lugs, locking them out. With this mechanism, the running tool does not attempt to expand or lock out the locking keys unless there is sufficient control line pressure on the safety valve.

Table 9-4: Safety Set Running Tool Principal Dimensions

Size (in.)	OD (in.)	Lock Fish Neck (in.)	Fish Neck on Tool (in.)	Length (in.)	Top Thread
4.000	3.780	3.120	2.313	35.500	1-1/16 - 10

1. Pump the valve open and visually check to ensure the valve is fully open. (Refer to the operating procedures for the valve for the correct opening pressures.)

2. Insert the running tool with all engagements retracted. Push the running tool into the lock until the retaining dogs are inside the fish neck and the top sub contact the top of the lock mandrel fish neck.

**Note**

If the running tool is installed into a locked lock mandrel, it will be necessary to insert the running tool into the lock until the retaining dogs are inside the fish neck. Attach a set of jars and 3 ft of stem to jar towards the lock, unlocking the lock mandrel.

3. With the running tool installed, hold the top sub down in contact with the lock mandrel fish neck and release the hydraulic pressure from the safety valve. The lock mandrel keys may try to expand as the valves closes against the running tool - this is normal. Pull the top sub of the running tool away from the lock mandrel to its full extension and push it back against the lock mandrel fish neck. The keys should retract and the top sub should now travel freely from the extended position to the fish neck, without expanding the keys. The top sub is lightly sprung loaded to the expender position and may or may not extend on its own in the horizontal position. It does not extend on its own in a vertical position.
4. Once proper installation is assured, vent the hydraulic pressure and remove all fittings from the safety valve. The running tool/lock/valve assembly is now ready to be attached to the toolstring.

9.2.2

Safety Set System Running Procedure

1. Run in the hole to the SSV landing nipple and jar down until the valve is against the no-go. Set the toolstring weight on the lock and valve.
2. Pressure up the control line to the proper pressure, opening the valve.
3. Once control line pressure is established, jar down once or twice to ensure contact with the no-go. Jar up until the running tool has released. Pull out of the hole.

**Note**

If for some reason the valve does not open when control line pressure is applied, the upward jarring will not set the lock and valve but extract it from the landing nipple. Check the weight indicator to verify the release.

4. Visually inspect the running tool for damage of any sort. If there should be any damage to the running tool, it would be unsafe to assume the valve is properly set and it should be pulled and reset.

5. The valve is now set and locked into place.

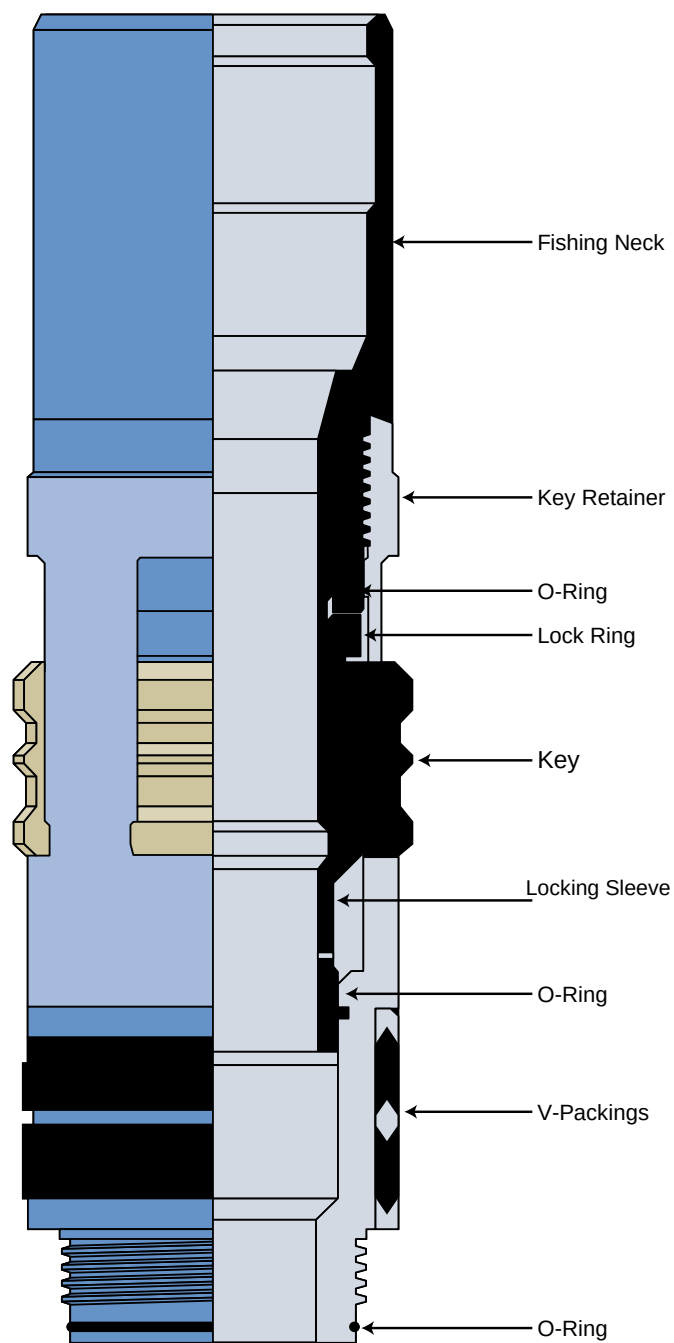


Figure 9-17: Safety Set Lock Assembly

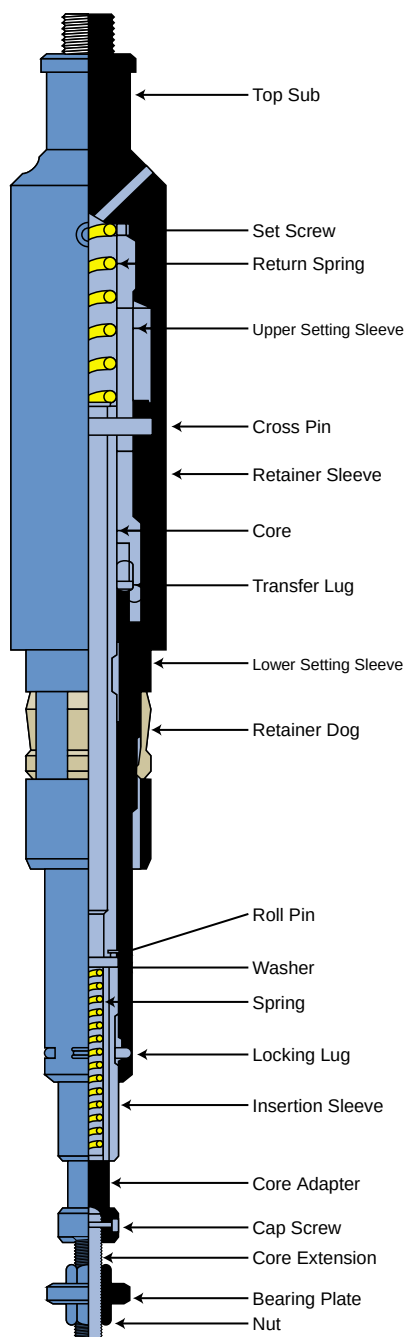
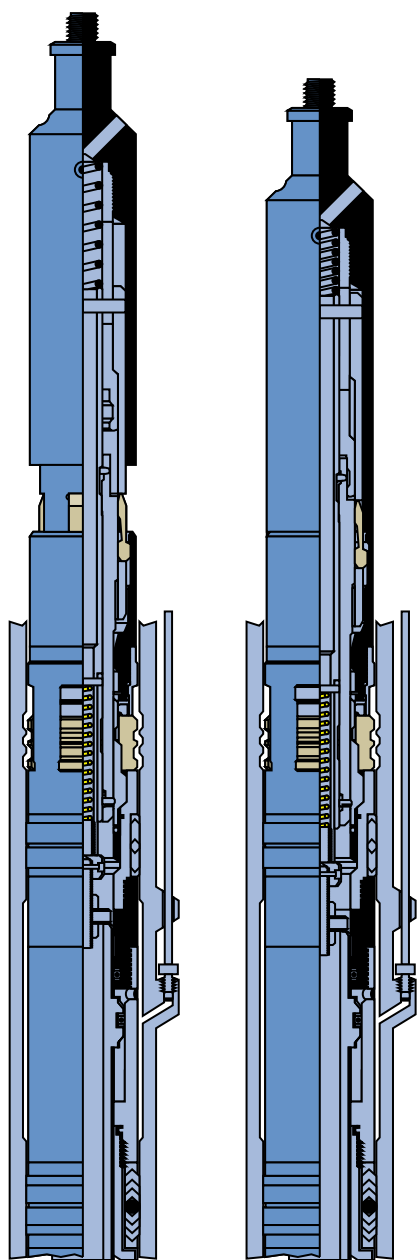


Figure 9-18: Safety Set Running Tool



1. Running Position

2. Locating

Figure 9-19: Safety Set Equipment-Running Sequence

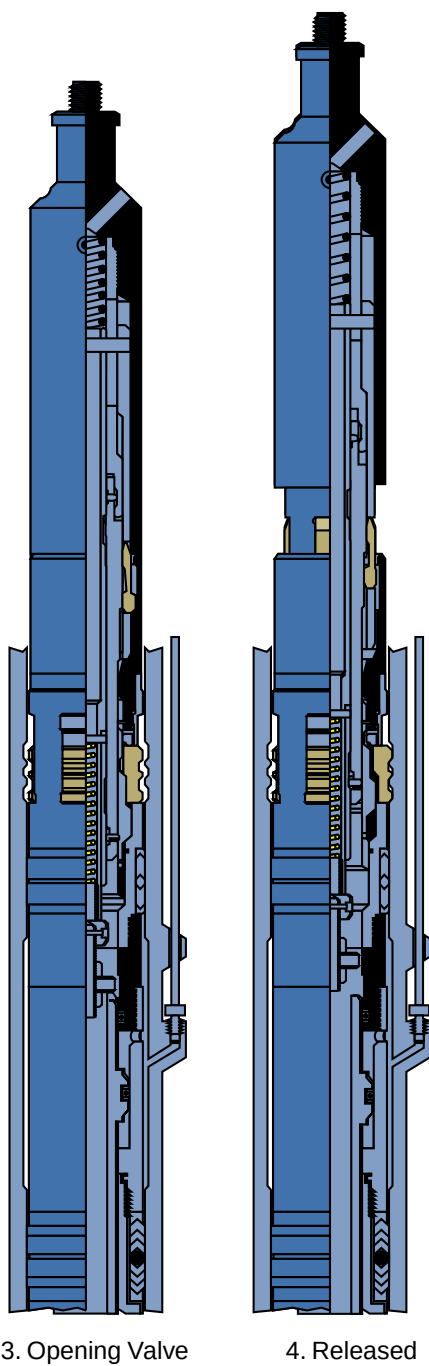


Figure 9-20: Safety Set Equipment-Running Sequence

9.2.2.1 Operating Sequence

Running Position

Keys of the lock are retracted and the sleeve is locked to the lock setting sleeve. The lower setting sleeve is free from the top sub and the lock fish neck is locked to the running tool through the retaining dogs.

Installing the Valve and Lock

The assembly is jarred down into the nipple by the top sub locating on the top of the lock fish neck.

Opening the Safety Valve

When the valve is opened, the core travels downward and locks the top sub to the lower setting sleeve.

Releasing from the Lock

Upward jarring pulls the lock setting sleeve up, locking the keys into the nipple. A snap ring holds the setting sleeve in this position. Simultaneously the retainer dogs in the lower setting sleeve are released from the lock setting sleeve and the retaining dogs from the lock fish neck, then the running tool is free from the lock mandrel.

9.2.2.2 Attaching the SS Running Tool

1. Place the safety valve assembly into a vise and attach any fittings necessary to operate it with a hand pump or other hydraulic pump.

2. Remove the adjustable core extension from the running tool. Back the socket head cap screw out with a hex wrench just until the core extension can be removed. It is not necessary to completely remove the screw. Loosen the jar nuts. With the safety valve pressured open (refer to the operating procedures for the valve for the correct opening pressures), insert the core extension into the up end bore of the valve. Adjust the all-thread such that the upper end is flush with the very top of the safety valve housing. This adjustment maximizes bypass flow.

**Note**

Adjustments with the all-thread below flush will provide fewer bypasses, while adjustments above flush will not allow the running tool to release. This adjustment must be done with the safety valve pressured fully open. Return the jam nuts against the bearing disc and tighten. Check the adjustment after the jam nuts are tightened to ensure the adjustment is correct. The adjustable extension replaces what would normally be considered a running prong.

3. Reinstall the core extensions on the running tool and tighten the cap screw. The extension should be free to rotate, but retained by the screw.
4. Make up the lock mandrel to the safety valve. The lock mandrel may be either locked or unlocked.
5. Prepare the running tool for insertion. Stand the running tool on the top sub inverted, core extension up. Push the core down and then pull it up. The lower setting sleeve should drop freely. The retaining dogs and locking lugs should be free to retract.

Running Tool Disassembly

1. Clamp the running tool in a vice at the top sub and remove the set-screw in the top sub.
2. Attach a strap wrench just below the retainer dogs, taking care not to damage the retainer sleeve and remove this assembly from top sub. Remove the return spring.
3. Place this subassembly into the vice and drive the cross pin out.
4. Stand this subassembly (core extension up) on a work surface and pull the core up and out by the core extension. This will reduce the chance of dropping out the locking lugs and transfer lugs.

5. Remove the locking lugs. Invert the remaining subassembly and pull up and off with the retainer sleeve.

**Caution**

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

The retaining dogs will drop out at this point.

6. Pull the upper setting sleeve up and off the lower setting sleeve and remove the transfer lugs from the lower setting sleeve.
7. The core is disassembled by removing the core adaptor, then the spring and washer. Drive the roll pin out and remove the inserting sleeve.
8. Remove the cap screw, core extension, nuts and bearing plate from the core adaptor.

Running Tool Assembly

1. Clean all parts in a suitable solvent and examine for damage or wear.
2. Slide the insertion sleeve onto the lower end of the core with the roll pin hole towards the upper end of the core. Align the hole in the insertion sleeve with the slot in the core and drive through the roll pin. File the roll pin flush with the insertion sleeve is necessary. Install the washer, spring and core adaptor. Ensure that the insertion sleeve returns freely on the core.
3. Stand the retainer sleeve, upper end down, on a work surface and insert the retainer dogs from the inside into the windows. The thick end of the dogs will be upwards at this point.
4. Insert the upper setting sleeve into the retainer sleeve, thread end down and set this subassembly aside in this position.
5. Install the transfer lugs into the lower setting sleeve. Apply a moderate amount of grease to hold them place. Position the lugs such that the retainer lip is towards the lower end of the sleeve.
6. Install the locking lugs and apply a moderate amount of grease to hold them in place. Orientate the lugs with the retaining lip towards the upper end of the lower setting sleeve.
7. Insert the lower setting sleeve and transfer the lugs downward into the retainer sleeve subassembly, as it was from step 4.
8. Insert the core, lower end up, into the subassembly from step 7.

9. Align the hole in the retainer sleeve with the slot in the upper setting sleeve and the hole in the core. Press the cross pin into place. Ensure the upper and lower setting sleeves have free movement.
10. Stand the subassembly up on the lower end of the core; insert the return spring and makeup the top sub onto the upper setting sleeve. This need only be moderately tight as it is locked down by the set screw. Reinstall the set screw with a non-permanent thread lock compound.
11. The assembly is now complete. Check that the lower setting sleeve is free to move, and that the locking lugs can be retracted in the insert position. Check for proper operation by preparing the running tool for installation. This is accomplished by standing the tool up, top sub down and pushing the core down as far as it will go, then pulling it up to full travel. The engagements (retainer dogs and locking lugs) should now be free to retract.

9.2.2.3

Safety Set Pulling

The safety set system utilizes a combination of tools to retrieve the safety set lock mandrel and valve assembly.

This combination consists of:

- Pulling prong
- Unlocking tool
- GR pulling tool

The universal pulling prong provides flexibility to the system by having one extra long prong, made from a thermoplastic material, to prevent damage to critical valve components in order to accommodate a wide range of valves.

Retrieval of the lock and safety valve requires the use of an unlocking tool between the pulling tool and prong. The unlocking tool has spring based engaging lugs free to retract, until encountering the face of the locking sleeve of the lock mandrel. Downward jarring overrides the lock ring, allowing downward relative movement to the locking sleeve of the lock mandrel. The unlocking tool is designed so as to not allow the pulling tool to engage the lock mandrel fish neck until the locking sleeve is unlocked.

An upward shearing type GR pulling tool is required for proper operation. Should a conventional down shear type GS pulling tool be used, the unlocking tool will not allow the pulling tool to move down far enough to shear on the skirt. For this reason, a GR is essential. (See the section on GR pulling tool).

Pulling Procedure

1. Attach the specified unlocking tool and pulling prong to the appropriate GR type-pulling tool. Once assembled, check the unlocking tool to ensure the unlocking lugs are free to move inward (retracted). The assembly is now ready to attach to the tool string.
2. Ensure by whatever means available, that the valve is equalized. Control line pressure alone will not assure the valve is open and equalized. The pulling prong may have to be omitted to pull an equalized SSSV with an inoperative ball mechanism.



Caution

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

Without a pulling prong, there is no mechanical safeguard against the possibility of pulling a safety valve that has not equalized.

3. Jar down two to five times or until the pulling tool latches the lock fish neck. This is verified by a bind on the line. The pulling tool will only latch the fish neck when the lock mandrel is unlocked.
4. Once the pulling tool has latched, the valve can be pulled by upward jar action. Since the GR is a shear up tool, apply small or moderate jar strokes followed by an occasional bind on the line. Monitor the tool weight to indicate if the valve has been retrieved. Pull out of the hole.



Note

If the GR type-pulling tool continuously shears off due to an extremely tight valve, a GS type tool can be used only if the unlocking tool is not used. Keep in mind that once the GR tool with the unlocking tool has latched the lock mandrel, it will be unlocked. If the GR shears off, the lock mandrel / valve is not relocked.



Caution

Potential Severity: Light
 Potential Loss: Assets
 Hazard Category: machinery equipment hand tools

DO NOT attempt to pull the valve using a GS with the unlocking tool attached. The unlocking tool would not permit the GS to shear off.

Table 9-5: Otis Type SS Unlocking Tool Principal Dimensions

Type	Size (in.)	Length (in.)	Top Connection	Bottom Connection	Will Engage Lock ID	Used in Conjunction with
SS	4.000	13.750	2 $\frac{1}{8}$ - 12 UN	2 $\frac{1}{8}$ - 12 UN	2.20040	GR 36800

Unlocking Tool Disassembly Procedure

1. Clamp the unlocking tool in a vice at the housing between the unlocking lugs and spring holes.
2. Remove the core, springs and lugs from the housing.

Unlocking Tool Assembly Procedure

1. Clean all parts in suitable solvent. Examine each for damage or wear.
2. Set the housing horizontal on a flat work surface. Using a moderate amount of grease on the lugs and a long blade screwdriver, install the lugs from the down end of the housing ID. The large chamber on the lug should be towards the up of the housing.
3. Stand the housing, bottom end up, on the work surface. Install the springs from the ID of the housing, making sure the straight end of the spring is in the notch in the lug and the hook is in the hole in the housing.
4. Coat the pin thread, adjacent surface and taper of the core with a good quality anti-seize compound. Push the core into the housing as prepared from step 3. Do not turn the core until it loads up in the springs. Push or tap the core in until the thread connection can be made up. Clamp the housing in a vice and make the connection up tight.

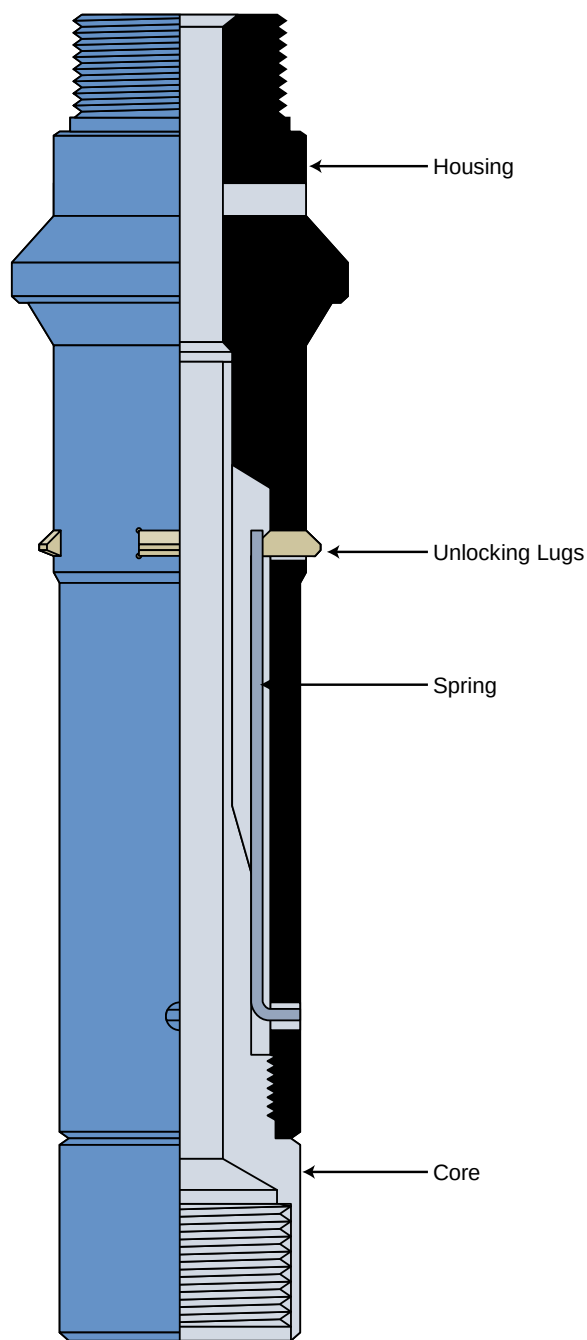


Figure 9-21: Safety Set Unlocking Tool

Pulling Prong Disassembly Procedure

1. Place the pulling prong in a vice. Grip on the adaptor.
2. Drive the pin out of the adaptor and prong.

3. Remove the prong from the adaptor.

Releasing Procedure

To release on the surface:

1. Place a pin punch or rod of the appropriate size through size through the J slot and into the hole of the collet.
2. Retract the collet upwards against the collet spring.
3. Lock the punch or rod into the J of the slot in the collet housing.
4. Slide the pulling tool from the fishing neck.

9.3 Plugs

The previous section dealt with lock mandrels, which are a method of attaching a flow control device to the inside of the tubing. This flow control device could be:

- Plug, e.g., type D plug
- Safety valve, e.g., type DK
- Separation tool
- Test tool, e.g., modified type P
- Amerada gauges, etc.

Plugs are divided into 3 categories:

- Hold pressure from below (e.g., D) - To fit on W slip locks or D collar locks
- Hold pressure both ways (e.g., XX/PX) - To fit on X/XN locks
- Hold pressure from above only (e.g., N test tool) - To pressure test tubing, set hydraulic packers etc.

In the Otis system, the letter (e.g., D) describing the plug is followed by the letter (e.g., W) describing the lock mandrel.

Example

DW	D plug on a W lock
XX	X equalizing sub on an X lock
PXN	P plug on an XN lock

9.3.1 Equalizing Device

Whenever a plug is installed a well, an equalizing device is required to equalize the pressure above and below the lock to enable retrieval.

This equalization must occur FULLY BEFORE UNLOCKING THE LOCK MANDREL.

Failure to equalize correctly is caused by any of the following errors:

- No equalizing prong
- Wrong equalizing prong
- Equalizing prong too short
- Insufficient time allowed for equalization
- Blocked equalizing ports

Each of these conditions could cause the following complications:

- High pressure below the lock
 - Tools could be blown up the hole
 - Lock could be difficult to unlock or release
- High pressure above the lock
 - Lock could be difficult to unlock or release



Note

CORRECT EQUALIZATION IS ESSENTIAL - Always observe surface pressures.

Any plug selection process should consider the following four factors.

9.3.1.1 Direction of the Pressure Differential

The plug selected must be capable of holding a pressure differential from that direction. A plug that holds a differential from the top only or a plug that holds a differential from both directions would not be differential from both directions would not be used with a slip type lock mandrel, since the slip type lock mandrels CANNOT support a differential from the top.

9.3.1.2 The Differential Pressure (psi)

Generally the working pressure of a plug is determined by the working pressure of the lock mandrel to which it is attached. Obviously then, in a plugging situation, the amount of differential to be held would determine the type lock mandrel to be used. As stated, the plug assembly usually assumes the working pressure of the lock mandrel used.

9.3.1.3 Depth at which the Plug is to be Installed

If a plug is to be set at an extreme depth and the tubing pressure above the plug is to be bled off (released), consideration must be given to the amount of pressure in the casing at the depth the plug is set. If the pressure differential from the casing exceeds the collapse resistance of the tubing, then the tubing is likely to collapse immediately above the plug. This type situation must be avoided. Abnormally high temperatures associated with extreme depth could also affect the type plug and/or lock mandrel to be used.

9.3.1.4 Well Conditions

The term well conditions could imply many things such as crooked tubing - deviated hole, restricted ID, scale build up on tubing wall, mud, sand laden fluid, etc. From a plugging standpoint we must consider all of these things in selecting the best plug assembly to accomplish the job.

For example, if the plug is set and the fluid in the tubing above the plug contains sand, the sand is quite likely to settle out of the fluid and fill the bore of the lock mandrel and equalizing sub as well as a portion of the tubing immediately above the plug assembly. This would prevent the pulling tool from reaching the plug when we attempt to retrieve it. The sand can usually be bailed or washed out of the tubing down to the top of the lock mandrel. But, depending upon the size and type of the lock mandrel, the sand which is inside the bore of the lock mandrel and equalizing valve may be difficult or impossible to remove. If this situation exists, the equalizing prong could not reach the equalizing valve and therefore the differential across the assembly could not be retrieved by conventional methods.

9.3.2 D Plug

The D plug is designed to hold pressure from BELOW only.

The plug assembly consists of three primary components:

- D equalizing sub
- Plug bean
- Bean cage

It can be used below the W slip lock and D collar lock.

The Hycar rubber element ensures a seal at relatively low pressure, while the metal-to-metal seat seals at high pressures. The pressure rating of any plug is determined by the lock mandrel on which it is run.

DW plug - Maximum nominal differential 1500 psi

DD plug - Maximum nominal differential 5000 psi



Note

Always check the manufacturers specifications for the type and model of plug to be used - the specifications vary with size.

A running prong is not required when running plugs on slip collar locks. As the element is not expanded until the lock is set, there is sufficient fluid bypass around the outside of the lock.

Fluid bypass effect is critical on nipple locks where the V-packing seal on each nipple bore as the plug is lowered down the well. Due to the fact that fluid is incompressible, an alternate bypass must be provided by holding the equalizing device off the seat while running.



Caution

Potential Severity:	Light
Potential Loss:	Assets
Hazard Category:	human

The slickline operator must observe any pressure changes on the lubricator gauge and before jarring up.

WAIT UNTIL FULL EQUALIZATION HAS OCCURRED.

If there is doubt that the equalizing device is functioning, pressure should be applied above the plug is pressure below is known. DO NOT OVERPRESSURE unless the plug is of a check valve type.

Tubing can also be completely filled with fluid to reduce chances of being blown up the hole.

There is no fixed rule to accurately determine the time required to equalize, as there are many variable to be considered. Where a plug has been used in these examples it could also be an SSV, SPM etc.

These variables are:

- Amount of pressure differential across the plug.
- Tubing size. (A larger bore has a larger volume to equalize.)
- Depth to the plug. (Increased depth increases the volume to the surface.)
- Port sizes in the equalizing device.
- Fluid viscosity.

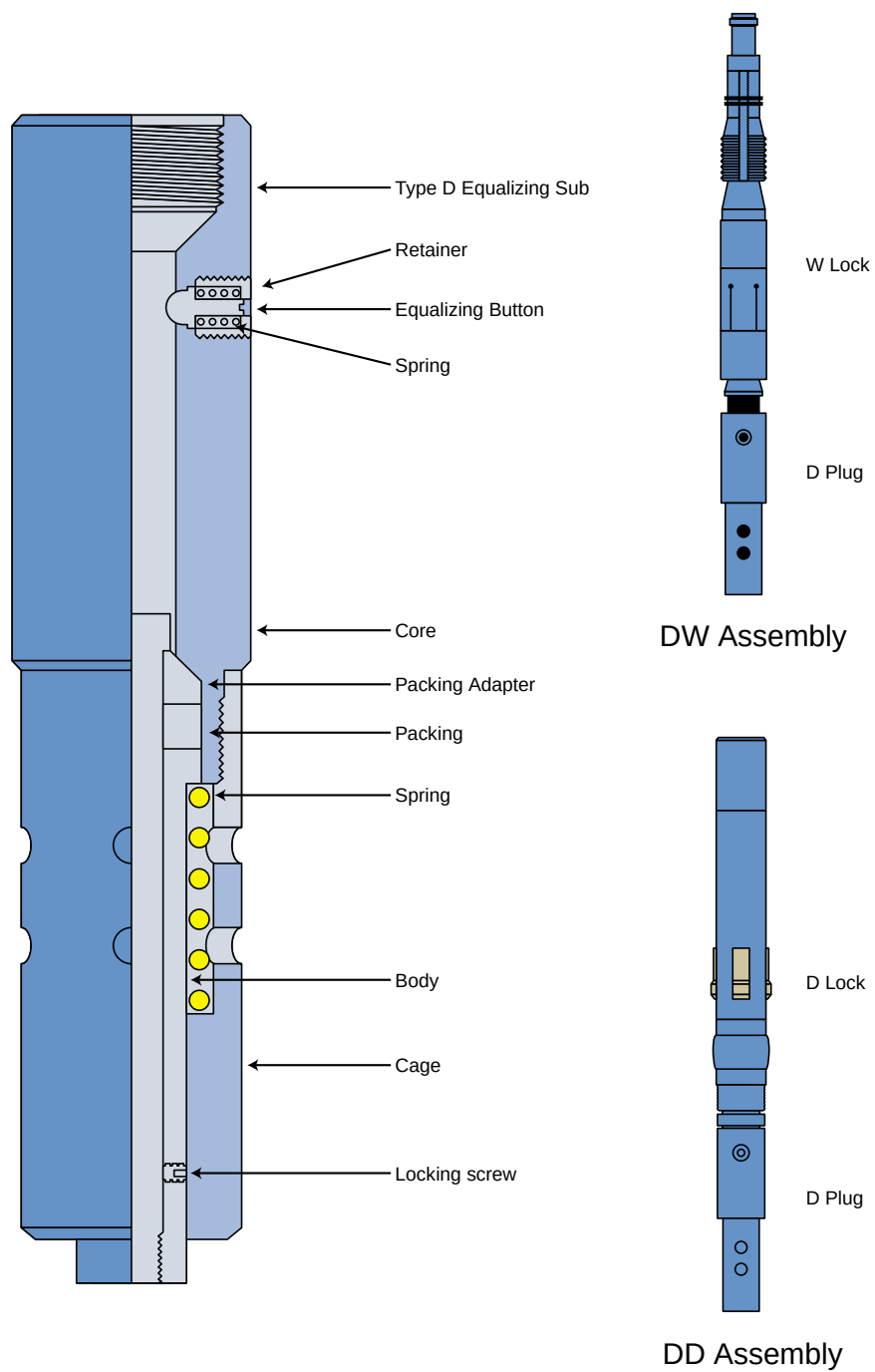


Figure 9-22: Type D Plug Assembly

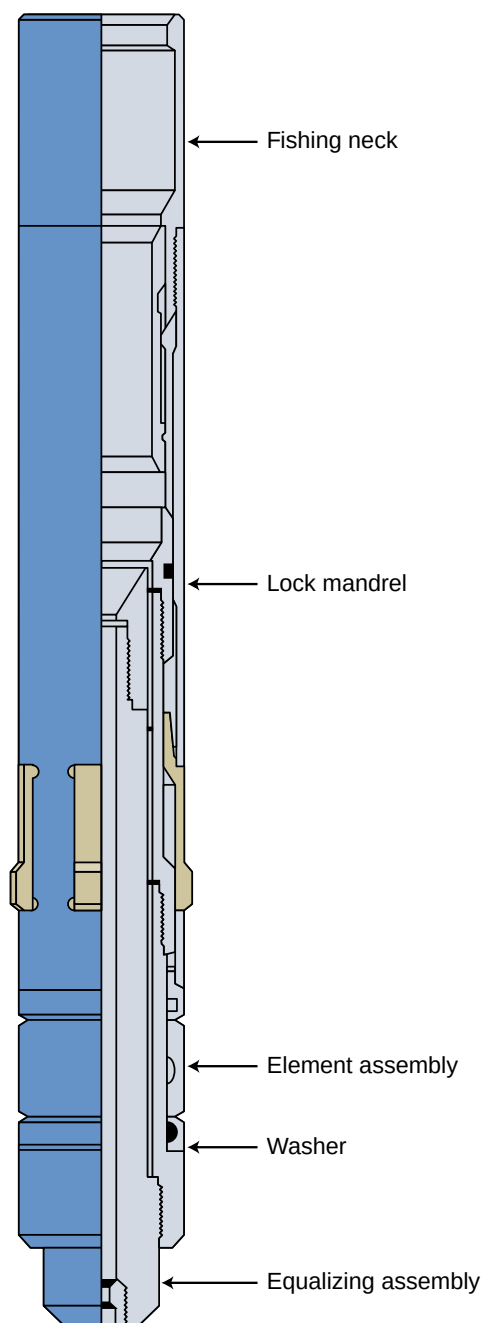


Figure 9-23: Type DD Bridge Plug

Table 9-6: Type DD Bridge Plug Specifications (a)

ASSEMBLY NUMBER			321DD3	321DD4	321DD6
NOMINAL SIZE			2 in.	2 in.	2 in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.
1	Fish Neck	1	310D26	310D27	310D48
2	Lock Mandrel	1	3100016	3100017	310D026
3	Element Assembly	1	310D045	3100044	310D046
4	Equalizing Assembly	1	321D03	321D04	321007
5	Washer	-	410W199	410W199	410W199
DATA AND CRITICAL DIMENSIONS					
Material			Stainless	Monel	Aluminum
Max. Expanded OD			2.12	2.12	2.12
Max. OD			1.84	1.84	1.84
Min. I. D. of Collar Lock			.94	.94	.94
Element			1.84	1.64	1.84
Thread Connection			1-5/16 - 18	1-5/16 - 18	1-5/16 - 18
Fishing Neck ID			1.36	1.38	1.38
Washer Size			1.75 x 1.34 x 0.030	1.75 x 1.34 x 0.030	1.75 x 1.34 x 0.030
ASSEMBLY NUMBER			321008	3210D1	321DD2
NOMINAL SIZE			2 in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.
1	Fish Neck	1	310D83	310D1	31008
2	Lock Mandrel	1	310D037	310D018	3100019
3	Element Assembly	1	310D047	3100052	3100051
4	Equalizing Assembly	1	321D011	321D01	321002
5	Washer	*	410W199	410W200	410W200
DATA AND CRITICAL DIMENSIONS:					
Material			4130	Stainless	Ductile
Max. Expanded OD			2.12	2.56	2.56
Max. OD			1.84	2.28	2.28
Min. ID of Collar Lock			0.94	1.38	1.38
Element			1.84	2.28	2.28
Thread Connection			1-5/16 - 18	1-22/32 - 14	1-21/32 - 14

ASSEMBLY NUMBER			321DD3	321DD4	321DD6
NOMINAL SIZE			2 in.	2 in.	2 in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.
	Fishing Neck ID		1.1.38	1.81	1.81
	Washer Size		1.75 x 1.34 x 0.030	2.19 x 1.78 x 0.030	2.19 x 1.78 x 0.030

Table 9-7: Type DD Bridge Plug Specifications (b)

ASSEMBLY NUMBER			321DD5	321DD7	321DD9
NOMINAL SIZE			2½ in.	2½ in.	2½ in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.
1	Fish Neck	1	310D32	310D56	310D75
2	Lock Mandrel	1	310D020	310D029	310D030
3	Element Assembly	1	310D050	310D053	310D049
4	Equalizing Assembly	1	321D05	321D08	321D010
5	Washer	1	410W200	410W200	410W200
DATA AND CRITICAL DIMENSIONS					
Material			Aluminum	4140 Norm.	4130
Max. Expanded OD			2.54	2.58	2.56
Max. OD			2.28	2.28	2.28
Min. ID of Collar Lock			1.38	1.38	1.38
Element			2.28	2.28	2.28
Thread Connection			1-21/32 - 14	1-21/32 - 14	1-21/32 - 14
Fishing Neck ID			1.81	1.81	1.81
Washer Size			2.19 x 1.78 x 0.0301	2.19 x 1.78 x 0.0301	2.19 x 1.78 x 0.030
ASSEMBLY NUMBER			321DD11		
NOMINAL SIZE			3 in.		
DET.	PART NAME	QTY	PART NO.		
1	Fish Neck	1	310D125		
2	Lock Mandrel	1	310D058		
3	Element Assembly	1	310D067		
4	Equalizing Assembly	1	321.D012		
5	Washer	*	410W201		
DATA AND CRITICAL DIMENSIONS					
Material			Alloy		

ASSEMBLY NUMBER			321DD5	321DD7	321DD9
NOMINAL SIZE			2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.
Max. Expanded OD			3.10		
Max. OD			2.84		
Min. I.D.of Collar Lock			2.18		
Element			2.84		
Thread Connection			2 $\frac{1}{8}$ -12		
Fishing Neck ID			2.31		
Washer Size			2.75 x 2.24 x 0.030		

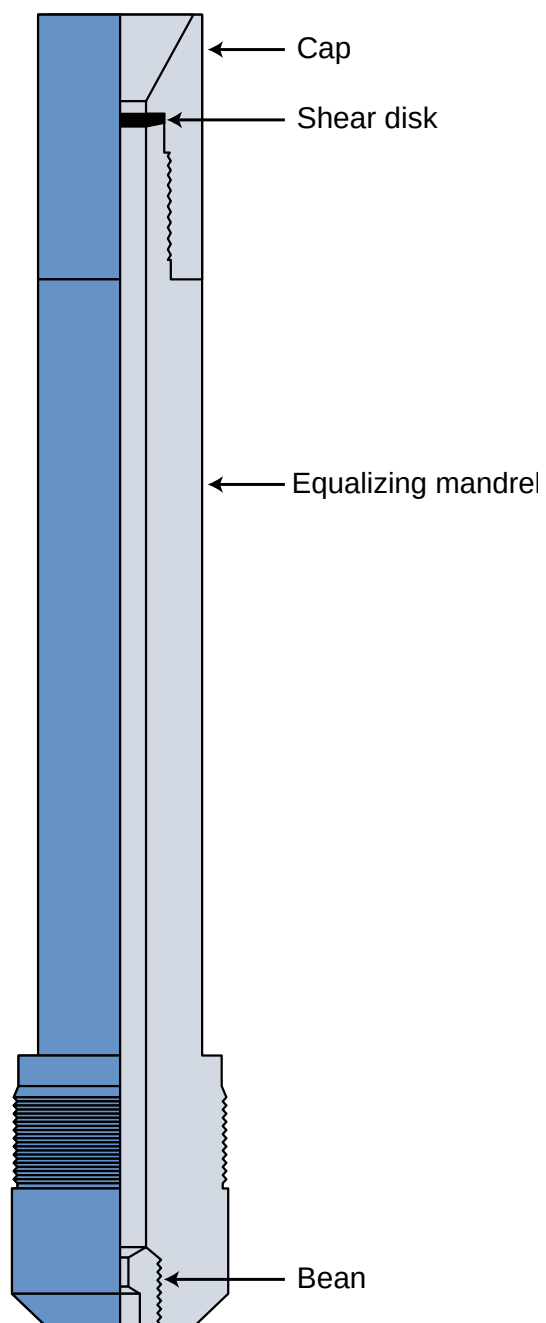


Figure 9-24: Type D Equalizing Assembly

Table 9-8: Type D Equalizing Assembly Specifications

ASSEMBLY NUMBER			321D06	321D09	321D05	321D011
NOMINAL SIZE			2 in.	2 in.	2 in.	2 in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.	PART NO.
A	Cap	1	321D5	321D6	321D13	321D19
B	Shear Disk	1	21G5	21G5	2105	21G5
C	Equalizing Mand.	1	321D7	321DB	321D14	321D20
D	Bean	1	21G6	21G6	21G6	2106
DATA AND CRITICAL DIMENSIONS:						
Material			Stainless	Monel	Aluminum	4130
Thread Connection			1-5/16 - 18	1-5/16 - 18	1-5/16 - 18	1-5/16 - 18

Table 9-9: Type D Equalizing Assembly Specifications

ASSEMBLY NUMBER			321D03	321D04	321D07	321D011
NOMINAL SIZE			2 in.	2 in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.	PART NO.
A	Cap	1	321D11	321D17	321D9	321D15
B	Shear Disk	1	2105	21G5	21G5	21011
C	Equalizing Mand.	1	321D12	321D18	321Db	321D16
D	Bean	1	2106	2106	2106	21G6
DATA AND CRITICAL DIMENSIONS:						
Material			Ductile	Norm. Alloy	Aluminum	Norm. Alloy
Thread Connection			1-5/16 - 18	1-5/16 - 18	1-21/32 - 14	1-21/32 - 14
ASSEMBLY NUMBER			321D010	321D01	321D02	321D012
NOMINAL SIZE			2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.	3 in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.	PART NO.
A	Cap	1	321D21	321D1	321D2	321D23
B	Shear Disk	1	21G5	2105	2105	2105
C	Equalizing Mand.	1	321D22	321.D3	321D4	321D24
D	Bean	1	21G6	2106	2106	2106
DATA AND CRITICAL DIMENSIONS:						
Material			4130	Stainless	Ductile	Stainless
Thread Connection			1-21/32 - 14	1-21/32 - 14	1-21/32 - 14	2 $\frac{1}{8}$ - 12

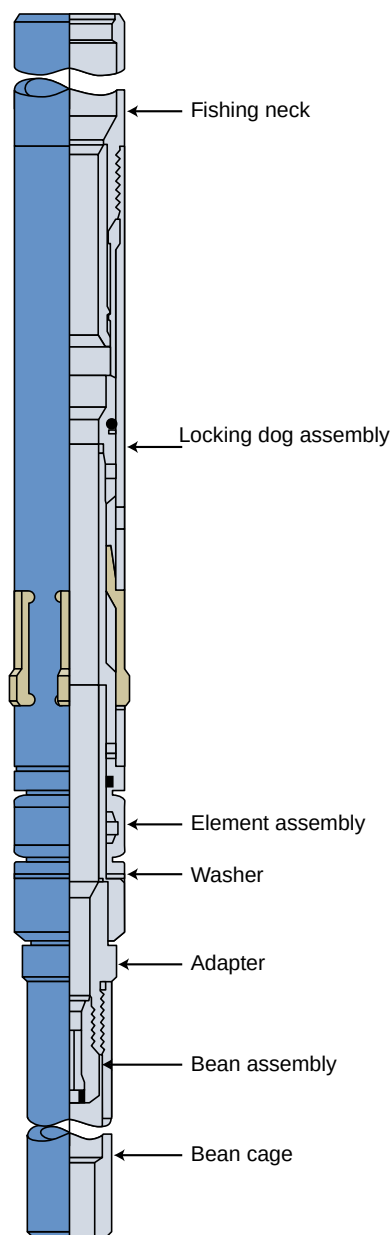


Figure 9-25: Type BD Collar Lock Choke Assembly

Table 9-10: Type BD Collar Lock Assembly Specifications

ASSEMBLY NUMBER			321BD1		321BD2	321BD6
NOMINAL SIZE			2 in.		2 in.	2 in.
DET.	PART NAME	QTY	PART NO.		PART NO.	PART NO.
1	Flab Neck	1	310D26		310D27	310D83
2	Locking Dog Ass'y.	1	310DO16		310DO17	310DO37
3	Element Ass'y.	1	310D045		310D044	310DO47
4	Adapter	1	310D30		310D31	310DO74
5	Bean Ass'y.	1	21B04		21B05	21B04'
6	Bean Cage	1	21B1		21B1	21B1
7	Washer	**	410W199		410W199	410W199
DATA AND CRITICAL DIMENSIONS:						
Material			Stainless		Monel	Alloy
Dia. X (Element Expanded)			2 $\frac{1}{8}$ "*1/32		2 $\frac{1}{8}$ "*1/32	2 $\frac{1}{8}$ "*1/32
Pulling Tool			40GRI		400R1	40GRI
Running Tool			411DO4		411DO4	411DO4
Fish Neck ID			1.38		1.38	1.38
OD			1.84		1.84	1.84
Washer Size			1.75 x 1.34 x 0.030		1.75 x 1.43 x 0.030	1.75 x 1.43 x 0.030
ASSEMBLY NUMBER			321BD3	321BD4	321BD5	321BD7
NOMINAL SIZE			2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.	2 $\frac{1}{2}$ in.
DET.	PART NAME	QTY	PART NO.	PART NO.	PART NO.	PART NO.
1	Fish Neck	1	310D1	310D8	310D32	310D73
2	Locking Dog Ass'y.	1	310DO18	310DO19	310DO20	310DO30
3	Element Ass'y.	1	310DO52	310DO51	310DO50	310DO49
4	Adapter	1	310D28	310D29	310D39	310D80
5	Bean Ass'y.	1	21B06	21B07	21B08	21B06
6	Bean Cage	1	21B2	21B36	21B47	21B2
7	Washer	**	410W200	410W200	410W200	410W200
DATA AND CRITICAL DIMENSIONS:						
Material			Stainless	Ductile	Aluminum	Alloy

ASSEMBLY NUMBER			321BD1	321BD2	321BD6
NOMINAL SIZE			2 in.	2 in.	2 in.
DET.	PART NAME	QTY	PART NO.		PART NO.
	Dia. X (Element Expanded)		2 $\frac{1}{32}$ - 1/32	2 $\frac{1}{32}$ - 1/32	2 $\frac{1}{32}$ - 1/32
	Pulling Tool		400R4	400R4	40GR4
	Running Tool		41DO5	41DO5	41DO5
	Fish Neck ID		1.81	1.81	1.81
	OD		2.28	2.28	2.28
	Washer Size		2.19 x 1.78 x 0.030	2.19 x 1.78 x 0.030	2.19 x 1.78 x 0.030

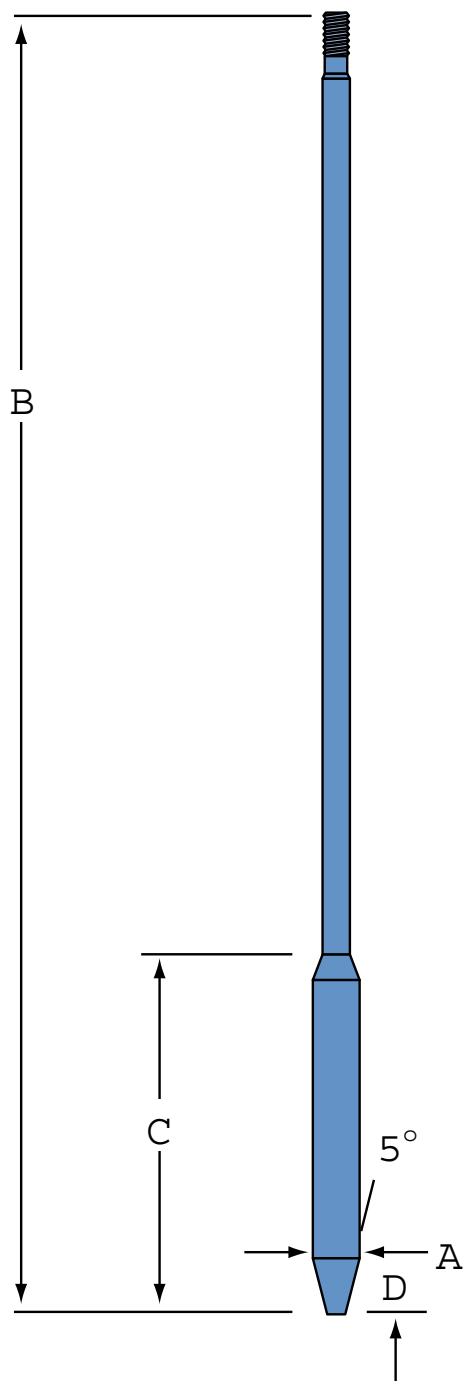


Figure 9-26: Type DW/DD Pulling Prong

Table 9-11: Type DW/DD Tool Combinations

Size (in.)	Running Tool	Pulling Tool	Prong	Running Tool	Pulling Tool	Prong
2 $\frac{3}{8}$	41W013	40RB17	49P176	-	-	-
2-7/8	41W014	40RB18	49P242	41DO11	40GRL4	49P
3 $\frac{1}{2}$	41W022	40RB19	49P141	41DO9	40GRL4	49P1533
DW Pulling Prong Dimensions (in.)						
Size	Number	A	B	C	D	Thread
2 $\frac{3}{8}$	49P176	0.500	25 $\frac{3}{16}$	-	$\frac{5}{16}$	$\frac{1}{2}$ - 13 NC
2-7/8	49P242	0.687	22 $\frac{1}{8}$	2 $\frac{5}{16}$	$\frac{5}{16}$	$\frac{1}{2}$ - 13 NC
3 $\frac{1}{2}$	49P141	1.125	23 $\frac{3}{8}$	2-5/16	$\frac{5}{16}$	$\frac{5}{8}$ 11 NC
DD Pulling Prong Dimensions (in.)						
Size	Number	A	B	C	D	Thread
2-7/8	49P	0.687	19-3/16	2 $\frac{5}{16}$	$\frac{5}{16}$	$\frac{5}{8}$ - 11 NC
3 $\frac{1}{2}$	49P1533	1.0621	20 $\frac{1}{4}$	4	$\frac{5}{16}$	$\frac{5}{8}$ - 11 NC
 Hint The DD plug above is not to be confused with the 'DD bridge plug', which utilizes a shear disc to hold pressure in both directions. The disc is sheared to equalize.						

9.3.3 Type XX/PX Plugs

There are two designs of plugs designed specifically for the X and XN locks.

- XX Plug
- PX Plug

9.3.3.1 Type XX Plug

The XX plug is designed to be run in clean production wells.

Running

To permit fluid bypass when running, the valve (melon) is held off its seat by a running prong attached to the core of the X running tool. This valve is closed when the running tool is sheared upwards after setting the lock.

Pulling

A pulling prong is attached to the core of the GR pulling tool to push the valve off the seat and permit equalization through the four points.



Note

Check that the pulling prong has not been inadvertently shorted by someone redressing the threads.

In order to make a plug, a valve cap is run below the equalizing sub. When assembling onto the running prong, check and grease the O-rings.



Note

The external recognition feature of the X sub-equalizing holes close to the NO-GO shoulder.

The following are the most common X equalizing subs:

Table 9-12: Equalizing Subs

Nipple Bore Reference (in.)	X Equalizing Sub	Valve Cap	Running Prong	Pulling Prong
1.875	20XO18701	20R208	49Q496	49QO35
2.313	20XO23100	20R7	49Q1056	49QO44
2.750	20XO27504	20R181	49Q599	49QO43
3.813	20XO38104	20R59	49P640	49P641

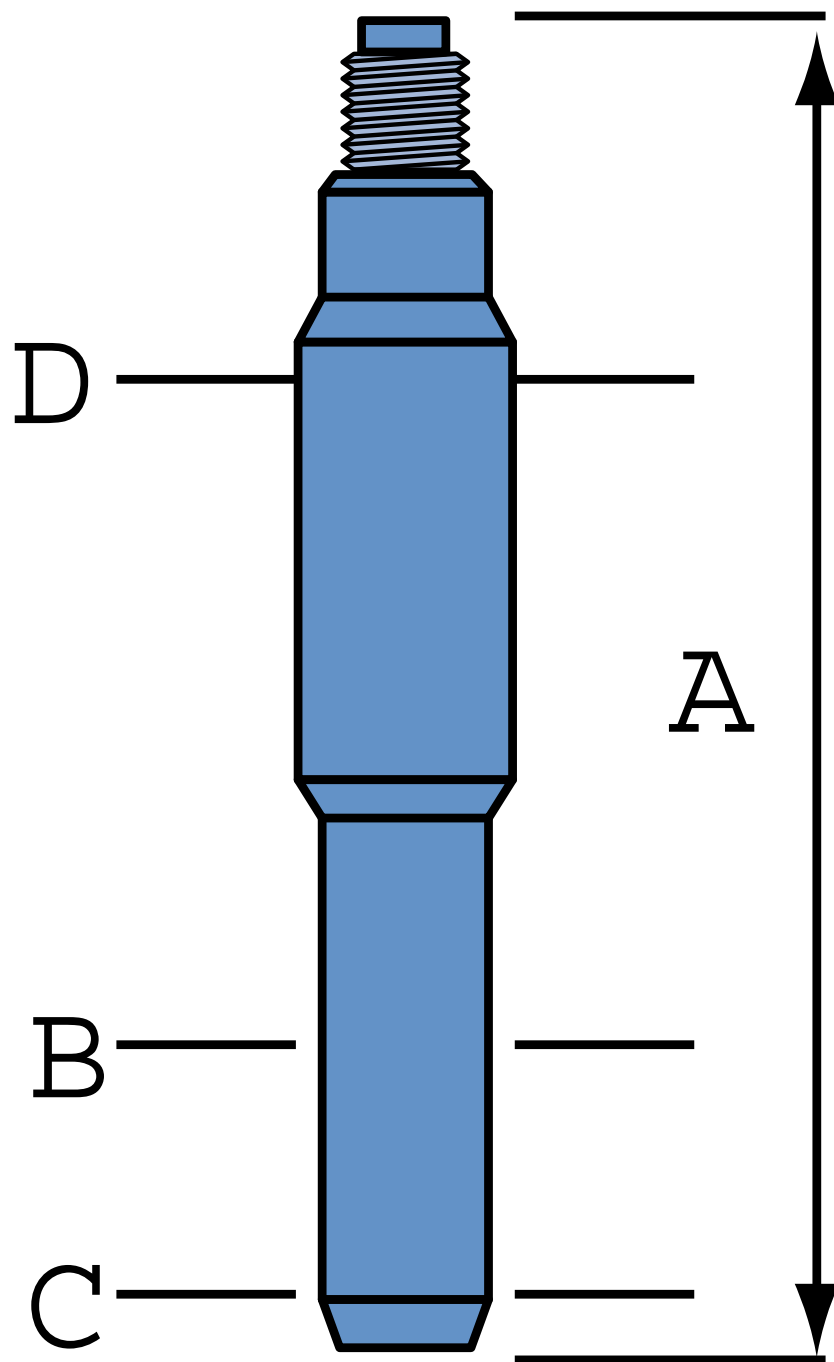


Figure 9-27: Type X Prong — Running

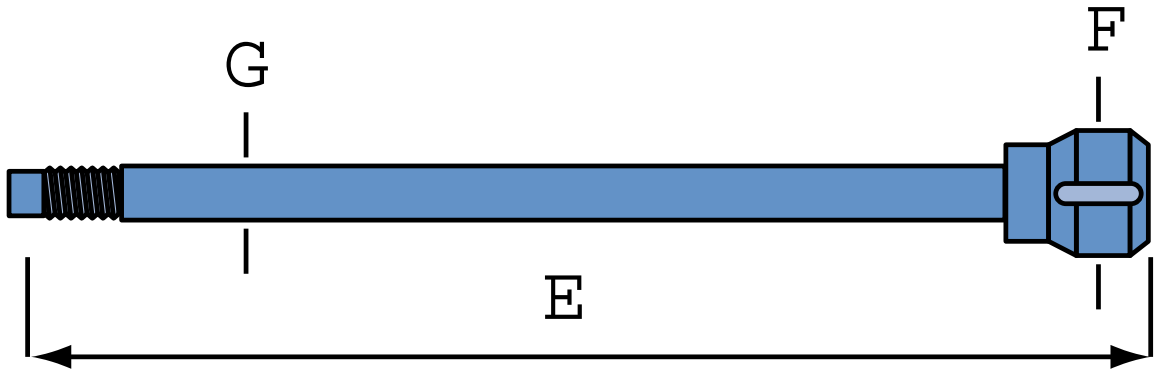


Figure 9-28: Type X Prong Pulling

Table 9-13: Prong Dimensions

	Reference	2 (1.87)	2½ (2.313)	3 (2.750)
Running	A	4 15/16	6 1/8	5 1/2
	B	0.750	1.095	1.500
	C	0.875	1.220	1.625
	D	0.965	1.340	1.710
	Thread	½-13 UNC 2A	5/8-11 UNC 2A	¾ - 10 UNC 2A
Pulling	E	12 1/4	13 7.8	13.000
	F	0.970	1.300	1.713
	G	0.500	0.750	0.750
	Thread	½-13 UNC 2A	5/8-11 UNC 2A	¾-10 UNC 2A

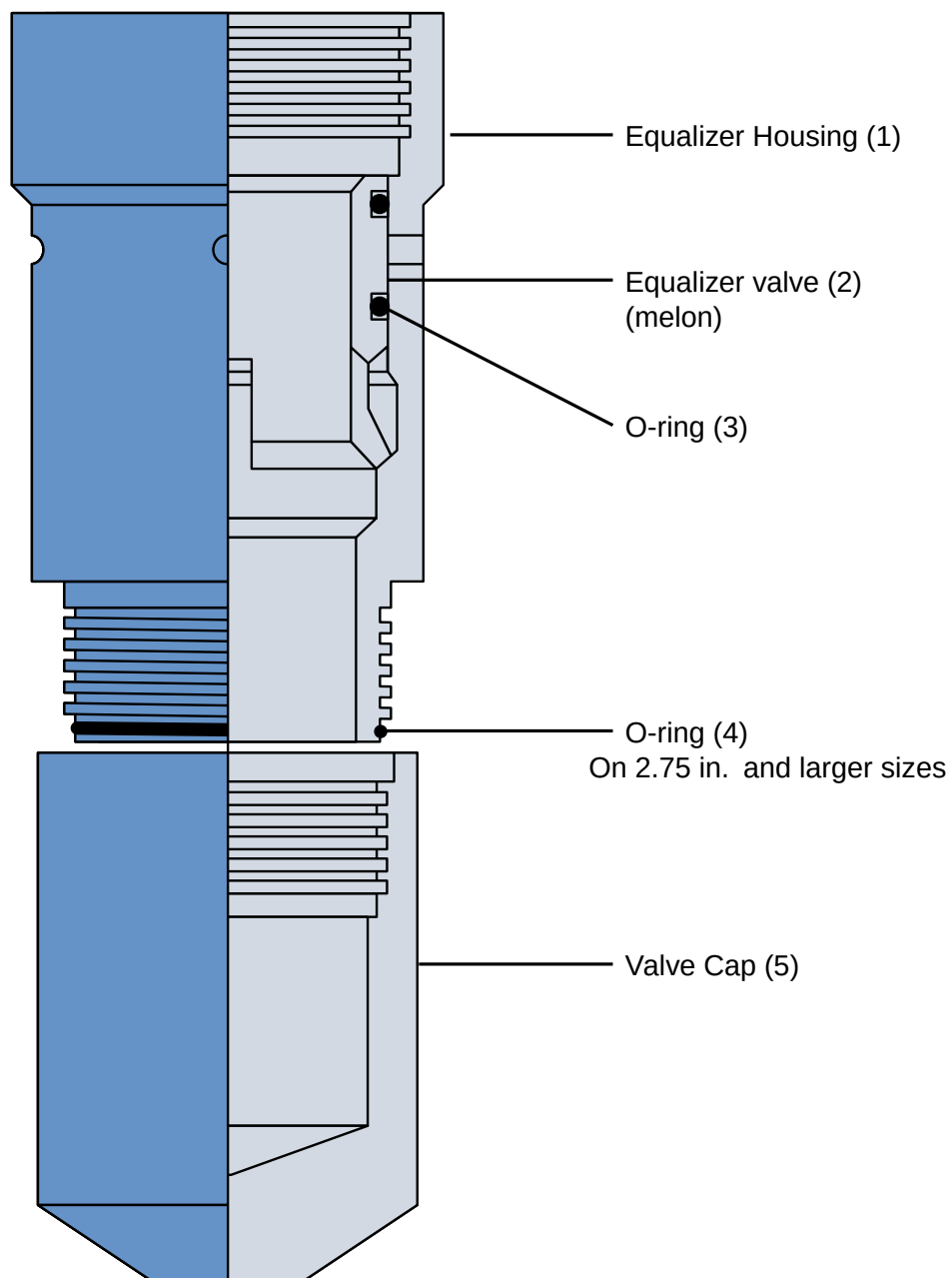


Figure 9-29: Type X Equalizing Sub

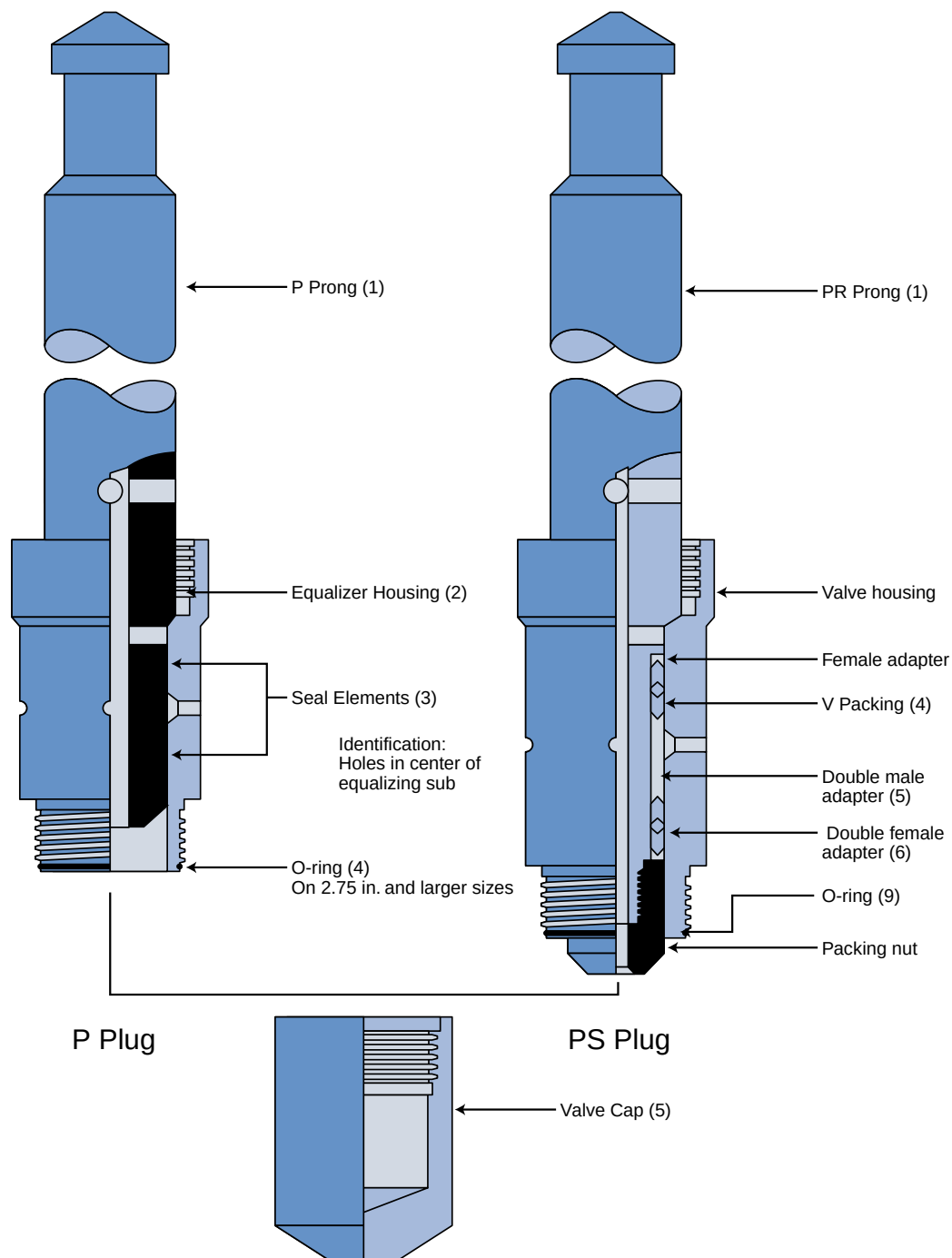


Figure 9-30: Type X Prong Pulling

9.3.3.2

PX Plug

The PX plug was designed to be run in wells containing solids, such as sand or pipe scale. The external fishing neck is easier to retrieve if bailing is required and the bulk of the steel bar prevents sand entering the lock and equalizing sub.

Running

The P prong is run on an SB (or T running tool). Prior to latching the prong, CHECK the running tool will shear correctly. The lock, plus the P equalizing sub and valve cap is run and locked in the X (or XN) nipple prior to running the prong. (No running prong is necessary as fluid bypasses through the sub, i.e., it takes two trips to set a PX (or PXN).



Note

The hole up the center of the P prong is for fluid bypass WHEN ENTERING THE EQUALIZING SUB. As fluid is incompressible, it would be impossible for the prong to enter the sub completely without this hole.

Pulling

The P prong is pulled using an SB pulling tool. Pressure equalization occurs during the time it takes to bring the prong to the surface and to run back with a GR to recover the lock. As with the XX plug - a valve cap is screwed below the equalizing sub.



Note

If the diameter for the standard equalizing holes (3/32 in.) have been increased to equalize in heavy fluid, DO NOT USE IN HIGH PRESSURE GAS OR THIN OIL. Rapid equalization may blow tools up the hole.

9.3.4 Test Tools

This is the third category of plugs, i.e., hold pressure from above only and are commonly used to:

- Test the tubing string - usually immediately after running tubing and prior to perforating.
- Set a hydraulic packer
- Protect the lower formations while stimulating an upper zone

9.3.4.1 Type N Test Tool

Designed to run into the XN nipple and seat against the no-go ring while sealing in the packing bore. As pressure will only be held from above, all V-packing elements face upward.

A built-in check valve permits easy equalizing. This check valve has a rubber seal for low pressure sealing, with a high-pressure metal-to-metal seat included.

This same design of check/equalizing device is utilized also on the X selective and modified P test tools.

It is usual to test against the N test tool after removing the tool string from the well. However, if the wire and tool string is to be left attached to the N test tool during the pressure test, the following precautions should be observed:

- Pressure test the lubricator assembly immediately prior to running the N test tool. This is to ensure there are no minor leaks, which could invalidate a tubing pressure test.
- Ensure the tubing is clean - Pressure testing flexes tubing and will deposit any scale and sand around the tool string

**Note**

IF THERE IS ANY DOUBT - REMOVE THE TOOLSTRING DURING THE TEST

- After the test, bleed the pressure off SLOWLY while pulling a bind on the wire with the hydraulics of the slickline unit.

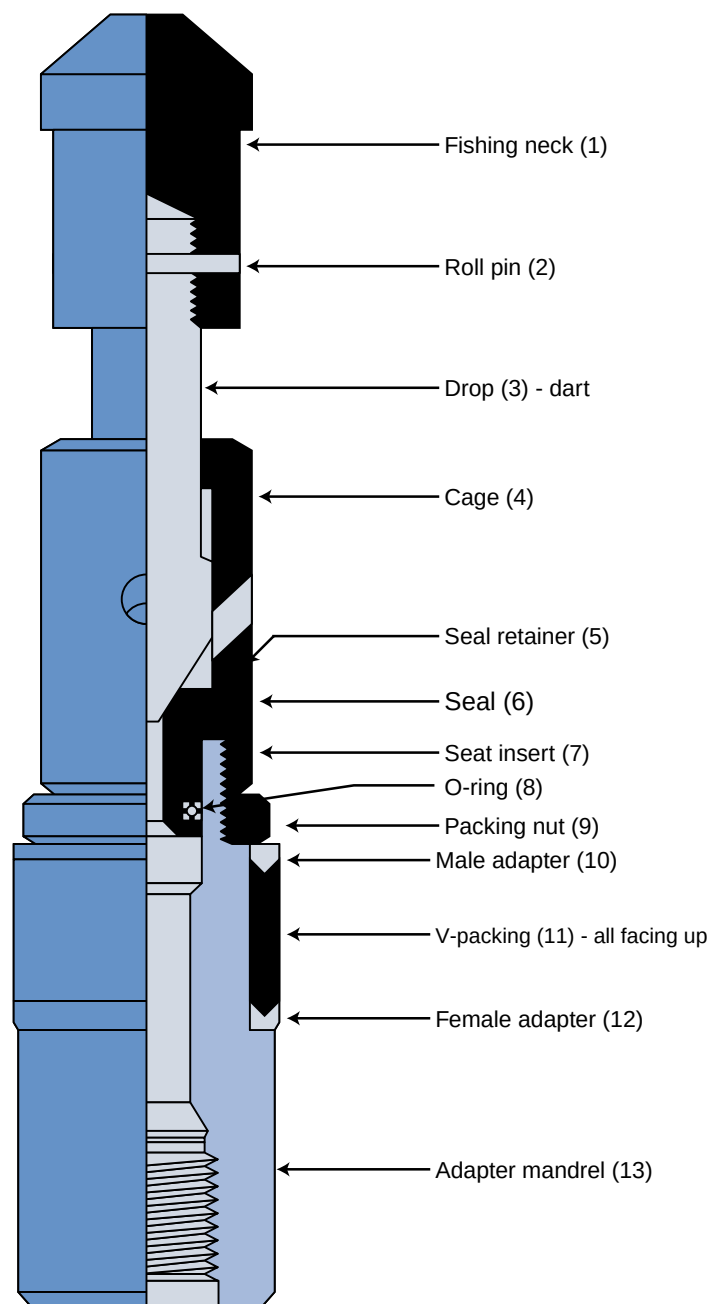


Figure 9-31: Type N Test Tool

9.3.4.2 Type X Selective Test Tool

The Otis type X selective test tool test tubing, locates leaks or sets hydraulic set packers. Designed to hold pressure from above, the type X selective test tool may be set in compatible X or XN landing nipples in the tubing string. Keys

retracted, the tool is run to a point below the desired nipple in the SELECTIVE position, then picked up to trip to NON-SELECTIVE. This expands the X profile keys and locates when the tool is lowered.

Pressure may then be applied from ABOVE.

Features

- Designed for high-pressure ratings: 8000 to 10,000 psi (depending on size).
- Located in the lowest nipple, then moving up the tubing with the test tool to minimize Slickline trips.
- Can be set in SSD profile.
- Can isolate the section of tubing, which may be leaking.

9.3.4.3 Modified PX Test Tool

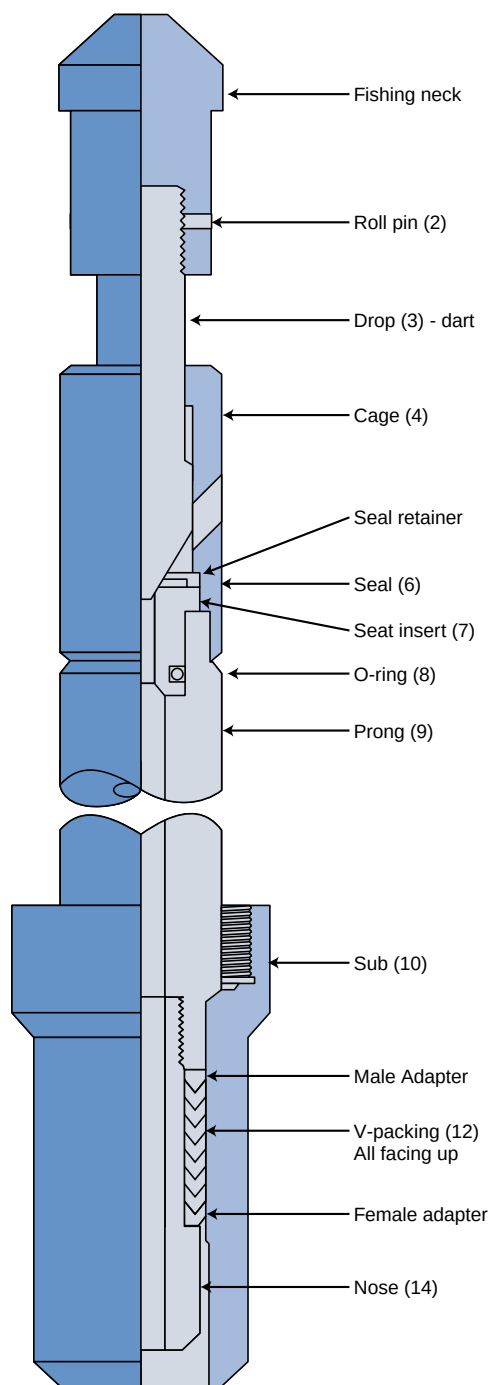


Figure 9-32: Modified PX Test Tool

The modified PX test tool holds pressure from above ONLY. For this reason, the V-packing on the lock and prong FACE UPWARDS.

The lock mandrel is run without keys, so the position of the lock fishing neck and expander mandrel can be opened or closed. For this reason, the prong can be inserted into the plug and the whole assembly runs on a type SB tool.

When pulling, it is occasionally possible to recover the prong and lock together. However, if there is any sand or scale to hold the plug, the prong will be recovered first and the lock is recovered with a GS or GR.

Use of this plug minimizes the risk of being struck beneath sand or scale after pressure testing the tubing.

**Note**

The prong is a V-packing type - not an element seal design.

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10 CIRCULATION DEVICES

10.1 Introduction

Circulation devices are installed in the tubing string during the well completion process to provide a means of communication between the tubing and annulus. Devices such as sliding sleeves or sliding side doors are commonly used for the following purposes:

- Displacing tubing and annulus fluid after completion
- Selective production, treating or testing of various zones
- Production of multiple zones
- Circulating to kill a well
- Gas lifting (in the absence of suitable gas lift mandrels)
- Circulating corrosion inhibitors
- Positioning co-mingling chokes for dual zone flow

There are three basic types of SSD in common use:

- Standard open down SSD - Otis type XO
- Larger flow area, open down SSD – Otis type XD
- Open up SSD – Otis XA

SSD's are available in either jar down to open or jar up to open designs. The most common are the jar down to open, such as the XO and XD. Any number can be installed and opened selectively using the 142-BO selective downshift tool.

All SSDs now being installed have an X profile in their upper bore (designated by the letter X in the title). This permits the installation of plugs, separation tools and X selective test tools, as may be required.

All Otis SSDs having an equalizing feature, whereby the movement of the inner sleeve towards the open position first uncovers a small port. Constant monitoring of the surface pressure (lubricator gauge) will indicate when the SSD has moved into this equalizing position. WAIT UNTIL THE PRESSURE HAS EQUALIZED before continuing jarring.

10.2 Halliburton Equipment and Tools

10.2.1 Model XO Sliding Side Door

The type XO Sliding Door is designed with a type X nipple profile above and a polished pack-off area below the inner sliding sleeve. With the inner sleeve in the closed position sealing off the side ports, the lower zone can be produced through the essentially full open bore. To produce the upper zone and close off the lower zone, the inner sleeve is opened to provide communication between the casing annulus and tubing string.

The type XO sliding side door is opened by downward jarring, a feature that increases the versatility of this tool for use with the entire X line of subsurface equipment. The sliding side door-shifting tool is designed not to lock in the type X nipple, nor are the running/pulling tools for the type X lock designed to affect the sleeve.

The type XO sliding side door may be located anywhere in the tubing string where it is required, or may be desirable to provide communication to the tubing/casing annulus. It may be run into the hole with the external groove (identifying the top) upward and with the sleeve in either the open or closed position. The sleeve is then closed or opened as necessary, using standard slickline methods. Take care not to allow torque to be applied across the central, thin walled section of the SSD. This area is often marked with arrows and a caution message.

Table 10-1: Model XO Sliding Side Door - Common Size Configurations

Assembly No.			121X01	121X03	121X054	121X080
Size (in.)			$2\frac{3}{8}$	$2\frac{7}{8}$	$3\frac{1}{2}^*$	$4\frac{1}{2}$
Material			9CR-1MO	9CR-1MO	9CR-1MO	9CR-1MO
Thread			EU	EU	EU	EU
Ref.	Part Name	Qty				
1	Top sub	1	121X1	121X8	121X58	121X475
2	Nipple	1	121X39	121A645	121X57	121A508
3	O-ring	2	91Q1229	91Q1234-H	91Q1237-H	91Q1246-H
4	Double male adapter	1	121A18	121A21	121X51	91V4219
5	Split ring segment	4	121A43	121A48	121X53	121A511
6	O-ring	1	91Q1331-H	91Q131-H	91Q1198-H	91Q1246-H

Assembly No.			121X01	121X03	121X054	121X080
Size (in.)			$2\frac{3}{8}$	$2\frac{7}{8}$	$3\frac{1}{2}^*$	$4\frac{1}{2}$
Material			9CR-1MO	9CR-1MO	9CR-1MO	9CR-1MO
Thread			EU	EU	EU	EU
Ref.	Part Name	Qty				
7	Female adapter	4	121A17	121A644	121X54	121A509
8	Closing sleeve	1	121A41	121A1435	121X56	121A510
9	V-packing	()	91V83 (10)	91V84 (12)	91V3329(8)	91V4768
10	O-ring	1	91Q1331-H	91Q131-H	91Q198-H	91Q164-H
11	Bottom sub	1	121A2	121A9	121X55	121A476
12	Female Adapter	2	121A17	121A644	121X54	121A509
13	Bottom V-packings	()	-	-	91V5042(4)	91V5038(4)
Length (in.)			33.940	37.930	44.880	49.670
OD (in.)			3.090	3.75	4.280	5.500
ID Nipple (in.)			1.875	2.313	2.750	3.813
Flow Area (in. ²)			1.459	2.446	4.459	5.560
Shifting Tool (standard)			42-BO 116	42-BO 118	42-BO 147	42-BO 111
Selective Shifting Tool			142-BO 4	142-BO 3	142-BO 1	142-BO 7
* Also available in 2.813 in. nipple bore.						

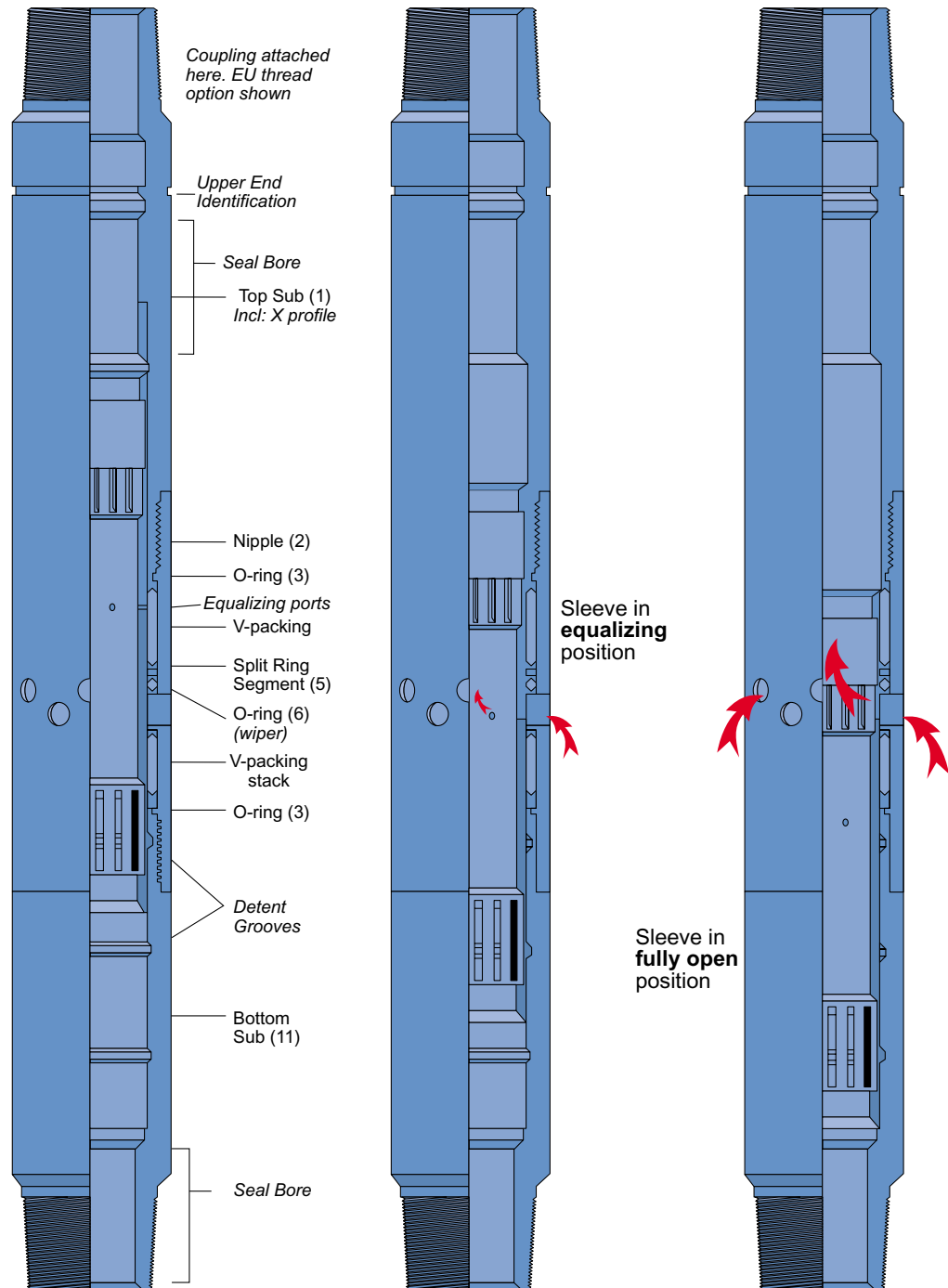


Figure 10-1: Model XO Sliding Side Door in Closed, Equalizing and Open Positions

10.2.2 Model XA Sliding Sleeve

The diagram in is representative of the Halliburton-Otis Type XA sliding side door and the Type 42BO-positioning tool. The schematics illustrate the equalizing, opening and closing of the side-door.

As the positioning tool with self-releasing keys enters the nipple restriction of the top sub, the spring-loaded keys are collapsed allowing the tool string to go through the SSD. When tool string is pulled back up and the keys reach the closing sleeve, the spring-loaded keys expand, allowing the 90° shoulder in the upper end of the closing sleeve of the SSD.

With upward jarring, the closing sleeve begins to move up until the collets of the closing sleeve reach the equalizing position. At this point, the equalizing ports of the closing sleeve have cleared the isolating packing and are aligned with the ports of the nipple. This position allows the pressure of the tubing and annulus to equalize.

Continued upward jarring, after equalizing, will move the closing sleeve into the full open position. Two things occur at this time. First the collet of the closing sleeve moves out into the detent to hold the sleeve in a fully open position. Second, as the self-releasing profile on the keys reach the inclined shoulder in the top sub, the keys are retracted and release from the closing sleeve. This is usually an indication that the SSD is fully opened if the pin in the 42BO has not sheared. With the SSD in the fully open position, communication is established through the outer ports and the slots of the closing sleeve.

The closing sequence of a sleeve is very much the same. To close the Type XA sliding side door the shifting tool is positioned with the 90° shoulders of the keys facing down. As the tool string enters the top sub, the keys are kept retracted until the tool is in the closing sleeve. Once in the closing sleeve, the keys expand to engage the 90° shoulder at the lower end of the closing sleeve.

Downward jarring moves the sleeve to the fully closed position. When the sleeve reaches the fully closed position, the keys release the closing sleeve and pass through the side-door. This is a preliminary indication that the sleeve is closed. Once the positioning tool is retrieved and inspected, the shear pin not being sheared is the second indication that the sleeve is fully closed.

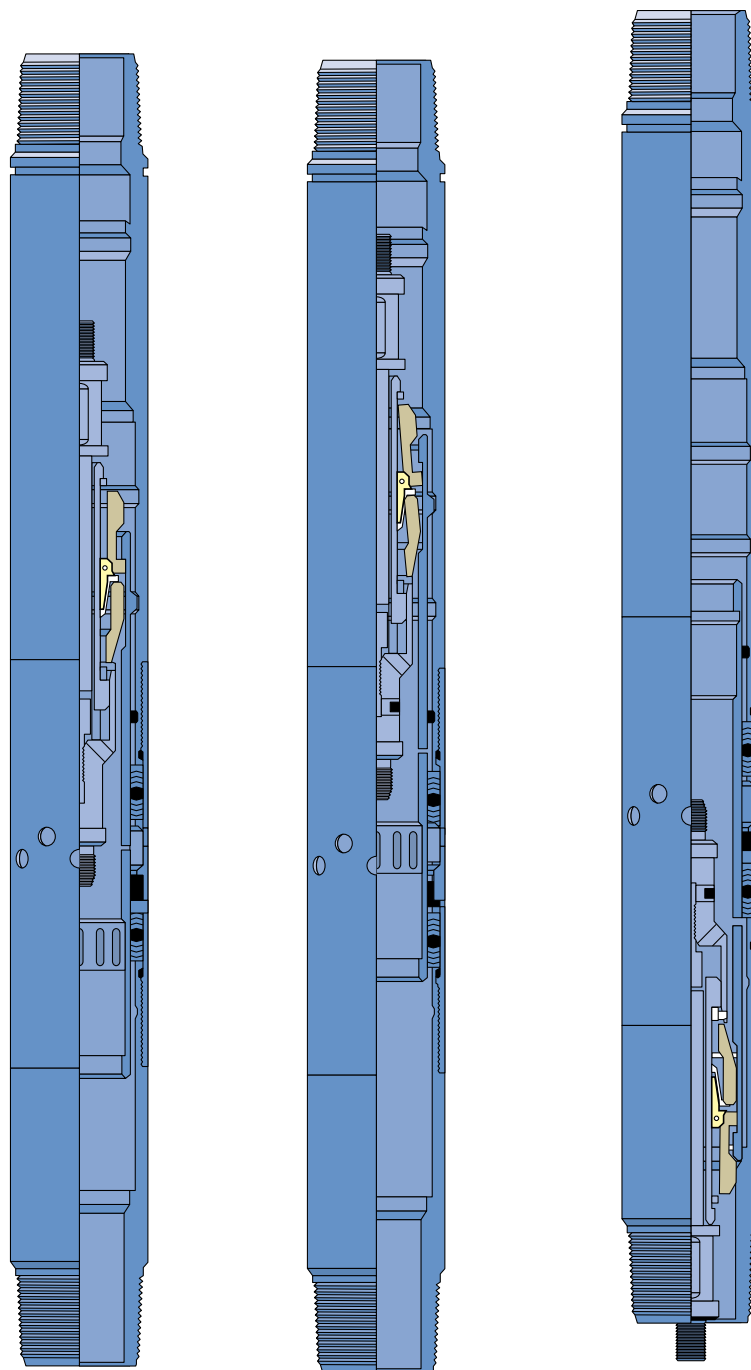


Figure 10-2: Model XA Sliding Side Door – Closed, Equalizing and Open Positions

10.2.3 Model XD Sliding Side Door

The model XD has larger flow ports between the tubing and annulus. The ID through the bore is the same as the XO. It is identical in operation to the XO (i.e., same overall dimensions, open down). It was developed for oil wells with heavy crude, so that side-door ports would not restrict the flow of oil from the formation of the tubing.

Compare the flow areas in the following chart with the flow areas of the same size XO and XA.

Table 10-2: Model XD Sliding Side Door Configurations

Assembly No.	121X1D23	121XD2	121XD3	121XD7
Size (in.)	$2\frac{1}{8}$	$2\frac{7}{8}$	$3\frac{1}{2}^*$	$4\frac{1}{2}$
Material	9CR-1MO	9CR-1MO	9CR-1MO	9CR-1MO
Length (in.)	33.940	41.000	44.880	46.000
OD (in.)	3.090	3.750	4.280	5.500
ID Nipple (in.)	1.875	2.313	2.750	3.813
Flow Area (in. ²)	2.854	4.200	5.900	12.600
Shifting Tool (standard)	42-BO 116	42-BO 118	42-BO 147	42-BO 111
Selective Shifting Tool	142-BO 4	142-BO 3	142-BO 1	142-BO 7

* Also available in 2.813 in. nipple bore - Uses 42-BO 146.

10.2.4 Model B Shifting Tool

The Otis B shifting tool was designed to open or close all of the Otis side-doors. This tool has two pin connections to permit either opening or closing of the sleeve by inverting the tool.

With the 90° shoulder on keys facing DOWN

- Opens - XO, XD
- Closes - XA

With the 90° shoulder on keys facing UP

- Closes - XO, XD

- Opens -XA

**Note**

To open an XO or XD sleeve, which is BELOW another SSD, the SELECTIVE DOWNSHIFT tool must be used.

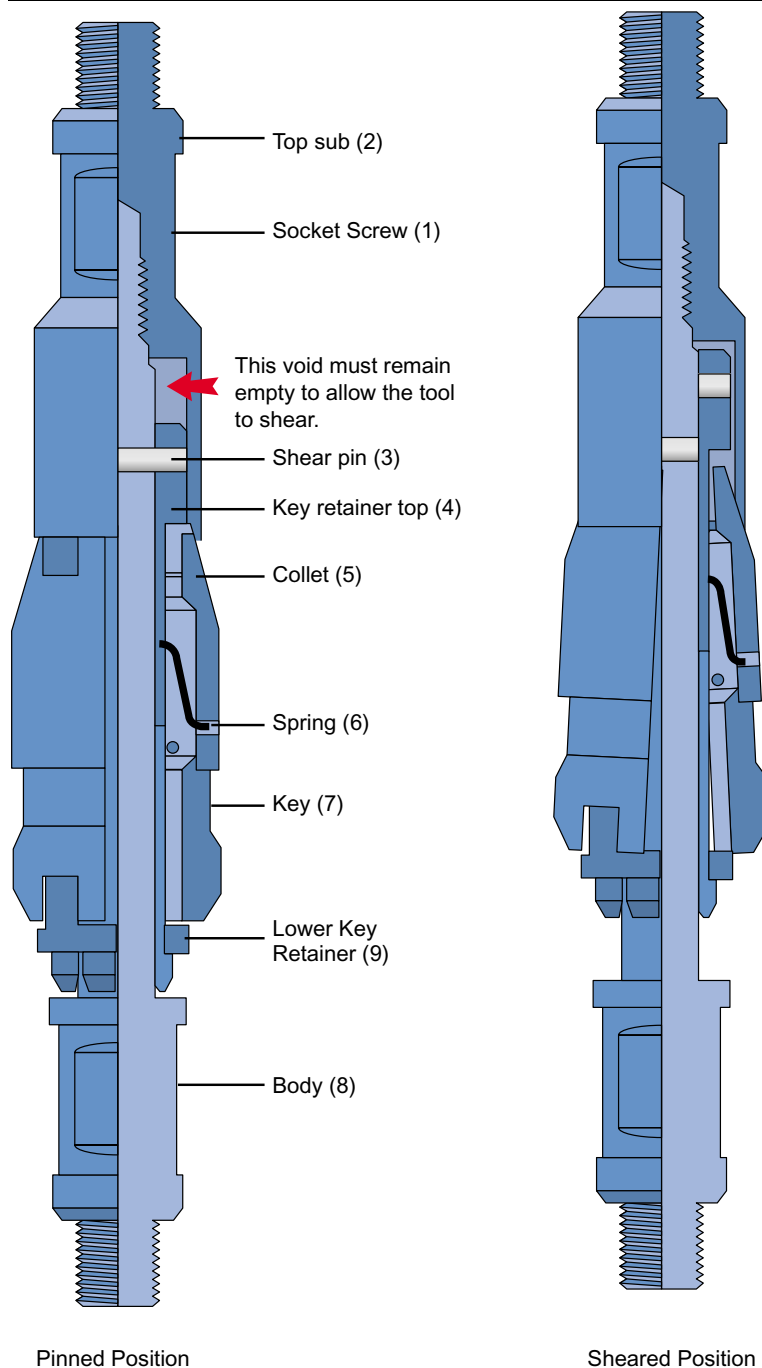


Figure 10-3: Model B Shifting Tool Operating and Release Positions

10.2.4.1 Operation

1. Select the direction in which the tool will shift the sleeve and install on the tool string with the 90° shoulder facing the direction of the required movement.
2. Run into the SSD and locate.
3. Jar against the sleeve in the desired direction. If moving the sleeve up, jars cannot be closed to hit a lick – Run into the SSD from below, adjusting speed to give the desired impact.
4. Observe the lubricator gauge pressure CAREFULLY. Stop when the pressure changes and WAIT until the pressure is equalized. The pressure should be fully equalized through the four small ports in the sleeve prior to the main flow ports being opened.
5. Continue jarring to fully open the SSD. The tool will automatically release when the ID of the polished bore squeezes the raised portion of the keys.
6. The tool should be passed completely through the SSD three times to check the SSD is fully open (or closed).
7. Pull out the hole and VISUALLY CHECK THE TOOL HAS NOT SHEARED. If the steel shear pin has sheared, the sleeve MAY NOT be fully open. Re-pin and rerun the tool. It is good operating practice to check/replace the pin before each run as the pin could be partially sheared from the jar action.

10.2.5 Otis Selective Downshift Tool

This tool was designed to selectively open XO and XD side-doors by passing through the upper sleeve(s). It will ONLY shift sleeves DOWNWARDS and should never be inverted (hence only one pin end) as it could get stuck below a tight sleeve.

Selective	Shifting keys retracted to pass the upper SSD's locator dogs extended to locate the packing bore
Non-Selective	Shifting keys extended to locate in the SSD

**Note**

This tool does not have a shear pin.

10.2.5.1

Setting the Tool in Selective

1. Grip the bottom of the main mandrel in the vice.
2. Insert the screwdriver in the slot through the hole (A) in the upper end of the spring housing and lever the housing downwards compressing the main spring.
3. At the same time as (2) above, squeeze the upper end of the locator dog inwards and release the screwdriver.
4. The tool should move partially to the SELECTIVE position.
5. Using the handle of the screwdriver, strike the lower ends of each shifting key inwards.
6. The tool should snap into SELECTIVE. If not, repeat from step 2 above.

Operation

1. The tool is run in SELECTIVE to below the SSD to be shifted.
2. Pull upwards through the SSD to trip to NON-SELECTIVE.
3. Sit down in the SSD and jar down. OBSERVE EQUALIZATION PROCEDURES – AS FOR THE B SHIFTING TOOL.
4. When the SSD has moved fully, the tool will automatically pass through the SSD.
5. Check by passing three times through the SSD.
6. Pull out of the well.

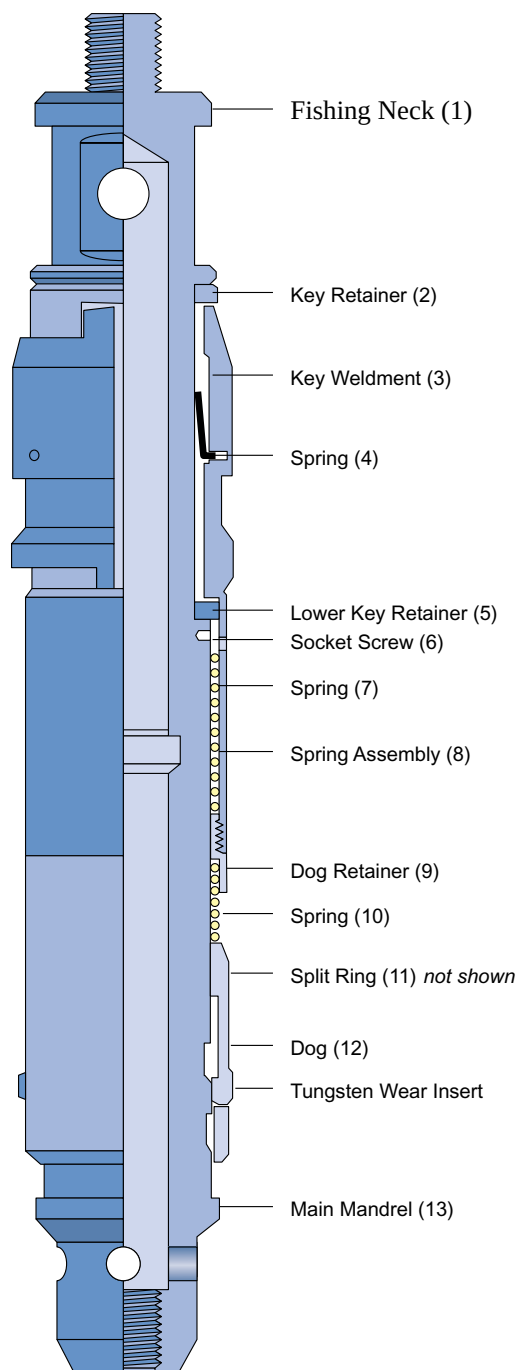


Figure 10-4: Selective Downshift Tool

10.2.6 Model X Shifting Tool

An alternate selective shifting tool is the Otis X selective, which is still in use by many locations.

The raised dog section of the key has two positions.

If it is extended as shown in the diagram, the tool is configured to latch the SSD profile.

The dog can be moved into a position close to the 90° key shoulder by picking up the tool string and lowering it down again to cycle the tool into a non-latching position.

The SSD is then bypassed and the process of reciprocating the tool string repeated to put the dog into the latching position.

This tool can be used selectively in eight directions to open or close the SSDs.

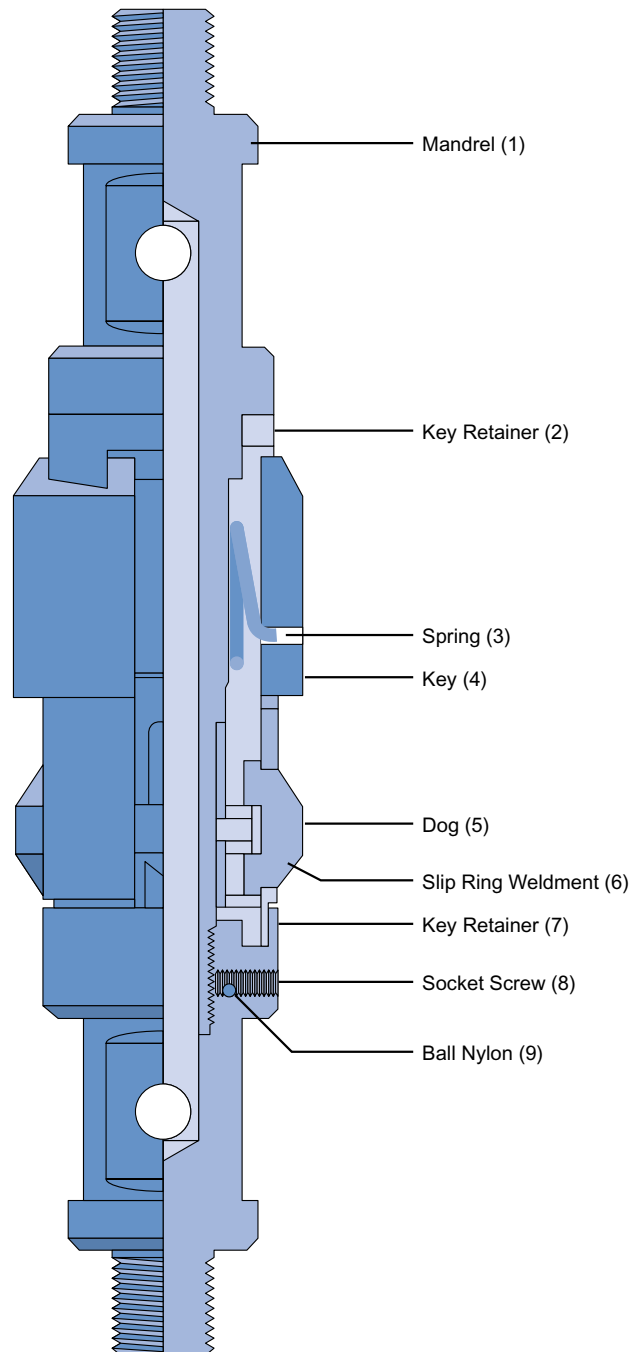


Figure 10-5: Model X Shifting Tool

10.2.7 Type 42 BO Special Positioning Tool

The Type 42 BO Special Positioning Tool is designed for selective down shifting sleeves that do not have a nipple profile. The tool has a locator arm that locates in the collar recess of the tubing or in the internal profile of the closing sleeve. As the positioning tool is lowered into the hole, the locator arm rest against the

tubing wall. When the positioning tool reaches a point in the tubing just below the sliding side door to be shifted, the tool string is stopped and pulled back up the hole. The locator arm will locate a tubing collar or the closing sleeve causing a pin to shear and allow the key retractor to move down releasing the keys. The positioning tool is then pulled up through the sleeve and is now in position to be lowered into and relocate the closing sleeve.

Once the key retractor has been moved down, the locator arm is retracted and the plunger pin holds it in that position. With locator arm retracted the tool can be retrieved from the well or move up hole to down shift any above sleeve.

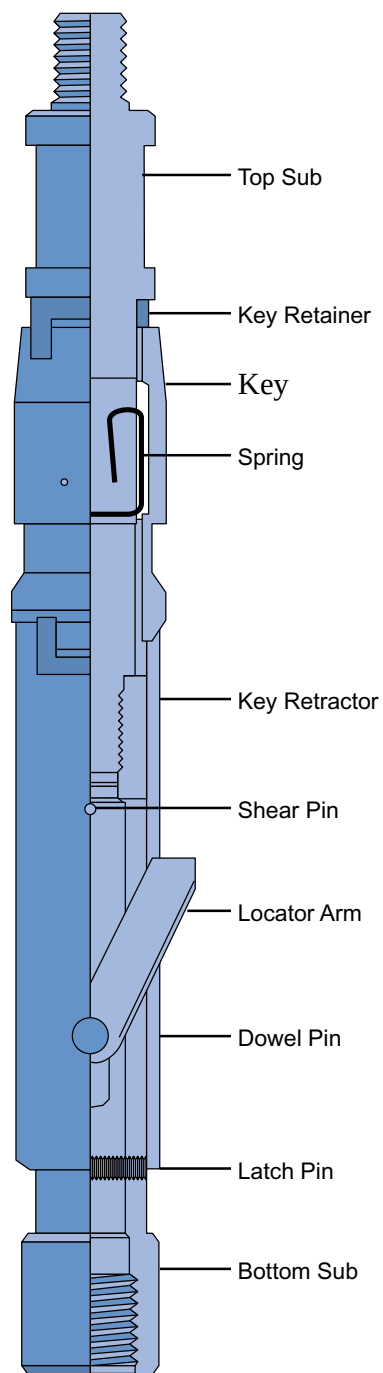


Figure 10-6: Type 42 BO Special Positioning Tool

10.2.8 Otis Separation Tool

The separation tool is made up of:

- X lock

- X separation sub
- Spacer pipe (mandrel extension)
- Packing mandrel

It is designed to plug a lower zone while permitting flow from the upper zone.

While this same result could be achieved by plugging the lower zone in the lower nipple and flowing the well through the SSD, this may cause a problem in sand producing zones.

As the production and sand enters the SSD, the abrupt change in direction will permit some of the sand to settle out onto the plug. This can make recovery of the plug difficult and time consuming, if a sand bailer must be used.

By running a separation tool directly into the SSD, the same effect is achieved, i.e., the bottom zone plugged and the upper zoned flowed. However, there is insufficient space between flow ports in the separation sub and integral plug to allow sand to accumulate.

10.2.8.1 Running

Procedure same for the XX plug. A running prong must be used to provide fluid bypass while running in.

10.2.8.2 Pulling

Using the GR and equalizing prong (as for the XX plug). Wait for pressure to equalize before pulling.



Caution

Potential Severity:	Light
Potential Loss:	Process
Hazard Category:	machinery equipment hand tools

Some separation subs still in use have the V-thread connections. Care must be taken to ensure the lock is compatible. (Newer locks have a square thread form.) It is advisable to plug the lower zone prior to opening the upper SSD and installing the separation tool for the following reasons:

- To prevent flow from zone to another if there is a pressure differential across the zones.
- To prevent excessive differential pressure across the tool when it is pulled.

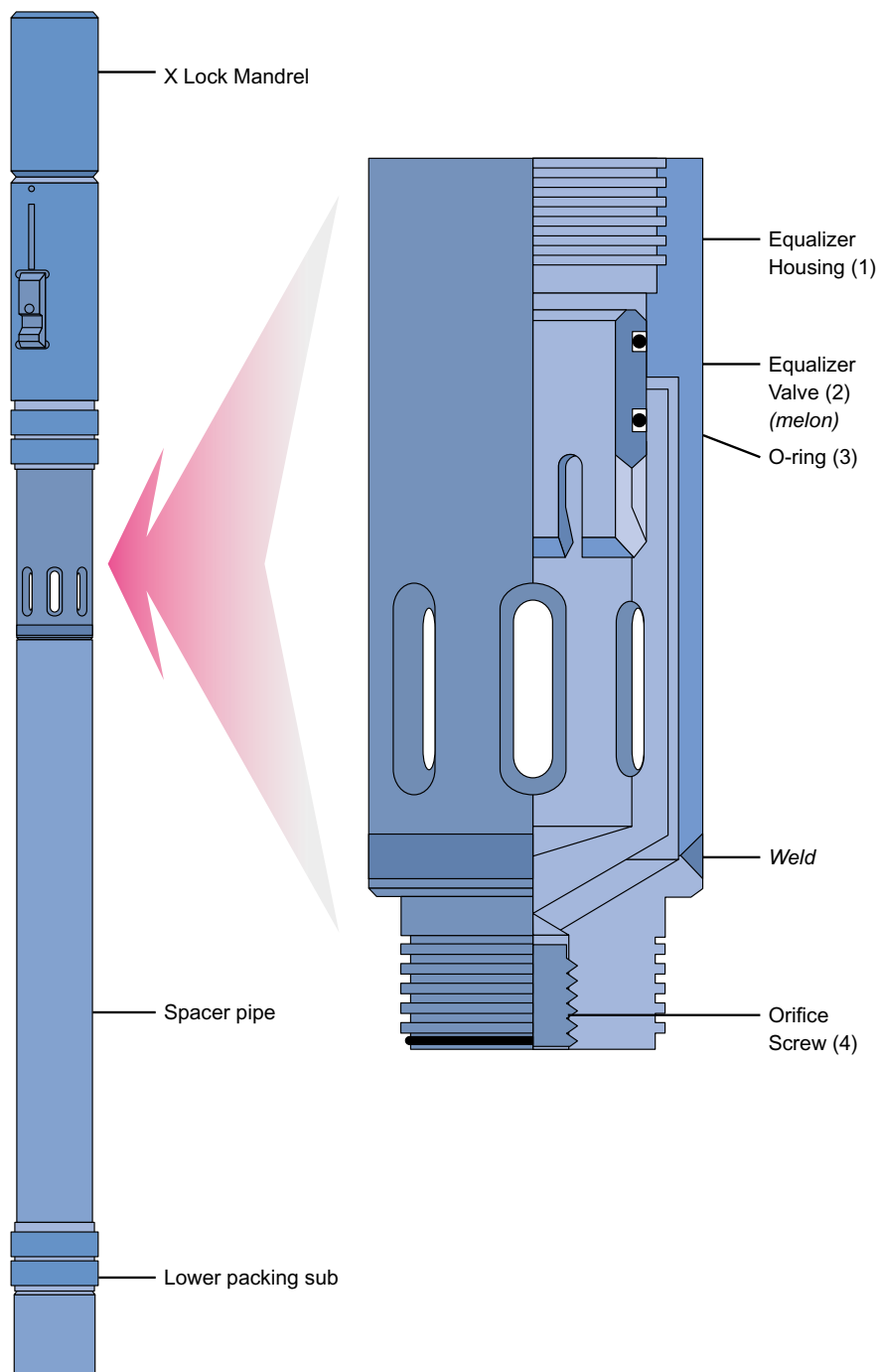


Figure 10-7: Otis Separation Tool

10.2.9 Otis Side Door Choke

Similar in appearance to a separation tool assembly, a side door choke uses an X equalizing sub in place of a separation sub. All other components are the same.

The purpose of the side door choke is to plug a leaking SSD. While its installation does reduce the flow area through the SSD, it permits continued production of the lower zone without communication with the upper zone.

The running and pulling procedure is identical to the XX plug and separation tool.

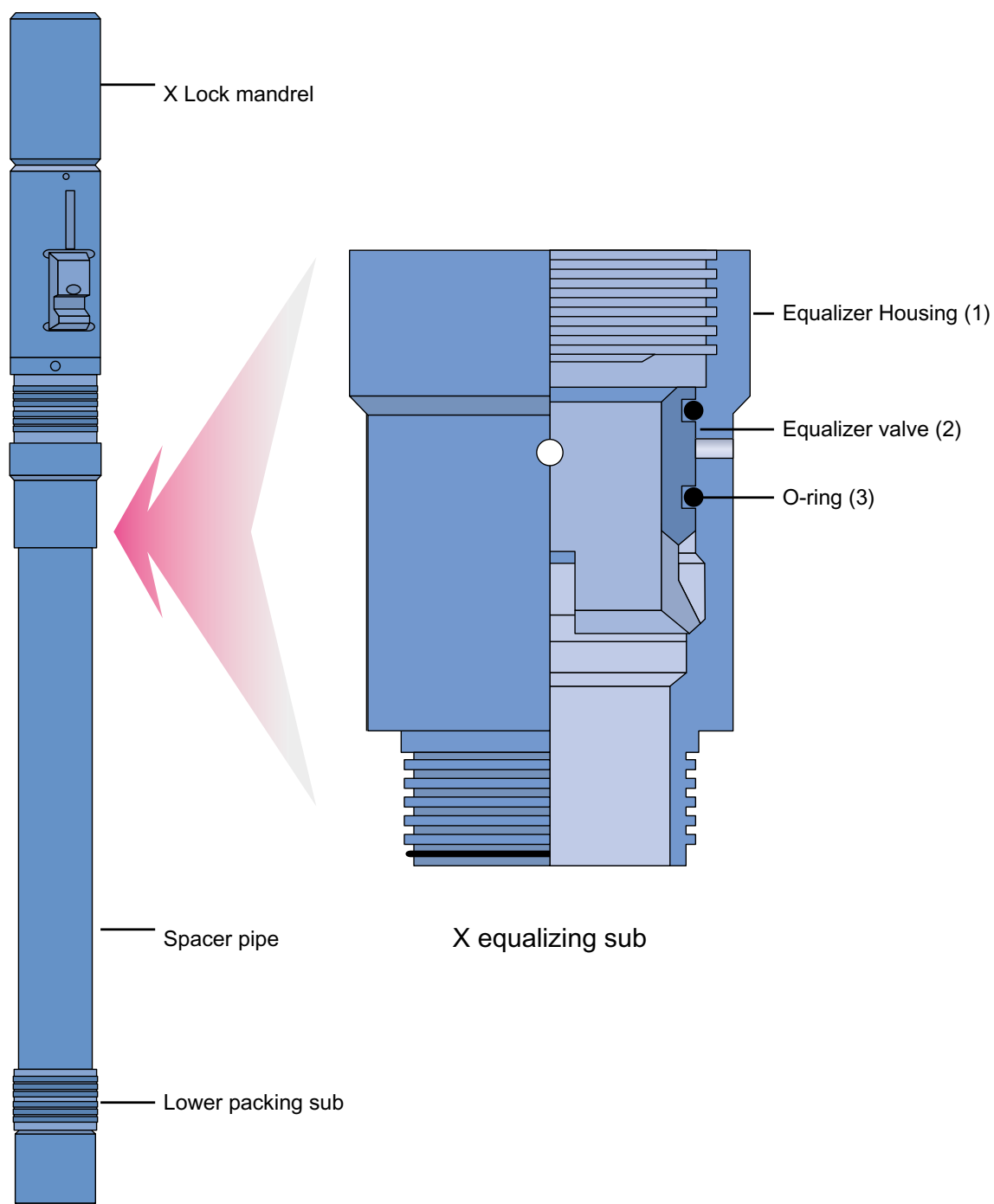


Figure 10-8: Otis Side Door Choke

10.3 Camco Equipment

10.3.1 C and W Series Sliding Sleeves

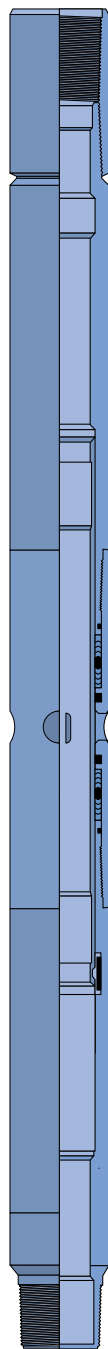


Figure 10-9: CB-1 Series Sliding Sleeve

Camco C and W series sliding sleeves are designed to provide a reliable and easy means of opening and closing communication between the casing annulus and the tubing.

Each Camco sliding sleeve has a collet stop acting on the inner sleeve to mechanically retain the sleeve in either the fully closed or fully open position. The inner sleeve, which is made of premium material, contains small equalization slots or hole, which are exposed first to provide a means of equalization before the primary circulation parts are fully exposed. The holes are used only in high-pressure sleeves and unlike the slots, are separate from the primary circulation ports. Seals above and below the holes prevent any flow through the ports during equalization. Two types of stationary seals are used to seal around the inner sleeve. The primary seals are V-packing, which is available in various compounds to suit specific well conditions. T-seals are also used to keep the packing sealing surface clean. In the open position, the port circulating flow area is equal to or greater than the tubing ID area, reducing pressure drop to a minimum.

The C and W sliding sleeve series include three types of sliding sleeves, C, CB and WB. C sliding sleeves, which do not have landing nipple profiles, are used when slickline installed flow controls are not required. Depending on installation, C sliding sleeves are opened by shifting the inner sleeve either upward or downwards. CB and WB sliding sleeves incorporate landing nipple profiles to allow landing, sealing and locking of blanking plugs, pack-off and separation tools. A polished sub area in the bottom of the sleeves receives the lower pack-off from a separation tool or a pack-off assembly. Various packing bore sizes are available on request.

CB sliding sleeves have no-go landing nipple profiles and include CB-1, CB-1D and CB-15-E sleeves. CB-1 and CB-15-E sleeves are opened by shifting the inner sleeve upward while CB-1D sleeves require downward shifting. Suitable for high pressure installations, CB-15 Sleeves also include an equalizing mode feature which consists of a secondary collet stop that mechanically retains the inner sleeve in the equalizing position to allow full exposure of the small equalization hole before the sleeve is shifted fully open.

WB Sliding Sleeve have selective landing nipple profiles and include WB-1, WB-1-E, WB-1D-E, WPB-1, WPB-1-E and WPB-1D-E sleeves. The WB-1, WB-1-E, WPB-1 sleeves are opened by shifting the inner sleeve upward while WB-1D-E and WPB-1D-E sleeves require downward shifting. WPB-1, WPB-1-E and WPB-1D-E sleeves feature premium threads, and WB-1-E, WB-1D-E, WPB-1D-E sleeves incorporate the equalizing mode feature. All Camco Sliding Sleeves can be shifted with standard Camco type C shifting tools.

10.3.1.1 □ **Operation**

When communication between the tubing and casing annulus is desired, a slickline shifting-tool is run to the depth of the sleeve. It automatically locates in the shifting profile machined into the inner sleeve. For sleeves, which open in the upward direction, light, upward jarring moves the inner sleeve slots past the seal rings so equalization can begin. After equalization, continued upward jarring fully opens the sliding sleeve and the shifting tool automatically releases. The shifting tool is turned over, run into the hole and the procedure is performed in reverse to close the sleeve. For sleeves, which open in the downward direction, the shifting procedure requires downward jarring.

10.3.2 DB Series Sliding Sleeves

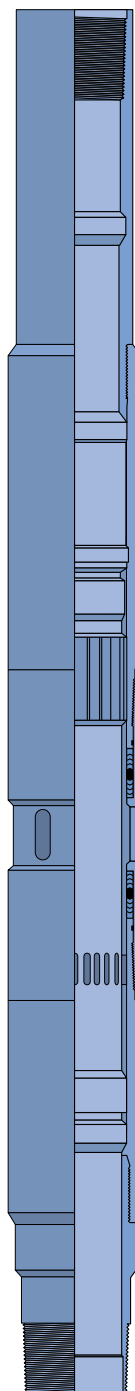


Figure 10-10: DB-1 Series Sliding Sleeve

Camco DB series sliding sleeves are designed to provide a reliable and easy means of opening and closing communication between the casing annulus and the large bore tubing. These sleeves contain a DB no-go landing nipple profile.

Each Camco sliding sleeve has a collet stop acting on the inner sleeve to mechanically retain the sleeve in either the fully closed or fully open position. The inner sleeve, which is made of premium material, contains small equalization slots, which are exposed first to provide a means of equalization before the primary circulation ports are fully exposed. Two types of stationary seals are used to seal around the inner sleeve. The primary seals are V-packing, which is available in various compounds to suit specific well conditions. T-seals are also used to keep the packing sealing surface clean. In the open position, the port circulating flow area is equal to or greater than the tubing ID area, reducing pressure drop to a minimum.

All DB series sliding sleeves incorporate no-go landing nipple profiles to allow for landing, sealing and locking of blanking plugs, pack offs and separation tools. A polished sub area in the bottom of the sleeves receives the lower pack off from a separation tool or a pack off assembly. The DB sliding sleeve series include DB-1, DB-1-E, DB-1D and DB-1D-E sleeves. Shifting the inner sleeve upward opens DB-1 and DB-1-E sleeves. DB-1D and DB-1D-E sleeves require downward shifting. DB-1-E and DB-1D-E sleeves also include an equalizing mode feature, which consists of a secondary collet stop that mechanically retains the inner sleeve in the equalizing position to allow full exposure of the small equalization slots before the sleeve is shifted fully open. All Camco sliding sleeves can be shifted with standard Camco type C shifting tools.

10.3.2.1 Operation

When communication between the tubing and casing annulus is desired, a slickline shifting-tool is run to the depth of the sleeve. The shifting tool automatically locates in the shifting profile machined into the inner sleeve. For sleeves, which open in the upward direction, light upward jarring moves the inner sleeve slots past the seal rings so equalization can begin. After equalization, continued upward jarring fully opens the sliding sleeve and the shifting tool automatically releases. The shifting tool is turned over, run into the hole and the procedure is performed in reverse to close the sleeve. For sleeves, which open in the downward direction, the shifting procedure requires downward jarring.

10.3.2.2 Sliding Sleeve Pack-offs

The CB, WB and DB series Sliding sleeve pack-offs, used in conjunction with appropriate Camco locks, are designed to pack off the communication ports within a sliding sleeve. The pack-off assembly seals in the upper integral landing nipple profile and in the lower polished nipple of through flow path for production fluids through the tubing and sleeve and to the surface.

The CB and DB pack-offs are equipped with non-selective no-go locks. The CB pack-off uses a C series no-go type lock and is run in a CB-1 or CB-1D sliding sleeve. The DB pack-off uses a DB series no-go type lock and is run in a DB-1 or DB-1D sliding sleeve. The WB series pack-off uses a selective M series type lock and is designed to be installed in a WB-1 or WB-1D series sliding sleeve.

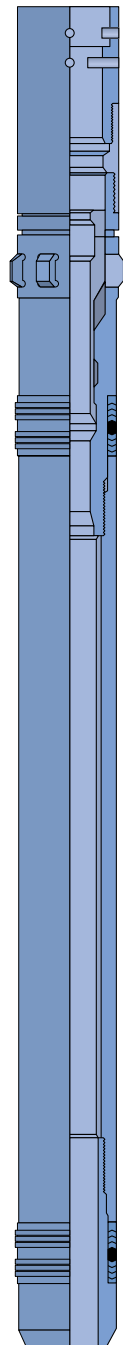


Figure 10-11: Sliding Sleeve Pack-Off – DB-1

Operation

To install a sliding sleeve pack-off assembly in the appropriate sliding sleeve, the lock and the attached pack-off assembly are lowered into the tubing using standard slickline methods. The running tool used is dictated by the type of lock. Downward jarring forces the locking dogs of the lock into the locking recess and anchors the assembly.

When removing these pack-off assemblies after equalization, upward jarring is applied to unlock the assembly. The pack-off can then be pulled from the sliding sleeve to the surface.

Table 10-3: Sliding Sleeve Pack-offs

Tubing		Assy #	Type	Lock Included	OD No-Go (in.)	Packing OD (in.)	Min. ID Lock (in.)	Install to Sleeve Assy #	Redress Kit Number	Running Tool	Pulling Tool
OD (Nom) (in.)	Weight (lb/ft)										
2.375 (2)	4.7	21611	CB-1	2 CC 10226	1.859	1.812	0.875	20818, 20889	18091	15783	15156
		21612	WB-1	2M 10602	N/A	1.875		20841, 20844	18093	15890	
2.875 (2½)	6.5	21593	CB-1	2½ CC 10227	2.296	2.250	1.125	20816, 20888	18073	15784	15158
		21405	WB-1	2½ M 10607	N/A	2.312		208875, 20887	16970	151.42	
3.500 (3)	9.3	21594	CB-1	3½ CC 10212	2.795	2.750	1.546	20819	18074	15785	15160
		21406	WB-1	3½ M 10609	N/A	2.812	1.545	20874, 20886	16719	15144	
		21401									
4.000 (3½)	11.0	21564	DN-1	4 DB-6 10322	3.360	3.312	1.875	21563	181.78	15096	15231
4.500 (4)	12.75	21414	DB-1	4½ DB-6 10260	3.735	3.687	2.250	21136, 21507	16680	15098	15203
		20955		4½ DB-6 10257	3.785	3.750		20803	18000		

Tubing		Assy #	Type	Lock Included	OD No-Go (in.)	Packing OD (in.)	Min. ID Lock (in.)	Install to Sleeve Assy #	Redress Kit #	Running Tool	Pulling Tool
OD (Nom) (in.)	Weight (lb/ft)										
5.500 (5 $\frac{1}{2}$)	17.0	20947	DB-1	5 $\frac{1}{2}$ DB-6 10274	4.482	4.437	2.781	20853	16977	15093	15204
		21595		5 $\frac{1}{2}$ DB-6 10263	4.545	4.500		20896. 20854	18075		
		21596		5 $\frac{1}{2}$ DB-6 10252	4.610	4.562		20893	18076		
7.000	26.0	21163	DB-1	7 DB-6 10267	5.920	5.875	4.000	21162	16978	15094	15205
Note: See pages 9-14 for Application Schematics											

10.3.3 Sliding Sleeve Separation Tools

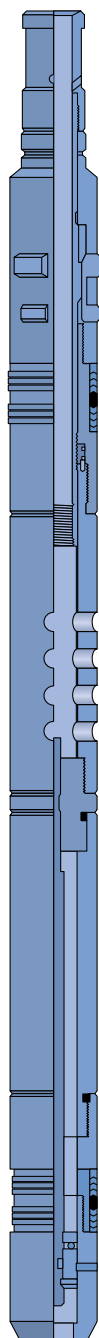


Figure 10-12: WB-1 Sliding Sleeve (Set Position)

The CB-1, WB-1 and DB-1 sliding sleeve separation tools are designed to allow flow from the casing annulus into an open sliding sleeve and up the production tubing, while blanking off the tubing just below the sliding sleeve. Use

of sliding sleeve separation tools enables alternating flow of two zones without commingling the zones during production. Sliding sleeve separation tools are designed to allow pressure to be equalized before they are retrieved from the well.

Each sliding sleeve separation tool is designed to be installed in a sliding sleeve that is equipped with a landing nipple in the top and a polished sub in the bottom. The CB-1 separation tool is run in the CB sliding sleeve, the WB-1 is run in the WB sliding sleeve and the DB-1 is run in the DB sliding sleeve.

The sliding sleeve separation tool assemblies include a Camco lock. The CB-1 sliding sleeve separation tool is made up to a C series lock, the WB-1 separation tool is made up to an M series lock and the DB-1 tool is attached to a DB-6 series lock.

10.3.3.1 Operation

To install the sliding sleeve separation tool in the appropriate open sliding sleeve, the separation tool, lock and integral pack off assembly are run into the tubing using standard slickline methods. The type of lock dictates the running tool used. Downward jarring forces the locking dogs of the lock into the locking recess, anchors the assembly, and seals it in the polished bores at the top and bottom of the sleeve.

When removing the assembly, downward jarring is applied to shear the equalizing device with the pulling tool and attached prong. Upward jarring unlocks the assembly, permitting removal from the sliding sleeve to the surface.

Table 10-4: Sliding Sleeve Separation Tools

OD (Nom) (in.)	Weight (lb/ft)	Assy #	Type	Lock Included	OD No-Go (in.)	Packing OD (in.)	Min ID (in.)	Install in Sleeve Assy #	Redress Kit #	Running Tool	Pulling Tool	Pulling Prong
2.375 (2)	4.7	21613	CB-1	2CC 10226	1.859	1.812	0.875	20818, 20889	18092	15783	15156	15646
		21614	WB-1	2 M 10602	N/A	1.875		20844, 20841	18094	15890		
2.875 (2- $\frac{1}{2}$)	6.5	21412	WB-1	2- $\frac{1}{2}$ M 10607	N/A	2.312	1.125	20887, 20875, 20886, 20885	16970	15142	15158	15931
		21597	CB-1	2- $\frac{1}{2}$ CC 10227	2.296	2.250		20816, 20888	18077	15784		15968

OD (Nom) (in.)	Weight (lb/ft)	Assy #	Type	Lock Included	OD No-Go (in.)	Packing OD (in.)	Min ID (in.)	Install in Sleeve Assy #	Redress Kit #	Running Tool	Pulling Tool	Pulling Prong
3.500 (3)	9.3	21598	CB-1	2- $\frac{1}{2}$ CC 10212	2.795	2.750	1.546	20819	18078	15785	15160	15969
		21600	WB-1	3- $\frac{1}{2}$ M 10609	N/A	2.812		20874, 20883	1880	15892		
4.500 (4)	12.75	21601	DB-1	4DB-6 10260	3.735	3.687	2.250	21507, 21136	18081	15098	15203	15723
		21602		4 DB-6 10257	3.785	3.750		20806, 20803	18082			
5.500 (5- $\frac{1}{2}$)	17.0	21603	DB-1	5- $\frac{1}{2}$ DB-6 10274	4.482	4.437	2.781	20853	18083	15093	15204	15606
		21599		5- $\frac{1}{2}$ DB-6 10263	4.545	4.500		20896, 20854	18079			
7.00	26.0	21604	DB-1	7DB-6 10267	5.920	5.875	4.000	21162	18084	15094	15205	15723

10.3.4 Type C Shifting Tools

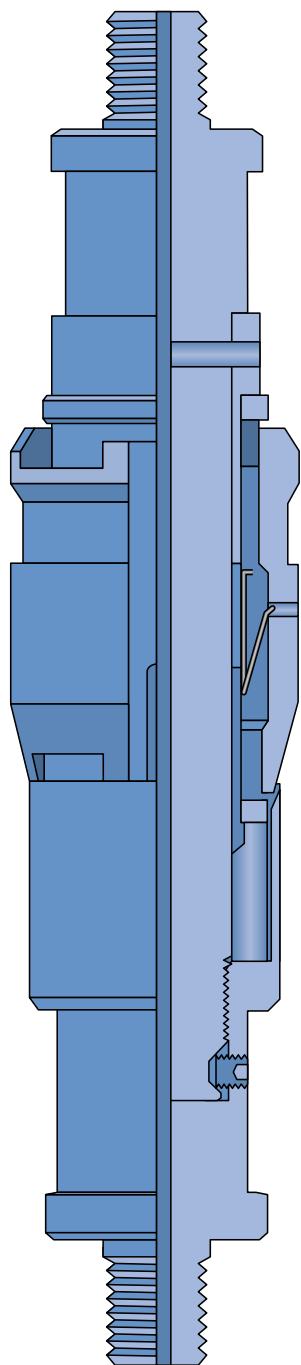


Figure 10-13: Type C Shifting Tool

The type C shifting tools are slickline service tools used to shift the inner sleeve of a Camco sliding sleeve. Type C shifting tools consist of a housing with a fishing neck and a pin thread connection on each end and spring loaded locating

keys. These tools automatically locate in the shifting profile of the inner sleeve and can be used to both open and close the sleeve, depending on the orientation of the locating keys. For example, after a sliding sleeve has been opened, the type C shifting tool is inverted, lowered into the shifting profile and the shifting procedure is performed in reverse to close the sleeve. These tools also feature an emergency shear release, which releases the tool if it does not automatically release after shifting the sleeve.

Table 10-5: Type C Shifting Tool

Nominal Size	Assembly Number	Minimum OD (in.)	Connecting Threads (Pin x Pin)	Fishing Neck OD (in.)	Pulling Tool*	Length (in.)
2	15349	1.750	15/16 in. - 10	1.375	15168	13.250
2½	15419	2.125	15/16 in. - 10	1.750	15170	14.000
3	15412	2.718	1-1/16 in. - 10	2.312	15172	14.000
4	15385	3.656	1-9/16 in. - 10	2.312	15172	14.875
5	13057	3.937	1-9/16 in. - 10	2.312	15172	16.000
5½	13239	4.468	1-9/16 in. - 10	2.312	15172	16.000
7	13229	5.864	1-9/16 in. - 10	2.312	15172	18.000
7	13231	5.781	1-9/16 in. - 10	2.312	15172	18.000

10.4 Baker Sliding Sleeves

Baker manufactures four basic types of sliding sleeve. All contain the F nipple profile in the upper sub and have a lower polished bore of the same ID as the upper seal area.

- Model L - opens upward using the Baker D-2 shifting tool with shifting tool reversed to close the sleeve. The model L sliding sleeve is run as an integral part of the tubing string.
- Model CMD - opens downwards using the Otis B (42 BO-) and Otis selective downshift (142-BO) shifting tools
- Model CMU - opens upwards using the Otis B shifting tool.
- Model T - opens downwards using the Otis B (42 BO-) and Otis selective downshift (142 BO-) shifting tools

The CMD and T models have an equalizing position between closed and open.

10.4.1 Model L Sliding Sleeve

The features of the model L sliding sleeve include:

- Seals are molded directly onto the sleeve
- Multiple sliding sleeves can be run and opened/closed selectively using the D-2 shifting tool
- Lower seal bore to permit installation of the following accessories:
 - Separation sleeves (LSE, LGE, LME)
 - Plugs (LSR, LWR)
 - Chokes (LSU, LWU, LGU)

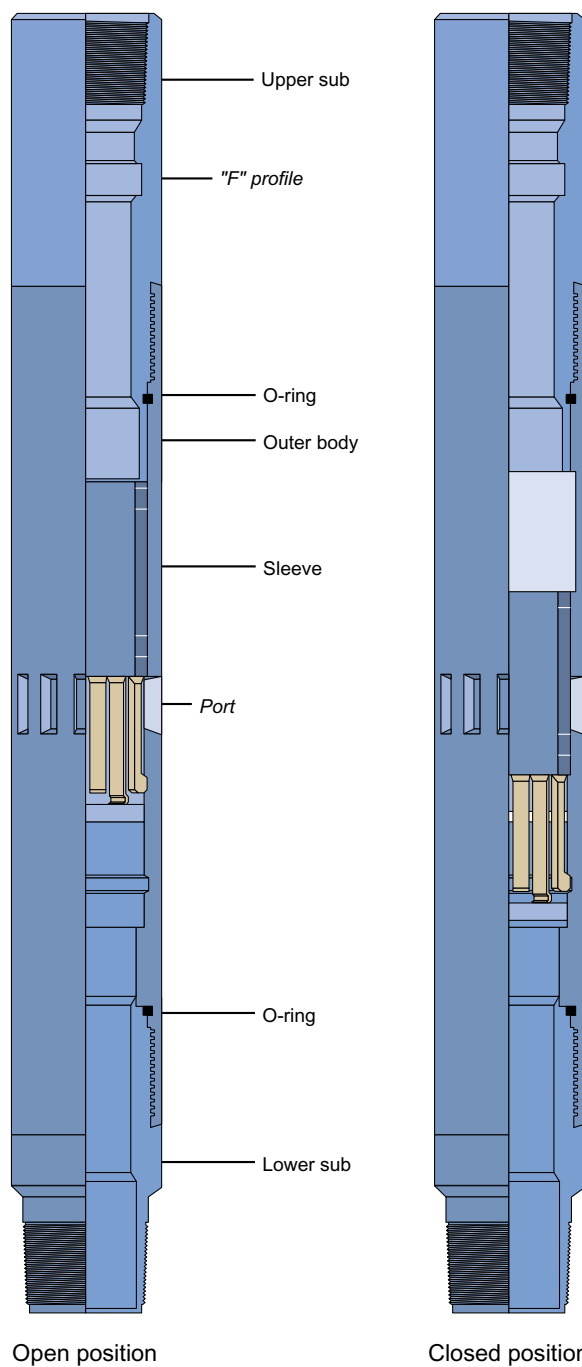


Figure 10-14: Model L Sliding Sleeve Open and Closed

10.4.2 Model D-2 Shifting Tool

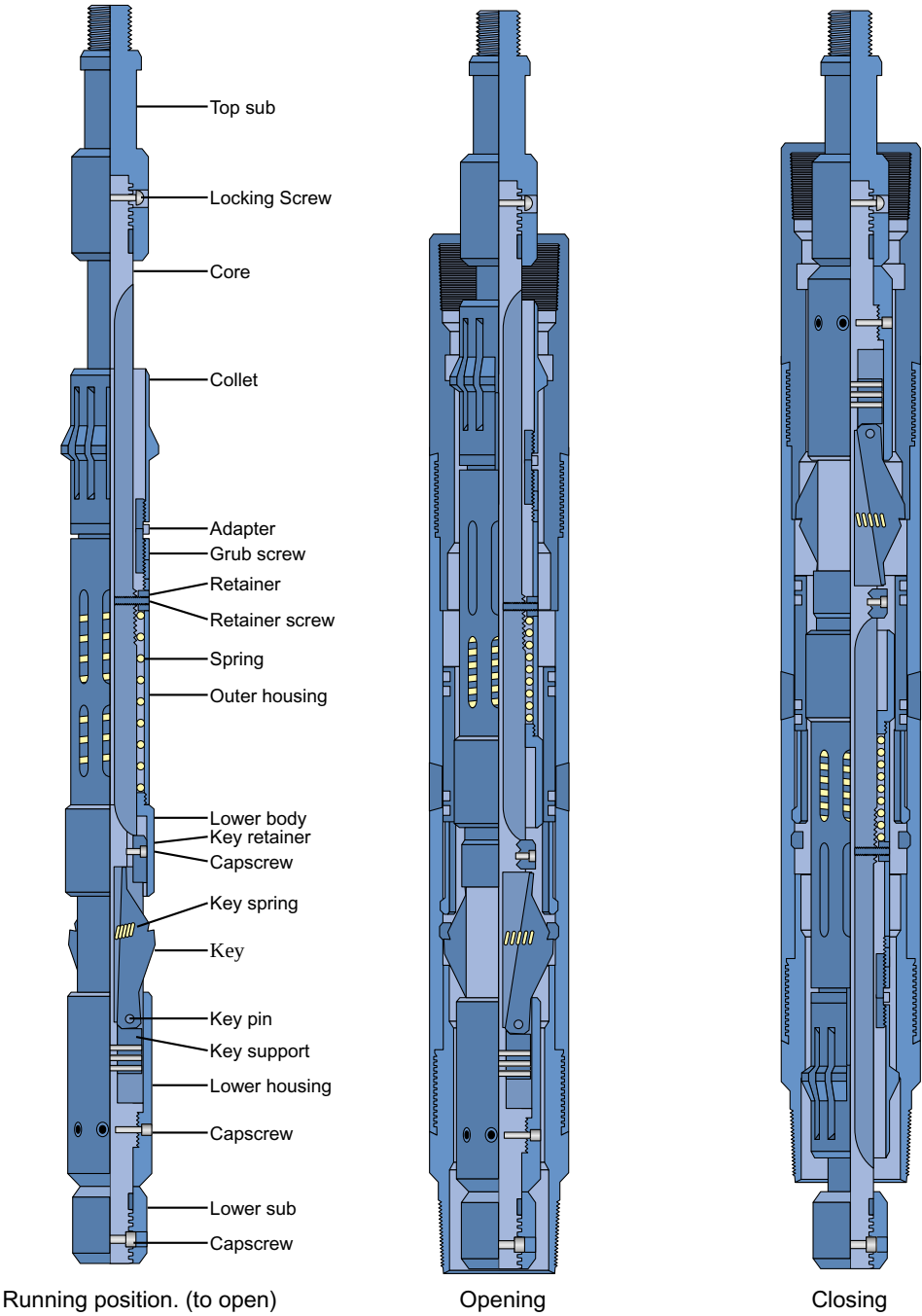


Figure 10-15: Model D-2 Shifting Tool Running, Opening and Closing Positions

The Baker D-2 shifting tool has two spring-loaded keys, which are held inwards, retracted, while running. On reaching the restricted bore of the L SSD, the collet provides friction against which the internal spring is compressed allowing the keys to move outwards to engage the end of the sliding sleeve.

The D-2 is run in either the opening position (shifting dogs facing up) or closing position by inverting the tool.

Refer to the diagram and chart for the two critical dimensions TO BE CHECKED BEFORE RUNNING, to ensure the correct LENGTH or distance between the collet and shifting keys.

10.4.2.1 Operation

1. If differential flow is encountered while opening the SSD, flow across the collet maintains the dog contact with the sleeve to reduce the change of tools begin blown up the hole.

i Note

During equalization, MAXIMUM strain should be maintained on the wire for two reasons, to assist in maintaining contact between the dogs and sleeve and to provide immediate rapid upward movement of the tool string if the dogs release.

2. The location of the SSD is verified by the operator when he encounters two seal bores across a distance of 2ft (as opposed to the single seal bore of a nipple profile).
 3. Verification that the sleeve has moved fully is achieved by attempting to re-latch after jarring is complete and the tool has released (assuming LENGTH has been correctly set).
 4. The D-2 shifting tool has three shear pins to permit the dogs to retract in the event that the sleeve will not move.
-

i Note

This shear pin should be checked as the tool is removed from the lubricator. If sheared, repin and rerun to verify that the sleeve is fully shifted.

An SSD with an upward opening direction has the following advantages:

- Hydraulic or spring jars can be utilized to increase upward impact

- In a thick, viscous fluid (heavy oil, drilling mud, etc.) a greater upward impact can be achieved from any given tool string weight/diameter.

To ensure the shifting tool moves the sliding sleeve fully, it is critical to check the following dimensions prior to running the tool.

- Collet OD - To ensure sufficient friction to locate in the seal bore to expand and engage the shifting dogs. If the collet is undersize, replace with a new collet.
- Length - Collet to dogs, to ensure:
 - Full movement of the sleeve prior to release (dog retracting)
 - Retracting of dogs to release the D-2 shifting tool after full movement of the sleeve. Not achieved if the length is too SHORT.

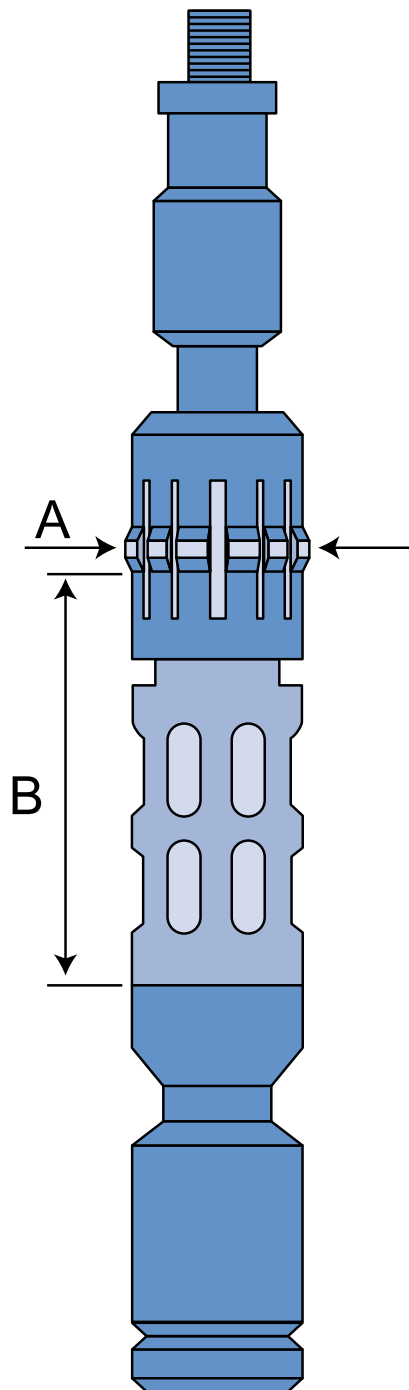


Figure 10-16: D-2 Shifting Tool

Table 10-6: D-2 Shifting Tool

Size	Dimension A		Dimension B		Pin Thread
	in.	mm	in.	cm	
1.18	1.213	30.81	14-17/32		0.625 OD
1.25	1.281	32.54		36.90	11N Thread
1.43	1.468	37.29	14-15/16		
1.50	1.531	38.89			
1.56	1.593	40.46		37.94	
1.62	1.656	42.06			0.937 OD
1.78	1.807	45.90	15-11/16		10N Thread
1.81	1.843	46.81		39.84	
1.87	1.906	48.41			
2.25	2.281	57.94	16-5/8	42.22	
2.31	2.343	59.31			
2.75	2.781	70.64	17-1/8	43.49	1.062 OD 10N Thread
2.81	2.843	72.21			
3.12					
3.25					
3.31					
3.68	3.743	95.07	22-11/16	57.62	
3.75	3.805	96.65			
3.81	3.867	98.22			
4.00					
4.12					
4.31	4.406	111.91	19 ⁷ / ₈	50.48	
4.56	4.656	118.26	19 ⁵ / ₈	49.84	
5.50	5.575	141.61	23 ⁵ / ₈	60.00	
2-1* <i>This size designation MUST be the same as the 'L' sliding sleeve.</i>					

10.4.3 Model CMU and CMD Sliding Sleeves

The Baker CM series sliding sleeves are high performance, equalizing sliding sleeves, which allow communication between the tubing and annulus for circulation or selective zone production. When desired, the sleeve can be shifted open or closed using standard slickline methods and a B type shifting tool. The tool is designed such that any lock profile and compatible seal bores can be specified to accept a wide range of slickline locks, and accessories. The sleeve is available in CMD downshift-to-open or CMU upshift-to-open versions.

The nominal working specifications for the sleeve, in most cases, are burst, collapse and tensile equal to N-80 tubing, 375°F service temperature with a 1500 psi maximum shifting differential. The sleeves have been designed in four standard materials; 4140, 9Cr-1Mo, 13% Cr and Inconel 718 for a wide range of services.

10.4.3.1 Features

In designing the CM series sliding sleeves, Baker Oil Tools combined several unique features to upgrade seal performance and increase service life.

- Specially designed diffuser ring made of high strength thermoplastic is critically spaced between the flow ports and the upper packing unit. This prevents damage to the upper packing unit during shifting by controlling the rush of fluid or gas and lessens the likelihood of tool string damage by providing for slow equalization of high differentials.
- Seal stack manufactured from proprietary, high strength, non-elastomeric compounds that are chemically inert and 30% stronger than commercially available materials. Rather than becoming hard and brittle or bonding to the metal, as is the case with elastomeric materials, our seal compound actually behaves as a lubricant, alleviating seal bonding problems.
- Mill slots replace drill holes as flow ports on both the housing and the insert to allow more flow area, reduce erosion and allow higher torque and tensile strengths through the sleeve.
- Locating the threaded connection inside the primary seal stack eliminates the need for O-ring thread seals and cuts the number of potential leak paths in half.
- A locking angled torque shoulder replaces the traditional square shoulder to allow higher torques and reduce thread back-off.
- The threat of galling is further reduced by coating the metallic components with proprietary surface treatments. This assures that the sleeve will be redressable in the future, even when ordered in CRA materials. These coatings also provide corrosion and erosion resistance. Alloy and stainless steel grades are treated with QPQ coating, which has performed flawlessly since 1985. High nickel alloys are coated with the BAKERTRON® ion plating process.
- The modular design permits conversion from a CMD to CMU or vice versa, by only changing the upper and lower subs.

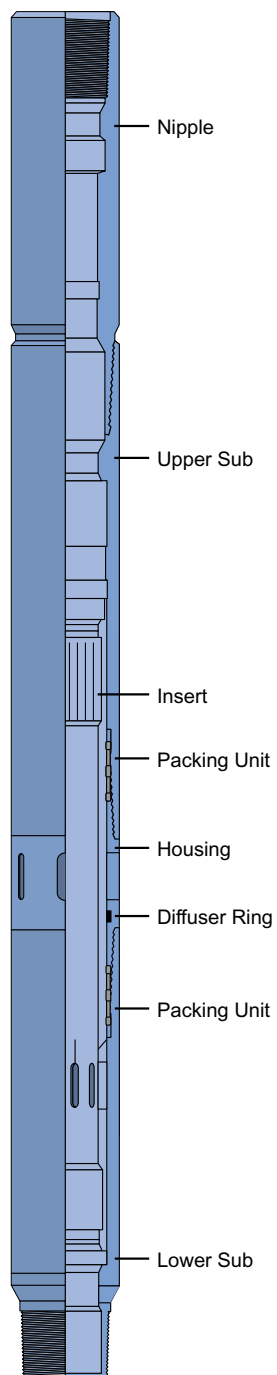


Figure 10-17: Model CMU Sliding Sleeve

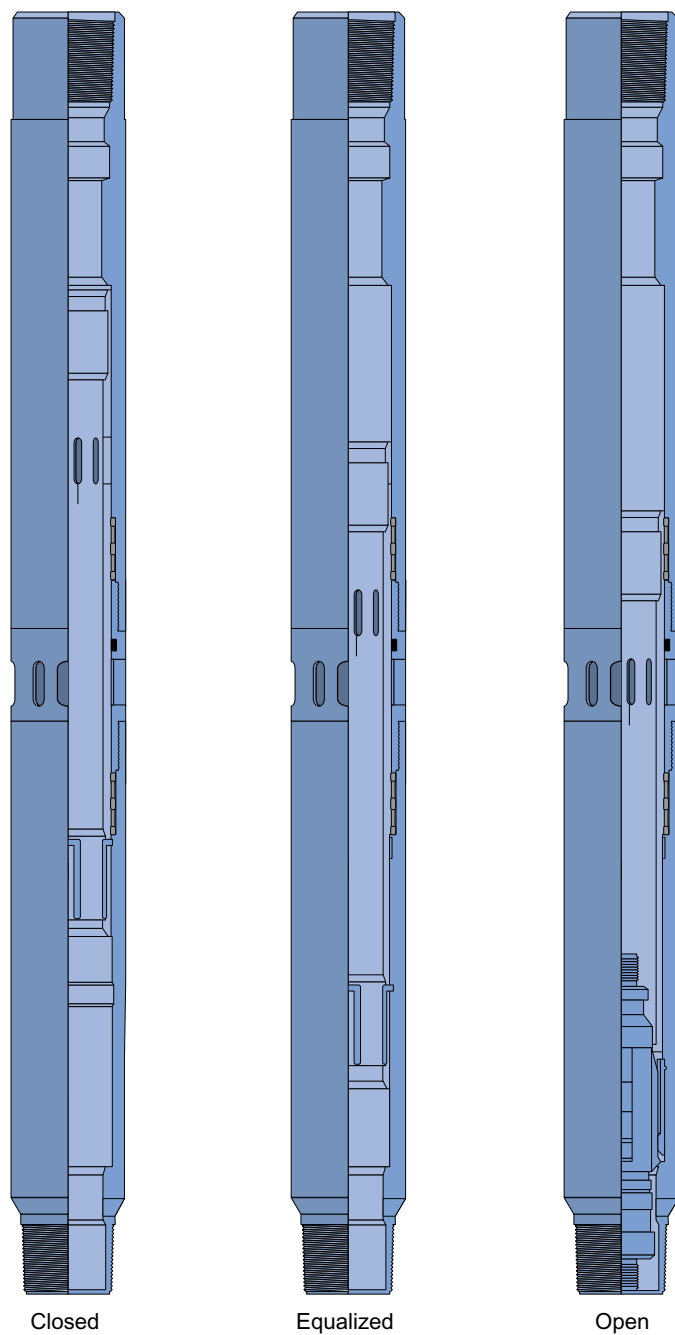


Figure 10-18: Model CMU Sliding Sleeve Closed, Equalizing and Open

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11 SAFETY VALVES

11.1 Introduction

There are three main categories of safety valves designed to protect personnel, installations and the environment:

- Subsurface Controlled Safety Valve (SSCSV)
- Surface Controlled Subsurface Safety Valve (SCSSV)
- Surface Safety Valve (SSV)

Subsurface Controlled Safety Valve

Originally known as storm chokes, these valves are run into the tubing by slickline and are designed to detect an abnormal situation or emergency and shut in to protect the well and environment.

The two basic designs either detect an increase in FLOW (differential type) or a DECREASE in pressure (ambient type) above or below normal limits. Although they have generally been replaced by the SCSSV type, they can still be set in place of an SCSSV if the control line develops a leak.

Surface Controlled Subsurface Safety Valve

As their names suggests, these valves are run below the surface but can be controlled from the surface. This control is achieved by hydraulic pressure transmitted from a control panel on the surface to the valve by stainless steel tubing. The two main options of this valve are:

- Wireline retrievable - Can be installed and recovered using slickline
- Tubing retrievable - Installed as part of the tubing string during the completion process

Both categories of SCSSV can have ball or flapper type closures. There are various design criteria that decide the choice of closure for the flowing conditions of a well. While the details of the relative designs are outside the scope of this manual, the following points can be relevant to slickline operations:

- The ball is closed by the control links
- Ball closure may cut the wire if closed during slickline operations

- While a flapper is unlikely to cut the line, it can be damaged if the tools are raised through a partially closed valve
- It is generally recommended that wireline retrievable valves be removed prior to slickline operations

Surface Safety Valve

Designed to automatically shut in the well at the Christmas tree in an emergency. The closing actuators can be pneumatic or hydraulic.

Various sensors maintain the pressure to the actuator mounted on the Christmas tree (on a wing valve or upper master valve). Should any abnormal situation be detected, the well is automatically.

If this actuator is on the upper master valve, it must be physically locked out of service before running slickline through the valve.

11.1.1 Subsurface Controlled Safety Valve (SSCSV)

The subsurface controlled safety valves are available in two basic types:

- The flow controlled type sense when the flow rate in the well exceeds the preset rate considered being within normal parameters. The differential force created across an internal choke bean closes the valve. These are normally open at the surface (zero flow).
- The Ambient Pressure sensitive type sense a drop in pressure below a preset valve considered to be within the normal flowing pressure variations. When the pressure surrounding the valve drops below the pre-charged nitrogen pressure and/or spring force, the valve closes. These are normally closed at atmospheric pressure.

Both of these types contain a detent mechanism to ensure a snap action closure. Without such a detent device, the valve could move partially closed to throttle the flow and not fully shut in. They are run on the appropriate lock mandrel with an equalizing sub attached.

These valve categories can have one of the following closing devices:

Table 11-1: Halliburton and Camco SSSCV Closing Devices

	Flow Controlled	Ambient Pressure Sensitive
Ball	Type J	Type H
Flapper	Type M, A	
Poppet	Type K, F	Type E, K, T

The type E is an ambient pressure sensitive poppet type closure, precharged with nitrogen (N₂). The balls act as a detent. As the well pressure drops below the internal pressure, the poppet snaps closed.

To reopen an SSCSV it is necessary to:

- Equalize pressure above the valve from the surface or
- Run an equalizing prong to open ports in the equalizing sub



Caution

Potential Severity: Light
Potential Loss: Assets
Hazard Category: pressure

Ensure that pressure is equalized before pulling a SSCSV.

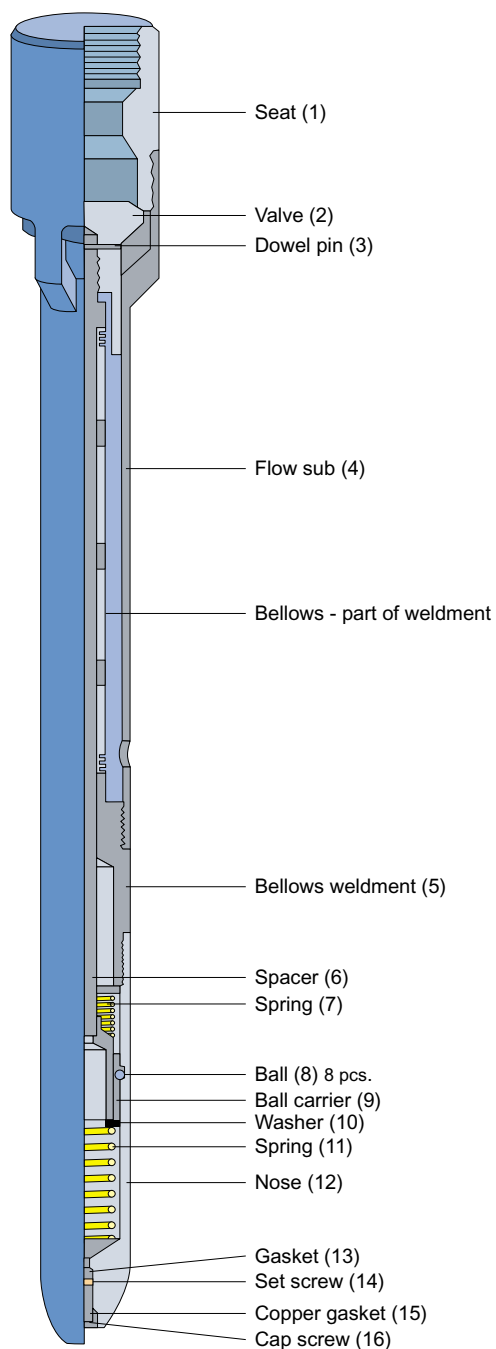


Figure 11-1: Type E SSCSV

11.1.1.1 Design

Safety valve uses a ball or flapper and seat, which effectively shut, in the well. The ball or flapper will rotate 90° in flow stream.

SCSSV's are normally closed valves, i.e., when not subjected to any pressure from the surface via the control line above the piston, the internal spring holds the valve in the closed position.

Calculation of Fail-Safe Depths

$$FSSD = \frac{FC - FS}{MFG}$$

$$FS = 0.15FC$$

where:

FSSD	The fail safe setting depth of the valve
FC	The minimum closing pressure in pounds per square inch
FS	The safety factor (psi) (should never be less than 75 psi)
MFG	The maximum fluid gradient in psi/ft. The gradient used should be based on the heaviest fluid (or combination of fluids) to which the hydraulic port of the valve can be exposed.

The selection of an operating fluid requires knowledge of the impact of different fluids on the operation of the surface controlled, subsurface safety valve (SCSSV). The fluid is a critical part of the safety system, which can impact the SCSSV closure response time and affect the long-term performance of the valve.

Select a fluid capable of retaining its properties at the temperatures anticipated. Give special consideration to selection of fluid for operations in temperature extremes (below 32°F and above 250°F). Camco recommend a clean fluid filtered to NAS-1638 Class 8 standards or better. Incorporate a filtering system with a suction filter of 10 microns or more into the hydraulic system. This type of filtering system will minimize the potential for solids intrusion into the hydraulic control line and thus minimize the chance of seal damage or wear.

11.1.1.2 Operation

When installed in the hydraulic nipple, control line pressure is applied between the two sets of V-packing and enters a port in the housing. This hydraulic pressure then acts on the piston, which moves downward against the spring force, thus rotating the ball or flapper to the open position.

Prior to commencing opening, the piston pushes the secondary sealing surface off its seat, which permits EQUALIZATION. With approximately 1:1 ratio, the well pressure equivalent will need to be applied to the control line.

The control line pressure should be maintained 1000 psi above the well shut in pressure.

11.1.1.3 Limitations

The standard slickline retrievable valves are designed to operate in wells up to 5000 psi shut-in pressure. They are also available in 10,000 and 15,000 psi models.

Maximum depth is determined by the hydrostatic pressure of the control line fluid. When the force created by this pressure is greater than the upward spring, the valve will no longer close due to loss of surface hydraulic pressure.

Advantages of Slickline Retrievable Systems

Advantages of the slickline retrievable subsurface safety valve include the following points:

- Accessibility - slickline retrievable valves can be installed in hydraulic landing nipples, communication nipples or locked out tubing retrievable subsurface safety valves.
- Slickline retrievable safety valves are easily installed and removed for repair or replacement.
- Situations requiring a valve with internal equalizing capabilities can utilize a sacrificial slickline retrievable valve with confidence. If the equalizing area is flow cut, the valve may be easily and inexpensively retrieved and repaired.



Note

If a means for pressuring the tubing above a closed SCSSV is available, it should be used. (See API RP 14B, Section 2, Paragraph 2.2f)

- Slickline retrievable safety valves may be removed during severe workover operations, such as acid sing or fracturing.

Disadvantages of Slickline Retrievable Systems

Disadvantages of slickline retrievable subsurface safety valve include the following points:

- During slickline operations, the valve must normally be removed. Hence, a downhole safety valve is not available.
- Flow rates can be restricted due to the smaller ID of slickline valves compared to the ID of tubing retrievable valves.
- Slickline valves are installed by slickline methods. They are not installed on the tubing string. Slickline operator errors or faulty locks may result in the slickline valve being blown from the nipple when closed.
- Before a valve is landed in a hydraulic landing nipple, the control line fluid is exposed to contaminating fluids in the tubing.

Advantages of Tubing Retrievable Systems

Advantages of the tubing retrievable subsurface safety valve include the following:

- High flow-rate capacity due to an ID equivalent to the tubing.
- Slickline operations may be carried out through a tubing retrievable valve due to its tubing compatible ID.
- The tubing retrievable SCSSV is made up on the tubing string.
- If the tubing retrievable valve should malfunction, a slickline retrievable valve may be located inside of it.



Note

If an all metal seal valve is utilized, it must be run with a communication nipple to provide secondary slickline capabilities.

- The valve is always in the well. It is not removed to perform slickline work.
- Control line fluid is not exposed to well fluids during installation and retrieval.
- The valve can usually be bridged during sever workover operations, such as acid sing or fracturing.

Disadvantages of Tubing Retrievable Systems

Disadvantages of the tubing retrievable subsurface safety valve include the following points:

- Accessibility – to retrieve a tubing retrievable SCSSV in the tubing must be pulled.
- Equalizing capabilities are not normally available in most Camco tubing retrievable valves. It is generally considered that conventional equalizing features are a misapplication. Camco do not recommend equalizing through any safety valve using conventional equalizing technology, especially not through a tubing retrievable valve. (Ref API-14B, paragraph 2.2F).

Camco Tubing Retrievable SCSSV's provide the following features:

- A field proven flapper closure system.
- Mechanical temporary lockout features in some valve types.
- Permanent lockout capabilities in all conventional tubing retrievable subsurface safety valve.
- A choice of concentric or rod piston actuation.
- Customer option of secondary valve capabilities with a hydraulic communication nipple.
- Standard, high or ultra high-pressure capabilities (5000 - 20,000 psi).
- All metal seal valves for harsh environments are made from premium alloys (Inconel, Elgiloy, etc) for high pressure, high temperature, high H₂S, CO₂ and chlorides.
- Variable setting depths, shallow or deep-set, depending upon the type and valve features.
- Reduced OD valves are available in some sizes for restricted casing clearance applications.
- Flapper security systems for preventing flapper and flow tube damage when unintentionally attempting to open against high differential pressures.
- Fully protected seat and flapper mechanisms during flowing conditions.
- Independent operation of the flow tube and flapper, no connection to any linkages.

- The flow is connected to the actuating pistons to take advantage of well pressure to assist in closure.
- Simple, rugged design with reliable field proven auxiliary features.

Applications for Slickline or Tubing Retrievable Subsurface Safety Valves

Slickline retrievable subsurface safety valves may be initially installed if a tubing restriction will not present a production problem. These valves can also provide safety in an initially installed tubing retrievable subsurface safety valve as a secondary valve. This application is used in wells where extremes in tubing-to-casing clearance make a tubing retrievable valve not feasible. Slickline retrievable valves are also used in special applications, other than these listed.

Tubing retrievable valves are generally used in all initial completions unless special previous sections of this unit. Vast amounts of field data indicate internal equalization mechanisms, whether they be across the main valve seat, through a hole drilled in the flapper or through an equalizing mechanism attached to the flow tube, are of poor reliability.

Reasons for this poor reliability, such as flow cutting, have also been highlighted. A valve with conventional internal equalizing mechanisms should always be thought of as sacrificial valves.

Table 11-2: Guide to Slickline Retrievable Safety Valves

Recommended Applications	A Series Velocity	A-1 Injection	B-7	WRDP-1 Series	WRDP-2 Series	WRDP-TPI Series	WRP-1A Series	WRP-1AH Series	WRDP-15 Series
Medium Pressure - to 7500 psi	X	X	X	X	X	X	X		
High Pressure - to 10,000 psi								X	
Ultra High Pressure-to 15,000 ft									X
Shallow Depth-to 1000 ft		X							
Medium Depth-to 2500 ft			X	X	X				
Deep Depth - to 6000 ft	X	X					X	X	

Recommended Applications	A Series Velocity	A-1 Injection	B-7	WRDP-1 Series	WRDP-2 Series	WRDP-TPI Series	WRP-1A Series	WRP-1AH Series	WRDP-15 Series
Standard Temperature - to 300°F	X	X	X	X	X	X	X	X	X
Corrosion - Sweet	X	X	X	X	X	X	X	X	X
Corrosion - Moderate	X	X	X	X	X	X	X	X	
Corrosion - Severe							X	X	
Sandy Service (Class II)			*	X	*	X	X	X	
API Standard - Weight Production Tubing	X	X	X	X	X	X	*	*	
Heavy-Weight Production Tubing						X	X	X	X
Features									
Orifice	X	X							
Concentric Piston Actuated			X						
Rod Piston Actuated				X	X	X	X	X	X
Elastomeric Seals	X	X	X	X	X	X	X	X	X
Spring/Spacer Adjustability				*	*		*	*	*
Internal Equalization			X	X	X	X			

Table 11-3: Guide to Tubing Retrieval Safety Valves

Recommended Applications	TRM-R, 4H	TRM-4E	TRM-4P, 4HP	TRM-4PE	TRM-4, DS	TRDPIT RSP-15	TRC-DH	TRTO
Working Pressure - to 5000 psi	X	X	X	X	X		X	
Medium Pressure - to 7500 psi	X		X				X	X

Recommended Applications	TRM-R, 4H	TRM-4E	TRM-4P, 4HP	TRM-4PE	TRM-4, DS	TRDPIT RSP-15	TRC-DH	TRTO
High Pressure - to 10,000 psi	X		X				X	
Ultra-High Pressure - above 10,000 psi						X		
Medium Depth-to 2500 ft	X	X	X	X		X		
Deep Depth-to 6000 ft					X			
Ultra Deep Depth-to 10,000 ft							X	X
Standard Temperature - to 300°F	X	X	X	X	X		X	X
High Temperature - 300 to 400°F						X		
Ultra High Temperature - 400°F and above						X		
Corrosion - Sweet	X	X	X	X	X	X	X	X
Corrosion - Moderate	X	X	X	X	X	X	X	X
Corrosion - Severe	X	X	X	X	X	X	X	X
Low Surface Operating Pressures (Tubing Pressure Insensitive)							X	
Sandy Service (Class II)	X	X	X	X	X	X		
Features								
Permanent Lockout Capability	X	X	X	X	X	X	X	X
Built-in Secondary Valve Capability	X	X	X	X	X			

Recommended Applications	TRM-R, 4H	TRM-4E	TRM-4P, 4HP	TRM-4PE	TRM-4, DS	TRDPIT RSP-15	TRC-DH	TRTO
Secondary Valve Capability with Optional Communication Nipple						X	X	
Elastomeric Dynamic Piston Seal							X	X
Non-Elastomeric Piston Seal	X	X	X	X	X			
Metal Dynamic Piston Seal						X		
Secondary Static Piston Seal			X	X		X		
Metal Body Joint Seal	X	X	X	X	X	X		
Internal Equalizing		X		X				

11.2 Camco Safety Valves

11.2.1 Camco WRDP-2 Safety Valve

These hydraulic surface controlled Camco slickline retrievable flapper safety valves have the following features:

- Working pressures up to 6000 psi
- Internal equalizing - which can be isolated before installation
- Straight through bore
- Rod piston operation
- Adjustable closing pressure

11.2.1.1 Principle of Operation

Hydraulic pressure from the surface control panel acts on two rod-pistons to hold the flow tube down to keep the flapper in the open position. The release of this hydraulic pressure permits the spring to move the flow tube and pistons upward, allowing the flapper to close and isolate the well fluids.

The WRDP-2 flapper valve has an internal equalizing feature. However, it is recommended to reduce the differential pressure across the valve as much as possible by adding pressure from an external source. If no external pressure is available, the procedure is different. This option is also covered below.

Shut the well in at the wellhead.

Equalizing

With external pressure source available:

1. Apply pressure slowly to the tubing above the safety valve at least equal to the shut-in tubing pressure below the valve.
2. Apply surface hydraulic pressure to the safety valve's hydraulic control line after differential pressure has been equalized, until the gauge registers the following pressure:

$$P = (\text{Shut-in pressure below valve} + \text{valve opening pressure} + 400 \text{ psi}) - \text{Hydrostatic pressure in control line.}$$

Without external pressure source available:

3. Apply surface hydraulic pressure until the valve starts to equalize.
4. Monitor the wellhead tubing pressure gauge to see if the tubing pressure is continuing to rise to shut in the pressure. Due to increasing tubing pressure acting to close the valve while equalizing, an occasional increase in hydraulic pressure may be required to keep the equalizing mode.
5. When the gauge registers a pressure equal to the tubing pressure, continue to apply hydraulic control line pressure until the safety valve is fully open. The fully open condition will be marked by a sudden increase in the pressure registered on the surface hydraulic control line pressure gauge. The valve should be opened with a zero psi opening pressure differential across the valve.
6. Adjust the hydraulic control line pressure until the control line pressure (P) registers as above.
7. Maintain this control line pressure on the safety valve to keep the valve fully open.

**Note**

In both of the above cases, the hydraulic control line pressure should not exceed the rated working pressure of the wellhead. Maintain this control line pressure on the safety valve to keep the valve fully open.

The opening pressure may vary slightly from valve to valve. This valve can be obtained from the safety valve to keep the valve fully open.

11.2.1.2 **Function Testing**

Functional testing of safety valves should be performed in accordance with API Specification 14A, Subsurface Safety Valves, Section 4 and Appendix C, latest edition.

**Note**

During the initial hydrostatic pressure test conducted at $1\frac{1}{2}$ times the rated working pressure, pressure should be applied simultaneously through a common line above and below the valve. It is equally important to bleed off this pressure through the line below the valve and not through the line above the valve to avoid trapping the hydrostatic test pressure across the flapper.

11.2.1.3 **Preparing the Running Tool**

The following procedure is recommended for use with:

- Lock mandrel - DB6
 - Running tool - Z-6
1. Install the running tool in a large vice. Clamp the vice on the fishing neck of the running tool.
 2. Remove the ring retainer from the lock housing position indicator.
 3. Place the ring retainer over the lower end of the running tool and move it up over the shear pin holes in the plunger of the running tool.
 4. Align the lower shear-pin holes of the ring retainer with the four pin holes of the running tool plunger.
 5. Tap the shear pins through the aligned holes of both the ring retainer and plunger.
 6. Move the plunger ring of the running tool down to meet the lock retainer ring.

7. Align the shear-pin holes of the plunger ring with the shear pin holes of the retainer ring. Install the shear pins. Tap the shear pins down firmly.
8. Make up the running prong to the lock pin retainer or fishing neck (depending on which thread connection prong was designed for).
9. Install the small garter spring on the end of the running tool plunger. There is a shallow groove for this purpose provided between the two deeper grooves at the end of the plunger.

When the garter spring is located in the deeper groove above the shallow groove, the proper setting of the lock is ensured.

The tattle tale garter spring will indicate the length of travel of the collet within the lock housing. The collet must move down fully, in order for the teeth to engage in the lock housing collet recess and ensure positive locking.

10. Remove the running tool from the vice.
11. Insert the running prong into the bore of the valve. When the flapper is contacted by the end of the running tool, gently ease it past the flapper in order to prevent possible damage to the flapper seats.
12. Make up the running tool and ring retainer onto the housing position indicator of the safety valve lock.



Note

Exercise care so that the garter spring is not rolled back as this step is accomplished.

13. Attach the running tool to the slickline tool string and proceed to run the valve in the well.

11.2.1.4 Lock Setting Procedure

Circulate a sufficient amount of hydraulic fluid down the control line and into the tubing to completely purge the control line of existing fluid. Run the tools into the well in the open position until the no-go ring contacts the safety valve nipple.

Jar downwards on the running tool to shear the pins holding the running tool plunger in the running position. Continue jarring down until a solid blow is indicated. The lock should be set in the nipple at this time.

Release the running tool from the safety valve by jarring upwards and shearing the pins holding the plunger ring of the running tool to the ring retainer of the safety valve lock.

Retrieve the running tool from the well. Examine the garter spring for proper positioning to indicate the positive setting of the safety valve lock.

**Note**

Pressure test the control line. Close the safety valve and test the valve for the proper operations.

11.2.1.5 Retrieving Procedure

The PRS pulling tool is used to pull the WRDP type safety valve. This style of pulling tool is used on safety valve locks, which incorporate locking members with internal fishing necks.

Sequence of Operation

Run the pulling tool with the appropriate pulling prong and slickline toolstring in the well. As the collets of the pulling tool contact the restricted diameter at the top of the lock collet, the pulling tool collet moves back against the collet return spring. Inertia allows the collet core to continue its downward travel. The collet fingers are deflected inward towards the reduced diameter of the collet core by the restricted diameter to the lock collet fishing neck.

Once the collet fingers are in the reduced diameter of the collet core, passage through the restricted opening of the fishing neck is made possible. As the collet fingers clear the opening of the fishing neck, the collet return spring shifts the collet fingers back over the larger diameter of the collet core and the running tool is locked into the locking recess of the fishing neck of the lock collet.

The lock is a pull-up-to-release mechanism. Pulling up on the pulling tool shears the brass shear pins in the neck of the collet and disengages the collet fingers of the lock collet. As the lock collet is pulled upwards, the locking dogs are released from the locking recess of the safety valve nipple and the valve can be pulled to the surface.

Aborting the Pulling Operation

If it becomes necessary to release the pulling tool without pulling the lock, downward jarring will bring the collet housing into contact with the top of the lock. This action will cause the shear pin holding the collet housing and inner mandrel to be sheared. When this occurs, the inner mandrel moves downward under continued downward jarring and the ratchet sleeve engages the inner mandrel and holds it in the downward position.

As the inner mandrel is extended and held in the downward position, collet core moves out from under the collet fingers and allows them to move inward into the reduced diameter of the collet core. In this position, the running tools can be separated from the safety valve lock. Redress the pulling tool each time a pulling operation is aborted.

Releasing the Pulling Tool from the Lock

Releasing the pulling tool from the lock following the removal from the well is accomplished by placing a pin punch or rod of the appropriate size in the hole of the collet. Retract the collet against the collet spring. There is a circumferential slot in the collet housing which allows the punch or rod to be rotated. The collet is retained in the retracted position when the punch is in the slot and the lock and pulling tool can then be separated.

Numerous alternative designs are available from a wide range of manufacturers. However from a slickline aspect the running/pulling procedures are similar, as the WRDP-2 presented in this manual.

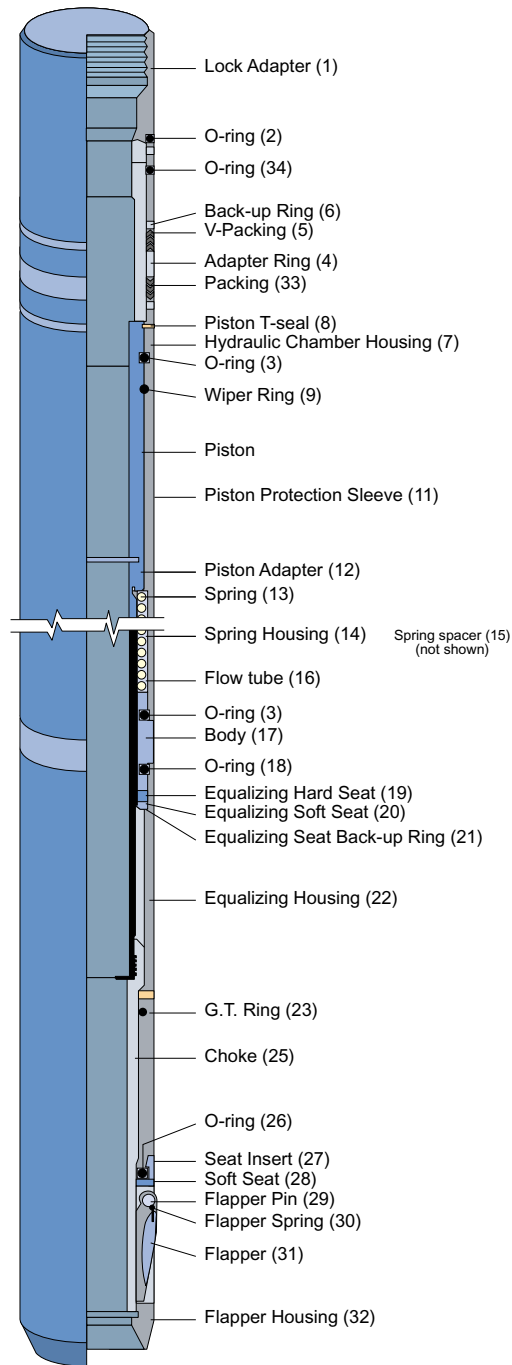


Figure 11-2: WRDP-2 Safety Valve

11.2.2 TRM-4 and 4H Series Safety Valves

The TRM-4 tubing retrievable, subsurface safety valves are value engineered to provide long lasting versatility and reliability. The TRM series valves feature rod piston actuation, metal body joints, a rugged, flapper closure mechanism and a

minimum number of critical seals to ensure maximum reliability. The versatile TRM-4 and 4H safety valves are available with a wide range of upper nipple profiles.

All TRM-4 series valves use a single rod piston with reliable non-elastomeric sealing elements and a static, full-closed, metal-to-metal seal. For maximum reliability, every TRM-4 valve features only two body joints and utilize Camco's proprietary, premium threads to achieve a solid, metal-to-metal seal. The flapper mechanism in the TRM-4 also has full, metal-to-metal sealing plus a secondary Teflon® soft seat and a leakage acceptance criterion that is less than one-quarter of one percent of that allowed by API specifications.

The modular design of the TRM-4 series allows a maximum of material and design options to cost-effectively fit specific applications and operating environments. TRM-4 valves are available with working pressure ratings to 10,000 psi and setting depths exceeding 2000 feet. Premium pistons, deep-set features, and self-equalizing valves are also available.

Table 11-4: TRM-4 SCSSV Features & Benefits

Features	Benefits
Short, compact and simple design	Cost-effective, easy to run, high reliability and durability
Minimum number of actual seals	Fewer potential leak paths, increased reliability
Metal seal body joints	Increased reliability
Non-elastomeric hydraulic seals	Highly resistant to corrosive chemicals and explosive decompression, reduces operating friction
Static operating piston seal when the valve is in the fully closed position	Increased reliability
Metal seal communication plug/lockout mechanism	Simple, one-trip lockout procedure with simultaneous secondary communication
Flapper lock-open without secondary communication	Provides for easy pulling during workover
Optimum geometry and clearance between sliding components	Reduces problems associated with solids and scale deposition
Valve can be repaired without being sent back to the factory	Cost effective

TRM-4 and -4H safety valves are designed for standard to moderately corrosive applications to 300°F. Camco Products & Services offers a special, surface treatment, ScaleGard™, for the TRM-4 and -4H that minimizes solids build-up on internal surfaces caused by produced fluids.

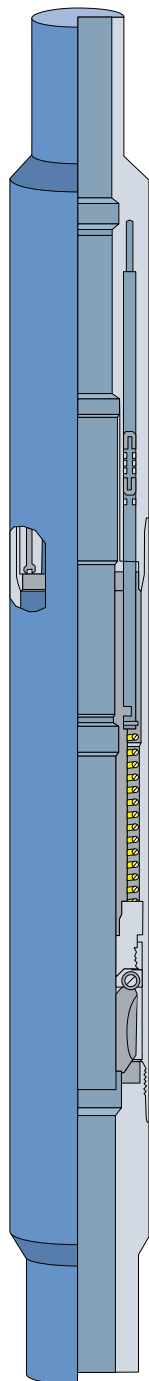


Figure 11-3: TRM-4 SCSSV Assembly

11.2.2.1 Operation

The TRM-4 safety valve is normally closed. It is opened by applying hydraulic pressure through a control line that extends from the safety valve through the wellhead to the surface control panel. Hydraulic pressure applied from the

surface forces the rod piston and the flow tube down. This downward force compresses the power spring and move the flapper off seat into the fully open position.

When the hydraulic control line pressure is released, the power spring pushes the flow tube and the rod piston up. The upward movement permits the hinged flapper to move into the flow stream and close against the flapper seat to shut in the flow from the well.

11.2.2.2 Lockout Procedure

A unique lockout mechanism enables a simple, one-trip, slickline procedure to permanently lock the valve open and initiate secondary hydraulic communication. A lockout sleeve, located above the flow tube, is shifted downward. This downward movement shears the shear plug, engages the lockout rod and permanently locks the safety valve open with hydraulic communication to the valve ID. A secondary slickline valve can then be installed in the TRM-4 or 4H valve. A second lockout option allows the TRM-4 and 4H to be locked open without hydraulic communication.

ENGINEERING DATA FOR TRM-4 SERIES SAFETY VALVES							
Tubing Weight Size* (in.)	Valve Type (lb/ft)	Assy Max	Standard Number	Working OD (in./mm)	Standard Polished Bore (in/mm)	Pressure (psi/bar)	Tensile Strength** (lb./kg)
2.375	4.70	TRM-4	23210-000	3.640 92.5	1.875	5000 340	142,000 64,410
		TRM-4	23201-000	3.688 93.7	47.6		127,000 57,606
2.875	6.50	TRM-4	23219-000	4.609 117.1	2.312 58.7		184,000 83,461
3.500	9.30	TRM-4	23218-000	5.176 131.5	2.812 71.4		261,000 118,388
4.500	12.75	TRM-4	23240-000	6.923 175.8	3.813 96.8		413,000 187,334
5,500	20.0	TRM-4	23265-000	8.226	4.562		466,000
				208.9	115.9		118,388
ENGINEERING DATA FOR TRM-4H SERIES SAFETY VALVES							

ENGINEERING DATA FOR TRM-4 SERIES SAFETY VALVES							
Tubing Weight Size* (in.)	Valve Type (lb/ft)	Assy Max	Standard Number	Working OD (in./mm)	Standard Polished Bore (in/mm)	Pressure (psi/bar)	Tensile Strength** (lb./kg)
2.375	4.70	TRM-4H	23209-000	4.124 104.7	1.875 47.6	10,000 680	133,000 60,328
2.875	6.50	TRM-4H	23233-000	5.166 131.2	2.312		222,000 100,698
		TRM-4H	23225-000	4.693 119.2	58.7		
3.500	9.30	TRM-4H	23249-000	5.916 150.3	2.812		263,000 119,295
		TRM-4H	23252-000	5.568 141.4	71.4		345,000 156,489
	10.3	TRM-4H	23254-000	5.568 141.4	2.750 69.9		263,000 119,295
		4.500	12.75	TRM-4H	23239-000		7.923 201.2
TRM-4H	232S5-000			7.425 188.6	96.8		7500 510

* Other sizes available on request.

** Tensile strength based on 80 K51 material, higher strength material available on request.

11.2.3 Camco TRM-4E Series Safety Valves

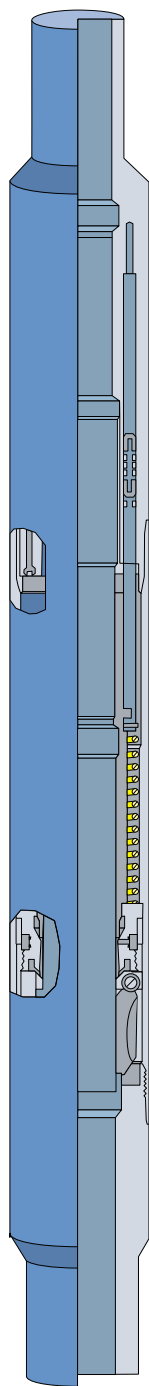


Figure 11-4: TRM-4E SCSSV

The TRM-4E tubing retrievable subsurface safety valves are value engineered to provide remarkable versatility and reliability. The TRM series features rod piston actuation, metal body joints, a rugged flapper closure mechanism and a minimum number of critical seals to ensure maximum performance. The versatile TRM-4E safety valves are also available with a wide range of upper nipple profiles.

All TRM-4E series valves use a single rod piston with reliable non-elastomeric sealing elements and a static, full-closed metal-to-metal seal. For maximum reliability, every TRM-4E valve has only two body joints and used proprietary, premium threads to achieve a solid, metal-to-metal seal. The flapper mechanism in the TRM-4E also has full metal-to-metal sealing plus a secondary Teflon® soft seat and a leakage acceptance criterion that is less than one-quarter of one percent of that allowed by API specifications.

The design of the TRM-4E series allows a maximum of material and design options to cost effectively fit specific applications and operating environments. TRM-4E valves are available with working pressure ratings to 5000 psi and setting depths exceeding 2000 ft. Premium pistons and deep-set features are also available.

11.2.3.1 Internal Equalizing Feature

The TRM equalizing system is a fail-safe system strategically located above the flapper seat. This design minimizes any effect from erosive velocities and prevents the equalizing dart from being dislodged. The ports within the dart provide a dedicated flow path for the wellbore fluid. They also protect the dart sealing surfaces and eliminate flow induced damage. For added wear resistance, the equalizing system components are manufactured from erosion resistant materials.

Table 11-5: TRM-4E SCSSV Features & Benefits

Features	Benefits
Short, compact and simple design	Cost effective, easy to run, high reliability and durability
Minimum number of critical seals	Fewer potential leak paths, increased reliability
Metal seal body joints	Increased reliability
Non-elastomeric hydraulic seals	Highly resistant to corrosive chemicals and explosive decompression, reduces operating friction
Static operating piston seal when the valve is in the fully closed position	Increased reliability
Metal seal, communication plug/lockout mechanism	Simple, one-trip lockout procedure with simultaneous secondary communication

Flapper lock-open without secondary communication	Easy valve pulling during work over
Internal self-equalizing dart system with dedicated flow path	Self-equalizing without compromising reliability.
Optimum geometry and clearance between sliding components	Reduces problems associated with solids and scale deposits

11.2.3.2 Application

TRM-4E safety valves are designed for standard to moderately corrosive applications to 300°F. A special surface treatment, ScaleGard™ that will minimize solids build-up on selected internal surfaces caused by produced fluids.

11.2.3.3 Operation

The TRM-4E safety valve is normally closed. It is opened by applying hydraulic pressure through a control line that extends from the safety valve through the wellhead to the surface control panel. Hydraulic pressure applied from the surface forces the rod piston and flow tube down. This downward force compresses the power spring and moves the flapper off seat into the fully open position. When the hydraulic control line pressure is released, the power spring pushes the flow tube and rod piston up. The upward movement permits the hinged flapper to move into the flow stream, close against the flapper seat and shut in the flow from the well.

11.2.3.4 Lockout Procedure

A unique lockout mechanism enables a simple, one-trip, slickline procedure to permanently lock out the valve and initiate secondary hydraulic communication. A lockout sleeve, located above the flow tube, is shifted downward. This downward movement shear a shear plug, engages a lockout rod and permanently locks the safety valve open with hydraulic communication to the valve ID. A secondary slickline valve can then be installed in the TRM-4E valve. A secondary lockout option allows the valve to be locked open without activating secondary hydraulic communication.

11.2.3.5 Equalizing Procedure

Only hydraulic pressure applied to the actuating piston is needed to open the valve when there is pressure below the flapper. The valve's flow tube moves downward and pushes a ported equalizing dart outward. The well bore fluid travels through a port in the equalizing dart and into the bore of the valve above

the flapper. The pressure above the flapper increases until it equals the pressure below the flapper. The flow tube will then move down to the fully open position shielding the closure mechanism.

Table 11-6: TRM-4E Series Safety Valves Engineering Data

Tubing Weight Size* (in./mm)	Valve Type (lb/ft)	Assembly	Maximum Number	OD (in.)	Standard Polished Bore (in/mm)	Working Pressure (psi/atm)	Tensile Strength** (lb/kg)	
2.875	6.5	TRM-4E	23206-000	4.609	2.312 58.7	5000 340	184,000 83,461	
3.500	9.20	TRM-4E	23227-000	5.176	2.812 71.4		261,000 118,388	
		TRM-4E	23253-000	5000			257,000 116,573	
		TRM-4E	23251-000				263,000 119,295	
4.500	12.6	TRM-4E	232S6-000	6923	3.812 96.8		413,000 187,334	
5.500	20.0	TRM-4E	23266-000	8 226	4.562 115.9		466,000 211,374	
* Other sizes available on request.								
** Tensile strength based on 80 K51 material, higher strength material available on request.								

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12 GAS LIFT SYSTEMS

12.1 Introduction

Gas lift was first used in Pennsylvania in 1865, but did not gain popularity until it was introduced in the Gulf Coast area of the United States in the early 1900s. It is now in common use worldwide as an efficient, cost-effective means of optimizing the production rate and enhancing the wells economics.

When the formation pressure is insufficient to overcome the hydrostatic head of the fluid in the tubing, the well will not flow. This can be the situation with a new well, or with an existing well where the Bottom Hole Pressure (BHP) has declined while producing. In both of these cases, gas lift can be utilized to help flow the well.

To understand the principle of gas lift, it is necessary to be familiar with hydrostatic pressure and gradient principals.

Hydrostatic pressure	the pressure exerted by a column of fluid, affected by the column height and specific gravity of the fluid.
Gradient	the pressure exerted per foot of vertical height of the fluid column. The gradient increases as specific gravity of the fluid increases.

12.1.1 The Principles of Gas Lift

While this section deals with the equipment and slickline related aspects of running and pulling gaslift valves, a basic description of the gas lift process has been provided to assist with an overall understanding of this topic. The calculation of gas lift setting pressure and the complete range of equipment options available is beyond the scope of this manual.

Gas is introduced into the oil as deep as possible. This is usually from the casing and into the tubing, but sometimes this is reversed, i.e., gas down the tubing and flow up the casing.

As the gas mixes with the oil it reduces the specific gravity of the oil, which means that the gradient has been reduced. By reducing the gradient, the hydrostatic pressure is reduced to a point where the formation pressure is greater than the BHP. As the oil and gas column moves upwards the finely divided particles of gas expand, thus further reducing the hydrostatic pressure.

Provided the correct amount of gas is injected, it will remain in the solution until the oil reaches the surface. The gas can then be separated and re-injected.

If too much gas is injected, it will break out of the solution and return to the surface without bringing any oil with it.

Valves can be divided into two main types:

- Tubing pressure sensitive - Close when the tubing pressure falls below the preset point
- Casing pressure sensitive - Close when the casing pressure falls below the preset point

The main types of side pocket mandrel and valve types used will be described later in this section.

12.1.2 The Unloading Sequence

The unloading sequence for gas-lift operations can be summarized as follows.

1. The well is ready to unload with the casing and tubing full of fluid.
2. Gas pressure displaces the fluid from the casing into the tubing through the valves, which are all open at this point. Gas has not entered the tubing, which is full of fluid.
3. The casing fluid level has been lowered below the first valve, and gas entered the tubing. From this moment, gas lifting commences even though only dead tubing fluid is being lifted. There is possibly little or no fluid flowing from the formation at this point.
4. The casing fluid level has been lowered below the second valve, and gas injection commences through the second valve. As the flow is established from the second valve, the tubing pressure gradient opposite the first valve decreases and the first valve closes. At this step in the unloading sequence, the back pressure on the formation has been decreased to the point where formation fluid may start feeding into the well bore and the fluid in the tubing gradually changes from load fluid to formation fluid. The formation fluid will be contaminated by load fluid being transferred from the casing as unloading continues.
5. The casing fluid level is now below the third valve and gas injection commences from this depth. As the flow is established from the third valve, the second valve closes because of the drop in tubing pressure. Injection through the third valve lowers the backpressure on the formation further and additional fluid flows into the well bore from the formation.

6. The fourth valve has been uncovered and injection commences at this point. The third valve closes and the flow stabilizes at the maximum rate possible for the installation.

**Note**

Dead Fluid - Contains little or no gas and has a higher gradient as compared to live fluid

Load Fluid - Dead fluid that is loading the tubing and creating a higher hydrostatic pressure, which prevents the well from flowing naturally.

Unloading valves with preset closing pressures are used in the upper side pocket mandrels (SPM).

An orifice valve (generally called a working valve) is positioned in the lowest SPM that is in use. It is possible that multiple orifice valves are used in some gas lifting configurations.

All valves have a check valve in the nose to prevent back flow of fluid from the tubing to the casing. Provided these valves are holding pressure, the well is faster to kick-off after it has been initially unloaded of casing fluid.

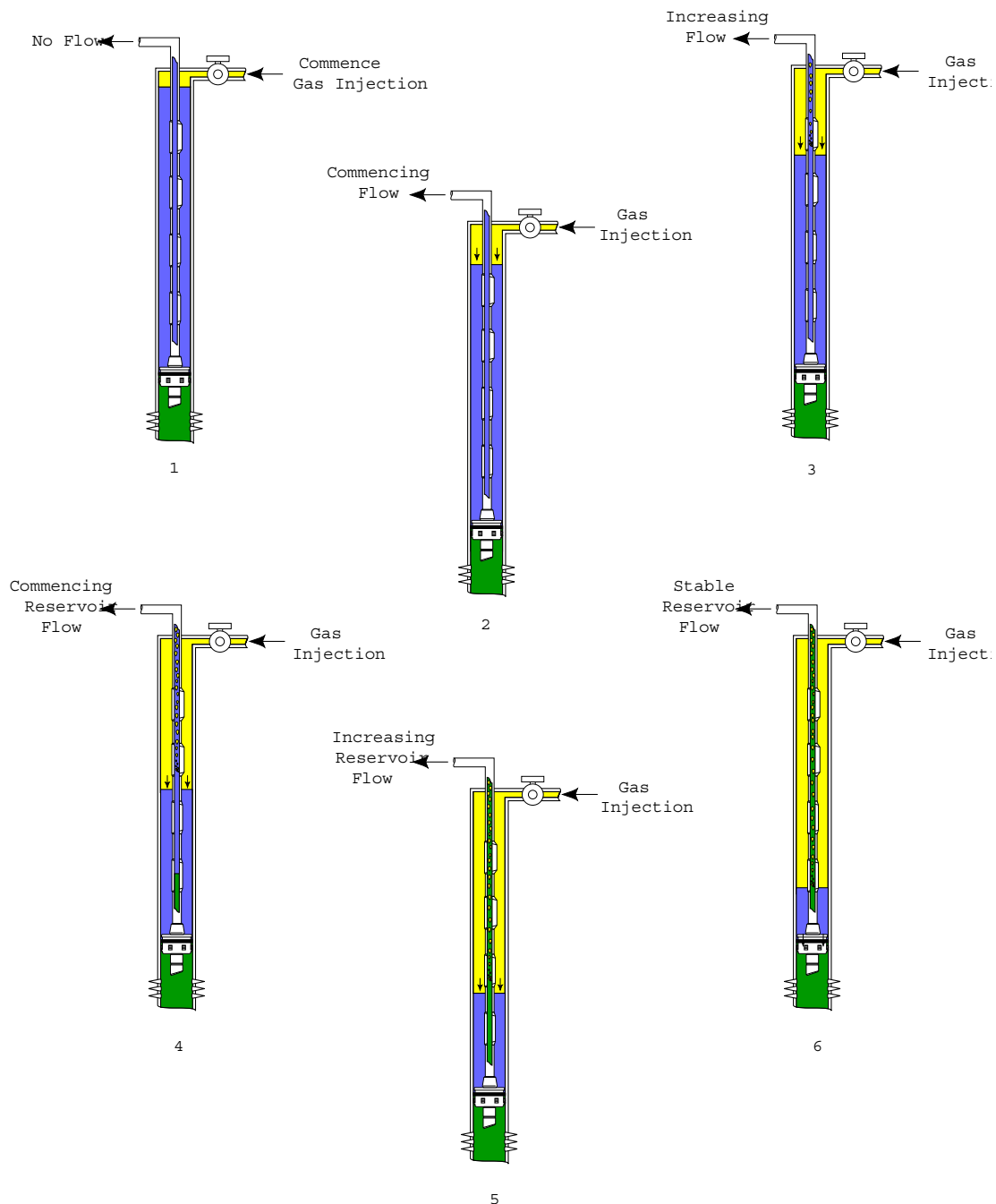


Figure 12-1: Gas Lift Unloading Sequence

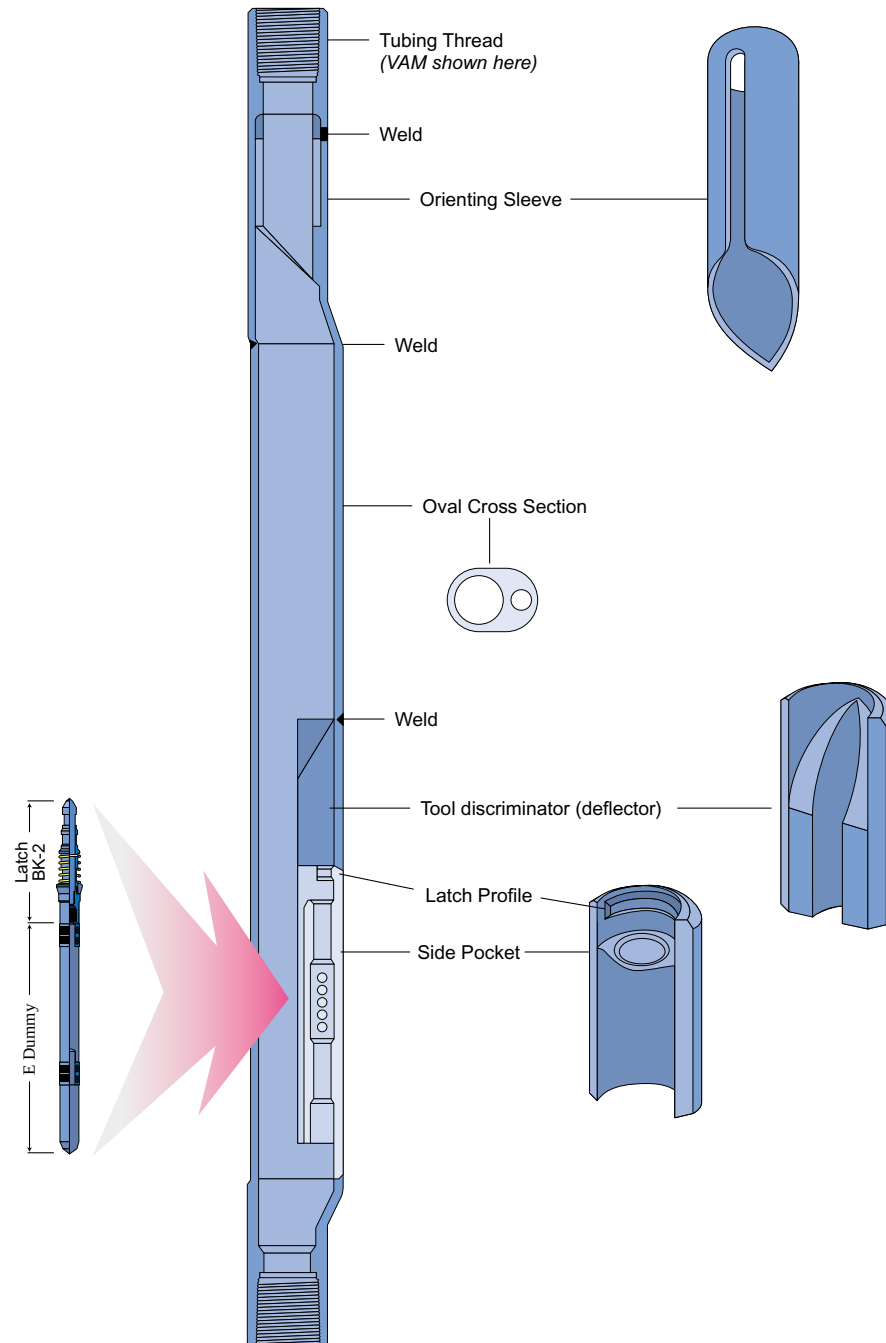


Figure 12-2: Side Pocket Mandrel Assembly

12.1.3 Slickline Equipment for Gas lift Servicing

The following items of slickline equipment are required to install and retrieve gas lift valves:

12.1.3.1 Kick-over Tool

To align the valve or pulling tool above the latch. In all new SPMs an orienting sleeve rotates the kick-over tool into the correct position relative to the side pocket.

Older style SPMs have no orienting sleeve, so spring centralizer kick-over tools (e.g., Camco L or R) must be used. These do not function well in highly deviated wells.

12.1.3.2 Running Tools

Matched to the type of latch in use and attached with shear pins, the running tool screws into the kick-over tool.

12.1.3.3 Pulling Tools

Selected to suit the latch in use, the pulling tool is attached to the kick-over tool to recover the valve.

12.1.3.4 Space Bars

In some deviated wells, spacers may be required between the pulling tool and kickover tool to enable the skirt to pass over the top of the latch. This situation usually occurs when the belly of the SPM is on the topside. Gravity acts to pull the tools down and away from the pocket. This situation can also occur when running valves and a spacer can be installed between the running tool and kick-over tool. Good well records, noting any such difficulties and use of spacers and their lengths, can reduce miss-runs after this potential problem has been identified.

There are a wide variety of side pocket mandrels available from a wide range of manufacturers. However, the design and operating principles are very similar. Within the scope of this manual, we have selected the types in most common usage. For details of SPMs for specific applications, please contact your equipment supplier.

12.2 Side Pocket Mandrel

The most common method of controlling the lift gas flow is by the use of side pocket mandrels (SPM) installed in the tubing during the completion. Their main advantage is that they do not obstruct the tubing ID, so plugs and BHP surveys etc. can be run to the bottom of the well without disturbing the gas lift system.

A wide variety of valves or control devices can be installed in an SPM:

- Gas lift valve
 - Sensitive to casing pressure
 - Sensitive to tubing pressure
 - Orifice valve to control rate of gas flow
- Dummy valve
 - Installed while running/pressure testing and prior to installing a gas lift valve
- Chemical injection valve
- Differential kill valve
- Electronic pressure and temperature gauges

Latches are attached to the devices run into an SPM to hold them in the correct position in the side pocket of the mandrel.

12.2.1 Camco Side Pocket Mandrels

In the Camco series, a range of SPM sizes from $2\frac{3}{8}$ to 7 in. are available.

- G Series - contain an orienting sleeve to position the kick-over tool
- K Series - have a 1 in. ID side pocket
- M Series - SPMs denoted with an M, but without a K, have a $1\frac{1}{2}$ in. ID side pocket

A wide range of SPMs is available for specialized applications, such as water flood and chemical injection.

Commonly used examples include:

12.2.1.1 MMA

These are still in used in some older wells. This SPM accepts $1\frac{1}{2}$ in. valves on an RA latch. It has no orientating sleeve, so a non-orienting kick-over tool must be used.

Kick-over tool options:

- Camco Type L or L-2D
- Type R

12.2.1.2 MMG

Accepts $1\frac{1}{2}$ in. valves with an RK latch. This SPM is similar to the MMA, but with the addition of an orientating sleeve and tool discriminator.

Kick-over tool options:

- OM series kick-over tool
- Type L¹²⁻¹ or L-2D¹²⁻¹
- Type R¹²⁻¹

12.2.1.3 KBMG/KBUG

Accepts 1 in. valves on a BK-2 latch. This SPM has a similar internal design to the MMG, including orientating sleeve and tool discriminator.

Kick-over Tool Options:

- OK series (OK-1 through to OK-6)

The orientating sleeve positions the kick-over tool to kick into the pocket when pulling upwards. The tool discriminator is a built in deflector that ensures the tools of larger OD than the gas lift valve, do not hang-up in the side pocket profile. Care must be taken when running small diameter tools such as a PX prong or other prongs so as not to kick over into a SPM.

Otis Side Pocket Mandrels

12-1. *Not recommended in highly deviated wells*

The central section of the Otis SPMs are machined from solid bar, with the tubing flow area and side pocket drilled and honed as required. This method eliminates the longitudinal weld. Full-length internal transfer rails (deflectors) reduce the bending forces on the valve as it is being installed or removed. End caps are welded in place, and the complete assembly annealed to provide optimum strength. The Otis mandrels are available in 2 main version from $2\frac{3}{8}$ to 7 in.

- Tru Guide - Oval cross-section SPM with 1 in. ID side pocket
- Hi-Strength Tru Guide - Round cross-section SPM with 1 in. and $1\frac{1}{2}$ in. side pocket

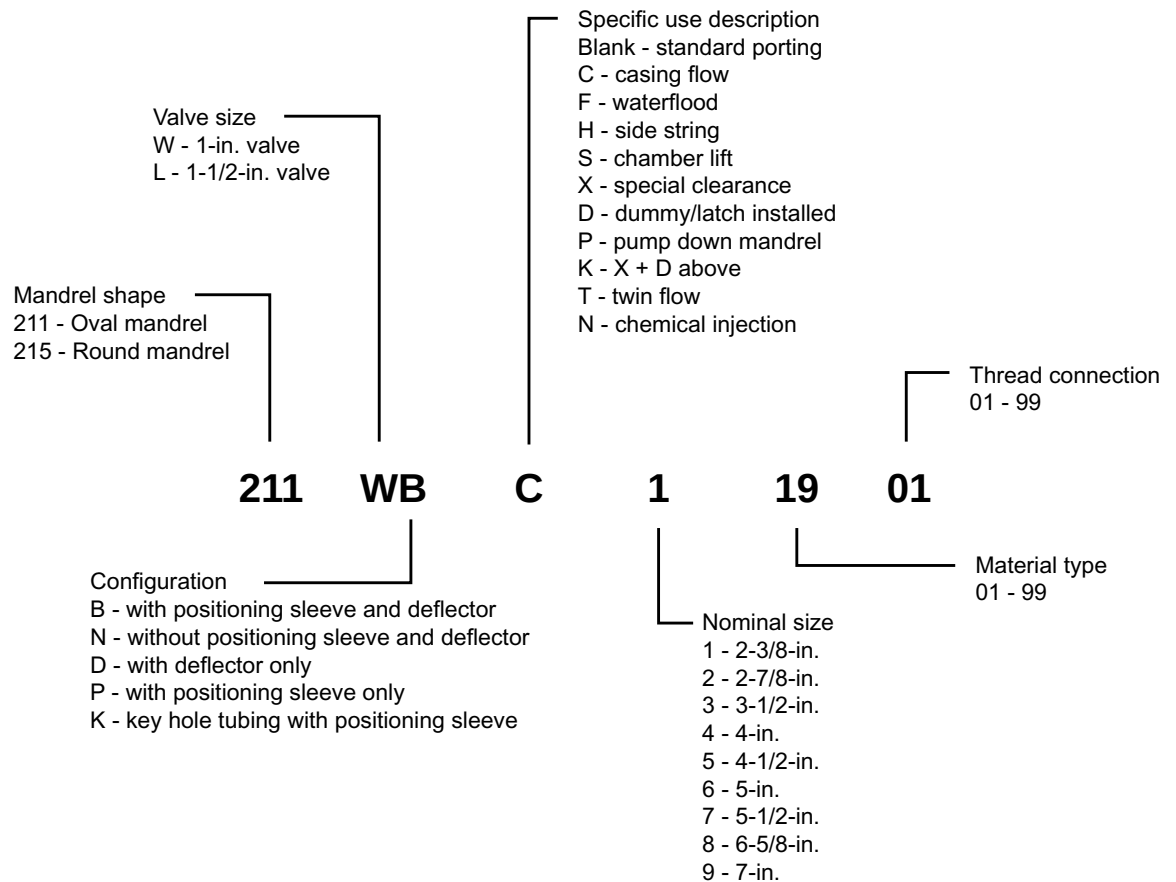


Figure 12-3: Otis Part Number Structure and Information

12.2.2 Merla Side Pocket Mandrels

TMPD Mandrels - 1 in. valves - Uses Merla TMP kick over tool (OK series tool compatible *)

TPD Mandrels - $1\frac{1}{2}$ in. valves - Uses Merla TP kick over tool (OM series tool compatible *)

- The orienting slot in a Merla, Otis and Macco SPM is not as wide as in a Camco SPM. When using a Merla kick over tool in a Camco SPM, the orienting finger must be reduced in width.

12.2.3 Macco Side Pocket Mandrels

SPM-1A and SPM-1N - 1 in. valve - OK series kick over tools

SPM-2 and SPM-2N - $1\frac{1}{2}$ in. valves - OM series kick over tools

12.3 Kick-over Tools

Kick-over tools, sometimes referred to as positioning tools, are run on the slickline tool string. The running or pulling tool is attached to the lower thread on the kick-over tool. Upward movement in the SPM selected causes the kick-over tool to rotate and align with the side pocket. A swivel or knuckle joint **must** be run directly above the kick-over tool to insure that the tool rotates properly when pulling up into the orienting feature.

12.3.1 Camco Kick-over Tools

OK-1 to 5	For 1 in. OD valves. Higher number indicates newer model.
OK-6	Newer version of OK series (using detent balls in place of shear pins).
UK-5	Reduced OD version of the OK-5 for use in reduced ID mandrels.
OM-1 to 5	For $1\frac{1}{2}$ in. OD valves in the MMG mandrel.
L	Spring centralizer type - for $1\frac{1}{2}$ in. OD valves in the MMA. Available in $2\frac{1}{2}$ in.
L-2D	Spring centralizer type - for $1\frac{1}{2}$ in. OD valves in $3\frac{1}{2}$ in. MMA. Available in $2\frac{1}{2}$ in. to 3 in.
R	Spring centralizer type - for $1\frac{1}{2}$ in. OD valves in the MMA mandrel.
Merla TMP	For 1 in. valves in KBMG and KBUG mandrels (and compatible SPMs).

Merla TP

For 1 $\frac{1}{2}$ in. valves in the MMG mandrels (and compatible SPMs).

Table 12-1: Kick-over Tool Quick Reference Table

Kick-over	SPM	Latch	Running Tool	Pulling Tool	Pulling Spacer*
OK-1	KBMG	BK-2	JK-2	1 $\frac{1}{4}$ in. JDS	-
OK-6	KBUG			1.66 in. SM	
OM-I	MMG	RK	RK-I	1 $\frac{3}{8}$ in. JDS Core extension 1 $\frac{1}{2}$ in. SB	11 $\frac{1}{4}$ in.
R	MMA	RA	JC-3	2 in. JDC 2-in. SB	20-9/16 in.
L	KBUG	BK-2	JK-2	1 $\frac{1}{4}$ in. JDC 1.66 in. SM	-
	MMA	RA	JC-3	2 in. JDC 2 in. SB	4 $\frac{3}{4}$ in.
L-2D	MMG	RK	RK-1	1 $\frac{5}{8}$ in. JDS+ Core extension 1 $\frac{1}{2}$ in. SB	4 $\frac{3}{4}$ in.
Merla	2 $\frac{7}{8}$ in. KBMG	BK-2	JK-2	$\frac{1}{4}$ in. JDC	-
TMP	3 $\frac{1}{2}$ in. KBUG			1.66 in. SM	
Merla TP	3 $\frac{1}{2}$ in. MMG	RK	RK- 1	1 $\frac{5}{8}$ in. JDS + Core extension	12 in. Spacer
	4 $\frac{1}{2}$ in. MMG			1 $\frac{1}{2}$ in. SB	7 in. Spacer

* Possible use in deviated wells

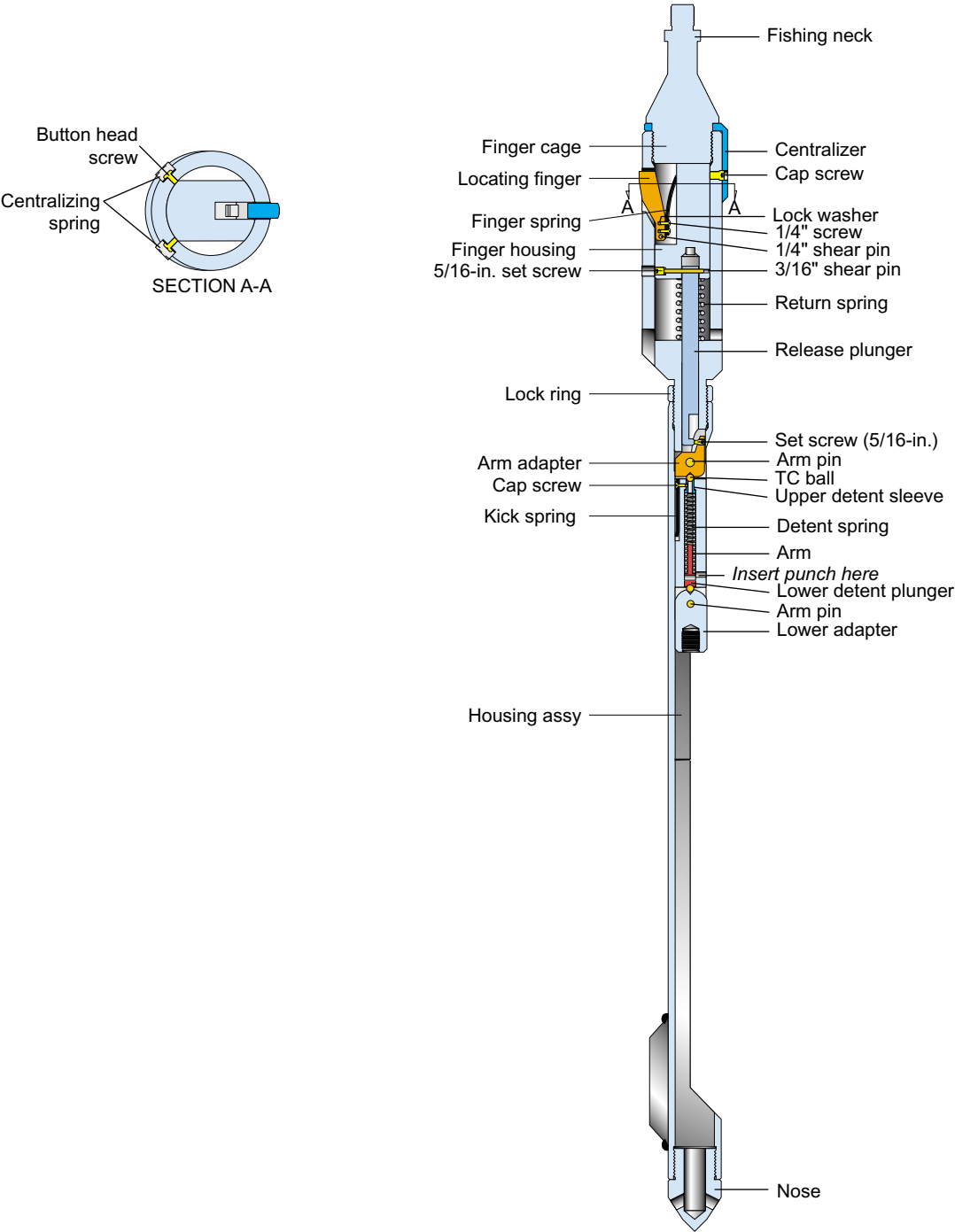


Figure 12-4: Camco OK-6 Kick-over Tool

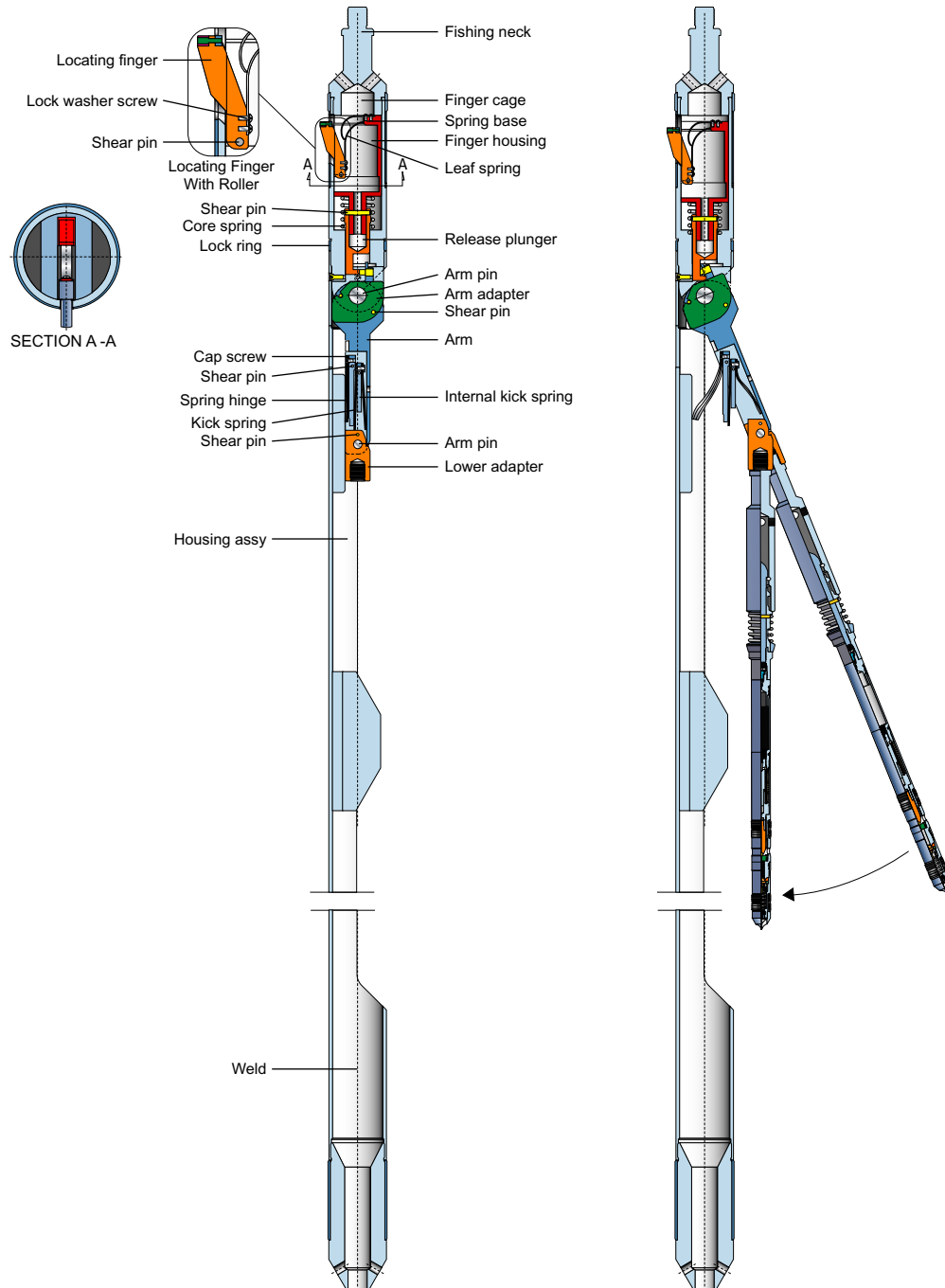


Figure 12-5: Camco OM-1 Kick-over Tool

12.3.1.1 OM-1 Tool Redress Procedure

Before preparing the kick-over tool for service, make sure that all parts are in good working order, do not bind or drag and are free of any condition which would affect their operation.

**Note**

Shear pins must be either free cutting brass (ASTM Specification B16 half-hard) or aluminum alloy 5052 with H38 temper. If the shear pins are made of anything harder, the kick over tool could be damaged or the pins might not shear.

1. Place the kick-over tool in a large vice, so that the grip of the vice is on the lower end of the finger cage and the locating finger is on the bottom.
2. Back out the locking set screw about five turns to allow positioning of the release plunger table under the locking setscrew.
3. Using a pin punch inserted into the hole in the finger cage, move the table of the release plunger under the locking set screw.
4. Pivot the arm and lower adapter down into the housing and hold firmly. Tighten the locking setscrew into the arm adapter until it firmly contacts the table on the end of the release plunger.
5. Rotate the kick-over tool 180° in the vice.
6. Remove the setscrew from the finger cage.
7. Rotate the kick-over tool 180° in the vice to allow the pieces of the sheared shear pin to fall out. A sight hole is provided 180° from the setscrew to aid in aligning and removing the shear pin.
8. Rotate the kick-over tool 180° in the vice.
9. Insert a new shear pin in the shear-pin holes in the finger housing and release plunger.
10. Install the setscrew into the hole in the finger cage.

12.3.1.2 Sequence of Operation

Use the minimum amount of stem (e.g., 5 ft) during all gas-lift slickline operations. The use of the minimum jar force will reduce the chances of damaging the latch and gas lift valve.

Running

Check that the kick-over tool and latch are correct for the side pocket mandrel. Pin the latch to the correct running tool. (Refer to the latch summary chart).

1. Run into the well and lower the tool string past the side pocket, which the valve is to be set.

2. Pick-up. The kick-over tool trigger will rotate the tool to face the pocket. This is caused by the orientating sleeve, which also guides the trigger into the no-go slot. Pull up (approximately 175 lbf) to lock the tool into the kick-over position.

**Note**

The amount of over pull increases with the tool size and deviation.

3. Lower the tool string to locate the valve in the pocket.
4. Jar down gently to ease the valve into the pocket. The exact amount of downward jarring is at the operator's discretion but must be sufficient to position the latch beneath the latch profile in the side pocket.
5. Jar up. This shears the two tangential pins on the running tool and shear pin on the lower arm. Also the internal shear pins shears as the trigger hits the no-go slot. This releases the tool to pull out of the hole.

Pulling

Attach the appropriate pulling tool to the kick-over tool. In highly deviated wells where the belly of the SPM may be on the high side:

1. Check well records to establish any previous difficulties.
2. Use a spacer bar if previous difficulty has been encountered locating the pulling tool on the latch. Add the additional kick-over spring leaf (and longer screw if necessary) to increase the kick force.

The sequence is the same as above, but with upward jarring to retrieve the valve. Downward jarring will shear the pin in the pulling tool.

Valve Catchers

A valve catcher should be set below the side pockets to ensure the valves do not drop into the casing. A valve catcher could be:

- An appropriate lock and plug or valve cap assembly run with no packing below the lowest SPM. The valve cap can be attached to a length of spacer pipe providing sufficient length to accommodate any dropped valves.
- A collar stop fitted with a cross pin to prevent the valves passing out the end of the tubing.

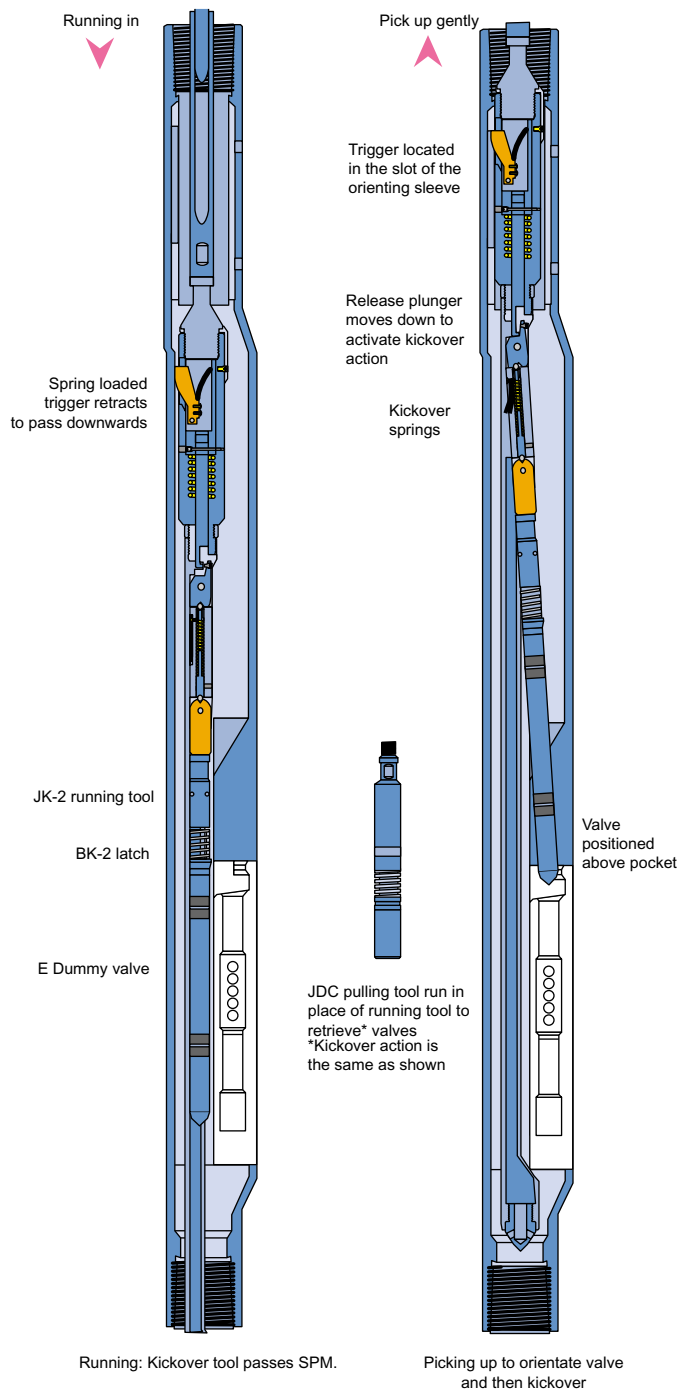


Figure 12-6: Camco OK-6 Running Sequence

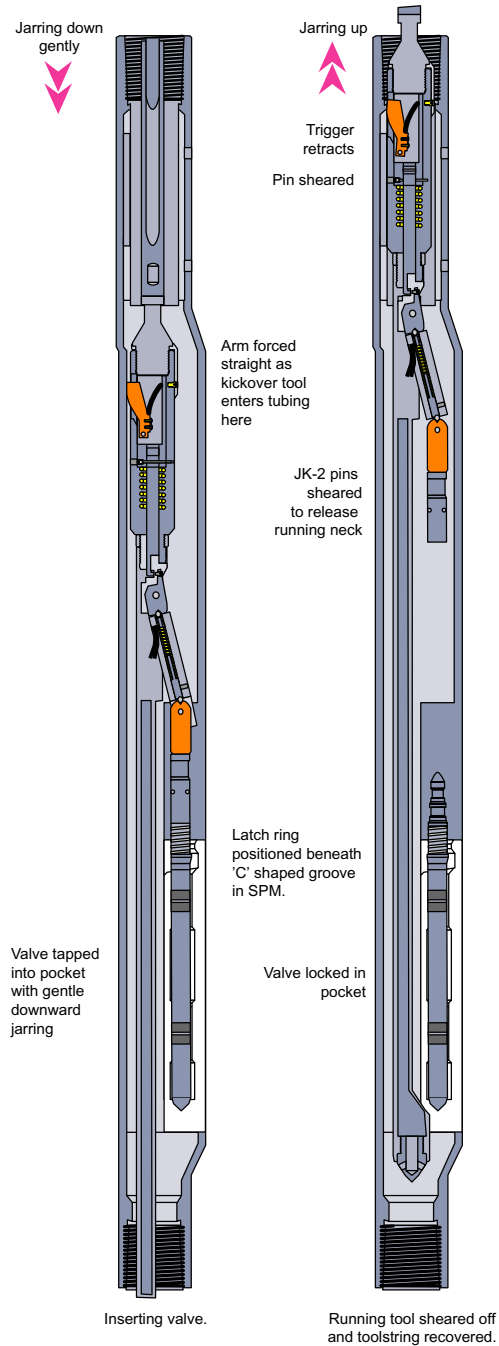


Figure 12-7: Camco OK-6 Running Sequence (Part 2)

12.3.2 TP and TMP Positioning Tools

The Merla positioning tool was introduced to the industry in 1973 and has been in continuous service throughout the world since that time. Continuous improvements have been made in metallurgy and manufacturing techniques while the basic design has been unchanged.

To complement the TP and TMP series mandrels, Merla developed the TP and TMP positioning tool to make slickline work more effective, particularly in deviated wells.

The positioning tool, when used with TP or TMP mandrels, performs three very important functions:

- locates the mandrel
- orients in the proper azimuth
- laterally offsets the valve or pulling tool into position over the pocket for setting or pulling from the mandrel.

12.3.2.1 □ **Operation**

Operation of the tool is not complicated and design features have been incorporated to make it easy to service and practical to use. For example, only the shear pin in the locator key must be replaced after each trip. Pin replacement requires no disassembly and may be performed easily with the tools hanging in the lubricator. Running and pulling, therefore, can be accomplished rapidly. Once the locator key pin is sheared as the valve is either set or pulled, the tool locks in a rigid position and may be raised or lowered past other mandrels - a very important feature in the event of a fishing job. The outside profile plus internal porting provides ample fluid bypass to ensure rapid running and pulling without a swabbing effect.

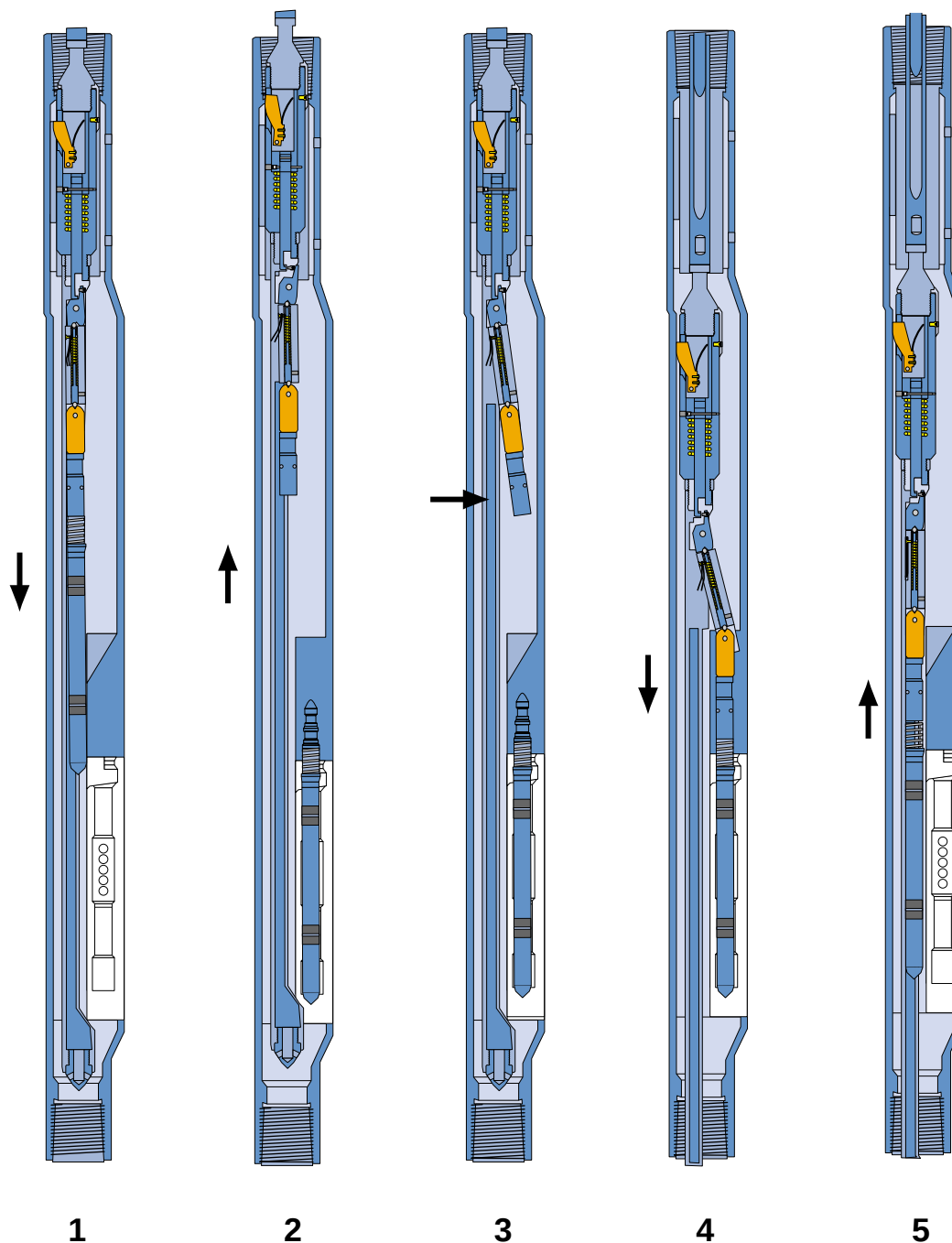


Figure 12-8: TP & TMP Positioning Tool Sequence

The operating series summarizes the steps required to operate the positioning tools.

1. The tool is run below the mandrel. Since the tool is locked in a rigid position, it cannot kick over accidentally.

2. The operator slowly raises the positioning tool until the key of the tool engages the orienting sleeve in the mandrel. Further upward movement causes the positioning tool to rotate until the key enters the slot. When the key reaches the top of the slot, the operator receives an indication on the weight indicator.
3. The positioning tool is now properly oriented. The operator pulls an additional strain on the line (200 lbf above the free weight of tools and line.) This strain forces the pivot arm to swing out and lock in position. The valve or pulling tool is now located just above the pocket or latch.
4. Once the tool is locked in the offset position, a valve may be installed or removed with the internal V-shape of the mandrel accurately guiding the tools.
5. Removal of the tool is accomplished when the shear pin is sheared as the key reaches the top of the slot. This action allows the trigger to glide freely out of the slot and through tubing. When the pivot reaches the small upper section of the mandrel, it snaps back and locks into the rigid position; thus, there is no drag on the tool or valve as it is removed from the well.

Each positioning tool is designed to operate in one specific tubing size and for one specific size valve. However, the running and pulling procedure and principle of operation is the same. The following information provides a description of the operational limits of each tool.

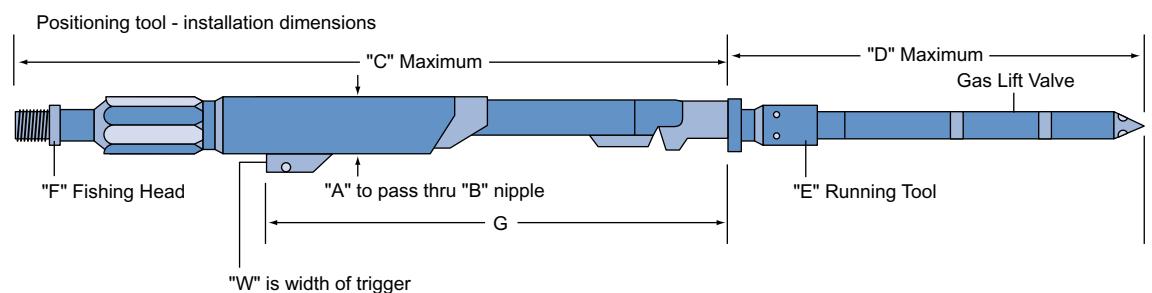


Figure 12-9: Positioning Tool Details

12.3.2.2 Maintenance

Under light duty non-corrosive conditions, the tool will only need oiling at three spots to get oil to the plunger.

- Slot in housing
- 5/16 in. holes in housing
- With tool activated, oil in between pivot arm and housing stop. Also oil around trigger and all other joints.

Under heavy-duty conditions (sour well and sand production), the plunger assembly should be pulled out after use and cleaned and re-greased. The lower adapter end may be washed in Varsol and then oil is inserted at the joint and into the ball cavity.

Molykote M-77 may be used on plunger and housing ID to be more corrosion resistant for the $2\frac{3}{8}$ in., $2\frac{7}{8}$ in., $3\frac{1}{2}$ in. TMP & TMP for Camco BK-1 valve. Remaining tools use Dow Corning Fs 3451 on plunger and housing ID.

Procedure for Running a Valve

1. Use a screwdriver to align the locator key with the trigger and install a $\frac{3}{16}$ in. brass shear pin.
2. Screw the running tool into the positioning tool, pin a valve in the running tool.
3. Lower the tool several feet past the mandrel being serviced. Do not run the tool below the next lower mandrel since the tool cannot pass up through the mandrel without shearing the locator key pin. (Once sheared, the tool will no longer orient or kick over).
4. Slowly raise the tool until the locator key engages the orienting sleeve. Further upward movement causes the positioning tool to rotate until the key enters the slot. A noticeable increase in weight on the weight indicator will be experienced when the tool has traveled to the end of the slot.
5. If the locator key misses the orienting slot, lower the tool again past the mandrel and repeat the procedure.

6. Once the key is located in the slot, gradually apply an extra pull above the weight of the tool and slickline. This will kick over the tool and latch it in position.

Table 12-2: Effect of Wellbore Deviation (a)

Additional Tension Required to Kick-Over and Latch Tool(lbf)					
Tool		Deviation from Vertical			
Type	Size (in.)	0 - 30 [°]	30 [°] - 45 [°]	45 [°] - 60 [°]	OVER 60 [°]
TMP	2 ³ / ₈	200	250	300	350
	2 ⁷ / ₈				
	3 ¹ / ₂				
	4	250	300	300	350
	4 ¹ / ₂				
TP	2 ³ / ₈	425	Not Recommended		
	2 ³ / ₈	350	400	450	500
	3 ¹ / ₂				
	4 ¹ / ₂	390	450	500	550
	5 & 5 ¹ / ₂				
	7				

7. After the extra upward pull force has been reached, lower the valve slowly into the pocket. Possibility of damage to the valve or latch is non-existent since the positioning tool will automatically align the valve with the pocket. Loss of tool weight is a positive sign that valve is entering pocket.
8. If for some reason the valve misses the pocket (do not lower tools more than 4 ft), try again from Step 3. Increase the extra pull 100 lb. In some wells, the tubing will be cork screwed resulting in much lower pull applied against the tool down hole than is indicated at the surface.
9. Normal procedure may now be followed for jarring the valve into place and shearing off the valve.
10. After the tool is sheared off the valve, upward travel will cause the tool trigger to reorient in the positioning sleeve. Upward jarring will shear the 3/16 in. pin holding the guide key in place. Once this is done, the tool will no longer orient at each mandrel as it is pulled to the surface. In pulling through the orienting sleeve, the kicked over arm of the tool will straighten and lock in the straight position. This feature eliminates considerable wear due to rubbing on the tubing walls.

11. When the tool is back on the surface, the only necessary operation, other than attaching another valve, is to re-pin the key to the trigger. (The key and trigger may be lined up by hand and the old pin tapped out and a new pin inserted without disassembly of tool.

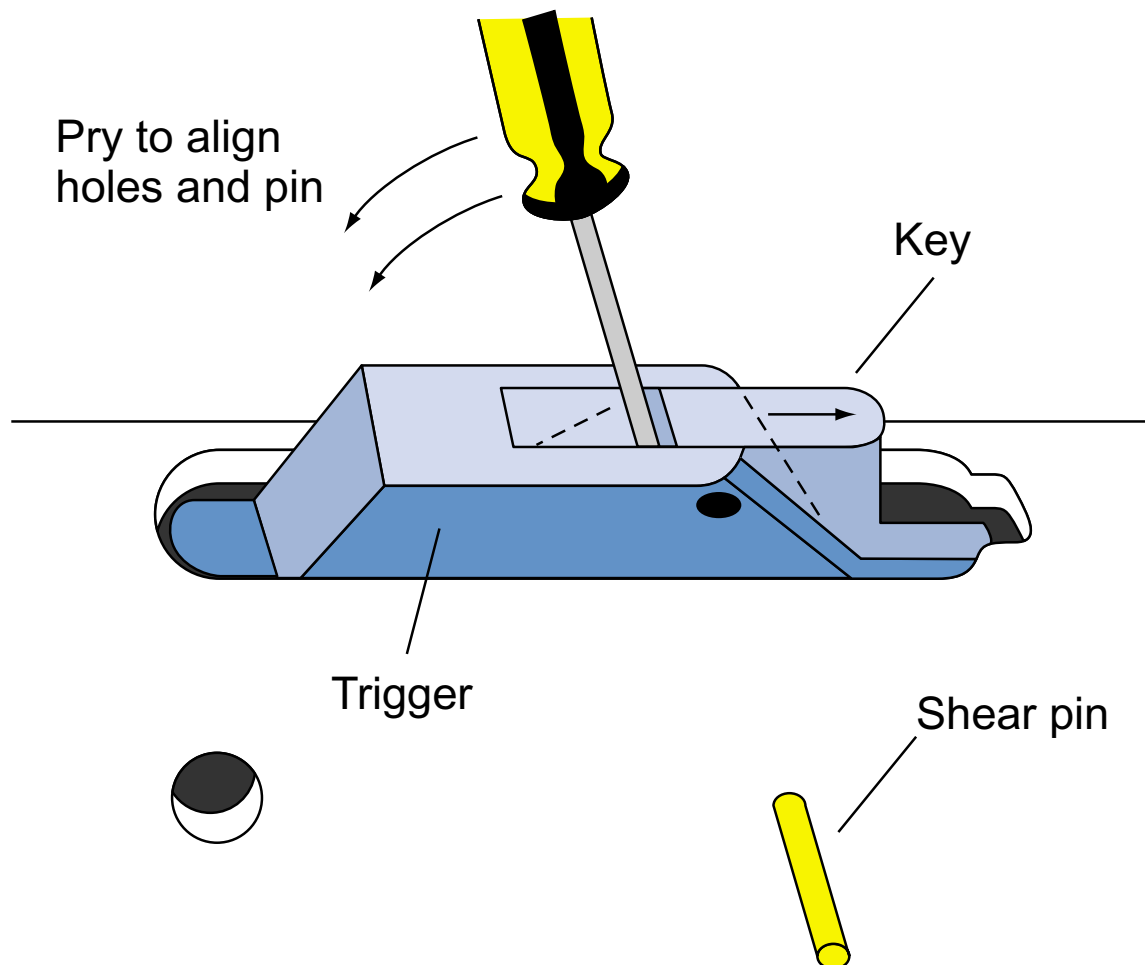


Figure 12-10: Positioning Tool Details

Procedure for Pulling a Valve

1. Use a screwdriver to align the locator key with the trigger and install a $\frac{3}{16}$ in. brass shear pin.
2. Check for your size tool and determine proper pulling tool (and extension if required). Screw the proper pulling tool (with extension, if required), onto the positioning tool. Extensions are required with TP tools as follows: 12 in. extension for $2\frac{3}{8}$ in., $2\frac{7}{8}$ in., $3\frac{1}{2}$ in., 7 in. extension for $4\frac{1}{2}$ in. and larger.

3. Lower the tool several feet past the mandrel being serviced. Do not turn the tool below the next lower mandrel since the tool cannot pass up through the mandrel without shearing the locator pin. (Once sheared, the tool will not orient or kick-over).
4. Slowly raise the tool until the locator key engages the orienting sleeve. Further upward movement causes the positioning tool to rotate until the key enters the slot. A noticeable increase in weight on the weight indicator will be experienced when the tool has traveled to the end of the slot.
5. If the locator key misses the orienting slot, lower the tool again past the mandrel and repeat the procedure.
6. Once the key is located in the slot, gradually apply an extra pull above the weight of the tools and slickline. This will lock over the tool and latch it in position.
7. After the extra upward pull force has been reached, lower the tool slowly until the weight indicator shows a noticeable drop in the line weight.
8. If, for some reason, the valve misses the pocket, try again from Step 4, increasing the extra pull by 100 lbf. In some wells, the tubing will be corkscrewed resulting in much lower pull applied against the tool down hole than is indicated at the surface.
9. Normal procedure may now be followed for jarring the latch to its release position and removing the valve from the pocket.
10. As the valve is being pulled from the pocket, upward travel will cause the tool trigger to reorient in the positioning sleeve. Additional jarring will shear the 3/16 in. pin holding the guide key in place. Once this is done, the tool will no longer orient at each mandrel as it is pulled to the surface. In pulling through the orienting sleeve, the kicked over arm of the tool will straighten and lock in the straight position. This feature eliminates considerable tool and valve wear due to rubbing on the tubing walls.

11. When the tool is back on the surface, the only necessary operation, other than removing the valve from the pulling tool and checking the pulling tool, is to re-pin the key to the trigger. (The key and trigger may be lined up by hand, the old pin tapped out and the new pin inserted without disassembly of tool)

Table 12-3: Effect of Well Bore Deviation (b)

Tools		Deviation	
Type	Size (in.)	0 - 30°	Over 30°
TMP	2 $\frac{3}{8}$	200 lbf	250 lbf
	2 $\frac{7}{8}$		
	3 $\frac{1}{2}$		
	4		
	4 $\frac{1}{2}$		
TP	2 $\frac{3}{8}$	425 lbf	Not Recommended
	2 $\frac{3}{8}$	350 lbf	400 lbf
	3 $\frac{1}{2}$		
	4 $\frac{1}{2}$		
	5		
	5 $\frac{1}{2}$		
	7		

12.4 Latches

Latches are designed to screw onto each gas lift valve and to latch the valve into the side pocket mandrel. The internal design of the SPM and OD of the valve determines the correct latch.

Table 12-4: Latch Profile Summary

Latch	SPM	Valve Size (in.)	Latch Design	Running Neck (in.)	Running Tool	Pulling Neck (in.)	Maximum OD (in.)	Pulling Tool
BK-2	KB*	1	Ring	0.750	JK	0.875	1.358	1 $\frac{1}{4}$ in. JDC
	KBG							1.66 in. SM
BEK-2	KB*	1	Ring	0.750	JK	0.875	1.358	1 $\frac{1}{4}$ in. JDC
								1.66 in. SM

Latch	SPM	Valve Size (in.)	Latch Design	Running Neck (in.)	Running Tool	Pulling Neck (in.)	Maximum OD (in.)	Pulling Tool
R	MMA	1 $\frac{1}{2}$	Cam	1.359	JC-3	1.370	1.750	2 in. JDC
								2 in. SB
RA	MMA	1 $\frac{1}{2}$	Cam	1.359	JC-3	1.370	1.750	2 in. JDC
								2 in. SB
RK	MMG	1 $\frac{1}{2}$	Ring	0.937	RK-1	1.187	1.176	1 $\frac{5}{8}$ in. JDS
								1 $\frac{1}{2}$ in. SB
RK-1	MMG	1 $\frac{1}{2}$	Ring	0.937	RK-1	1.187	1.176	1 $\frac{5}{8}$ in. JDS
								1 $\frac{1}{2}$ in. SB
Integral	KB*	1	Collet	0.875	GA-2	0.875	1.100 collet 1.130 top sub	1 $\frac{1}{4}$ in. JDC-1** 1 $\frac{1}{4}$ in. JDC

* Core extension required to pull the BEK latch

** DC-1 - Longer core (0.906 in. reach) and has no prong threads in the core.

12.4.1 1 in. Latches

12.4.1.1 BK-2

In common use worldwide. The spring-loaded latch ring moves up and to the side as the latch enters the C shaped profile in the SPM. It locks in place until the pulling tool shears the pin and lifts the pulling neck.

12.4.1.2 BEK-2

Similar in appearance to the BK-2 latch and identical for running/pulling. The BEK-2 (and BEK-3) have a $\frac{3}{8}$ in. hole through the latch center for use with circulating or flow devices.

12.4.1.3 **Integral Latch**

The KB series mandrels have a profile at the lowest end, which will also accept an integral latch (sometimes referred to as a bottom latch). This is used if the upper profile becomes worn.

12.4.2 **1 $\frac{1}{2}$ in. Latches**

12.4.2.1 **R**

The R latch use a spring-loaded rotating cam which deflects upward as the latch passes into the full circular profile at the upper end of the side pocket. Upward jarring on the pulling neck shear the pin and lifts the latch pin to allow the cam to rotate downward permitting recovery.

12.4.2.2 **RA**

Similar to the R latch but with two O-rings to prevent solid particles settling around the latch. This latch is used more commonly than the R.

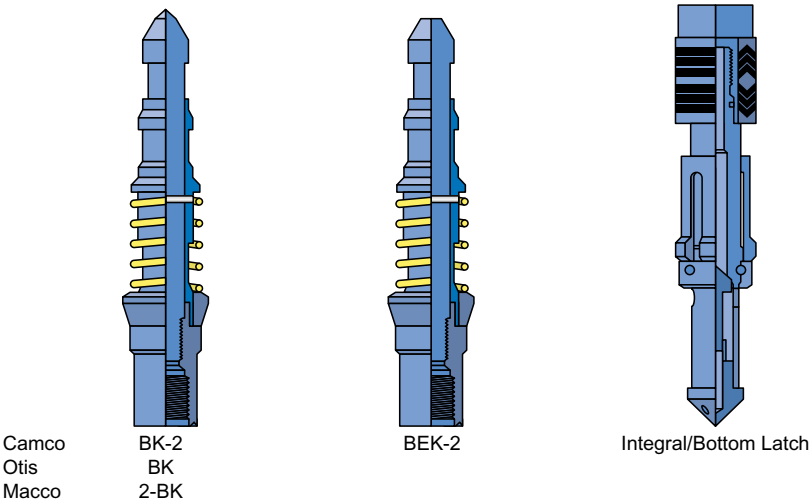
12.4.2.3 **RK**

This latch is a scaled up version of BK-2. Its principle of operation is the same. It has two O-rings to prevent debris collecting around the latch ring. It is the most commonly used 1 $\frac{1}{2}$ in. latch.

12.4.2.4 **RK-1**

Similar to the RK latch but without the two O-rings.

1-in. Latches



1-1/2-in. Latches

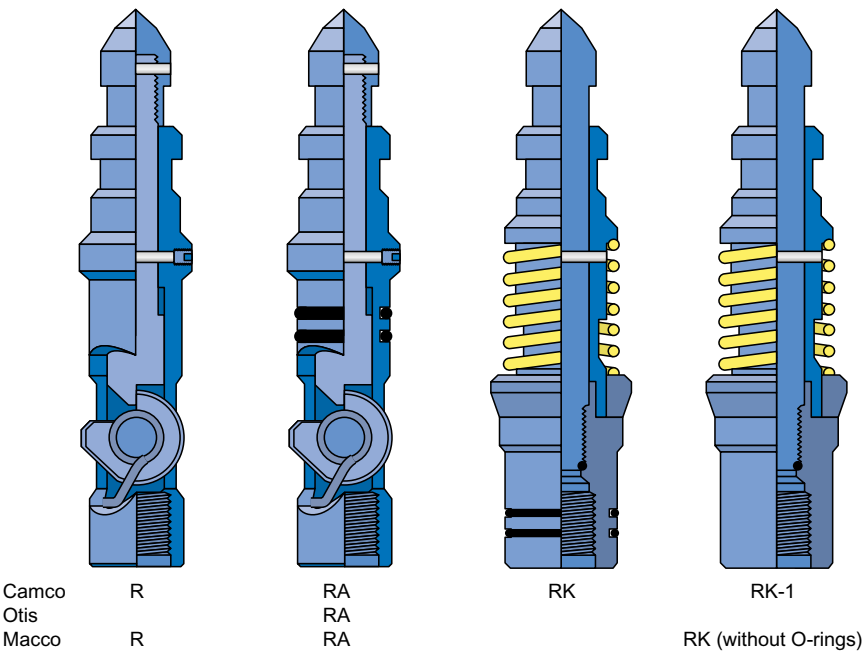


Figure 12-11: 1 in. and 1-1/2 in. Latches

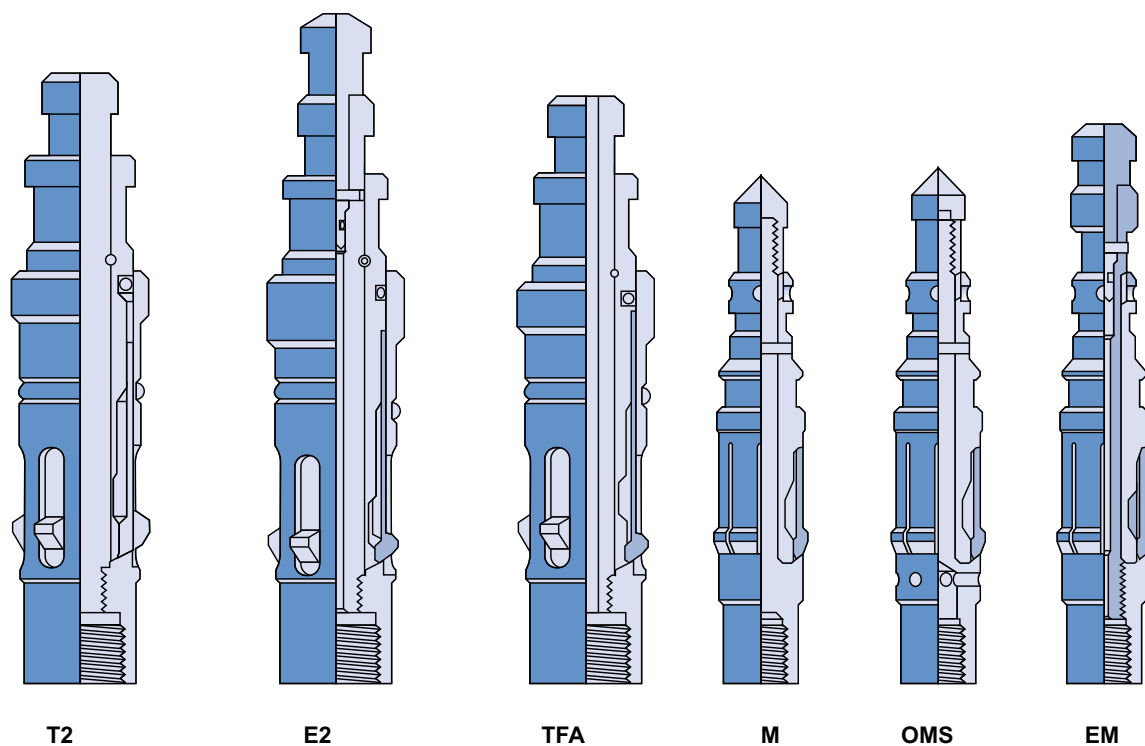


Figure 12-12: Merla Latch Profile

12.4.3 Camco BK-2 Latch

The BK-2 Latch is the most commonly used 1 in. latch. It has similarities with the BEK-2 and BEK-3 and also the $1\frac{1}{2}$ in. RK latches.

- Running tool - JK
- Pulling tool - $1\frac{1}{4}$ in. JDC (Otis equivalent = $1\frac{1}{4}$ in. SM)

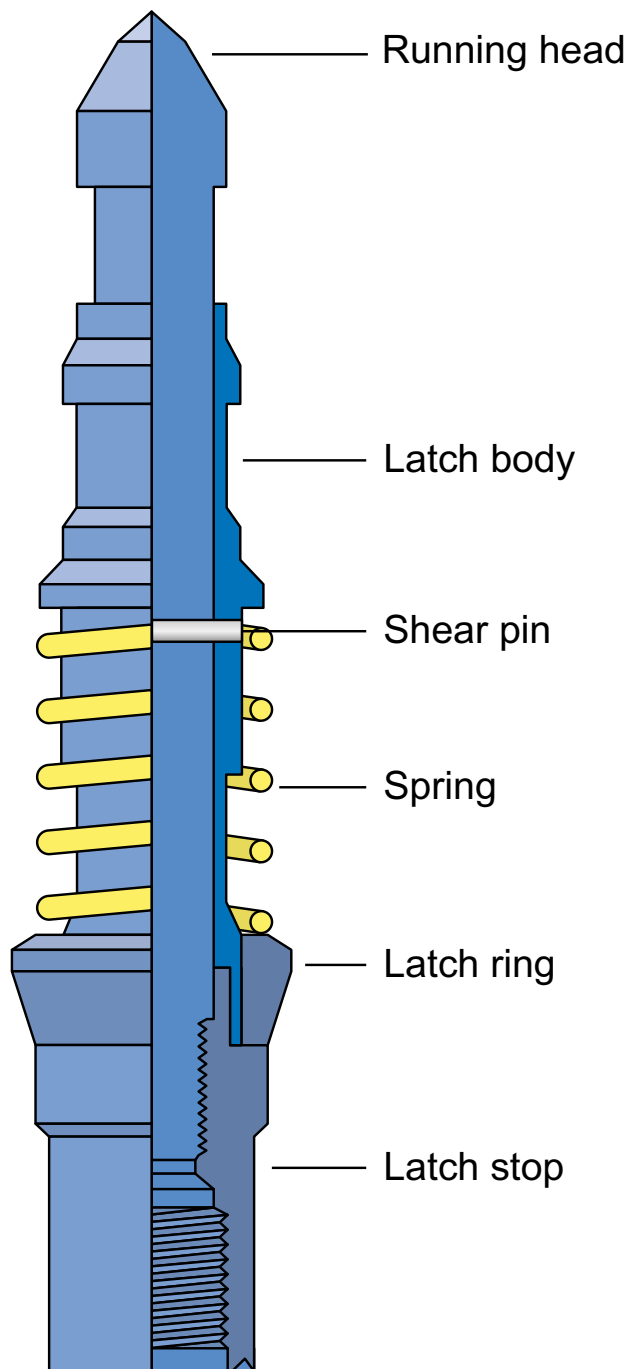


Figure 12-13: Camco BK-2 Latch

12.4.3.1 Pinning Procedure

With the latch made up to the valve to be run:

1. Check that the latch shear pin is not sheared.

2. Position the JK running tool over the top of the latch.
3. Insert two $\frac{1}{8}$ in. brass shear pins through the tangential holes.
4. Cut off the excess pin and file flush to the running tool.

**Note**

Do not cut/file the running tool OD.

5. Attach the running tool to the appropriate kick-over tool, e.g. OK-6.

12.4.3.2 Pulling Procedure

1. The $1\frac{1}{4}$ in. JDC is attached to the kick-over tool - with a spacer bar if required.
2. A spacer bar may be required between the pulling tool and kick-over tool in highly deviated wells where the belly of the SPM is on the high side.
3. When the pulling tool is correctly positioned in the SPM, it engages the fishing neck.
4. Upward jar action shears the pin in the latch and lifts the latch body upwards.
5. The latch ring can move sideways to provide clearance to move upwards out of the profile.

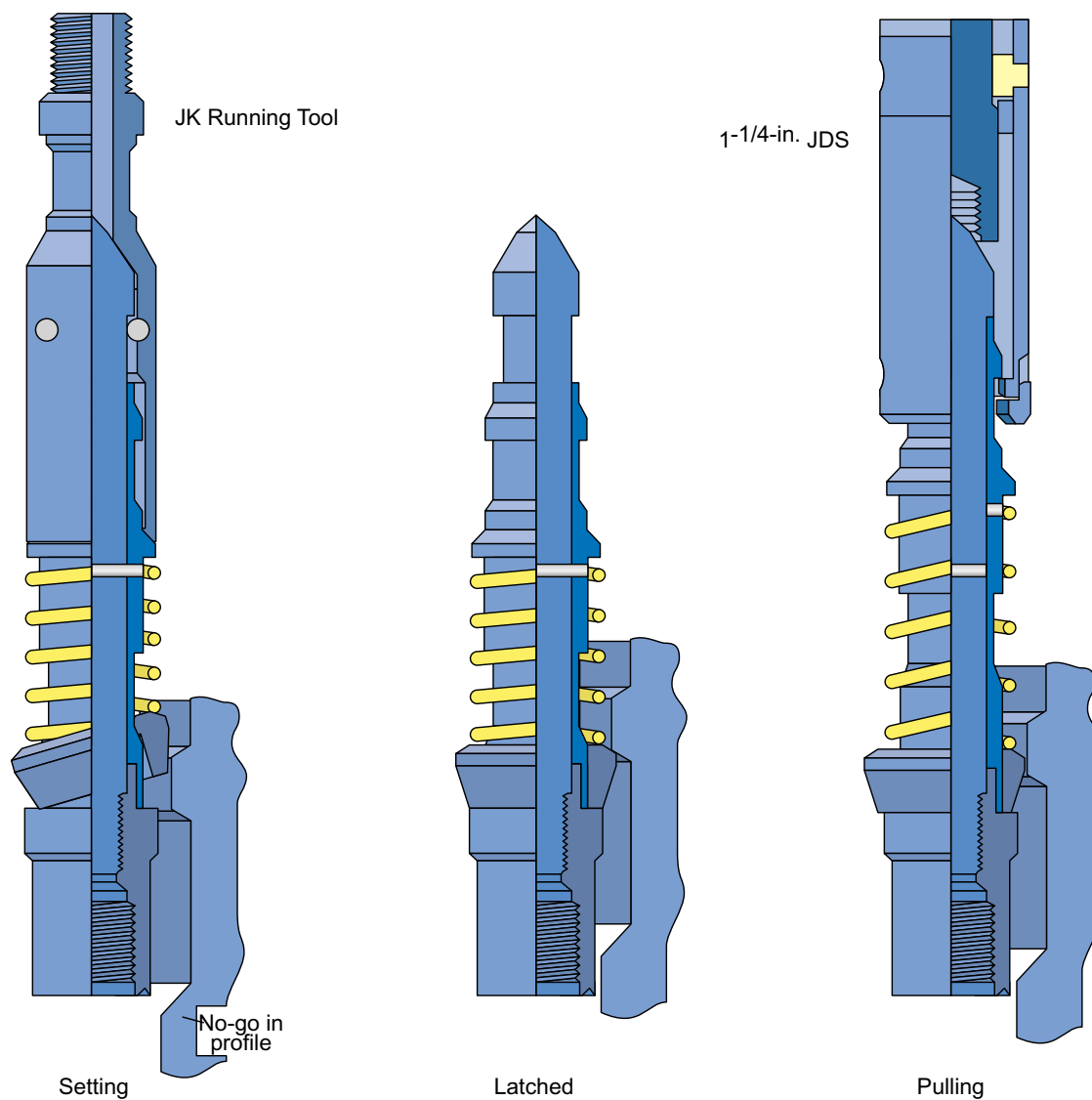


Figure 12-14: Camco BK-2 Latch Setting, Latched and Pulling Positions

12.4.4 Camco RA Latch

The RA Latch is a $1\frac{1}{2}$ in. latch used in MMA mandrels.

- Running tool - JC-3
- Pulling tool - $1\frac{5}{8}$ in. JDS (Otis equivalent = $1\frac{1}{2}$ in. SB)

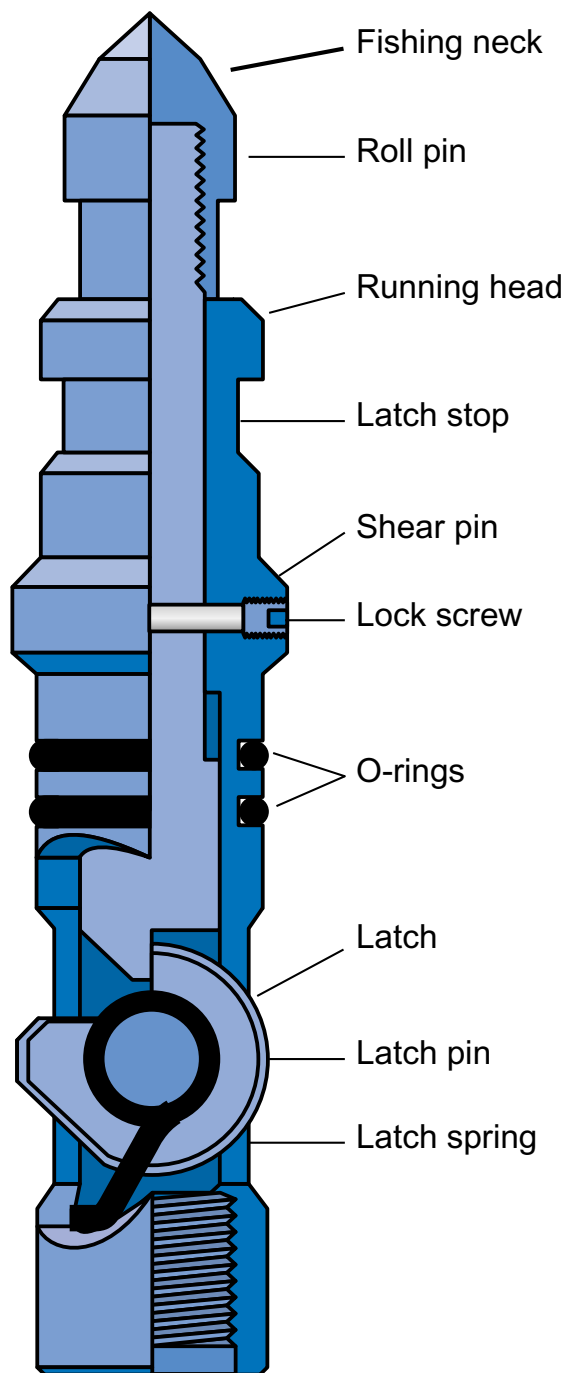


Figure 12-15: RA Latch Assembly

12.4.4.1 Pinning Procedure

With the latch made up to the valve to be run:

1. Check that the latch shear pin is not sheared.

2. Position the JC-3 running tool over the top of the latch.
3. Insert two 3/16 in. brass shear pins through the tangential holes beneath the running neck.
4. Cut off the excess pin and file flush to the running tool.

**Note**

Do not cut/file the running tool OD.

5. Attach the running tool to the appropriate kick-over tool, e.g. OM-1.

12.4.4.2 □ **Pulling Procedure**

1. The 1 ¹/₂ in. JDS is attached to the kick-over tool - with a spacer bar is required.
2. A spacer bar may be required between the pulling tool and kick-over tool in highly deviated wells where the belly of the SPM is on the high side.
3. When the pulling tool is correctly positioned in the SPM it engages the fishing neck.
4. Upward jar action shears the pin in the latch and lifts the latch stop upward.
5. The latch is now free to rotate downwards to permit the valve to be jarred upwards of the profile.

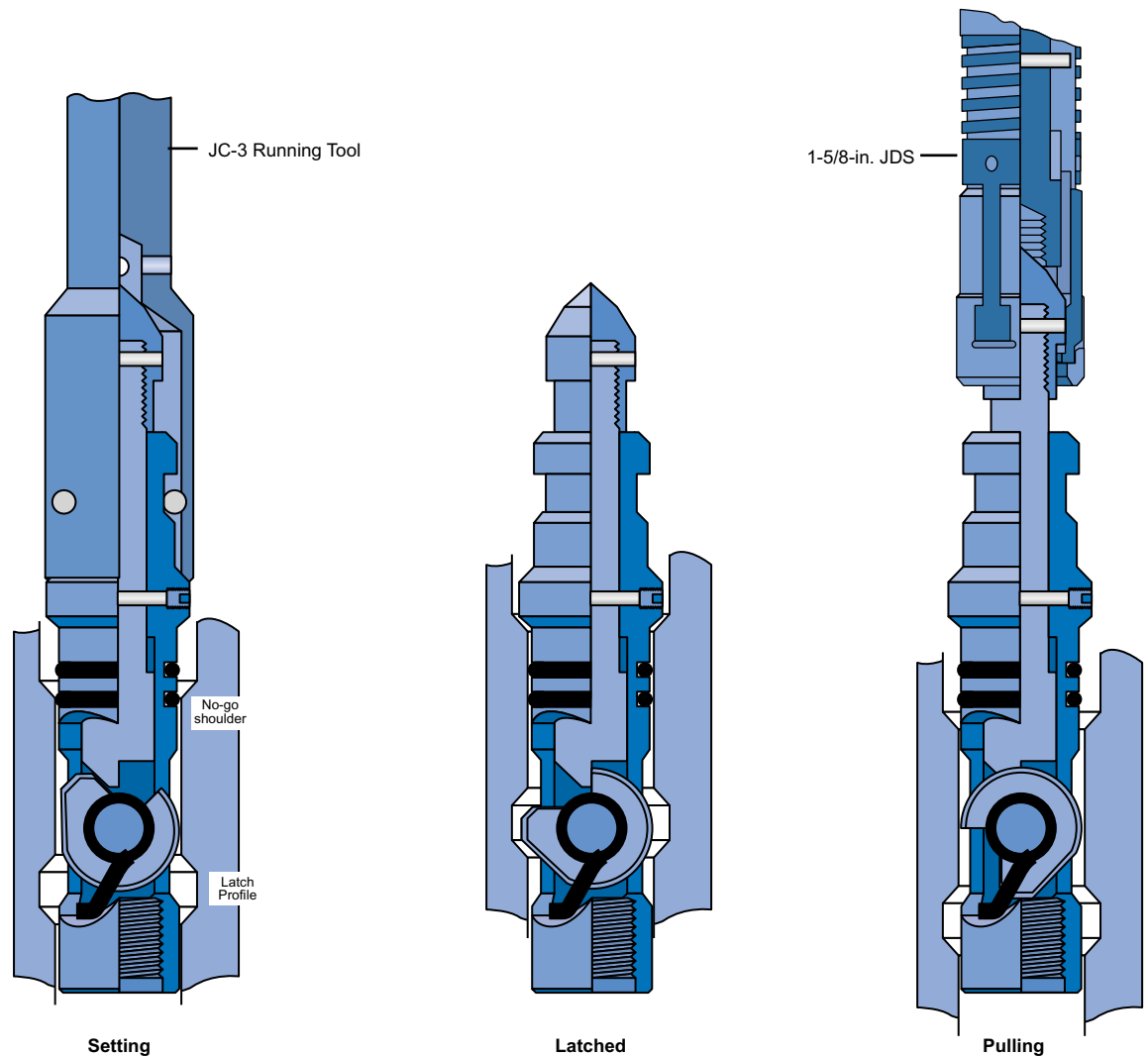


Figure 12-16: RA Latch Assembly Setting, Latched and Pulling Positions

12.4.5 Integral Latch

The integral or bottom latch is used on 1 in. valves when the upper latch profile is worn or damaged. The bottom latch is also used in some flowing applications. It is attached to the nose of the valve and a running head is attached to the upper end.

- Running tool - GA-2
- Pulling tool - $1\frac{1}{4}$ in. JDC

12.4.5.1 Pinning Procedure

1. Remove any old pieces of shear stock.

2. Check that both steel roll pins are in good conditions.
3. Move the plunger to line up the top shear pin hole with the stabilizer
4. Insert two $\frac{1}{8}$ in. brass shear pins and file smooth.
5. Back off the plunger by rotating anti-clockwise (to the left).
6. Place the latch fully into the running tool.
7. Insert two $\frac{1}{8}$ in. brass shear pins and file smooth.
8. Screw the plunger down to hold the valve firmly.
9. The internal adjustable plunger holds the valve more firmly and straighter than the JK type running tool. This makes it easier to locate the valve into the SPM in deviated wells.
10. Attach the GA-2 to the appropriate kick-over tool for the side pocket mandrel.

12.4.5.2

Running Procedure

1. As with all kick-over tool operations - do not use too much stem and avoid excessive jarring action, as this can damage the valve and/or the SPM. Use a minimum amount of stem.
2. Locate the SPM as normal.
3. Tap downward gently to insert the valve into the pocket.
4. Once the valve is fully located, the downward jar action achieves the following:
 - a. Shears the top shear pins and running neck shear pins simultaneously.
 - b. The plunger is moved upward (relative to the body by the top of the latch).
5. Apply an upward pull on the latch.
6. Gentle jarring may be necessary to disengage the GA-2, but all pins are already sheared.
7. The running tool is now free to be picked up without any upward jarring.

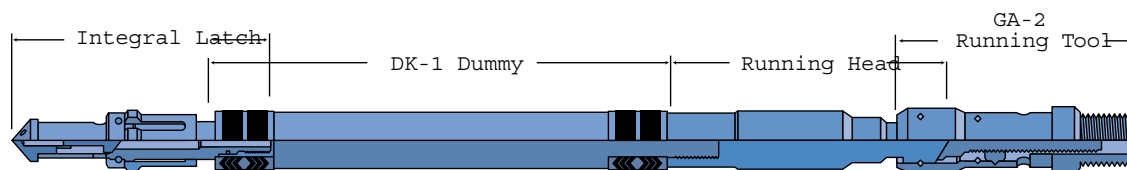
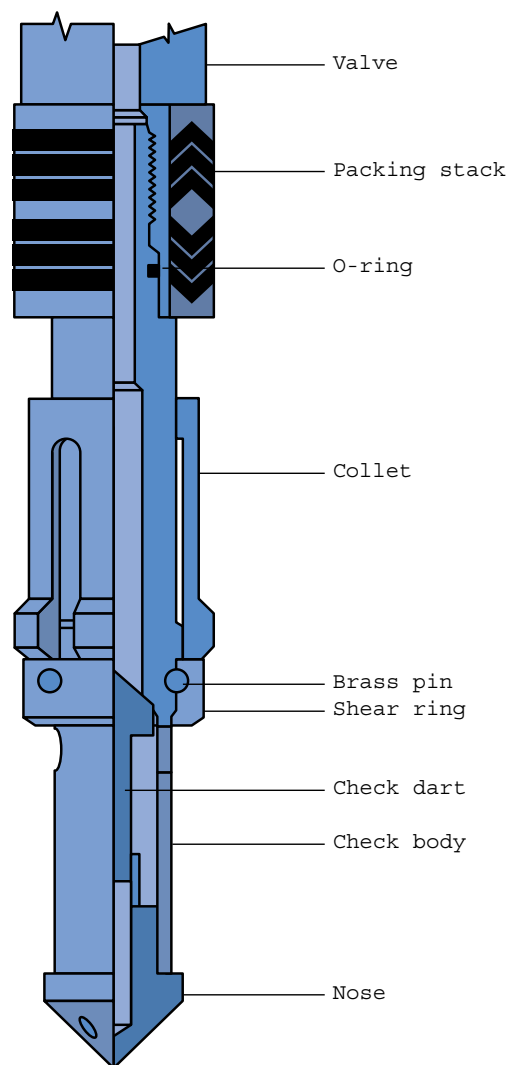


Figure 12-17: Integral Latch Assembly

12.5 Running Tools

The running tools are attached to the 15/16 in. - 10 thread on the bottom end of the kick-over tool arm. The type of tool used depends on the latch.

- **GA-2** Used to run the integral latch.
- **JK** To run the BK and similar style latches.

- **RK-1** To run the RK style latch. Similar in function to the JK tool.
- **JC-3** To run the R and RA style latches.

All these tools, except the GA-2, jar down to set the latch in the pocket and jar up to shear 2 tangential pins. The GA-2 shears downwards after the latch is fully set. Upward jarring on the GA-2 could shear the collet latch pins on the integral latch.

Table 4-5: Running Tool Summary

Running Tool Summary Chart - Variations					
Type	Assembly No.	Maximum OD (in.)	Fish Neck (in.)	Length (in.)	Latch To Run
JEK	15069	1.312	1.187	4.562	EK dummy valves*
JEK-1	15061	1.187	1.187	6.312	EK-1 dummy valves*
JC-5	13112	1.750	1.375	7.750	R and RA latches in Otis SPM's

* Equalizing type

- **JEK** Varies from the JK by - No fishing neck, approximately $\frac{1}{2}$ -in. longer
- **JEK-1** Varies from the JK by -Approximately $1-\frac{1}{2}$ -in. longer
- **JC-5** Varies from JC-3 by - $5\frac{3}{8}$ in. shorter
(To allow for length variation in Otis SPMs)

12.5.1 Pinning

Shear pins are usually brass, although a combination brass/steel or steel pins can be used. Take care not to damage the running tool when cutting/filing off ends of the shear pins.

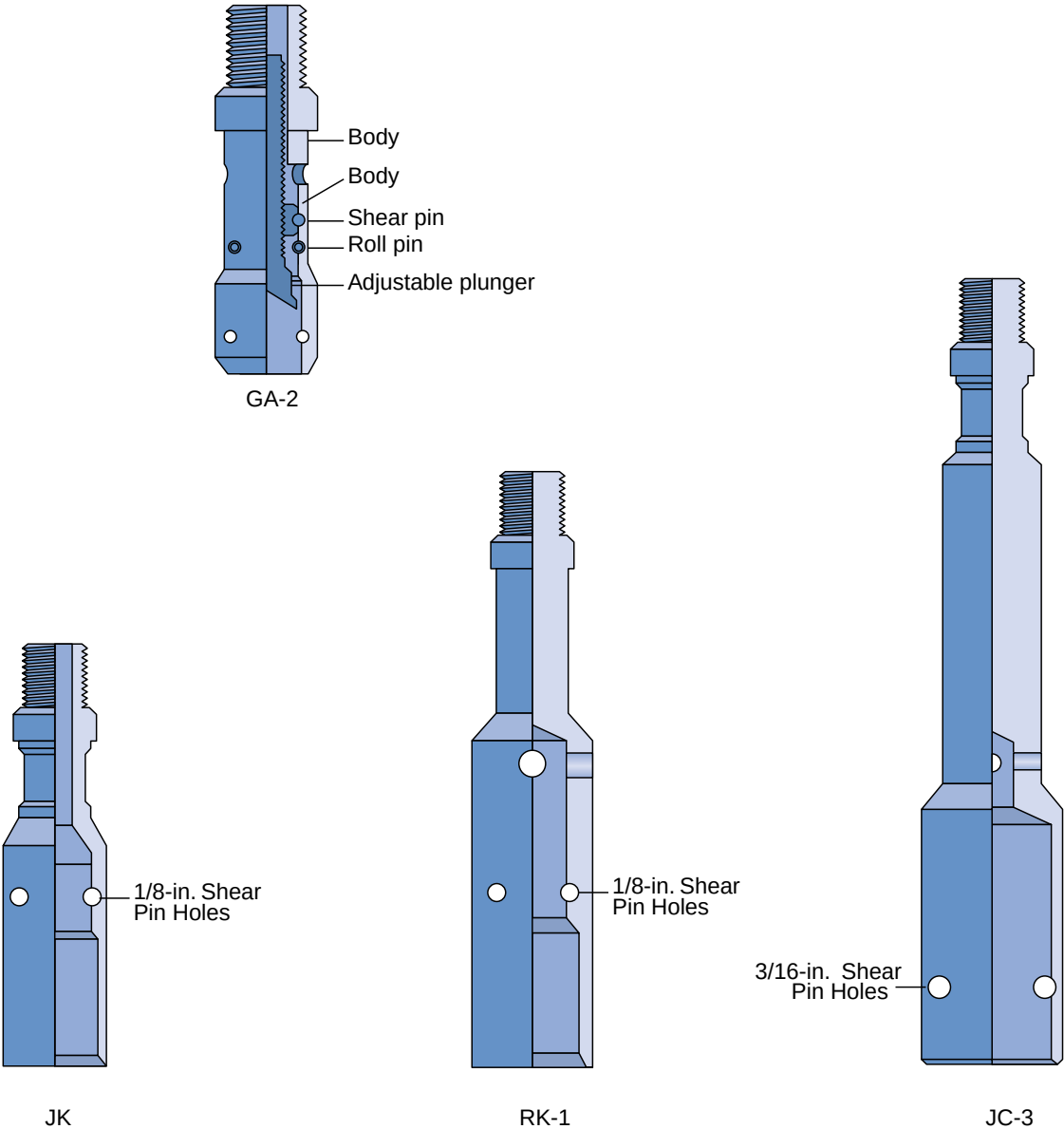


Figure 12-18: Running Tools

Table 12-6: Running Tool Summary

Running Tool Principal Dimensions					
Type	Assembly No.	Max. OD (in.)	Fish Neck (in.)	Length (in.)	Latch To Run
GA-2	15052	1.187	1.187	4.375	Bottom/Integral
3K	15072	1.312	1.187	3.984	Bk and BK-2
RK-1	15079	1.437	1.187	7.000	RK
JC-3	15065	1.750	1.375	13.125	R and RA

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12.6 Pulling Tools

The correct pulling tool for each type of latch and side pocket mandrel can be determined from the chart. The following tools are used to pull the common range of latches:

- **$1\frac{1}{4}$ in. JDS** - Standard Camco jar down to shear pulling tool.
- **$1\frac{1}{4}$ in. JDC-1** - As for JDC above, but with a shorter reach and no threads in the core.
- **1.66 in. SM** - Otis version of the SB with a hole in the core to take the latch top.
- **$1\frac{5}{8}$ in. JDS** - Camco jar down to shear pulling tool with a medium reach.
- **$1\frac{1}{2}$ in. SB** - Otis jar down to shear pulling tool with a short reach.
- **2 in. JDC** - Camco jar down to shear pulling tool with a short reach.
- **2 in. SM** - Otis jar down to shear pulling tool with a hole in the core to take the latch top.

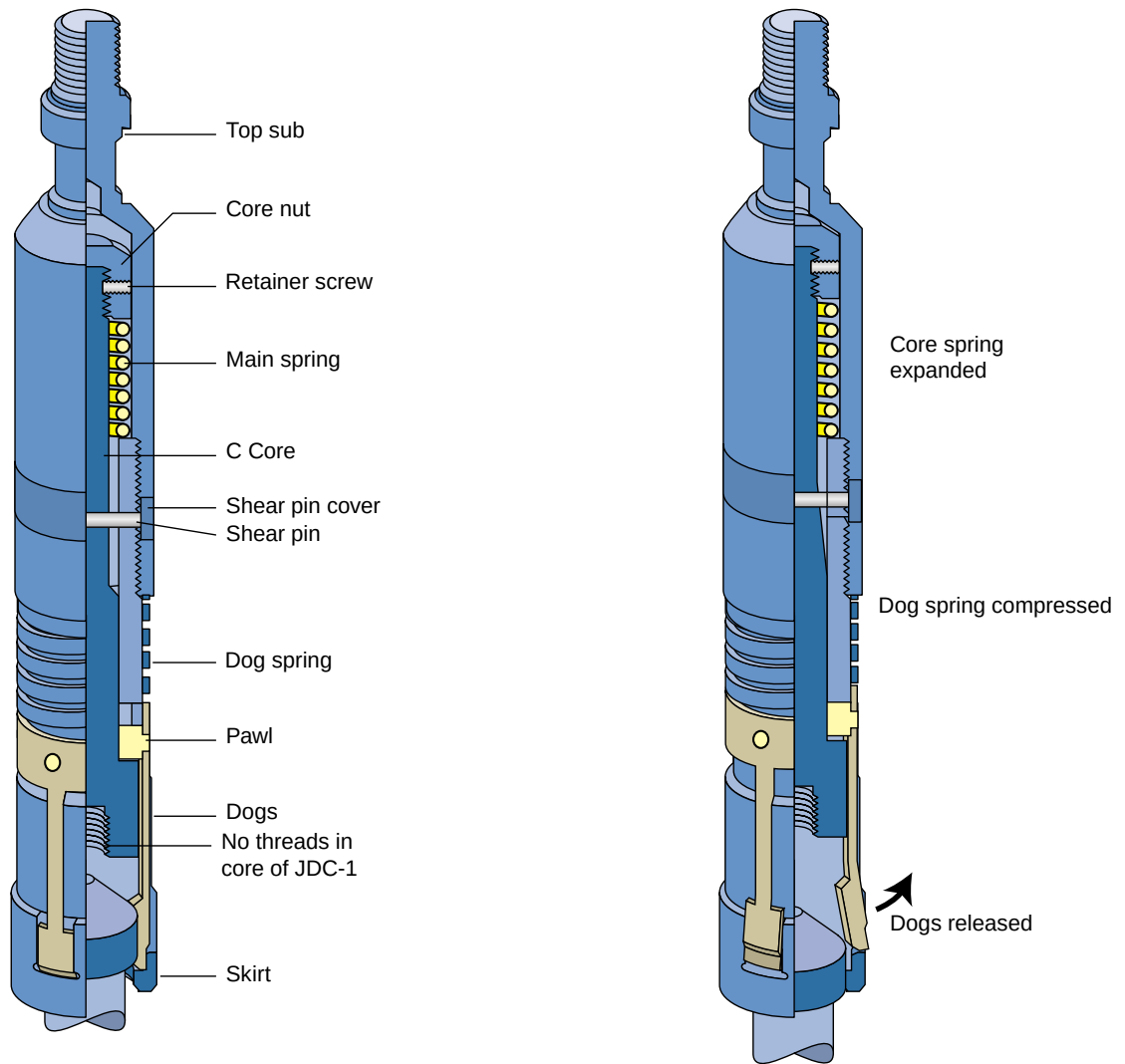
It is recommended that Camco and Otis tools should match the latch manufacturer to ensure compatible fishing neck angles.

Table 12-7: Pulling Tool Summary

Pulling Tool Critical Dimensions								
Size (in.)	Type	Maximum OD (in.)	Latches (in.)	Reach (in.)	Minimum Working OD* (in.)	Core Thread	Fish Neck (in.)	Length (in.)
$1\frac{1}{4}$	6.1 JDC	1.291	0.875	1.937	1.312	$\frac{1}{4}$ in.-20	1.187	13.00
$1\frac{1}{4}$	JDC-1	1.291	0.875	0.906	1.312	None	1.187	13.00
1.66	SM	1.188	0.875	1.680	N/A	$\frac{1}{2}$ in.-13	1.000	-
$1\frac{5}{8}$	JDS	1.625	1.187	1.843	1.640	$\frac{1}{2}$ in.-13	1.187	13.00
$1\frac{1}{2}$	SB	1.437	1.187	1.297	N/A	$\frac{1}{2}$ in.-13	1.187	-
2	JDC	3.000	1.375	1.437	N/A	$\frac{1}{2}$ in.-13	1.375	17.437
2	SM	1.770	1.375	1.640	N/A	$\frac{1}{2}$ in.-13	1.375	-

* On some Camco tools, the dogs expand outside the nominal OD when sheared.

Attention should be paid to the use of the correct spacer bar, as this provides the correct leverage and reach to enable the pulling tool to engage the latch. This becomes critical in highly deviated well where the SPM may be positioned belly upwards.



JDC - In pinned position.

JDC - In sheared position.

Figure 12-19: JDC Pulling Tool Pinned and Sheared Positions

12.6.1 Pulling Procedures

There is no set rule as to pulling top or bottom valves first. In many areas it is left to the preference of the operator. In other areas, the sequence is specified in the program. The following facts are relevant to recovering gas lift valves:

- By reducing the pressure differential between casing and tubing, the chance of being blown up the well are reduced.

- Excessive tubing pressure differential can make pulling valves difficult.
- Balanced tubing/casing pressures at the surface does not mean equal pressure at the valve depth.
- The hydrostatic pressure created by the difference in the tubing/casing fluid depths can be difficult to calculate.

The vertical height and density of both column of fluid must be known. While the tubing fluid depth and gradient may be available and even the annulus fluid gradient may be known, it is difficult to determine the annulus fluid depth. (It is possible by conducting an Echometer survey, but this is not usually a viable option at most locations.)

This pressure difference can be reduced or eliminated by:

- Shutting in the well in advance of slickline operations and allowing the well to stabilize. However, if all the check valves are holding correctly they will prevent the fluid levels from equalizing.
- Decreasing casing pressure as far as is practical, e.g. to manifold pressure.
- Increasing tubing pressure.
- Opening an SSD above the packer and allowing the fluid levels to equalize.
- Pull the bottom valve and observe the following precautions carefully.

The operator should be prepared for the valve to be blown out of the SPM by:

- Maintaining high engine speed
- Ensuring the unit is high gear BEFORE beginning to jar up
- If the weight indicator drops suddenly, pull upwards IMMEDIATELY
- Retain line pull after each upward jar stroke and observe the weight indicator to ensure the valve is not free.

**Note**

By pulling the bottom valve first, the annulus can become equalized prior to recovering the upper valves. By pulling the upper valve first and working down the well, the pressure differential is likely to be less therefore reducing the chances of being blown up hole.

12.6.2 Basic Gaslift Valves

The specific details of the extensive choice of flow control devices, which can be installed in SPMs are beyond the scope of this manual. However, a brief overview of some of the more common devices is as follows:

There are two basic categories of gas lift valve:

- Casing pressure sensitive
- Tubing pressure sensitive

12.6.2.1 Casing Pressure Sensitive Valves

Also known as injection pressure sensitive, these valves are operated by casing gas pressure acting on a bellows against the force of the preset nitrogen pressure inside the valve.

These valves are installed with the highest-pressure valves nearest to the surface, i.e., each deeper valve has a lower pressure setting than the valve above. An orifice valve is usually installed at the bottom and this becomes the working valve. The upper valves are used to unload the column of fluid in the well only and then shut in as the casing pressure drops.

Examples:

- 1 in. valves - BK, BK-1, BKT, BKT-1
- 1½ in. valves- R-20, RMI

12.6.2.2 Tubing Pressure Sensitive

Also known as production pressure sensitive, these valves are operated by pressure in the tubing acting against the preset spring through a crossover seat. When the tubing pressure exceeds the spring force then it opens and permits gas from the casing to enter the tubing. Casing pressure will not open these valves.

The lowest pressure valves are nearest to the surface, i.e., each deeper valve has a higher pressure setting than the valve above. An orifice valve is usually installed at the bottom and this becomes the working valve. The upper valves are used to unload the column of fluid in the well only.

On the surface and while running in, these valves will be closed. The valve will only open when the hydrostatic pressure in the well exceeds the preset spring tension. Therefore all the valves should be open when installed at their correct depths.

Examples:

- 1 in. valves - BKR-5, BKF-6
- $1\frac{1}{2}$ in. valves- R-25, R-25P

12.6.2.3 Orifice Valves

Installed in the SPM for continuous tubing flow gas-lift applications, sometimes below a sequence of casing or tubing pressure sensitive valves. These valves are available with fixed orifice within the range of $\frac{1}{8}$ in. to $\frac{3}{8}$ in. (in $\frac{1}{16}$ in. increments) with a check valve in the nose to prevent back flow from the tubing to casing.

Examples:

- 1 in. valves - DKO-2, BKO-3
- $1\frac{1}{2}$ in. valves - RDO-5

12.6.2.4 Dummy Valves

Dummy valves are used to block off the ports in the SPM during the completion phase to enable pressure testing of the tubing and other down hole components. The SPMs with the dummy valves installed, should be pressure tested at the surface prior to being run into the well.

The dummy valve remains in place until gas-lift valves are required to be installed to enhance and optimize the production rate of the well.

The following types of dummy valves are in use:

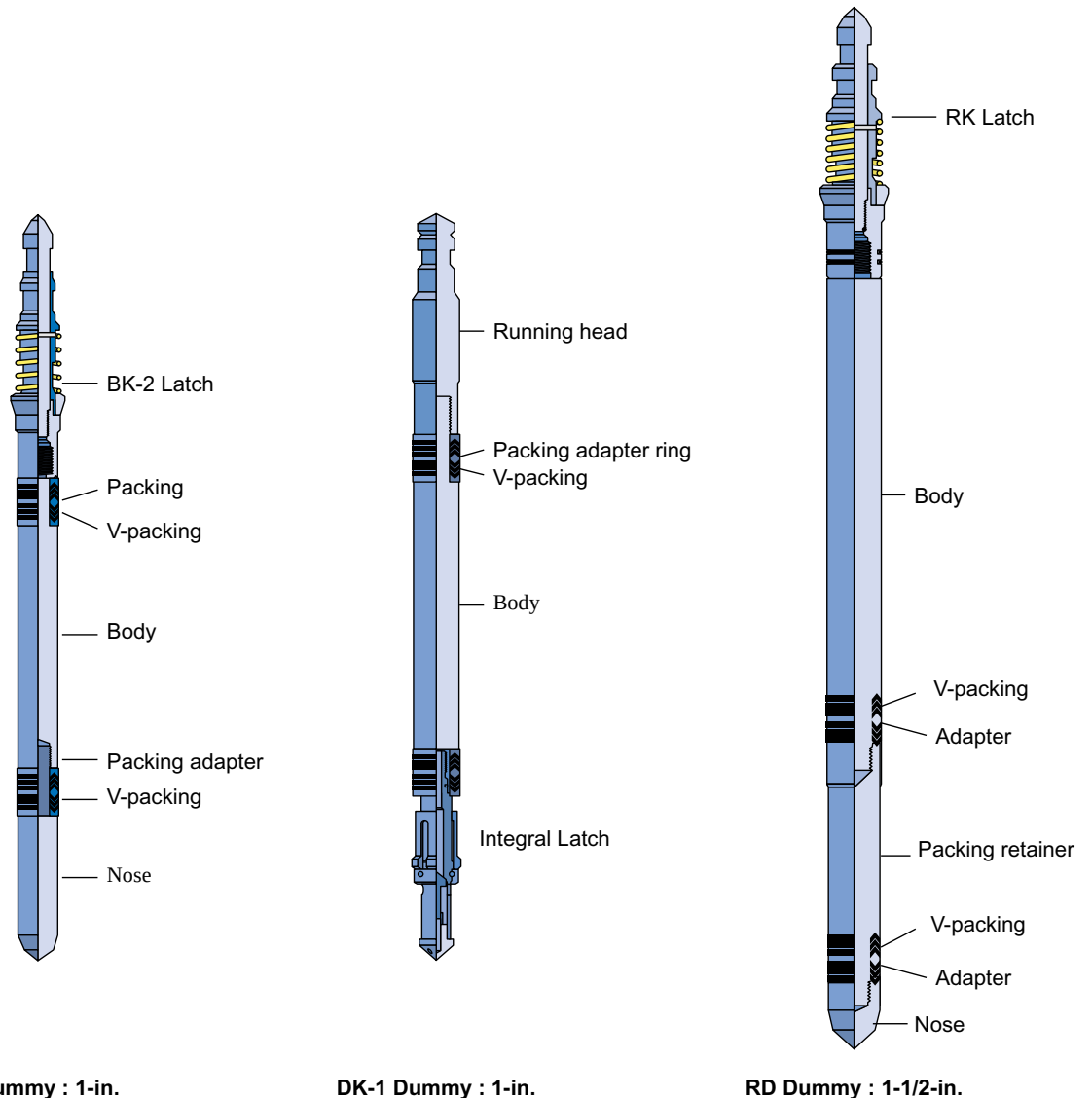
- **E dummy (1 in.)** - Run with a BK-2 latch into KB series mandrels
- **DKO-1 (1 in.)** - Run with an integral latch
- **RD Dummy ($1\frac{1}{2}$ in.)** - Run into the MM series mandrels on an R or RA latch

12.6.2.5 Equalizing Dummy Valves

Dummy valves are available with an equalizing device to permit the balancing of the pressure differential at the valve before pulling the valve from the pocket.

- **EK-1, BKEOT** - Fitted with an internal sleeve that moves downward to open an equalizing port.

EK, RKED, CEV - These have a removable inner prong which is recovered in a separate run prior to recovery of the body of the valve.



E Dummy : 1-in.

DK-1 Dummy : 1-in.

RD Dummy : 1-1/2-in.

Figure 12-20: Dummy Gas Lift Valves

12.7 Camco Gas Injection Valves

12.7.1 Single-Point-Injection Gas Lift Orifice Valves

Camco retrievable single-point-injection gas-lift orifice valves are used for continuous tubing flow gas-lift production. This line of valves includes 1 in. OD DKO-2, BKO-3 and OM-20R valves and 1½ in. OD RDO-5, O-21R and O2-30-R valves. An integral choke controls the flow of gas through these normally open valves into the production conduit. BKO-3, RDO-5, OM-20R, O-21R and O2-30R valves have floating chokes and DKO-2 valves have non-floating, replaceable chokes. All these valves contain integral reverse flow check valves.

Port sizes available for 1 in. OD valves are 1/8 in. through 3/8 in. in 1/16 in. increments for DKO-2 valves 1/8 in. through 5/16 in. in 1/16 in. increments for BKO-3 valves and 1/8 in. through 7/16 in. in 1/16 in. increments for OM-20R valves.

Port sizes available for 1½ in. OD RDO-5 valves are 3/16 in. through ¾ in. in 1/16 in. increments. Port sizes available for the O-21R are 1/8 in. through 5/8 in. in 1/16 in. increments and 1/16 in. through 5/8 in. in 1/16 in. increments for the O2-30R.

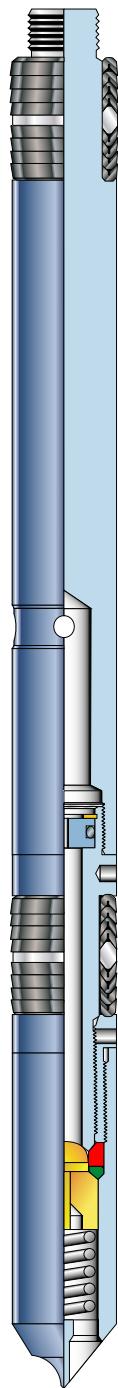


Figure 12-21: BKO-3 Orifice Valve

12.7.1.1 Operation

Injection gas enters the valve through the external ports between the valve packing sets and travels through the choke, past the reverse flow check valve and into the production conduit.

Table 12-8: Single-point Injection Gas Lifts Orifice Valves

Type	Assembly Number	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assy Number	Type	Assembly Number	
DKO-2	01072	1.000	Integral Bottom	GA-2	15052	JDC	15151*	KEM, KBMM
								KBMG, KBTG
BKO-3	01179	1.000	BK-2, M	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
OM-20R	02413	1.000	BK-2, M	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
RDO-5	01423	1.500	RA, RM	JC-3	15065	JDCI	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG
O-21R	02414	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-7	15079	JDS	15155	MMM, MMG, MTG
02-30R	02415	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS j	15155	MMM, MMG, MTG

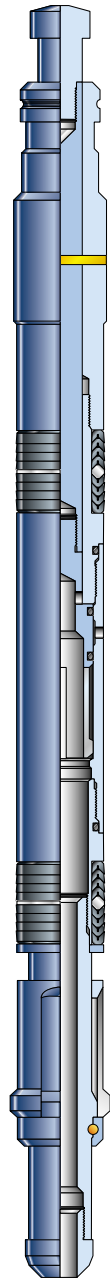
* Use core extension 15152-012-00000 with this pulling tool.

12.7.2 Equalizing Dummy Valve

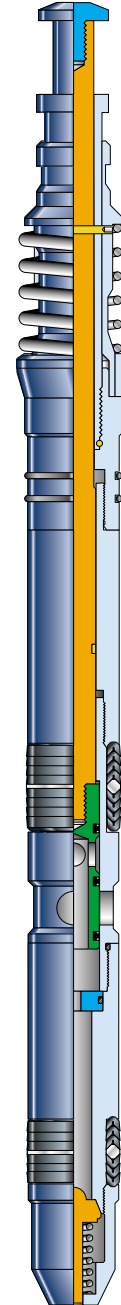
Camco retrievable equalizing dummy valves are isolation and pressure equalization devices that prevent communication between the tubing and the casing. This line of valves includes 1 in. OD EDM-30-R, EK-1 and BKEO valves and 1½ in. OD ED-30-R, CEV and RKEO valves. These valves each have two set of packing which straddle and pack off the casing ports in the side pocket mandrel. Any of these equalizing dummy valves can be used for equalizing tubing and casing pressure; however, only BKEO, EDM-30-R, ED-30-R and RKEO valves are recommended for circulating fluid before valve retrieval. RKED and CEV valves each have an equalizing prong, which positively seals off communication between the tubing and the casing. These valves require two slickline trips for retrieval, the first to pull the prong and equalize the valve and the second to retrieve the valve. EK-1, BKEO, EDM-30-R, ED-30-R and RKEO valves can be both equalized and retrieved with one slickline trip.

BKEO and RKEO valves have replaceable orifices.

Flow area for EK-1, RKED and CEV valves is equivalent to a 17/64 in. port. Port sizes available for BKEO valves are $\frac{1}{8}$ in. through $\frac{5}{16}$ in. in $\frac{1}{16}$ in. increments and for RKEO valves are $\frac{5}{16}$ in. through $\frac{1}{2}$ in. in $\frac{1}{16}$ in. increments. The port size for the EDM-30R is $\frac{5}{16}$ in. and $\frac{1}{4}$ in. for the ED-30R.



EK-1



RKEO

Figure 12-22: EK-1 and RKED Equalizing Dummy Valve

12.7.2.1 Operation

For RKED and CEV valves, first the equalizing prong is retrieved by standard slickline methods with a pulling tool and a core extension. Pressures are then allowed to equalize and the valve is retrieved from the side pocket mandrel. For EK-1, BKEO, EDM-30-R, ED-30-R and RKEO valves, downward jarring on the pulling tool shift the equalizing prong downward to open the valve equalizing ports. After equalization, upward jarring removes both the equalizing prong and the valve from the side pocket mandrel.

Table 12-9: Single-point Injection Gas Lift Orifice Valves

Type	Assembly Number	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel
				Type	Assembly Number	Type	Assembly Number	
EDM-30R	02416	1.000	Integral	JK	15072	JDC	15151*	KBM, KBMM,
			Top					KBMG, KBTG
EK-1	01125	1.000	Integral	GA-2	15052	JDC	15151	KBM, KBMM,
			Bottom					KBMG, KBTG
BKEO	01181	1.000	Integral	JK L	15072	JDC	15151	KBM, KBMM,
			Top					KBMG, KBTG
ED-30R	02417	1.500	Integral	RK-1	15079	JDS	15155	MMM, MMG, MTG
			Top					
CEV		1.500	Integral	JC3	15065	JDC	15156	MMA, MTA
			Top					
RKEO	01428	1.500	Integral	RK-1	15079	JDS	15155	MMM, MMG, MTG
			Top					

* Use core extension 15152-012-00000 with this pulling tool.

12.7.3 Orifice Venturi Gaslift Valves (NOVA™)

The NOVA™ series of orifice operating valves replace conventional operating orifices. These valves have an exclusive computer generated flow profile to promote a constant flow gas injection rate. This profile induces maximum gas

passage with minimal differential across the valve. All of this is achieved with the same number of moving parts as a typical gas lift orifice valve and it will fit in any existing side pocket mandrel.

The flow regime present in the NOVA valve virtually eliminates any effect of tubing pressure on the gas injection rate. The gas injection pressure is stabilized and this may lead to a more stable tubing pressure, which usually results in increased production. Lower injection pressure reduces operating expenses.

The injection rate through conventional orifice valves is inherently unstable because of the effect of tubing pressure. Even slight variations in the flow regime in the tubing can lead to wide fluctuations in the tubing pressure resulting in unsteady injection rates, instability and slugging.

The NOVA Series orifice valve works to stabilize this dynamic situation. Critical flow is achieved through this valve with as little as a 10% pressure drop or less. Conventional valves require approximately 40% pressure drop to achieve critical flow and in most cases it is not practical to operate with this much loss.

Operating in the critical flow regime is beneficial to gas-lift operations because the injection rate is constant-the tubing pressure does not affect the injection volume. Also, stabilizing the injection pressure can lead to reduced maintenance costs.

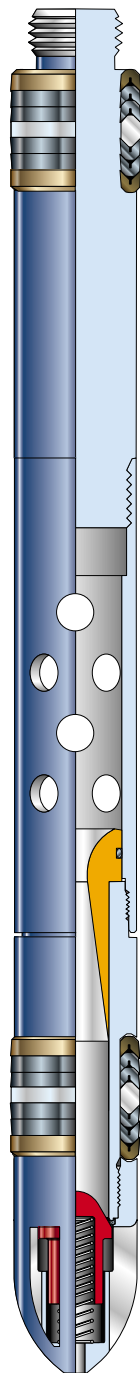


Figure 12-23: Orifice Venturi Gaslift Valve (NOVA)

12.7.3.1 Operation

This valve design utilizes an orifice (choke) as well as check valve for continuous flow operations. Injection fluid or gas enters through the entry ports, then flows through an orifice. Injection pressure moves the check valve off of the seat allowing gas or fluids to enter the tubing. Reverse flow pushes the check valve closed to prevent tubing fluids and pressure from flowing into the casing.

For injection of fluids or gas from the tubing to the tubing/casing annulus, the valve is installed in a mandrel with a type EC pocket which has tubing ports between the seal bores. Flow vents out the bottom of the valve, past the check and into the casing/tubing annulus.

Table 12-10: Single-point Injection Gas Lifts Orifice Valves

Type	Assembly Number	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assembly Number	Type	Assembly Number	
NOVA 10	02411	1.000	BK-2, M	JK	15072	JDC	15151*	KBM, KBMM,
								KBMG, KBTG
NOVA 15	02412	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
	RKP		RKP	RK-1	15079	JDS	15155	MMM, MMG, MTG

* Use core extension 15152-012-00000 with this pulling tool.

12.7.4 Shear Orifice Valves

The retrievable shear valve provides a means of communication between the casing and the tubing and is activated by differential pressure. This line of valves includes 1 in. OD SO2M-14R valves and 1½ in. OD SO2-30R valves. The valves, which act initially as dummy valves, have a piston, which seals off the circulating ports in the valve and the side pocket mandrel. The piston is held in the closed position with a draw bar. The shear diameter of the draw determines the casing-to-tubing pressure differential required to open the valve.

Port sizes available for 1 in. OD valves are ⅛ in. through 7/16 in. in 1/16 in. increments for SO2M-14R valves.

Port sizes available for 1½ in. OD valves are ⅛ in. through ⅜ in. in 1/16 in. increments for SO2-30R valves.

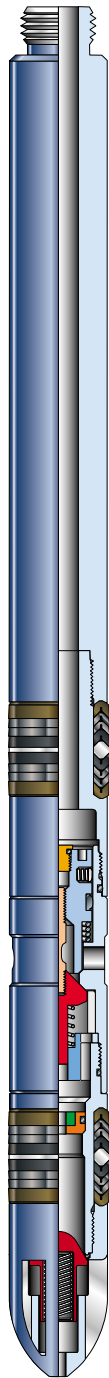


Figure 12-24: Shear Orifice Valve

12.7.4.1 Operation

Annular pressure must be increased enough to obtain the required differential pressure to shear the draw bar holding the valve piston closed. When the draw bar shears and the piston locks open, well fluids are free to flow in either direction. An increase in tubing pressure will not open the valve.

Table 12-11: Shear Orifice Valves

Type	Assembly Number	Nominal OD (in.)	Latch Series	Running Tool		Pulling Tool		Mandrel
				Type	Assembly Number	Type	Assembly Number	
SO2M-14R	02419	1.000	BEK-2	JK	15072	JDC	15151*	KBM, KBMM,
								KBMG, KBTG
SO2-30R	02418	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RKP	RK-1	15079I	JDS	15155	MMM, MMG, MTG

* Use core extension 15152-012-00000 with this pulling tool.

12.7.5 Circulating Valves

Retrievable circulating valves are used to circulate fluid through the side pocket of a mandrel without damaging the pocket. This line of valves includes 1 in. OD CSK-1 and BKFS valves and 1½ in. OD RCS, RKFS, RG-2 and RGR-2 valves. CSK-1, BKFS, RCS and RKFS valves do not contain integral reverse flow check valves and permit circulation from both the casing to the tubing only and RGR-2 valves permit circulation from the tubing to the casing only. RG-2 and RGR-2 valves contain integral reverse flow check valves. Fluid is dispersed through both ends of each circulating valve to enable circulation with a minimum pressure drop. BKFS and RKFS valves feature a replaceable orifice choke and an ID that is specially treated to resist the erosive effects of high flow velocities.

Circulating areas available for 1 in. OD valves are 0.186 in.² for CSK-1 valves and 0.150 in.² maximum for BKFS valves. Orifice choke sizes available for BKFS valves are 1/16 in. through 7/16 in. in 1/16 in. increments. Circulating area available for 1½ in. OD valves are 0.776 in.² for RCS valves, 0.360 in.² maximum for RKFS valves and 0.392 in.² for RG-2 and RGR-2 valves. Orifice choke sizes available for RKFS valves are 1/16 in. through 5/8 in. in 1/16 in. increments.

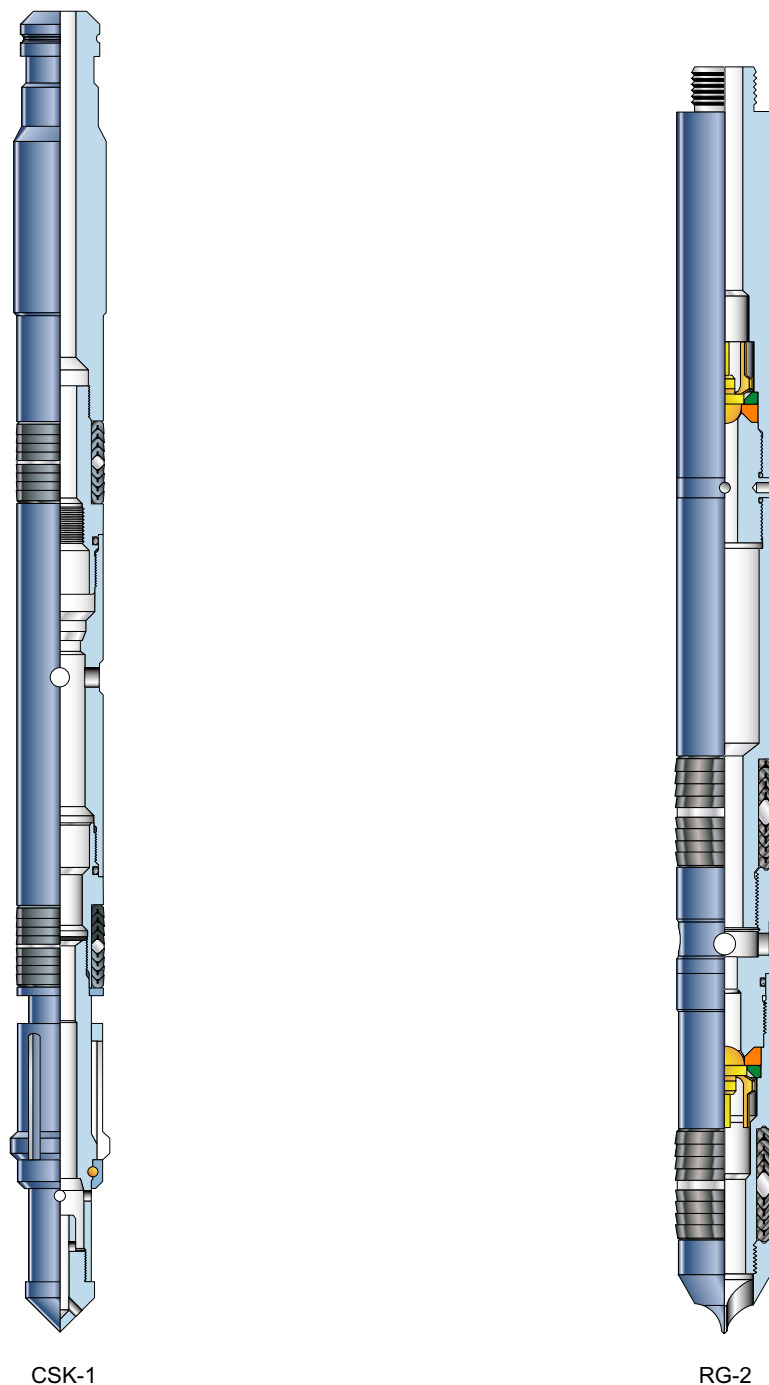


Figure 12-25: CSK-1 and RG-2 Circulating Valves

12.7.5.1 Operation

In casing-to-tubing circulation applications (for all except RGR-2 valves), fluid in the casing annulus enters the valve through the external ports between the valve packing sets and flow simultaneously upward through the valve top and

downward through the valve nose into the tubing. The integral reverse flow check valves in RG-2 valves prevent back-flow and circulation from the tubing into the casing. In tubing-to-casing circulation applications (for all except RG-2 valves), fluid in the tubing enters the valve simultaneously through the valve nose and the valve top and flows into the casing annulus through the external ports between the valve packing sets. The integral reverse flow check valves in RGR-2 valves prevent back-flow and circulation from the casing into the tubing.

Table 12-12: Retrievable Circulating Valves

Type	Assy Number	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series	Maximum Circulating Area (in. ²)
				Type	Assy Number	Type	Assy Number		
CSK-1	01061	1.000	Integral	GA-2	15052	JDC	15151*	KBM, KBMM,	0.186
			Bottom					KBMG, KBTG	
BKFS	01177	1.000	M, BK-2	JK	15072	JDC	15151	KBM, KBMM	0.150
			BEK-3**				15151*	KBMG, KBTG	
RCS	01317	1.500	RA,RM	JC-3	15065	JDC	15156	MMA,MTA	0.776
			RK-1	RK-1	15079	JDS	15155	MMM, MMG, MTG	
RKFS	01218	1.500	RK	RK-1	15079	JDS	15155	MMM, MMG, MTG	0.360
RG-2	01375	1.500	RKP	RK-1	15079	JDS	15155	MMM, MMG, MTG	0.392
RGR-2	01374	1.500	RKP	RK-1	15079	JDS	15155	MMM, MMG, MTG	0.392

* Use core extension 15152-012-00000 with this pulling tool.

** The BEK-3 latch provides fully open flow capability.

12.7.6 Water-flood Flow Regulator Valves

The Camco retrievable water-flood flow regulator valves precisely regulate water injection volumes into multiple isolated zones through a single tubing string. This line of regulator valves includes 1-in. OD KCW, KWW and FM-14R valves and 1½ in. OD RW, RWW and F-12R valves. Each regulator valve consists

of a hardened Monel piston, a stainless steel spring and an integral reverse flow check valve. A fixed orifice in the piston of these valves allows an infinitely variable flow rate adjustment within a specified range.

Flow area for 1 in. OD KCW, KWW and FM-14R valves ranges from an equivalent $\frac{1}{8}$ in. minimum port to an equivalent $\frac{7}{32}$ in. maximum port.

Flow area for $1\frac{1}{2}$ in. OD RW, RWW and F-14R valves ranges from an equivalent $\frac{1}{8}$ in. minimum port to an equivalent $\frac{3}{8}$ in. maximum port.

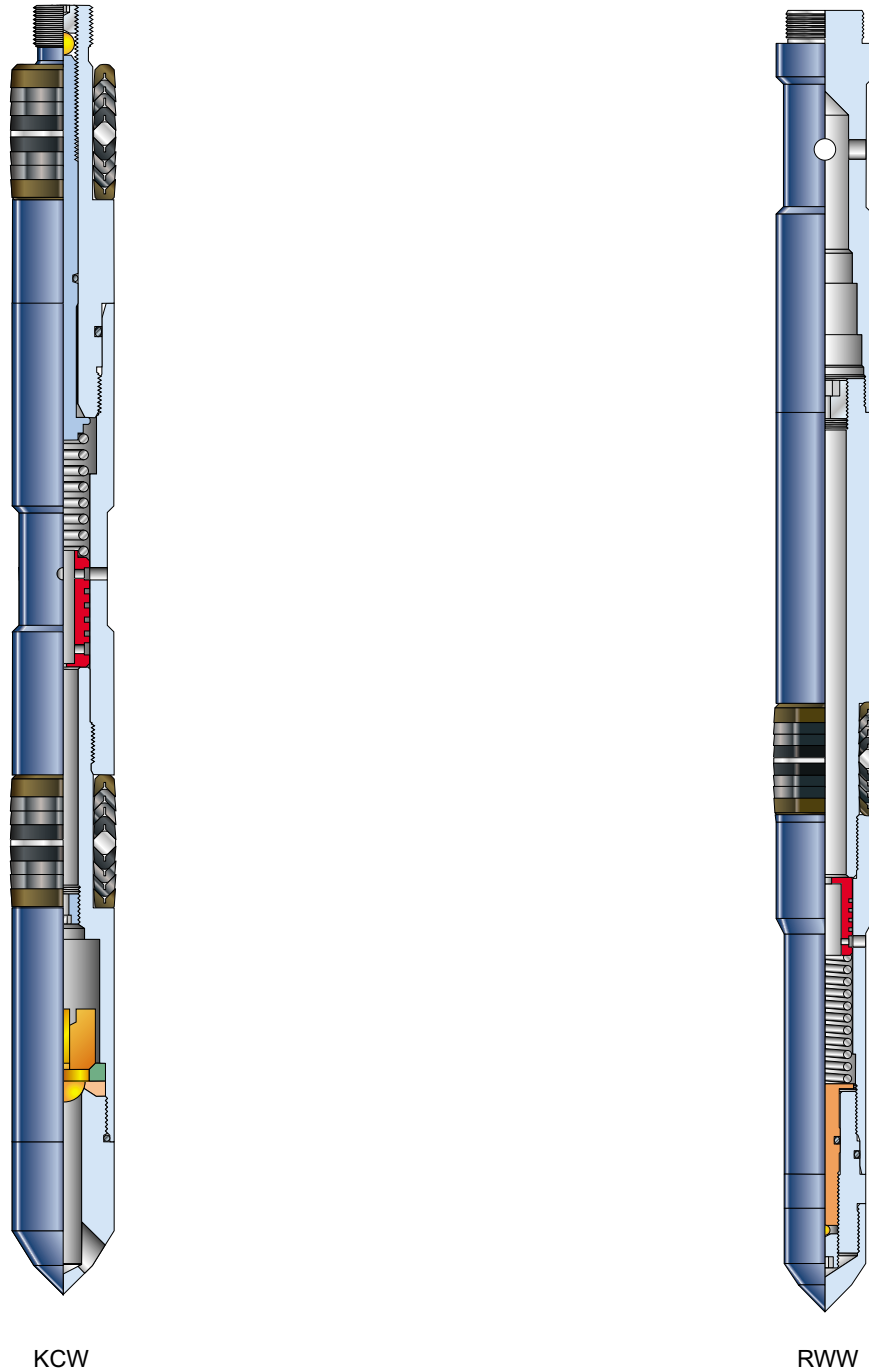


Figure 12-26: KCW and RWW Water-flood Flow Regulator Valves

12.7.6.1 Operation

Water injected into the tubing enters the flow regulator valve, passes through a fixed orifice in the piston and exits through variable exit port into the zone being flooded. If the pressure differential through the orifice increases, the pistons

position changes in relation to the exit port and restricts flow through the exit port. Flow rate is maintained at a predetermined and preset rate, regardless of changes in pressure characteristics between the injection stream and the zone being flooded.

Table 12-13: Retrievable Water-flood Flow Regulator Valves

Type	Assy #	Nom OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series	Fresh Water Flow Rate Range (bwpd)
				Type	Assy #	Type	Assy #		
FM-14R	02422	1.000	M, BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG	100-475
KCW	01359	1.000	M, BK-2	JK	15072	JDC	15151	KEM, KBMM, KBMG, KBTG	60-530
KWW	01116	1.000	BEK-2	JK	15072	JDC	15151*	KBMGW	60-530
F12R	02423	1.500	RA, RM	JC-3	15065	JDCI	15156	MMA, MTA,	302, 100
			RK	RK-1	15079	JOS	15155	MMM, MMG, MTG	
RW	01358	1.500	RA, AM	JC-3	15065	JDC	15156	MMA, MTA,	60-1,000
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG	
RWW	01357	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA	60-1,000
			RK	RK-1	15079	JDS	15155	MMGW	

* Use core extension 15152-012-00000 with this pulling tool.

12.7.7 Nitrogen Charged Chemical Injection Valves

The Camco retrievable nitrogen-charged chemical injection valves control chemicals injected into the production fluid at valve depth. This line of valves includes 1 in. OD BKCI-2 and BKLK-2 valves and 1½ in. OD RCI-2 and RCB valves. A nitrogen-charged bellows or piston provides the force necessary to maintain each of these valves in a normally closed position. BKCI-2 and RCI-2

valves contain metal-to-metal seal nitrogen containment pistons which make these valves suitable for high-pressure service. BKLK-2 and RCB valves contain a multiply Monel bellows and are used for low to medium pressure applications. All of these valves contain spring loaded reverse flow check valves and floating seats. BKCI-2, RCI-2 and RCB valves use a metal ball and seat containment for the nitrogen charge in the filling port, while BKLK-2 valves use a dill core.

Port sizes available for 1 and $1\frac{1}{2}$ in. OD valves are $\frac{1}{8}$ and $\frac{3}{16}$ in.

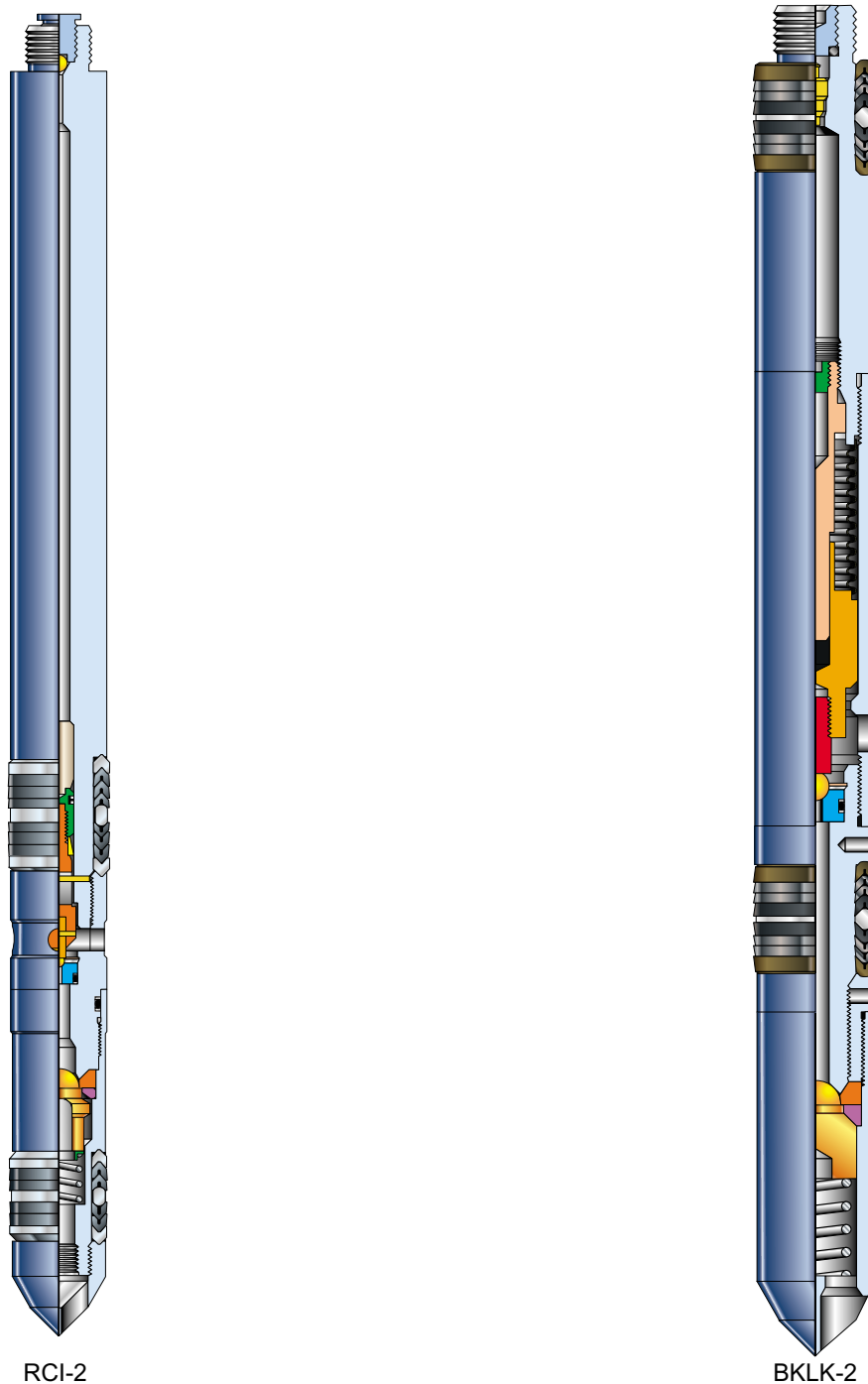


Figure 12-27: RCI-2 and BKLK-2 Nitrogen Charged Chemical Injection Valves

12.7.7.1 Operation

In an open injection system, injection chemicals enter the valve from the casing annulus. In a closed injection system, injection chemicals enter the valve from a separate injection line attached to the appropriate side pocket mandrel. Injection

chemical pressure acts on the effective bellows area. As injection pressure overcomes the pre-charged nitrogen pressure in the bellows, the bellows is compressed and lifts the stem tip off the seat. Chemicals then flow through the seat, past the reverse flow check valve and into the production conduit.

Table 12-14: Retrievable Nitrogen Charged Chemical Injection Valve

Type	Assy #	Nom OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series	Max Nitrogen Pressure (psi/bar)
				Type	Assy #	Type	Assy #		
8KCI-2	01186	1.000	M. BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG	5500 374.1
BKLK-2	01043	1.000	M BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG	2800 190.5
RCI-2	01425	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA	5,500
			RK-1	RK-1	15079	JDS	15155	MMM, MMG, MTG	374.1
RCB	01420	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA	2,800
			RK-1	AK-1	15079	JDS	15155	MMM, MMG, MTG	190.5

12.7.8

Spring Loaded Chemical Injection Valve

The Camco retrievable spring-loaded chemical injection valves control chemicals injected into the production fluid at valve depth. This line of valves includes 1 in. OD CM-30R valves and 1½ in. OD C-30R valves. An MP-35N or Elgiloy spring provides the force necessary to maintain each of these valves in a normally closed position. All of the valves contain integral reverse flow check valves and crossover seats.

Spring-loaded chemical injection valves are available in a 3/16 in. port size.

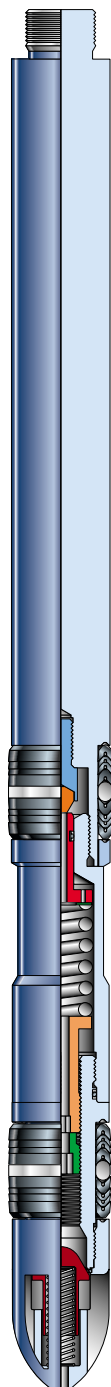


Figure 12-28: Spring Loaded Chemical Injection Valve

12.7.8.1 Operation

In an open injection system, injection chemicals enter the valve from the casing annulus. In a closed injection system, injection chemicals enter the valve from a separate injection line attached to the appropriate side pocket mandrel. As

injection pressure overcomes the preset spring force plus tubing pressure, the spring compresses and lifts the stem tip off the seat. Chemicals then flow through the seat, past the reverse flow check valve and into the production conduit.

Table 12-15: Retrievable Spring-loaded Chemical Injection Valve

Type	Assembly Number	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assembly Number	Type	Assembly Number	
CM-30R	02400	1.000	M, BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
C-30R	02401	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			AK	RK-1	15079	JOS	15155	MMM, MMG, MTG

12.7.9 Injection Pressure Operated Gas Lift Valves

The Camco retrievable injection pressure operated gas lift valves are used for either continuous or intermittent flow gas lift production. This line of valves includes 1 in. OD BK, BK-1, BKT, BKT-1 and 1½ in. OD R-20 and R-20-DC valves. A nitrogen-charged, multi-ply Monel bellows provides the force necessary to maintain the valves in a normally closed position. These valves contain integral reverse flow check valves and the BK, BK-1, BKT, BKT-1 and R-20 valves have floating seats. The R-20-DC features a double reverse flow check.

Depending on valve type and side pocket mandrel porting, these gas lift valves can be used for either tubing or annulus flow. BK, BK-1, BKT, BKT-1 and R-20 valves, used for either continuous or intermittent flow gas lift production, are used for tubing flow when installed in standard side pocket mandrels and annular flow when installed in side pocket mandrels ported for annular flow.

Port sizes available for 1 in. OD valves are ⅛ in. through 5/16 in. in 1/16 in. increments for BK valves, ⅛ in. through 3/8 in. in 1/16 in. increments for BK-1 valves and ⅛ in. through 3/8 in. in 1/16 in. increments for BKT and BKT-1 valves.

Port sizes available for 1½ in. OD valves are 1/8 in. through 1/2 in. in 1/16 in. increments for R-20 and R-20DC valves and 1/4 in. through 3/8 in. in 1/16 in. increments for RS-6.

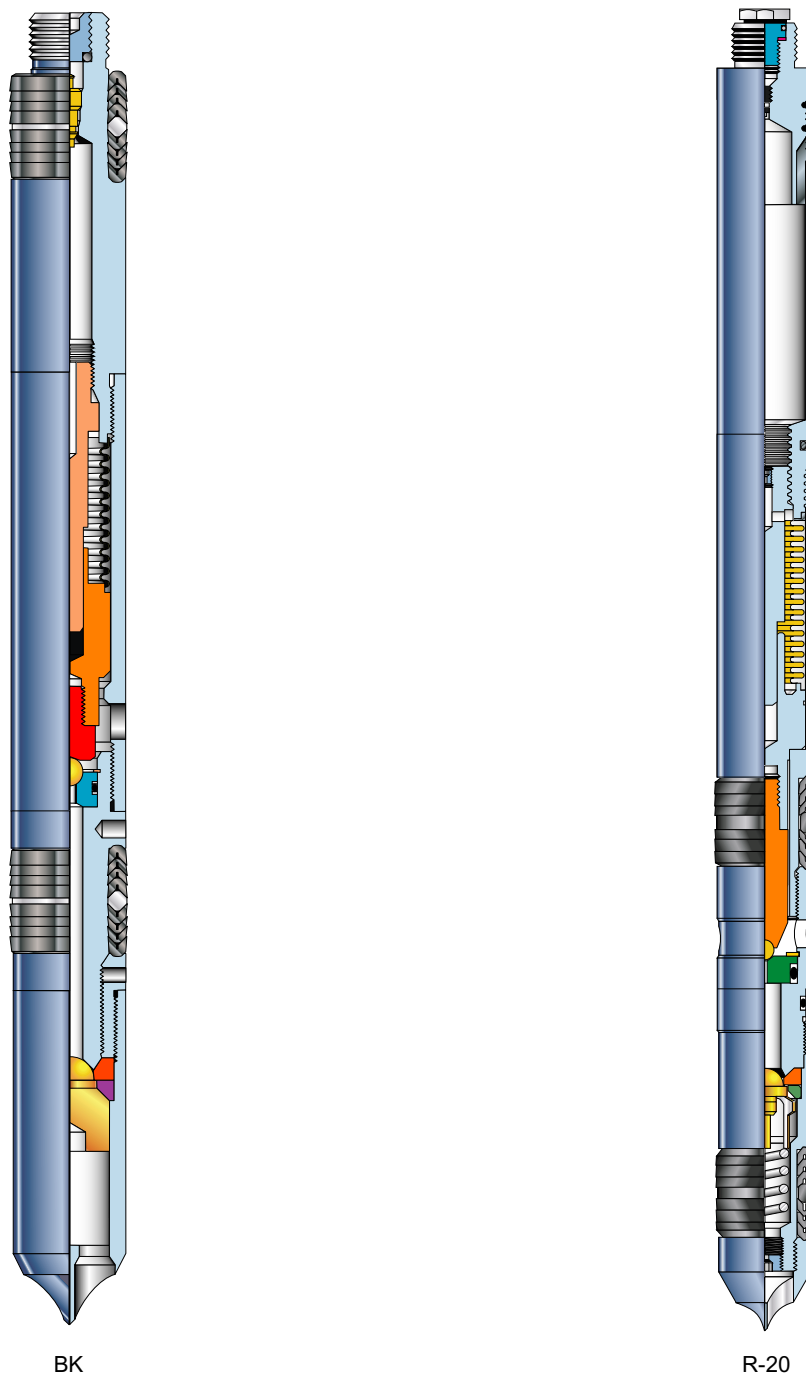


Figure 12-29: BK and R-20 Injection Pressure Operated Gas Lift Valves

12.7.9.1 Operation

Injection gas enters the valve and acts on the effective bellows area. The injection pressure necessary to compress the bellows of BK, BK-1, BKT, BKT-1, R-20 and R-20-DC valves is controlled by pre-charged nitrogen pressure. As

injection pressure overcomes the pre-charged nitrogen pressure in the bellows or the preset spring force, the bellows is compressed and lifts the stem tip off the seat. Injection gas then flows through the seat, past the reverse flow check valve and into the production conduit.

Table 12-16: Injection Pressure Operated Gas Lift Valves

Type	Assy #	Nom OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assy #	Type	Assy #	
BK	01050	1.000	BK2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
BK-1	01146	1.000	Integral Bottom	GA-2	15052	JDC	15151"	KBM, KBMM, KBMG, KBTG
BKT	01161	1.000	BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
BKT-1	01162	1.000	Integral Bottom	GA-2	15052	JDC	15151*	KBM, KBMM, KBMG, KBTG
R-20	01400	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG
R-20-DC	01467	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG
RS-6	01462	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG

* Use core extension 15152-00000 with this pulling tool.

12.7.10 Production Pressure-Operated Gas Lift Valves

Retrievable production pressure operated gas lift valves are used for continuous tubing flow gas lift production. This line of valves includes 1 in. OD BKR-5, BKF-12, RVM-16R valves and 1½ in. OD RV-15R valves. A nitrogen charged multi-ply Monel bellows provides the force necessary to maintain the BKR-5 valve in a normally closed position. An atmospheric pressure charged, multi-ply Monel bellows and an Inconel spring provide the force necessary to maintain

BKF-12, RVM-16R and RV-15R valves in a normally closed position. All of these valves contain integral reverse flow check valves and crossover seats and BKR-5 and BKF-12 valves have floating seats.

Port sizes available for 1 in. OD BKR-5 and BKF-12 valves are $\frac{1}{8}$ in., $\frac{3}{16}$ in. and $\frac{1}{4}$ in..

Port sizes available for 1 in. OD RVM-16R valves are $\frac{3}{16}$ in., $\frac{1}{4}$ in. and $\frac{5}{16}$ in.

Port sizes available for $1\frac{1}{2}$ in. OD valves are $\frac{3}{8}$ in. for RV-15R valves.

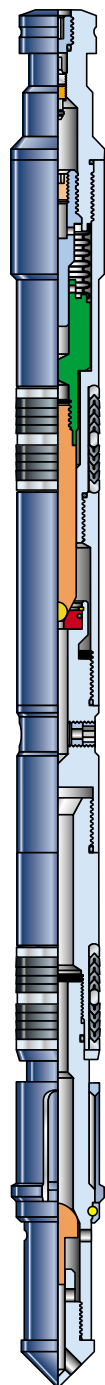


Figure 12-30: BKR-5 Production Pressure Operated Gas Lift Valve

12.7.10.1

Operation

Production fluid enters the valve and acts on the effective bellows area. The production pressure necessary to compress the bellows of BKR-5 valve is controlled by pre-charged nitrogen pressure. The force necessary to overcome

the Inconel spring in BKF-12, RVM-16-R and RV-15-R valves is provided by differential pressure (production pressure minus atmospheric pressure) times effective bellows area. As production pressure overcomes the pre-charged nitrogen pressure in the bellows or the preset spring force, the bellows is compressed and lifts the stem tip off the seat. Injection gas then flows through the seat, past the reverse flow check valve and into the production conduit.

Table 12-17: Retrievable Production Pressure Operated Gas Lift Valves

Type	Assy #	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assy #	Type	Assy #	
BKR-5	01182	1.000	Integral Bottom	GA-2	15052	JDC	1515P	KBM, KBMM, KBMG, KBTG
BKF-12	02404	1.000	BK-2	JK	15072	JDC	15151	KBM, KBMM KBMG, KBTG
RVM-16R	02402	1.000	BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG. KBTG
RV-15R	02403	1.500	RA, RM	JC-3	15065	JDC	15156	MMA,MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG
* Use core extension 15152-012-00000 with this pulling tool.								

12.7.11 Pilot-Operated Gas Lift Valves

Retrievable pilot operated gas lift valves are used for intermittent tubing flow gas lift production. This line of valves includes 1 in. OD PK-1 and WFM-14R valves and 1½ in. OD RP-6 and WF-14R valves. Each pilot operated valve consists of a pilot section and a power section. A nitrogen-charged multi-ply Monel bellows provides the force necessary to maintain the pilot section in a normally closed position and an Inconel spring provides the force necessary to maintain the power section in a normally closed position. PK-1, WFM-14R, WF-14R and RP-6 valves contain integral reverse flow check valves and floating seats.

The power section of 1 in. OD PK-1 valves has a flow area equivalent to a 3/8 in. port. Port sizes available for the PK-1 pilot section are 1/8 in. through 5/16 in. in 1/16 in. increments.

The power sections of the 1 in. OD WFM-14R and 1½ in. OD WF-14R valves have 0.180 in.² and 0.430 in.² flow areas respectively. Port sizes are available for the 1 in. OD WFM-14R and 1½ in. WF-14R pilot section is 1/8 in. through 5/16 in. in 1/16 in. increments.

The power section of 1 $\frac{1}{2}$ in. OD RP-6 valve has a flow area equivalent to a 9/16 in. port. Port sizes available for the RP-6 pilot section are $\frac{1}{4}$ in. through $\frac{1}{2}$ in. in 1/16 in. increments.

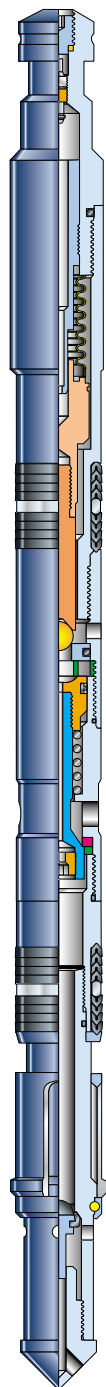


Figure 12-31: PK-1 Pilot-Operated Gas Lift Valves

12.7.11.1 Operation

Injection gas first enters the valve pilot section and acts on the effective bellows area. As injection pressure overcomes the pre-charged nitrogen pressure in the bellows, the bellows is compressed and lifts the stem tip off the seat to open the pilot section. Injection gas then flows downward through the valve until it overcomes the preset spring force of the power section. As the power section opens, injection gas flows through the valve, past the reverse flow check valve (in RP-6 and PK-1 valves only) and into the production conduit.

Table 12-18: Retrievable Pilot Operated Gas Lift Valves

Type	Assy #	Nominal OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assy #	Type	Assy #	
PK-1	01151	1.000	Integral Bottom	GA-2	15052	JDC	15151*	KBM, KBMM KBMG, KBTG
WFM-14A	02405	1.000	M, BK-2	JK	15072	JDC	15151	KBM, KBMM, KBMG, KBTG
RP-6	01396	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG
WF-14A	02406	1.500	RA, AM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JOS	15155	MMM, MMG, MTG

* Use core extension 15152-012-00000 with this pulling tool.

12.7.12 Proportional Response Gas Lift Valves

The L series proportional response valves are slickline retrievable throttling valves designed for high gas-volume and high-pressure, continuous flow installations. The predictable proportional response operating characteristics of this design permit the optimum volume of gas to pass from the annulus to the tubing in response to fluctuations in production pressure. The service life is increased by incorporating hydrostatic and vibration protection for the Monel bellows assembly.

The proportional response capability, determined by dynamic flow tests of these valves, enables accurate calculation of gas injection volumes throughout the anticipated range of operating conditions of the well. A tungsten carbide ball and seat are designed to minimize erosion and maintain positive closure of the valve.

The LN model features a special nitrogen-charged bellows design that allows very high set pressures and improved throttling characteristics.

LN-21R: 1½ in. slickline retrievable, proportional response valve can inject maximum gas volumes of over 10 mmcf/d. The LN-21R is designed for use in M series mandrels with an RA, RM or RK latch.

LN-31R: 1 in. slickline retrievable, proportional response valve for a K series mandrel with a BK-2 or M latch.

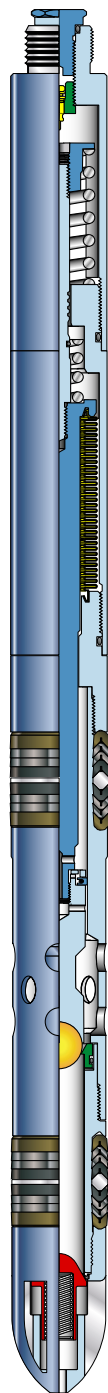


Figure 12-32: LN Series Proportional Response Valve

12.7.12.1 Operation

The dome pressure is preset at the reference temperature and corrected to operating temperature. The nitrogen dome charge applied to the external area of the bellows provides the downward force, holding the valve on its seat. The

opening forces on the valve are the casing pressure acting on the internal area of the bellows (less the area of the seat) and the tubing pressure acting on the seat area. When the combined casing and tubing pressure are sufficient, the valve opens. The valve remains open until the tubing pressure is reduced to the predetermined closing pressure. Valve closing pressures can be set to 2500 psi.

Table 12-19: Retrievable proportional response gas lift valves.

Type	Assy #	Nom OD (in.)	Latch	Running Tool		Pulling Tool		Mandrel Series
				Type	Assy #	Type	Assy #	
LN-31A	02407	1.000	BK-2, M	JK	15072	JDC	15151	KBM, KBMM KBMG, KBTG
LN-21A	02409	1.500	RA, RM	JC-3	15065	JDC	15156	MMA, MTA
			RK	RK-1	15079	JDS	15155	MMM, MMG, MTG

12.7.13 Special Valves

12.7.13.1 Chemical Injection Valves

Used to permit the introduction of chemicals such as inhibitor, injected down the casing. The production is treated at valve depth, which reduces the amount of tubing subjected to corrosive fluids. Volumetric control is achieved using a metering pump on the surface.

The valve is actuated by differential pressure between the tubing and annulus, and the spring rate can be adjusted to the required injection pressure. A check valve in the nose prevents reverse flow.

Examples:

- 1 in. valves - BKHLK-2 (N₂ charged), LK-3 (spring set)
- 1½ in. valves- RCBH (N₂ charged), RLC-3 (spring set)

12.7.13.2 Differential Kill Valve

Designed to hold differential pressure from the tubing, but can be pumped out with pressure from the casing.

Pressure at which the internal sealing plug moves to permit the annulus pressure to enter the tubing is predetermined by the number of shear screws inserted in the valve. When this valve is opened (sheared) the piston remains in the locked open position. The valve must be retrieved to be reset.

Examples:

- 1 in. valves - DCK-2
- $1\frac{1}{2}$ in. valves- DCR-1

12.7.13.3 **Water Flood Control Valves**

Water-flood flow regulator valves regulate water injection volumes into multiple zones through a single tubing string.

Examples:

- 1 in. valves - KCW
- $1\frac{1}{2}$ in. valves- RW, RWW

12.7.14 **Pressure and Temperature Recorders**

Several types of electronic memory recorders (EMR) are available for installation in the side pocket to record well flowing and shut-in pressures/temperatures over extended periods of time without restricting well flow.

Metrol (UK) manufacture a system, which permits inductive transfer of data and reprogramming from an instrument, positioned adjacent to the gauge in the pocket.

12.7.15 **FCV Series Flow Control Valves**

The FCV series flow control valves are manually adjusted valves designed to provide repeatable settings. Available in 1 in. and 2 in. body-sizes and a wide range of body and trim configurations, these valves feature a valve adjusting cap calibrated in sixty-fourths of an inch increments for accurate setting. The valve-stem packing gland is equipped with Teflon[®] packing for positive seal and minimum maintenance. Threaded connections are rated for 5000 psi, socket weld connections for 3600 psi and butt weld connections for 5000 psi. They are designed to operate in any position and to resist the effects of vibration on the selected setting. Their construction allows easy inspection or replacement of internal components without removing the valve from the line. Type 316, 410 or Duplex stainless steel bodies, and stainless steel handles and indicator rings are available for corrosive service.

Valve trim and seats are available in stainless steel, hard chrome or tungsten carbide materials. The valve and seat sizes available are $\frac{1}{8}$, $\frac{1}{4}$, $\frac{1}{2}$ or $\frac{3}{4}$ in.

Camco/Merla FCVT High Temperature Flow Control Valves are designed for steam injection or other high temperature gas or liquid service. Rated for 3500 psi working pressure at 700°F these 2 in. angle body valves feature $\frac{1}{4}$, $\frac{1}{2}$ or $\frac{3}{4}$ in. stainless-steel, hard chrome or tungsten carbide long throat trim and high temperature packing. The high temperature configuration is also available in an adjustable choke valve model (ACVT-5). The FCVT valve series is available with flanged, threaded or butt welded end connections.

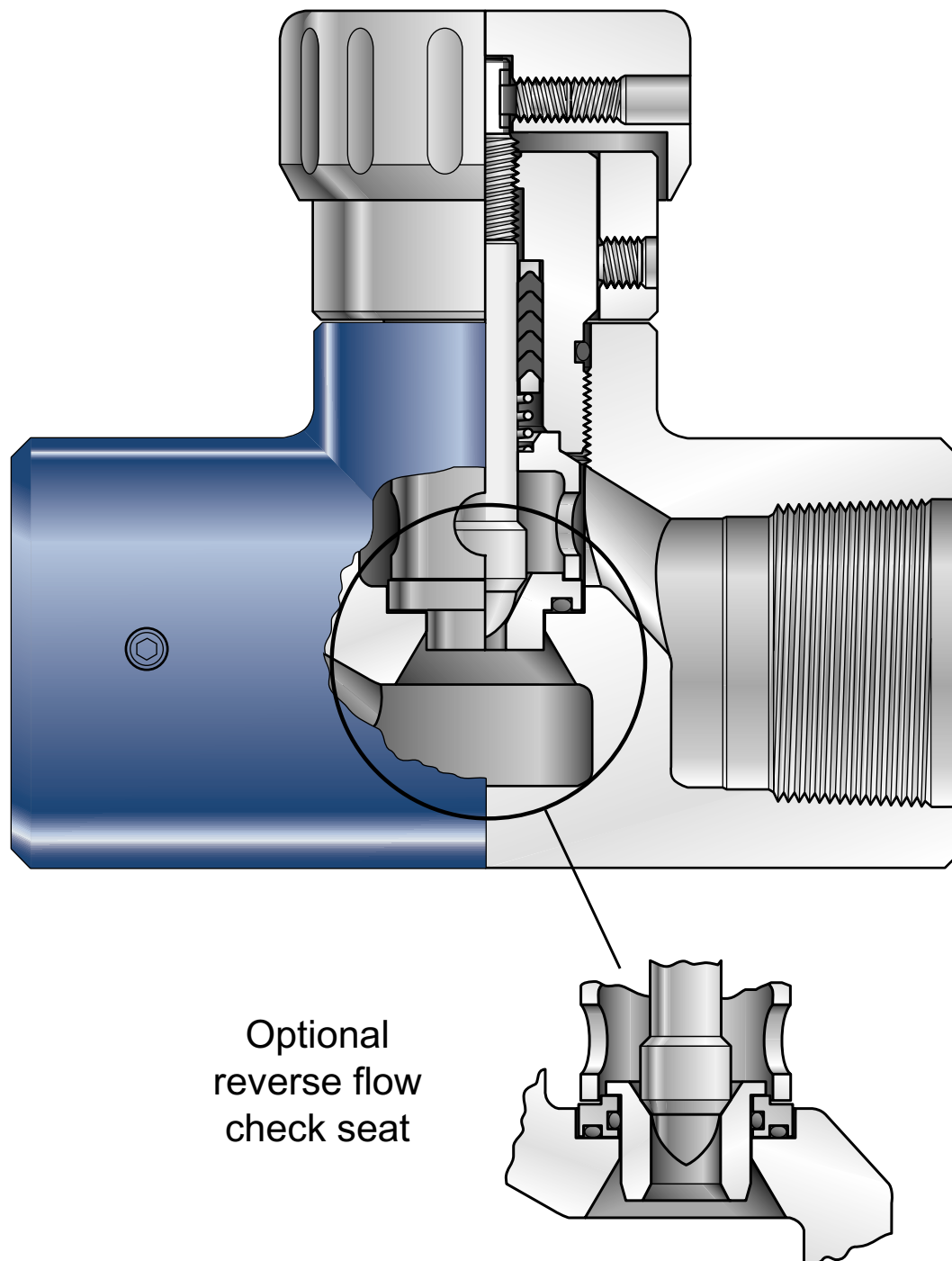


Figure 12-33: FCV Flow Control Valve

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13 DOWNHOLE RECORDERS

13.1 Introduction

Formation pressure and temperature data is essential for reservoir evaluation and monitoring. The instruments to obtain this information are available in the following types:

- Mechanical Gauges
 - Such as the Amerada equipment described in this section.
- Electronic Gauges
 - Electronic memory recorders (EMR) can be run on slickline and store data to be downloaded to a computer when the gauge is returned to the surface.
 - Surface read-out (SRO) gauges can be run on mono-conductor, multi-core cable or fiber-optic cable, to transmit data to the surface for real-time readout.

13.2 Amerada Gauges

The original mechanical gauge is the GRC Amerada gauge system initially developed in 1929 for Amerada Petroleum Company.

The Amerada bottom hole recorder is designed to enable bottom hole pressures or temperatures to be taken in a well, either flowing or shut in. The Amerada gauge has four main parts:

- Sensing element (pressure or temperature)
- Chart holder and stylus assembly
- Lead screw assembly
- Clock

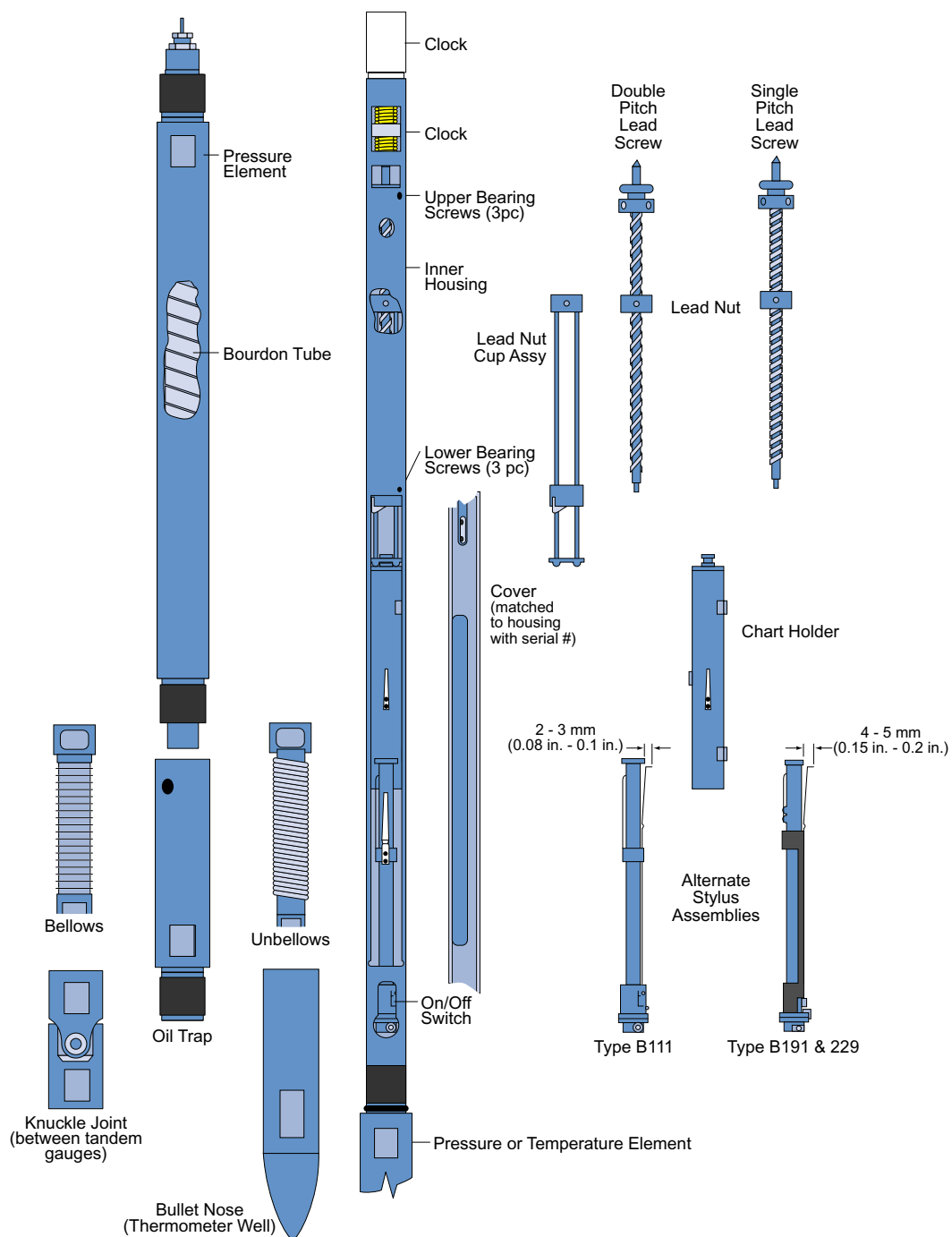


Figure 13-1: Amerada Gauge Components

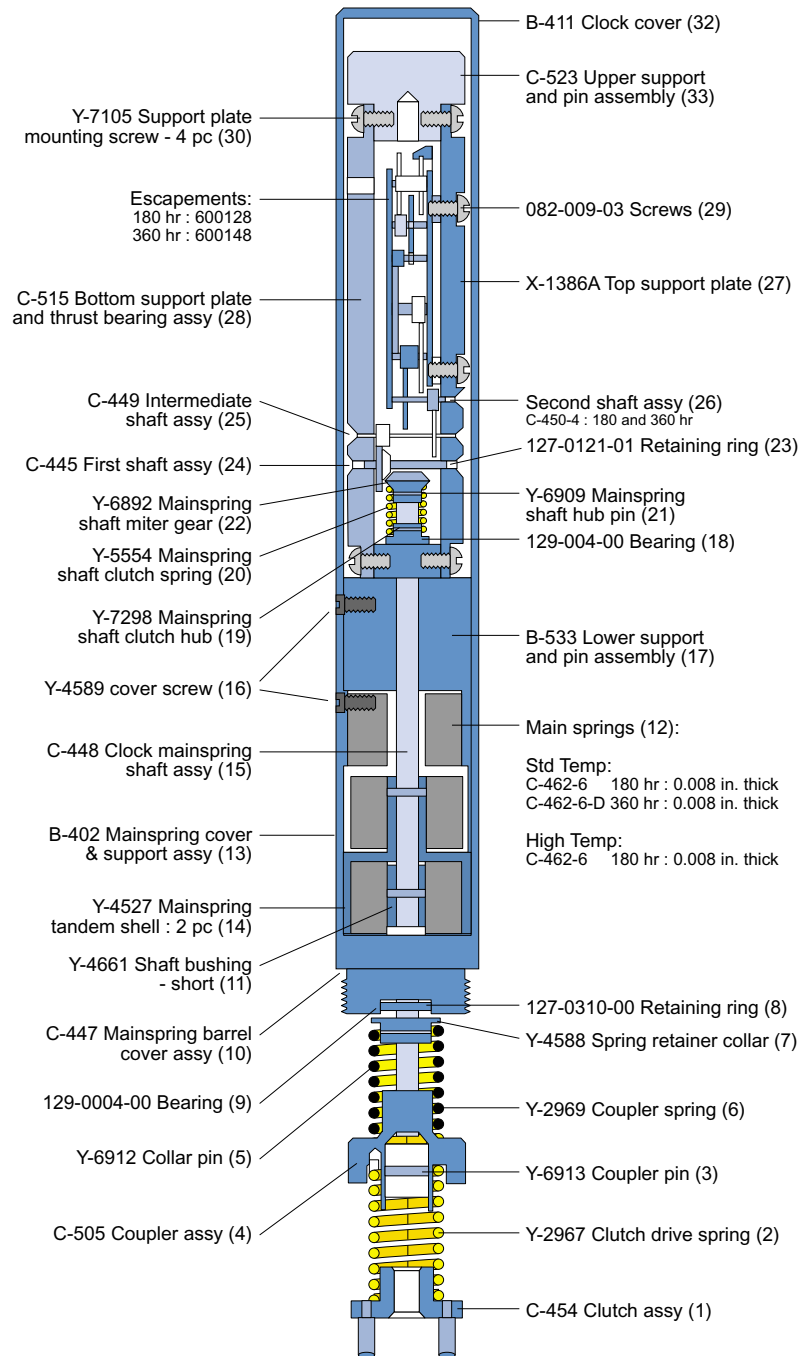


Figure 13-2: Amerada Clock Components

13.2.1 Sensing Elements

There are two sensing elements, pressure and temperature. The pressure element consists of a bellows and helical wound Bourdon tube, filled with a low confluent of expansion liquid manufactured under the trade name of Ucon. The well pressure which is in contact with the bellows (or through the unbellows)

compresses the Ucon in the Bourdon tube. The increase in pressure in the Bourdon tube makes it unbend, causing the free end to which a shaft is attached to rotate.

The temperature element consists of a cylinder containing a volatile liquid in connection with a helical Bourdon tube. Variations in well temperatures change the vapor pressure of the liquid and thus the pressure inside the Bourdon tube causing rotation of the free end.

13.2.2 Chart Holder and Stylus Assembly

Attached to the shaft, on the free end of the Bourdon tube of either the pressure or temperatures element, is a stylus, which rotates to make a chart. This arm is given a small amount of freedom of movement by means of a support spring.

The charts are thin sheets of brass, which have a non-reflective coating on one side. There are two types – flanged and flat. The flat type requires the use of a special guide in the chart holder.

The chart holder is a stainless steel cylinder through the center of, which passes a steel rod acting as a stylus guide. The outside of the holder has guides to prevent rotational movement and a small spring to prevent lateral movement.

The top of the chart holder assembly fits into a cup between two push rods. The lead screw assembly controls the linear movement of these rods.

13.2.3 Lead Screw Assembly

The lead screw assembly converts the rotational movement of the clock into the linear movement of the chart. The lead screws, fixed at each end by bearings, may be single pitch or double pitch. (Double pitch will run the full chart length in half time of the clock).

13.2.4 Clock

The clock, which is the extreme upper element of the Amerada, is the basic timing unit. The range of the clock is defined as the time required for 15 complete revolutions which, applied to a single pitch lead screw, will drive the chart holder exactly 5 in.

The range of clocks available are (in hours) – 3, 12, 24, 48, 72, 120, 144, 180 and 360.

The lead screw assembly may be used either with a single or double pitch lead screw.

Clocks should be maintained regularly and the escapement mechanism replaced if the clock is sticking.

Standard clocks can be used to 300°F. High temperature clocks are available for use in temperatures of 500°F and ultra-high temperatures to 700°F.

13.2.5 Selection of Elements and Components

Apart from the chart holder and stylus assembly, each of the elements of the Amerada may be varied to suit the job.

The pressure element give the most accurate and repeatable readings when the pressure to be read lies in the region between 1/3 and 3/4 of the nominal pressure of the element. The elements commonly used range between 500 and 15,000 psi, but they are available up to 25,000 psi.

Temperature elements exist to give temperature measurements between 0° and 650°F in the normal range provided by the manufacturer, GRC (Geophysical Research Corporation), but Kuster manufacturers high temperature elements with a range up to 750°F.

Table 13-1: Amerada Gauges Housing Specifications

Model	Maximum WP	Collapse Strength
RPG-3 or RT-7 with K-Monel bulb	22,000 psi	24 - 25,000 psi
RT-7 with copper alloy bulk (old type)	12,000 psi	
RT-7A	10,000 psi	15,000 psi
RPG-3 / age hardened housing stamped '28-K'		
RPG-4RT-8	18,000 psi	20 - 21,000 psi
RT-8A	12,000 psi	15,000 psi
RPG-4 / age hardened housing stamped '25-K'	25,000 psi	28 - 29,000 psi
RPG-5	20,000 psi	23 - 24,000 psi
KPG-K3	22,000 psi	
K2	20,000 psi	
K4	12,000 psi	

13.2.6 Temperature Limitations

Recording section (without clock)	345°C	650°F
Diagrams	345°C	650°F
Clocks standard	150°C	300°F
High temperature	260°C	500°F
Very high temperature	345°C (Kuster 370°C) * 650°F (Kuster 700°F) *	
Pressure sensors – GRC		
(with bellows)	150°C	300°F
(with unbellows or filter)	345°C	650°F
Pressure sensors – Kuster	370°C	700°F

* Higher temperature clocks are available from specialized manufacturers.

The bellows is the most delicate part and most affected by corrosive environments.

All other parts of the Amerada gauges that are exposed directly to well fluids, are made of materials known to be most resistant to the severely corrosive conditions that can occur in an oil or gas wells.

13.2.6.1 At Temperature ≤ 300 °F (150 °C)

Use Teflon coated bellows.

Before each run, fill the oil trap with clean oil or an inhibitor such as Kontol liquid.

After each run, clean the bellows thoroughly to remove traces of contaminating fluids.

If after the above precaution bellows' failure occurs, additional precautions may be taken by using a capillary oil trap together with Teflon coated elbows.

13.2.6.2 At Temperature > 300 °F (150 °C)

Use unbellows instead of bellows.

Make sure the oil trap is completely filled with clean oil or an inhibitor before running in hole.

Table 13-2: Amerada Gauges Manufacturer Rated Performances

Model	Accuracy	Sensitivity	Repeatability
RPG-3 RPG-4	0.200% full-scale	0.050% full-scale 0.055% full-scale	0.100% full-scale
RPG-5	0.250% full-scale		
RT-7 RT-7A RT-8 RT-8A	±20°F (1°C)	0.050% full-scale 0.055% full-scale	
KPG P T K2, K3 P T	0.200% full-scale ±3.5° F (2° C) 0.250% full-scale ±3.5° F (2° C)		

13.2.7 Isolation Devices

Isolation devices are required to keep potentially corrosive well fluids and solid particles away from the interior of the Bourdon tube. Ideally, these isolation devices should not affect the response of the gauge to pressure changes.

13.2.7.1 Bellows

The bellows type requires a minimal amount of energy to compress the metal used in its construction. This is a very small amount and it is compensated for during calibration. It does provide 100% isolation protection to the Bourdon tube. Bellows should not be used above 300°F.

Before use, the bellows should be inspected to ensure there are no sand particles in the corrugations and that it's length is as per the dimensions on the diagram below.

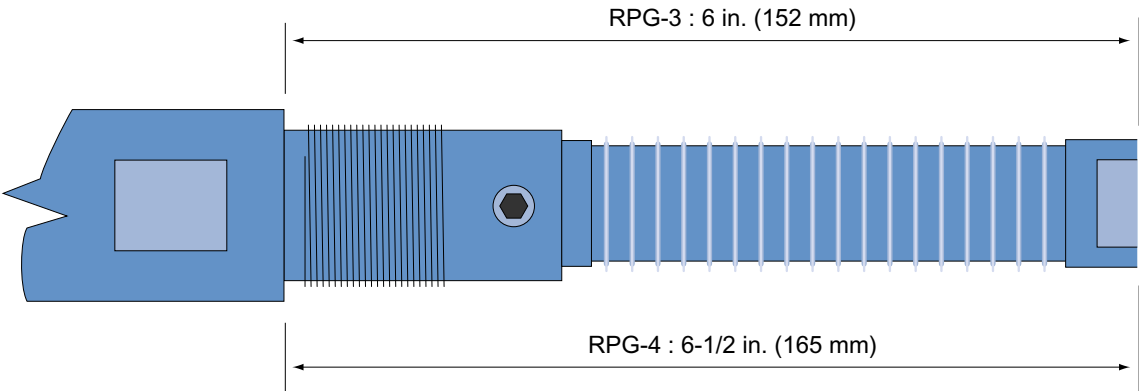


Figure 13-3: Isolation Devices Bellows

13.2.7.2 Unbellows

The unbellows consists of a stainless steel capillary tube (with a very small hole up the inside) wound onto a solid core. The lower end is drilled for pressure access via stainless steel mesh filters.

Before use, the unbellows should be back flushed with light oil to ensure they are free of blockages. Additionally, the oil in the tube acts as a further isolation to prevent well fluids reaching the Bourdon tube. As there is no compression of any components to absorb energy and the well pressure acts directly into the Bourdon tube, the unbellows are more accurate than the bellows.

The unbellows are more robust and less likely to be damaged and therefore are becoming more widely used.

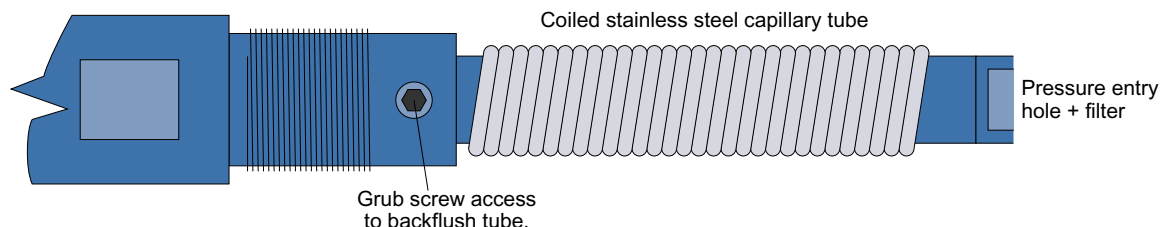


Figure 13-4: Isolation Devices - Unbellows

13.2.8 Gauge Calibration

When pressure is applied to the bellows of the pressure element, the resulting increase in pressure in the Bourdon tube causes rotation of the pin and stylus. The degree of rotation is a function of the applied pressure. The problem of calibration is to find the movement of the stylus over the chart for a number of known pressures and to measure the corresponding deflections produced by the pressure.

There are a number of different methods of interpretation, the method used depends on the client. The following method is normally used by Flopetrol, based on the assumption that the element is linear, i.e., equal changes in pressure give equal deflections.

This method may not be used with temperature elements because the calibration curves are noticeably curved. The only method available for these elements is to use a calibration curve and to read the temperature directly from the curve.

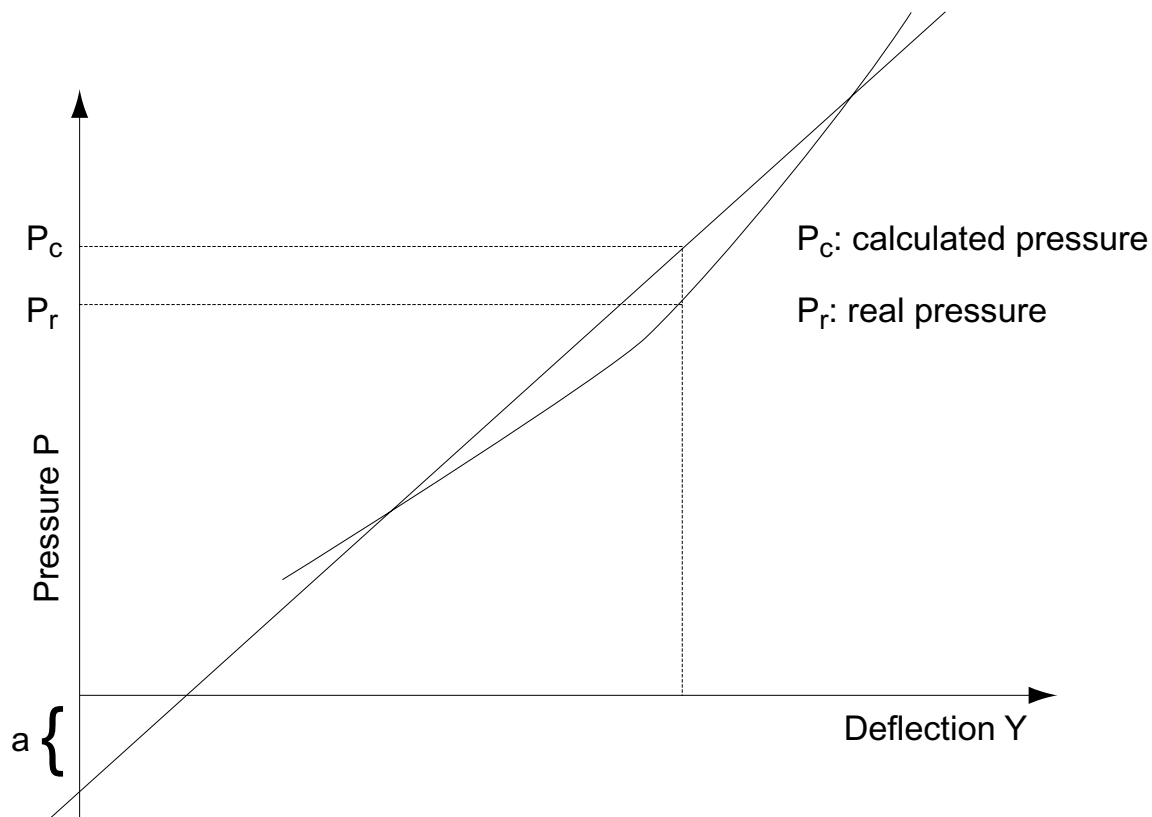


Figure 13-5: Calibration Theory - Least Square Method

Assuming that the calibration curve of a pressure element is a straight line, there must exist a formula for it of the type:

$$P = KY \pm a$$

Where:

P is the pressure

Y is the corresponding deflection

K is the gradient of the line (space)

A is the point at which the line cuts the pressure axis (positive or negative)

The least square method is a method of determining K and 'a' to a high degree of accuracy, allowing values of pressure to be determined from a known deflection.

It is a mathematical method of finding the line which best fits the calibration points.

13.2.8.1 Calibration

- At ambient temperature:
 - Manufacturer's calibration cell
 - Dead weight tester
- At bottom hole temperature:
 - Flopetrol temperature calibration cell
 - Dead weight tester
 - Clock or crank

13.2.8.2 Bottom Hole Pressure Calculation

After the survey the chart is read with a chart scanner.

1. The pressure deflection, Y, is carefully measured for all significant points of recording and the corresponding pressure calculated by using the general formula, $P = KY/a$, where K and 'a' have been determined by using the adequate steps of calibration.
2. Although the principle of chart reading and pressure calculations is simple, numerous slight errors or inaccuracies could be accumulated (i.e., time scale, zero, on base line etc.) and lead to false results.
3. This is only overcome by taking general care and experience.
4. With the correct preparation and care, it is possible to obtain results with an accuracy of 0.2% of the full range, i.e., 10,000 psi gauge $\pm$ psi.

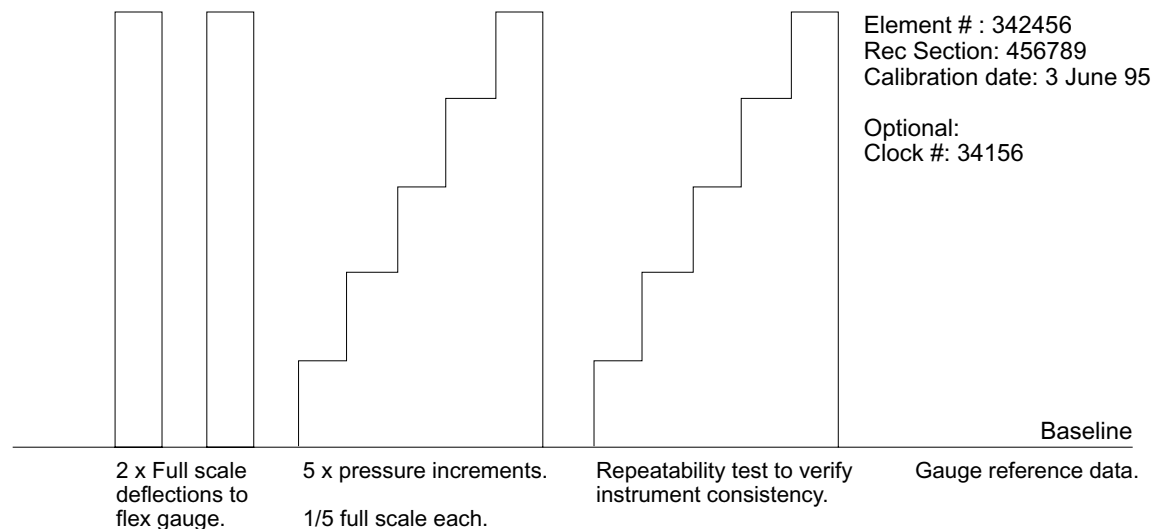


Figure 13-6: Calibration Theory - Bottom Hole Pressure Calculation

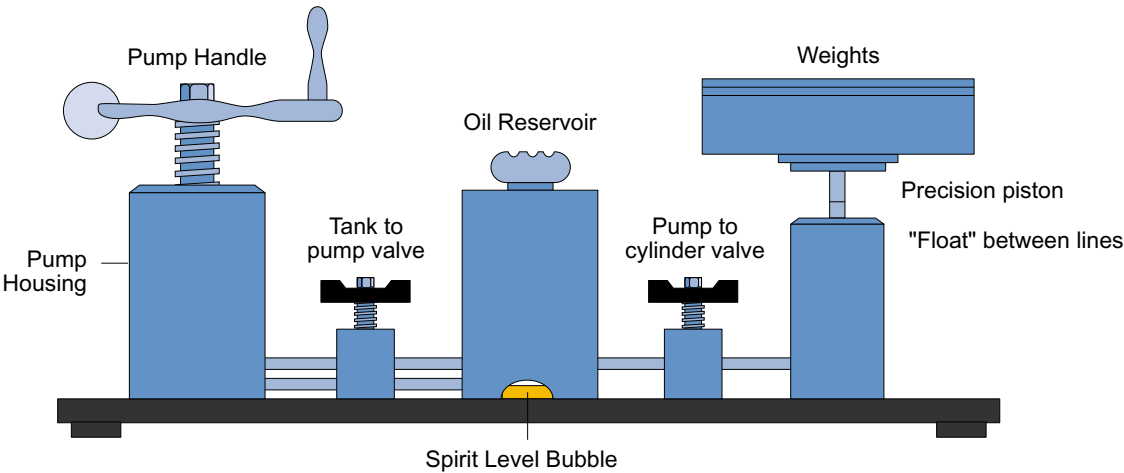


Figure 13-7: Calibration Bench Typical Set-up

i Note

Before use, make sure that the control box, heating cell and cabin are all connected together and physically grounded.

t Tip

Do not touch inside the control box without disconnecting the main's plug, even if the power switch is in the OFF position.

13.2.8.3 Direct Heating Calibrating Cell

Working pressure	10,000 psi
Test pressure	15,000 psi
Temperature range	80° F to 350° F
Accuracy	± 0.5° F
Power supply	220V/50 – 60 Hz
Recommended oil	Teresso 43 or equivalent

Table 13-3: Direct Heating Calibrating Cell

Dimensions	Single Cell (M801135)	Triple Cell (M801134)
Height	7.1 in.	
Body diameter	8 in.	11 in.
Base diameter	13 in.	16 in.

Dimensions	Single Cell (M801135)	Triple Cell (M801134)
Weight	250 lbm	520 lbm
Power requirements	2 kVA	3 kVA

13.3 Gauge Running and Retrieving Procedures

1. Follow the safety instructions.
2. Before running in with the Amerada, a control run is compulsory.
3. Standard practice is to run the Amerada in tandem.
4. Make up the tool as shown.
5. Connect first the top Amerada to the slickline string. Note the exact time the stylus is engaged and all serial numbers and ranges of the elements.
6. Connect the bottom Amerada to the crossover. Note the exact time the stylus is engaged and all serial numbers and ranges of the elements.



Note

A knuckle joint can be used between the Amerada, especially in deviated wells. This practice is however not recommended in high rate producing wells, particularly in gas wells because of vibrations.

7. Running in is made at a speed not exceeding 10,000 ft/hr. Slow down through the crossover, nipples etc., in the tubing string.
8. Make gradient steps while running in, not pulling out, to avoid the hysteresis effect.
9. Note the time of all events that can affect the recording.
10. Slow down 300 ft above the logging depth and stop at this depth. Note the exact time. If the logging depth is accidentally passed, come up 300 ft above this depth and go down again to the logging depth. This eliminates the hysteresis effect.
11. Come out of the hole at the running speed of 10,000 ft/hr.
12. After recovering the chart, write ON THE CHART the serial numbers of the clock and gauge.
13. Note the maximum thermometer reading.

14. Stops at each depth should be one minute for every one-hour on the clock, e.g., 3 hour clock – 3 minute stops.
15. Remove the clocks and put them back in clock cases immediately after pulling out of the hole.
16. Avoid rough handling. Treat as instruments.
17. Lubricate with grease on all threads.
18. Do not tighten connections. O-rings seals will hold the pressure.
19. NEVER use pipe wrenches on the cases.
20. REMEMBER to make a BASELINE.
21. TURN ON THE STYLUS BEFORE RUNNING.

13.3.1 Troubleshooting Guide

13.3.1.1 Trace Fails to Return to Baseline

- Element has not been pre-pressurized before use. This is necessary if the gauge has not been used within two days.
- Pressure leaking into bellows during survey. Check length immediately after survey.

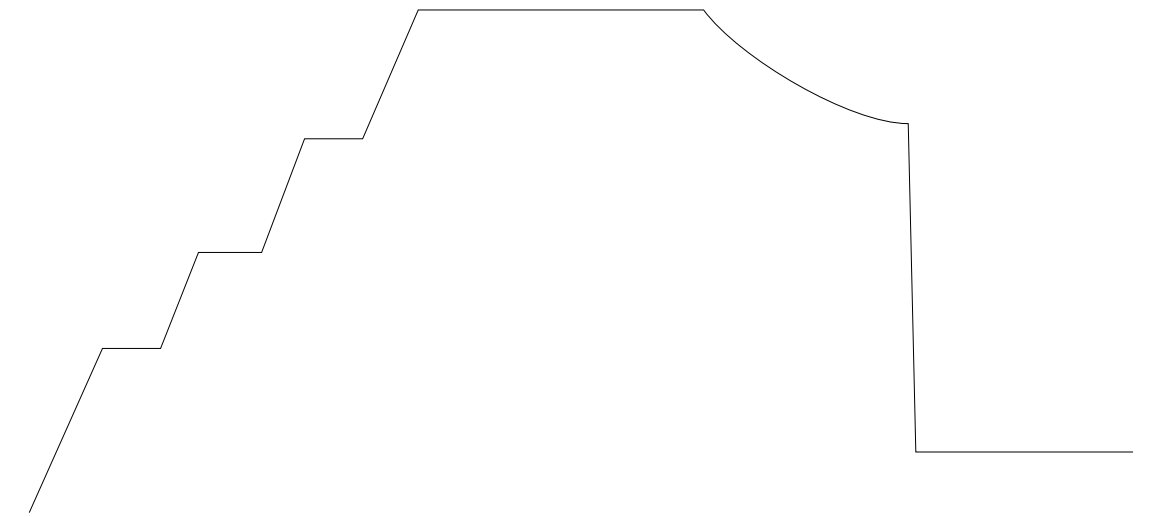


Figure 5-8: Trace Fails to Return to Baseline

13.3.1.2 Trace Returns Below Baseline

- Leaking Bourdon tube

- Leaking O-ring

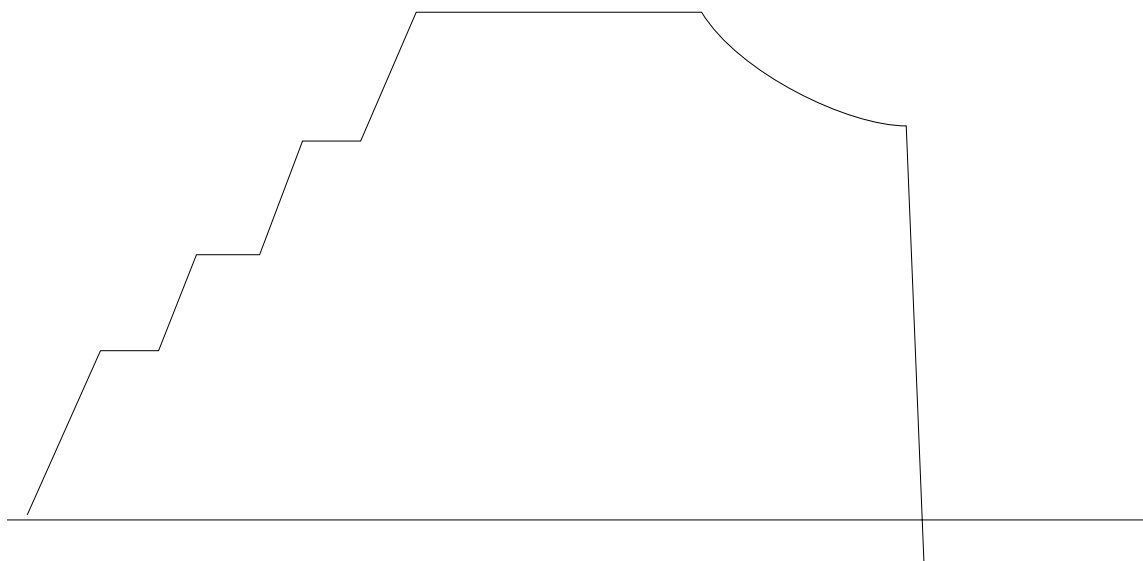


Figure 13-9: Trace Returns Below Baseline

13.3.1.3

Jagged Trace while Gauge is Stationary

- Dirty stylus shaft bearing.
- Stylus spring too far out.
- Abnormal friction on chart holder.

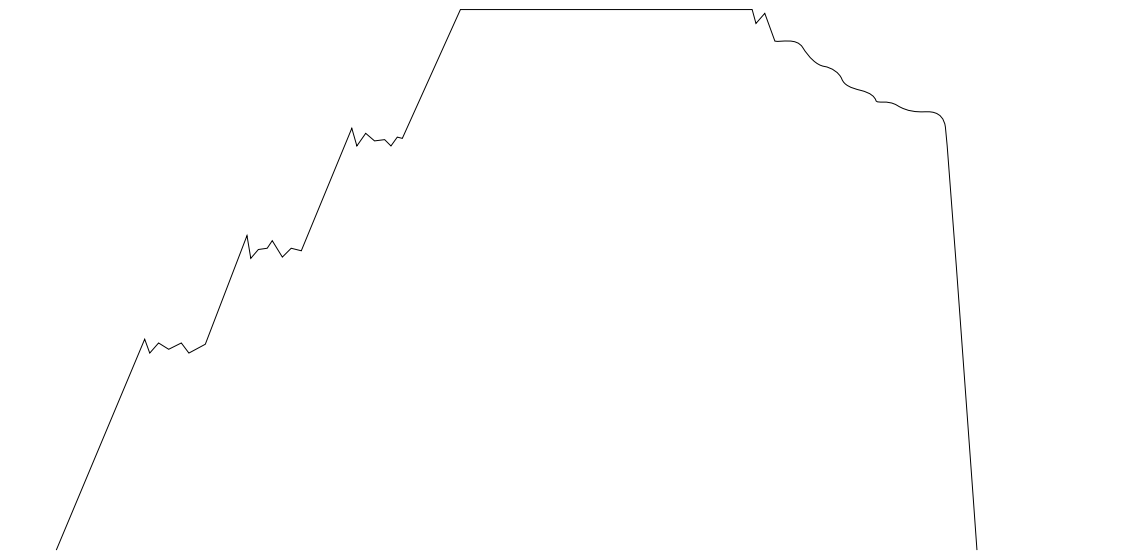


Figure 13-10: Jagged Trace while Gauge is Stationary

13.3.1.4 Time Stops Much Longer Than Expected

- Clock slippage - allowing the lead screw to turn suddenly.

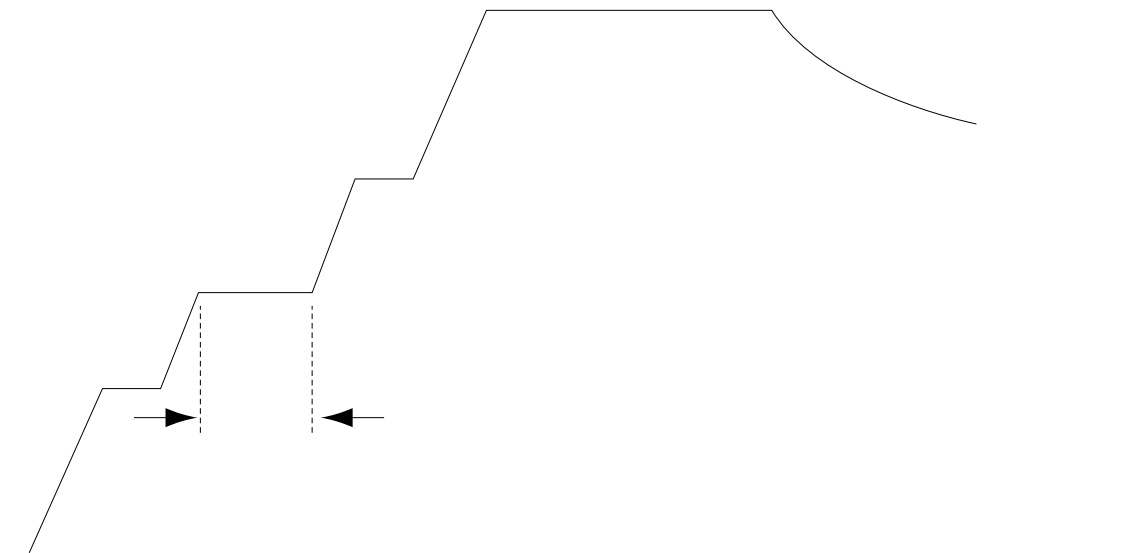


Figure 13-11: Time Stops Much Longer Than Expected

13.3.1.5 Gradient Stops Smaller Than Expected

- Shortened bellows.
- Loss of fluid from Bourdon tube or bellows.

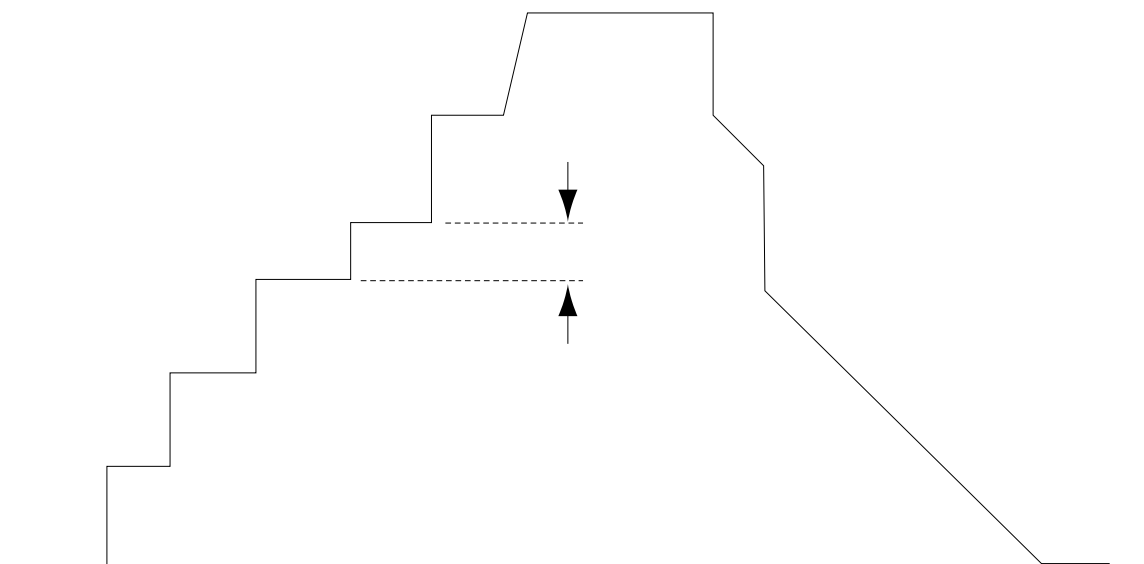


Figure 13-12: Gradient Stops Smaller Than Expected

13.3.1.6 Gradient Stops Shorter than Expected

- Chart holder not moving down freely. Being driven by clock - check free fall before use.
- Downhole movement can be sufficient to move chart holder down at irregular intervals.

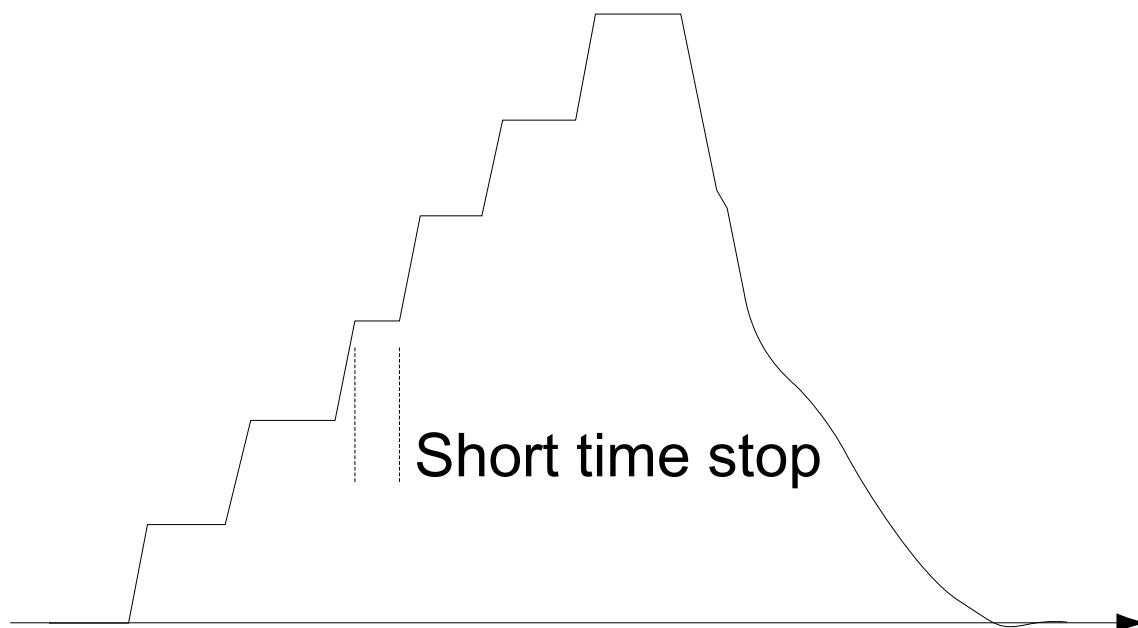


Figure 13-13: Gradient Stops Shorter Than Expected

13.3.1.7 Completely Erratic Trace

- Loose fitting components. Check fit and cover/housing match.
- Screws not secure in internal components.

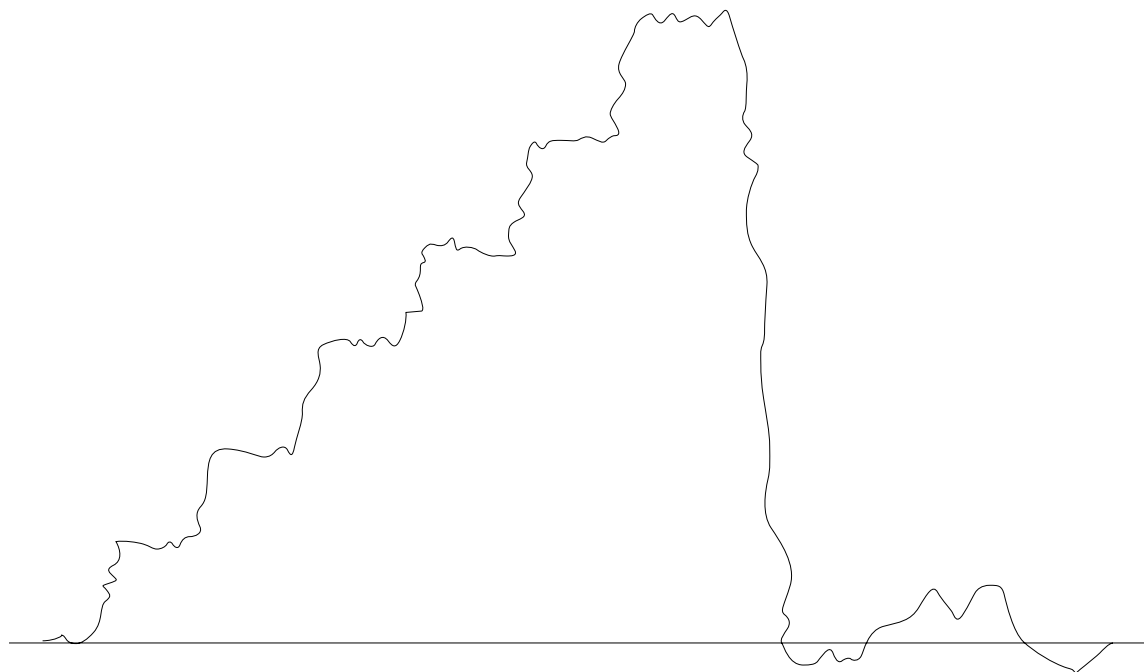


Figure 13-14: Completely Erratic Trace

13.3.1.8 Crooked Baseline

- Not visible or detectable until viewed through a scanner. Indicates an error in the method of drawing the baseline or a twisted inner housing.

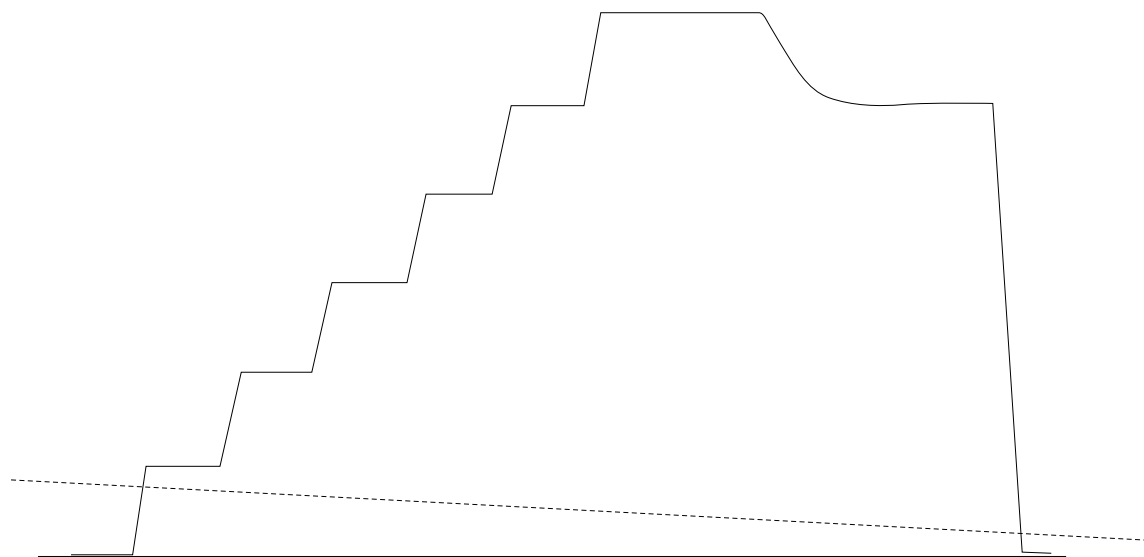


Figure 13-15: Crooked Baseline

13.3.1.9 Trace Slants Towards Baseline and Ends Below

- Pressure build-up within gauge. Pressure may be heard to escape as gauge is broken apart.

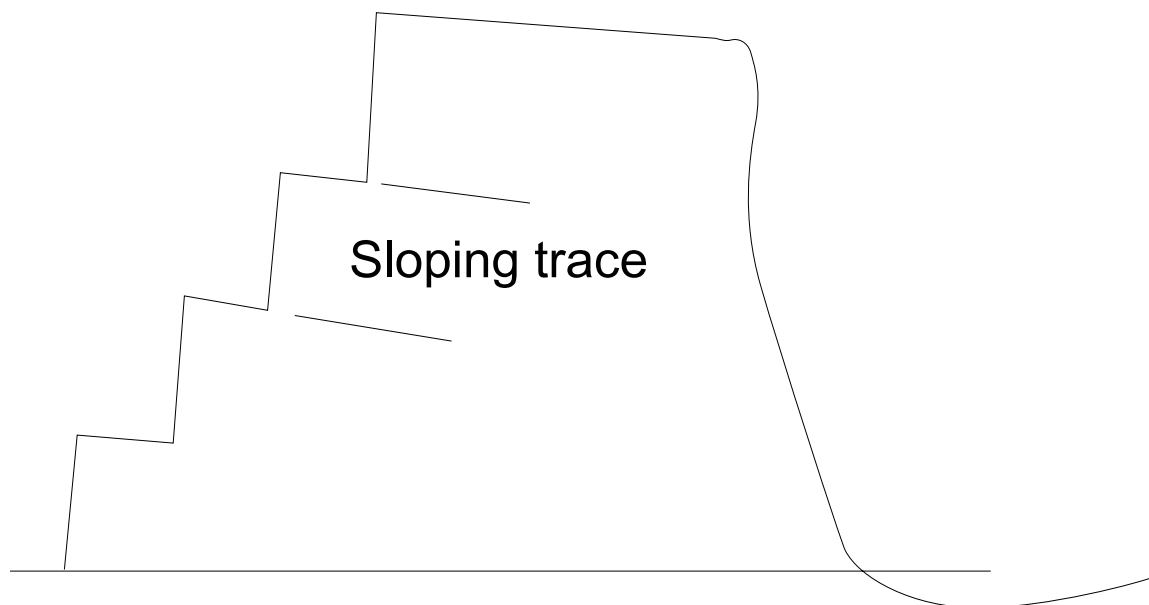


Figure 13-16: Trace Slants towards Baseline and Ends Below

13.3.1.10 Deflection Variation for Identical Depths

- If stops are made going in and coming out of the well, deflections at each point will be different. Provided the trace returns to the baseline, survey is OK.

**Note**

Gauge must be calibrated in the same direction as it will be used, i.e., increasing calibration pressure steps for increments running into the well.

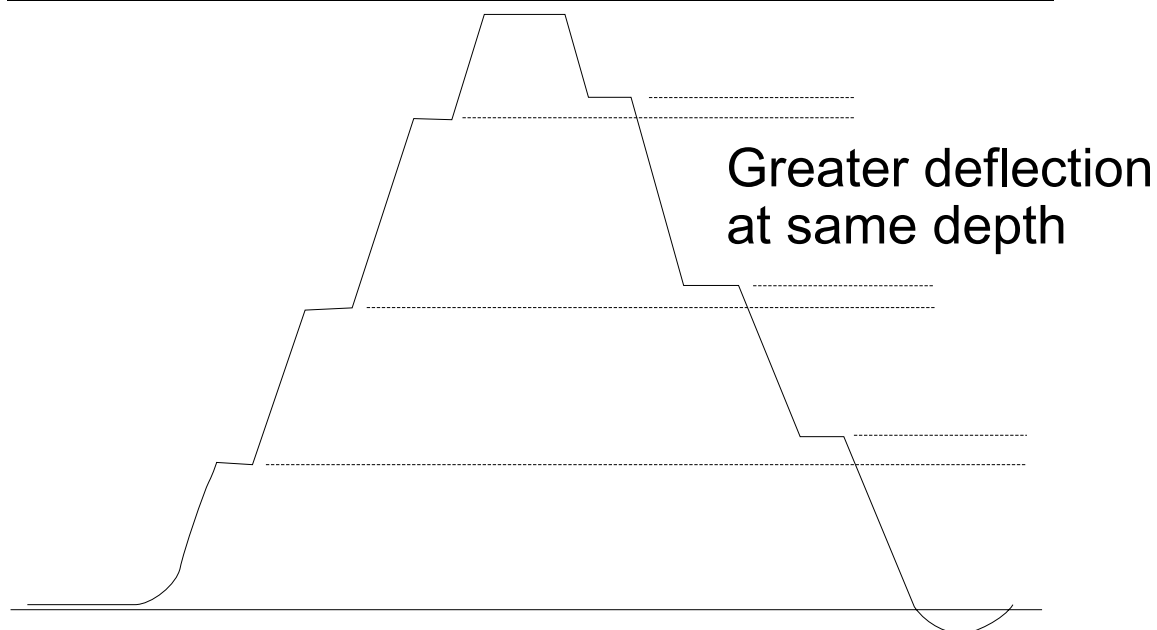


Figure 13-17: Deflection Variation for Identical Depths

13.3.2 Data Recording

The importance of supplying accurate data cannot be overstressed. If the charts are to be sent for detailed interpretation, all relevant times and depths must be recorded.

13.3.2.1 Chart

The following data should be recorded directly onto the top right hand corner of the chart:

- Well number
- Date
- Element number and range
- Clock number and range
- Upper/lower (to identify which instrument chart it is from)

13.3.2.2 Chart Envelope

In addition to the above information, you should record:

- Ambient temperature
- Stops – depth and time

13.3.2.3 Field Recording Sheet

This must be filled out as accurately as possible to enable the chart reader to determine the exact sequence of events at the wellhead. Any changes in the flow rate or flow conditions (such as well shut-in) must be recorded at the time they occur. Any variations from the original program, such as extended time at any depth, should be recorded.

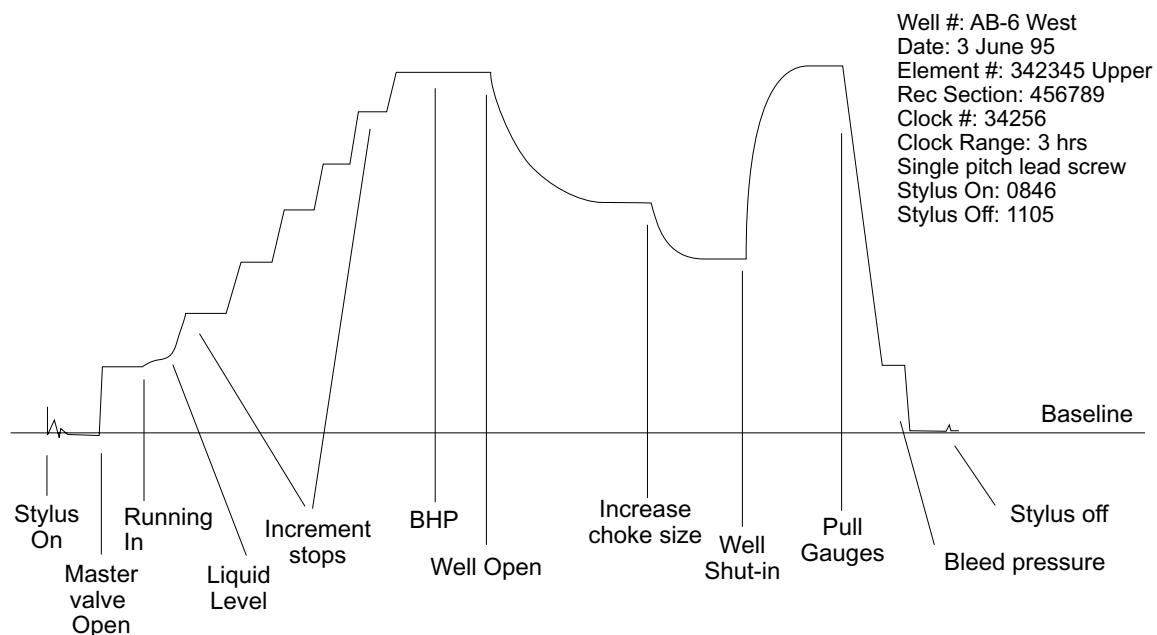


Figure 13-18: Field Recording Sheet

13.4 Otis Soft Set Hanger System

The Otis soft set bomb hanger is designed to set instruments virtually anywhere you have installed an Otis landing nipple (types X, XN, R and RN). It is designed to carry up to 140 lbm of temperature and pressure survey instruments and to eliminate the need for jarring to set, aiding in assuring that charts show true well conditions rather than the effect of jarring. Additionally the hanger can be set in one of many Otis landing nipples, so that you can run surveys at known locations down hole allowing reliable comparisons of results at different depths.

Hangers can be run in either standard or heavyweight tubing, with only one hanger required for installation in either selective or no-go type nipples of comparable size. The latch on the hanger is designed to be tripped by the restricted honed bore of the landing nipple, permitting the dogs in the hanger to locate in the nipple profile and lock in place as the fish neck is pushed down by the tool string weight.

An Otis hydraulic running tool is designed to be used to run and set the soft set bomb hanger. The hanger weight is balanced hydraulically in the running tool by the tool's spring force. The load carrying capacity of the running tool is adjustable using washers, with the number of washers being determined by the weight of the instruments attached. The running tool is designed to gently release within 30 to 60 sec after the slickline is pulled to a minimum of 150 lbm over tool string weight.

All soft set bomb hangers are designed to run and retrieved under pressure, using conventional slickline methods. With this hanger, surveys can be made with the slickline out of the hole. This can mean sufficient savings:

- When several wells in a field are to be surveyed.
- In fields where a highly corrosive environment requires the slickline to be removed from the well during prolonged testing.

**Note**

Use the GR ONLY. If the GS is used, there is insufficient space to shear downwards to release.

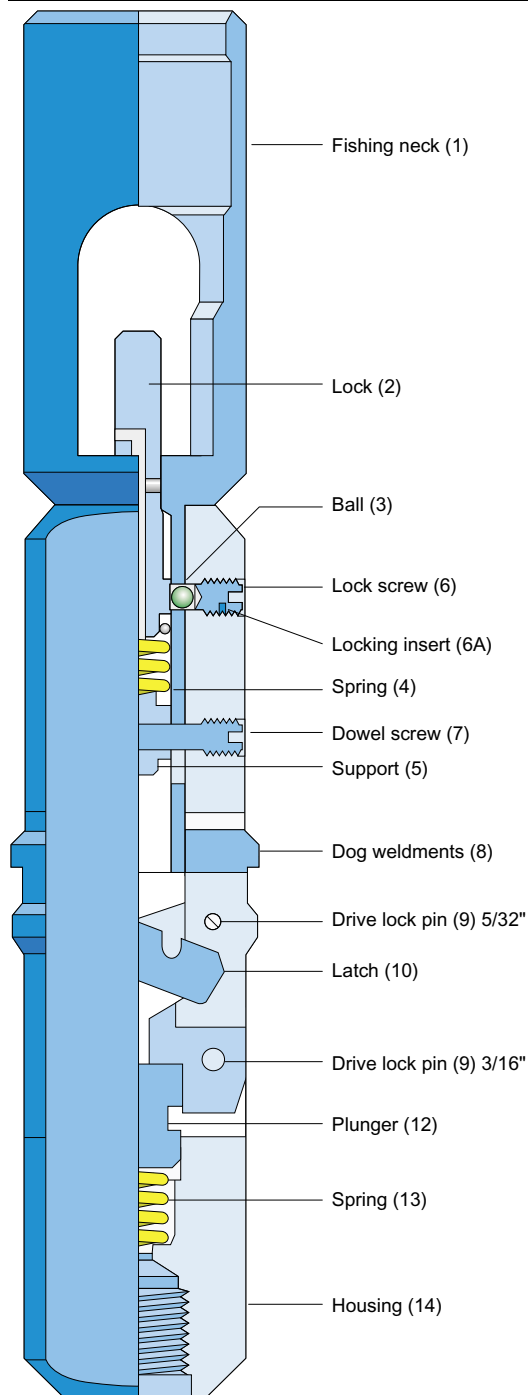


Figure 13-19: Otis Soft-Set Hanger System

13.5 HR Running Tool

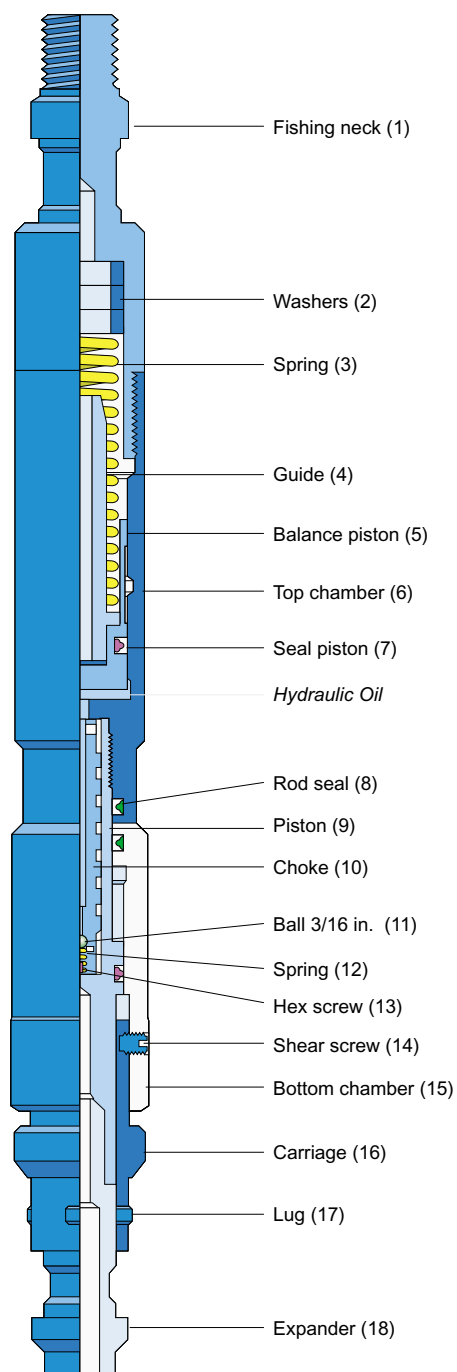


Figure 13-20: HR Running Tool

13.5.1 Operation

1. When running in with the running tool, the hanger is extended to keep the selective locking keys in their retracted position. The running tool/bomb assembly is run below the landing nipple or to the no-go shoulder. The hanger is now in position for locating in the landing nipple profile.
2. Pulling the assembly back through the landing nipples restricted bore, trips the hanger's keys. Continued pulling, a few feet above the nipple, places the hanger in its locate position.
3. Upon setting down, the hanger is designed to be set and locked in the matching nipple profile. The tool string weight is designed to force the hanger fish neck down, causing a spring loaded lock to force a set of balls against their retainers. This is designed to lock the hanger in the nipple and allows for retrieving the running tool.
4. No jarring is required to release the hanger. An upward pull on the slickline (also an indication to the operator that the hanger is locked in place) of 150 lbf over the tool string weight is designed to release the running tool within 30 to 60 sec.

A type GS Otis Pulling Tool, with the shear up adapter and pulling prong, are used to retrieve the hanger. The prong is designed to move the hanger's lockdown, releasing the balls, allowing the fish neck to engage, and the keys to retract. The assembly may then be pulled.

13.6 Baker Soft Set System

Designed to set in the Baker R (bottom no-go nipple) the Baker soft set system is used to set instruments such as Amerada gauges and electronic memory recorders in a well without any jarring action.

The RZB instrument hanger is run on the Baker soft release running tool (No. 811-40) plus C-1 running prong (No. 811-06). After attaching the instruments to the hanger and running tool, the complete assembly is run in the hole to the R nipple no-go. The keys on the hanger will engage the nipple profile and an upward strain can be applied. The tools are then slacked off and the running tool should release, as the collet fingers should now be expanded. If the tool has not released, the strain should be reapplied in increasing increments until the collet expands.

To convert the ID of various R nipple bores to suit the RZB hanger, a range of nipple inserts are available. These are run into the R nipple on an Otis GS tool (shear down to release).

The insert becomes locked in place when the RZB hanger is positioned inside the insert.

The RZB hanger* is pulled with an Otis RB (jar up to shear)

or Otis SB (jar down to shear)

or Camco JUC (jar up to shear)

or Camco JDC (jar down to shear)

The nipple insert is recovered with an Otis GS.*

Refer to the chart for the correct tool size and part number.

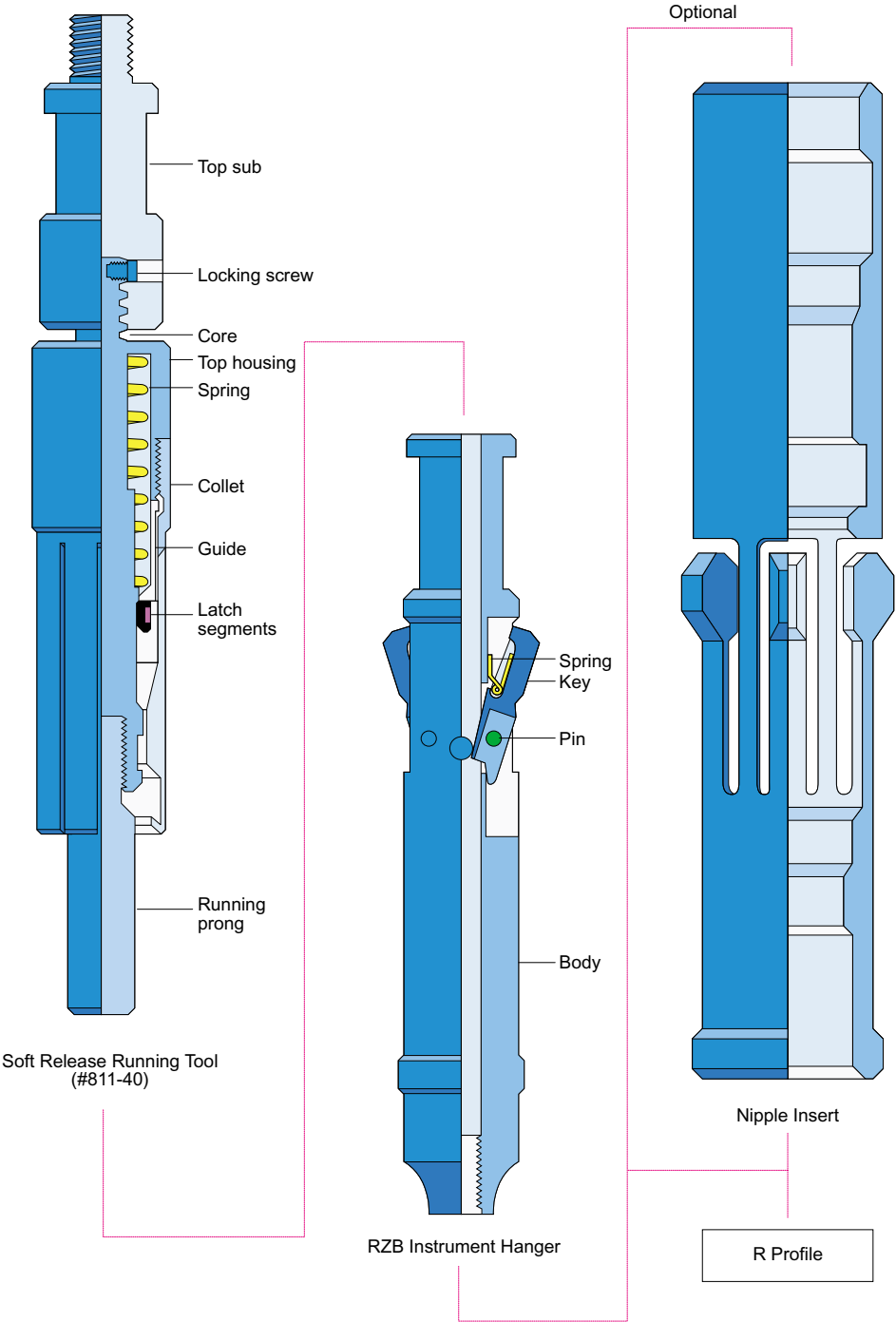


Figure 13-21: Soft Release System Components

13.7 TIC Tools

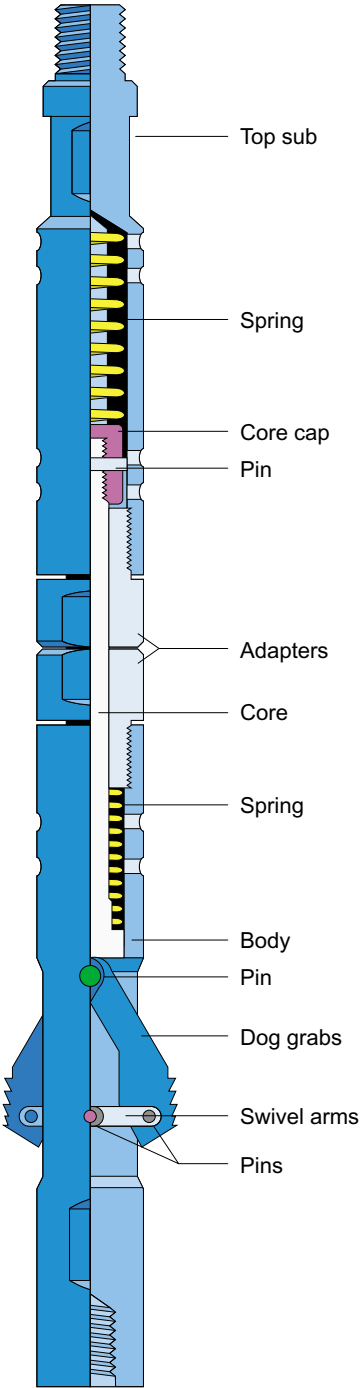


Figure 13-22: TIC Anti-Blow Tool

John Mayzel\\Release Date: Provisory\\EDMS UID: /Published: //

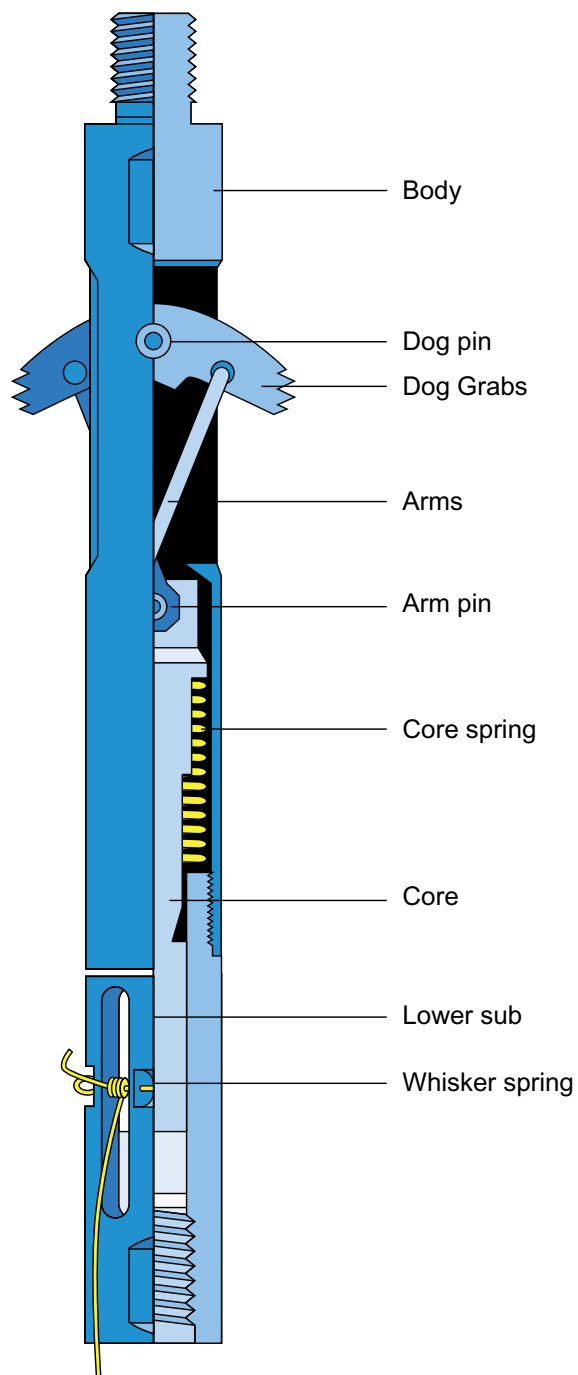


Figure 13-23: Plunk Whiskered Bomb Hanger (for Tubing)

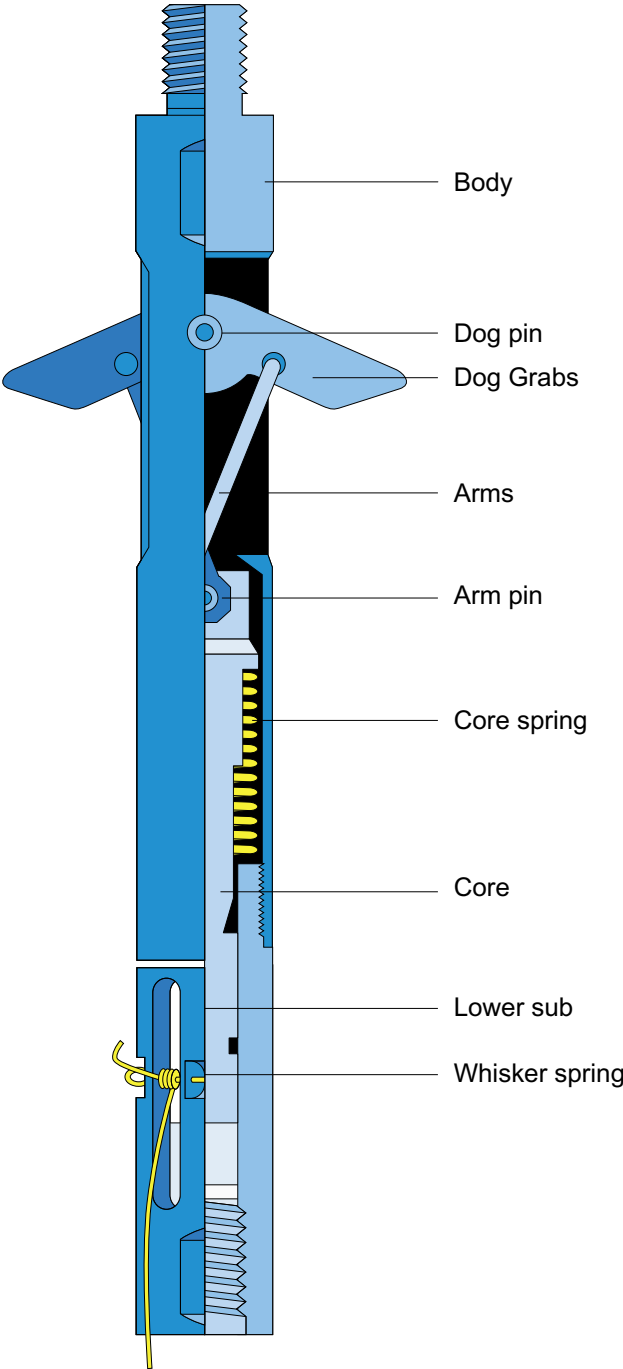


Figure 13-24: Plunk Whiskered Bomb Hanger (for Collars)

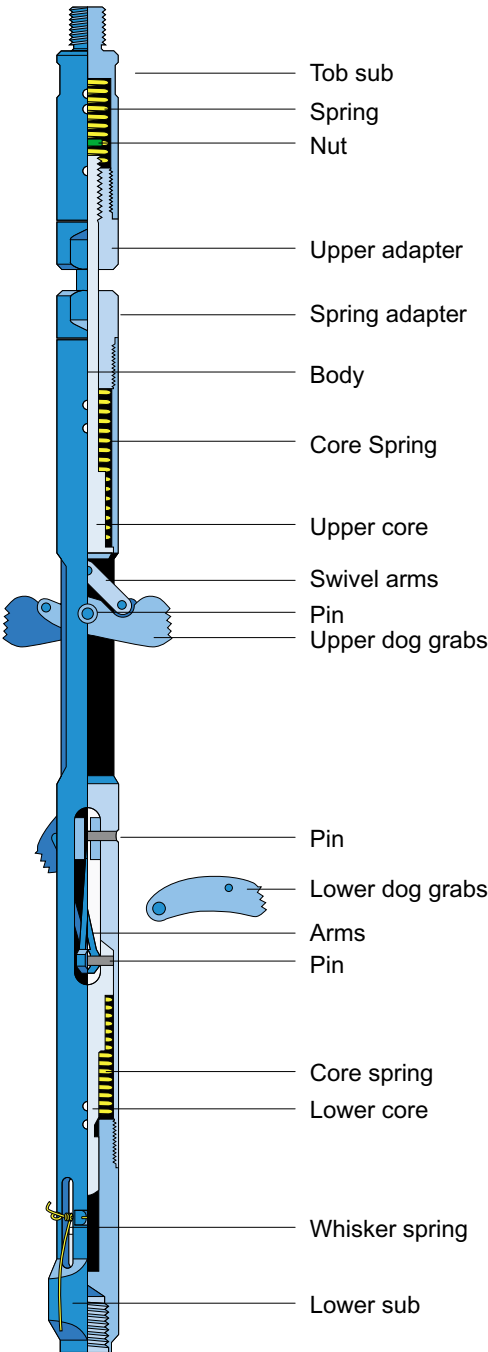


Figure 13-25: Plunk Whiskered Bomb Hanger (for Casing)

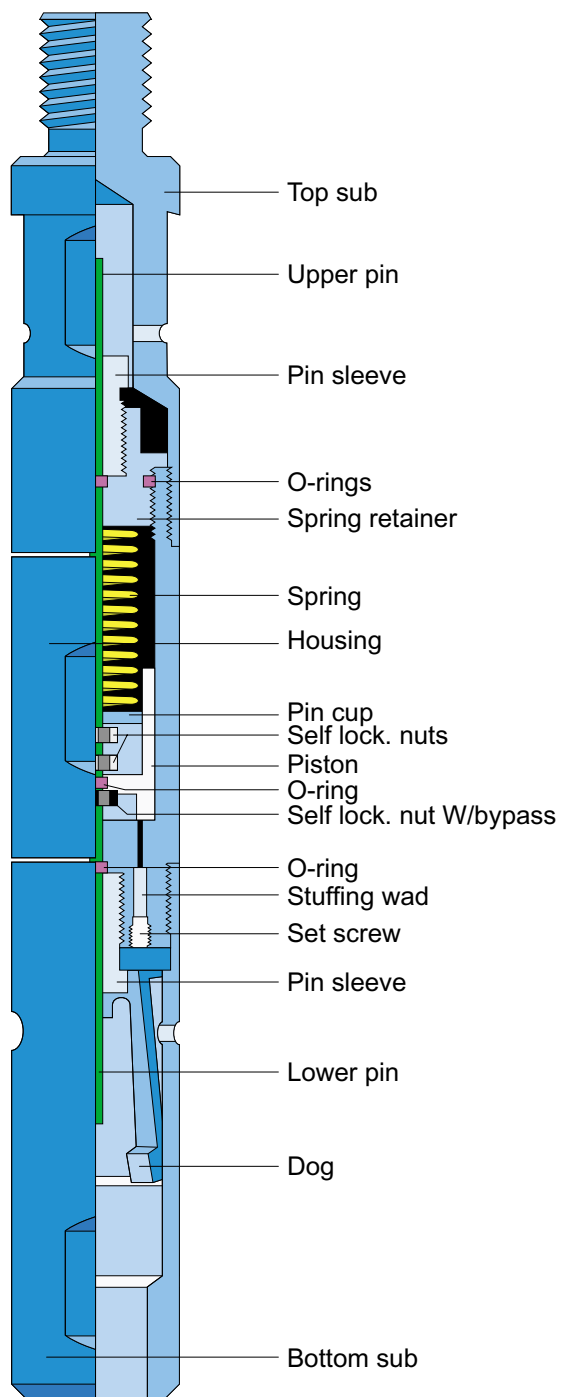


Figure 13-26: Plunk Hydrochem Releasing and Setting Tool

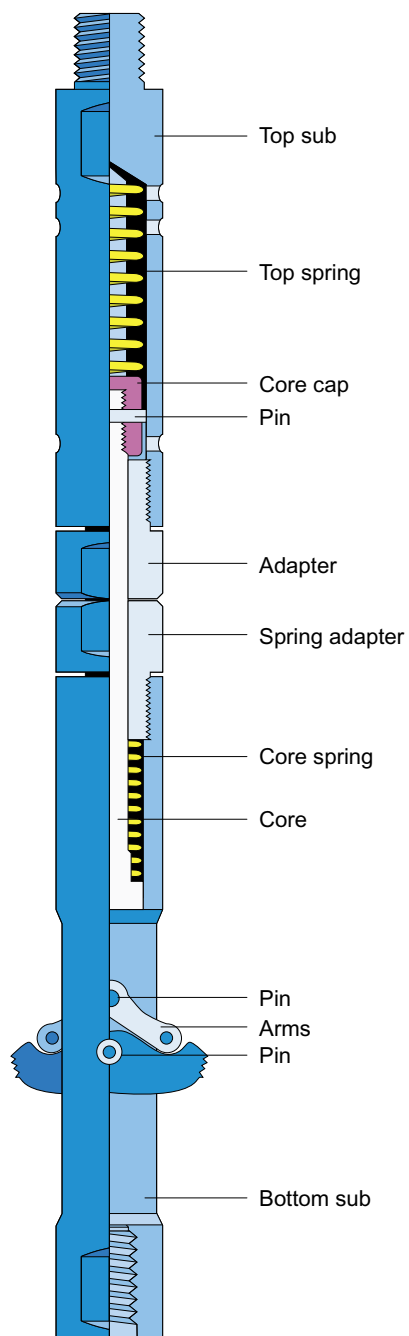
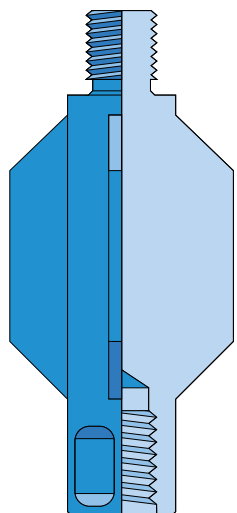
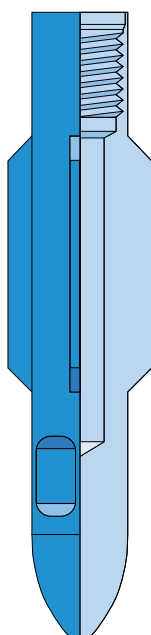


Figure 13-27: Plunk Hanger Safety Tool



Top No-Go Sub



Bottom No-Go Sub

Figure 13-28: Plunk No-Go Subs

13.8 Camco DHSIT

The Camco MD isolation tool is a down hole shut-in tool (DHSIT) that can be run on slickline to suspend BHP/BHT gauges of either the mechanical (Amerada) or electronic memory recorder (EMR) type.

The ability to obtain a flowing pressure through the large flow ports and then shut in the well with the DHSIT, enables a more rapid stabilization of pressure as the tubing volume does not have to be pressurized. This tool isolates the tubing from the formation, thus removing the tubing storage effect. It has both metal-to-metal and resilient sealing surfaces to ensure a seal.

13.8.1 Test Procedure

Use the following procedure to test the MD isolation tool for leaks prior to installation:

1. Attach the MD isolation tool to the appropriate lock mandrel.
2. Lock the isolation tool and lock assembly into a landing nipple.
3. Run the appropriate setting prong into the isolation tool to release the release collet and close the tool.
4. Cap off the lower end of the landing nipple.
5. Fill the landing nipple with water.
6. Remove all air from the nipple and pressure the nipple to 5000psi.
7. Maintain the test pressure for 30 minutes and inspect the tool for leaks.
8. Bleed the test pressure and remove the isolation tool from the landing nipple.
9. Manually lock the tool open.

13.8.2 Running Procedure

1. Check all internal O-rings and equalizing piston shear pins.
2. The DHSIT tool is attached to a lock mandrel, and a shock absorber is placed between the DHSIT and the recording instruments to isolate the vibration from the jarring action required to set the lock into the nipple profile.
3. Manually lock the DHSIT into the open position.
4. Lower the assemblies into the well bore and lock it in the nipple profile.

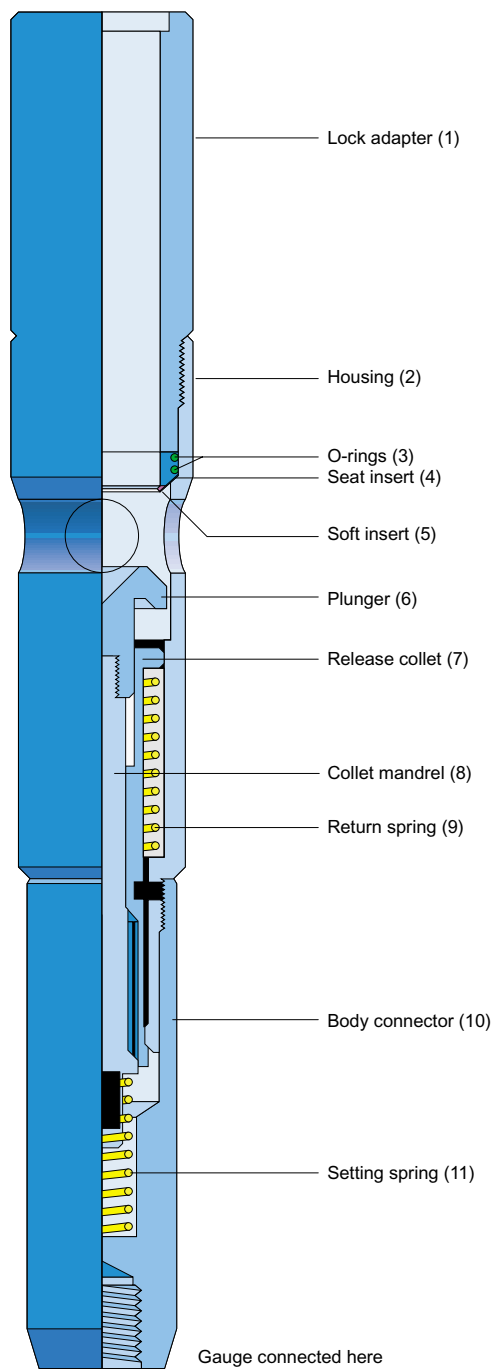


Figure 13-29: Camco DHSIT Assembly

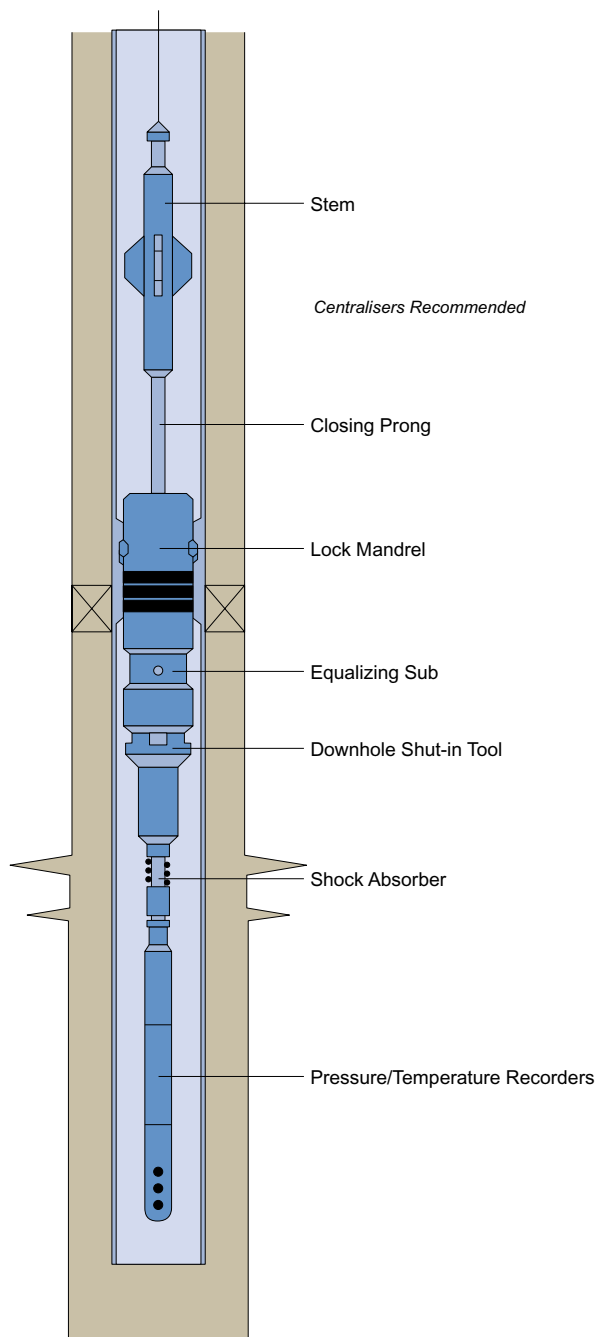


Figure 13-30: Camco DHSIT Wellbore Position

13.8.3 Operating Procedure

1. The well is flowed through the tool to obtain a flowing bottom hole pressure and temperature.

2. When a shut-in is required:
 - Attach a prong to a tool string.
 - (It is recommended to use centralizers on the stem, especially in large diameter tubing.)
 - Lower the tools until the prong contacts the release collet and unlatches the collet fingers.
 - The upward pull on the tool string closed the plunger (10) and blocks the flow.

13.8.4 Pulling Procedure

1. Select the correct pulling tool for the lock mandrel.
2. Attach the equalizing prong.
3. RIH with the pulling tool and prong.
4. When the tool reach the DHSIT, jar down very gently to shear the tangential pin in the equalizing piston.
5. Observe equalization at the surface.
6. When fully equalized - recover the complete assembly.

13.8.5 Manual Locking Procedure

Follow this procedure to lock open the MD isolation tool prior to installation. Refer to the assembly drawing and parts list for the item numbers in parentheses.

1. Back off the body connector until the milled window in the housing is fully exposed.
2. Completely depress the plunger with a setting prong.
3. Insert a screwdriver through the milled window into the groove in the release collet.
4. Move the screwdriver handle up to force the upset diameter of the release collet below the recess diameter of the housing.
5. While holding the screwdriver in the up position, release the force of the setting prong on the plunger to allow the collet mandrel to move up and lock the release collet in place.

13.9 PS Isolation Tools

The PS isolation tool is a two-section slickline retrievable shut-in device used to alternately flow and shut-in a well at depth for use with electric wireline. The surface recording instrument is located immediately above the PS isolation tool. The tool may be adapted for use with most locks, either Camco or other

manufacturers and with most surface recording pressure and/or temperature instruments. The assembly is installed in a landing nipple located near the depth of the producing zone in a well completed with a production packer. The tool shortens the standby period necessary to obtain pressure build-up information and is equipped with a soft release mechanism that protects the pressure instrument when releasing for retrieval to the surface. This device is extremely useful in obtaining accurate bottom-hole reservoir data and conducting multi-well interference tests.

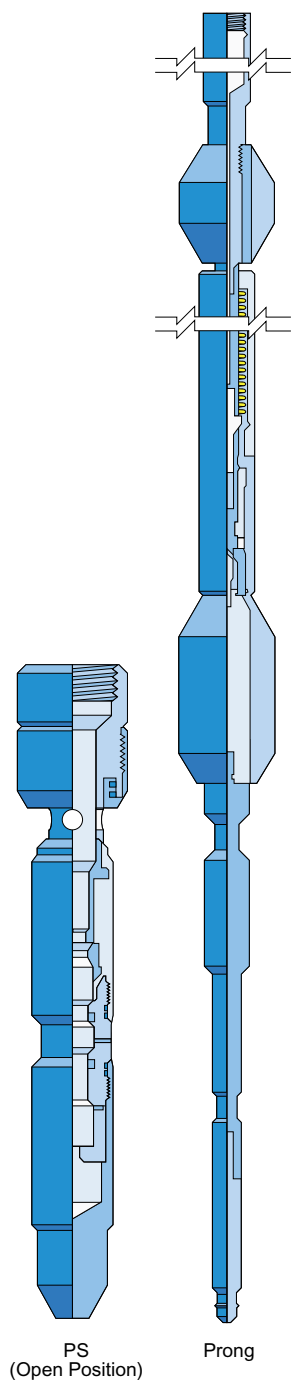


Figure 13-31: PS (Open Position) and Prong

13.9.1 Operation

When running the PS isolation tool, two trips are made into the well using standard slickline methods. First, the applicable lock and attached open isolation tool blanking assembly are lowered into the nipple and locked. Secondly, the

isolation tool prong assembly, soft release mechanism and pressure sensing instrument are lowered into the lock and blanking assembly on electric wireline. After contact, straight pickup to a predetermined value above tool weight closes the isolation tool blanking assembly and routes zone pressure from below the isolation tool to the instrument for surface recording.

When retrieving the PS isolation tool, straight pickup on the slickline will release the sensing instrument from the prong. Two trips into the well are then required: first to pull the prong and second, to retrieve the lock and blanking assembly.

Table 13-4: PS Isolation Tool Engineering Data

Tubing		Assembly Number	Maximum OD (in.)	Lock Connecting Thread	Redress Kit Number	Prong Pulling Tool
Nominal OD (in.)	Weight (lb/ft)					
2.375 (2)	3.25	13183	1.875	1 $\frac{5}{8}$ in. – 14	18925	15154
2.875 (2 $\frac{1}{2}$)	6.5	15852	2.250	1-15/16 in. – 14	18126	15154
3.500 (3)	9.3	13136	2.610	1-15/16 in. – 14	18277	15154
4.500 (4)	12.75	13094	3.735	2-15/16 in. – 12	18273	15154

13.10 Battery Operated Shut-In Tool (BOST)

The slickline conveyed battery-operated shut-in tool (BOST) can be landed in most well completions because it uses the nipple's matching lock mandrel.

A down hole pressure recorder is run below the valve, either hung from a second nipple independently of the BOST or hung from the BOST by way of a shock absorber.

The BOST is a one-shot valve that permits down hole shut-in of a completed well, close to the producing interval. As a result, well bore storage effects are minimized, and the pressure response obtained allows a better and quicker reservoir analysis to be performed. The BOST can also be used on wells that do not naturally flow to surface (for example, gas lift) where a surface shut-in would be meaningless.

Valve operation is controlled by an electronic clock that is programmed with a time delay prior to running in the hole with the valve open.

The BOST is landed in the appropriate nipple, and the well is flowed until the programmed delay expires. When the valve closes, down hole shut-in is achieved and recorded.

At the end of the buildup, an equalizing valve is operated by a prong on the pulling tool, and the BOST and gauges are retrieved.

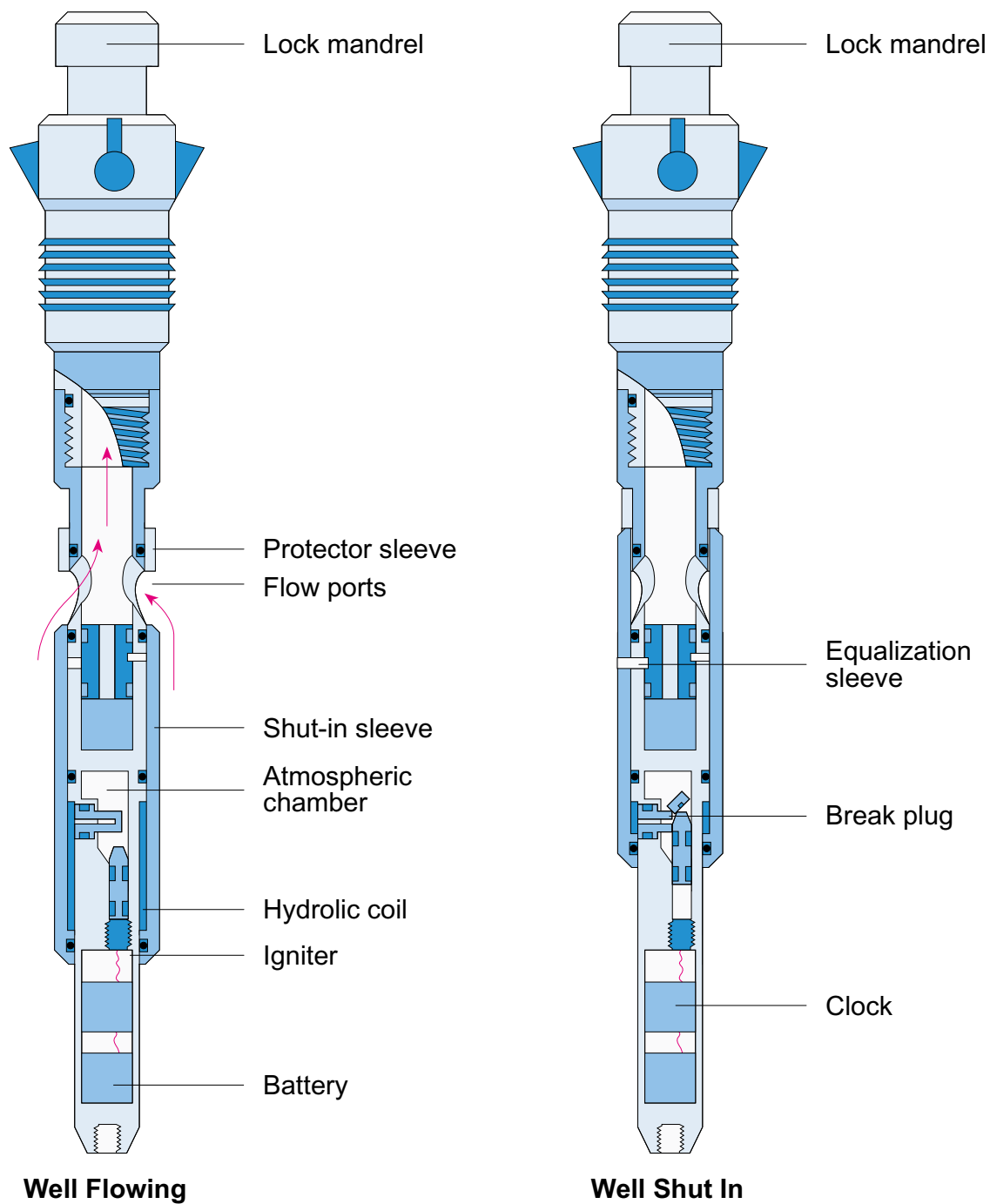


Figure 13-32: Battery-Operated Shut-In Tool (Flowing and Shut-In)

13.10.1 Specifications

Project code	Tubing size	Assembly Number
BOST-AA	2 $\frac{3}{8}$ in.	M-837841
BOST-BA	2 $\frac{7}{8}$ in.	M-837210
BOST-CA	3 $\frac{1}{2}$ in.	M-838842
BOST-DA	4 in.	M-838843
BOST-EA	4 $\frac{1}{2}$ in.	M-838844
Service H ₂ S		
Certifying authority	None	
Design code	NACE MR 01-75	
Differential pressure	5000 psi	
Flow area	Depends on lock mandrel ID	
Working temperature	14 to 302° F, depending on clock rating	
Connections		
Top	Crossover to Otis X mandrel, box up (other mandrels possible)	
Bottom	15/16-in. SR box	
Length without gauge	Typically 77 in.	

BOST set includes valve assembly, crossover to Otis X mandrel, and short air chamber only. BHST clock/battery assembly, upper head and regulator assembly must be supplied separately.

13.11 Multi-Operation Shut-In Tool (MOST)

The multiple operation shut-in tool (MOST), a multishot down hole shut-in device, can be used in most well completions because it uses the nipple's matching lock mandrel.

The valve is operated by pulling up on the slickline. The MOST tool is designed for surface readout with electric line but can be used with slickline and a down hole pressure recorder.

The MOST valve assembly is run in the hole with slickline and set in the desired nipple. The actuator and gauge are then run on electric line.

The valve is shut by pulling up 100 lbf on the slickline. Slacking off opens an equalizing port. When the pressures above and below the valve are equalized, the shut-in sleeve reopens.

Up to 12 shut-in/reopen cycles can be performed before the actuator automatically releases from the valve. After pulling out the gauge/latch assembly, a slickline run is made to retrieve the lock mandrel and valve.

The MOST-A tool can hold 5000 psi from below; the MOST-B tool can hold this pressure from above and below.

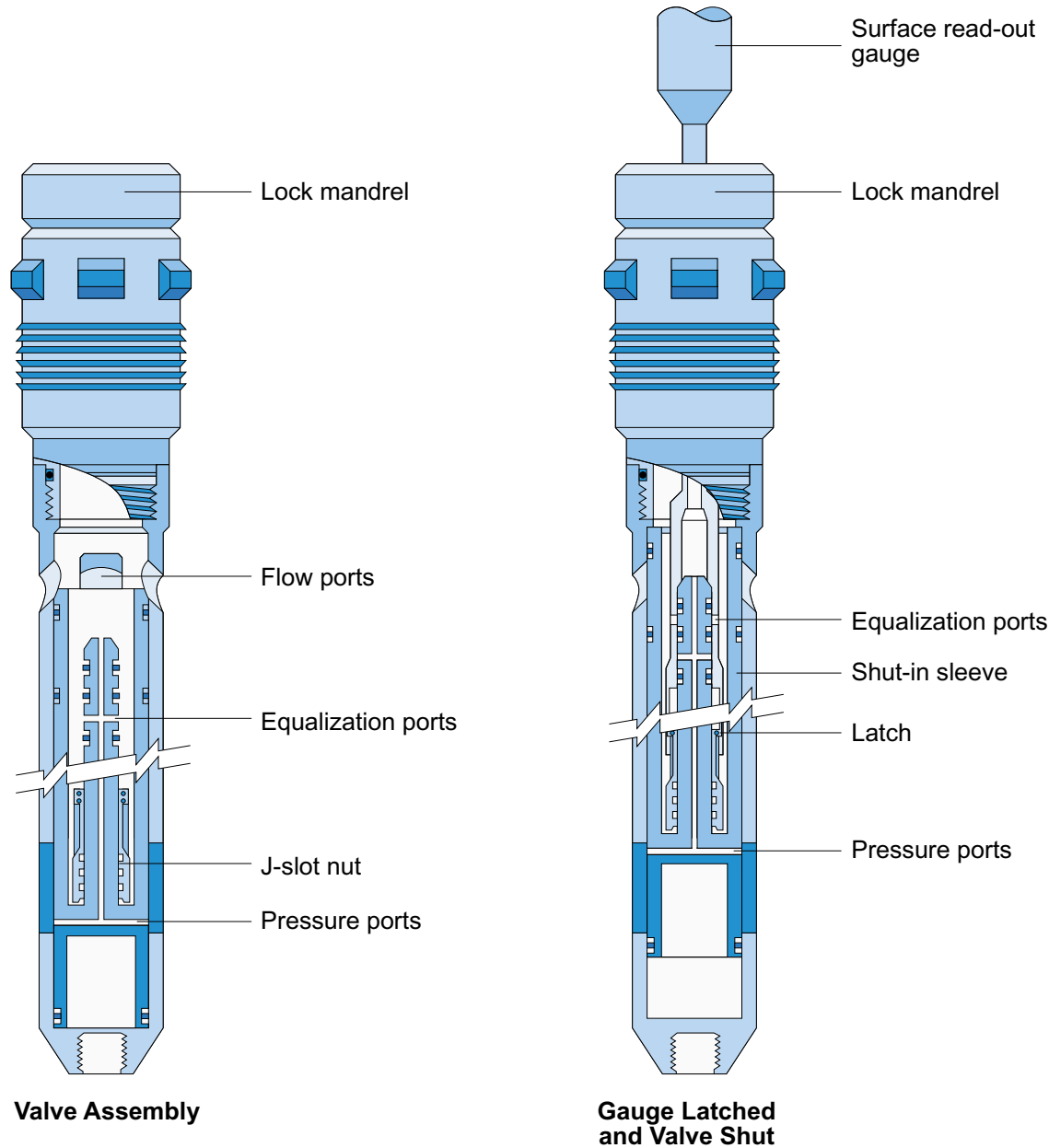


Figure 13-33: Multiple-Operation Shut-In Tool Valve Assembly

13.11.1 Specifications

Certifying authority	None
Design code	NACE MR 01-75
Service	H ₂ S
Differential pressure	5000 psi
Flow area	Depends on lock mandrel ID
Working temperature	14 to 302° F
Length of valve assembly	Typically 31 in.

Project code	Tubing size	Assembly number
MOST-AA	2 $\frac{7}{8}$ in.	P-839210
MOST-AB	3 $\frac{1}{2}$ in.	P-837837
MOST-AC	4 in.	P-839331
MOST-AD	4 $\frac{1}{2}$ in.	P-838332
MOST-BA	3 $\frac{1}{2}$ in.	P-838727
MOST-BB	2 $\frac{7}{8}$ in.	P-839601

Connections

Top of valve	Crossover to Otis X mandrel, box up (other mandrels possible)
Bottom of valve	15/16 in. SR box
Top of latch	1 $\frac{1}{8}$ in. UNF box for gauge

The MOST set includes the valve assembly, crossover to the Otis X mandrel and a latch assembly with centralizer.

13.11.2 Options

MOST-BA crossover (3 $\frac{1}{2}$ in. x 4 in.) [M-839334]

MOST-BA crossover (3 $\frac{1}{2}$ in. x 4- $\frac{1}{2}$ in.) [M-839333]

Test plug for MOST-BA/MOST-BB [M-872877/M-872876]

Lock mandrel for Baker 2.31 in. F nipple [M-870483]

Prong for M-870483, M-870489

Lock mandrel for Baker 2.75 in. F nipple [M-832268]

Crossover to $3\frac{1}{2}$ in. Baker mandrel [M-870506]

Lock mandrel for Baker 2.688 in. F nipple [M-832281]

Crossover to 4 in. Baker mandrel [M-870504]

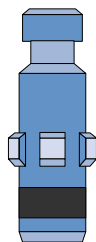
Crossover to $4\frac{1}{2}$ in. Baker mandrel [M-870503]

Glydring tool [M-839627]

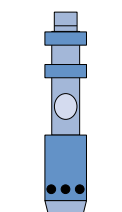
13.12 EFST System

LOCK MANDREL

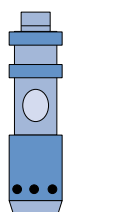
Type and size
according to
Completion



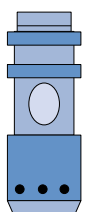
EFST VALVES



2-3/8 in.
(EFSV-A)
P584104



2-7/8 in.
(EFSV-B)
P582915



3-1/2 in.
(EFSV-C)
P584005

EFST ACTUATOR (EFS-A) P582914

The same actuator
is used to trigger
any size of valve



PRESSURE RECORDERS

Can be connected
directly below the
Actuator or hung in a
lower nipple



Figure 13-34: EFST Components

Table 13-5: EFST Specification

Valve	Length (in.)	Max OD (in.)	Sleeve	Equiv. Flow area (in. ²)
ESFV-A	11.7	1.73	1.65	1.02
ESFV-B	12.1	2.05	1.90	1.25
ESFV-C	12.6	2.52	2.48	1.67

13.12.1 Features

The EFST is a down hole shut-in tool for production wells and is functionally identical to the BOST (Battery Operated Shut-In Tool). A single shut-in can be pre-programmed. The tool is landed in its nipple on slickline. The down hole valve closes after the chosen delay. At the end of the build-up, a prong is run to equalize across the valve before retrieving it on slickline. The difference with respect to the BOST is that these functions are performed purely mechanically. There are no batteries, electronics or explosives.

13.12.2 Advantages

- No batteries, electronics or explosives = simple, reliable very low running costs (seals + oil are the only consumables)
- No import, shipping or disposal problems for explosives or batteries.
- Very short and slim = maximum flow in small completions
- High temperature rating

13.12.3 Specifications – General

Max working pressure	10,000 psi absolute 5000 psi differential
Min operating pressure	150 psi
Max temperature	200°C
Connections - Top	adapts to any mandrel
Bottom	15/16 in. SR Female
Service	H ₂ S

13.13 Electronic Gauges

Electronic gauges provide a higher degree of accuracy than mechanical gauges. The electronic data is easier to manipulate into a wide variety of output formats to aid interpretation of formation of formation conditions.

There are three main types of gauges currently in use to measure and record down hole pressure and temperature. The significant differences in these are the accuracy, price and durability.

13.13.1 Strain Gauges

Pressure and temperature act on a flexible diaphragm that transmits the force to a strain gauge. The current passing through the strain gauge is altered in direct proportion to the magnitude of the change. This change is detected in a Wheatstone Bridge circuit and recorded.

Accuracy - 0.25% of full-scale deflection

Durability - Good resistance to shock and vibration

Relative Cost - Lowest (\$200 to \$1000)

13.13.2 Capacitance Gauges

Pressure temperature act via an isolation device to move a diaphragm, which varies the capacitance of the electronic circuit.

Accuracy - 0.02% of full-scale deflection

Durability - Poor to medium resistance to shock and vibration

Relative cost - Medium (\$1500 to \$3000)

13.13.3 Quartz Crystals

Pressure and temperature act via an isolation device onto vibrating crystals, usually quartz. The deformation of the crystal changes its vibration frequency relative to a reference crystal. These changes are measured and recorded as raw data to provide the most accurate results.

Accuracy - 0.1% of full-scale deflection

Durability - Reasonable resistance to vibration poor resistance to shock

Relative cost - Highest (\$3000 to \$20,000)

Miniature tape drives that were once used have been replaced with solid-state chip memory devices. Electronic gauges can be used on slickline as electronic memory recorders (EMR) or as surface read-out (SRO) gauges by attaching the appropriate transmission device to the upper end of the gauge. The sensing devices and electronic systems are virtually the same for both EMR and SRO types.

13.13.4 **Unigage Sapphire (SLSR-A)**

The universal pressure platform introduces a new family of well testing pressure gauges developed around new generation sensors.

The Unigage Sapphire is a reliable gauge based on the 10 kpsi Sapphire sensor.

The gauge provides down hole recording either on slickline or in a DST/TCP operation. It can also be used with the DataLatch - DGA system during DST operations. A downhole electric line interface is also available to provide surface readout.

The Unigage Sapphire characteristics make it ideal to address the production environment.

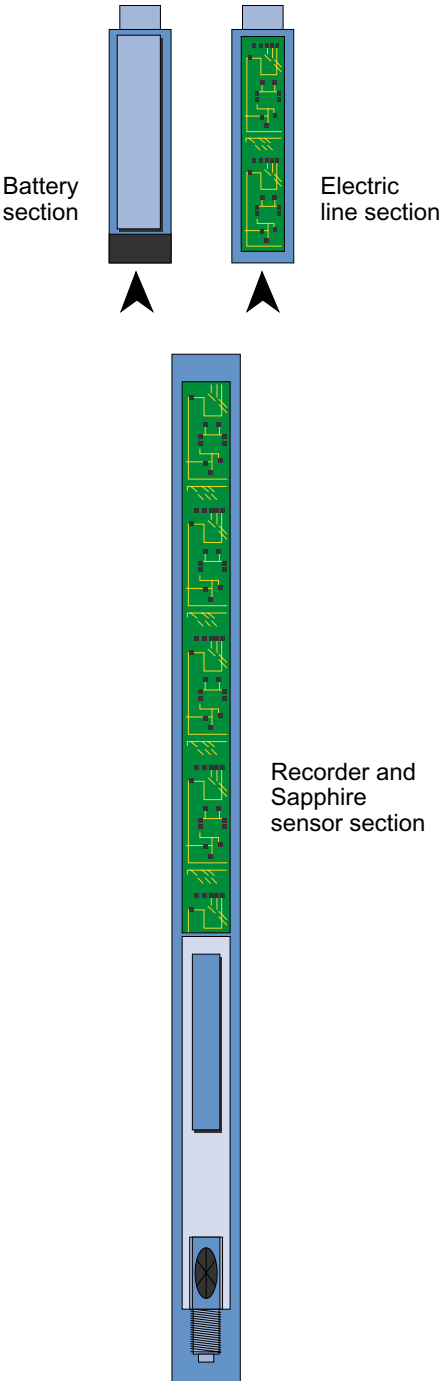


Figure 13-35: Unigate SLSR-A

13.13.4.1 Specifications

Pressure rating	10,000 psi
Temperature rating	130°C

Max. OD	1.2 in.
Make up length	58.3 in.
Shock environment (TCP)	Class 6†
Service	H ₂ S/CO ₂
Number of data sets	120,000 (256 kbyte)
	480,000 (1 Mbyte)
Battery autonomy	50 days
	(6 month on request)

13.13.4.2 Measurement Performances

Pressure accuracy	± psi
Pressure resolution	0.05 psi
	At 1-sec scan
Long term stability	1 psi/week
	(decreasing with time)
Temperature accuracy	± 0.5°C
Temperature resolution	0.001°C
Calibration ranges	1000 to 10,000 psi
	And 25 to 130°C

13.13.4.3 References

SLSR-A	P583187
Monocable electric line adapter	P581174

This gauge can be sold outside the Schlumberger organization with memory gauge capabilities only.

13.13.5 Unigage* CQG (WCQR-B)

The universal pressure platform introduces a new family of well testing pressure gauges developed around new generation sensors.

The Unigage CQG used a Schlumberger CQG Crystal Quartz Gauge sensor.

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The gauge provides down hole recording either on slickline or in a DST/TCP operation. It can also be used with the DataLatch - DGA system during DST operations. A down hole electric line interface is also available to provide surface readout.

The Unigage CQG provides the best quartz quality measurement in terms of accuracy, drift and resolution. In addition, the dynamic compensation algorithm of the CQG sensor allows near instant correction of the pressure data during pressure and temperature transients.

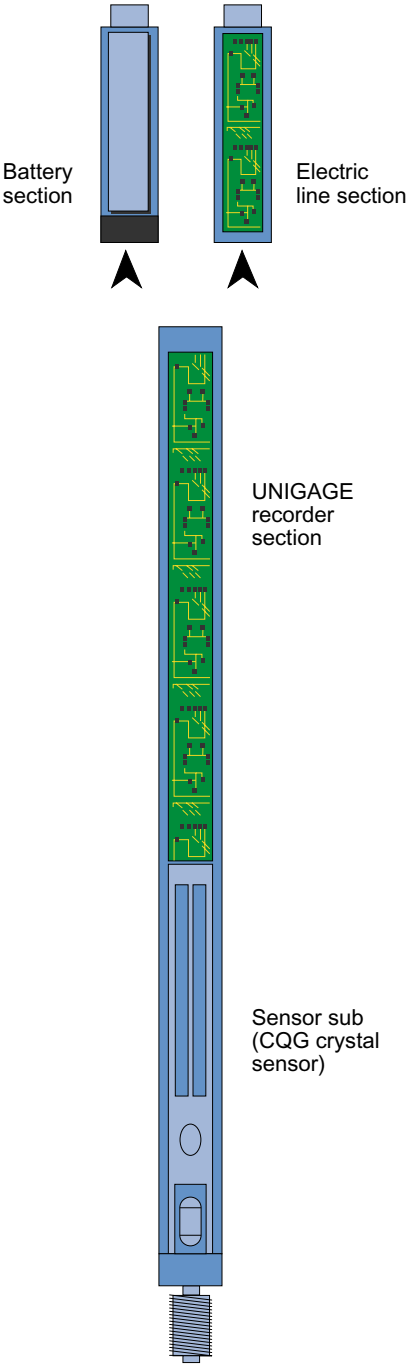


Figure 13-36: Unigage WCQR-B

13.13.5.1 Specifications

Pressure rating	16,000 psi
Temperature rating	177°C
Max. OD	1.2 in.

Make up length	71.2 in.
Shock environment (TCP)	Class 6+
Service	H ₂ S/CO ₂
Number of data sets	100,000 (256 kbyte)
	400,000 (1 Mbyte)
Battery autonomy	40 days
(with 1 min scanning rate)	70 days

13.13.5.2 Measurement Performances

Pressure accuracy	± 1 to 2.5 psi
Pressure resolution	0.01 psi at 1-sec scan
Long-term stability (6 months)	± 1.5 to 2 psi
	At 10,000 psi, 150°C
Temperature accuracy	± 0.5°C
Temperature resolution	0.001°C
Calibration ranges	1000 to 15,000 psi
And 25 to 175°C	

13.13.5.3 References

WCQR-B	P776561
WPHC-A Common Recorder	P579770
WCQG-B CQG section	P776561
Monocable Electric line adapter	P581174
WCQR-A Kit to WCQR-B specs	P781334

13.13.6 Unigage* QUARTZ (WTQR-A)

The Universal Pressure Platform introduces a new family of well testing pressure gauges developed around new generation sensors.

The Unigage Quartz uses a Schlumberger customized QUARTZDYNE® sensor.

The gauge provides down hole recording either on slickline or in a DST/TCP operation. It can also be used with the DataLatch - DGA system during DST operations. A down hole electric line interface is also available to provide surface readout.

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The Unigage Quartz is being replaced by the Unigage CQG with the improved performances of the CQG-F sensor.

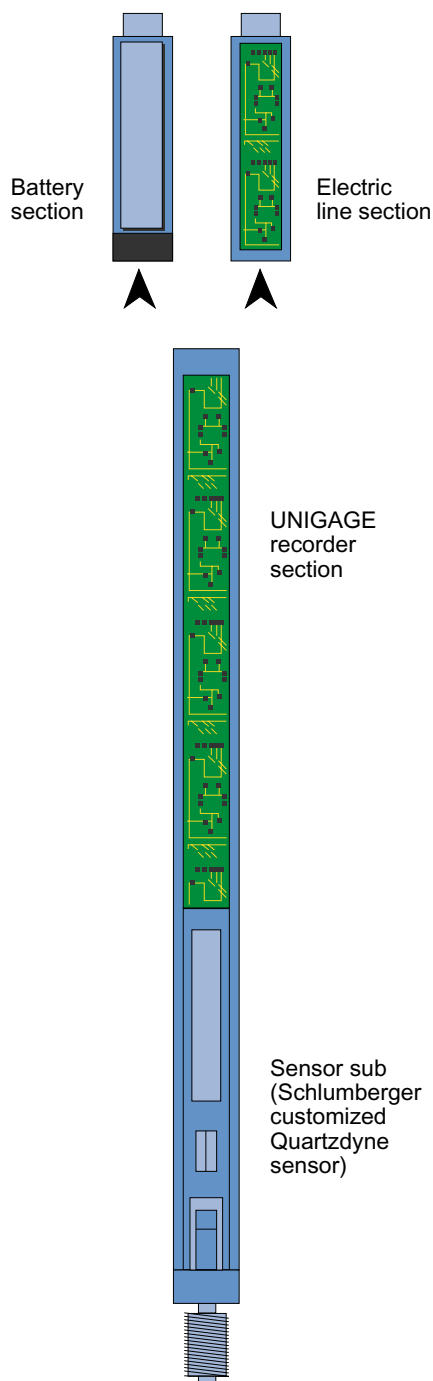


Figure 13-37: Unigage WTQR-A

13.13.6.1 Specifications

Pressure rating	18,000 psi
Temperature rating	177°C
Max. OD	1.2 in.
Make up length	68.4 in.
Shock environment (TCP)	Class 6†
Service	H ₂ S/CO ₂
Number of data sets	120,000 (256 kbyte)
480,000 (1 Mbyte)	
Battery autonomy	70 days
	(1 year on request)

13.13.6.2 Measurement Performances

Pressure accuracy	± 3.2 psi
Pressure resolution	0.01 psi at 1-sec scan
Long-term stability (6 months)	± 3 psi
	At 7000 psi, 150°C
Temperature accuracy	± 0.5°C
Temperature resolution	0.001°C
Calibration ranges	1000 to 16,000 psi
	and 25 to 175°C

13.13.6.3 References

WTQR-A	P579768
WPHC-A Common Recorder	P579770
WPQG-A Quartzdyne section	P579771
Monocable Electric line adapter	P581174

13.13.7 Unigage* H-Sapphire (WTSR-A)

The universal pressure platform introduces a new family of well testing pressure gauges developed around new generation sensors.

The Unigage H-Sapphire (H for Hostile) is based on the 20 kpsi Sapphire sensor.

The gauge provides down hole recording either on slickline or in a DST/TCP operation. It can also be used with the DataLatch - DGA system during DST operations. A downhole electric line interface is also available to provide surface readout.

The Unigage H-Sapphire has the added capability of providing real-time data from two gauges on electric cable. The bottom gauge can be any type of the Universal Pressure Platform.

The Unigage H-Sapphire is especially suited for hostile environment such as very high pressure and temperature.

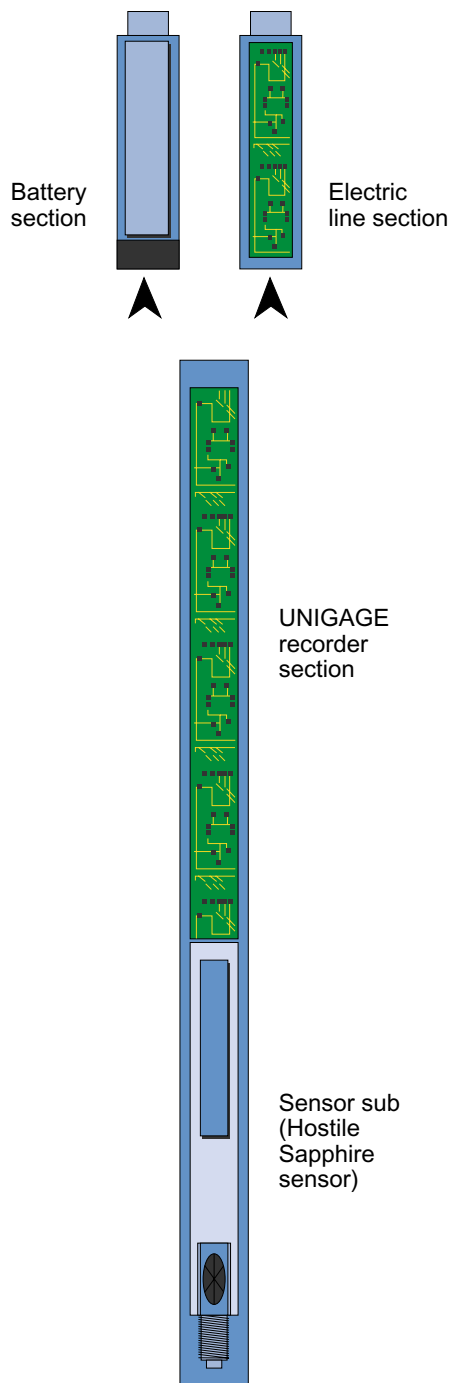


Figure 13-38: Unigage WTSR-A

13.13.7.1

Specifications

Pressure rating	20,000 psi
Temperature rating	190°C

Max. OD	1.2 in.
Make up length	68.4 in.
Shock environment (TCP)	Class 6†
Service	H ₂ S/CO ₂
Number of data sets	60,000 (256 kbyte)
	240,000 (1 Mbyte)
Battery autonomy	30 days

13.13.7.2 Measurement Performances

Pressure accuracy	± 5 psi up to 175°C
	± 10 psi up to 190°C
Pressure resolution	0.1 psi 1-sec scan
Long-term stability	1 psi/week
	At 10,000 psi, 150°C
Temperature accuracy	± 0.8°C
Temperature resolution	0.001°C
Calibration ranges	1000 to 20,000 psi
	and 25 to 190°C

13.13.7.3 References

WTSR-A	P579772
WPHC-B Recorder	P586565
WPSG-A Sapphire section	P579773
Monocable top E-line adapter	ELIT P586673
Monocable bottom E-line adapter	ELIB P586674
Sampler adapter for PDM-D	P784469

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14 REMEDIAL SLICKLINE EQUIPMENT

14.1 Introduction

There are numerous operations which can be carried out by slickline that will enhance production or defer a costly rig work over operation. Some of the topics and equipment, which fall into this category, are detailed in this section.

- Perforating - slickline can provide some viable options for limited perforating operations where conditions permit.
- Sand bailing – small volume clean-outs can be carried out on slickline to remove sand built up above the plugs below a producing zone and to remove sand from the casing. However, sand removal in larger volumes is more efficiently accomplished using a coiled tubing unit to circulate out sand and solids.
- Swabbing – can be conducted by slickline or preferably braided line, when it is required that fluid be removed from the well. While not technically remedial work, swabbing can be an economic technique to initiate production.

14.2 Perforating

14.2.1 Otis Type A Perforator

The Otis type A perforator is a mechanically operated tool used to perforate standard and heavy wall tubing. Perforating procedures are carried out under pressure with standard slickline tools.

No explosives are used. The danger of premature perforating is reduced and the possibility of accidentally perforating the casing is eliminated. Typical applications include:

- Provide access to the casing annulus to circulate fluid or kill the well.
- Bring in additional production zones.
- Permit production through the tailpipe that has been plugged for remedial procedures and cannot be opened by regular methods.
- To gas-lift old wells that do not have gas-lift mandrels.

The features of the type A perforator include:

- Greater tubing penetration
- Positive indication of perforation on removal of the tool.
- Safety release mechanism used for removal of the perforator from the tubing without perforating.
- The perforator is designed to withdraw the punch and release automatically after perforating.
- Utilizes upward jarring for perforating action.

The standard size of hole punched by the perforator is 3/8 in., but this can be varied $\pm 1/16$ in. (i.e., 5/16 in. or 7/16 in.) by changing the punch and bushing.

An alternative is to use the Kinley explosive perforator, which can also be used to install orifice inserts.

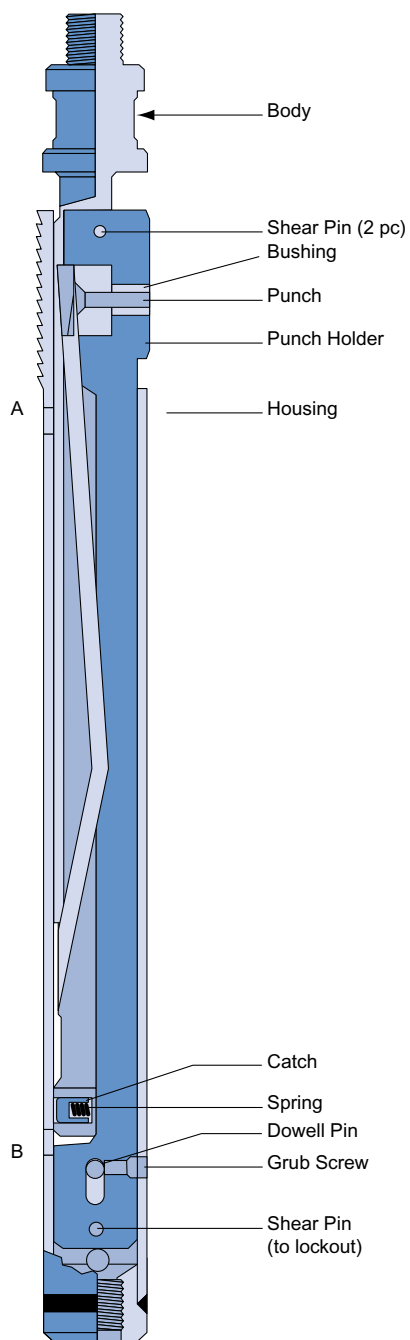


Figure 14-1: Type A Perforator

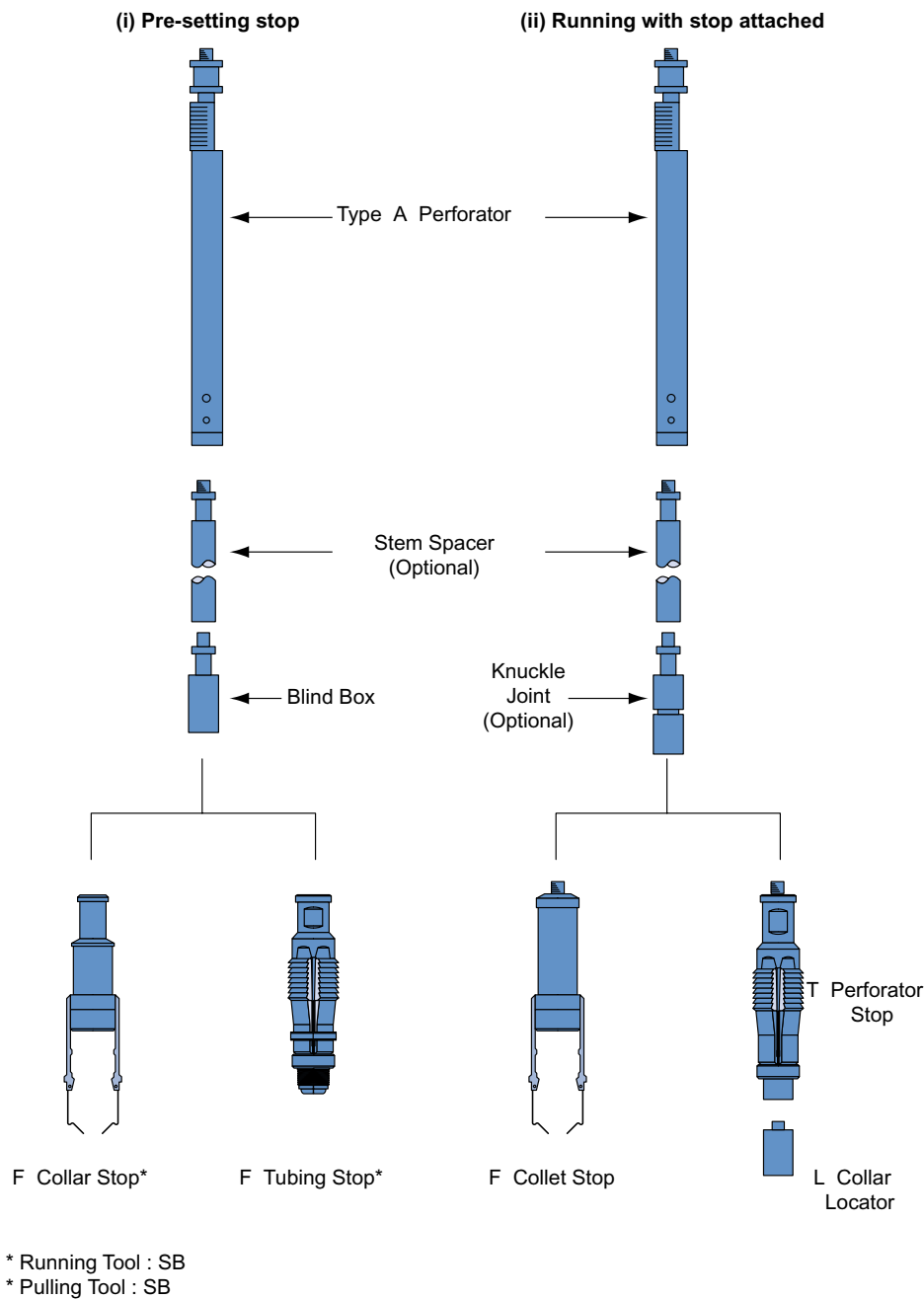


Figure 14-2: Type A Perforator Configuration Options

14.2.1.1 Tool Preparation

1. Function-test the perforator by hand. The body should open and close freely. Check the bushing is tight on the punch and moves with the punch.

2. A steel pin is placed in the shear-pin hole at the bottom to hold the punch holder and outer housing together. The punch holder should be in the upward position.
3. Two short brass pins are placed in the upper shear pinhole to pin the body to the punch holder.
4. Ensure the wedge is well coated with high-pressure grease.

14.2.1.2 Operation

The perforator can be run with tubing or collar stops attached, or the stop can be set separately prior to running the perforator. Assuming a stop has been set:

1. Make up the perforator on standard tool string.
2. Run down the well as far as the pre-set stop. At this point, provided you have not jarred down, the perforator can still be removed WITHOUT PUNCHING A HOLE.
3. Jar down GENTLY – Pick up each time after jarring. If the top two pins are sheared, the body will pick up. Extend the punch and bushing together, then push the slips against the opposite tubing wall. IF A HOLE IS NOT REQUIRED – JAR DOWN HARD TO SHEAR THE BOTTOM PIN. The safety catch will lock in Port B and lock the perforator out of service.
4. Pick up (gently in case the bottom pins are not sheared and pull out of the hole).
5. TO PERFORATE – jar up. Sit down slowly and jar up again. Continue jarring up until the perforator comes free. At this point, the safety catch will lock in Port A. Pull out of the well.

14.2.1.3 Operating Precautions

1. The top pins do not take much jar force to shear. Check after each downward lick.
2. After perforation has commenced – DO NOT JAR DOWNWARDS as this may break the punch.
3. The bushing must be a tight fit on the punch so that it moves to the tubing wall and supports the punch.
4. Hydraulic jars can be used.
5. While the pressure should equalize as soon as the hole is punched and before the punch is withdrawn, the operator should be aware that it is possible to be blown up the hole. Keep a bind on the wire after each upward lick.

6. Check the specifications of the perforator match the tubing weight prior to using.

14.2.2 Type A Perforator Support Tools

14.2.2.1 Type F Collar Stop

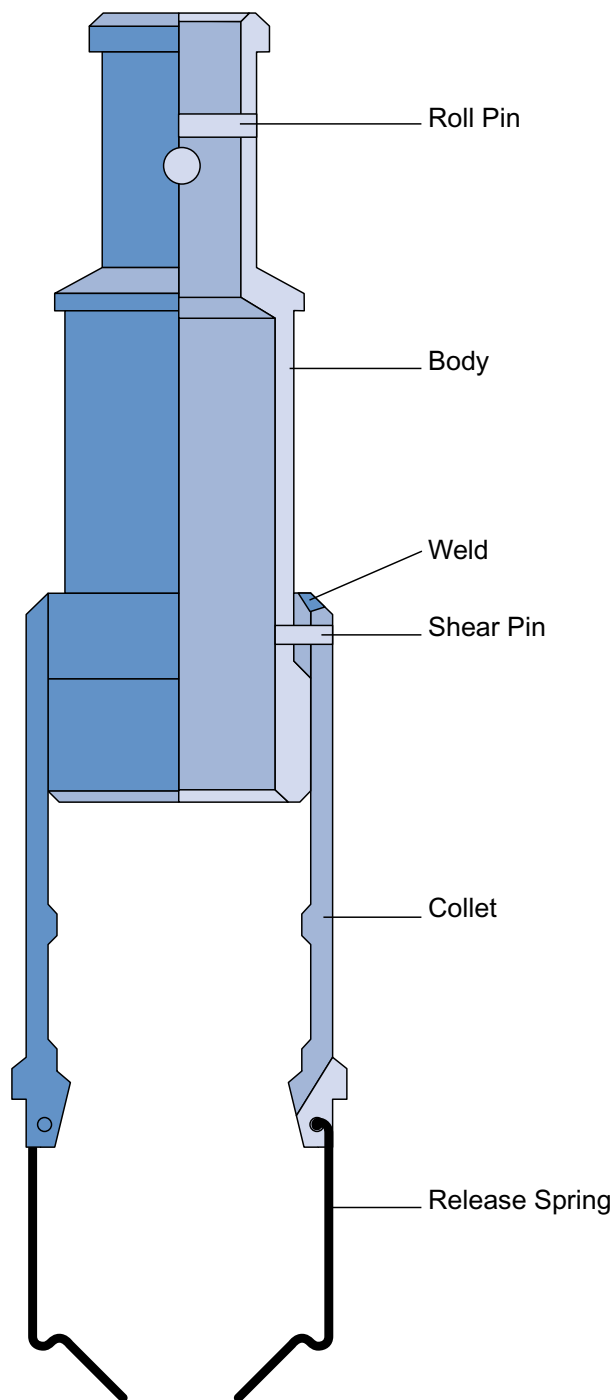


Figure 14-3: Type F Collar Stop

The type-F collar stop is designed to be set in the collar recesses of EU and NU tubing. It is run and pulled on a SB pulling tool.

To run, place the collet in the lower position and squeeze together in a vice until the springs snap together. This holds the shoulders retracted during running.

- Pin in the downward position.
- Run into the tubing to below the desired collar. Pick up the tripping springs and set down into the collar. Jar down to lock and shear off.
- Latch with the SB to pull by jarring downwards.

14.2.2.2 **Type F Tubing Stop**

The type F tubing stop is designed to set in all tubing (except plastic coated) and hold the force from the top. It is run and pulled on a SB.

Run slowly to the desired depth, then overrun the slips to grip the tubing wall. If the position is incorrect, pick up and reposition. Jar down to set tight and shear the SB.

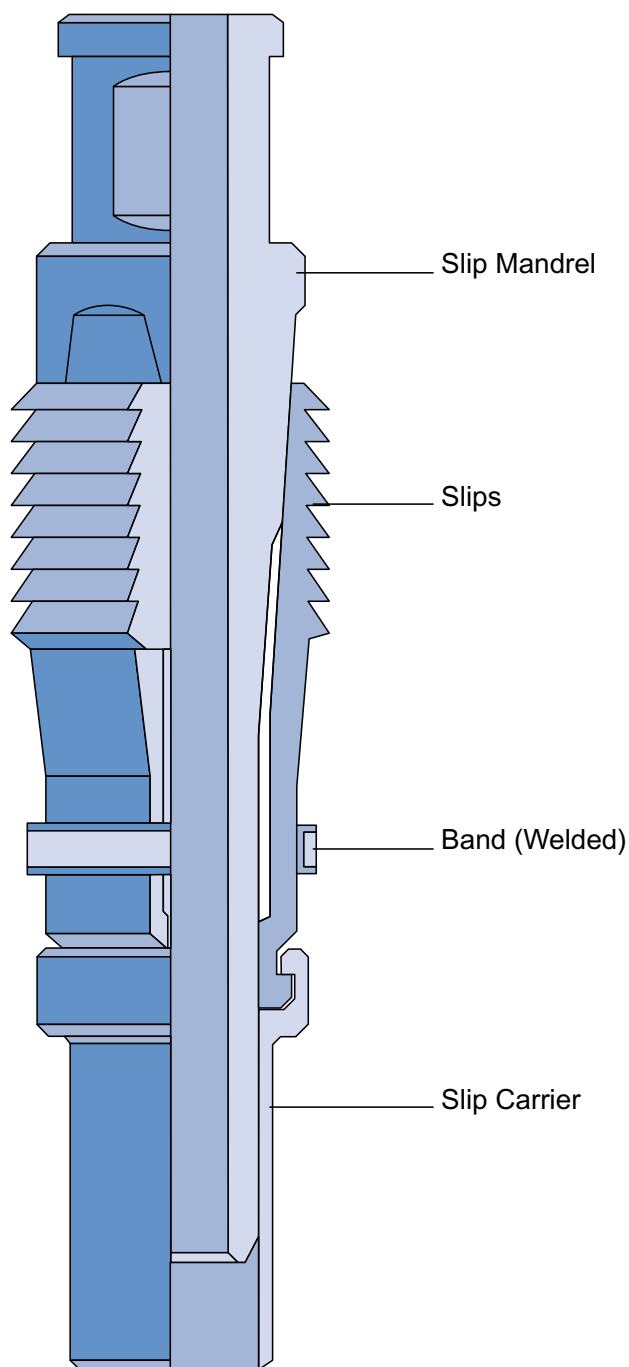


Figure 14-4: Type F Tubing Stop

14.2.2.3 Type F Collet Stop

The type F perforator collet stop is designed to screw directly into the base of the perforator (or via the knuckle joint).

It is set in the same manner as the F collar stop but by attaching to the perforator; time is saved setting and pulling the collet stop.

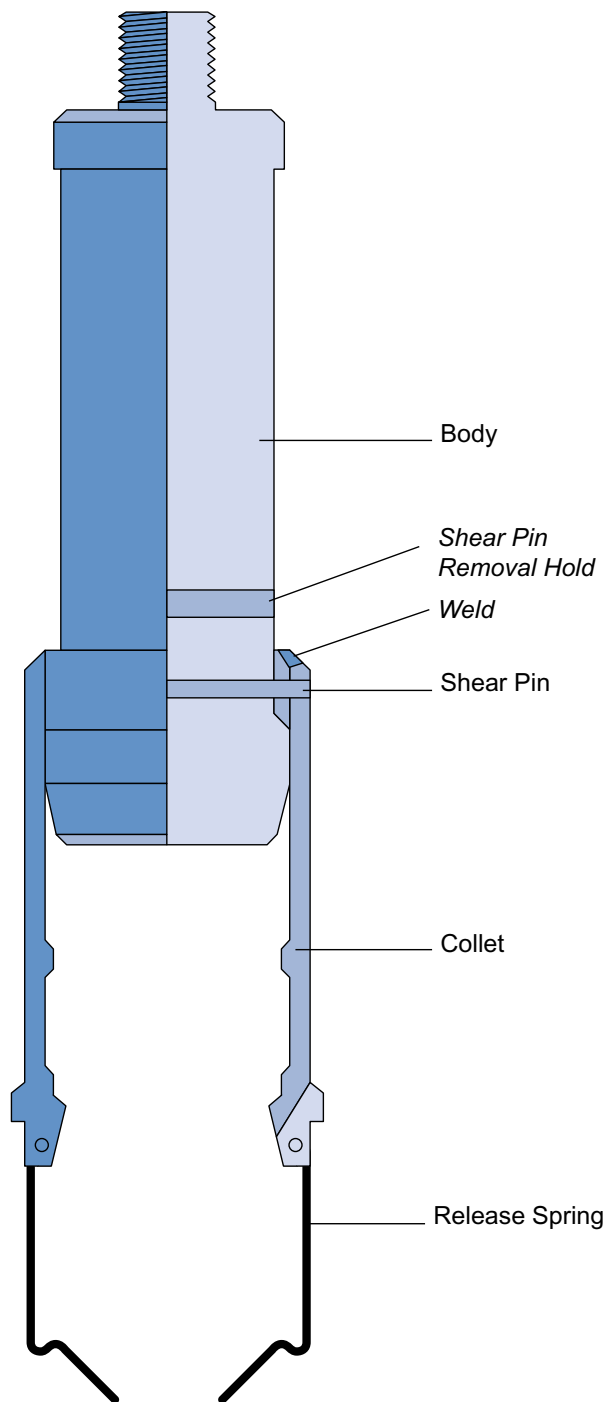


Figure 14-5: Type F Collet Stop

14.2.2.4 **Type F Perforator Stop**

The type F perforator stop is attached to the perforator.

Running in slowly, the whole assembly can be lowered to perforating depth. Rapid downward movement overruns the slips. The stop provides a firm base on which to trip the perforator.

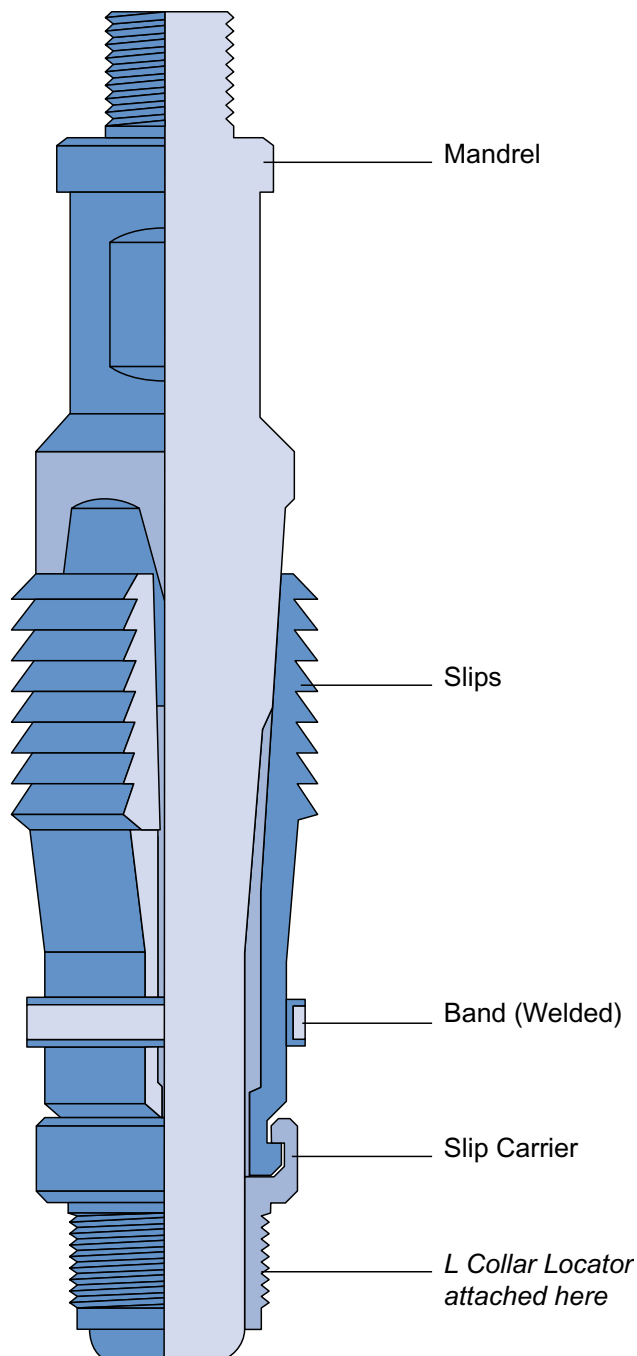


Figure 14-6: Type F Perforator Stop

14.2.2.5 Type L Collar Locator

The type L collar locator is screwed onto the type T perforator stop.

It is pinned to extend the latch for the correct tubing size. The upper end of the latch carrier keeps the slips disengaged until the upward movement locates the collar and trips the latch, shears the pin and releases the slips. This tool ensures the perforator does not punch a hole in the collar. This would be too thick and would damage the perforator.

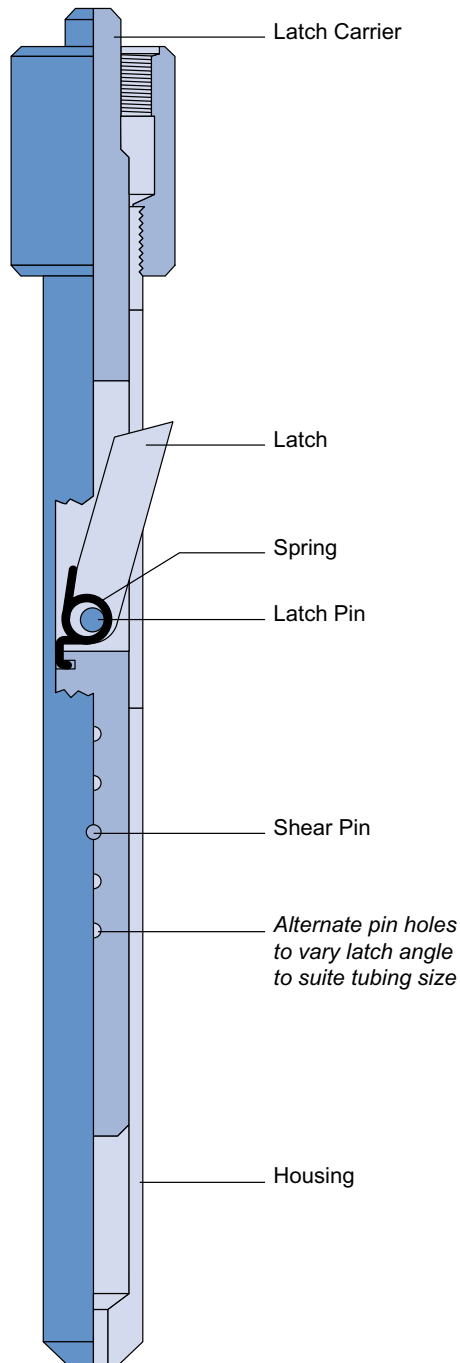


Figure 14-7: L Collar Locator

14.3 Bailers

Occasionally slickline service involves sand bailing prior to the actual pulling or setting of subsurface flow controls. Techniques vary, but the operation of the sand pumps is very much the same. After a few trips, the operator should know what to do to get a bailer full each trip, i.e., how long the pump must be stroked, whether it is necessary to drive down on the bailer (this seldom helps) or how fast to work the plunger.

Short bridges in the tubing will require some more precautions due to the possibility of pressure trapped under a bridge. The most important of these precautions is that the operator should never stroke the pump and stop at the top of the stroke. He should keep the tools moving on up the tubing until he is sure there is no pressure and then set the pump back down to make another stroke.

When the bailer falls through a bridge, the tools should be pulled back up several feet above the point where the bridge was first encountered to make sure the bridge of sand is completely clear before going deeper.

Sand is prone to become packed tight on the top when pressure has been applied to the tubing above, which is very often done to keep the pressure equalized above and below the sand bridge. This makes it difficult to pick up with the sand pump. In this case, it might be necessary to run a tool to loosen it. This could be a pointed tool with barbs welded on it, to drive down into the hard sand and pull back out. A round tool with teeth cut around the bottom edge will sometimes loosen it enough for the pump to pick it up (e.g., serrated gauge cutter).

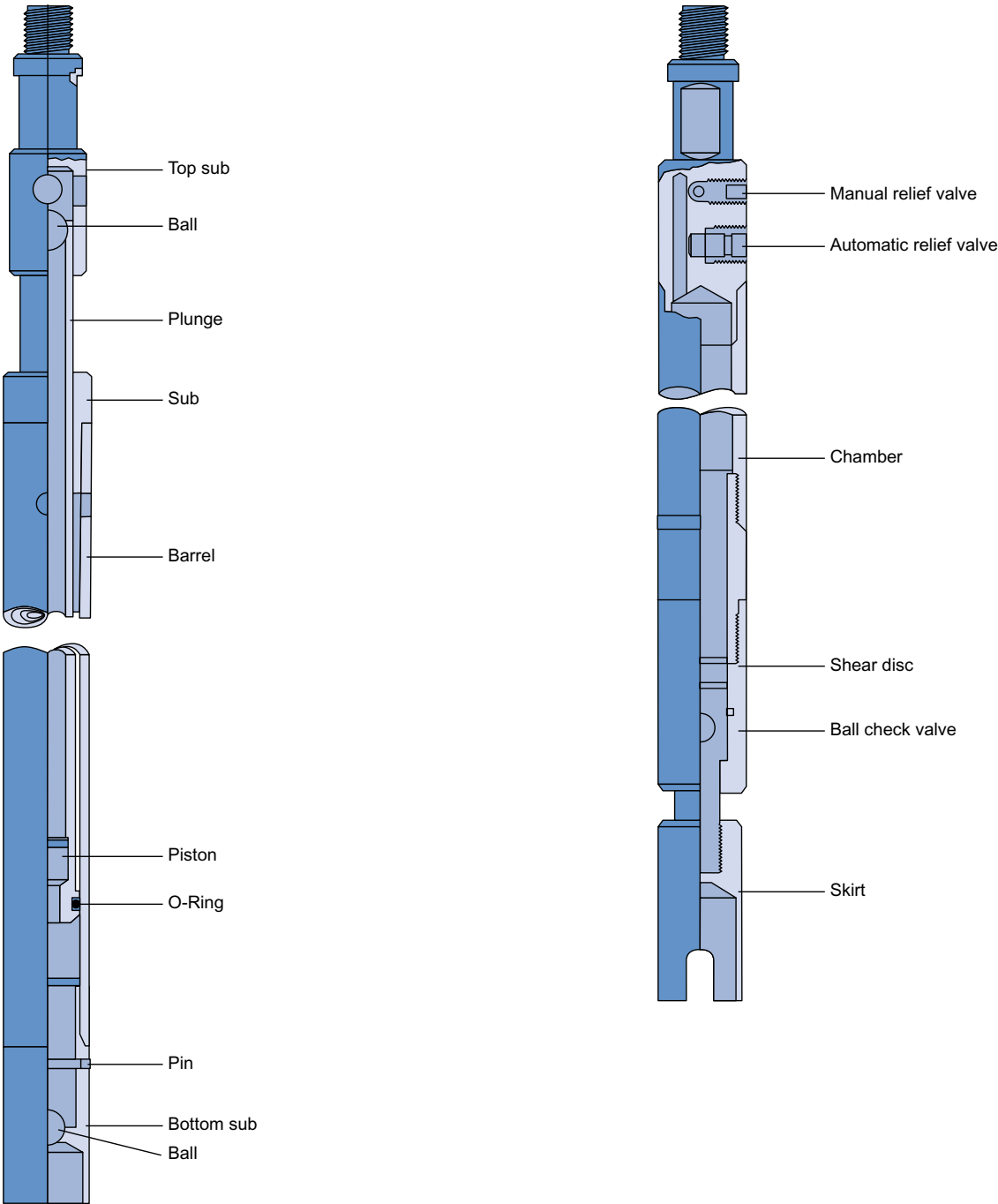


Figure 14-8: Otis Type FN 854 Bailer

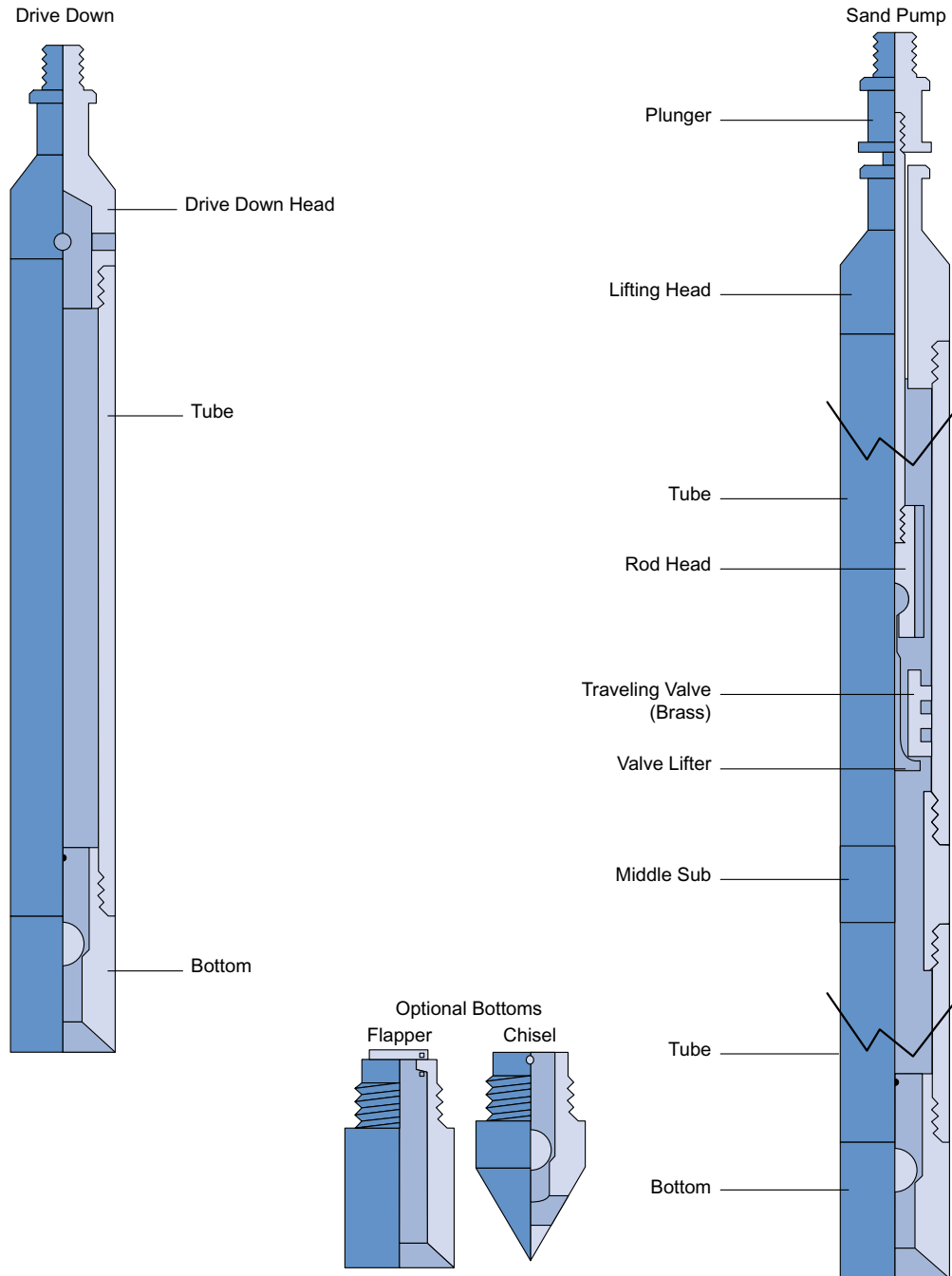


Figure 14-9: Maxwell Bailer Drive Down and Sand Pump Options

Sand pump bailers become much more efficient when the pump section is increased to an eight or ten foot stroke. The load sections can also be extended in length to carry much more sand to the surface on each run. Eighty-foot long bailers are in common use in some geographical areas.

Special sections on the lower end the bailer can be employed to capture frac balls, debris, junk and larger objects while at the same time, the flapper or ball/seat section can be moved upward in the load section so that sand can be retained on the same trip. When unloading this type of arrangement, it may be necessary to take apart the bailers at multi-points to empty.

It is necessary to run a set of up stroke or hydraulic jars 100% of the time when bailing with a pump bailer. This will be the only jar utilized to free bailer when it gets stuck. Bailer will frequently get stuck in sand, cement and debris. Pick up frequently and jar free immediately when stuck.

Sand bailers are of two basic designs:

- Pump bailers
- Hydrostatic bailers

There are five types of pump bailers:

- Pump bailers
- Core bailers
- Sample bailers
- Dump bailers
- Hydrostatic bailers

14.3.1□ **Pump□Bailers**

The pump bailer are commonly used to remove sand or debris from above temporary tools or equipment that have been placed in the in the well bore. The pump bailer is configured a hollow tube with a check valve (ball or flapper) at its lower end, which is usually mule-shoed (cut at 45°). It contains a piston and valve attached to a rod, which passes through a loose hold (for fluid bypass) at the upper end of the tube. This rod is attached to the tool string.

As the bottom of the bailer sits on the sand, the weight of the tool string pushed the piston to the bottom of the tube. As this piston is picked up, it sucks sand and debris into the bottom of the bailer. This slow stroking process continues until the bailer is full.

14.3.1.1□ **Core□Bailers**

Core Bailers are very useful when bailing slurry sand and sand mixed with gel. Use of this bailer rather than the sand pump allows greater recovery per run because all sections of the bailers become load sections.

14.3.1.2 Sample Bailers

A sample bailer is very useful prior to starting a bailing or clean out slickline procedure. A small sample is recovered which will be used to determine which bailer or tool should be used next.

When using any bailer to clean off the top of a retrievable device, chisel-marks should be used on bottom of bailer shoe to aid in determining that job is nearing completion.

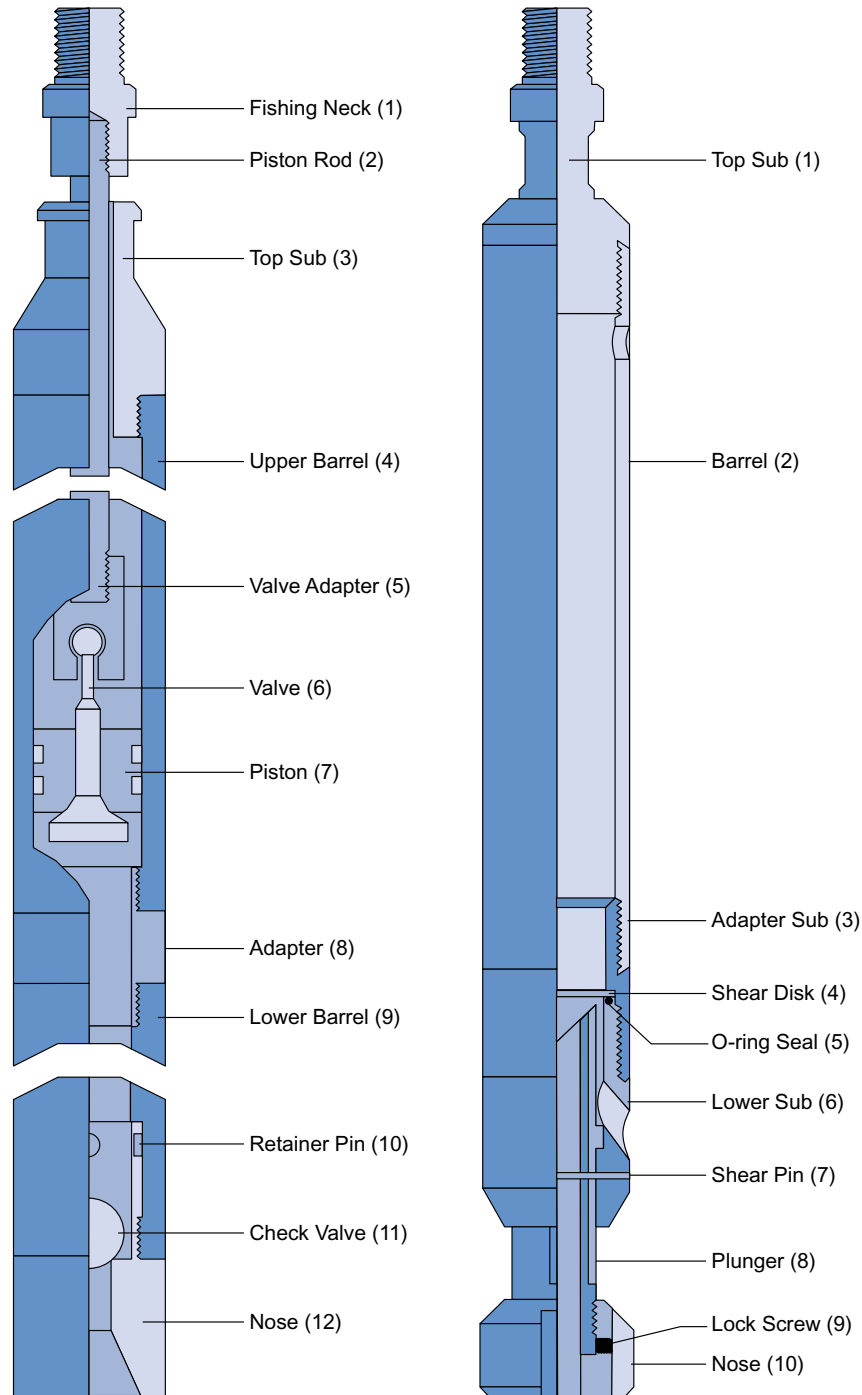


Figure 14-10: Pump and Dump Bailers

14.3.1.3 Dump Bailers

Dump bailers are used to convey sand or slurry for precise placement in the well bore, e.g., for placement of small volumes of cement above a mechanical plug to ensure a high-integrity hydraulic seal.

14.3.2 Hydrostatic Bailers

A hydrostatic bailer consists of a chamber sealed at atmospheric pressure. When the bailer reaches the top of the sand and is jarred down, a shear disk is ruptured and the bottom hole pressure surging into the chamber sucks up the sand. A ball check in the bottom serves to trap the sand in the chamber.

These bailers are used to clean off sand or foreign materials from around a fishing neck very successfully, but are not recommended for normal bailing operations. In soft sand, this bailer will bury itself each time it goes off. It usually requires a hard object against which to shear the disc or shear pin.

Always use a pump bailer to remove the bulk of sand etc. until the pump bailer is resting on the plug or whatever is to be removed. A hydrostatic bailer can be used to clean around the fishing neck.

Hydrostatic bailers are not recommended for normal bailing operations because:

- The operating method cause them to make too slow progress
- There is high possibility of sticking in the sand due to the suction action when the sealed chamber is opened.



Note

Sand pumps and hydrostatic bailers can be dangerous after pulling them to the surface and when unloading the sand, due to pressure trapped inside the chamber. Caution should be taken when removing the check valve on the bottom to make sure there is no pressure inside. This can be determined usually by how hard the bottom is pressured up. Do not hammer on a bailer to remove sand. These bailers are subject to bottom hole pressure. It is a good idea to visually inspect these bailers for wear and wall reduction.

Pump Bailers and Hydrostatic Bailers have pressure relief valves and some have an automatic pressure relief valve. These become plugged easily and can be dangerous to handle, so observe the above caution when unscrewing the bottom.

14.3.2.1 Preparing the Tool

Before running, check the following points:

- Upper manual pressure relief closed (fully IN).

- Automatic pressure relief – Check the O-ring and that the disc is in position.
- Insert the shear disc – to ensure 100% sealing. It is helpful to wrap Teflon (PTFE) tape around the edge or grease the disc.
- Check the skirt is tight.

14.3.2.2 Operation

1. Hydrostatic is run to solid obstruction. The tubing pressure outside is much greater than the atmospheric pressure inside. Downward jar action will shear the disc.
2. The disc is forced inside the cylinder as the sand, scale and fluid rushes in to fill the cylinder. The pressure inside and outside is now equalized.
3. As the bailer is pulled out of the well, the tubing pressure decreases near the surface. Pressure trapped inside by the check valve is now greater than the tubing pressure. The automatic relief valve should release excess pressure.



Caution

Potential Severity: Light
 Potential Loss: Process
 Hazard Category: pressure

This relief valve can be easily blocked by sand.

4. On the surface, the manual relief valve should be loosened (do not remove completely) and the ball check pushed off the lower seat by a brass rod to ensure no pressure is trapped inside. Remove the lower housing.
5. Clean threads and grease before reassembling.



Note

Because of the forces that can be encountered when running the hydrostatic bailer, it is not recommended that this tool be used prior to talking to and cleaning this operation with a specialist.

14.3.2.3 Type B Hydrostatic Bailer

Hydrostatic bailers are used when the substance to be bailed cannot be removed by pump type bailer. This is sometimes the case when small metallic particles become lodged on top of the dogs of a locked mandrel.

The tool is made of a cylinder, about 5 ft long, with a shear disc mechanism at the bottom. The cylinder is at atmospheric pressure sealed off from well pressure with O-rings. When the obstruction is reached, the shear disc is sheared by downward jarring (5 times); different size skirts can be fitted for different tubing and tool sizes.

Also different thickness' of disc for different well pressure ranges (discs are made of brass) are available:

- 1/32 in.(0.8 mm) up to 3700 psi
- 1/16 in.(1.6 mm) up to 7400 psi
- 3/32 in.(2.4 MM) up to 11,000 psi

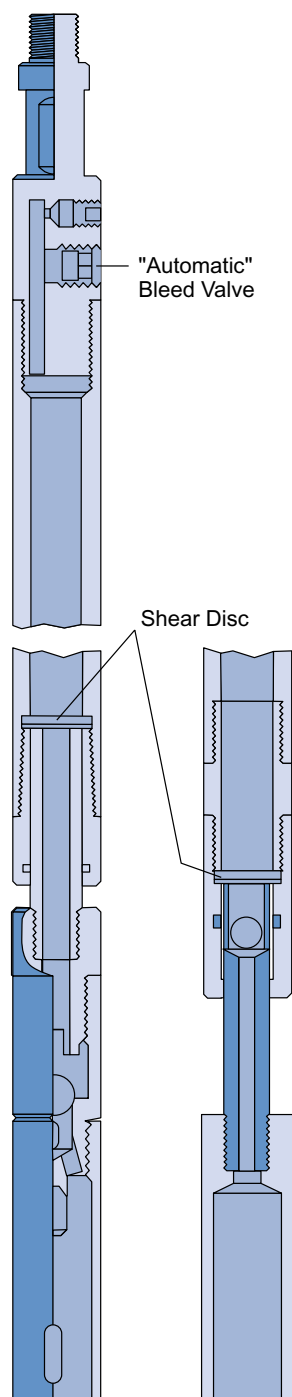


Figure 14-11: Otis Type B Hydrostatic Bailer



Caution

Potential Severity: Light
Potential Loss: Assets
Hazard Category: pressure

As the lubricator is bled off to atmospheric pressure, the seal plug of the automatic bleed valve should be forced into the recess of the safety screw. If not, back out the cup point screw a few turns to release the pressure. Then, force the bottom non-return steel ball off its seat with a screwdriver. Bailer can then be opened.

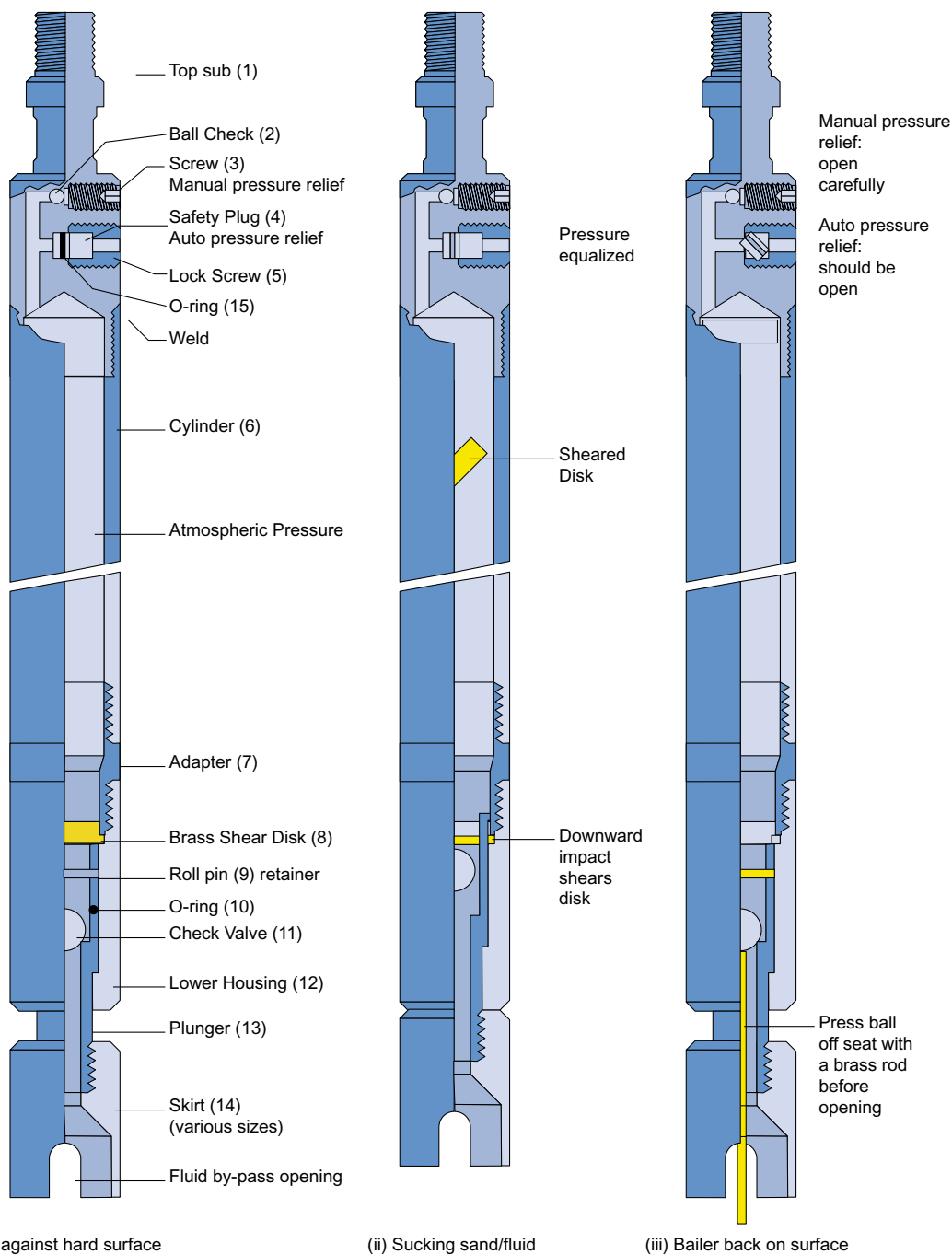


Figure 14-12: Hydrostatic Bailer Operating Sequence

14.4 Pack-Off

A pack-off is designed to straddle and isolate holes or any other communication paths in the tubing string, while still permitting production to pass through the hollow center of the pack-off.

The pack-off is installed with the upper and lower seals on either side of the leak in the tubing. The lubricator length and the deviation of the tubing limit the spacer pipe length. If spacers longer than approximately 6 ft to 8 ft are required, a seal extension is used and spacers are assembled down hole.

A pack-off assembly is generally made up of the components shown in the figure below.

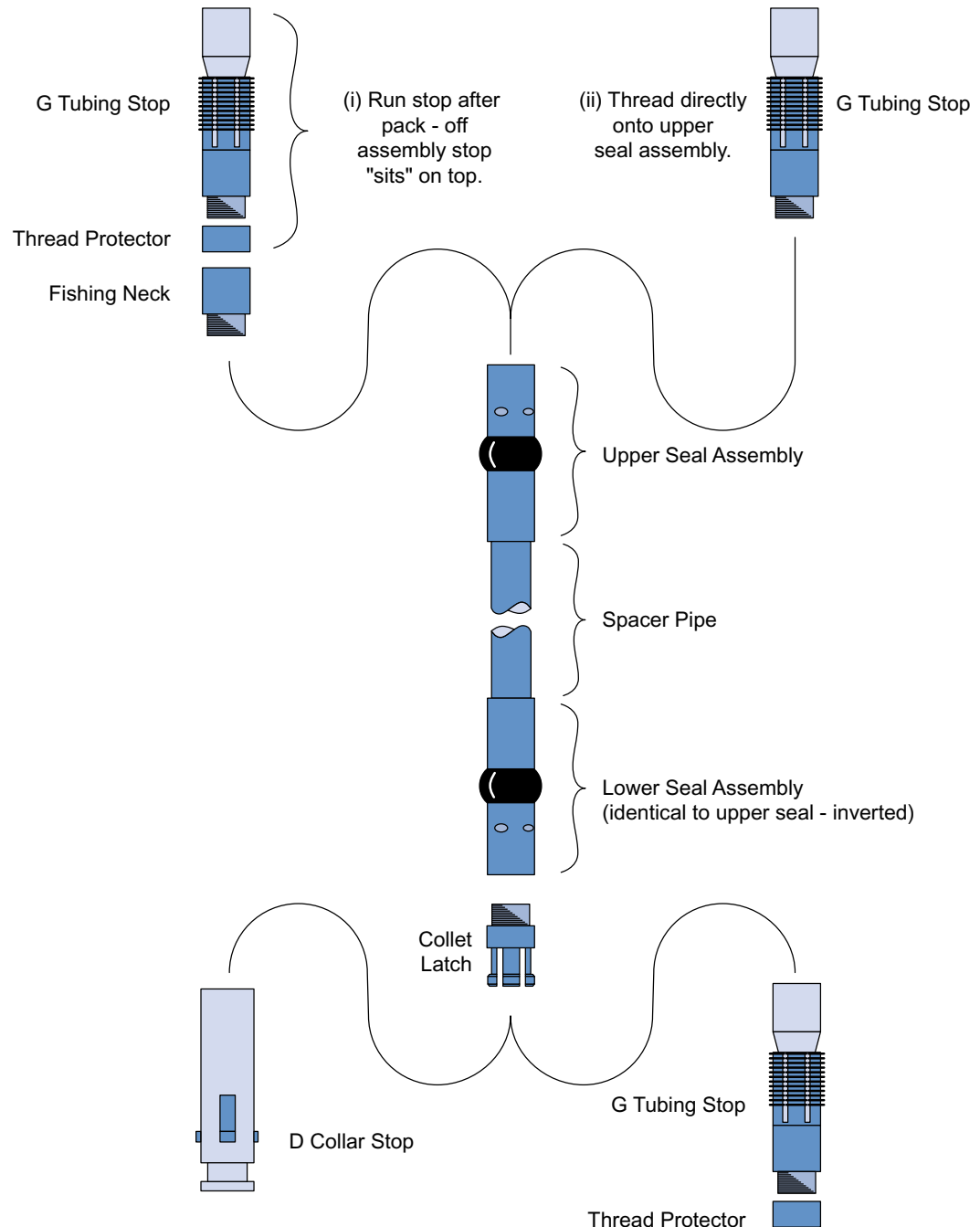


Figure 14-13: Pack-off Components and Configuration

14.4.1 Type G Pack-off

An ideal pack-off assembly should incorporate the following features:

- An internal fishing neck permits a larger flow bore
- Reliable seal elements
- Can be set in collar type or smooth joint tubing, using different bottom stops.
- Upper and lower seal assemblies should be similar.
- Straightforward running and pulling procedure.

The bottom stop is run first. The type of tubing joint determines the pack-off type.

- EU or NU tubing (with collar recess) - Type D collar stop
- Smooth joint tubing (e.g. HCS or VAM – Type G tubing stop)

The remainder of the pack-off is run onto this stop, either in one piece or with the pack-off and upper hold-down run separately.

The upper hold-down is also a G tubing stop, and both of these components are run and pulled on a GS.

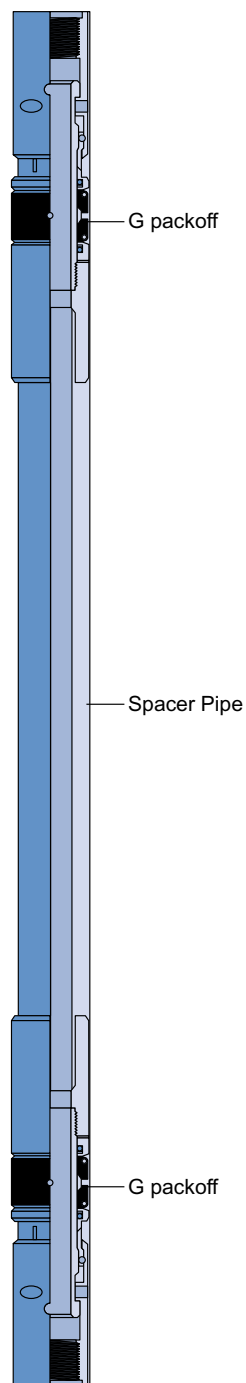


Figure 14-14: G Pack-off Assembly

14.4.2 Type G Element

The G element assembly can be used on both ends of the spacer pipe. It is shown in the upper position, but by inverting the complete assembly it can be used as the lower seal.

After setting the lower stop, the pack-off assembly is lowered into position using a GS running tool. Downward jar action compresses the elements and they expand against the tubing wall.

Spacers can be added beneath the expander to alter the expanded OD of the element to suit the tubing weight.

As a lower seal, the collet is screwed into the lower end. This latches into the fishing neck of the D collar lock or G tubing stop. When pulling the pack-off, this collet ensures both elements are fully retracted before the pack-off is pulled.

As an upper seal, the G tubing stop can be directly attached or a fishing neck can be attached to the internal thread.

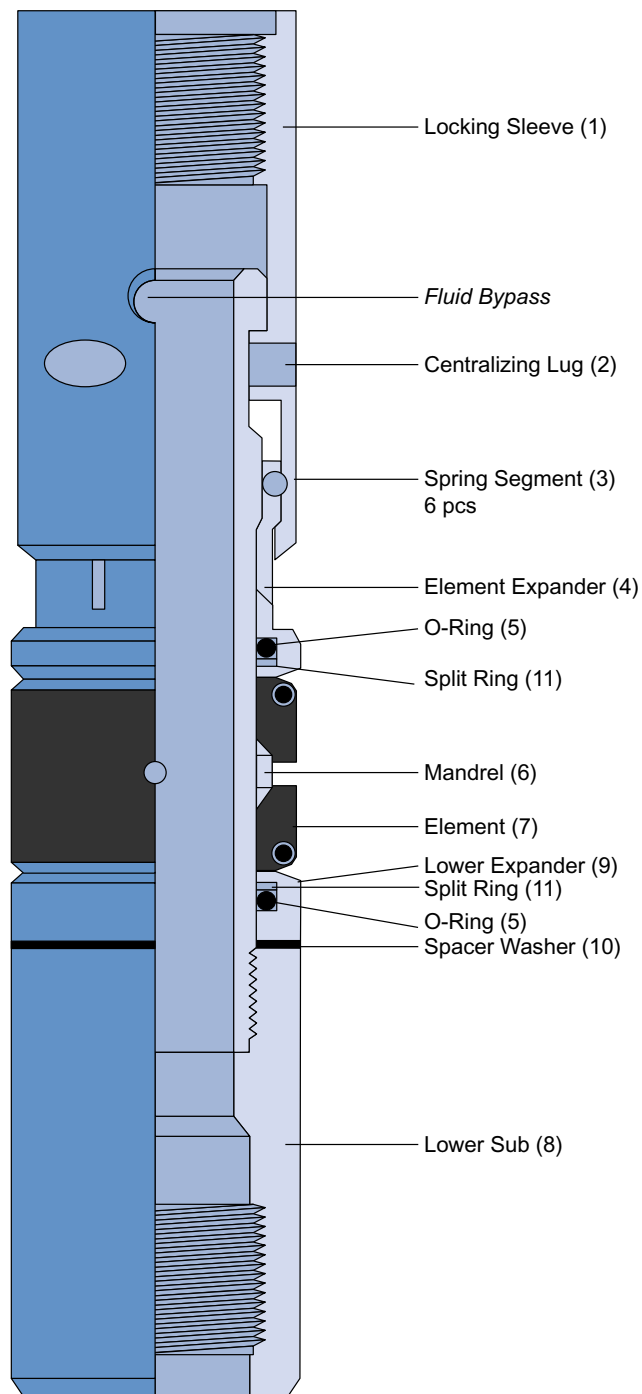


Figure 14-15: Type G Pack-off Element

14.4.3 Type D Collar Stop

The type D collar Stop is run on a C running tool, which is pinned, to the lower end of the mandrel. It can be located in any EU or NU tubing collars.

It is lowered to below the collar and then picked up until the dogs latch in the collar recess. Jar up to shear the pin and pull the running tool to the surface.

The collar stop is pulled on a GS.

Holes marked "A" are lined up and locked with a punch to unscrew the mandrel cap when stripping this tool.

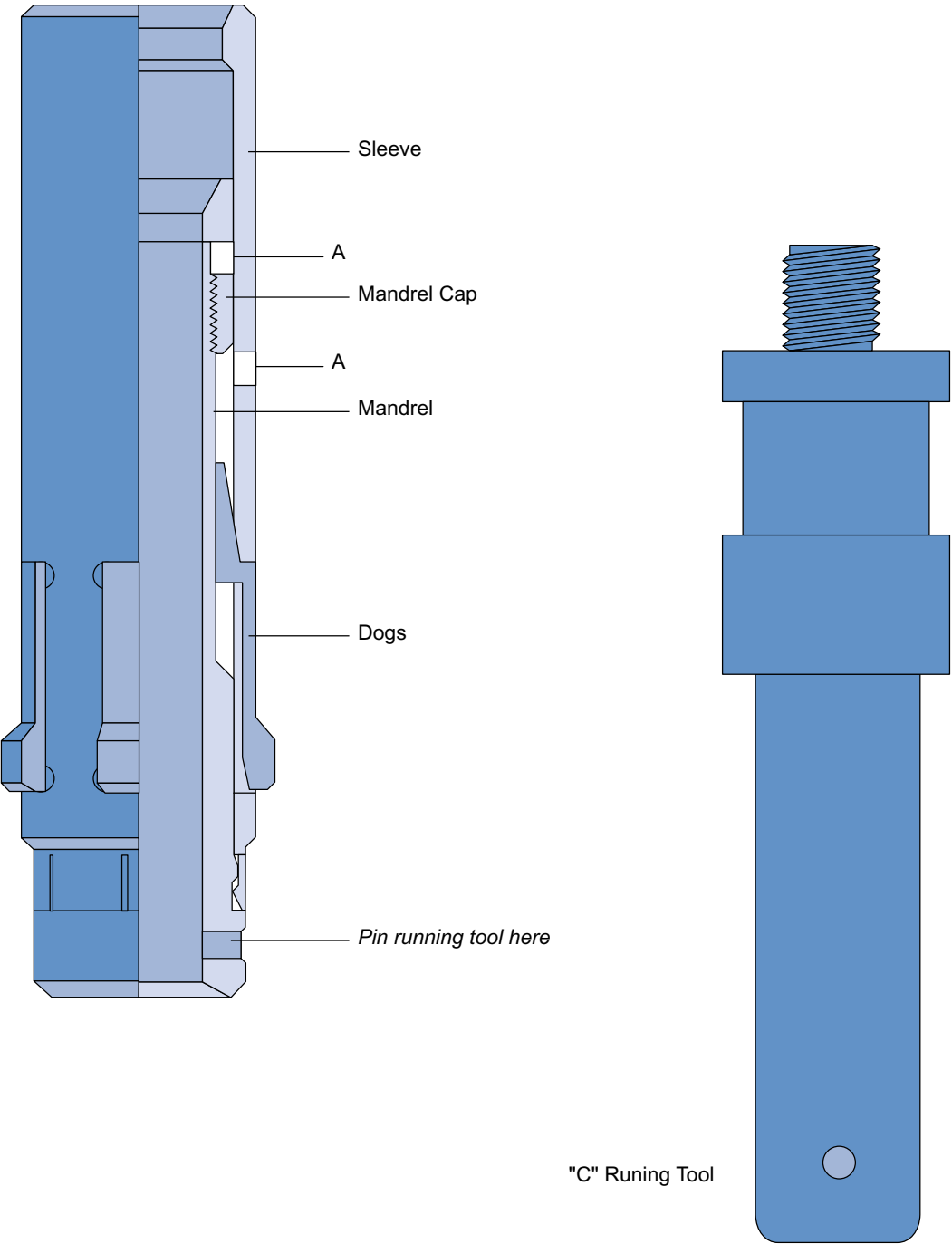


Figure 14-16: Type D Collar Stop and Running Tool

14.4.4 Type G Tubing Stop

The type G tubing stop can be run and pulled on a GS pulling tool. To set, the assembly is run in the hole slowly. At the depth at which the tubing stop is to be set, the rate of descent is increased until the slip mandrel overrides the slips. If the position is incorrect, pick up and reposition. Jar down to set.

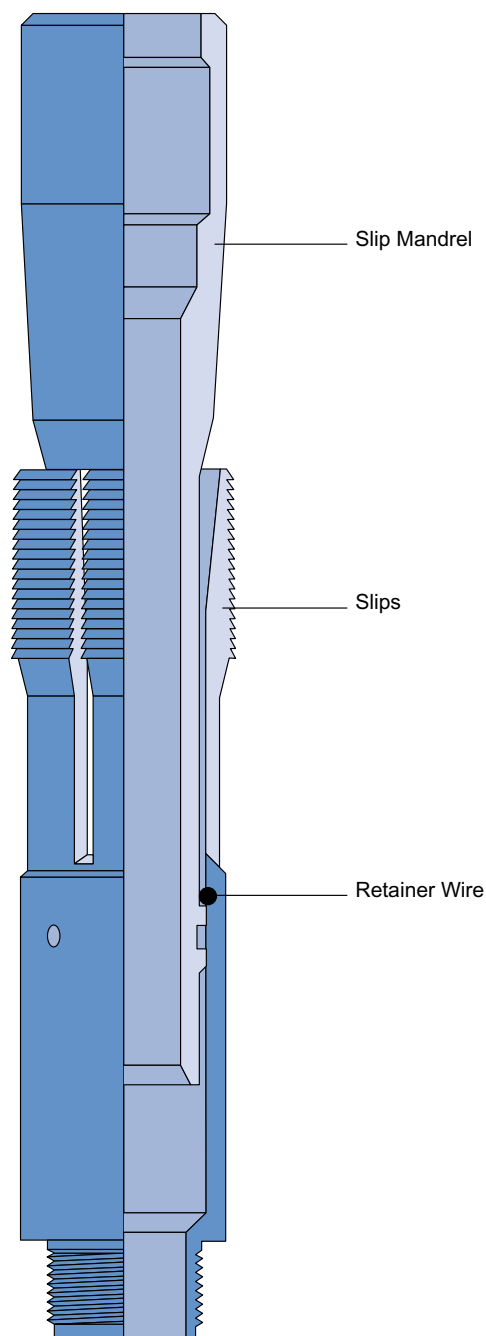


Figure 14-17: Type G Tubing Stop

14.5 Baker Straddle Systems

The Baker Model K-2 and K-3 straddle pack-off are slickline retrievable tools that provide communication control between the tubing and the annulus. They can be positioned as desired, under pressure, in a landed tubing string and are compatible with normal slickline equipment. Both models perform the same function but have minor design differences.

The straddle pack-off system consists of two separate pack off units and two model B tubing stops.

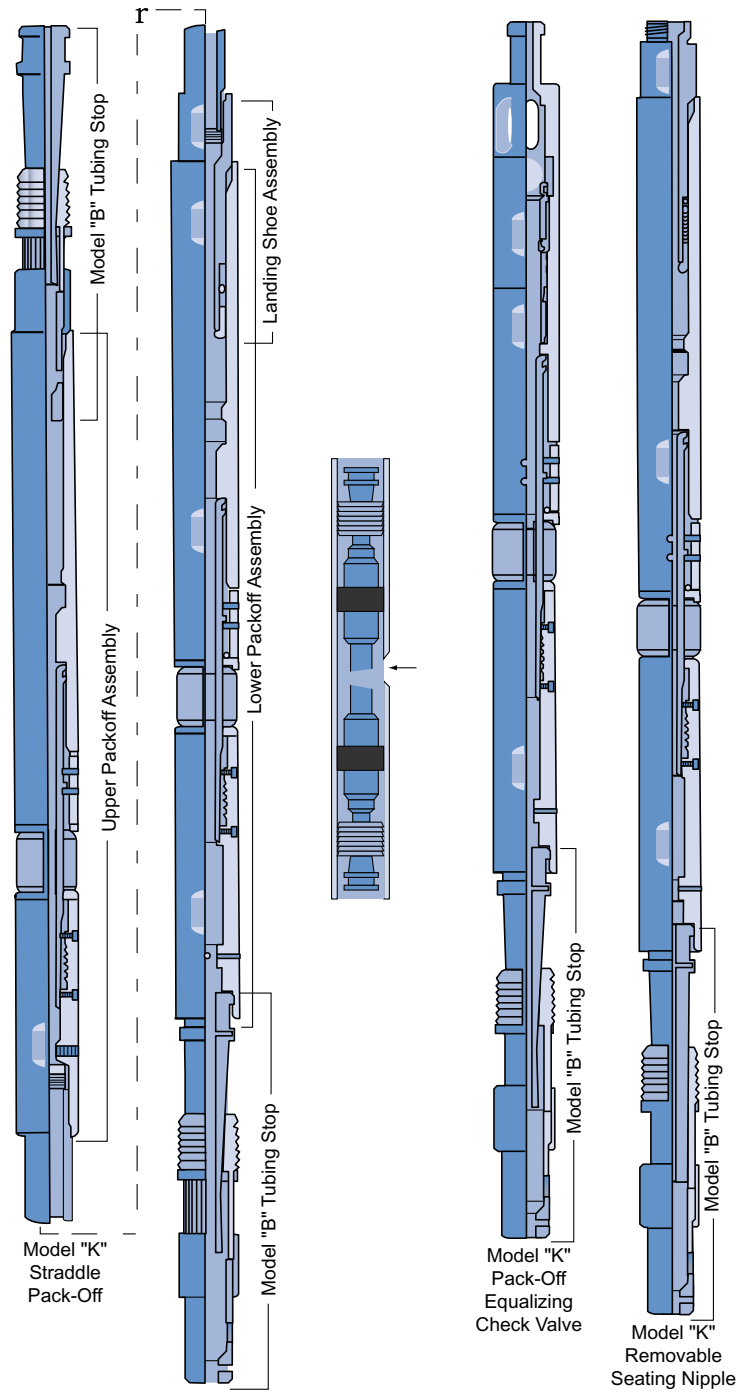


Figure 14-18: Model K Straddle Pack-off

14.5.1 Features

- Provides two pack-offs, one above and one below a tubing communication point

- Hydraulically balanced so pressure from above aids pack off force
- May be positioned where desired under pressure
- Compatible with normal slickline equipment
- Operating pressure to 5000 psi and temperatures of 275°F

14.5.2 Applications

- Isolates tubing leaks
- Used to install concentric gas-lift equipment
- Isolate a zone during treatment
- Blank off a perforated nipple

14.5.3 Spacer Pipe Subassembly

A useful accessory for the K-2 and K-3 straddle pack-off is the spacer pipe subassembly. The spacer pipe subassembly is used to increase the amount of spacer pipe required between the upper and lower pack-off assemblies. Consisting of a special landing receptacle, additional spacer pipe and a landing shoe subassembly, it can be run under pressure and stabbed into the top of an existing lower pack-off assembly down hole.

The running/pulling tools are the same as those used with the upper and lower pack-offs.

14.5.4 Model K Straddle Pack-Off System

The model K straddle pack-off system consists of a set of slickline retrievable tools that provide communication control within the tubing or between the tubing and the annulus. The system can be used to: isolate a tubing leak; install concentric gas-lift equipment; isolate a zone during treatment or blank-off a perforated nipple.

The straddle pack-off system consists of two separate pack-off units and two model B tubing stops. This arrangement of the equipment is suitable for isolating concentric gas-lift equipment.

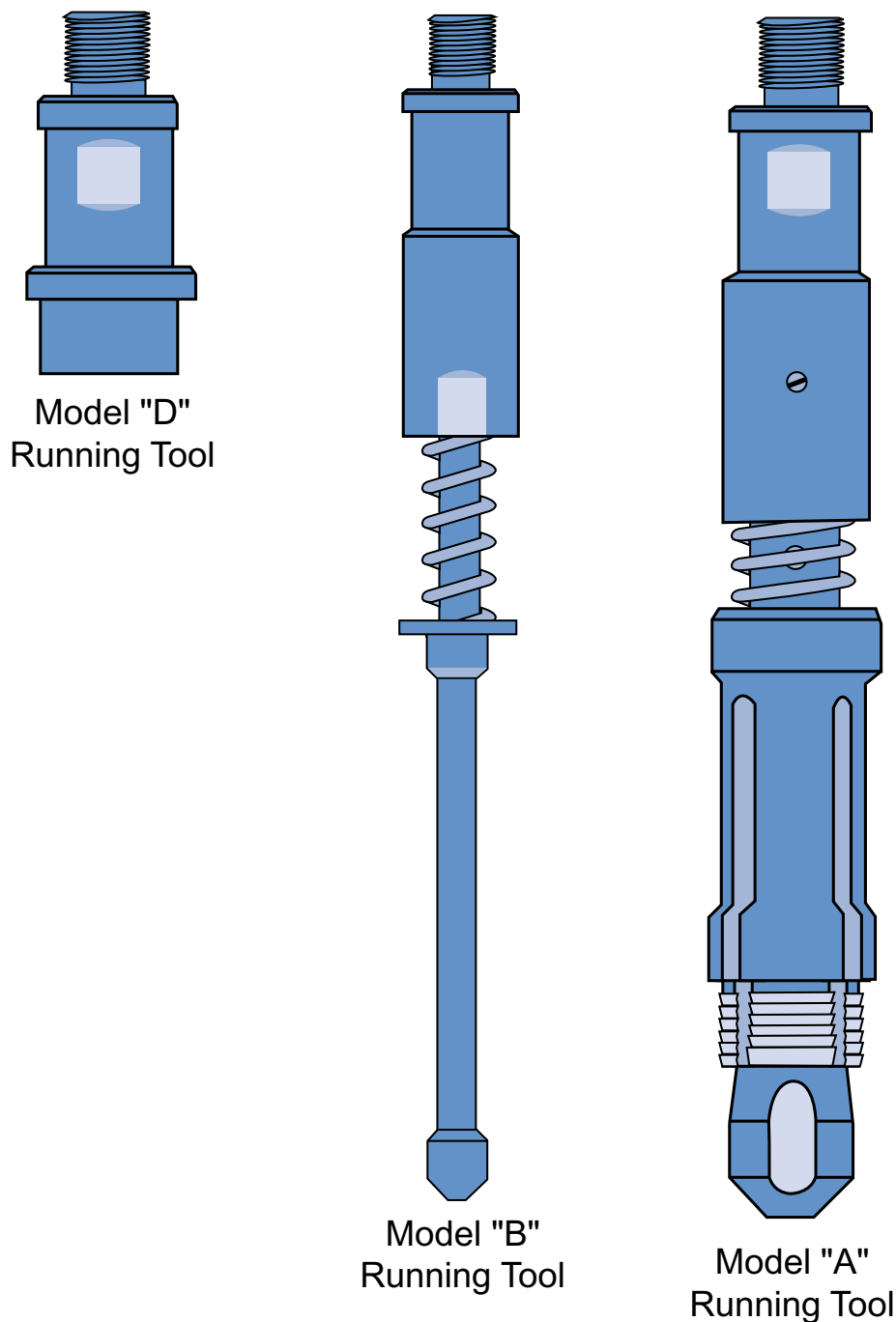


Figure 14-19: Model D, B and A Running Tools

The tools described below are used to run and pull the pack-off equipment.

- Model D Running Tool

The model D running tool is used to run model K removable seating nipples and straddle pack-offs.

- Model B Running Tool

The model B running tool is an inertia-triggered device used for running and setting Baker flow control model B tubing stops and is compatible with normal slickline procedures and equipment.

- Model A Spear

The model A spear is a spring loaded, internal slip-type tool used to retrieve model K removable seating nipples and model K straddle pack-offs.

14.5.5 □ **Installation Using Straddle Pack-Off Equipment**

To isolate a hole in the tubing, first run a model B tubing stop on a model B running tool to the desired location. Next, run the lower pack-off unit on a model D running tool, jarring down against the tubing stop will set the pack-off unit. Make up the landing shoe (to seal into the lower pack-off unit), the line pipe (to space out the pack-off unit across the hole) and the upper pack-off unit and run in with the model D running tool. Jar down against the lower pack-off unit and tubing stop to set the upper pack-off unit. Run and set a model B tubing stop against the upper pack-off unit to prevent any upward movement.

Tubing Specifications			K Straddle Pack-off						B Tubing Stop								
OD	Wall Thk	Drill	Size (A)	Seal Bore	Max OD	To Run	To Pull	Size	Min ID	To Run	To Pull						
in. mm	in. mm	in. mm		in. mm	in. mm	D r unning Tool Prod. No. 811-07	A Spear Prod. No. 812-17		in. mm	B Runni ng Tool Prod. No. 822-04	Pulling tool						
1.900 48,26	0.145 3,68	1.516 38,51	19 (1.427 x 1.18)	1.187 29,97	1.427 36,25	1.18		19	0.500 12,70	19	40SB6, JDC15154 or 40SB8						
			19 (1.511 x 1.18)		1.511 38,38												
2.000 50,80	0.165 4,19	1.576 40,03	20 (1.490 x 1.18)		1.490 37,85			20									
			20 (1.571 x 1.18)		1.571 39,90												
2-m 52,37	0.156 3,96	1.656 42,06	21 (1.552 x 1.16)		1.552 39,42			21									
			21 (1.651 x 1.18)		1.651 41,94												
2-3/8 60,33	0.336 8,53	1.609 48,87	21 (1.552 x 1.16)	1.552 39,42					0.796 20,22	23	40SB1 or JDC-TD15169						
	0.218 5,54	1.645 40,80	23 (1.612 x 1.50)	1.612 46,02													
	0.190 4,83	1.901 48,29	23 (1.812 x 1.50)	1.666 47,90													
2-7/8 73,03	0.440 11,18	1.901 48,29	23 (1.612 x 1.50)	1.500 38,10	1.612 46,02	1.50	23										
			23 (1.886 x 1.50)		1.555 47,911												
			23 (1.812 x 1.50)		1.612 46,02												
	0.405 10,29	1.971 50,80	23 (1.886 x 1.50)		1.686 47,911												
			25 (2.216 x 1.76)		2.216 56,34							1.76	28		1.406 35,71	28	40SB2 or JDC-TD15171
			26 (2.342 x 1.76)		2.341 59,49												
3-W 88,90	0.530 13,46	2.315 58,80	26 (2.216 x 1.76)	2.216 56,34													
	0.289 7,34	2.797 71,04	35 (2.740 x 2.25)	2.250 57,15	2.740 69,60	2.25	35		1.421 36,09	35	40SB7 or JDC-TD15181						
	0.254 8,45	2.067 72,82	35 (2.740 x 2.25)		2.062 72,99												
4-1/2 114,3	0.205 to 0.337 8,2 to 8,56	3.985 to 3.701 100,7 to 94,01	45 (3.676 x 3.31)	3.31 84,07	3.676 93,42	3.31	45		2.375 60,33	45	40SB10 or JDC- TD15183						

Figure 14-20: Model K Straddle Pack-off Engineering Data

14.5.5.1 Model K Removable Seating Nipple

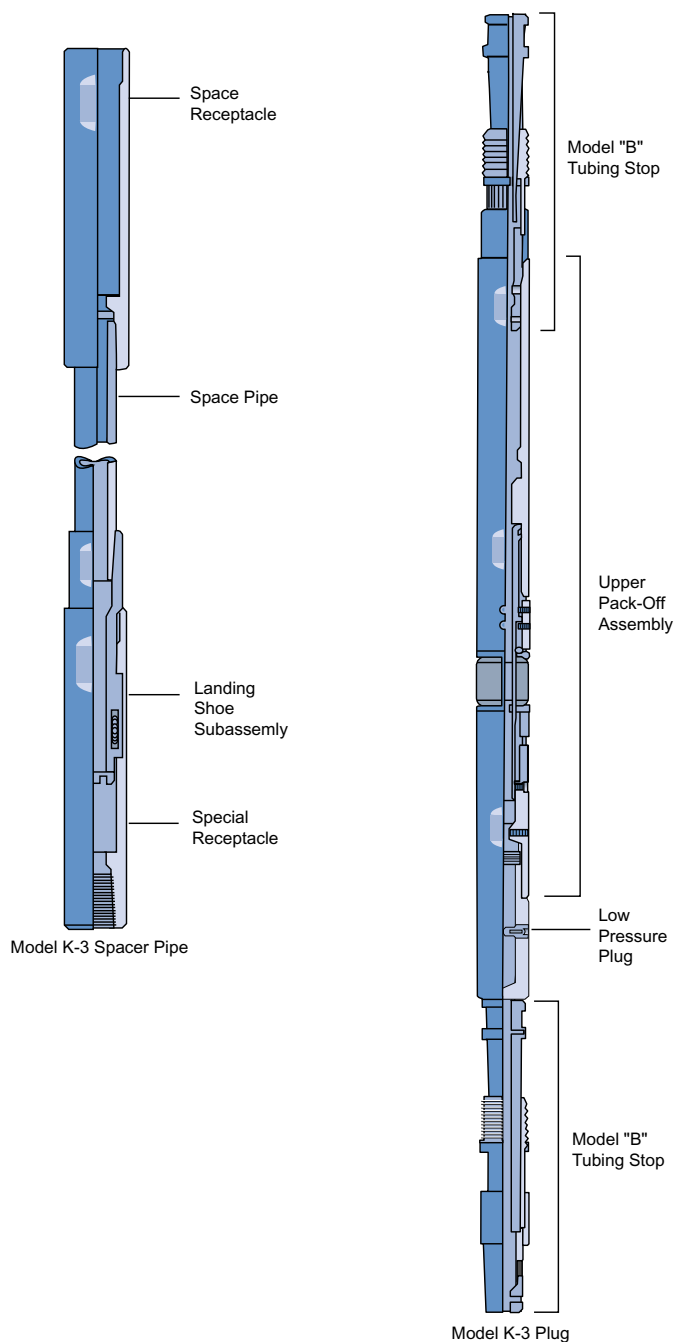


Figure 14-21: Model K Removable Seating Nipple

The Baker flow control model K removable seating nipple is a landing receptacle that can be used for seating and anchoring a pump, testing tubing internally and various other operations of this type. It is run in on slickline, landed on a model B tubing stop and packed off by jarring down. The receptacle portion accepts accessories equipped with chevron packing.

The Model K locator seating assembly is used to seat pumps in K removable seating nipples.

The Model FB-2 check valve can also be used with K removable seating nipple.

Model FB-2 Equalizing Check Valve

Baker equalizing check valves, sometimes called standing valves, prevent downward flow while allowing upward flow. These slickline retrievable check valves are run and landed in Baker model F seating nipples.

Features

- Provides simple means of testing tubing and setting hydraulically actuated equipment
- Run and retrieved with standard slickline equipment or run in place with the tubing
- Integral equalizing feature for quick and easy retrieval of equalizing check valve

Model K Pack-Off Equalizing Check Valve

The model K pack-off equalizing check valve is a ball and seat type valve that permits upward but not downward fluid flow in the tubing. The valve pack-off in the tubing ID rather than in a seating nipple. It is run in on slickline, landed on a model B tubing stop and packed off by downward jarring. The valve contains an equalizing sleeve to permit the equalization of pressure before retrieving.

Model K-2 and K-3 Low Pressure Pack-Off Plug

Utilizing the upper pack-off assembly and the upper and lower tubing stops of the K-2 and K-3 straddle pack-off system, a low pressure tubing plug capable of holding pressure from above and below can be provided for completion strings not having seating nipples.

For safe use of this plugging system, careful consideration must be given to the anticipated pressures, size and condition of the tubing to be plugged.

A knock-out type-equalizing plug is provided to equalize pressure prior to retrieving the tubing plug.

14.6 Swabbing

Swabbing provides a means to remove fluid from the well using slickline. Situations where swabbing is used are as follows:

- To initiate the flow in a well, which has insufficient formation pressure to flow initially or after it has been shut in for a period of time.
- To obtain a formation sample during exploration drilling, by swabbing fluid from the tubing until the tubing volume has been removed and the formation fluid is at the surface.
- To reduce the fluid level in a new well prior to perforating, to reduce the hydrostatic pressure to create an underbalanced condition. This creates an initial surge as the perforating guns fire to clean out the perforation debris.



Note

If fluid is to be removed prior to perforating, a means of permitting fluid entry at the bottom of the well is essential or the swabbing cups cannot be moved upwards, e.g., lift the seals out of the packer to provide fluid entry from the annulus.

It is recommended that braided line be used for swabbing operations. The line forces, which are generated, can be too high for slickline. However if the line force expected is within slickline limits, it can be used. Line forces can be reduced by slower pulling speeds and by taking less fluid at each trip.

14.6.1 Operating Guidelines

- Record the fluid level during first and subsequent trips into the well. The toolstring will slow down and the weight will drop as the tools enter the fluid.
- Record any increase in fluid level, as this will indicate an inflow of fluid from the formation.
- Increase the depth into the fluid slowly to check the line tension, e.g., on the first trip, 100 ft and pick-up. If the tension is within the acceptable limits, increase the depth.

- A common amount of fluid to be recovered is 500 ft. This varies with the tubing diameter.
- The line speed will affect the tension and fluid recovery. As a guide, wire should be spooled at a speed similar to a slow run and adjusted to maintain near maximum tension for optimum.
- The volume of output fluid should be recorded, by flowing to a tank, preferably via a flow meter.
- The wing valve or choke must be able to be closed quickly if the well starts to flow.
- If the fluid level is rising, it is prudent to observe the well between swabbing trips to see if it will flow naturally.
- Failure to restrict or shut off the output can result in the tool string being blown up the well.

14.6.1.1

Swabbing Cups

- Check the OD of the swabbing cup is correct for the tubing.
- Cups should be used two or three at a time and replaced when worn.

**Caution**

Potential Severity: Light
 Potential Loss: Environmental
 Hazard Category: toxic corrosive hazardous substances

Do not use quick release type swabbing heads during swabbing operations. If the tools are being blown up the hole, the quick release type swabbing head can be released and permit well fluids to flow to the atmosphere.

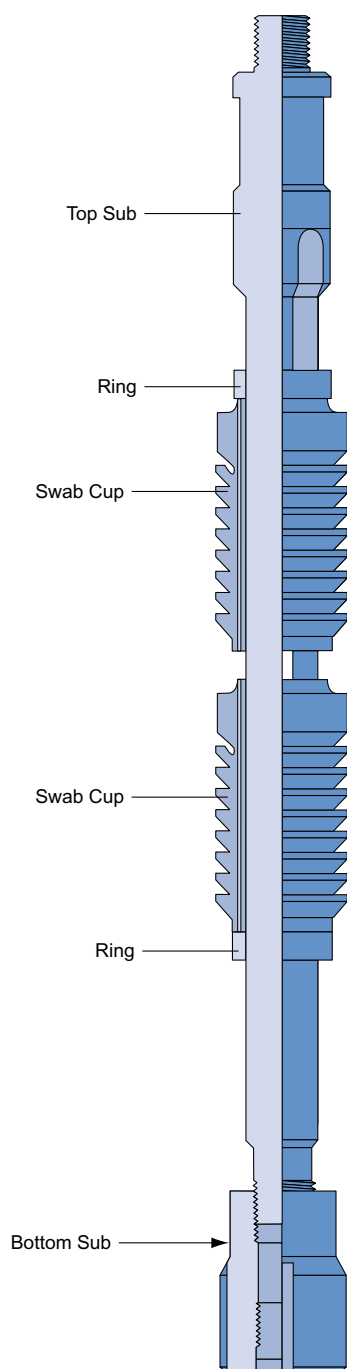


Figure 14-22: Swab Mandrel

Swab cups come in a number of sizes and styles. Cups with steel fingers should be avoided. Tubing IDs and nipple sizes must be addressed to ensure proper size swab cups are used. For intermediate sizes, cups may be turned down by a machine shop.

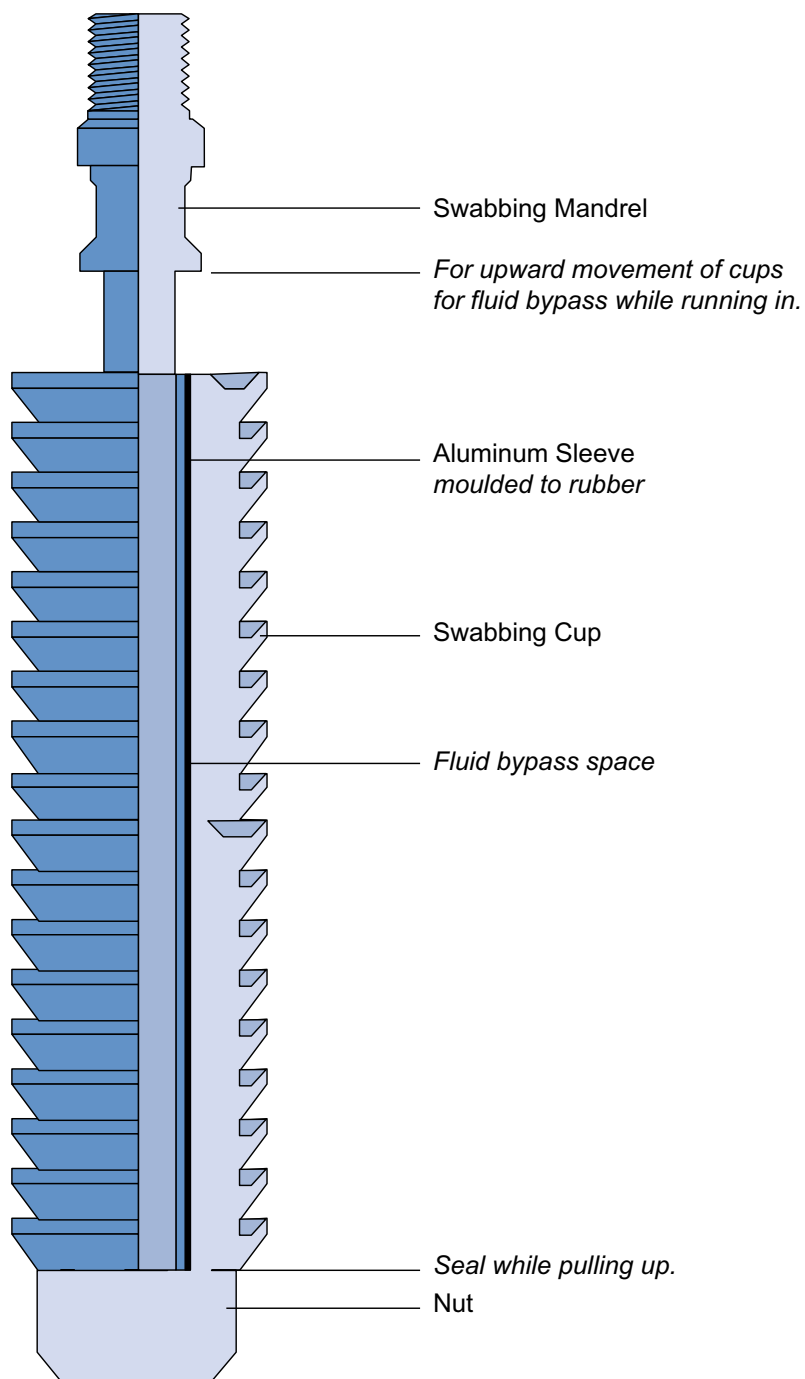


Figure 14-23: Swabbing Tool

Intentionally Blank

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15 FISHING

15.1 Introduction

Many fishing operations are conducted under circumstances of urgency that bring additional pressure to the personnel designing and executing the job. To ensure that a thorough and logical approach is maintained the following guidelines should be reviewed during slickline fishing operations.

1. Calmly assess the situation and consider immediate actions to ensure the safety of personnel and security of the well.
2. Establish control of well site events while observing standing and special safety precautions.
 - Gather the facts and job design details:
 - Well bore diagram
 - Depth of tool when wire broke
 - Counter reading with wire at known point
 - Details of lost tool string
 - Review operational circumstances prior to the break
 - Lubricator length and location of zero-point
 - Distance from lubricator to unit
3. Establish lines of communication with client representative, supervisor and rig superintendent.
 - Prepare a plan of action, considering worst case scenarios and potential outcomes
 - Availability of appropriate equipment - function and pressure tested
 - Prepare detailed procedures and contingency plans
 - Select tool string and jars to ensure functionality and contingency release
4. Execute the plan of action
 - Use diagrams to visualize the down hole environment
 - Run tool string at low speed under a high level of control
 - Maintain constant check of weight indicator readings
 - Do not pass the top of wire, start looking for wire 100 ft above calculated depth
 - Maximum ball wire – 5 ft
 - Maintain a close record of wire recovered
5. Evaluate operation.

15.2 Broken Wire Calculations

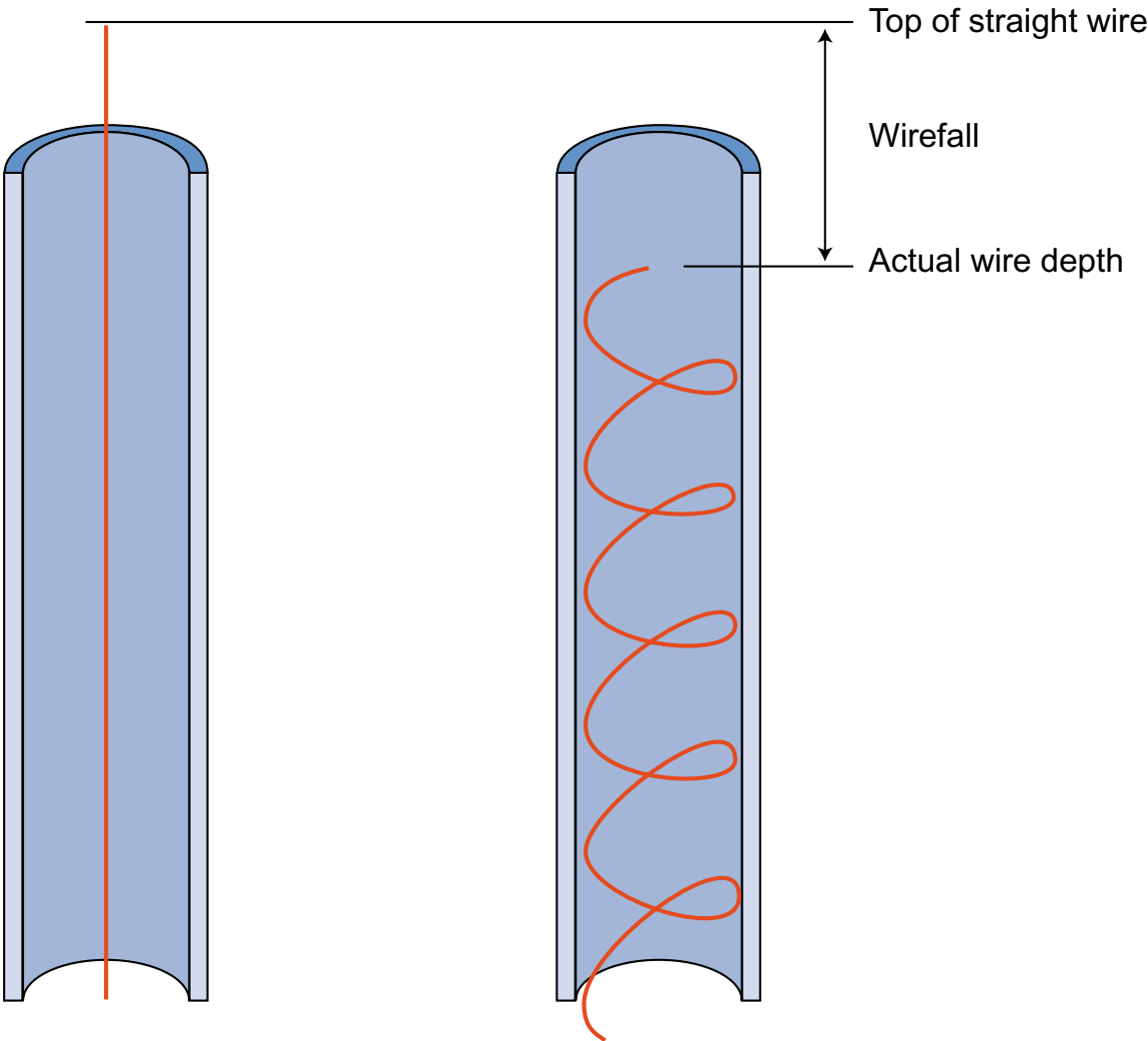


Figure 15-1: Wire Fall Characteristics

Table 15-1: Estimated Wire Fall for Various Tubing Diameters

Tubing Size (in.)	Slickline OD (in.)	Fall (ft/1000 ft)
2 ³ / ₈	0.092	2 - 3
2 ¹ / ₂	0.092	5 - 6
3 ¹ / ₂	0.092	8 - 10
3 ¹ / ₂	0.108	
3 ¹ / ₂	3/16	

Tubing Size (in.)	Slickline OD (in.)	Fall (ft/1000 ft)
4 $\frac{1}{2}$	0.108	8 - 10
4 $\frac{1}{2}$	0.092	
4 $\frac{1}{2}$	3/16	
5 $\frac{1}{2}$	0.108	10 - 14
5 $\frac{1}{2}$	0.092	
5 $\frac{1}{2}$	3/16	
7	0.108	14 - 18
7	3/16	

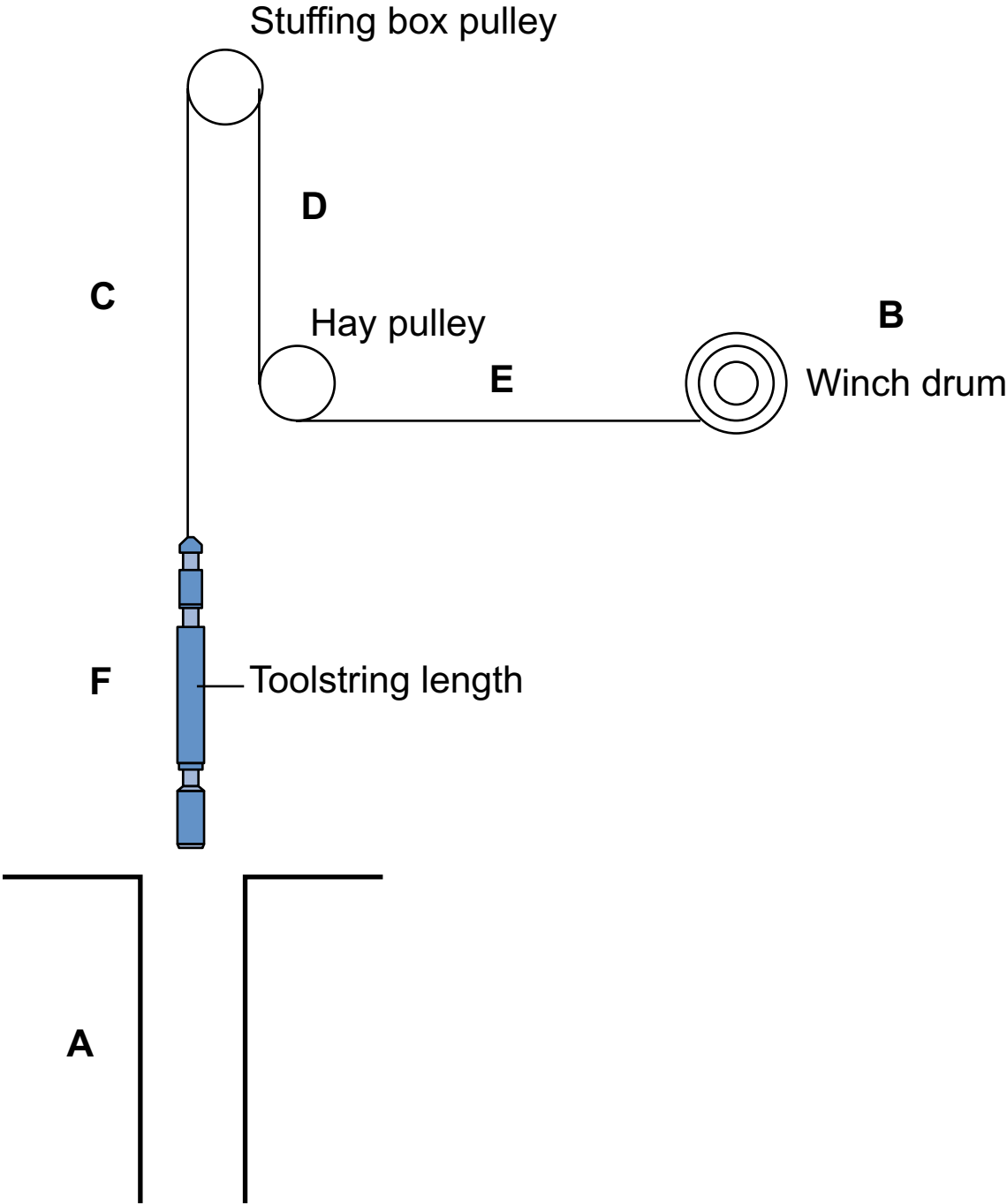


Figure 15-2: Wire Fall Calculations

Where:

A	Depth in hole when wire broke
B	Reading on odometer when wire recovered to know point (our example uses the counter head)

C	Length of wire – tool string to stuffing box
D	Length of wire - stuffing box to hay pulley
E	Length of wire - hay pulley to counter head
F	Length of tool string
G	Wire fallback - depends on wire and tubing size

How much wire is in the well?

$$B + C + D + E = \text{Wire in Well } (W_2)$$

Where is the top of wire?

$$A - (W_1 - G) = \text{depth of wire from zero (Datum Point)}$$

15.2.1 Example (To Calculate Top of Wire)

Scenario - When using 0.092 in. and attempting to retrieve a plug @10,000 ft in 3½ in. tubing, the wire broke.

A	Depth of tool when wire broke = 10,000 ft BRT
B	Reading on odometer when recovered to counter head = 4500 ft
C	Length of wire, tool string to stuffing box - 10 ft
D	Length of wire, hay pulley to stuffing box - 24 ft
E	Length of wire, hay pulley to counter head - 100 ft
F	Length of tool string - 14 ft
G	Wire fallback - 0.092 in. wire in 3½ in. = 8 ft - 10 ft/1000 ft

Using the formula:

Question 1 - How much wire is in the well bore?

$$B (4500 \text{ ft}) + C (10 \text{ ft}) + D (24 \text{ ft}) + E (100 \text{ ft}) = W_1 (4634 \text{ ft})$$

Question 2 - Where is the top of the wire?

A - (W_1 - G)

10,000 ft - (4634 ft - 37 ft) & 10,000 ft - (4634 ft - 46 ft)

10,000 ft - 4597 ft 10,000 ft - 4588 ft

5403 ft BRT 5412 ft BRT

Top of wire approximately 5403 - 5412 ft BRT

If the slickline tool string is stuck:

1. You need first to cut the wire on the rope socket
2. Locate and make a ball (not more than 5 ft)
3. Grab and fish the wire of hole
4. Fish tool string stuck in hole

If the slickline tool string is free

1. Locate and make a ball (not more than 5 ft)
2. Grab and fish the wire of hole
3. Pull out wire and fish



Note

- Use the smallest OD wireline grab when fishing wire
 - Always use a socket on the top of your grab and run it on a RB or JUC Pulling Tool
 - Use a tubular jar in the composition of your tool string when fishing wire
-

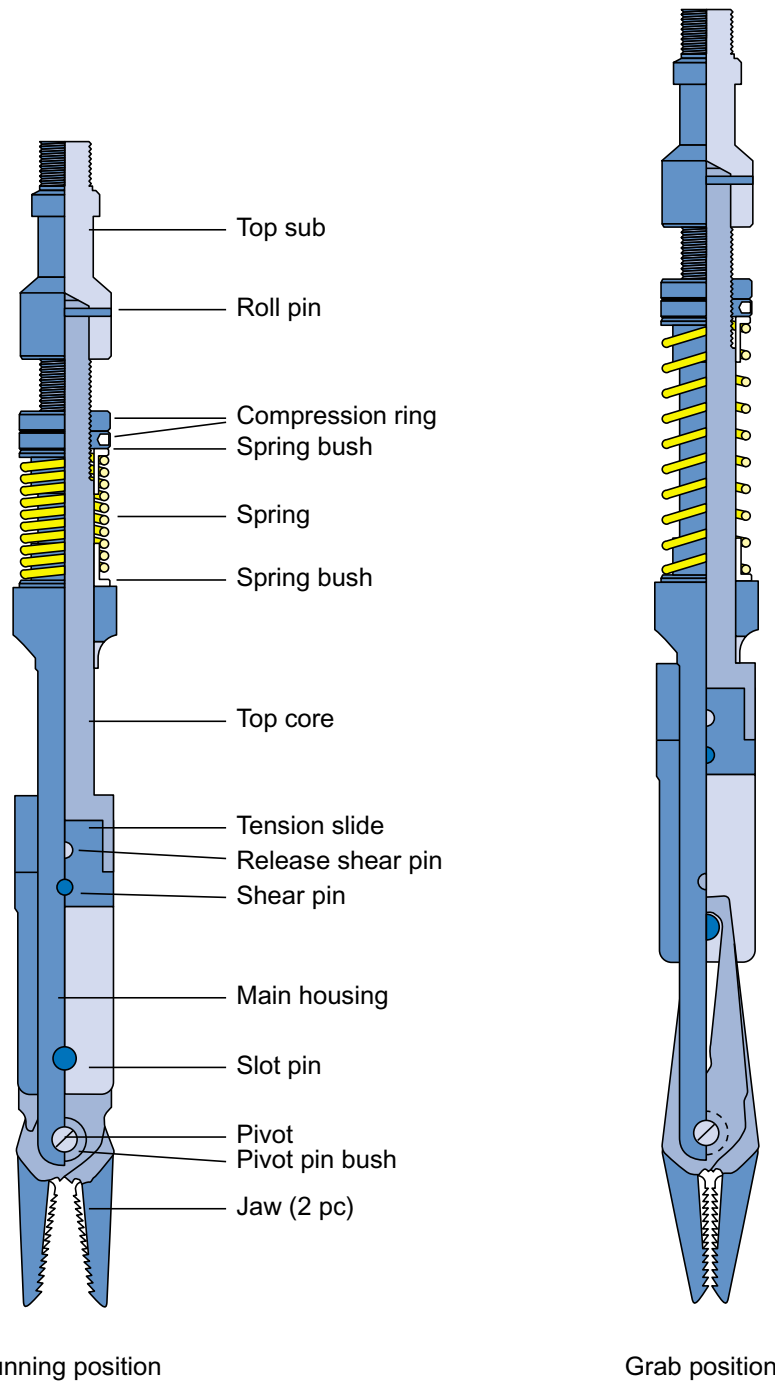
15.3

Fishing Tools

15.3.1

Alligator Grab

The alligator grab operates with a spring powered pincer action to secure small items or wire for recovery. The shear pin activation system enables only a single opportunity per run in the well bore



Running position

Grab position

Figure 15-3: Alligator Grab Running and Closed Positions

15.3.2 Wire Spear

The Center Spear is not recommended for general wire fishing operations. It is made by welding barbs on a pointed rod, staggered around the outside and vertically. This tool can be very difficult to move up the tubing should it be run too

far below the end of the line and become engaged in the wire. The wire above it will ball up and become tighter as it is jarred up the tubing until it is impossible to move it. It cannot be released from its bite once the wire is wrapped around it.

The only time this tool should be used is in a case where the wire is balled up so badly that it is impossible to get hold of it with a two-prong grab. The pointed spear can sometimes be driven into such a ball and break off a small piece at a time until the ball has been loosened enough to be able to move it up the tubing. In this case, it is recommended that the two-prong grab then be used, since it will come nearer to straightening out the wire making it easier to pull.

This tool should also be run with a rope socket and latched into a model RB in case it becomes entangled.

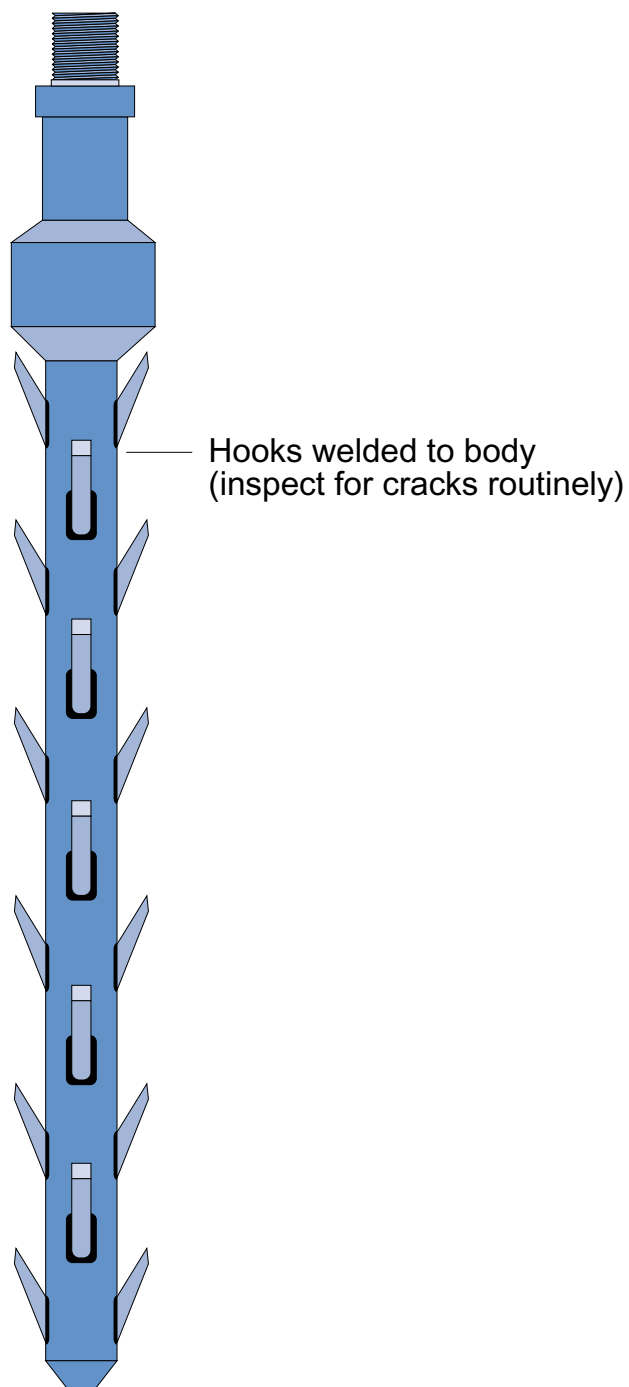


Figure 15-4: Wire Spear

15.3.3 Type C Choke Extractor

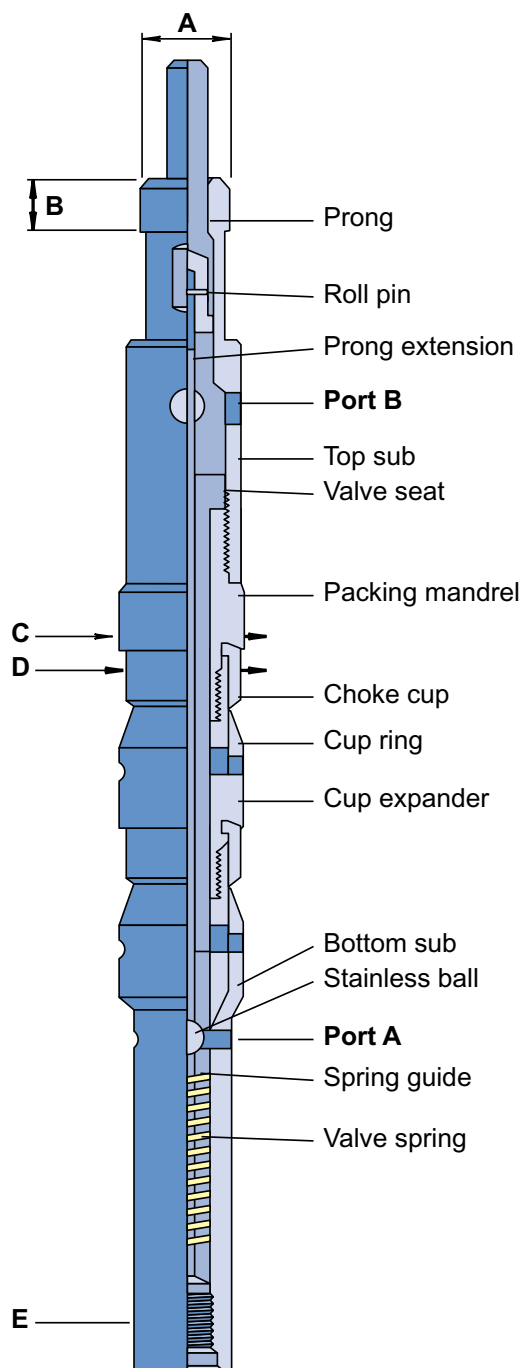


Figure 15-5: Type C Choke Extractor

The type C choke extractor is used in conjunction with existing well pressure to remove the Otis side door choke and certain subsurface controls that may not or should not be pulled by conventional slickline methods.

Table 15-2: Choke Extractor

Assembly No.	Nominal Size (in.)	A	B	C	D	E Thread	Running Tool	Pulling Tool
48C015	1.26	1.00	0.38	1.23	1.27	1 1/8" 11 NC	411406	40RB10
48C014	1.50	1.18	0.56	1.48	1.64	15/16 - 10 NC	411409	40RB14
48C017	1.75	1.13	0.56	1.62	1.62	15/16 - 10 NC	411409	40RB14
48C010	2.00	1.38	0.75	1.84	1.73	15/16 - 10 NC	411407	40RB17
48C012	2.50	1.75	0.75	2.38	2.25	15/16 - 10 NC	411402	40R818
48C013	3.00	2.31	0.76	2.81	2.77	1 1/16-10 NC	411403	40RB19
48C016	4.50	2.31	0.75	3.81	3.81	1 1/16 - 10 NC	411403	40R819
48C013	5.00	2.31	0.75	3.87	3.88	1 1/16 - 10 NC	411403	40R819

15.3.3.1 Operation

The type C choke extractor is run into the well on a conventional slickline tool string with the proper running and pulling tools for the operation.

- The subsurface control that is to be pulled must be identified and the proper pulling tool selected.
- Make up the pulling tool on the lower end of the choke extractor
- Make up the Otis type H running tool on a tool string
- Attach the running tool to the running neck of the choke extractor
- Lower the tool string into well until the subsurface control is contacted.



Note

Anytime the choke extractor is attached to a running or pulling tool, the Prong (1) is forced downward pushing the Ball (12) off seat. This will allow a fluid by-pass through Ports A and B.

When the subsurface control is contacted, downward jarring will move the choke cups over the expander forcing them against the inside tubing wall.

This same jarring action should disengage the control from the nipple and release the running tool. The tool string may now be retrieved.

When the running tool disengaged the extractor, the ball will move back on seat. This will allow a differential to be applied under the extractor by flowing the well through the surface choke. As the well is flowed at the surface, the differential will force the choke out of the nipple and flow the tools up the tubing. As the tools approach the surface, the well is shut in, stopping the tools about one thousand feet below the surface.

The running tool should be replaced by a pulling tool and the extractor and controls removed from the well by conventional slickline methods.

**Note**

Caution should be used before attempting to latch the pulling tool to the extractor after flowing it up the tubing since a pressure differential may still exist. There is a small port in the valve seat immediately above the threads to allow pressure to equalize but it is small and pressure will equalize slowly.

Also the bottom cup should be left off when running the extractor in fluid due to the construction of the tool. There is no way to move the bottom cup up off the expander by pulling up with the pulling tool. This cup would ride down on the expander and in some cases prevent pulling until the cup is torn off.

15.3.3.2 Disassembly

1. Place the assembly in a vise gripping on the packing mandrel and remove the top sub.
2. Pull out the prong and prong extension.
3. Hold a back up on the valve seat and remove the bottom sub and shake out the ball, spring guide and spring.
4. Pull out the valve seat and remove the cup expander.
5. Remove the upper cup ring and cup.
6. Place the cup expander in a vise and remove lower cup ring and cup. Clean and inspect all parts thoroughly.

15.3.3.3 Assembly

Replace the choke cups with new ones and assemble in reverse order of disassembly.

15.3.4 Schlumberger Cable Cutter

A cable cutter is used when a line must be cut in the well. The Schlumberger cable cutter is run under its own weight, guided by the wire. When the cable cutter strikes the tool, it cuts the wire and wedges the upper portion so that the cable cutter can be pulled out with the line. There are two models of the cable cutter: one designed for use with slickline and the other for stranded line. The Schlumberger cable cutter is usually used in the standard version. Where there is a risk of cutting the line at an interface, it can be used in the interface version with its go-devil.

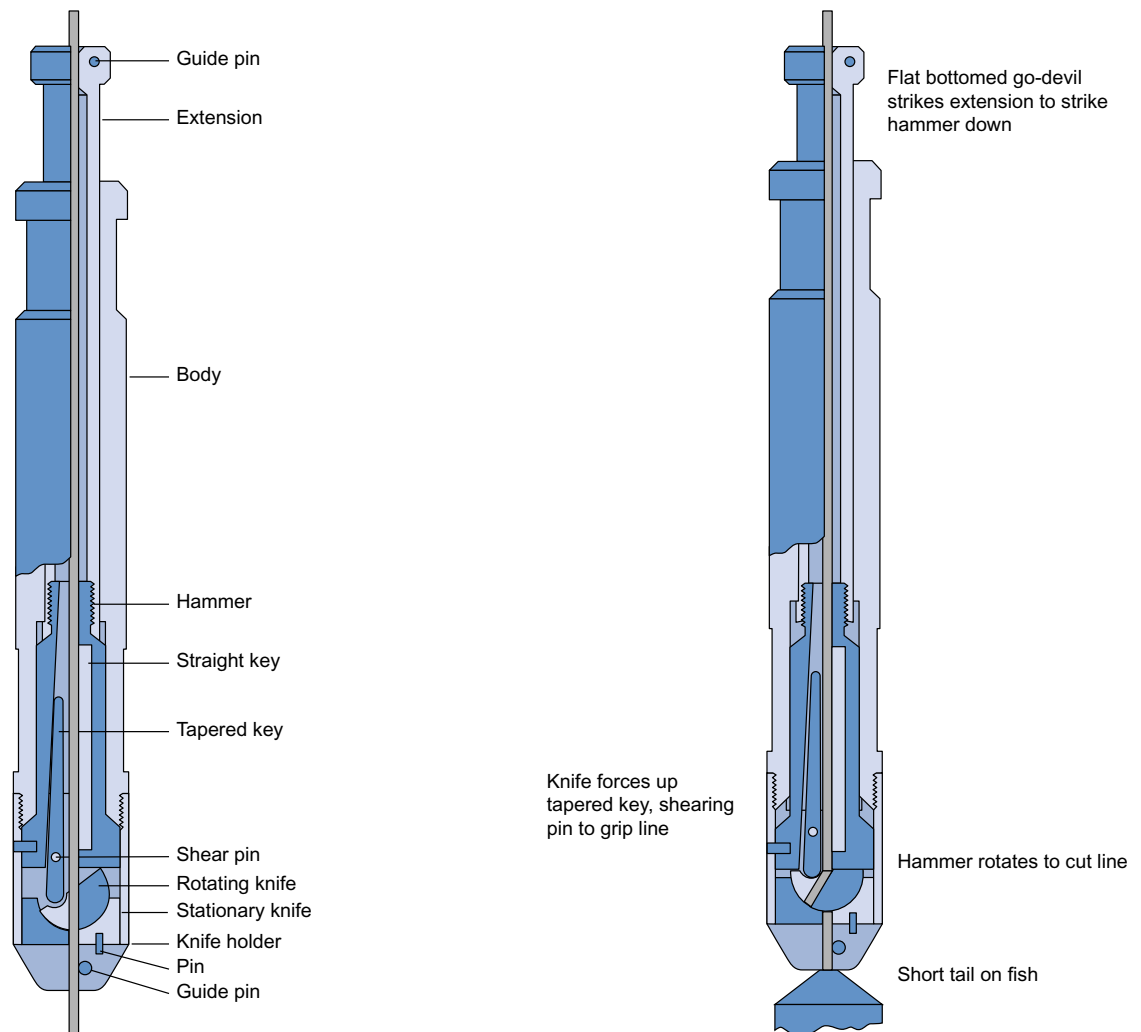


Figure 15-6: Schlumberger Cutter

When the cable cutter strikes the socket of a stuck tool, the shock provided by the inertia of the hammer shears the pin. The hammer of the standard version is used as a go-devil in the interface version. The shock is transmitted to the

rotating knife, which shears the wire. The rotation of the knife pushes up the tapered slip, which wedges the wire. At the end of the rotation movement of the knife, the wire is cut, bent and wedged in the cable cutter. It can then be pulled out with the cutter.

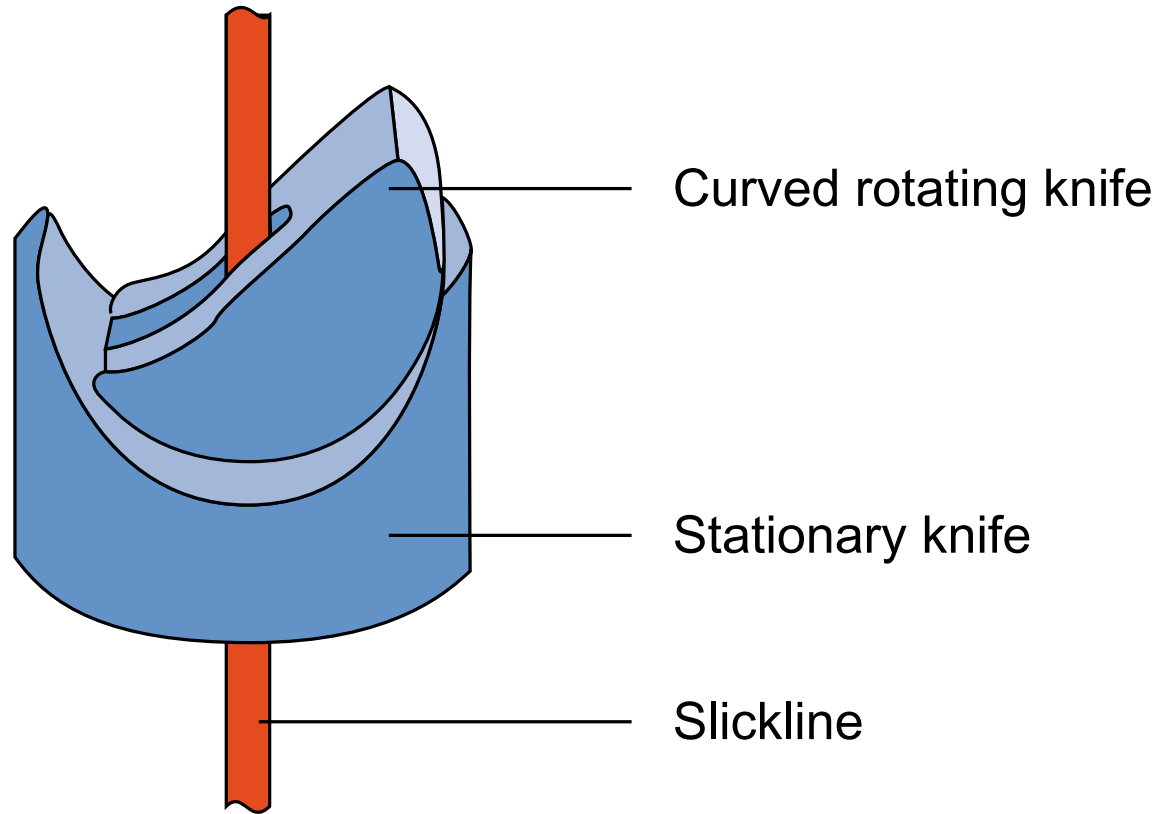


Figure 15-7: Cutter Mechanism Detail

Schlumberger cable cutters have the following advantages:

- No danger of cutting at an interface
- Do not cut against the tubing
- Wire cutting and cable cutter recovery are carried out in the same operation
- Clean wire cutting by shearing is obtained even with regular use over a long period, thanks to the shape of the knives (see [Figure 15-7 Cutter Mechanism Detail](#)).
- Wire is cut short near the socket - 1-in. making unobstructed latching possible
- The cutting force is provided by the momentum rather than an outside energy supply.

The curved knife provides a shearing cutting force on the line. As the knife rotates it bends the end of the wire, which provides an additional means of retaining the cutter further to the wedge.

The following precautions should be observed:

1. ALWAYS COVER THE HOLE WHEN ASSEMBLING THE TOOL ON THE WIRE.
2. CHECK the tool/tubing sizes to ensure the tools cannot bypass the wedge.
3. Pull a light bind on the wire during dropping/cutting (equal to the jars open weight).
4. Depending on fluid – allow approximately one minute per 300 m for the cutter to drop.

Table 15-3: Cable Cutter General Specification and Dimensions

Cable Cutter	Wireline		Standard Line	
Version	Standard and Interface		Standard and Interface	
Assembly number	M-802709		M-802721	
Capacity	0.072 - 0.082 - 0.092 0.102 - 0.105 - 0.108		0.187 - 0.219 - 0.250	
OD	1-29/64 in.		1-3/16 in.	
Length	26.5 in.	11.25 in.	52.875 in.	16.625 in.
	with hammer	without go-devil	with hammer	without go-devil
Go-devil	-	23.625	-	47.25
Weight	10.5 lbm	4.5 lbm	32.5 lbm	9.5 lbm
	with hammer	without go-devil	with hammer	without go-devil
Go-devil weight	-	9.5 lbm	-	29.5 lbm
Remark	The line is cut 1 in. from the rope socket		The line is cut 2 in. from the rope socket	

Table 15-4: Cable Cutter Components

Rep.	Design	Slickline (M-802709)	Braided Line (M-802721)
1*	Knife holder	M-802700	M-802710
2*	Fixed knife	M-802699	M-802716
3*	Rotating knife	M-802701	M-802712
4*	Tapered key for 0.072-in.	M-802804	-

Rep.	Design	Slickline (M-802709)	Braided Line (M-802721)
	Tapered key for 0.082 in.	M-802705	-
	Tapered key for 0.092 in.	M-802805	-
	Tapered key for 0.102 in.	M-812423	-
	Tapered key for 0.105 in.	M-812424	-
	Tapered key for 0.108 in.	M-813980	-
	Tapered key for 0.125 in.	M-873365	-
	Tapered key for 3/16 in.	-	M-802711
	Tapered key for 7/32 in.	-	M-802801
	Tapered key for $\frac{1}{4}$ in.	-	M-802802
5*	Shear pin $\frac{1}{8}$ in. brass	G-823980	-
	Shear pin 1/16 in. brass	-	G-823556
6*	Parallel key	M-802702	M-802717
7*	Long sinker bar	M-802708	M-802719
8*	Plug	M-802698	M-802718
9	Hammer	M-802701	M-802715
10	Slickline guide	M-802121	M-800832
11	Hammer retainer	M-801121	M-802714
12	Short sinker bar	M-802706	M-802720
13	Extension piece	M-802707	M-802713
14	Screw HC MS x 0.8 - 10	M-802703	G-824867
15	Screw HC M8 x 12S - 12	G-820401	G-824867

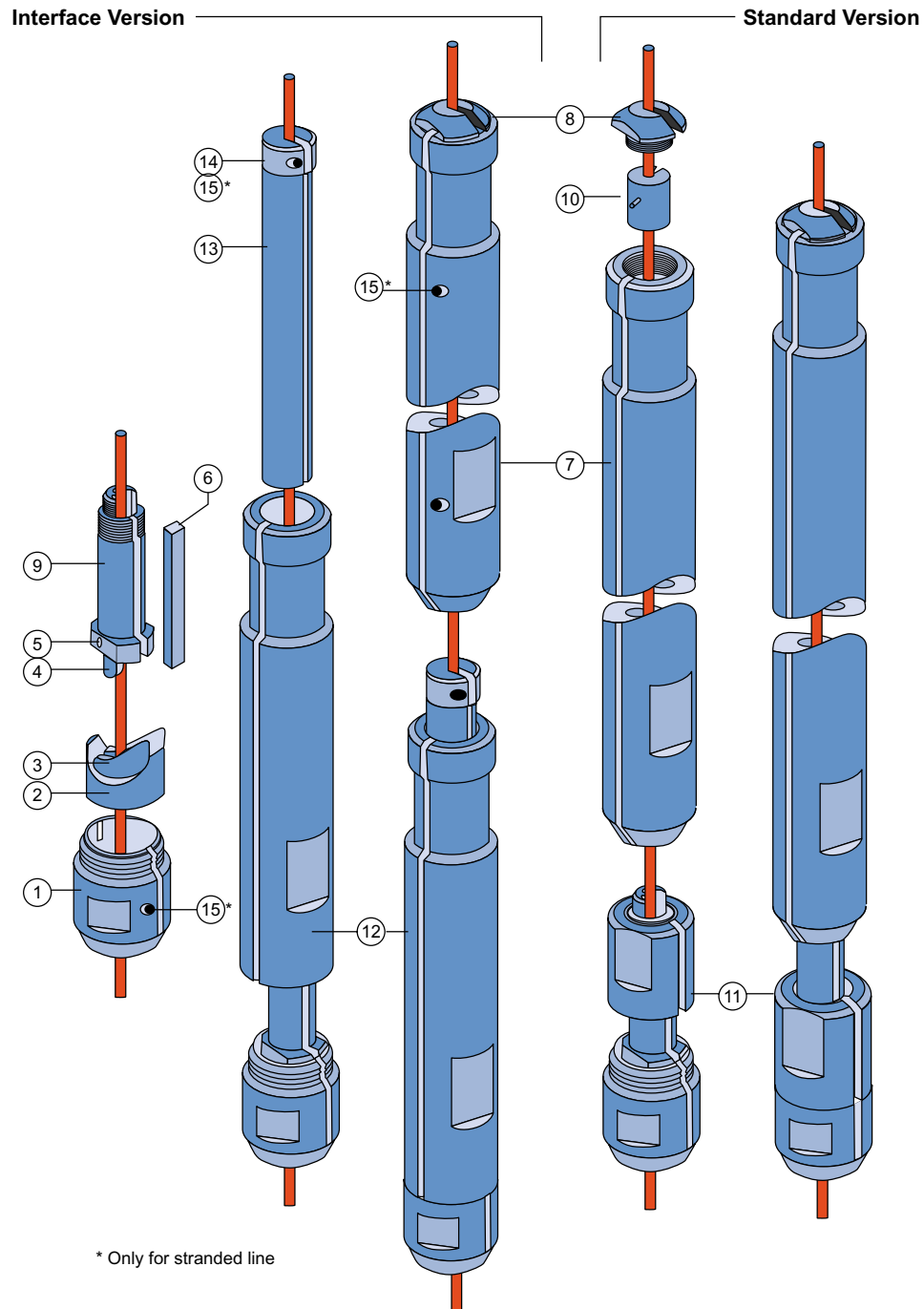


Figure 15-8: Schlumberger Cable Cutter Interface and Standard Versions

15.3.5 Sidewall Cutter

The sidewall cutter is designed to run down the well beside the broken wire and cut against the tubing wall.

This tool can be run on a shear down tool (SB) or on a C running tool. The cutters have a shear pin which prevent them expanding prematurely.

Cut wire must be recovered before any attempt is made to pull this cutter, as the loose end of the wire would ball up ABOVE the cutter.

When running, it is advisable to use a rope socket with only $1\frac{1}{2}$ in. wraps. It is possible for the cut end of the wire to become entangled in the tool string and the use of this weak rope socket knot will allow the tool string to be left behind.

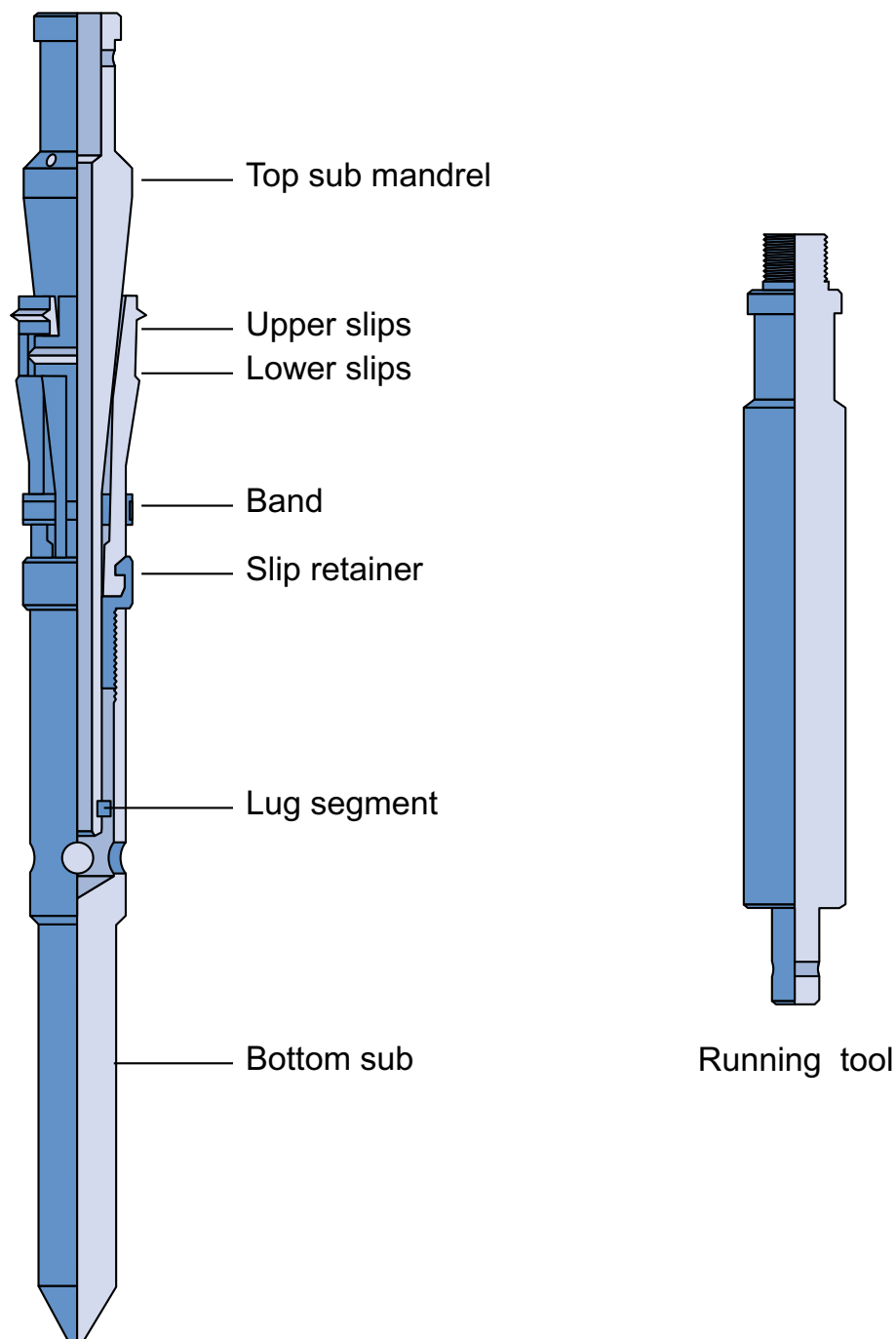


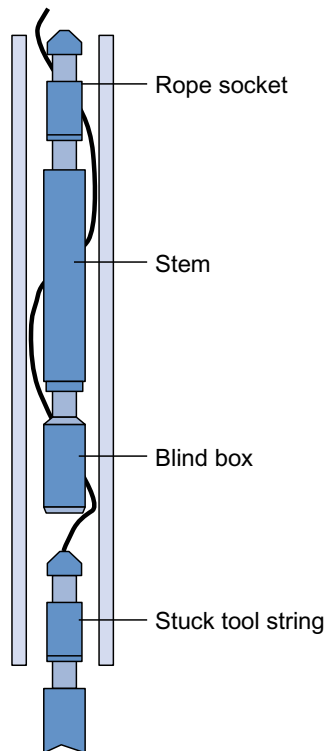
Figure 15-9: Sidewall Cutter and Running Tool

15.3.6 Cutter Bar

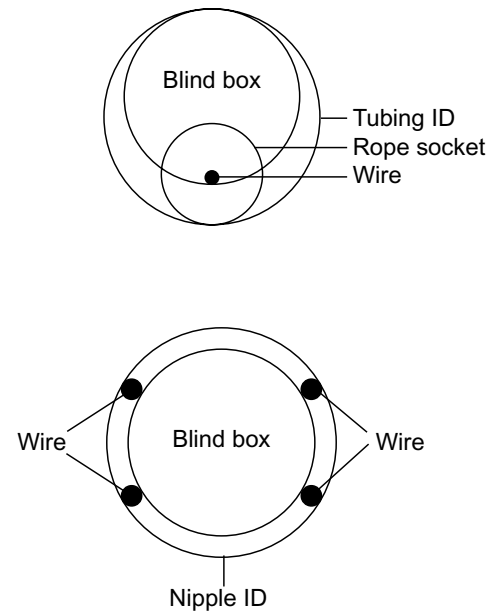
The cutter bar consists of one or more lengths of slickline stem, which has a blind box attached to its lower end and a slickline socket made up on the upper end.

The purpose of the cutter bar, when dropped is to cut the wire at the top a slickline socket of a tool string, which cannot be retrieved.

The blind box has to be of a size that will hit the wire at the rope socket, bending it sharp enough to cause the wire to break. Also, having a blind box that is too large can be a problem. How to determine the right size blind box is a matter of simple calculations.



Cutter bar assembly



Blind box sizing

Figure 15-10: Cutter Bar Assembly and Blind Box Sizing

Example (Minimum Blind Box Size):

Tubing size is $2\frac{7}{8}$ in. having an ID of 2.441 in., the tool string has an OD of 1.5 in. (which has a fishing neck OD of 1.375 in.), and the wire OD is 0.108.

Formula for finding Minimum blind box size is:

$$\text{Tbg. ID} - (\text{Rope Socket}/2) + (\text{Wire}/2) = \text{Blind Box Size}$$

Or using the example:

$$2.441 - (1.375 / 2) + (0.108/2) = 2.441 - 0.6875 + 0.054 = 1.8075 \text{ in. Blind Box}$$

When considering the largest blind box for any application, the possibility of a landing nipple and four strands of wire. The standard nipple size for that tubing is 2.313 in. ID.

Use the formula:

Nipple ID - (Wire OD x 4) = Max. Blind Box

2.313 - (0.108 x 4)

2.313 - 0.4320 = 1.8810 in. Blind Box

Conclusion:

Blind box size range is from 1.8075 in. to 1.8810 in.

The cutter bar can be dropped from the surface or run part-way in the well and dropped at some point above the stuck tool string (using a RB pulling tool minus the core spring, a SSB without a shear pin, a UO pulling tool adjusted as and SB minus the shear pin, or using a gauge ring and string.) When the desired depth is reached, simply bounce the tool string to release the cutter bar.

Determine the method used is a matter of considering the following factors:

- Is there fluid in the well? At what depth?
- How heavy are the well fluids?
- Is the well straight or deviated?
- What are the depths of the landing nipples?
- Are there side pocket mandrels in the well?

These factors are considered in the following manner:

1. How fast will the cutter bar be traveling when it hits the fluid? Is there any possible damage that can occur when the cutter bar is traveling at that high rate of speed?
2. How much weight bar is needed for the bar to travel down hole in that heavy fluid? (Note: It will be much less than tool string weight because you don't have to overcome wire drag in the stuffing box.)
3. Will extra weight bar be necessary in the deviated portion of the well?
4. If there is a possibility of damaging the landing nipple or cutting the wire at the landing nipple due to the speed in which the cutter bar is traveling?

5. Is there a possibility of damaging the side pocket mandrel or cutting the wire at the SPM due to well deviation and speed of the cutter bar?

Due to all things considered, some customers do not allow the use of cutter bars.

But the need to free the wire from a stuck tool string still needs to be accomplished and can be done using the blind box.

The blind box can be attached to the slickline tool string, with a 3 to 5 ft piece of weight bar between the jars and blind box and run down pass the wire to the rope socket to cut the wire.

**Note**

Using this procedure requires careful running of the tool string, traveling in and out of the well at a slow rate of speed so as to keep the wire from balling around the tool string.

Also, using the knot type rope socket with only one and one half wraps for the knot should be considered.

15.3.7 Go Devil

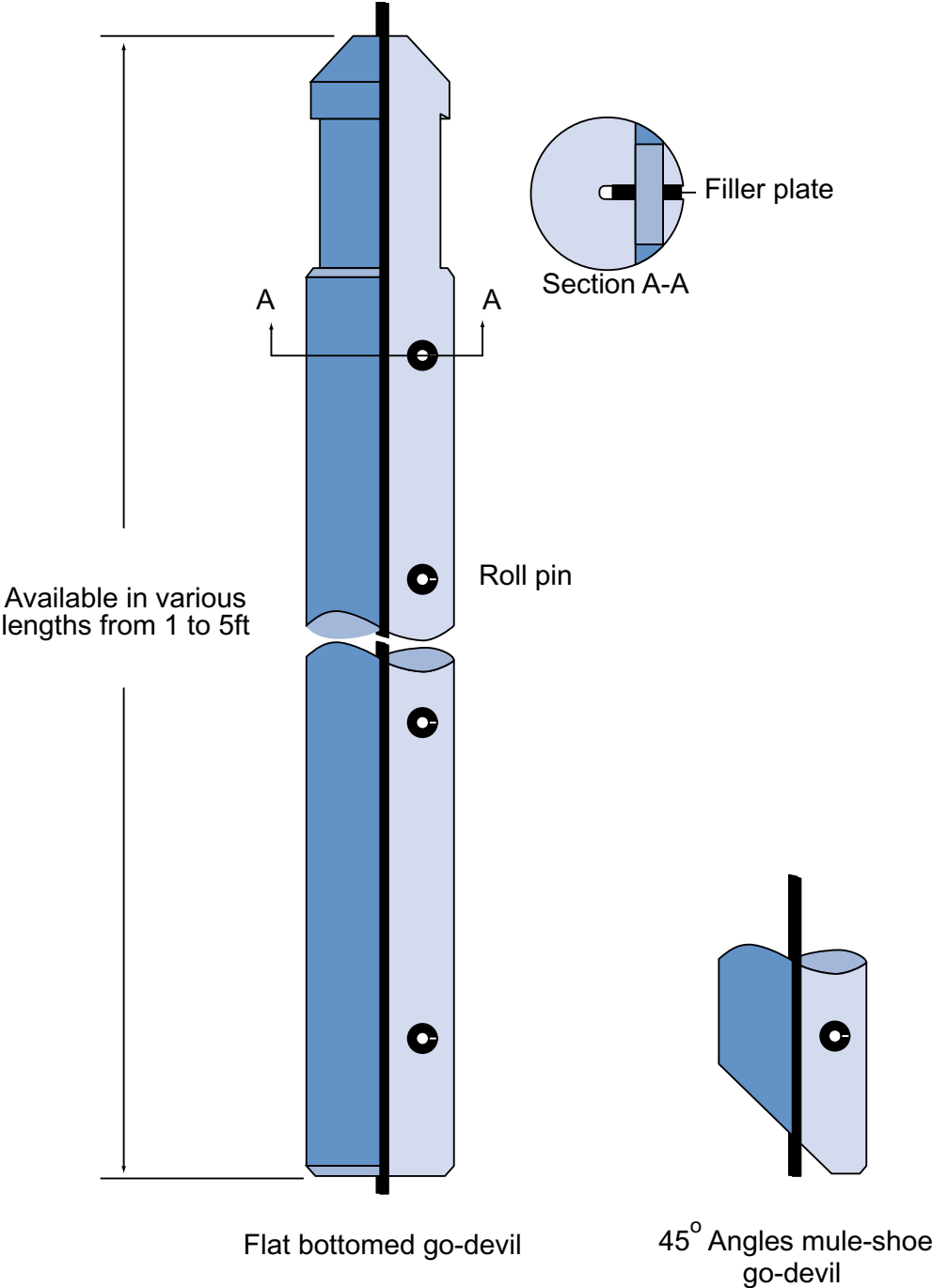


Figure 15-11: Go Devil

15.3.8 Impression Block

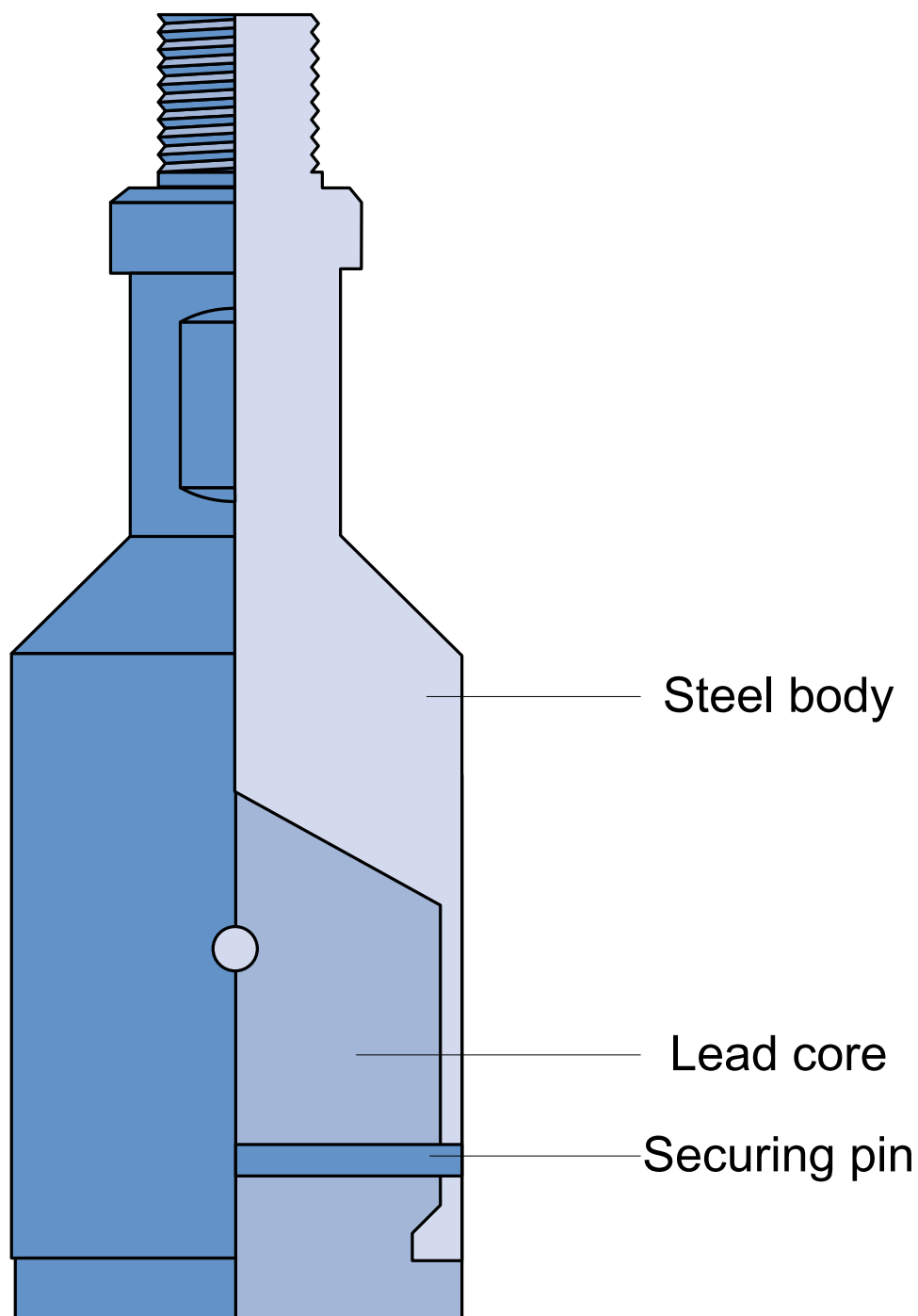
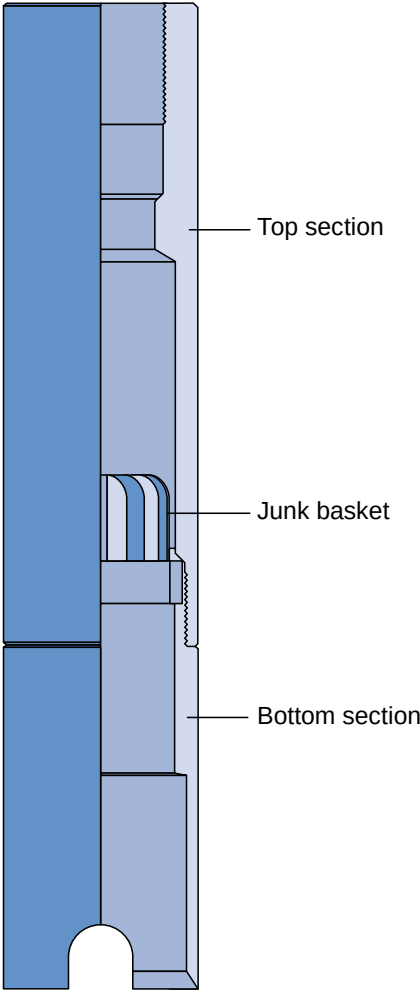
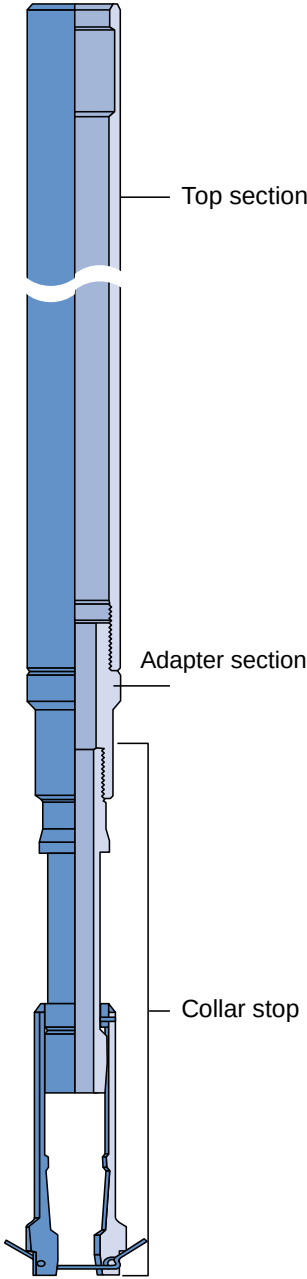


Figure 15-12: Impression Block

15.3.9 Junk Baskets



Junk basket for hydrostatic bailer



Junk basket with collar stop

Figure 15-13: Junk Baskets

15.3.10□ **Magnet**

The magnetic fishing tool is designed to remove small pieces of ferrous metals from the top of tools in the well.

This tool does not have a hole through it for fluid bypass, as do other tools. The magnet is fitted with a sleeve on the outside and a spring, which compresses the sleeve to keep it below the end of the magnet. Upon reaching the depth of the fish, the operator sets the tool string down gently on top of the fish.

The weight of the tool string then forces the magnet down inside the sleeve to pick-up small pieces of wire or ferrous metals that might be lying on top or around the fish.

This is to be retrieved from the well, slowly so as not to lose the particles that has been retrieved.

Magnets will also retrieve metallic scale.

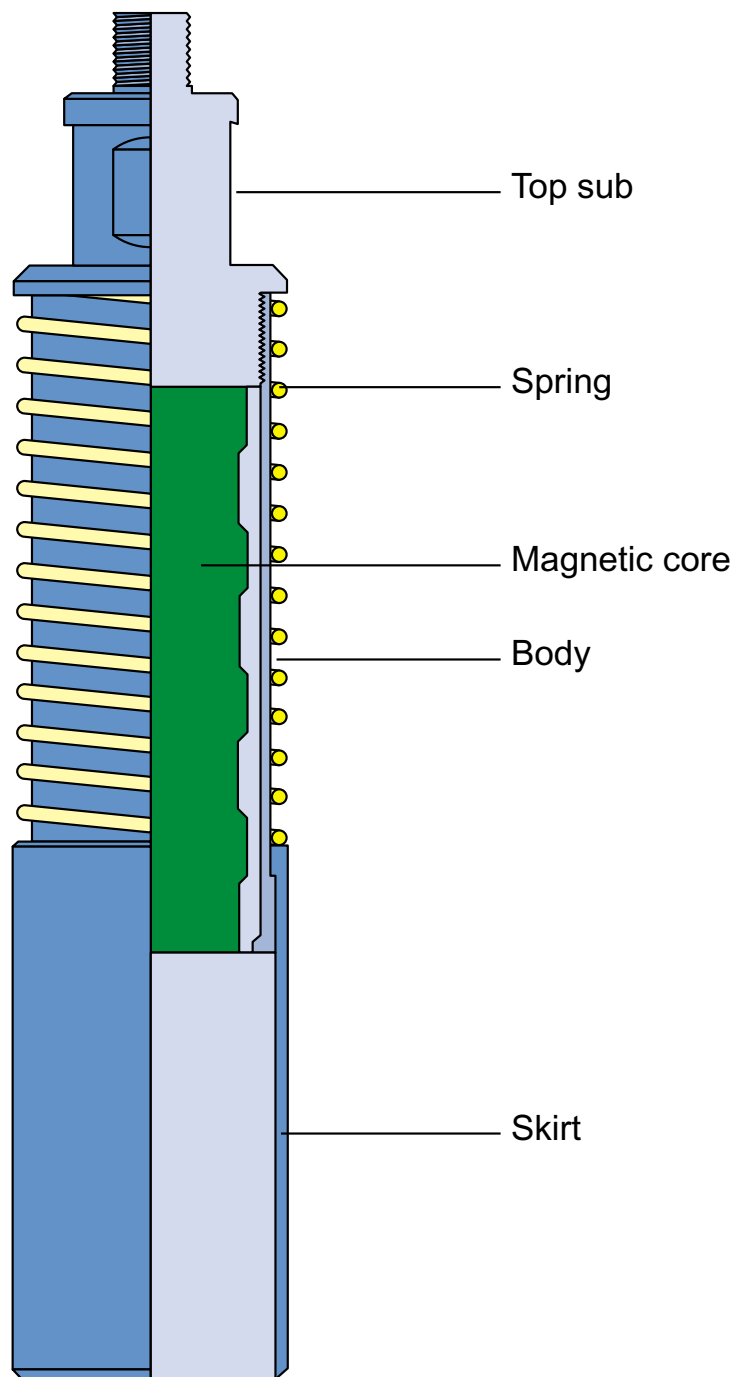
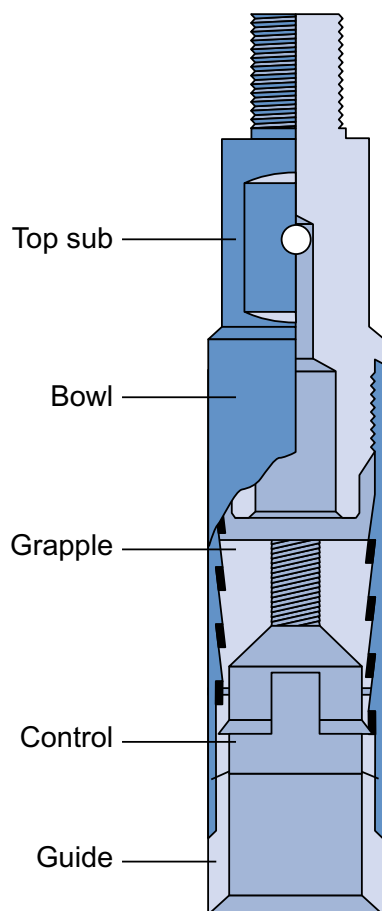
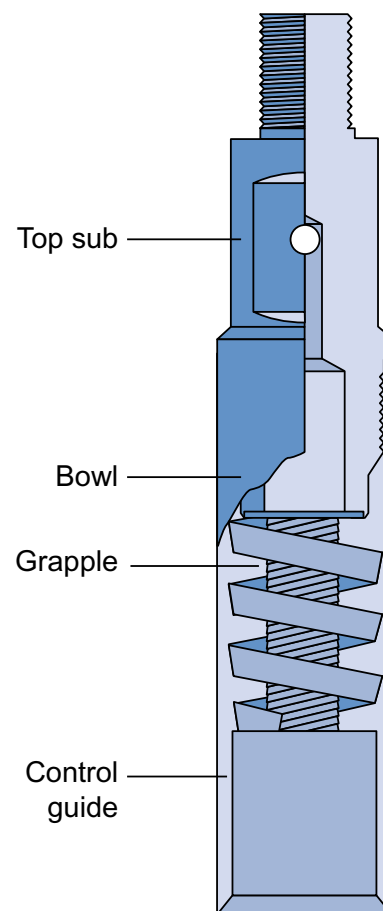


Figure 15-14: Magnet

15.3.11

Bowen Series 10 Sucker Rod OvershotsSeries 10 Overshot
with basket grappleSeries 10 Overshot
with spiral grapple**Figure 15-15: Series 10 Overshot Options**

Series 10 Bowen releasing sucker rod overshoot is the best available tool for engaging and retrieving sucker rods, couplings and similar items from inside tubing strings.

Bowen series 10 overshoot are available in sizes to engage up to 2 in. OD inside of $2\frac{7}{8}$ in. tubing and up to $1\frac{5}{8}$ in. OD inside $2\frac{3}{8}$ in. tubing.

The Bowen series 10 overshoot consists of a top sub, a bowl, a spiral grapple and a control guide. When a basket grapple is used in the series 10 assembly, a basket grapple control and a plain guide are required.

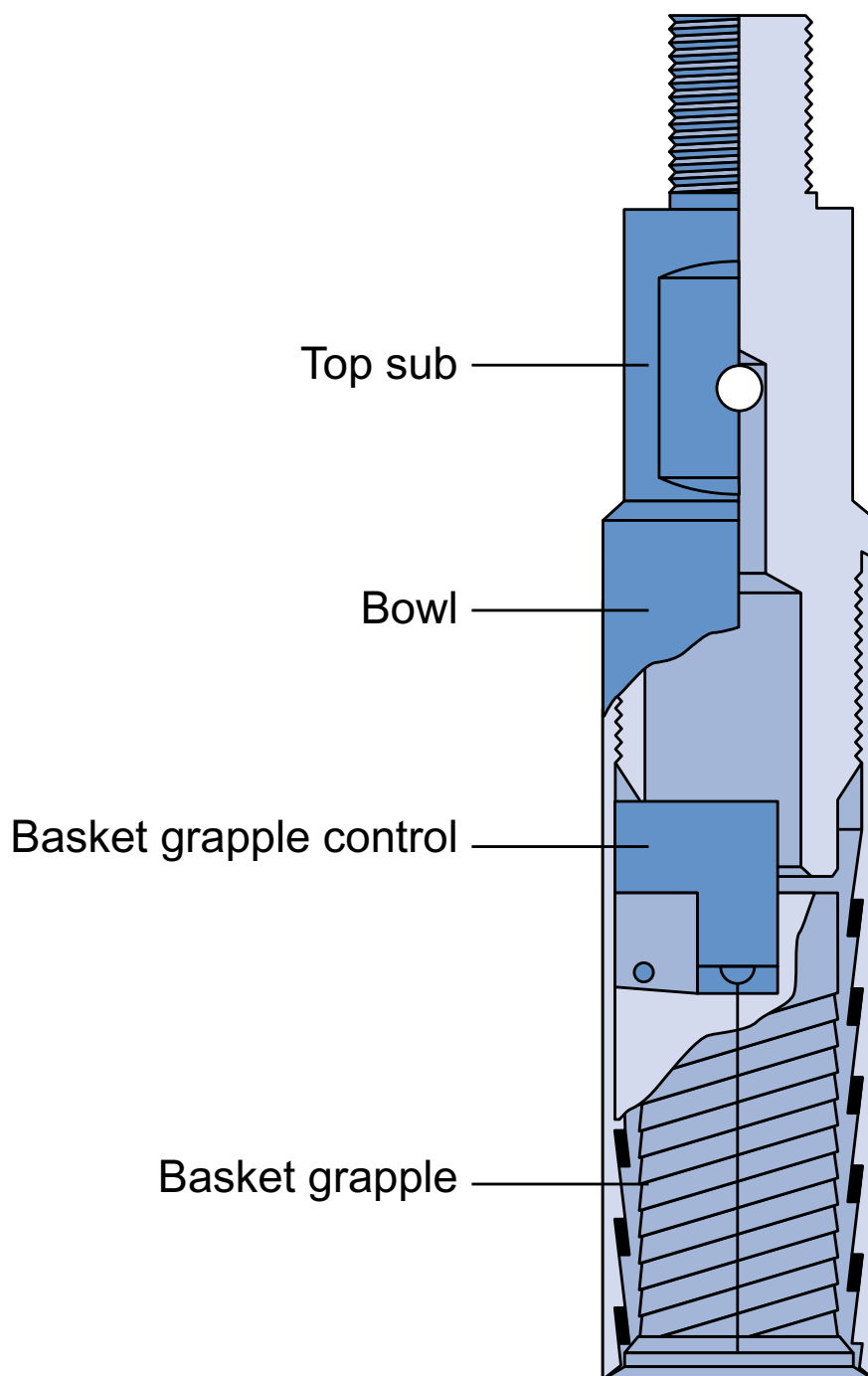
To engage and pull the fish, connect the overshot to the fishing string and run it in the hole and lower it slowly over the fish while rotating slowly to the right. Allow any twist to slack out of the fishing string and then pull on the fish by elevating the fishing string.

To release from the fish, drop the weight of the fishing string heavily against the overshot, the simultaneously rotate to the right and slowly elevate the fishing string until the overshot is clear of the fish. To release from a recovered fish, follow the same procedure while holding the fish below the overshot.

Table 15-5: Series 10 Bowen Short Catch Overshot

SPECIFICATIONS—SERIES 10 BOWEN SUCKER ROD OVERSHOT											
Maximum Catch Spiral	1-1/16	1-1/4	1-1/2	1-1/2	1-5/8	1-5/8	1-13/16	1-15/16	2	2	2-3/8
Maximum Catch Basket	7/8	1-1/16	1-5/16	1-5/16	1-7/16	1-7/16	1-5/8	1-3/4	1-15/16	1-15/16	2-1/16
Overshot OD	1-9/16	1.43	1-25/32	1-29/32	1-29/32	2-5/16	2-5/16	2-1/4	2-5/16	2-7/8	2-27/32
Top Connection Standard	3/4 Rod	3/4 Rod	3/4 Rod	3/4 Rod	3/4 Rod	7/8 Rod	7/8 Rod	7/8 Rod	7/8 Rod	7/8 Rod	7/8 Rod
Type	F.S.	S.H.	S.H.	S.H.	S.H.	F.S.	S.F.S.	S.H.	S.H.	F.S.	S.H.
Complete Part Assembly No.	9790	17985	13940	9990	9340	9880	11480	16070	9400	9530	15860
Weight	4	4	4	4-7/8	5	5	4-7/8	4-3/4	6	6-5/8	6 5/8
REPLACEMENT PARTS											
Top Sub	Part No.	9791	17986	13941	9341	9341	9341	11481	16071	9401	9531 15863
Bowl	Part No.	9792	17987	13942	9991	9342	9881	11482	16072	9402	9532 15861
Grapple (Spiral)	Part No.	9793	17988	13943	9992	9343	9343	11483	16073	9403	9403 9872
Control Guide	Part No	9796	17989	13945	9993	9349	9883	11484	16076	9406	9535
4 BASKET PARTS											
Grapple (Basket)	Part No.	9793	17988	13943	9992	9343	9343	11483	16073	9403	9403 9872
Grapple Control	Part No.	9794	18003	13947	9993	9344	11485	16074	2	9405	9405 9873
Plain Guide	Part No.	9795	18004	13944	9994	9345	9345	11486	16075	9404	9533 15862

15.3.12

Bowen Series 20 Short Catch Releasing Overshots**Figure 15-16: Series 20 Bowen Short Catch Sucker Rod Overshots**

The series 20 Bowen short catch releasing overshoot are designed to catch sucker rods, couplings and the exposed portions of other items, which are too short to be engaged, by the Series 10 or other conventional overshoot.

The overshoot consists of a top sub, a bowl, a grapple control and a basket grapple. It differs from the series 10 in that there is no guide and the grapple control is above the basket grapple, permitting the basket grapple to be placed at the lowermost position in the bowl.

Operation of the series 20 short catch overshoot is identical to that of the series 10 overshoot.

Table 15-6: Series 20 Bowen Short Catch Sucker Rod Overshoot

SPECIFICATIONS—SERIES 20 BOWEN SHORT CATCH SUCKER ROD OVERSHOTS											
Maximum Catch Basket Only	$\frac{7}{8}$	1	$1\frac{1}{4}$	$1\frac{3}{8}$	$1\frac{1}{2}$	1-13/16	$2\frac{1}{8}$	$2\frac{1}{8}$	$2\frac{3}{8}$	$2\frac{1}{2}$	
Overshoot OD	$1\frac{1}{4}$	$1\frac{3}{8}$	$1\frac{5}{8}$	$1\frac{3}{4}$	1-29/32	2-5/16	2-25/32	$2\frac{7}{8}$	$3\frac{1}{8}$	$3\frac{1}{4}$	
Standard Top Connection	$\frac{5}{8}$ Rod	$\frac{5}{8}$ Rod	$\frac{5}{8}$ Rod	$\frac{3}{4}$ Rod	$\frac{3}{4}$ Rod	$\frac{7}{8}$ Rod	$\frac{7}{8}$ Rod	$2\frac{3}{8}$ TUB	$2\frac{3}{8}$ TUB	$2\frac{3}{8}$ TUB	
Type	S.H.	S.H.	S.H.	S.H.	S.H.	S.H.	S.H.	F.S.	S.H.	F.S.	
Complete Assembly	Part No.	17315	25780	28760	18355	11555	17438	18305	20170	20645	22270
Weight		$4\frac{7}{8}$	$4\frac{7}{8}$	5	$5\frac{1}{8}$	$4\frac{7}{8}$	$7\frac{5}{8}$	$7\frac{1}{4}$	$10\frac{1}{2}$	$10\frac{1}{2}$	$10\frac{1}{2}$
REPLACEMENT PARTS											
Top Sub	Part No.	17316	25781	28761	18356	9341	9401	18306	20172	20646	22271
Bowl	Part No.	17317	25782	28762	18357	11556	17439	18307	20171	20647	22272
Basket Grapple	Part No.	17318	25783	28763	18358	11557	17440	18308	18308	20648	22273
Grapple Control	Part No.	17319	25784	28764	18359	11558	17441	18309	18309	20649	22274

15.3.13 Flopetrol Releasing Overshoot

The Flopetrol releasing overshoot will retract the slips and release the fish by jarring down. It has a wide range of slips from $\frac{1}{2}$ in. to $2\frac{7}{8}$ in., to fit two different sizes of overshoots.

- Used to fish slickline tools, which have no fishing neck. It can also be used to fish broken slickline tools, sucker rods etc., which cannot be fished by a magnet.

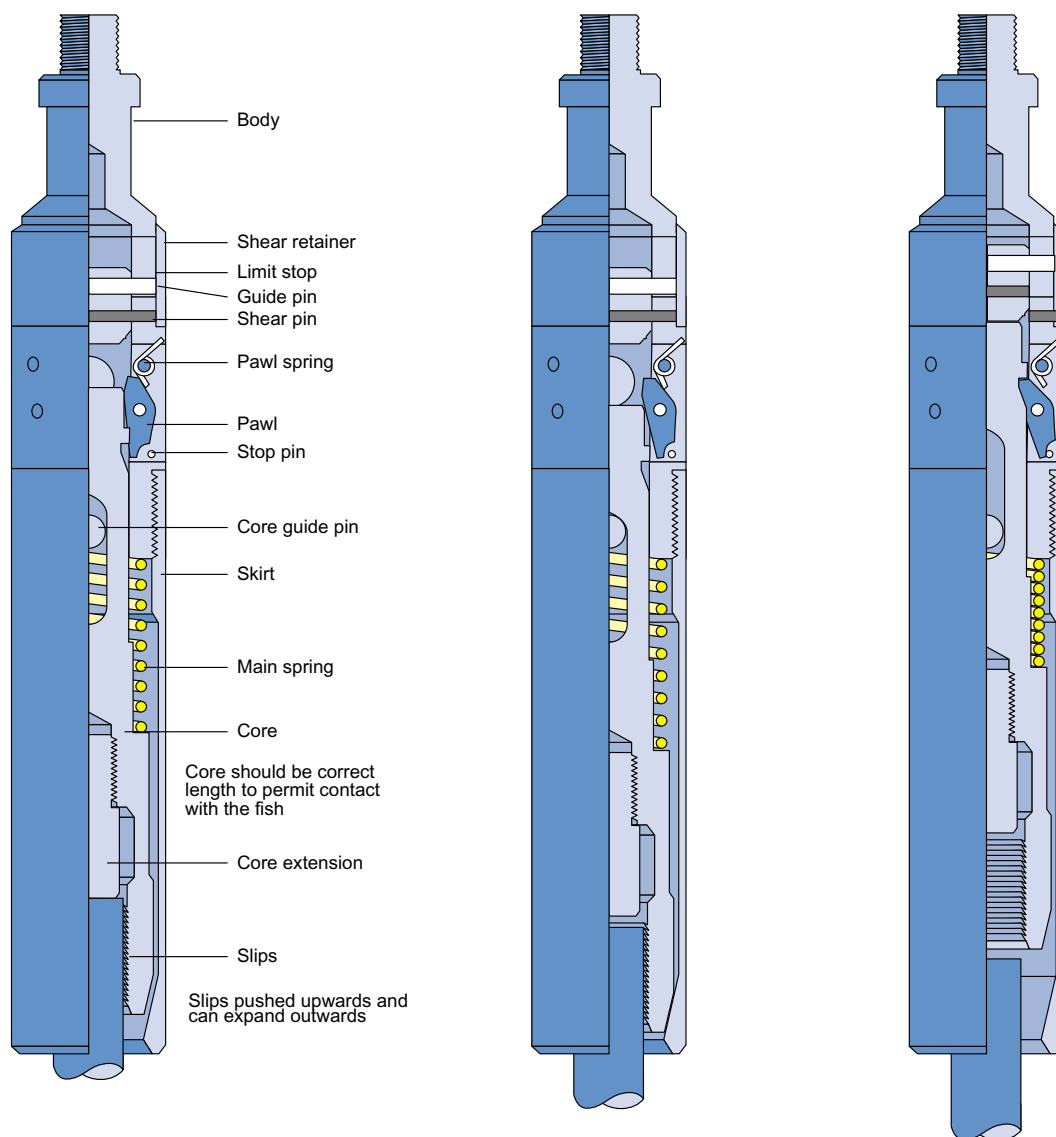
- It can be used in $2\frac{3}{8}$ in., $2\frac{7}{8}$ in., $3\frac{1}{2}$ in. and 4 in. tubing. (Refer to table giving items to be made up together, versus tubing size and fish OD.)

Prior to running the tool check:

- Steel shear pin
- Correct slip size
- Correct core extension (long or short)

**Note**

The choice of the core extension is critical. In order to activate the shear pin, the extension must be in contact with the fish but not the skirt.



Latching: slips engage fish

Pulling: Slips grip

Sheared: Downward jarring.

Figure 15-17: Flopetrol Overshot Latching, Pulling and Sheared Positions

Table 15-7: Replacement Parts

Item	Flopetrol Name (as shown)	QTY	Part Number	Part Number
1	Body (Body)	1	M-805635	M-8065?
2	Sliding slip support (Core)	1	M-804012	M-805??
3	Short core extension	1	M-804167	M-803??
4	Long core extension	1	M-804149	M-803??
5	Spring (Main Spring)	1	M-804249	M-808??
6	Latch spring pin	3	G-820483	G-824??
7	Latch (Pawl)	2	M-804147	M-804??
8	Latch pin	2	G-823585	R-86???
9	Thrust pin (Stop Pin)	2	R-860365	R-860??
10	Latch spring (Pawl Spring)		2 M-803088	M-80???
11	Shear nut (Limit Stop)	1	M-803832	M-80???
12	Shear pin (Shear Pin)	1	$\frac{1}{4}$ in.	1/?
13	Safety ring (Shear Pin Retainer)	1	M-805514	M-80???
14	Slip support guide axle (Core Guide Pin)	1	M-804148	M-80???

15.3.13.1 Operation

Latching

The slips move upwards and slide over the fish until the core extension hits the top of the fish. The spring then pushes the slips tighter.

Pulling

An upward pull sets the slips tighter. The upward jar force is transmitted through the skirt and slips. No tendency to shear the pin.

Shearing

The downward jar action forces the core upwards against the spring. (Considerable jarring is sometimes required) Once the pin is sheared, the two pawls hold the core in the upward position to keep the slips retracted.

15.3.14 O'Bannon Overshot

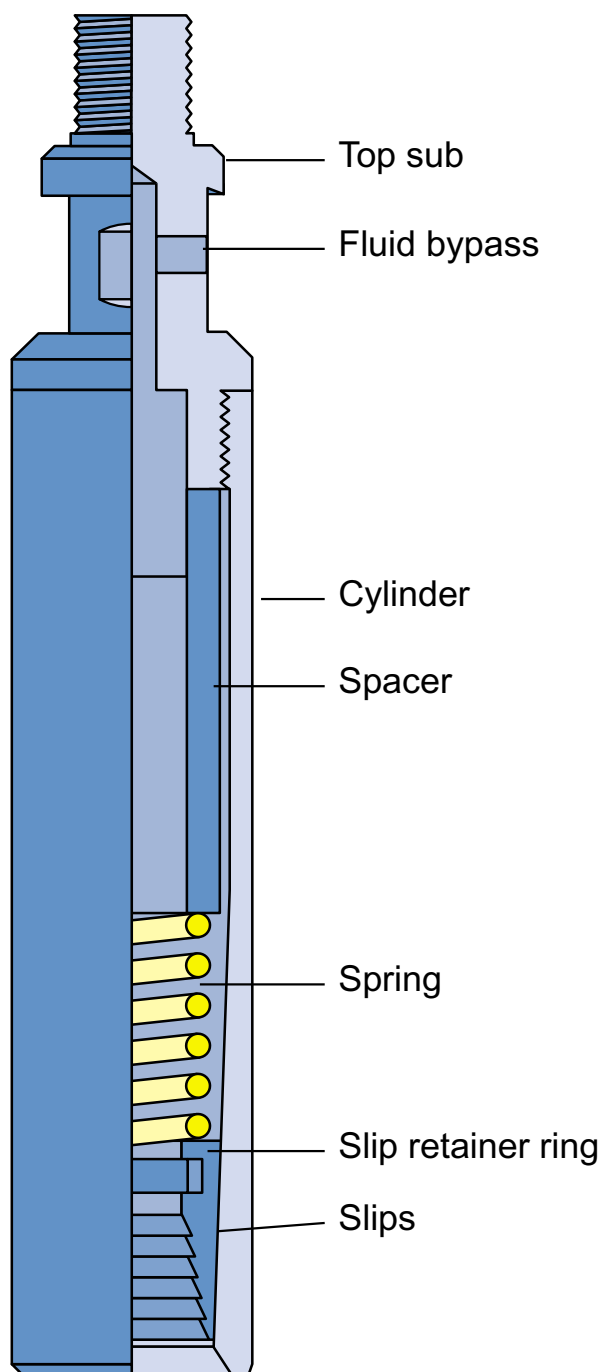


Figure 15-18: O'Bannon Overshot

15.3.15 Petroline Heavy Duty Releasable Overshot

The Petroline heavy-duty releasable overshot has been designed to withstand the high jarring forces created during heavy-duty fishing operations.

The overshot can be released by downward jarring, which shears the pin and engages the internal split collet with the top sub of the slip assembly.

Upward jarring then pulls the slips free of the fish, so that the overshot and tool string can be recovered.

The core is available in various lengths to provide at least $\frac{1}{2}$ in. of downward movement once the slips are latched.

Available lengths include:

- 0.787 in. reach
- 1.287 in. reach
- 4.685 in. reach

The overshot is available in $2\frac{1}{2}$ in. and 3 in. sizes with a range of slip mandrels available in the following sizes:

Table 15-8: Overshot Specification for $2\frac{1}{2}$ in. and 3 in. Sizes

$2\frac{1}{2}$ in.		$3\frac{1}{2}$ in.	
To Fish (in.)	Part No.	To Fish (in.)	Part No.
0.56 - 0.72	440-2500-30-11	1.40 - 1.56	440-2750-30-11
0.70 - 0.83	440-2500-31-11	1.56 - 1.72	440-2750-31-11
0.82 - 0.95	440-2500-32-11	1.72 - 1.88	440-2750-32-11
0.93 - 1.06	440-2500-33-11	1.87 - 2.03	440-2750-33-11
1.04 - 1.18	440-2500-34-11		
1.16 - 1.29	440-2500-35-11		
1.28 - 1.41	440-2500-36-11	1.39 - 1.53	440-2500-37-11
1.51 - 1.64	440-2500-38-11		
1.63 - 1.75	440-2500-39-11		

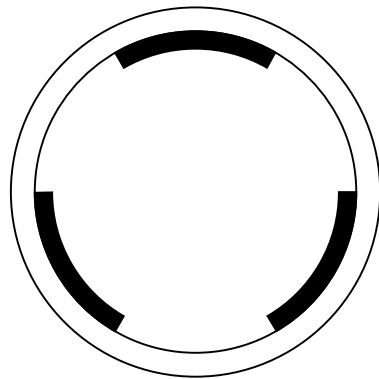
15.3.16 Petroline Heavy Duty Pulling Tool

The Petroline heavy-duty pulling tool has been designed to increase the contact area against the external fishing neck, and therefore spread the load during heavy-duty fishing operations. This reduces the chance of damage to the fishing neck.

The 50% contact area of conventional pulling tools is shown in [Figure 15-19 Pulling Tool Contact Areas](#), compared to the 95% area of contact of the heavy-duty pulling tools.

Conventional pulling tool

50% contact area



Heavy-duty pulling tool

95% contact area

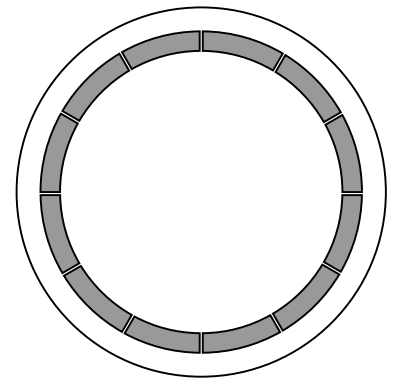


Figure 15-19: Pulling Tool Contact Areas

The core is designed to permit latching of fishing necks with and without threads. (i.e., the equivalent of the Otis B and S cores and Camco C and S cores.)

Downward jarring shears the pin and pushes the finger core upwards to latch into the release collet. This keeps the finger core expanded until the disassembly tool is inserted at the surface to retract the release collet and retract it from the finger core.

15.3.16.1 Resetting Procedure

When the tool is in the sheared/released position:

1. Remove the grub screw and back out the top sub and spring.
2. Insert the disassembly tool by threading it into the top of the release collet.

3. Apply force by rotating the pressure plate of the disassembly tool until the release collet comes free of the finger core.
4. Align the finger core with the shear-pin holes and remove the old pieces of shear pin.
5. Insert a new shear pin.
6. Remove the disassembly tool and insert the spring.
7. Make up the top sub and replace the grub screw.

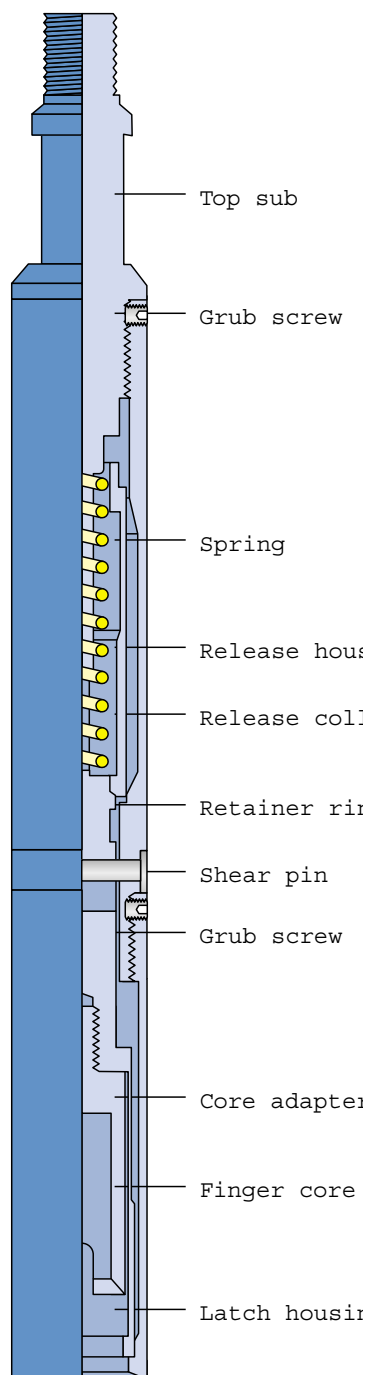


Figure 7-20: Heavy Duty Pulling Tool

15.3.17 PCE Heavy Duty Releasable Pulling Tool

The PCE heavy-duty releasable pulling tool is a collet type-pulling tool used to latch and retrieve slickline tools with badly damaged external fishing necks.

The heavy-duty releasable pulling tool is extremely robust in construction and allows a full 360 degrees of engagement with the fishing neck to be latched. The fishing socket can be released by jarring downward provided a solid footing is available for the core to be driven against.

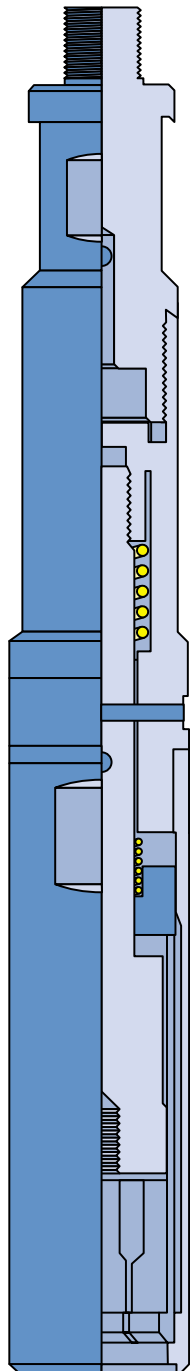


Figure 15-21: PCE Slickline Heavy Duty Releasable Pulling Tool

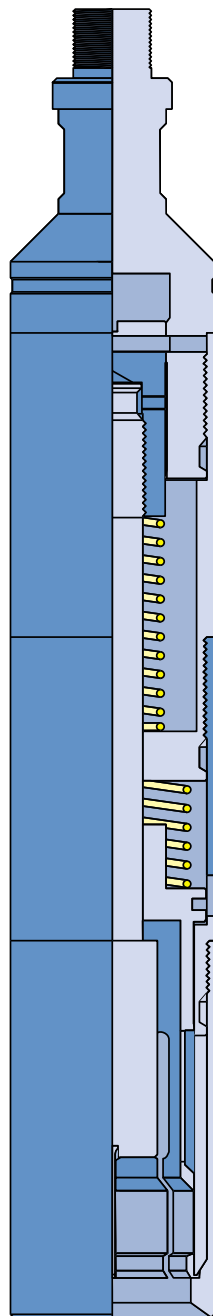
Table 15-9: PCE Heavy Duty Releasable Pulling Tool Specifications

Nominal Size (in.)	Actual OD (in.)	To Catch Fish neck (in.)	Fish neck OD	Top Connection	Product Number
1.25	1.285	0.875	1.187	15/16 UN	B138-029
1 $\frac{3}{4}$	1.750	1.000	1.187	15/16 UN	B138-012
1 $\frac{5}{8}$	1.625	1.187	1.187	15/16 UN	B138-008
2	1.875	1.375	1.375	15-16 UN	B138-003
2.5	2.250	1.750	1.375	1-1/16 UN	B138-002
3	2.870	2.313	2.313	1-1/16 UN	B138-006
4	3.800	3.125	2.313	1-9/16 UN	B138-007

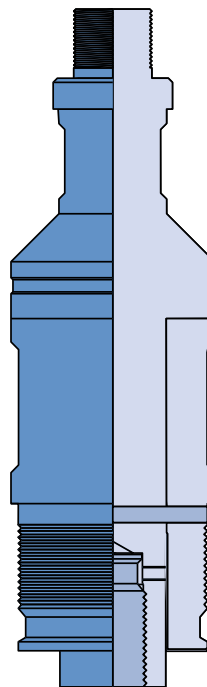
15.3.18 BDK Heavy Duty Pulling Tool

The BDK heavy-duty pulling tool is designed for running and retrieving down hole flow control devices. The tool is based on a collet style slip design to give maximum coverage of the fishing neck and features unique supports between the collet fingers. The supports centralize the fishing neck, preventing it hanging on the collet fingers even in highly deviated conditions.

The tool can be converted from a shear-up tool to a shear-down tool by changing the top sub and is available with a choice of cores, expanding the range capabilities of the tool.



Shear Up Assembly



Shear Down Assembly

Figure 15-22: Heavy Duty Pulling Tool

Table 15-10: Heavy Duty Pulling Tool Specifications

Nominal Size (in.)	Maximum OD (in.)	Core	Reach (in.)	To Fish	Assembly Number
1.250	1.680	Short	0.95	1.000 F/N	9866-**
		Medium	1.53		
		Short	1.09		
1.500	1.875	Medium	1.53	1.187 F/N	7650-**
		Long	2.28		
		Short	1.16		
		Medium	1.52		
		Long	2.52		
2.000	2.125	Extra Long	2.85	1.375 F/N	7422-**
		Heavy Duty	2.93		
		Trinity	3.16		
		Short	1.35		
		Medium	1.52		
		Long	2.65		
2.500	2.500	Extra Long	2.87	1.750 F/N	6223-**
		Heavy Duty	3.56		
		Trinity	3.16		
		Short	1.56		
		Medium	1.56		
3.000	3.050	Long	2.80	2.312 F/N	7651-**
		Extra Long	3.03		
		Heavy Duty	4.58		
		Trinity	4.06		
		Short	1.54		
		Medium	2.03		
4.000	3.800	Long	2.80	3.125 F/N	7652-**
		Heavy Duty	5.04		

15.3.19 Kinley Snapper

The Kinley Snapper is assembled on the wire above the BOP. All pieces are split to enable assembly around the wire.

This upside-down version is used to prevent cutting on the fluid level at restrictions and side pocket mandrels.

A flat-bottomed go-devil is dropped to strike the top cap plunger. This causes the knife to slide the slipper sideways, which slices the wire.

Go-devil and Kinley Snepper are usually recovered in separate runs.

CHECK the ODs of the go-devil, cutter and tool string, to ensure they cannot bypass or become wedged in the tubing ID.

**Note**

Cover the hole when assembling to prevent junk falling down the well bore.

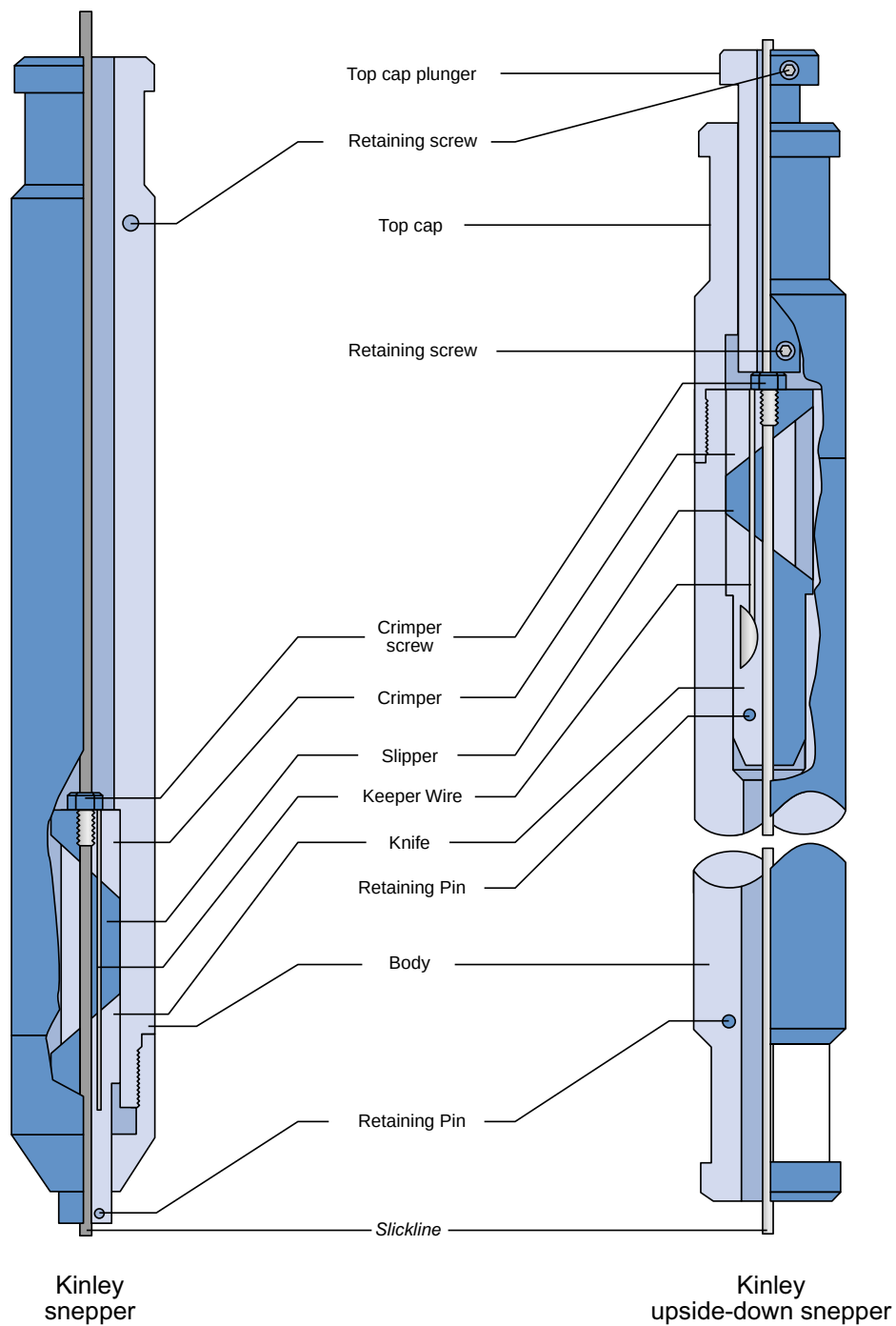
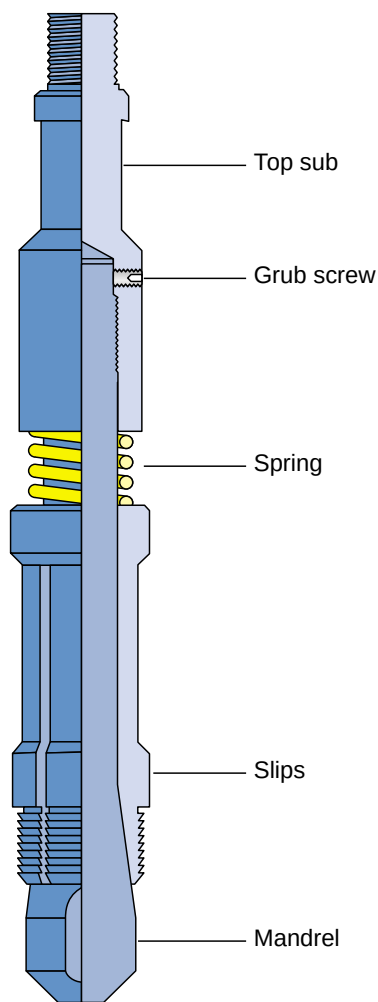
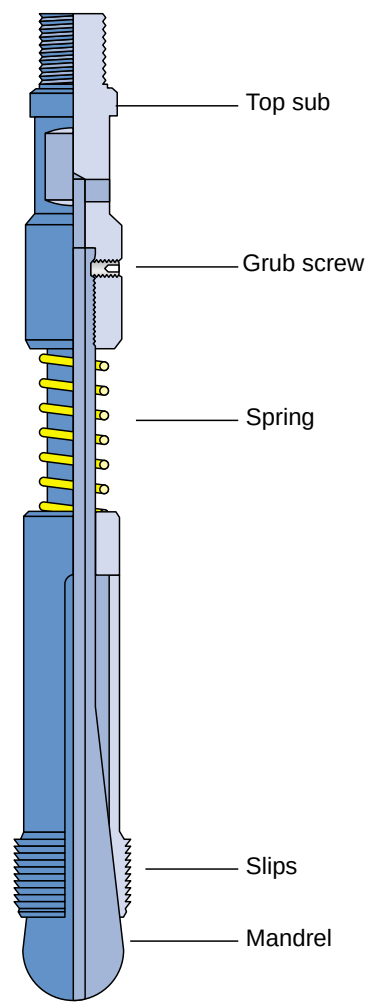


Figure 15-23: Kinley Snepper

15.3.20 Center Spears



Baker Type A Spear



Kendle Spear

Figure 15-24: Center Spears - Baker Type A and Kendle

15.3.21 D&D PR Tool

The D & D PR tool is a releasable bull nose spear. It can be used as either a running or pulling tool. As a running tool, the PR tool can be used to run slickline equipment that has an internal fishing neck. It can be released by jarring down.

As a pulling tool, the PR tool is a versatile fishing tool. It is a very rugged tool that can be released by jarring down to shear the pin. There are various sized dogs that can be interchanged on each tool. The PR tool comes in $1\frac{1}{4}$ in., $1\frac{5}{8}$ in., 2 in., $2\frac{1}{2}$ in. and 3 in.. These tools can also be converted into the GS pulling tool.

The PR-GS tool is essentially the same tool as the PR tool. It is converted by changing the core and the dogs. The PR-GS is used to retrieve slickline equipment utilizing internal fishing necks. The PR-GS has two very special features that are not incorporated in the standard GS fishing tool. They the dogs have a grabbing area of approximately 90% and, as the tool is pulled upward, the dogs are not only forced downward, but also outward. This is accomplished by using a tapered core, essential in the elimination of slippage.

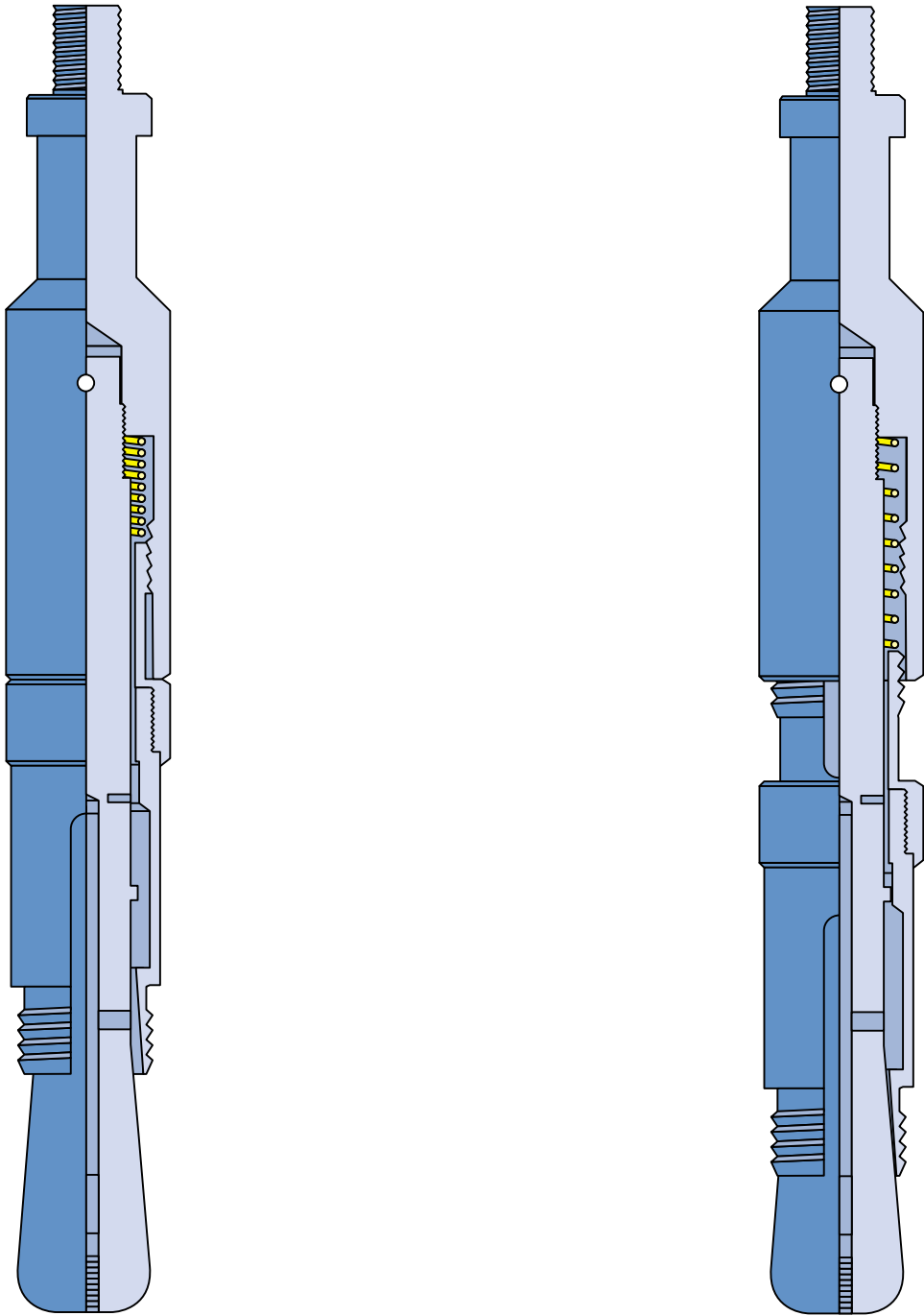


Figure 15-25: D&D PR Tool

15.3.22 Tar Baby

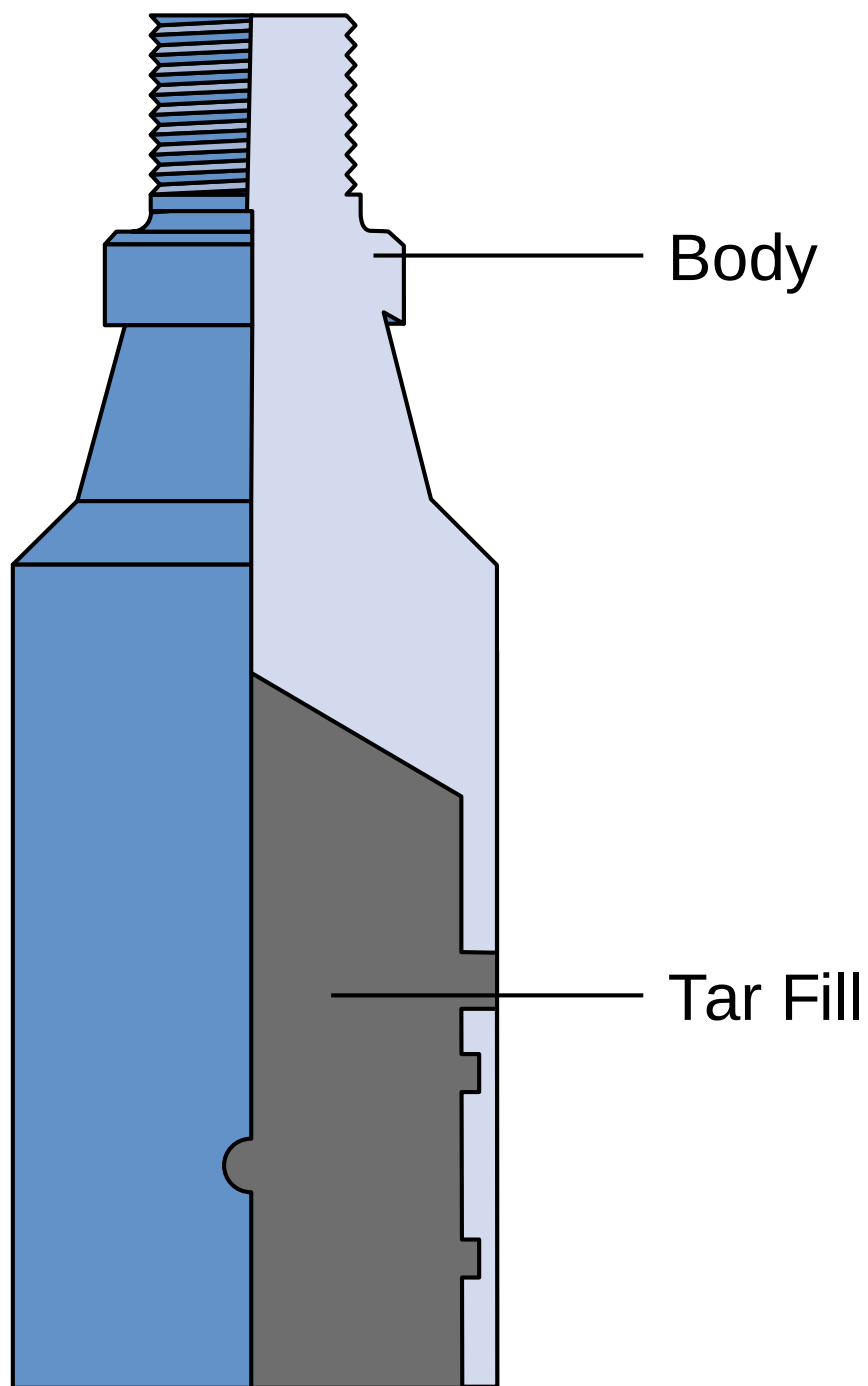


Figure 15-26: Tar Baby

15.3.23 Wire Finders

It is important to estimate the approximate depth of the broken wire to have a STARTING POINT to look for the wire. It is very easy to bypass the end with the wire finder, especially if the broken end is tucked in a collar recess, nipple bore, SSD, etc. For this reason, we must continue to search either side of the calculated depth. It is not good practice to continue running in the hole past the top of the wire.

15.3.23.1 Wire Grab

The wireline grab is used to retrieve broken slickline from the well bore after making a small ball with a wire finder.

When a slickline breaks and a considerable length of it is left in the well bore, the upper section of the line tends to coil and conform to the ID of the well bore creating friction or resistance, which prevents the entire length of the line from dropping.



Note

When attempting to retrieve the slickline, it is imperative that the top of the wire first be located and balled with a wire finder before running the grab.

If this is not done, the wire grab may miss the top of the slickline and bypass several feet of wire before engaging it. Once this happens, the slickline that is above the grab will tend to stack around the grab as it is being retrieved and, if more than a few feet of line has been bypassed, it will foul the grab to the extent that it cannot be retrieved short of further fishing operations.



Caution

Potential Severity:	Light
Potential Loss:	Assets
Hazard Category:	human

ALWAYS RUN ATTACHED TO A ROPE SOCKET and latch into an RB (or equivalent) pulling tool. If the grab becomes entangled and cannot be retrieved, the RB can be sheared and the tool string returned to the surface.

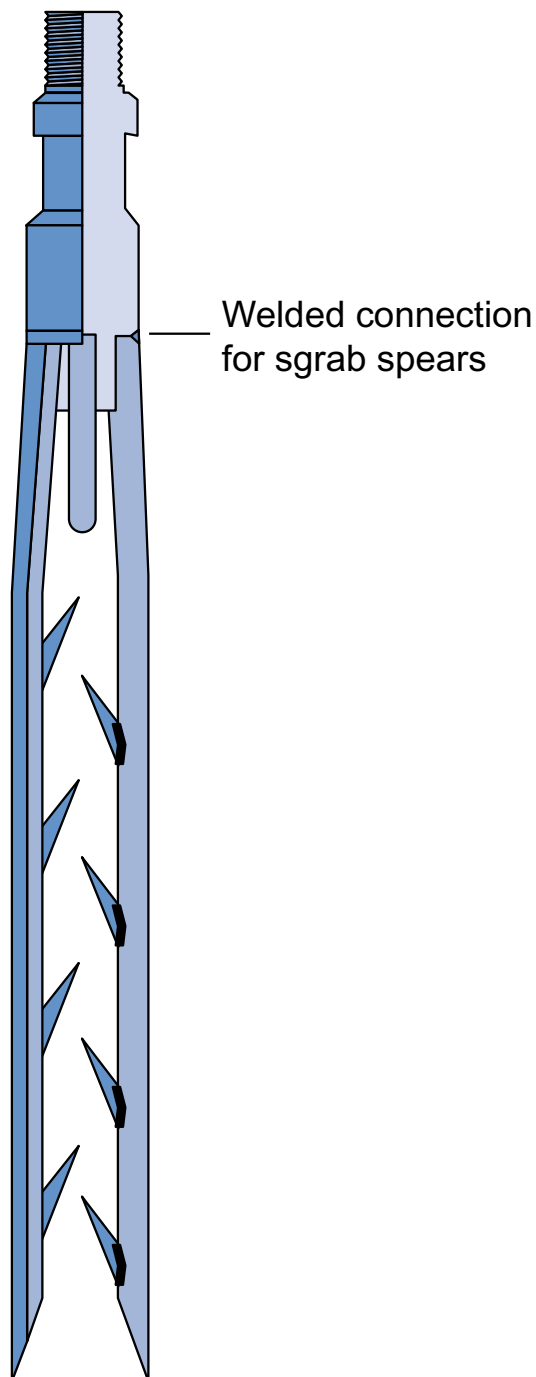


Figure 15-27: Wire Grab

15.3.23.2 Bowen Broken Wire Finder

The Bowen wire finder has a flexible spring steel skirt, which is available in a range of sizes to suit the tubing size (ID). The fingers of the skirt can be flexed gently to a snug fit in the tubing.

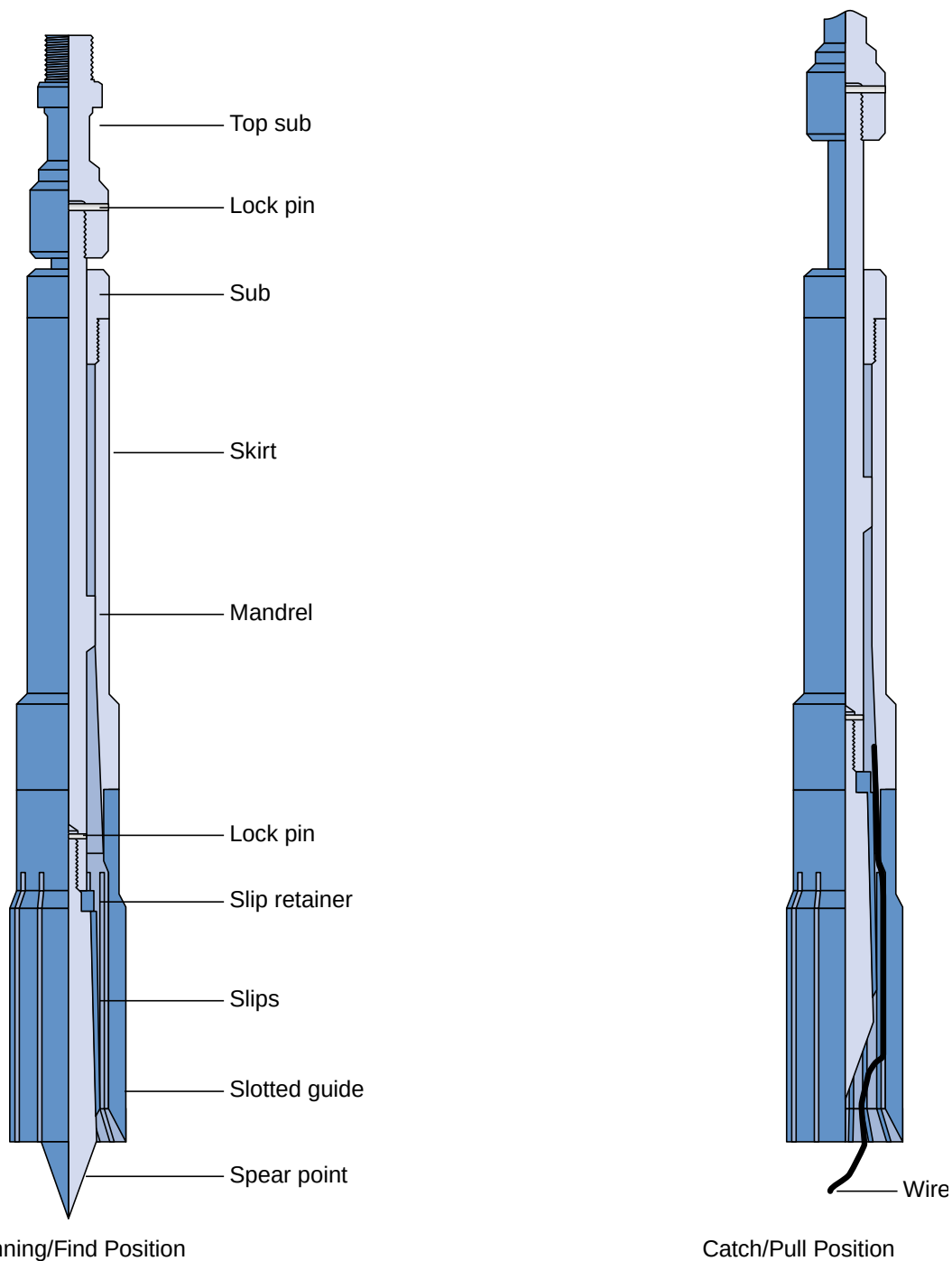


Figure 15-28: Bowen Wire Finder Running and Catching Positions

Limitations

If the wire is below a nipple, care must be taken not to jar down against the nipple ID, as it is possible to bend or break the fingers of the skirt. It can be difficult or impossible to successfully pass a nipple profile.

Therefore if the top of the wire is expected or calculated to be below a nipple profile, the use of this tool should be carefully considered.

Operation

As the tool is lowered downwards, the skirt rides upwards. The fingers press against the tubing wall and are designed to locate the top of the wire, then direct it up inside the finder.

As the tool string is picked up, the internal taper is designed to grip the wire, but in practice this rarely occurs.

However, this tool is an efficient method of finding the top of the wire.

15.3.23.3 Petroline Broken Wire Finder

The Petroline collapsible wire finder is designed to run through a nipple without the finger catching in the profile.

The housing is selected to match the nipple profile and the collapsible finder is run into the well. Several housings are available to suit the various nipples in use.

The housing is fitted over the expanding finder and shear pinned in place, As the finder is run into the well, the housing will stop in the nipple bore.

Downward jarring shears the pin and allows the finder to be lowered out the bottom end and past the profile.

The tool string is then lowered to the calculated or expected top of the wire. After making a small loop or ball at the top of the broken line, the finder is retrieved.

As the finder passes back up through the nipple profile, the housing is collected and the complete assembly is returned to the surface.

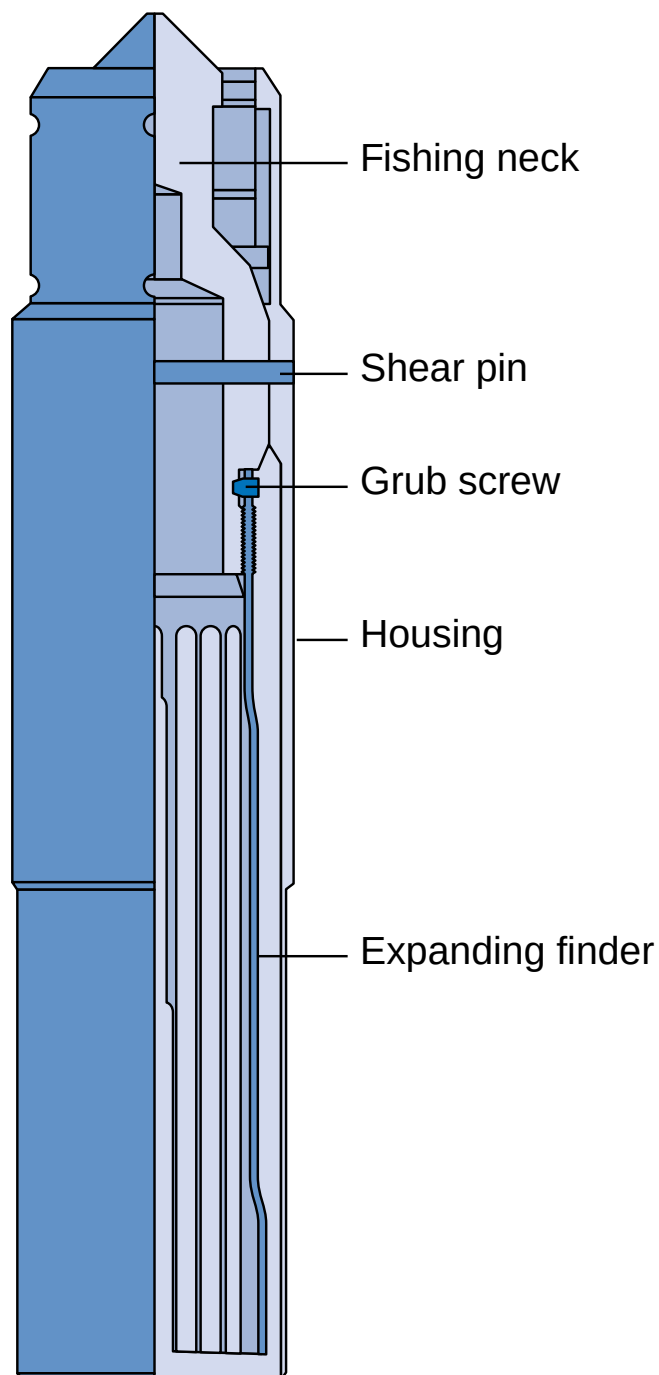


Figure 15-29: Petrolite Wire Finder

15.3.24 Wire Scratcher/Finder

A wire scratcher can be fabricated by passing the wire through holes in a bar (or old piece of stem or sucker rod) until loops form a snug fit in the tubing size in which fishing is to be performed.

This type of wire finder can be used in any tubing at any depth. Nipple profiles and equipment such as side-doors should cause no problems.

However, exercise caution near the side pocket mandrels, as a loop of wire can get caught around the latch.

If the wire finder threaded with wire fails to locate the top of the line, it can be baited with a piece of rope. By weaving a 3 to 6 ft length of $\frac{1}{2}$ in. to $\frac{3}{4}$ in. diameter rope through the wire, the chances of the finder bypassing the top of wire are reduced.

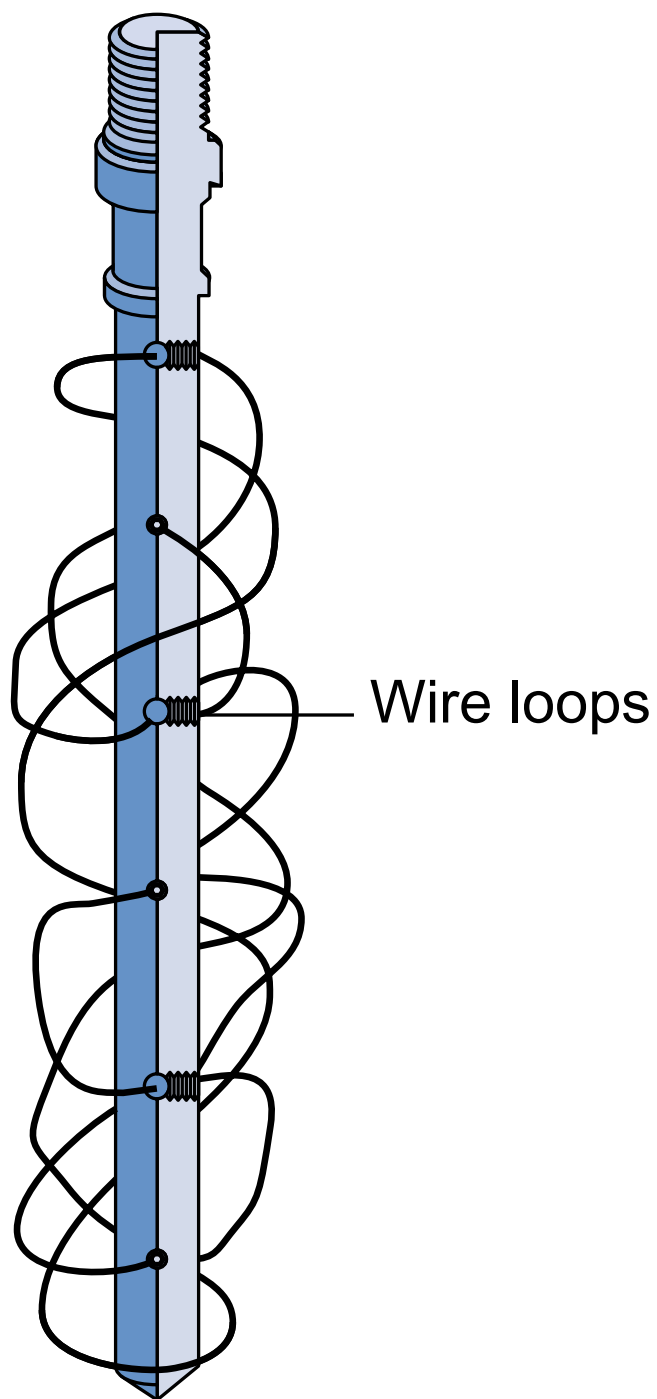


Figure 15-30: Wire Scratcher/Finder

15.3.24.1□ **Operation**

All designs of wire finder should be run in the well to approximately 150 ft above the estimated wire depth. Run slowly past the expected wire top to 150 ft below the wire depth, while carefully observing the weight indicator for a drop in the weight. Pick-up and continue covering this area until the wire is located.



Note

Recheck the wire fall calculations before running to far past the end of the wire.

15.3.24.2□ **Line Location**

When the weight is lost indicating the wire finder has located the end of the line, jar down gently to make a ball of approximately 3 ft to 6 ft ONLY. Excessive jarring or downward movement will make too large a ball, which can cause a problem.

The aim is to loop the wire over sufficiently to permit a wire grab to become entangled. Too large a ball will make it difficult to extract the wire grab and wire ball from the lubricator and get the BOP closed and sealing.

Intentionally Blank

16 Special Tools

16.1	BDK Safe Joint	16-1
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16 SPECIAL TOOLS

16.1 BDK Safe Joint

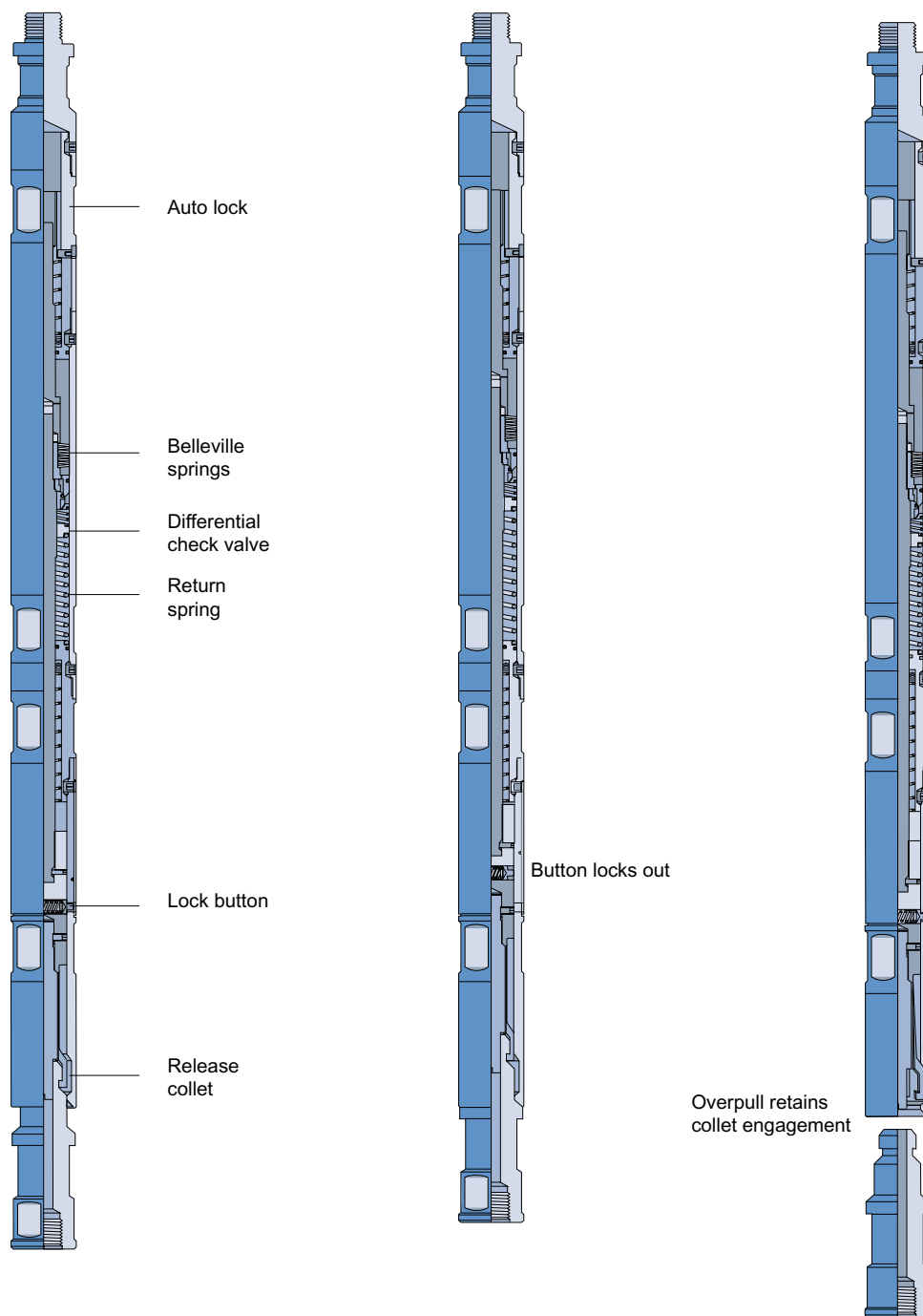


Figure 16-1: BDK Safe Joint

The BDK safe joint is designed for use as a standard item in the slickline tool string.

The main purpose of this tool is to eliminate the uncertainty of whether or not a stuck tool string will come free before the wire breaks, or whether you should risk dropping cutters and go-devils into the well and possibly causing additional problems.

The safe joint can be installed as a rope socket using the conventional rope socket and pear drop configuration or set lower in the string with the majority of the stem above the safe joint which offers the added advantage of more weight when pulling back to the surface. This is especially important when operating in high-pressure well situations.

To install the safe joint further down the string (but always above the jars) offers the operator the opportunity, in a fishing situation, to retrieve the majority of the tools, i.e., rope socket, stem etc. thus eliminating one extra section of lubricator when fishing for the remainder of the tools.

Table 16-1 BDK Safe Joint General Specifications

OD (in.)	Operating Range (lb/f)	Part No.
1.500	400-2000 lb	5338-**
1.875	400-2700 lb	4036-**
2.125	400-2700 lb	5654-**
2.500	400-4000 lb	5164-**

** Refer to connection codes

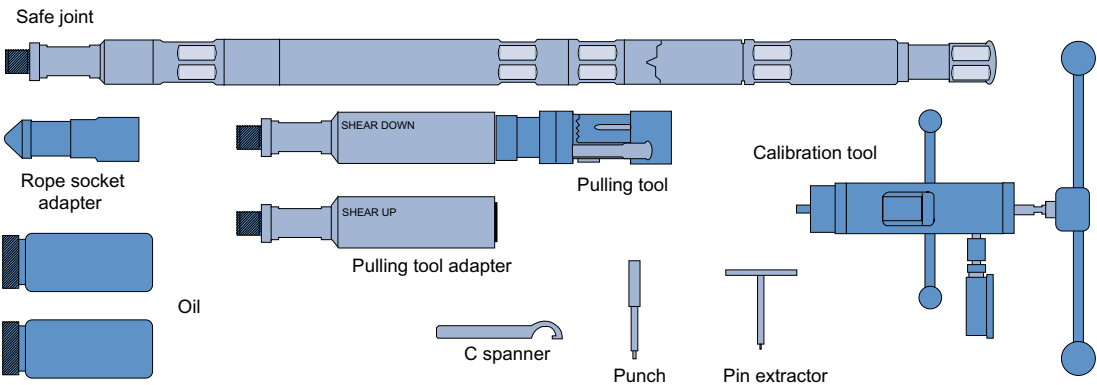


Figure 16-2 BDK Safe Joint Calibration Tool

John Mayzel\\Release Date: Provisory\\EDMS UID: /Published: //

16.2 BDK Compact Tool string

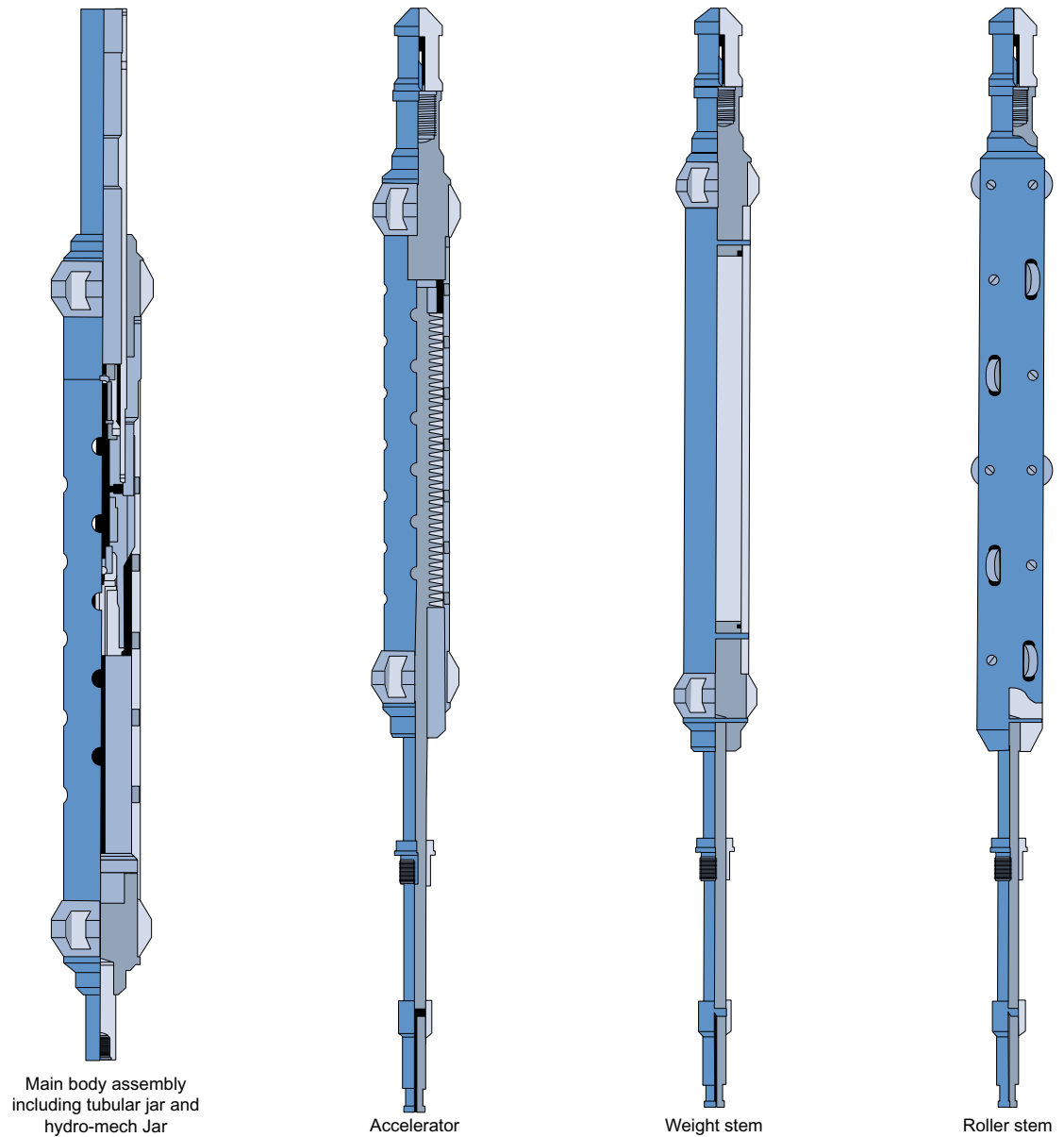


Figure 16-3: BDK Compact Tool String Main Body Assembly

The BDK compact tool string offers the operator a selection of tool string configurations, which can be utilized in a wide range of well parameters and operations. Ideal for use with restricted lubricator height and in deep and highly deviated wells.

All options of assembly are deployed by use of an interchangeable rope socket.

The compact tool string functions in the same manner as a conventional tool string, features include tubular jar for upward and downward jarring and a hydro-mechanical jar for assisted upward jarring.

Compact tool string configurations include weighted stem or multi-roller stem, accelerator and Teflon wear rings. The standard tool size is 3.250 in. OD.

16.3 BDK Combined Action Tool

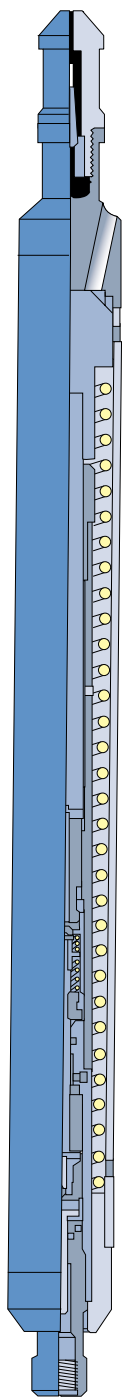


Figure 16-4. BDK Combined Action Tool

The BDK combined action tool is designed for use in applications close to the wellhead where slickline stretch is at a minimum and tool string length is of critical importance.

The CAT consists of an integral rope socket, weight sub, accelerator and hydro-mechanical jar.

The tool offers the operator all the components required for high impact upward jarring, housed in one very short unit. The combined action tool is capable of delivering extremely high impact forces, even when used at depths close to the surface, without causing any damage to the slickline.

Standard sizes are 3.600 in. OD and 4.500 in. OD and tool is available in standard or long stroke configuration.

16.4 Petroline High Impact Integrated Tool String

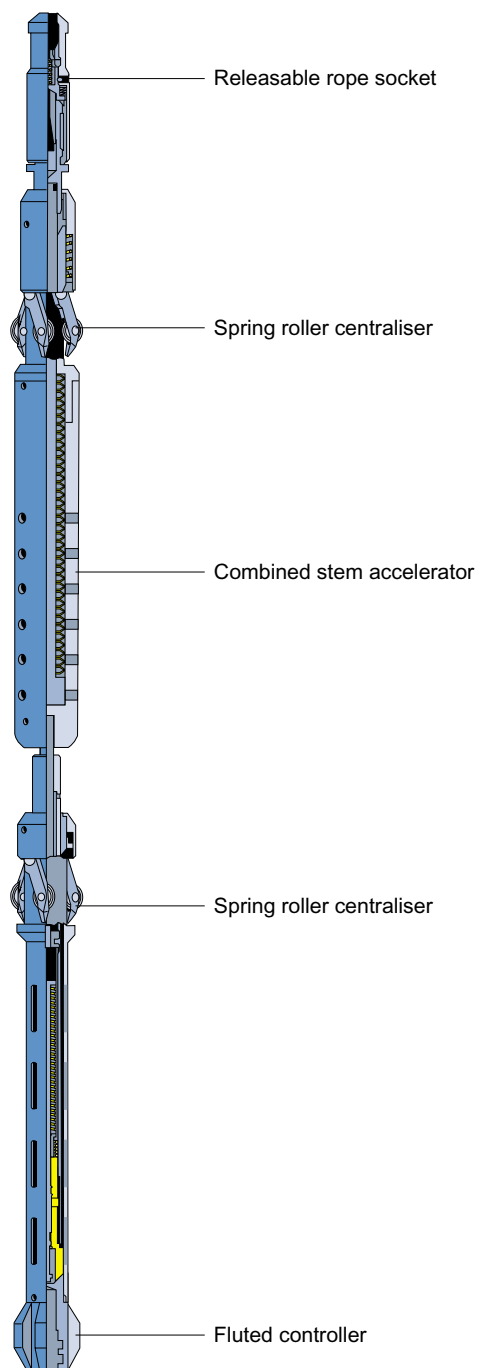


Figure 16-5: High Impact Integrated Tool String (HIIT)

The high-impact integrated tool string (HIIT) System has been developed to offer the maximum tool string performance in the shortest practical package. Traditionally when working below decks, height limitations have necessitated that tool string configurations be compromised. Often this can cause severe operational difficulties resulting in failures.

In a conventional tool string these components would be over 27ft in length. The HIIT is only 6ft long when closed and 9ft long when fully open.

Should additional weight be needed, large diameter stem sections are optionally available. Due to the use of spring roller centralisers HIIT equipment can be used in wells with up to 80 degrees deviation.

16.5 PCE Universal Pulling Tool

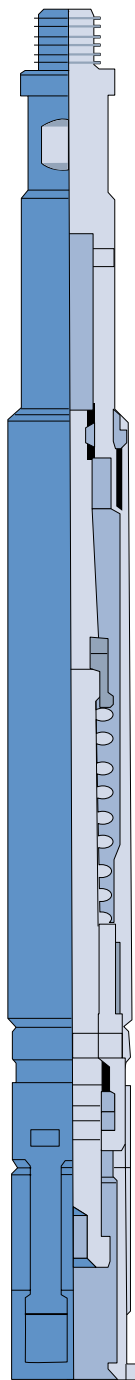


Figure 16-6: PCE Universal Pulling Tool Assembly

The PCE universal pulling tool is a shear up, shear down, three reach pulling tool used to set and retrieve sub surface devices with an external fish neck from the well bore.

The PCE universal pulling tool can be adapted from a shear up to release to a shear down to release tool, without the need for any additional parts. The tool has a universal core that permits the same tool to be able to retrieve devices with fish necks of different lengths or reach (i.e., short, medium or long reach).

The PCE universal pulling tool combines modern innovation with traditional principles to enable a single tool to replace two to six conventional tools normally associated with slickline operations.

The PCE universal pulling tool is available in 1-1/4 in., 1-1/2 in., 2 in., 2-1/2 in. and 3 in. and 4 in. sizes and is available in 18-22 Rockwell C condition for H₂S service (including dogs). All pulling tools are manufactured with Inconel springs as standard.

16.5.1 Features

- Can be converted from shear down to shear up without the need for any additional parts or the need to purchase two different types of tools, i.e., does the same job as an Otis R or S series pulling tool or a Camco JD or JU series pulling tool.
- Can be pinned in the short, medium or long reach position without the need to purchase additional cores, as would be necessary with Otis or Camco pulling tools, i.e., eliminates that need for 5 Otis or 3 Camco cores.
- Superior pawl design eliminates pawl and core damage, and prevents the possibility of the pawls swelling the apertures in the dog assembly and therefore dangerously increasing the pulling tool OD.
- Internal dog spring in conjunction with stainless steel shear pin retainer enables shear pin replacement without the need to disassemble the pulling tool.
- Dogs are manufactured from AISI 4140 or British equivalent in Rockwell hardness of 30-36 for standard service or 18-22 for H₂S service, thereby eliminating the possibility of 'shucking dogs tips' as occurs with high heat treat dogs as used by other manufactures.
- Superior dog skirt engagement, thereby minimizing the possibility of dog distortion resulting in an inability to release from the fishing neck engaged.

Integral bell guides are available to suit this tool. Optional 2.75 in. OD tool available on request.

Table 16-2: PCE universal pulling tool specifications.

Actual OD (in.)	Nominal OD (in.)	Fish neck OD (in.)	Top Connection (in.)	Reach (in.)	Length (Shear Up) (in.)	Length (Shear Down) (in.)	Weight (lbm)	To engage fish neck (in.)	Product Number
1.29	1-1/4	1.187	15/16	Medium Long	15.00 15.25	16.75	3	0.875	B118-005
1.437	1-1/2	1.187	15/16	Medium Long	15.05 15.60	17.04	4	1.187	B118-007
1.86	2	1.375	15/16	Short Medium Long	19.02 19.82 20.37	22.45	7	1.375	B118-001
2.25	2-1.2	1.375	15/16	Short Medium Long	20.28 21.08 21.58	23.61	10	1.75	B118-002
2.80	3	1.75	1-1/16	Short Medium Long	20.55 21.40 21.55	23.75	15	2.313	B118-010
3.75	4	2.313	1-9/16	Short Medium Long	20.73 21.38 22.00	24.00	28	3.125	B118-011

16.6 PCE Integral Bell Guide

The PCE integral bell guide concept is used when it is necessary to retrieve small diameter fish neck profiles from large diameter tubing. By utilizing the shear pin retainer profile on the PCE pulling tools, the integral bell guide is compatible with a full range of tool size.

The PCE integral bell guide is available for the PCE universal, SU and SD pulling tools.

When ordering this product please specify PCE product number and the actual OD of tool required.

Table 16-3: PCE Integral Bell Guide

Size Range (in.)	Product Code
1.75 - 1.99	B118
2.00 - 2.99	B118
3.00 - 3.99	B118
4.00 - 4.99	B118
5.00 - 5.99	B118

Size Range (in.)	Product Code
3.0 – 3.99	B118
4.0 – 4.99	B118
5.0 – 6.00	B118

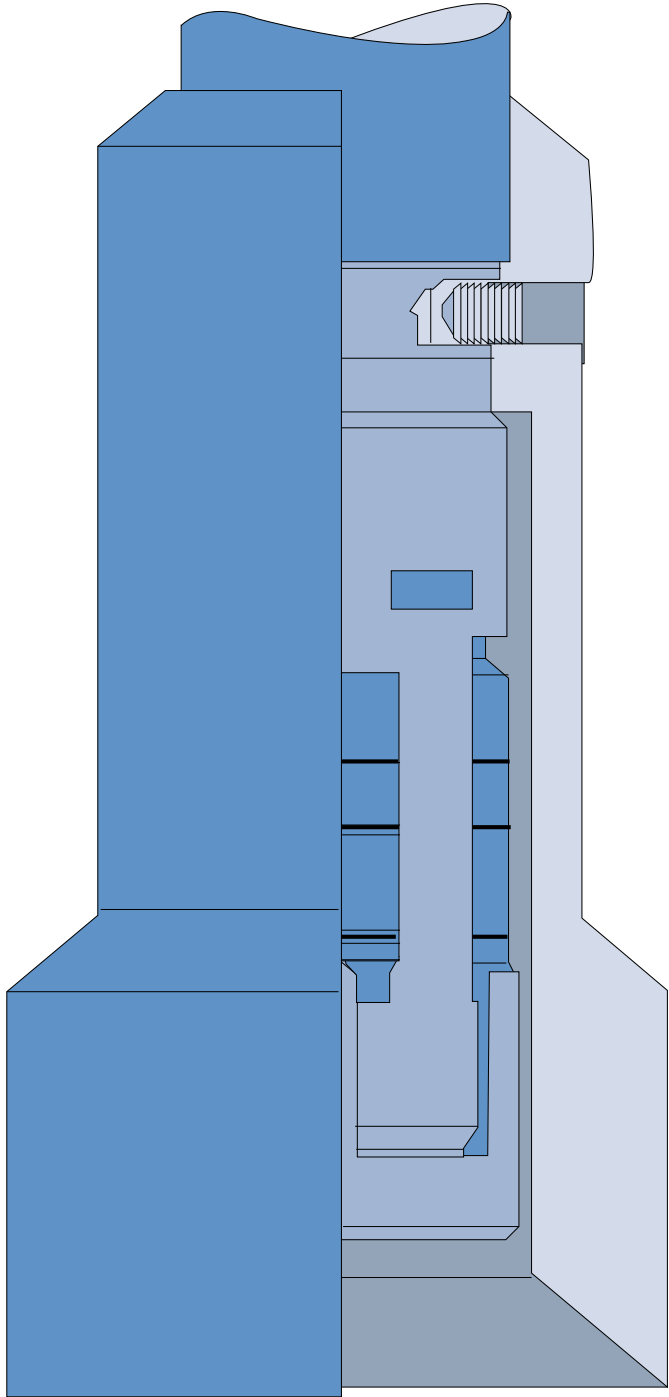


Figure 16-7: PCE Integral Bell Guide

16.7 Rotating Tools

Rotating tools can be assembled for either right- or left-hand rotation and operate on the down stroke of mechanical jars.

Rotating tools in combination with mills, broaches, overshots, etc. have been used successfully to back off stuck tool strings, take apart down hole CIBP, drill cement, mill through debris, crystallized sand plugs and other jobs on slickline.

Rotating tools in combination with bailers allow clean out of well bore utilizing slickline.

16.7.1 BDK J-Slot Rotating Tool

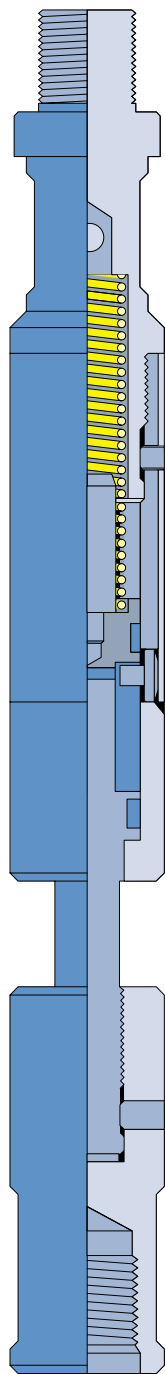


Figure 16-8: BDK J-Slot Rotating Tool

The BDK J-slot rotating tool is designed to rotate the tool string in a controlled manner. To operate the J-slot rotating tool, simply sit the tool string down. As the tool is telescoped down, it rotates to its next indexing. Subsequent up and down movement will continue to rotate the tool string.

The J-slot rotating tool is typically used for the following applications:

- Loosening debris around fishing necks
- Dislodging debris from behind gas valves etc.

Tools are manufactured to any size required.

16.8 ISI Slickline Impact Tool

The impact selector slickline tool is an all-mechanical high impact tool that will work in any combination of well pressures and temperatures in which other mechanical tools operate. The impact jar will accommodate any amount of tension that can be provided through any size slick or braided line. The tool is open to well fluids and pressure will equalize inside the impact jar while it is in the hole. Therefore, the tool will not collapse or lock up during use. Key specifications include:

- The Impact Jar is 1-1/2 in. OD, 48 in. in overall length and weighs 28 lbm.
- The tool is surface adjustable for impact levels from 200 lbf of line tension up to 1300 lbf of line tension.
- The impact jar stroke is surface adjustable between 4 in. minimum and 9 in. maximum.

16.8.1 Tool Adjustment

The impact selector slickline tool can be pre-adjusted on the surface before going in the hole. To change the impact setting of the jar, the top body section must be removed exposing the adjustment sleeve at the top of the Belleville spring assembly. Remove the Allen screw from the slot in the adjustment sleeve so that the adjustment sleeve can be rotated or turned right or left. The adjustment sleeve slot is marked from 200 lb minimum setting to 1300 lb maximum setting. Rotate or turn the adjustment sleeve to the right to lessen the setting, or to the left to increase the setting.

When the desired impact setting is located opposite the screw hole for the Allen screw, reinstall the Allen screw and the jar will impact at the selected setting. The impact jar may be set between the 400 and 600 lbm; the jar will impact at 500 lb. Replace the top body/top sub section, and the jar will be ready to run.

The jar stroke can be adjusted to a minimum 4 in. stroke or a maximum 9 in. stroke. This feature allows the operator to utilize the 4 in. stroke to compensate for less line stretch while fishing up high in the well bore and still deliver a high level of impact. This 4 in. setting will also greatly reduce any slingshot effect in the event that the tool shears or the fish comes free. To adjust the stroke after the desired impact has been set, insert a screwdriver into the slot located in the center of the lower body jar and push upward on the latching and release sleeve that is visible in the slot. Pull downward on the bottom sub at the same time and the jar will open.

Unscrew the bottom stop from the lower body and pull the bottom stop downward on the lower shaft. Place horseshoe spacers above the bottom stop downward on the lower shaft to adjust the stroke to the desired length and screw the bottom stop into the lower body. Tighten the connection and turn the jar upside down to cause impact jar to close and re-latch. The jar is now ready to run in the hole.

16.8.2 Tool Operation

- The impact tool design has a built in acceleration feature that eliminates the need to run an accelerator tool in order to cushion impact forces to the slickline and rope socket or to improve jar performance.
- Set the desired impact tension for the job to be run and set the desired stroke length.
- The impact jar is run into the hole in the usual manner and the fish is engaged.
- Line-tension to the impact tool is increased until the selected tension amount for impact is reached causing the jar to impact.
- Tension can be maintained on the line momentarily after impact to determine if the fish is moving or has come free. If the fish did not come free, all line tension to the jar is released and the jar will close and relatch. Line tension can be released slowly in order not to shear off or can be released quickly in order to shear off.
- Jarring action should be continued until the fish is free and removed from the well or until jarring action is no longer desired.

16.8.3 Assembly and Disassembly

16.8.3.1 Disassembly

- To disassemble the tool, remove the top body/top sub assembly from the jar. Use a screwdriver to unlatch the jar as described under tool adjustment. Unscrew the bottom stop from the lower body and pull the lower shaft away from and out of the lower jar body. Unscrew the body from the body connector and remove it from the jar.
- Clean the spring (Belleville) section and the latching system with proper cleaning fluid and a wire brush to remove well bore fluids and any rust until the assemblies are clean and until the jar can be freely latched and latched released by hand. Coat all parts with any good grade lubricating oil and jar is ready to reassemble. Before assembly, replace any worn or cut O-rings on the body connector. These O-rings help prevent the jar from backing off during heavy prolonged jarring action.

16.8.3.2 Assembly

Place the top body over the spring section and screw tightens the top body connector sub. Replace the lower body and tighten the connection. Insert the lower shaft into the lower body and screw connects the bottom stop into the lower body. Turn the tool upside down to relatch the jar. We recommend that the tool be stored in the plastic pipe case filled with oil to prevent rust.

16.9 Cast Iron Bridge Plug Removal

This tool was designed to remove normal CI-BPs in 2-7/8 in. tubing tool which consist of 10 in. stroke tubular jar with special offset collar on lower end which allows use of a prong screwed into offset collar while allowing tubular jar to extend through offset collar. Below the tubular jar, two 1-1/4 in. knuckle joints are used with a Bowen 1-29/32 short catch overshot and 1-1/4 in. grapple fitted below.

Use of this tool involves RIH with tool and latching CIBP core, jar down to shear pin in collar and drive down prong along side overshot which breach of the CIBP core. When this happens, pressure equalizes across the CIBP, prong is wedged along side overshot to prevent tools from being blown up hole. A jar up releases prong and tools are pulled retrieving top of core on CIBP.

A two-step chisel is then run to knockout remainder to core and break body of CIBP away from pipe wall. All of this becomes debris, which is taken to the bottom of well or can be recovered by using bailer with junk catchers.

Other size tools are in use by adjusting sizes of prong and overshot to accommodate these plugs.

With the use of this tool on slickline, a cast iron bridge plug can be removed in approximately 6 hours location time.

It may be necessary to utilize bailers to clean off top of CIBP prior to using this tool so prior to running tool an impression block is run to be sure CIBP top is clean.

16.10 Homco Patch Removal

The Homco casing patch is a patch set with use of a rig and rolled out against pipe wall reducing the ID of the casing by only 0.092 in. This allows logging, perforating, plugs, BHP gauges, etc. to pass through patch.

Occasionally this patch may be set in the wrong place or become deformed due to pulling too much differential across patch. When this happens, it may be necessary to remove the patch from the well bore.

The first step in this process involves locating and crimping the top of the patch. The tool used is a simple three-finger tapered tool that is spread to ride the pipe ID. Jarring down crimps in the top of the patch. The second tool run is a modified bar with an orienting half-collar, kick-over bow spring and a barb to latch the bottom of the patch. Stem is added above this tool to the same length of the patch (usually 20 ft).

Down stroke jars and stem are used to drive the tool down along the outside of the patch. When this happens, the patch deforms lengthwise pulling it away from the casing wall for 95% of its circumference.

When the tool reaches the lower end of the patch, the barb latches under the patch allowing the upward jarring to break free of the entire patch, which is then retrieved from the well bore.

16.11 Shear Sub For Bailers

When conducting large volume bailing jobs with 40 – 80 ft bailer assemblies occasionally the lower load section of the bailer becomes stuck in sand or debris. To eliminate the problem of leaving entire tool in well bore, a shear sub in the bailer is being used.

The shear sub is installed at the top of the lower load section of the bailer. Just above the shear sub, a ball and seat is used to prevent dumping upper load sections onto lower load section when shear sub is used.

When upper jarring activates the shear sub, a pin is sheared and the tool string, bailer pump section and upper load sections are pulled from well bore. The remaining load section then can be retrieved by latching fishing neck of shear sub and using jars to free up load section.