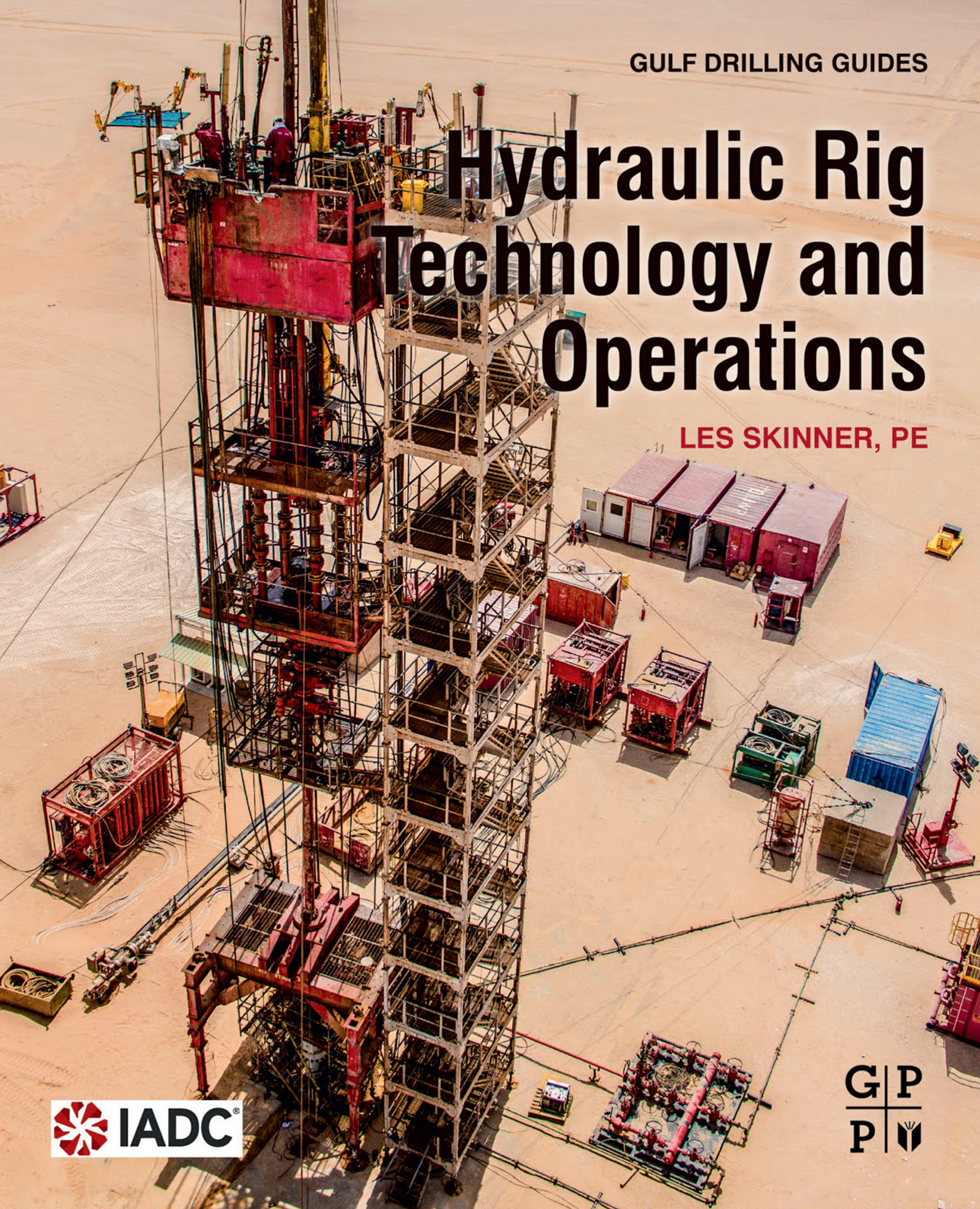

GULF DRILLING GUIDES

Hydraulic Rig Technology and Operations

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This book is dedicated to my wife, Phyllis, who has tolerated me for 50 years of marriage. She has also tolerated long nights alone in the den while I sat at my desk drafting this book. Then, she listened patiently to all my doubts, concerns, complaints, gripes, and outright foolishness along the way. Thanks for not killing me (yet), dear.

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Introduction

This book was written as part of the International Association of Drilling Contractors (IADC) Drilling Series and is a companion to the previously published *Coiled Tubing Operations* by the same author. It was written with the intent of helping oil-field personnel and students having limited experience better understand the characteristics and uses of these versatile units. Hydraulic rigs are those that use large hydraulic cylinders to hoist a tubular pipe string instead of the block-and-tackle system used by conventional rigs.

Two classifications of hydraulic rig operations are discussed: those on wells with pressure at the surface ("live wells") and those without pressure ("dead" wells). Hydraulic unit operations on "live" wells are known as snubbing. Operations on "dead" wells using hydraulic rigs are known as hydraulic workovers (HWO).

Snubbing differs significantly from a hydraulic workover. When snubbing, surface pressure can push the pipe out of the hole. The weight of the pipe hanging in the well eventually balances this expulsion force. Until it does, the pipe must be held down to prevent expulsion. The force direction on the pipe string (expulsion due to pressure inside the well or pipe weight) impacts the way the hydraulic rig operates along with its components.

The uses of hydraulic rigs are widely varied both in snubbing and in hydraulic workovers. Almost any operation that can be performed by a conventional rig can be done by a hydraulic rig as long as the rig is properly sized. In general, hydraulic rigs lack the heavy-load-hoisting capability of a large conventional drilling rig. The hydraulic unit's center bore, often limited by the rig's blowout preventers, cannot manage very-large-diameter casing strings.

In general, there is no one rig type that is best for all oil-field operations whether it's a conventional rig, hydraulic rig, coiled tubing unit, wireline unit, etc. Sometimes a hydraulic rig is a better choice than a conventional rig. A coiled tubing unit might be the right choice in others. Wireline or slickline might be the proper system for use in still other circumstances.

Hydraulic rigs, like most other oil-field technologies, involve emerging science and applications. This book gives the reader a snapshot of those technologies. The uses of hydraulic rigs in the oil field is limited only by the imagination of the user and the willingness to use these and other proved technologies in new ways.

Chapter 1

History of Snubbing

CHAPTER OUTLINE

1.1 BACKGROUND AND DEFINITION

What is snubbing? Oil field snubbing is the process of pushing pipe into or pulling pipe from a well with significant surface pressure when expulsive force from well pressure exceeds the weight of the pipe in the hole. Stripping is the process of lowering the pipe in the hole when the weight of the string exceeds the expulsive force exerted on the pipe by well pressure. Obviously, the well is underbalanced in both operations since bottom-hole pressure inside the wellbore is less than reservoir pressure. Part of that reservoir pressure is experienced at the surface, sometimes a significant part.

The reasons for naming this operation "snubbing" in the past is unclear, but it probably has to do with a similar term used in several other industries. Snubbing has traditionally meant "securing a load with several wraps of rope around a stationary anchor point." In marine and railroad operations, vessels were traditionally secured with several line wraps around a bollard

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on a dock or in a yard. As the vessel moved slightly, tension could be increased by tugging on the rope. If positioning is required, the rope could be let out a bit while still maintaining control of the vessel.

Horses are often broken by securing a rope to their bridle and then making a few wraps around a "snubbing post" located in the center of a corral. The trainer changes the length of rope available to the horse by slacking off the rope or taking up line without completely releasing the animal. This prevents the horse from hurting itself while expending its energy against the snubbing post and not just the trainer.

Most likely, oil field snubbing was a combination of these two concepts. Snubbing has been used for securing loads on pipe in wells for decades. The author's grandfather, a cable tool driller, explained one use for oil field snubbing. When early wells were drilled with percussion tools, the hole interior was often very rough since it had little or no fluid involved, and the bit was free to drift from side to side leaving ledges, doglegs, and undergauge (tight) hole sections. Casing in the late 1800s and early 1900s was thin-walled and relatively light. My grandfather often referred to surface casing as "stovepipe."

Excessive pipe-on-wall friction meant that the pipe would not slide into the hole under its own weight. So, cable tool drillers would run a "catline" line through a pulley mounted on the rig floor, taking a few wraps on the casing and tug on the catline "snubbing" or "pulling" the pipe down into the well even though there was no pressure involved.

This technique was used by the author in 1976 to "snub" large-diameter casing into a storage well drilled in a salt dome near Andrews, Texas. It worked well for grandad, and it worked well for me.

Snubbing became the process of "pulling" pipe into the hole when pressure inside the well was trying to push it out of the hole. This is also known as being "pipe-light" meaning the pipe in the hole is not heavy enough to go down under its own weight. The well pressure exerts too much upward force to allow the pipe to go down the hole by weight alone. Obviously, this requires a pressure seal at the surface that is loose enough to allow vertical pipe movement (i.e., if there is no seal, there is no pressure inside the well).

Snubbing is often confused with another operation frequently performed on live wells, stripping. Stripping is used to run pipe into a well under pressure when there is sufficient pipe weight in the hole to overcome the expulsive force trying to push pipe back out of the well plus friction of all types. This means that the string is "pipe-heavy." Stripping on a drilling rig is often performed, for example, to get a bit back on bottom after having taken a kick or influx from the formation into the wellbore. This allows the entire kick to be circulated out of the well safely from the bottom up.

There are three basic requirements for snubbing or stripping:

- Both snubbing and stripping require a seal at the surface on the outside of the pipe to prevent pressure and fluids (often gas) from escaping upward around the pipe. Obviously, if there is no seal around the pipe, there is no upward expulsive force acting on the cross-sectional area of the pipe. Venting the pressure would make it far too dangerous to perform any work on a hydrocarbon-producing well in the first place.
- Both operations also require a float or check valve inside the string below the surface to prevent fluid from flowing up the pipe and out into the air for the same reason.
- Finally, there must be a means to handle the pipe to keep it from being pushed out of or falling into the hole. If the string is "pipe-heavy" only a load hoisting means is needed to lower the pipe under pressure. However, if the string is "pipe-light" some provision must be made to control the upward movement of the pipe as pressure tries to push it out of the hole.

When stripping is being performed, the pipe is in tension along its entire length. However, when snubbing is performed, the pipe above the seal at the surface is in compression both going into and coming out of the hole. This requires special equipment and skill to prevent catastrophic buckling and pipe failure depending on a number of factors including the pressure in the well, the pipe diameter, and its wall thickness.

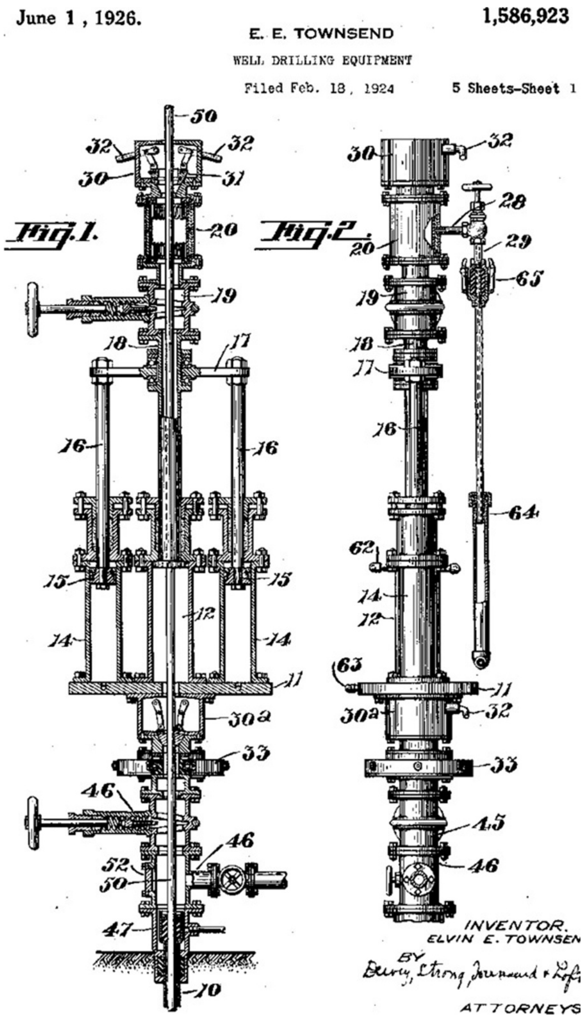
Crewmembers are often exposed to very high volume hydrocarbon leaks when a seal fails during a snubbing operation. There is an inherent exposure risk associated with snubbing operations because crewmembers must be in close proximity to the upper snubbing BOP and the pipe string. Recently, some snubbing operations are being performed remotely to mitigate this risk with nobody positioned above the snubbing "stack." In the past, however, crewmembers were very close to potential leak sources while running or pulling pipe under pressure prompting well control pioneer, Red Adair, to conclude that "snubbing is the most dangerous job in the oil field."

Equipment, sealing elements, and procedures have improved since snubbing became a viable oil field operation in the early 1920s. Crews are at less risk now, but there is no reason to become complacent when performing any work on a well under pressure. The development of modern snubbing equipment and practices provides an appreciation for industry incentives to expand this versatile operation to a number of wells around the world.

1.2 EARLY DEVELOPMENT

1.2.1 Townsend Patent—1924

On 18 February 1924, Elvin E. Townsend filed for a patent on "well drilling equipment" that was, in fact, the first snubbing unit (Fig. 1.1). This device had a movable frame that could be raised and lowered along with a stationary frame connected to the wellhead. Each frame contained a set of slips to



■ **FIG. 1.1** Townsend patent, 1924.

hold pipe in compression, and each contained a sleeve with 24 metal reinforcing "arms" that would affect a seal around the pipe, an annular blowout preventer (BOP).

The movable frame was raised and lowered using two hydraulic cylinders manifolded together for uniform lifting power. The two cylinders and the two annular BOPs operated using well pressure routed through pipes to each device. The slips on each frame were manual screw-type slips. The screws were run in to grip the pipe, and run back out to release the slips.

This device was intended to be used with the drilling rig that hoisted the pipe (i.e., a rig-assist snubber). The movable frame repositioned the traveling annular BOP and slips to get another discreet section, or "bite," of pipe. The cylinders then pulled the pipe in the hole as the blocks were lowered. When coming out of the hole, the traveling frame held the compressive force back on the pipe in short "bites" to keep the string from being expelled from the well.

The most important part of this invention was the annular BOP. The element with its steel fingers became the basis for the first general use of annular preventer later used on almost every rig. This portion of the invention was purchased by the Hydril Company and is referred to in subsequent literature as the "Townsend Hydril packer" (Fig. 1.2). The similarities to current-day annular BOPs are obvious.

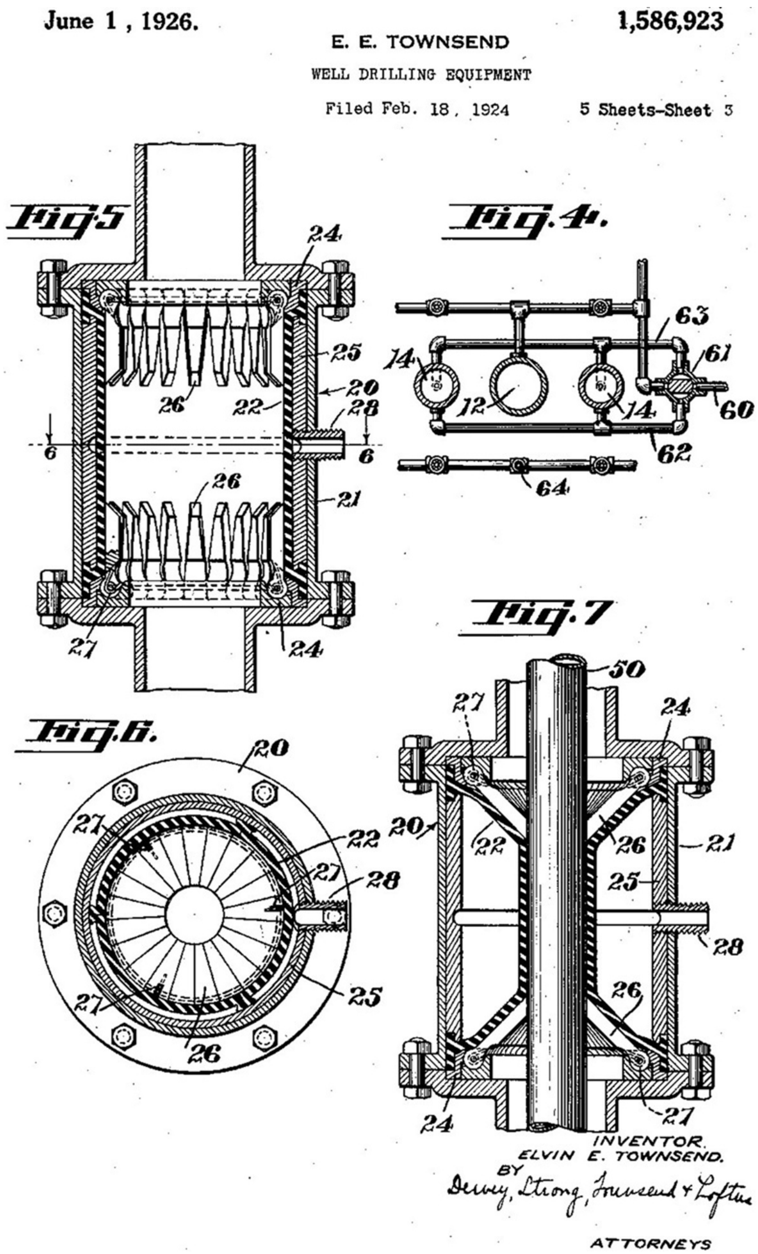
It is not known whether this snubbing unit was ever actually built. The basis of design is such that it could have been used for pipe-light conditions as a rig-assist unit. Later designs of a similar type were used in the field.

The US Patent office granted Townsend his patent on 1 July 1926, number 1,586,923.

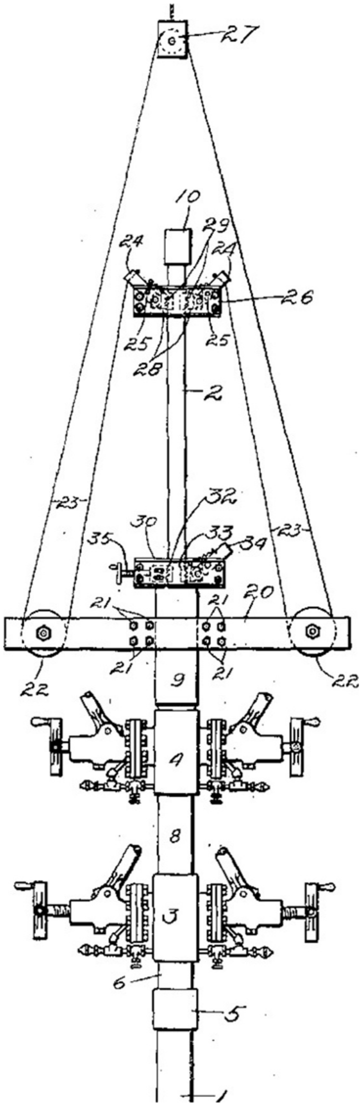
1.2.2 Otis Patent—1929

On 26 September 1929, H. C. Otis filed a patent for an "apparatus for inserting tubing in wells, serial number 395,315" now known as a conventional snubbing unit (Fig. 1.3). Like the Townsend patent, this device used a stationary frame mounted directly to the well and a traveling head both with slips designed to grip the pipe.

The traveling head in this device was connected to the rig's blocks by a single cable strung through pulleys at or near the rig floor and just below the traveling block. The sheaves were installed in a frame that was attached directly to the wellhead through a set of flanged "spacer" pipe spools. Unlike



■ **FIG. 1.2** Townsend Hydril packer.



■ **FIG. 1.3** Otis patent, 1929.

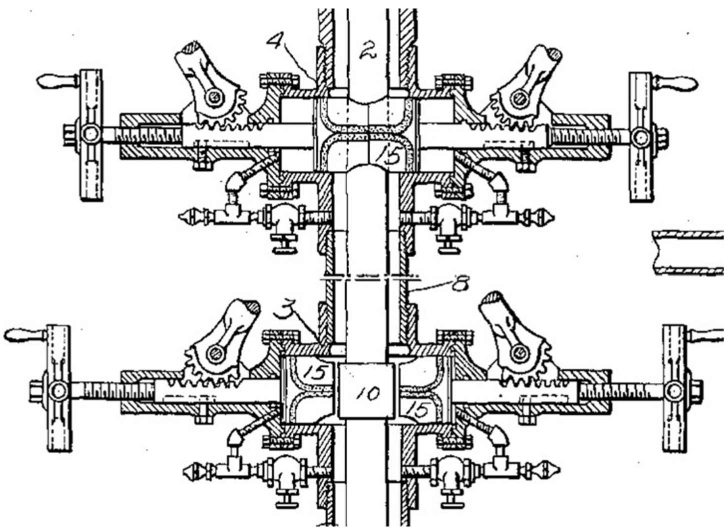
the Townsend design, the Otis design had two BOPs mounted below the snubbing device. The pipe was snubbed DOWN by pulling UP on the blocks until the connection (usually a collar) was just at the top of the upper BOP. The lower BOP was closed, and the pipe was snubbed down a short distance until the connection was just at the top of the lower BOP. Then, the upper

BOP was again closed, the lower BOP was opened, and the process was repeated on each joint of pipe in the drill string. This process is called ram-to-ram snubbing, and it is still used today.

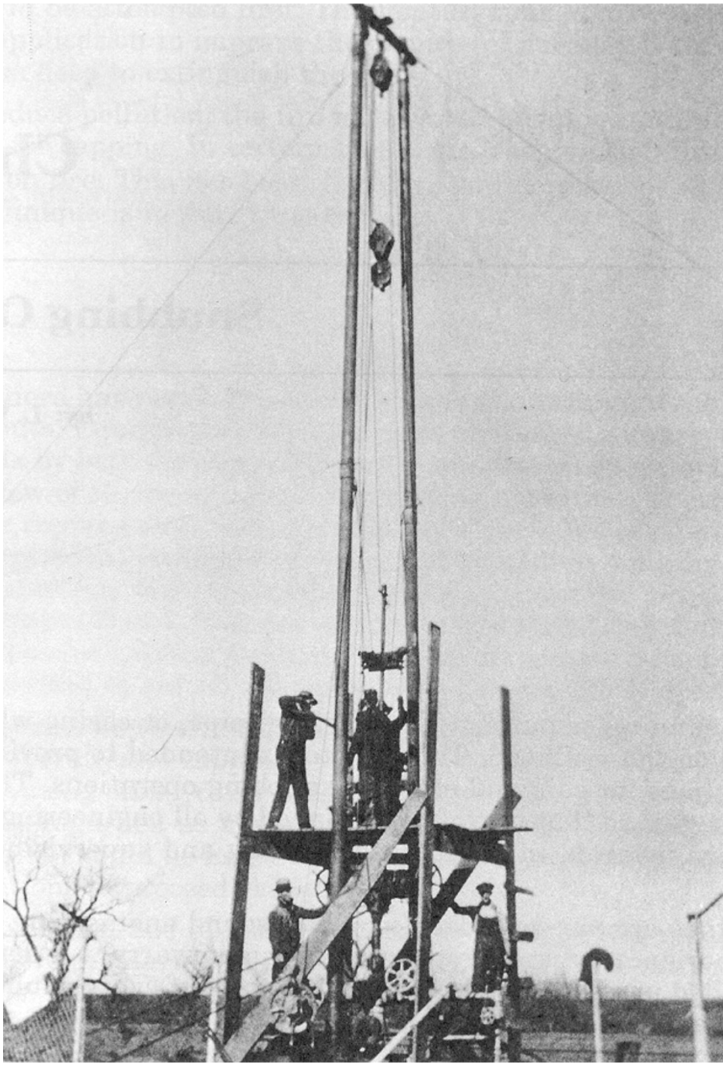
Mr. Otis reported that it took considerable training and control for most drillers to operate this snubbing unit, at least the first time. It was quite unnerving for a driller to watch the pipe going in the hole while he was picking up on the blocks. Many drillers locked down the brake handle and refused to snub tubing into a well because they became so confused about the "backward" operation of this unit.

Otis also filed a patent on the tubing BOPs on 16 November 1928, serial number 319,864. The BOPs had rubber elements that were "crushed" onto the tubing exterior by a piston. The piston rod was attached to a simple tooth gear with an extended handle. Each BOP cavity was equipped with a bleed line and valve to relieve pressure buildup in the cavity and in the well below the rams. The rubber elements could be opened quickly using the handle allowing the connection to pass through after bleeding off the pressure (Fig. 1.4).

This device allowed much faster operation than the hydraulic annular BOPs in the Townsend device. The slips, both stationary and traveling, were also actuated by a lever. The result was that tubing could be run or pulled quickly in a pressured well without having to kill the well and keep it dead (Fig. 1.5).



■ **FIG. 1.4** Otis BOPs.



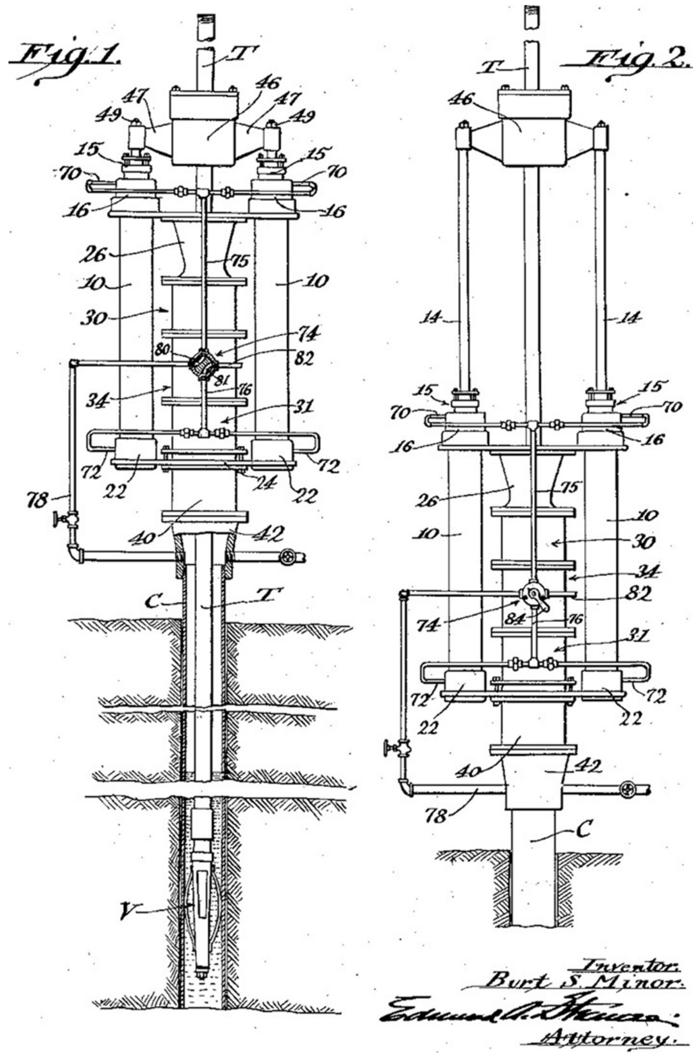
■ **FIG. 1.5** Early Otis snubbing unit installing tubing, *circa 1926*.

Otis' patent for this apparatus was granted on 17 January 1933, Patent No. 1,894,912, and it was the mainstay of the snubbing industry for several decades. It also became the basis upon which Otis Engineering (later merged with Halliburton Services) was built and prospered for many years. There are still a few conventional snubbing units in existence, but they are rarely deployed. Many of the innovations in this design are still in use today, however.

1.2.3 Minor Patent—1929

Bert S. Minor filed for a patent on a hydraulic snubbing unit on 21 October 1929. The patent was granted on 24 January 1933, patent no. 1,895,132, only 1 week after the Otis patent.

This snubbing unit has some of the features of the Townsend patent, but it differs significantly in several respects (Fig. 1.6). First, the BOPs in the Minor patent are all pneumatically operated using pressured gas to close them



■ **FIG. 1.6** Minor patent—1929.

onto the tubing. These BOPs are inflatable "bags" that surround the pipe unlike the mechanical "glands" used in both the Townsend and Otis designs.

Secondly, this design includes an extra BOP below the snubbing unit, a BOP we now term a "safety" because it allows the well to be closed in to change out the sealing elements in the upper two snubbing BOPs.

Pipe slips were spring-loaded for gripping and running pipe in the hole. As a connection (coupling) approached the slips, they simply opened allowing the connection to pass through the slips. They would then snap onto the pipe body behind the collar. There is no mechanical activation of the slips. Presumably, when snubbing out of the hole, the slips could simply be turned upside down so they will grip in the opposite direction.

Finally, the cylinders are large and robust. They are designed to use gas and well pressure to lift or snub the entire string simply by directing pressured gas to one end of the pneumatic cylinder or the other. In other words, the cylinders can either pull or push.

In his application, Minor mentioned the complexity, the time required to rig up, and the confusion associated with the "cable" snubbing unit design offered by Otis. Literature mentions that the Otis design was being used in the field before this patent was granted, so Minor may have seen the difficulties associated with the "backward" operation of the conventional Otis unit (also mentioned by Otis himself).

This unit has essentially all of the features of a modern snubbing unit except that these new units operate using pressured hydraulic power fluid instead of gas from the well. Further, because this unit is tied directly to the wellhead, all force is transferred to the well's casing instead of a rig. In fact, except for handling pipe, this is a standalone pneumatic snubbing unit; no rig is required for snubbing pipe into or out of the hole in this design.

It is not known if Minor ever built this snubbing unit, but soon after the patent was granted, a similar unit was mentioned in the literature. It is possible that another company, possibly Otis, purchased Minor's patent and began manufacturing a pneumatic snubbing unit based on his design. It is truly the forerunner of modern snubbing units.

1.3 EARLY SNUBBING EXPERIENCE

Available literature mentions several snubbing operations in the early 1930s. There is a gap in the literature until about 1960, but snubbing had become an accepted method of dealing with pressured wells and several innovations had been introduced without fanfare. So, the absence of literature is not unexpected.

1.3.1 Kettleman Hills Field—1931

In 1927, two wells drilled in the Kettleman Hills field in California blew out. Both wells were capped. One was allowed to produce in a cap-and-divert configuration because surface pressures would have exceeded wellhead capabilities causing the well to blow out again.

In 1931, the wells were reentered and equipped for long-term service using a combination of equipment described in the Townsend and Otis patent applications. A pull-down yoke was connected to cables operated by a "sand reel" mounted above the drawworks on a modified drilling structure. The yoke was used to pull pipe into the well or snub it out of the hole.

Wellhead pressure was contained by a combination of a Townsend Hydril packer (annular BOP) mounted on the wellhead (actually the capping stack). A special composite packer was mounted above the annular BOP. It was composed of two sections. The bottom section was a rubber "bag" that could be inflated to trap pressure against the outside of the 3½ in. drill pipe. The upper section was a cone of "special composition" rubber that could be deformed onto the drill pipe exterior by a piston using well pressure. Controlling the pressure to this piston allowed the pipe to move without excessive rubber element wear. In today's terminology, this upper section would be called a "pressure assist annular BOP."

The device contained two sets of slips, one stationary and one on the traveling yoke. The slips were manually operated but had to be held open by an operator. This created a fail-closed feature in case of an emergency. If the slip operator turned loose of the handle for any reason, the slips automatically set on the pipe.

Maximum well pressure on the first well was 1300 pounds per square inch (psi) that placed an upward thrust of approximately 12,000 lb_f on the 3½ in. drill pipe. After snubbing 870 ft. of pipe into the hole, the weight of the string exceeded the expulsion force, and the pipe was run through the two annular BOPs for continued operations. When this depth was reached coming out of the hole, snubbing was resumed to prevent expulsion of the pipe. A drill string fish was recovered from the first well, and a new drill string was run to total depth (TD). The well was circulated with kill weight mud, and the well was deepened. The well was deepened using conventional drilling techniques before being returned to production.

The same snubbing equipment was rigged up on the second well. The drill string fish in the second well was engaged at 1596 ft. by snubbing a pack-off overshot on 3½ in. drill pipe to the top of the fish. Heavy mud was circulated through the drill string fish to the bottom of the well and back to the surface killing the well. Normal workover operations continued after the well was killed.

These two jobs clearly showed the value of snubbing for well control, one of the common uses for snubbing since that time. Prior to these jobs, bullheading heavy fluid into a well with similar downhole conditions was the only known way to kill the well making it safe for normal operations.

1.3.2 Managed Pressure Drilling—1933

In 1933, M. C. Seamark of the Anglo-Persian Oil Company wrote a paper outlining experiments in Persia (present-day Iraq) on drilling and completing live wells (wells having surface pressure on the wellhead). The purpose was to avoid killing wells using heavy oil-based muds causing reservoir damage and to prevent blowouts should the wells become underbalanced.

Anglo-Persian's efforts involved drilling with pressure on the wellhead. This involved both cable tool and rotary drilling. In cable tool drilling, a polished rod and stuffing box were used to trap pressure while still allowing the drill line to reciprocate. Pressure could be trapped under the stuffing box preventing the well from flowing fluids from objective formations, filling the hole and limiting progress. According to Seamark, this was used successfully up to 750 psi wellhead pressure.

Rotary drilling used both a Townsend Hydril annular packer and an inflatable bag (similar to a diverter element) to seal around rotating drill pipe. Seamark also accurately described a rotating head "… with a rotating element that would seal on the drill string driven by a head that conformed to the shape of the kelly." This preceded the invention of the rotating head and rotating BOP by several decades.

Importantly, this paper describes using snubbing equipment to pull or run a drill string under pressure. The Otis-style conventional snubbing unit was described (despite never crediting Otis) as being a "well-known" method of snubbing. He also described two hydraulic rig-assist units. The cylinders of one used "gas or liquid" pressure to operate the rams that raised or lowered the traveling frame. The other used mud pumps (i.e., "slush pumps") to provide pressure to the cylinders while snubbing in and out of the hole. In this design, the traveling slips were connected to an anchor point using chains instead of a frame.

This paper pointed out the necessity of snubbing as part of a managed pressure drilling (MPD) scenario to avoid killing the well. In this drilling technique, wellhead pressure is maintained to control flows. If mud were used to kill the well, the benefits of drilling with an overbalanced mud column to sustain an adequate tripping margin would have been lost. The well is drilled under a balanced back pressure at all times. This technique is still used in MPD today. Snubbing is still required to prevent overpressure from impacting sensitive formations.

Another 1933 paper, written by C. A. Moon, also discussed pressure drilling applications in Venezuela. He mentioned that flush joint drill pipe had the advantage of allowing continuous rotation in pressured drilling with an annular BOP or stuffing box. The use of flush joint drill pipe for this purpose was introduced in Mexico. It was extended to fields in Venezuela due to higher formation pressures although it was 15% “dearer” (more expensive) than jointed drill pipe.

Moon indicated that the avoidance of problems snubbing collared drill pipe into and out of the hole and during rotation easily compensated for the additional drill string cost. The use of this pipe also allowed the use of smaller-diameter casings since the collar in standard drill pipe at that time was no longer a consideration. The casing ID could be reduced, and this dropped at least one casing size on each well providing even better economics for some wells. In the alternative, larger-diameter drill pipe could be used in a standard casing design. In his example, 4½ in. flush joint drill pipe could be run with adequate clearance inside 6⅝ in. casing instead of the usual 3½ in. collared drill pipe.

Moon also discussed borehole instability issues resulting from using kill weight muds. Soft, friable formations and shales sloughed into the hole when using heavy muds. The use of a lighter density mud prevented this from occurring. More importantly, the cost of maintaining the heavy mud was avoided making marginal drilling opportunities cost-effective.

Disadvantages of using flush joint drill pipe such as added casing wear due to greater contact with the casing interior while rotating (i.e., no centralization from collars) and weak joints/connections were not apparent during 2½ years of pressured drilling work in Venezuela. Again, the ease of snubbing and rotating this pipe relieved much of the cost and risk associated with MPD.

1.3.3 Pressured Completions—1929–1974

H. C. Otis presented a paper in 1929 in which he discussed snubbing using the Otis apparatus in high-pressure wells to initiate production without killing wells after they have been completed. He also discusses well control options for cable tool-drilled wells, snubbing liners or screens into producing wells, and fishing operations all with pressure on the wellhead.

Otis also introduced a rule of thumb in this paper that is still in use today. He said that "approximately 1 ft. of pipe of any diameter must be snubbed (before reaching the neutral point) for each pound of pressure on the wellhead."

He also introduced a breakable tubing plug made of cast iron. Once the tubing was landed on the bottom, the plug in the base of the tubing, equipped with a pointed projection, shattered a cast iron disk permitting flow up the tubing. This would be modified later to permit dropping a bar to shatter a thick glass or ceramic disk to initiate production without turning the tubing once it landed in the tubing head and the tree is installed. This technique was the forerunner of underbalanced perforating using tubing-conveyed perforating guns.

This paper and his snubbing apparatus application established Otis as the expert on snubbing in its early history. He is often referred to as the inventor of snubbing although there was an earlier patent application for a snubbing apparatus and the use of snubbing as a technique for getting pipe into difficult holes.

A 1933 paper by James Cuthill described running tubing into recently drilled and perforated wells with pressure on the wellhead. Cuthill's paper deals with both BOPs and snubbing equipment.

The Minor and Otis equipment was reviewed in this paper along with ram-to-ram snubbing using ram-type BOPs. Cuthill also discussed the various types of BOPs, various types of pack-offs, and the use of a bottom "safety" ram for high-pressure operations. He also discussed an innovation that involved a dual ram snubbing system mounted on a hinge in the derrick. This was used when snubbing tubing into or out of the hole, but once the string became pipe-heavy, it could be folded out of the way to allow operations to continue until it was needed again. This is the first mention in the literature of a true rig-assist snubbing unit.

A paper written in 1934 by E. V. Foran discussed snubbing drill pipe while drilling the Ellenburger formation at about 8300 ft., and later snubbing tubing into wells, in the Big Lake Field south of Midland in West Texas.

Formations down to a point a few hundred feet above the Ellenburger were drilled with water. The hole was cased with 7⅝ in. pipe. The Pennsylvanian lime is a low-pressure zone that could not withstand a full column of water. So, to avoid losing circulation, high-pressure gas was introduced along with water to drill through this formation and into the fractured, but higher-pressure, Ellenburger. Obviously, this meant that flammable gas was returned to the surface along with water and drill cuttings from the annulus.

Pressure was controlled by a Hydril annular "drilling packer" (another annular BOP) with a second annular BOP and a conventional ram BOP below it for safety. Conventional hydraulic snubbers and a hydraulic rotary table were used during these "live" drilling operations.

The drill pipe was snubbed out of the hole, and a packer was prepared to be run on tubing. The tubing was snubbed in the hole using an Otis conventional snubbing unit (cable equipped). The well was allowed to flow through a choke manifold, while the tubing and packer were snubbed in the hole. The packer was landed and set, and the tubing plug was pulled to initiate production up the tubing.

Interestingly, in the discussion portion of the paper, another Operator mentions using the same drilling and completion technique using an Otis conventional snubbing unit in the Yates field with similar results.

A 1974 paper written by R. J. Silberman and Rod Wetzel discussed the use of both hydraulic snubbing units (jacks) and coiled tubing to limit formation damage due to overbalanced mud columns. Some formations are sensitive to certain chemicals used in the mud systems, and pore throat plugging from back flooding of solids from heavy muds is possible. Problems included plugging from perforating gun debris, shale swelling and sloughing, and unstable formation production, primarily sand. Completing and working over wells underbalanced using snubbing and coiled tubing equipment avoided this formation damage while providing a safe working environment for crewmembers.

1.4 RECENT DEVELOPMENTS

Numerous innovations and modifications of equipment and procedures have resulted in the expansion of snubbing from an early well control process into general use in the oil field. These uses include pressured drilling, workovers, well control restoration, and snub drilling.

1.4.1 All Hydraulic Units

By 1960, snubbing units had evolved into those using high-pressure hydraulic fluid and hydraulic/pneumatic control systems that simplified snubbing operations to the extent that only a four-man crew was needed to manage most jobs. Hydraulic cylinders (jacks) made control much finer resulting in increased safety, speed, and reliability. The popularity of snubbing as a competitive technique for dealing with "problem" situations improved, and the availability of snubbing equipment and crews increased.

In 1973, the first standalone snubbing units were introduced. These units did not require support from a rig of any kind. They were rigged up on top of the wellhead and guyed to anchors common on most locations. A tall jib (crane) handled tubing joints that were pulled and laid down on the site later to be picked up by the jib and snubbed back in the hole. This was particularly important in offshore operations because a jack-up or platform rig was simply not needed, and the snubbing unit occupied a small footprint on the platform. Now, truly "rigless" operations were possible for jointed pipe both onshore and offshore.

Some of the onshore rigs were trailer-mounted, and a crane was required to rig them up. They were heavy, and rigging up was slow and cumbersome. Often, the crane was used to support the tall snubbing unit or to handle pipe instead of using the jib.

1.4.2 Combination Hydraulic/Mechanical Units

In 1975, Otis Engineering Corporation filed a patent application for a snubbing unit that used a combination of two hydraulic cylinders and a cable system attached to the traveling head. This unit was a rig-assist unit (it needed a mast of some type to support the upper pulleys) that could use rig pumps as a source of hydraulic power. When pump capacity was limited, the drawworks on the rig itself could be used to snub pipe into and out of the well. When both were available, the unit could snub heavy loads such as casing strings with little difficulty (Fig. 1.7).

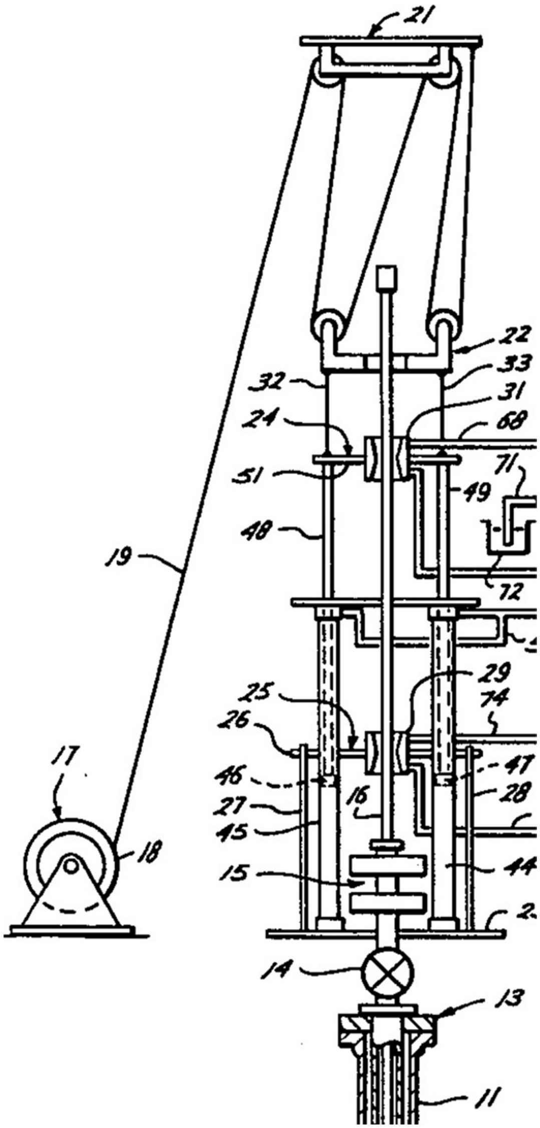
Again in this design, the rig's BOP stack was used as a "safety."

US Patent No. 3,999,610 was assigned to this invention when the patent was approved on 28 December 1976.

1.4.3 Snub Drilling Unit

David Buck and Dan Bangert filed an application for a patent on a snubbing unit equipped for drilling in early 2000. This patent was significant because it included a power tong and backup tong for making up and breaking out jointed pipe. This feature is included on many snubbing units today. It also included a rotating traveling slip and hydraulic rotary table used to turn the pipe string (Figs 1.8 and 1.9).

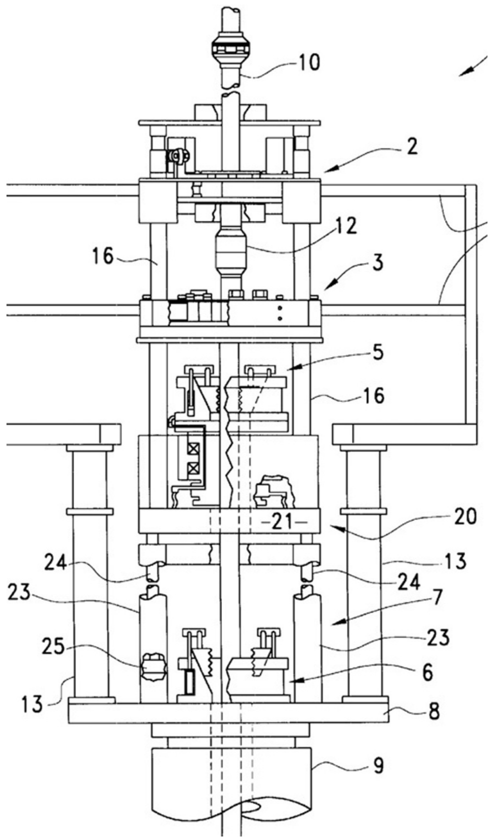
A final improvement was a set of stationary arms to prevent the traveling table from turning in response to reverse torque applied by the rotary table (Fig. 1.10). The jack rods were not exposed to this torque, one of the primary dangers of snub drilling. If the jack was to be twisted by the torque, the hydraulic cylinder would not function properly due to excessive



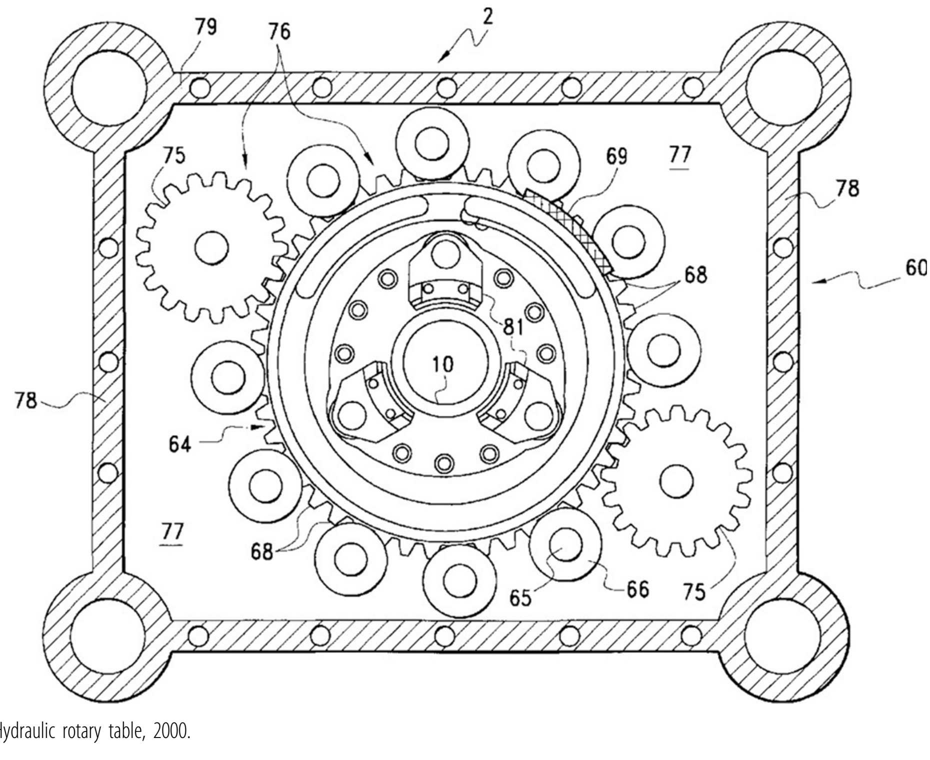
■ **FIG. 1.7** 1975 Otis Combination Snubber, 1976.

ram-on-wall friction. This is still one of the most serious concerns with rotary operations from a snubbing unit: twisting a jack or set of jacks.

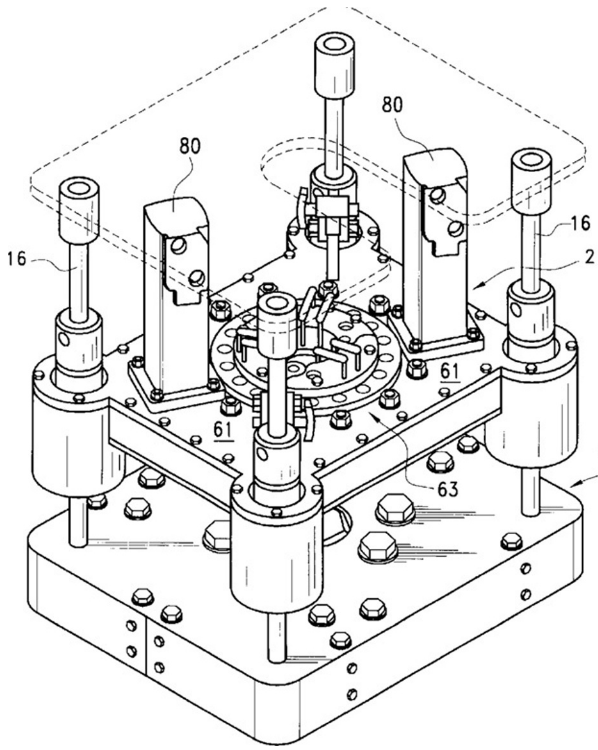
The invention of this rotary table and rotating slip assembly made workovers, recompletions, and sidetrack drilling possible using a standalone snubbing unit or as an assist to a small workover rig. This also made offshore



■ **FIG. 1.8** Rotating traveling slips, 2000.



■ **FIG. 1.9** Hydraulic rotary table, 2000.



■ **FIG. 1.10** Antirotation arms, 2000.

workovers requiring pipe rotation capability much less expensive because of the snubbing unit's small footprint and its standalone features. Rigless workovers became much more attractive for many wells.

1.4.4 Miniaturized Rig-Assist Units

In the late 1970s, designs of small hydraulic snubbing units were introduced in Canada to replace old cable-type snubbing units for installing tubing in low-pressure, shallow gas wells. These 50–300 psi wells only required snubbing capabilities for a short section of the tubing string, so small snubbing units with limited stroke length, hoist, snubbing capacity, and reduced manpower became attractive.

These small snubbing units were intended to fit inside the completion rig's derrick, and the rig's usual BOP stack provided the safety BOP function. The rig handled all pipe while snubbing was in progress. As soon as the string became "pipe-heavy," the snubbing unit's BOPs permitted ram-to-ram stripping, and the stationary slips were used to run the tubing in the hole.

■ **FIG. 1.11** Rig-assist unit. *(Courtesy of International Snubbing Services.)*

The first rig-assist units were short hydraulic units with only about 6 ft. stroke length (Fig. 1.11).

They could be rigged up in two lifts using the rig's hoisting system. One lift would set the snubbing BOPs on top of the rig's annular BOP using a flanged pipe riser to get the BOPs above the rig floor. The second lift would hoist the jack frame into position. Often, the rig's tongs would be used to make up and break out tubing connections. Depending on derrick height, the pipe could often be racked into the derrick in doubles (two-joint sections) or thribbles (three-joint sections).

The early designs had from 160k to 228k lb (160,000–228,000 lb_f) hoisting and from 80k to 110k lb snubbing capability. The hydraulic power-pack was included that supplied pressured fluid to operate the unit, a return holding tank, and an accumulator system to store pressured fluid. BOP controls were remote to the snubbing unit. They either rested on a skid set on the ground near the rig or remained on a truck or trailer to facilitate rapid operation. Only two snubbing crewmembers were required since the rig crews managed pipe-handling duties.

Other small snubbing units quickly became available, some with integrated jack/BOP designs that could be installed in a single lift. These were fitted inside the rig's derrick and used in underbalanced drilling operations. One of these small rig-assist units is known as a push-pull machine.

Push-pull machines are small devices. Some are short jack-operated units with maximum hoist capability of about 89k lb. Like their larger brothers, these units have both stationary and traveling slips with very limited vertical travel for each "bite" of pipe. Another design has a set of parallel vertical tracks for chains that carry a traveling frame equipped with slips to pull or push the pipe out of or into the hole under low pressures. Stationary slips are located in the unit's base. The rig's safety BOPs and a rotating pack-off or annular preventer are the only devices used to control pressure in the annulus (Fig. 1.12).

In this example, the chain is operated by hydraulic motors instead of jacks. The motor is reversible such that snubbing in or out of the hole is possible. There is no overhead work basket; controls are located in a panel on the rig floor. The power-pack is remotely positioned with hydraulic fluid supplied through hoses to the rig floor. This unit has a very small footprint and is designed to simply be moved to the side once snubbing operations are complete. The unit slides back into position when it is needed again.

In another design, rollers driven by hydraulic motors are used to pull or push the pipe. Two sets of these are mounted on a rigid frame with hydraulic pistons that push the rollers onto the pipe. The pistons maintain constant lateral force against the pipe regardless of whether a pipe, a collar, or an upset is beneath the roller. Snubbing occurs continuously as long as the rollers are engaged. Once the string becomes pipe-heavy, the rollers are retracted by releasing pressure on the roller cylinders. The rig can then handle the pipe without interference from the push-pull system.

Between 1980 and 2000, just under 100 rig-assist units of various designs were introduced into the Canadian market, many performing only completion and workover operations. Some of these units had passive rotary tables to permit makeup and breakout of tool assemblies.

■ **FIG. 1.12** Push-pull machine. *(Courtesy of Halliburton Boots and Coots.)*

Miniaturized snubbing units were introduced in 2004. These units have 40–90k lb hoisting capability and are self-contained (Fig. 1.13). They have 3–4 ft. stroke lengths for light weights and low pressures. The unit has no BOPs, relying instead on an RS100 stripper assembly, similar to a pack-off on a

■ **FIG. 1.13** Mini snubbing unit. *(Courtesy of Team Snubbing.)*

coiled tubing unit. There is no equalizing or vent loop. Any trapped pressure is bled off through a valve. Once again, the rig's BOPs are used as safeties.

These units are very light and can be hoisted into position in a single lift. Installation and rig up/rig down are simple and rapid. There is no basket on the unit; the operator has a small control panel that sits on the ground, platform deck, the rig floor, or the bed of the same truck that transports the unit. The truck engine powers a hydraulic pump through a power takeoff (PTO). All pipe handling, makeup, and breakout are done by the rig. The crew commonly consists of only one person. These units entered the shallow, low-pressure Oklahoma gas well market in 2006.

In 2007, an adaptation of the hydraulic rig-assist unit was made that allowed them to work as standalone units. These are known as standalone rig-assist (SARA) units. These were fitted with a jib (small mast and hydraulic counterbalance winch) for pipe handling. These are still in use today throughout the United States, Canada, and worldwide adding considerable flexibility to the market. One of these is shown in standalone mode in Colorado in Fig. 1.14.

This SARA unit is shorter than a conventional similar standalone unit. The top handrail around the work basket here is 21 ft. above the ground where the top handrail of a 150k standalone unit is at 34 ft. This truck-conveyed unit

■ **FIG. 1.14** 142k SARA snubbing unit. *(Courtesy of Snubbertech Manufacturing.)*

requires only about 30 min to rig up in a single lift where a conventional snubbing unit can require upward of 4 h to rig up. The unit has an 11 ft. stroke making it capable of running a full joint of pipe in three bites after the strings becomes pipe-heavy, so it can compete easily with the 150k standalone unit. Obviously, it is small enough to fit inside a derrick to work in rig-assist mode as well.

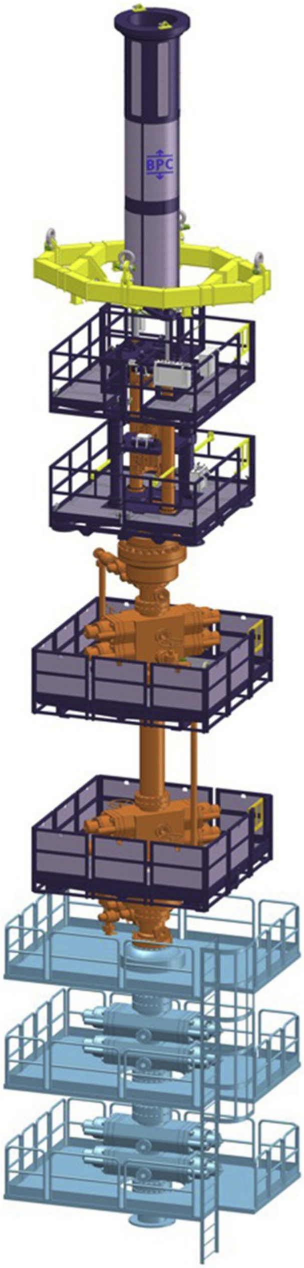
Some of these small SARA units now have load-spreading supports so that they do not require guy wires and ground anchors. Others are skid-mounted and self-elevating with the skid serving as the load support. Rigging up is simple and very fast. Most of these units have only one person in the basket running both the snubbing function and the winch panel. Only one other person is required to help pick up and lay down pipe.

A recent adaptation of the rig-assist snubbing unit is a concentric snubbing unit. This unit is installed completely below the rig's rotary table on an offshore well or an onshore well with a tall substructure. The unit is remotely controlled and is equipped with an electric-driven power-pack that runs off rig power instead of a diesel or gasoline engine (Fig. 1.15).

The unit does not interfere with normal rig operations as it is below the rig floor. One man operates the unit from the driller's cabin using three computer monitors with operating conditions shown along with video feeds of the equipment.

Recently, a 160k snubbing unit has been incorporated into a system that is 100% remotely operated. It includes the rig, connection makeup and breakout tools, a hydraulic catwalk, pipe-handling equipment, and a snubbing unit. There are no crewmembers on the rig floor or in the snubbing basket. The system makes extensive use of computer-controlled robotic devices, controls, and cameras for equipment observation. Controls are housed in a remote cabin or trailer with no humans near the wellhead during operations except for maintenance. This, of course, significantly improves safety and reduces human error since all commands require computer "agreement." Should a safety interlock be overridden, human operators must first disengage the lock out provided by the computer system.

It is anticipated that remote operation of full-sized snubbing units coupled with robotics will be the future of snubbing in the oil field. Other future innovations and improvements are expected as snubbing and hydraulic workover technology continues to advance.



■ **FIG. 1.15** Concentric snubbing unit. *(Courtesy of Balance Point Control.)*

CHAPTER 1 QUIZ

1. What is the definition of oil field snubbing?
- **A.** Pushing pipe into a well using a snubbing unit
- **B.** Pushing pipe into a well when expulsion for due to wellbore pressure exceeds the weight of pipe in the hole
- **C.** Pushing pipe into a well when the weight of pipe in the hole exceeds expulsion force due to wellbore pressure
- **D.** Running pipe into a well

2. How did oil field snubbing get its name?
- **A.** From nonoil field sources such as marine or railroad operations
- **B.** From agricultural sources such as breaking horses with a "snubbing post"
- **C.** From oil field operations to pull stubborn pipe into a hole when it wouldn't run under its own weight
- **D.** Nobody knows for sure

3. What is the definition of stripping?
- **A.** Pushing pipe in the hole when the expulsion force from well pressure exceeds the weight of the string
- **B.** Removing any unwanted coatings or coverings from pipe before it is run in the hole
- **C.** Running pipe in the hole under pressure when the weight of the string exceeds the expulsive force on the pipe from wellbore pressure
- **D.** Running pipe into a well

4. Stripping requires the use of a snubbing unit.
- **A.** True ____
- **B.** False____

5. When was the first patent, also known as the Townsend patent, filed in the United States?
- **A.** 1924
- **B.** 1926
- **C.** 1929
- **D.** 1933

6. The most important portion of the Townsend invention involved what device?
- **A.** The use of hydraulic cylinders for snubbing
- **B.** The annular blowout preventer
- **C.** The compact size of the unit
- **D.** The unit's rig-assist capability

7. The first practical snubbing unit was invented, manufactured, and operated by whom?
   - A. Elvin E. Townsend
   - B. Herbert C. Otis
   - C. Bert S. Minor
   - D. Red Adair

8. Work on two early Kettleman Hills North Dome Field wells clearly established snubbing as an attractive means for what overall purpose?
   - A. Running tubing into wells
   - B. Underbalanced drilling in an overpressured reservoir
   - C. Well control
   - D. Avoiding regulatory intervention

9. Using H. C. Otis' rule of thumb for snubbing to the balance point of a pipe string, how many feet of 2⅜ in., 4.7 lb/ft., external upset end (EUE), eight-round thread (8rt) tubing must be snubbed if well pressure is 5000 psi at the surface?
   - A. 3000 ft.
   - B. 4700 ft.
   - C. 5000 ft.
   - D. 7000 ft.

10. Using H. C. Otis' rule of thumb for snubbing to the balance point of a pipe string, how many feet of 3 ½ in., 9.3 lb/ft., EUE, 8rt tubing must be snubbed if well pressure is 8000 psi at the surface?
    - A. 5000 ft.
    - B. 8000 ft.
    - C. 9300 ft.
    - D. 11,000 ft.

11. Ram-to-ram snubbing or stripping is a means to control well pressure while avoiding excessive wear to the upper ram packers.
    - A. True ____
    - B. False____

12. The Buck and Bangert patent for snub drilling filed in the early 2000s included the following significant features:
    - A. An elevated work basket that allowed operators to visually monitor drilling operations
    - B. An extended jib pole
    - C. A hydraulic rotary table, rotating traveling slip, and a power tong for connections
    - D. Hydraulic cylinders for snubbing and hoisting pipe

13. When imparting rotary motion at the top of a hydraulic snubbing unit, the most serious concern involves:
  A. Sizing the rotating equipment to turn the entire string of pipe in the hole to provide enough horsepower to turn the bit at a high rotary speed
  B. Making sure that power tongs can break connections that have been over-torqued during rotary drilling operations
  C. Maintaining a penetration rate that competes with conventional drilling rigs
  D. Twisting the hydraulic jacks due to reverse torque

14. A rig-assist snubbing unit is required on a conventional rig for what reason?
  A. To provide the capability for pushing pipe in the hole since the rig's hoisting gear usually cannot snub pipe
  B. It is needed throughout the entire trip running pipe into and pulling it out of the hole
  C. Uses equipment that is not connected to the rig's blowout prevention system
  D. It is very simple and can be operated by the rig's floorhands and roustabouts

15. A push-pull machine is a type of rig-assist snubbing unit.
  A. True _____
  B. False_____

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Chapter 2

Snubbing Unit Components

CHAPTER OUTLINE

Hydraulic Rig Technology and Operations. https://doi.org/10.1016/B978-0-12-817352-7.00002-6

2.1 INTRODUCTION

What is a snubbing unit? What is a hydraulic workover (HWO) unit? What is a hydraulic drilling rig?

This chapter describes the basic components of hydraulic rigs in general terms to acquaint the reader with the equipment involved in these units and with some of the nomenclature used for both the equipment and the processes involved in each. More detailed descriptions of certain components along with discussions on how they were developed are included in Chapter 3.

Snubbing units of all types share some common characteristics whether they are the old cable-style conventional snubbing units, freestanding hydraulic rigs, rig-assist hydraulic snubbing units, or push-pull units. They all have the primary purpose of pushing pipe into a well under pressure and restraining the pipe from expulsion while coming out of the hole as long as the string is "pipe-light" (i.e., when the weight of the pipe in the hole is less than the expulsion force created by well pressure). The way they accomplish this purpose varies slightly from unit to unit.

An HWO unit is similar to a snubbing unit in that hydraulic cylinders are used for lowering pipe into and hoisting it out of the well. Hydraulic workovers are performed on dead wells implying that there is no expulsion force from well pressure and therefore no need to snub or strip pipe into and out of the hole. An HWO unit is configured differently than a snubbing unit although both share some common characteristics and equipment.

A hydraulic drilling rig uses hydraulic cylinders to provide hoisting and snubbing capability when needed. It also has the capability to rotate pipe using a hydraulic rotary table or other device while simultaneously lowering the pipe string to drill new hole. It might be equipped for ram-to-ram snubbing for underbalanced drilling (UBD), or it might be equipped like an HWO unit for dead well drilling operations with no snubbing capability.

Knowledge of the components of all three types of hydraulic rigs is needed to understand the forces and design parameters used to build and operate these units.

2.1.1 Naming Conventions

All hydraulic rigs employ the "hand-over-hand" method of transferring loads that use common terminology in describing their components. The "hand-over-hand" method refers to having a set of slips in an anchored position with another set of slips that can move vertically. The load is transferred from one set to the other much as one would describe if using one's hands.

When running a pipe string into the hole using a hydraulic rig, one hand raises and grabs the pipe to show how a grip is taken by the movable (traveling) slips. The hand is lowered to show running or snubbing pipe in the hole. Then, the other hand closes and grabs the pipe (the stationary slips). It holds the pipe, while the other hand (the traveling slips) is raised to grab another "bite" of pipe. Then the process repeats. The motions are reversed when coming out of the hole.

A common condition for snubbing or stripping pipe involves the annular seal that must be present to hold annular pressure. This seal can be an annular blowout preventer, a stripping head, a conventional ram blowout preventer (BOP), or any other device that captures and holds pressure inside the annulus. Without this seal, there is no annular pressure and no need for snubbing since there is no expulsion force acting on the pipe. On snubbing units, the type and use of these devices establish a naming convention for them.

If there is no seal, there obviously is no pressure on the well. Then, the hydraulic rig is configured for dead well workovers or drilling, not snubbing. There is no need for some of the equipment found on a snubbing unit or a UBD hydraulic rig to control surface pressure.

There are many common oil field terms that are used in describing hydraulic rigs.

2.1.2 Common Component Descriptions

Some of the common components in almost all hydraulic rigs are described below:

- Stationary slips
  This is a friction-grip device that is mounted in a fixed position designed to hold the entire expulsive force imposed by well pressure on the pipe being snubbed when pipe-light and the weight of the entire string when the string is pipe-heavy. The stationary slips may be connected to components of the BOP "stack" that are supported by the wellhead. They may be mounted to some other fixed point such as the rig floor. Regardless, they are not movable while moving pipe (hopefully).

- Traveling slips
  This friction-grip device is usually mounted on a frame that can move vertically allowing the unit to attach to the pipe a discreet distance up on the string allowing the unit to take a "bite." The length of the bite is defined by the maximum travel allowed by the movable frame (usually 10–12 ft.) or the permissible travel depending on the maximum unsupported length of pipe in the "bite" to avoid buckling (see discussion in Chapter 4).
- Traveling frame (or traveling head)
  A frame connected to some device that imparts vertical motion to the frame whether cables, hydraulic cylinders, chains, or a combination of these. The traveling frame holds the traveling slips and other components such as the hydraulic rotary table below the traveling slips.
- Snubbing BOPs (strippers)
  These are the annular pressure control devices through which the pipe slides as it is being snubbed into or out of the hole. These can be of any design as long as provisions are made to seal on the pipe while it is moving. Often, abrasion limits the life of expendable members within these devices requiring replacement to guarantee a seal. Strippers are not required for dead well operations.
- Safety BOPs (safeties)
  A set of pressure-containing devices that are not actively used for snubbing. These usually remain open except on rare occasions. Instead, they are kept in reserve for emergency situations. In snubbing, they are required to seal on the pipe should the snubbing BOPs fail or require repair. In rig-assist snubbing operations, these BOPs are often the rig's standard ram-type BOPs. Safety BOPs allow only minimal pipe movement to avoid element wear and leakage. The rig's annular preventer can be used as a safety in low-pressure applications, or it can be used to snub/strip pipe in some situations. In HWO and dead well drilling, the only BOPs are safeties (there are no strippers).
- Float
  This is a device run inside the pipe that prevents the flow of fluids up the pipe and into the work basket. It can be a check valve that allows downward flow of fluids through the pipe, but not upward flow, or it can be a plug that prevents the fluid flow in either direction.
  The float is not required in HWO jobs or dead well hydraulic rig drilling since there is no pressure on the well. However, to avoid wellbore fluids from entering the string and being squirted out the top of the pipe, a float is sometimes installed as an option. They may also be used to reduce the risk of an inside-the-pipe blowout if the well should become pressured unexpectedly.

In snubbing, pipe floats and/or plugs are an absolute necessity. There are usually multiple floats installed with the second and subsequent floats being backups to the primary. If one should fail, the other(s) should hold. The primary float must be run far enough down inside the string to permit snubbing the entire string. Backups can be run at various points along the string as needed.

2.2 CONVENTIONAL SNUBBING UNIT

This type of mechanical snubbing unit involves a set of cables and sheaves rigged up to the traveling frame that uses the rig's hoisting system to "pull" the pipe into the hole or, using the rig's braking system, to hold back on the pipe as it is being removed from the hole under pressure. The first of these was built and operated by H. C. Otis in the late 1920s. Since it requires a rig of some type to operate at all, it is, by definition, a rig-assist unit.

While it is not a hydraulic rig, it is included here for completeness. Some of the specific components of this style snubbing unit are shown in Fig. 2.1 and described below.

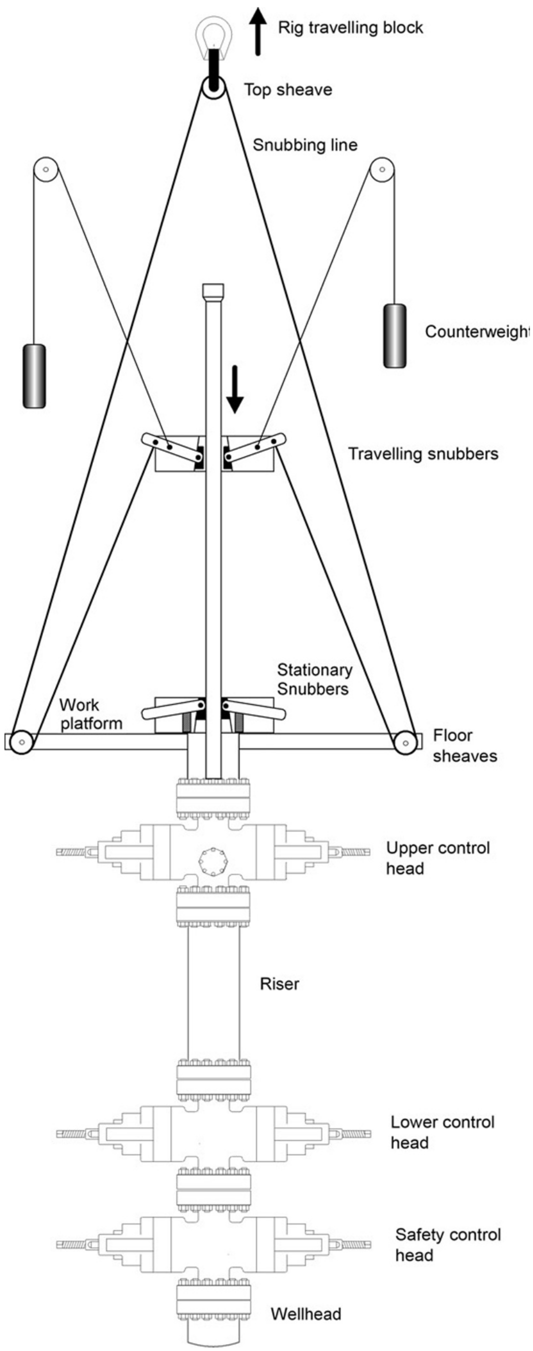
2.2.1 Traveling Snubbers

A rigid traveling frame holding the traveling slips is operated by two cable systems, the snubbing line and the counterweight lines. The frame to which these cables are attached must be capable of transmitting the entire snub force to the traveling slips without being distorted (bending).

In this design, each set of cables also releases or sets the traveling slips as opposed to the manually operated traveling slips in the original Otis patent. The slips are set by the downward pull of the snubbing line and released by the upward pull of the counterweight lines. This allows the unit to get a new "bite" of pipe each time the traveling slips are repositioned without having to reset them manually. In Fig. 2.1, the traveling slips are released as the rig's blocks are lowered (and the traveling snubbers raised) to catch another "bite" of pipe while the stationary slips are set.

2.2.2 Snubbing Line

This cable is a single line both ends of which attach to the opposite sides of the traveling frame. The cable goes through large, heavy stationary sheaves on the floor and over the top sheave attached to the rig's traveling block. In some designs, there are two cables attached to the traveling head and



■ **FIG. 2.1** Conventional snubbing unit components.

directly to the rig's traveling blocks. It is necessary that both of these cables be of identical length, or the traveling frame will cock to one side or the other. This, in turn, prevents the traveling slips from releasing. The one-piece cable using an upper sheave avoids this problem. The traveling frame will always be balanced with identical force being exerted on either side of the frame.

2.2.3 Counterweight Cables and Sheaves

These are designed to lift the traveling head upward when the stationary slips are set and the traveling slips are released to get another "bite" of pipe. The blocks can be lowered to provide slack in the snubbing line, but the traveling slip won't rise unless some upward force is applied. The counterweights provide that force working through the counterweight lines. They also release the traveling slips until they are reset by the rig's upward pull on the snubbing line.

The counterweight cables run over sheaves (small pulleys) hung somewhere in the derrick. The small sheaves are only involved in repositioning the traveling snubbers so they do not experience the same force as the stationary sheaves on the floor for the snubbing line. They can be smaller and less robust.

The counterweight sheaves should be hung at about the same elevation in the derrick, and the two counterweights are of equal weight to prevent the traveling snubbers from cocking sideways while being repositioned on the pipe. The counterweight cables do not have to be the same length, however.

2.2.4 Stationary Sheaves and Work Floor

These are large, robust sheaves for the wire rope that comprises the snubbing line. They are mounted on a frame attached to the stationary portion of the snubbing stack usually just above the top snubbing BOP. This frame is also the foundation for the work floor where crews are stationed. The floor sheaves are spaced far enough apart to prevent interference with the traveling frame and slips. The floor is designed to carry the required snubbing loads, and it must be mounted to resist rotating about the well axis to prevent twisting the snubbing line.

2.2.5 Stationary Snubbers

The stationary snubbers include a bowl and slips connected to an anchor point (usually the wellhead or snubbing BOPs) that hold the expulsion force, while the traveling snubbers are reset in a new position along the pipe in preparation for taking another "bite." In Fig. 2.1, the stationary snubbers are spring activated so that they slide along the pipe's outer surface during the downward stroke. This causes them to set in a fail-safe manner anytime the pipe tries to move up the hole. However, it also risks scoring the outside surface of the pipe while continuously dulling the slips on each stroke. Some stationary slips are manually operated as described in the original Otis patent. These are neither automatic nor fail-safe.

The stationary slips may be the rig's slips inverted for snubbing. They can also be used for running pipe without pressure on the well or for stripping pipe after the string becomes pipe-heavy. In several designs, there are two sets of slips and bowls in both the traveling snubbers and in the stationary snubbers. One of these sets is configured in running mode, and one set is in snubbing mode. These are both bi-directional meaning that both will hold the pipe to keep it from being expelled from the well or from falling into the hole. If they are not bi-directional (i.e., there is only one slip/bowl combination in each snubber), the entire slip/bowl assembly must be flipped upside down (inverted) when the string goes from pipe-light to pipe-heavy and *vice versa*.

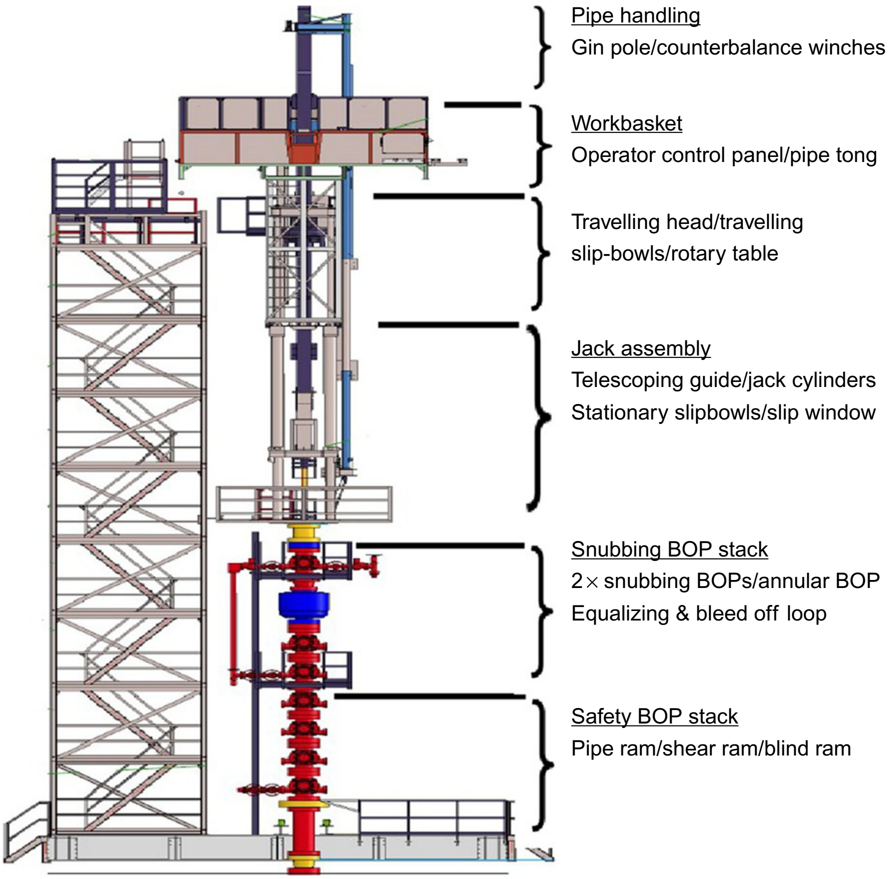
Cable-type snubbing units have undergone several modifications by various inventors after the initial Otis snubber was patented. In one design, the snubbing line(s) are driven by separate hoists or by hydraulic cylinders. In other designs, two power sources are used with one being the rig's drawworks. In others, a rig was not used at all. Power comes from some remote source, and the unit is a standalone unit instead of a rig-assist unit.

Conventional cable-style snubbing units are rarely used today. They have been largely replaced by hydraulic rigs, both standalone and rig-assist, since these are more flexible and easier to operate than the old cable-style snubbing units. There are still several conventional snubbing unit cable sets in existence. Many of today's snubbing crews got their original snubbing training on one of these units. They remain as fully functional backup units but are rarely used.

2.3 HYDRAULIC SNUBBING UNIT

Components of a hydraulic snubbing unit differ from those of a cable-type snubbing unit, primarily in the power source. In hydraulic rigs, the power comes from hydraulic cylinders or "jacks." These jacks use pressured fluid acting on a cross-sectional area providing force in either direction (double-acting hydraulic cylinders). The direction of motion depends on which side of the piston is exposed to the high-pressure power fluid and which side vents low-pressure fluid as the piston moves. The design and operation of hydraulic cylinders are discussed more fully in Chapter 3.

Fig. 2.2 is a diagram of the common components of a standalone hydraulic snubbing unit. Rig-assist units, HWO units, and hydraulic drilling rigs share many of the same components. Standalone hydraulic rigs have no specific need for a conventional rig since they can manage all functions of the job including pipe handling. Major components of a hydraulic snubbing unit are described below.



■ **FIG. 2.2** Standalone hydraulic snubbing unit components. *(Courtesy of International Snubbing Services.)*

2.3.1 Traveling Frame or Head

The traveling frame is the vertically movable portion of the hydraulic snubbing unit that carries the traveling slips and other equipment such as a hydraulic rotary table and other devices. Hydraulic jacks provide the vertical motion and power to raise the frame or lower the frame with or without a snub load. The frame must be centered over the stationary slips, and the load between the individual hydraulic cylinders must be balanced to prevent the frame from cocking side to side resulting in slip lock and bending the pipe where the traveling slips attach during each new “bite.”

2.3.2 Traveling Slips

These are friction-grip devices that hold the pipe once the traveling frame is repositioned to take a “bite” of the pipe. When the unit is snubbing pipe against well pressure in a pipe-light situation, these slips prevent expulsion of the string while allowing for vertical motion. Once the string becomes pipe-heavy and stripping ensues, these slips provide running or hoisting capability (i.e., there is no block-and-tackle hoisting system to strip the pipe into or pull it from the hole associated with a standalone snubbing unit).

The traveling slips must be aligned with the stationary slips and the pipe centerline. If the traveling head and slips are not in alignment, one side of the slips gouges into the pipe, and the other side remains unloaded (loose). This can cause the overloaded slips to become so tightly wedged in place that they cannot be released, a situation called “slip lock.”

2.3.3 Work Basket

The work basket is the relatively small elevated cage that houses the snubbing unit control panels and certain tools such as a stab-in safety valve with the diameter and thread type of the pipe in the string. The cage is the work area for the snubbing crew of 2–3 persons usually with an open top to permit easy ingress and egress. The traveling head is generally centered within the work basket allowing the operator to visually monitor progress and control snubbing operations while allowing full 360º walk-around access. The unit operator runs the jack and slip sets. Another crew member is charged with making up and breaking out joints of pipe from just above the traveling head. The same or another worker operates the hydraulic hoist(s) on the jib (crane) that lifts or lowers pipe to a worker on the ground or platform deck.

Movement within the work basket is restricted because of its small size and the number of people required to operate the snubbing unit. There is an inherent risk to operating a snubbing unit since the basket is aligned with and just above pressure-containing devices packing off the annulus outside the pipe. Leaks from these devices can immediately place the snubbing crew at risk.

The work basket is equipped with one or more emergency evacuation systems. In one of these systems, all crewmembers are fitted with a harness connected to controlled descent devices for rapid basket escape as well. Another involves a slide from the work basket floor to the ground. The work basket is equipped with handrails to prevent accidental falls. It is often winterized for crew comfort and to protect controls from freezing.

The basket may not be present at all on remotely controlled snubbing units. All functions are controlled by personnel in a cabin or at a console positioned on the ground or platform deck. Obviously, there are no crewmembers inside the basket on a remotely controlled snubbing unit.

2.3.4 **Control Console**

This panel contains all controls for the devices associated with the operation of the snubbing unit including jack lift/snub (up/down joystick), traveling and stationary slip controls, snubbing BOP open/close controls (for each ram), and valves for venting pressure trapped below the upper rams. The snubbing unit operator is stationed directly in front of the panel; other crewmembers are positioned elsewhere. The panel also has needle valves to control hydraulic fluid flowrate and pressure. These control hydraulic device operations, such as jack speed. The control panel also houses gauges of various types to show critical operating parameters such as pressures and temperatures.

2.3.5 **Jib (Mast)**

The jib is a small crane with one or more wire rope hoisting lines operated by hydraulically powered reels. The reels and their controls are usually positioned in the work basket opposite the control panel. The jib is used to hoist individual pipe joints from the ground, a transport vessel or truck, or from a platform deck as long as the lift does not exceed the jib's load rating. It then holds the pipe vertically, while the bottom of the joint is connected to the joint in the slips when going in the hole. The reverse procedure is used when the pipe is coming out of the hole, and the jib lays the joint down after it is disconnected.

The jib is used in lieu of a separate crane performing the same service. In some operations where a crane is already on the site, such as a platform crane, it is used instead of the jib usually because of its higher load ratings. The jib, for example, may not be capable of hoisting a heavy bottom-hole assembly (BHA) component such as a drill collar. If another crane is already there, it is often used instead of the jib for heavy loads.

2.3.6 **Hydraulic Jacks**

A common snubbing unit uses either two or four double-acting hydraulic jacks (cylinders) to provide hoisting or snubbing power to the traveling head. When in snub mode, the cylinders pull the pipe into the hole or resist expulsion force while coming out of the hole. When in stripping mode, the cylinders work only in hoisting mode after the neutral point is reached and the string becomes pipe-heavy. In pipe-heavy mode, the string is in tension along its entire length, so snubbing is no longer necessary. Jacks have a snubbing capacity that is roughly one-half of their hoisting capacity because of the way a double-acting hydraulic cylinder is made (see Chapter 3).

Jacks must be balanced in their power-producing capability. If one jack is weak and an opposing jack is strong, the traveling head may be cocked to the side resulting in slip lock. Usually, if one jack requires overhaul for any reason, all the other jacks are overhauled at the same time to ensure that they all operate in common. Power fluid is provided to all jacks equally through a manifold system. This ensures that the pressure needed to operate all the jacks is identical.

Power provided by the hydraulic cylinder to the traveling head depends on the inside diameter (ID) of the cylinder plus the pressure of the power fluid. Larger-diameter cylinders have a larger cross-sectional area across which the pressure acts to provide a force. So, a large-diameter jack operating with lower-power fluid pressure may provide the same force as a smaller-diameter cylinder using higher-pressure fluid.

The size of the hydraulic unit is based on its rated hoisting capacity that, in turn, is a reflection of the ID and number of hydraulic jacks installed. The maximum stroke of the snubbing unit is a measure of the length of the hydraulic jacks (usually 10–12 ft.). The actual stroke used in a snubbing operation depends on wellhead pressure and the maximum unsupported length of pipe of a given outside diameter (OD), wall thickness, and total system friction.

It is critical that jacks remain straight and aligned with the well's centerline to provide the power needed for snubbing. The worst possible scenario for multiple jack operations is for the unit to become twisted. The bending damage to the cylinders and pistons can prevent the jack from extending or retracting, and operations cease quickly. Costly repairs or replacement are usually required when this occurs.

2.3.7 **Telescoping Pipe Guide**

Some hydraulic snubbing units are equipped with a sleeve that surrounds the pipe positioned between the traveling and stationary slips. Because the distance between the two slip sets varies during the stroke, the pipe guide is a telescoping device. It is not a pressure-containing tube. It's only function is to prevent excessive pipe bowing or "lateral displacement" (i.e., it limits the radius of gyration of the pipe being snubbed as the traveling slips compress the pipe). This prevents the pipe from folding, breaking, and exiting the snubbing unit between the two slip sets.

2.3.8 **Base**

The snubbing unit base supports the weight of the snubbing unit and transmits snub loads through the BOP stack and the wellhead to the well's casing. The base is the point to which the hydraulic jacks are connected and, through stationary supports, the work basket and jib. These are all immovable components of the snubbing unit, and the base is the anchor point for all of them.

2.3.9 **Stationary Slips**

Like the traveling slips, these are devices that hold the pipe using friction to prevent vertical movement. They may be single- or bi-directional slips. If they are single-acting slips, they must be inverted when the string goes from pipe-light to pipe-heavy and *vice versa*. Single-acting slips are composed of a bowl and slip segments that "wedge" onto the pipe. Bi-directional slips have two opposing bowls with segments that may be hydraulically or mechanically operated to provide a friction hold on the pipe in both directions. Bi-directional slips do not require reversing, or inverting, at the neutral point. Many hydraulic rigs employ two sets of these slips plus another set to manage heavy pipe loads.

In hydraulic units, both sets of slips are operated by small hydraulic or pneumatic control cylinders connected to rocking arms that drop or retract the slips.

Stationary slips are located above the snubbing BOPs. A riser section may be included to provide a gap to swallow downhole tools that must be snubbed into the hole in a single long section such as perforating guns, jars, motors, and fishing tools. This riser section is commonly called a lubricator since it has the same function as a wireline lubricator. Pipe above the stationary slips is added and the BHA may be snubbed at one time into the hole. Smaller bites can be taken if the BHA is snubbed through an annular preventer that will close on odd-shaped items, not just round pipe.

2.3.10 Work Window

This is a simple frame positioned below the stationary slips and above the safety BOPs that allows access to the pipe being snubbed into or out of the hole in both pipe-light and pipe-heavy situations. The pipe is held in compression when snubbing, but the work window allows the installation of various parts such as centralizers, cables, or certain fishing tools to the string. If the attachment is larger than the traveling and stationary slips can accommodate, the work window provides a way to install the items after the pipe body is run through the snubbing unit.

Often, the pipe string must be disconnected inside the work window to add certain string components. If the string is pipe-light, a slip ram must be installed in a separate BOP ram below the window to prevent expulsion of the string until the snubbing unit's slips can reengage the pipe.

In some situations, where pressures and snub forces are high, a flanged nipple is installed in the window to prevent pipe from bowing, buckling, and exiting the window. It simply limits the lateral movement of the pipe and prevents pipe failure just like the telescoping pipe guide does. It is only used for structural reasons. Because neither the top nor base of the window is movable, there is no need for it to be a telescoping guide. Sometimes, this work window guide has a hinged side door available for inspection or installation of certain tools such as centralizers, clamps, and other external attachments.

In underbalanced hydraulic rig drilling and sidetracking operations, the work window provides a position on top of the BOP stack to install a rotating control device (RCD) such as a rotating head or rotating BOP. This device is usually attached directly to the base of the work window that, in turn, is attached to the top of an annular BOP. This arrangement allows pressure to be controlled while also allowing rotary motion of the pipe string.

In hydraulic drilling operations, the work window also provides a space to install a supplementary rotating device such as a power swivel. The reverse torque from turning the pipe is transmitted to the rigid work window legs instead of being absorbed by the traveling frame. This avoids twisting the jacks.

2.3.11 **Snubbing BOPs (Strippers)**

These are two hydraulically actuated ram-type BOPs equipped with special packer (elastomer) segments that seal around the pipe. The seal is maintained by these packers while the pipe is stopped and also while it is in motion. The ram packers are usually equipped with a hardened elastomer face such as nylon instead of soft rubber like normal ram packers. The hardened surface allows the ram to seal but not wear as quickly as soft-rubber ram packers as the pipe is being snubbed into or out of the hole.

Two BOPs are used to facilitate ram-to-ram snubbing. The upper snubbing BOP remains closed around the pipe until a pipe connection approaches it. Then, the lower snubbing BOP is closed; pressure between the BOPs is vented through an equalization circuit and choke manifold. Then, the pipe is snubbed down to the top of the lower snubbing BOP. The upper snubbing BOP is closed, and again, pressure is equalized between the BOPs. The lower rams are opened, and snubbing continues through the upper snubbing BOP.

Most of the snubbing work is done through the upper snubbing BOP, and frequent ram packer changeouts are required. The lower snubbing BOP can be closed along with one or more safety rams to isolate the upper snubbing packer so the elements can be changed out quickly before snubbing work resumes. Snubbing can be done using the lower snubbing BOP as the primary device. The upper and lower snubbing BOPs can be alternated to equalize wear and extend the time between BOP ram changeouts as well. Sometimes, the upper stripper is used as the primary snubbing BOP going in the hole, and the lower stripper is used as the primary coming out of the hole.

These BOPs usually have the same rating as the safety BOPs mounted directly on the wellhead. BOP bore sizes depend on the diameter of equipment to be snubbed through them and the bore of the snubbing unit. Their pressure rating selection depends on the anticipated annular pressure (worst-case scenario).

2.3.12 **Equalizing Loop**

Pressure trapped between snubbing BOPs and in the stack across safety BOPs can damage ram packers if released suddenly. Some devices may fail to function properly if there is an excessive pressure differential across them. Obviously, if pressure trapped between the snubbing BOPs is released to the atmosphere suddenly, the results could be catastrophic.

A system of valves and piping is commonly installed that can carry this pressure away from the top cavity and to equalize pressure across rams. This system is known as the equalizing loop (or equalizing circuit). It is a vital part of ram-to-ram snubbing operations. One side of this circuit is usually connected to a choke manifold that has a vent or flare line to release pressure slowly from a cavity in the stack. Conversely, well pressure can be funneled above a closed ram through the system to equalize the cavity with well pressure.

Operation of the equalizing and vent loops is through hydraulically operated valves controlled from the basket by the snubbing unit operator. Backup operation of some manual systems is performed by crewmembers located at various positions along the stack. Most of these are controlled from the basket.

2.3.13 **Guy Lines**

Many standalone hydraulic snubbing systems can be quite tall once all safety BOPs, spacer spools (lubricator), annular preventer, snubbing BOPs, a work window, and the snubbing jack are erected. The jack assembly is also quite bulky making the entire assembly, or stack, top heavy. Stack flanges are capable of supporting some of the side forces involved in operations but not all, especially in high winds. Guy lines are commonly run from points on the work basket and along the stack to anchors. These prevent the stack from bending and ensure that the unit will remain erect and aligned with the well centerline.

2.3.14 **Power-Pack**

The power-pack provides pressured hydraulic fluid (power fluid) to the snubbing unit to operate hydraulic components of the system. It is usually an engine- or electric motor-driven high-pressure pump system that takes suction from a tank mounted above the pump. Power fluid is piped through hoses to the hydraulic rig. Low-pressure return fluid flows to the tank from the unit, again through hoses. Each device using this fluid requires two lines of some kind, one for power fluid and the other for low-pressure fluid return. Many use hoses unless they feed directly through hard piping from manifolds installed on the snubbing unit.

The power-pack also provides hydraulic fluid to both sets of slips and to the snubbing BOPs. These BOPs are used as controls and not barriers. Most of the safety BOPs also get power fluid from the unit although some have their own pumps in a skid-mounted accumulator unit.

As hydraulic fluid powers various devices in the stack, the fluid heats up as work is performed due to fluid friction. The power-pack usually has a cooling device to reduce the temperature of the hydraulic fluid preventing breakdown and the loss of fluid properties. If the power-pack is engine-driven, another heat removal device is needed for the engine coolant. A third might be needed to cool engine oil. Sometimes all of these are positioned in the same shell with different coils used for each fluid. The engine fan provides air flow for cooling all the fluids.

2.3.15 BOP Accumulator and Remote Controls

The bottommost BOPs in the snubbing stack are known as safety BOPs. These are usually conventional ram-type BOPs that may include slip rams (to hold the pipe without sealing), blind rams (to seal the open hole), shear rams (to cut the pipe), or combination rams (such as blind/shear rams).

These usually operate off the snubbing unit's power-pack as a parasitic user of hydraulic fluid until the accumulator bottles are charged. The bottles are connected in parallel and have internal rubber bladders. The bladder/tank annulus is precharged with nitrogen that is compressed by the power fluid providing a gas cushion. This provides storage of pressured hydraulic fluid ready to operate the safety BOPs without the need for additional pumping. Often, however, there is inadequate accumulator system volume installed on the unit. Multiple functioning of the safety BOPs will require pumping power fluid from the power-pack and sometimes waiting for the bottles to recharge. This is clearly not desirable in an emergency situation.

On some jobs, a secondary accumulator system is installed similar to ones used in conventional drilling, completion, and workover operations. These have their own pumps and power supply plus and a large number of accumulator bottles. These units are usually skid-mounted and are connected through hoses or hard piping to the BOPs. Each BOP is controlled with a separate four-way valve mounted on the skid. The skid and control valve system are generally situated some distance away from the wellbore to avoid exposure during an emergency event.

2.4 HYDRAULIC RIG-ASSIST SNUBBING UNITS

Hydraulic rig-assist snubbing units have essentially the same working components as those in hydraulic snubbing units with some minor differences. The components of a rig-assist unit are shown in Fig. 2.3, and they are discussed briefly below.

■ **FIG. 2.3** Hydraulic rig-assist snubbing unit components. *(Courtesy of Cased Hole Well Service.)*

2.4.1 Hydraulic Jacks

Rig-assist units can have only two jacks although many units have four jacks. The jack stroke length is generally shorter than a standalone snubbing unit (although some standalone jacks can be used as rig-assist units). These units are intended to be smaller and more compact to save both space and weight on a rig floor. The unit must be small enough to rig up and work inside the conventional rig's derrick.

2.4.2 Traveling Head

The traveling head on a rig-assist unit likely does not carry hydraulic or backup tongs to make or break connections. The rig's tongs are generally reconfigured and used for this purpose. Alternatively, a set of hydraulic pipe tongs, with its own backup device, may be installed to avoid using the rig tongs in the restricted area of the work basket. When the traveling head does not contain tongs, the weight and power-pack size are reduced making the rig-assist unit lighter.

2.4.3 Jib

The rig-assist unit uses the rig's derrick and pipe handling capabilities, so a jib is unnecessary for these small units. Pipe is rarely laid down during rig-assist operations but is stood back in the derrick by the rig's hoisting equipment and personnel. The jib would only complicate rigging up the hydraulic unit. It would be redundant since the rig's pipe handling system is used on these jobs. So it is simply not included.

2.4.4 Work Basket

The work basket on a rig-assist unit is smaller than the one of a standalone snubbing unit for obvious reasons. It too must fit inside the derrick so it must have a small area. Only two workers are needed in the basket (and sometimes only one). Escape devices are shorter and limited since the basket is often less than 15 ft. above the rig floor.

2.4.5 Work Window

A work window is rarely used with these units. The primary purpose of a rig-assist unit is to help the conventional rig get the pipe into or out of the hole with pressure on the well. The window would add to the snubbing unit height, so if a work window is in the stack at all, it is usually just a short mini-window (about 3 ft. tall).

2.4.6 Safety BOPs

The safeties for a rig-assist unit are usually the rig's BOP stack that uses the rig's accumulator bank and control package. Rigs usually have a remote control panel for their BOPs on the rig floor, so control is maintained without rigging up additional BOPs that would increase stack height. The snubbing BOPs are commonly rigged up immediately on top of the rig's annular preventer or on top of a short riser.

2.4.7 Equalizing Circuit

Rig-assist units must be equipped with an equalizing circuit to vent pressure between snubbing rams before the upper rams are opened. There is usually a short spacer spool with a side outlet that is used for equalizing pressure across the bottom ram. Pressure is vented through the rig's choke manifold.

2.4.8 Power-Pack

For land units, the power-pack may be permanently mounted on a small truck or gooseneck trailer. Sometimes, the truck's engine runs the power-pack through a power takeoff. The truck stays on the job as long as the rig-assist unit is needed. In offshore situations, a small power-pack can be skid-mounted and carried with the unit. It can also be carried in a basket along with hoses and other gear. In both cases, the power-pack is compact and light.

2.4.9 Guy Lines and Anchors

Minimal guying is required on most rig-assist snubbing units due to reduced height and side loading. Often, these units stand unassisted on top of the flanged connections off the rig's BOP stack. In some situations, the snubbing jack is simply tied off to convenient attachment points inside the derrick itself. Heavy anchor blocks or ground anchors are not required for these small units.

2.5 HYDRAULIC WORKOVER UNITS

The definition of a HWO varies from place to place and with time. In the past, any postcompletion job done on a well using a hydraulic rig, including a snubbing unit, was considered an HWO. For this book's purposes, an HWO is one performed using a hydraulic rig on a dead well (i.e., no surface pressure throughout the job). In these jobs, the string is always pipe-heavy. Because the well cannot have surface pressure, the configuration of an HWO unit need not be the same as a snubbing unit. Snubbing units can be used to perform dead well workovers, but HWO units cannot be used to perform live well snubbing jobs.

An HWO unit is capable of performing any task that a conventional workover unit or drilling rig can do. The difference is the use of the hoisting system only. If there is a reasonable chance that well pressure will increase during the workover, such as a recompletion to a new interval, a snubbing unit should be used instead of an HWO unit.

Another consideration is the speed of pipe tripping. An HWO unit is usually slower than a block-and-tackle hoisting system. Another consideration is the footprint of the unit used for the work. An HWO unit has a considerably smaller footprint than a conventional drilling or workover rig. Often, on limited access sites with limited space, such as an offshore platform, the HWO unit takes up far less space and is much less expensive to mobilize, rig up, operate, and demobilize than a bottom-supported rig (jack-up) or platform rig. Daily spread cost for the HWO unit is often a fraction of the cost of a conventional rig and its support equipment.

Blowout preventers are needed for an HWO to ensure that well control is maintained at all times. Thus, the HWO base is rigged up directly on top of the annular preventer just as a snubbing unit would be. However, there is no need for snubbing BOPs or the equalization loop. The well is dead. There is no need for ram-to-ram snubbing to manage upset connections or collars. Therefore, there is no need for a system to equalize pressure between the strippers.

Most HWO units only have a pipe-heavy slip/bowl pair (stationary and traveling) since the string will always be pipe-heavy in a dead well workover. There is no need for an inverted slip/bowl pair since there is no need to push pipe into the hole. If there is the possibility that pressure will be encountered, a snubbing unit is usually deployed, but the inverted slip/bowls simply remain locked open until pressure develops on the wellhead.

The BOP stack is composed of ram-type BOPs plus an annular BOPs (and, perhaps, a stripping head). The ram-type BOPs include a set of blind or blind-shear rams, at least one BOP ram for each pipe size, or variable bore rams (VBRs) in one BOP body. The BOP stack might include slip rams for special purposes. The annular BOP can close on the BHA and odd-shaped elements of the workover string. For the most part, all the BOPs including the annular can remain open during pipe running or pulling in a dead well workover, except during testing as required by regulations or Operator policy.

Most other components of the HWO rig are similar to a hydraulic snubbing unit. They include the hydraulic cylinders, traveling head, work basket, control panels, jib winches, rotary table, work window, and guy lines as described above. They may contain other elements that are job-dependent such as high-pressure pump lines, return lines for circulation, and sheaves for wireline or cable depending entirely on the job design and objectives.

The height of the HWO stack is usually smaller than a snubbing unit since the snubbing BOPs and some other components are not required. Rig up and rig down is simplified and some HWOs can be assembled in a single lift. This allows the HWO to fit easily on top of a tubing head or even a production tree. Unit weight is also smaller than a snubbing unit.

Operation of an HWO is also simpler. Instead of small bites to snub pipe into a well, the entire stroke is available that increases running and pulling speed. The jack simply replaces a conventional rig with its block-and-tackle hoisting system on dead wells. The highest tripping speed using the HWO unit is important to remain competitive.

2.6 HYDRAULIC DRILLING RIGS

Hydraulic drilling rigs have the same hoisting system as snubbing units and HWO units (hydraulic cylinders), but they are equipped with the capability of rotating the entire drill string. They also include mud circulation systems, drilling fluid cleaning and pit management equipment, mud chemical mixing units, return line from the well to the pits, and other components of conventional drilling rig.

Hydraulic drilling rigs are used for drilling new hole segments. Drilling out cement, plugs, or other material inside an existing wellbore involves the use of snubbing units or HWO units depending on whether the well requires snubbing or not. Hydraulic rig drilling generates formation cuttings and requires the same attention to drilling hydraulics as conventional drilling. The major difference is that hydraulic drilling rigs that use hydraulic cylinders are used for hoisting and snubbing for underbalanced or pressured drilling instead of conventional block-and-tackle hoisting gear.

Hydraulic rigs may have considerable advantages over conventional rigs in certain applications, but not all. Hydraulic rig drilling is discussed more completely in Chapter 6 including equipment descriptions.

2.7 PUSH-PULL UNITS

There are many designs for push-pull rig-assist snubbing units many of which are field fabricated units that are neither patented nor described in the literature. The plethora of styles and operating systems available in the industry precludes a discussion of the components in a general sense. Each unit has different components, so many so that each unit must be described individually.

CHAPTER 2 QUIZ

1. What is one specific item that is required when using a snubbing unit?
- **A.** A hydraulic cylinder to hoist the traveling frame
- **B.** Guy lines to secure the unit from tipping
- **C.** A work basket in which the operator and helper are stationed
- **D.** An annular seal to trap pressure in the wellbore

2. Two of the common components of a snubbing unit include:
- **A.** Traveling and stationary slips
- **B.** Two hydraulic jacks

C. Engine-driven hydraulic power-pack and a backup power-pack
D. Annular BOP and rotating head

3. What is the name of the device used to prevent pressure and fluid from traveling up to the inside of the pipe being snubbed/stripped in the hole?
A. Bull plug
B. Packer
C. Float
D. Head

4. In a conventional snubbing unit, the snubbing line is commonly strung from the traveling frame to what?
A. Counterweight hung in the derrick
B. The rig's traveling blocks
C. The rig's drawworks
D. A separate pneumatic tugger under the rig floor

5. Traveling slips must be aligned with stationary slips to prevent slip lock.
A. True _____
B. False_____

6. Power is transmitted to the traveling frame of a hydraulic snubbing unit through which system?
A. Hydraulic cylinders or "jacks"
B. Pressured hydraulic fluid operating the jacks
C. A hydraulic power-pack
D. All of the above

7. In remotely controlled snubbing units, what function does the work basket perform?
A. An elevated cage in which operating personnel are stationed
B. A platform with escape device(s) for personnel
C. None—it may not be present except for maintenance
D. A position above the jacks for personnel monitoring snubbing operations

8. The jib is a small crane with a mast attached to the snubbing unit base and hoist line powered by a hydraulic winch to lift relatively light loads.
A. True _____
B. False_____

9. What is a work window on a snubbing unit?
  A. An open frame below the snubbing unit base and the safety BOP stack that allows access to pipe being snubbed into or out of the hole
  B. An elevated platform that houses the control console, power tongs, and personnel operating the snubbing unit
  C. A time during which weather conditions permit snubbing operations on a well
  D. A clear opening in wind walls surrounding an enclosed work basket so the operator can see the ground

10. Guy lines are used on tall snubbing unit stacks to provide a means of escape from the work basket (similar to the Geronimo line on a drilling rig).
  A. True _____
  B. False_____

11. What is the purpose of an equalizing circuit in ram-to-ram snubbing or stripping?
  A. To prevent pressure buildup in the well as pipe is snubbed into the hole
  B. To ensure that the pressure between rams is the same and to vent pressure if the upper rams need to be opened
  C. To equalize hydraulic pressure in all the cylinders raising and lowering the traveling frame
  D. To keep the force on the snubbing unit frame identical when hoisting pipe using a number of hydraulic cylinders

12. What features of the safety BOPs are necessary to provide the redundancy for safe snubbing operations?
  A. Their rated pressure must be sufficient to control the highest surface pressure of the well encountered during snubbing operations.
  B. They are functioned using pressured hydraulic fluid from the snubbing unit power-pack.
  C. Safety BOP controls are only operated from the work basket.
  D. They are rarely functioned since the snubbing unit already has snubbing BOPs for ram-to-ram snubbing.

13. Hydraulic rig-assist snubbing units have which of the following features?
  A. They operate using hydraulic cylinders (jacks) just like standalone snubbing units.

B. They have an equalizing circuit that vents through the rig's choke manifold.
C. Pipe handling duties are performed using the rig's derrick and often the rig's tongs.
D. All of the above

14. A rig-assist hydraulic snubbing unit is used throughout the entire job to lower or raise the pipe string even after the string becomes pipe-heavy.
A. True _____
B. False_____

15. What components of a hydraulic rig-assist snubbing unit are NOT commonly deployed and used on a snubbing job?
A. Hydraulic jacks to raise and lower the traveling head
B. A compact hydraulic power-pack
C. A jib and hydraulic winch
D. An equalizing circuit piped across the lower snubbing BOP

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Chapter 3

Hydraulic Unit Equipment Features

CHAPTER OUTLINE

Hydraulic Rig Technology and Operations. https://doi.org/10.1016/B978-0-12-817352-7.00003-8

3.1 INTRODUCTION

Some of the components that make up snubbing and hydraulic workover (HWO) units require additional explanation to gain a complete understanding of how they operate both individually and systemically in a well operation. Snubbing units are not simply individual pieces of hydraulic and mechanical equipment cobbled together. Each is designed in concert with all the other components to form a single, integrated unit capable of performing its required tasks under a given set of circumstances. As such, it should be considered systemically, a single unit with many parts, just like an internal combustion engine. All the parts must work together cohesively or the unit will not function properly.

This chapter centers on a more detailed description including design requirements for some of the components of a snubbing or HWO unit. Hydraulic units have replaced the old cable-style conventional rig-assist snubbing units. It would not be profitable to spend time discussing the design parameters of the old cable-style units. Some were field fabricated using whatever pieces were available on the rig (wire rope, sheaves, slip assemblies, etc.). Modern hydraulic rigs have more capabilities than the old cable-type units, and they are less difficult to rig up and rig down.

Some hydraulic units can be rigged up in just a few lifts with a crane. However, modern units have many individual parts. Designing a hydraulic unit requires considerable time and technical expertise.

Snubbing and HWO unit crews, in addition to being highly trained in operations, are also accomplished in repairing and replacing worn, defective, and missing parts in the field. Often, this capability makes all the difference between a smoothly functioning job and one with significant lost time due to equipment malfunction or failure. Some repair jobs, however, exceed crew capabilities such as overhauling hydraulic cylinders or repairing control systems in the field. Often, the only solution for a "dead-in-the-water" hydraulic unit is replacement with another unit. The disabled unit is then taken to the shop for extensive repairs by mechanics and technicians. The safety BOPs and other components, such as the power-pack, may remain on the job, however.

There is a constant emphasis on safety in snubbing and HWO operations. In the past, this was not the case, and several good people were injured, often horribly, because of malfunctioning equipment or poor operating procedures. It took a good bit of skill and lots of nerve to climb into the basket on early jobs. Now with more reliable equipment, better procedures and lockout systems coupled with an overarching emphasis on safety, snubbing and HWOs are less risky than they were in the past.

3.2 HYDRAULIC JACKS

A hydraulic cylinder converts pressure supplied by a fluid into a force that is extended through a given distance to perform work. A fluid is used in hydraulic cylinders because it is relatively incompressible. A pneumatic cylinder performs the same function using compressed air or some other gas, but the gas is compressible. The conversion of pressure to power is less efficient using a gas for this purpose. Heavier lifts are possible using a fluid. In many applications, pneumatics are desirable, but in the oil field, fluid-filled hydraulic systems are more frequently used.

3.2.1 Basic Theory

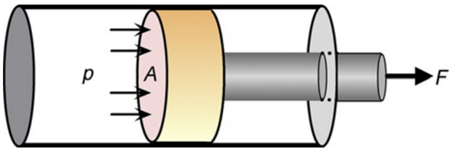
Basic hydraulic theory concerns pressure acting on a given cross-sectional area:

$$F = pA \tag{3.1}$$

where

F = force, lb_f
p = pressure, pounds per square inch (psi)
A = area, square inch(es) or in.^{2}

The equation implies that this relationship must take place within a closed vessel. If it is uncontained, there is no pressure. Fig. 3.1 shows the relationships in this basic equation.



■ **FIG. 3.1** Simple piston.

In Fig. 3.1, the pressure of the hydraulic fluid, p, is contained inside the cylinder to the left of the piston. It is acting on the area on the bottom of the piston, A. The force, F, is transmitted to the right by the piston and the connected rod.

For a circular piston, the area of its base is

$$A = \pi r^2 \tag{3.2}$$

where $r =$ radius of cylinder.

Because the diameter of the cylinder, d, is twice the radius, Eq. (3.2) can be rewritten:

$$A = \frac{\pi d^2}{4} \tag{3.3}$$

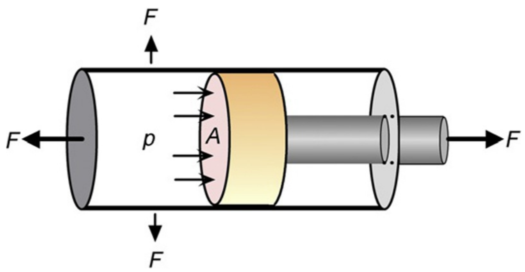
or

$$A = 0.7854\, d^2 \tag{3.4}$$

In these equations, the internal radius or diameter of the cylinder is used instead of the diameter of the piston. In real systems, the piston will be slightly undersized to go inside the cylinder with the tiny gap between the outside of the piston and the inside of the cylinder wall. This gap is occupied by a set of elastomer seals. The pressure acts across the entire piston area and the area occupied by the seals. So, the inside diameter (ID) of the cylinder is the important dimension, not the outside diameter (OD) of the undersized piston.

Although it may not seem immediately obvious, fluid pressure in the left-hand side of the cylinder is acting on the walls of the cylinder and its base as well (Fig. 3.2). The cylinder walls and base must be constructed of a material (usually steel) with sufficient thickness and minimum yield strength to resist deformation. If the cylinder swells (balloons), the seal across the piston is lost, and pressure simply bypasses from one side of the piston to the other around the seals, and no force is generated to move the piston.

This can become problematic when large-hydraulic forces are involved such as lifting a heavy weight using a large-diameter hydraulic cylinder. Let's



■ **FIG. 3.2** Forces on cylinder.

assume that 200 in.^{2} of piston area are needed to lift the weight 10 ft. A single cylinder would need to have an approximate 16 in. ID to satisfy this requirement. The area of the cylinder walls exposed to the hydraulic pressure with the weight at a height, h, of 10 ft. would be

$$A_{cyl} = \pi rh \tag{3.5}$$

In this example, the cylinder wall area would be 3016 in.^{2}. This entire area would be exposed to the same pressure as the base of the piston. The cylinder must have very thick walls to resist ballooning with this much force pushing out on the cylinder wall. A thick cylinder wall means that this large-diameter cylinder would be very heavy, and handling it would be awkward and difficult.

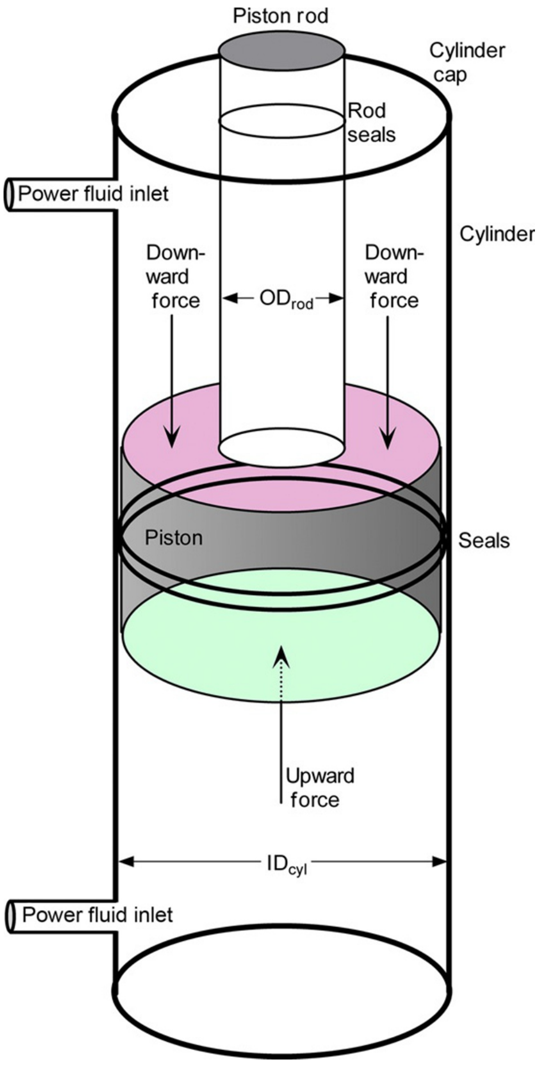
The same weight could be lifted by two hydraulic cylinders each having a piston area of 100 in.^{2}. This would equate to a cylinder with an ID of about 11.3 in. and a wall area of 2130 in.^{2}. Even better would be four cylinders each having a piston area of 50 in.^{2}. These would each have an ID of 8 in. Each cylinder would have an exposed inner wall area of 1508 in.^{2}. The wall thickness required for an 8 in. cylinder would be far less than that of a 16 in. cylinder, and managing four 8 in. cylinders would be much easier than handling one large, heavy, cumbersome, 16 in. cylinder.

The point is that a number of hydraulic cylinders can be used in combination for heavy lifting with each cylinder sharing an equal portion of the load. The only requirement is that there must be a sufficient supply of pressured fluid to power all of the cylinders simultaneously.

Obviously, the method used to connect the cylinder wall to the base must be sufficiently strong to resist failure. These are sometimes welded connections, but most have some type of removable endcap for access to the cylinder interior for overhauls and repairs. Regardless, the entire cylinder must be sufficiently robust to handle internal pressure along the entire travel of the piston.

Figs. 3.1 and 3.2 depict single-acting cylinders. Here, the power fluid is acting only on the "bottom" of the piston. In snubbing operations, the cylinders are double-acting cylinders in which the power fluid can act on both the bottom and the top of the piston (Fig. 3.3).

Power fluid can be pumped into either of the two inlets on the cylinder. If fluid is pumped into the lower inlet under pressure, the cylinder behaves as a single-acting system just like the simplified drawings in Figs. 3.1 and 3.2. In



■ **FIG. 3.3** Double-acting hydraulic cylinder.

this case, fluid above the piston would vent back to the power-pack through low-pressure return lines and into the reservoir as the piston moves upward. Additional high-pressure fluid would continue to be added through the lower-power fluid inlet as the piston moves up the cylinder. The power fluid *inlet* at the top of the cylinder would become a return fluid *outlet* in this operating mode.

Theoretically, by combining Eqs. (3.1), (3.4), the force on the piston rod would be

$$F = p \, \mathrm{x} \, 0.7874 \, d^2 \tag{3.6}$$

This theoretical force cannot be achieved in real life due to several inefficiencies. These inefficiencies reduce the theoretical force produced by a cylinder by 5%–10%. In the alternative, this inefficiency in the system requires more pressure to generate for the theoretical force. Eq. (3.7) shows the actual force that can be expected from a hydraulic cylinder in a working situation:

$$F_U = p \, \mathrm{x} \, 0.7854 \, d^2 \, \mathrm{x} \, EF \tag{3.7}$$

where $EF =$ cylinder efficiency factor.

Fig. 3.3 depicts the way hydraulic cylinders are mounted on a snubbing unit. So, Eq. (3.7) defines the upward lifting or hoisting force.

The efficiency factor is actually a combination of several factors. First, note that there are two sets of seals involved in this design. One contains pressure from bypassing around the piston. The other prevents pressure and fluid from escaping around the piston rod at the cylinder cap. Both sets of seals exert friction when the piston and rod move. The actual inefficiency depends on the type and age of the seal sets (new seals exert more friction than used ones) and hydraulic fluid lubricity.

Example

Calculate the upward (hoisting) force of a hydraulic cylinder with a 5 in. OD, a 4 in. ID with a piston OD of 3.985 in., and a piston rod OD of 2 in., with a power-pack that produces 4000 psi hydraulic fluid pressure. Assume 90% cylinder efficiency.

From Eq. (3.7),

$$F_U = 4000 \, \mathrm{x} \, 0.7854 \, \mathrm{x} \, 4^2 \, \mathrm{x} \, 0.9$$

$$F_U = 45{,}239 \, lb_f$$

Note that neither the piston OD nor the rod diameter has any impact on the hoisting force calculation. The operative diameter for hydraulic calculations is the cylinder ID. The slight difference between cylinder ID and piston OD is supplied by the piston seals. Pressure is acting both on the piston head and the seals, so the cylinder ID is used to calculate hoisting force.

A second inefficiency in a hydraulic system arises from static friction. This friction must be broken before the piston can move at all. There is usually a very brief pressure spike in the power fluid at the beginning of a "stroke." As soon as this static friction is broken, only dynamic friction is experienced by the moving piston/rod system, and it is lower than the static friction force. The direction of the friction force is always opposite the direction of piston/rod movement.

There is another inefficiency introduced when initiating motion from a static start. As the piston/rod first begins to move, there is a brief time of acceleration. At the end of the stroke, there is a matching short deceleration time when the piston and rod slow down as they approach a new static position. Acceleration requires a bit more pressure to get the system moving than the steady-state movement of the piston in midstroke. Slightly less pressure is needed during deceleration.

A final inefficiency involves pressure differential due to fluid friction in the return fluid system. The power equations normally used for snubbing involve only consider the power fluid pressure. In fact, there is always some pressure on the return side of a cylinder due to fluid friction through the valves, connections, and lines that return hydraulic fluid to the reservoir on the power-pack. The jack operates on the basis of the pressure *differential* from the power side of the seals to the return side. If small-diameter connections and hoses are installed on the hydraulic unit's return fluid plumbing, the unit cannot operate efficiently or as fast as it can with larger-diameter return lines due to fluid friction generated in the return system.

The cylinder inefficiency from power fluid/return fluid pressure differential, momentum, seal friction, and static friction is usually ignored for job planning and simply gathered into an overall "friction" for the job (usually around 25%–30% additional total force).

A pressure gauge on the power fluid system will record several changes in power fluid pressure during a stroke. This pressure spiking and dipping behavior is a characteristic of all hydraulic systems in the field.

The downward force generated by hydraulic fluid pressure acting on top of the piston is different because a portion of the surface area of the piston is occupied by the rod. Thus, the force is the net area of the piston available after subtracting the area occupied by the rod. So, the actual pull-down force is a two-part equation:

$$F_D = p\left\{\frac{\pi\left(ID_{cyl}^2 - OD_{rod}^2\right)}{4}\right\} \text{x}\, EF \tag{3.8}$$

or

$$F_D = p\,\frac{\pi}{4}\left(ID_{cyl}^2 - OD_{rod}^2\right) \text{x}\, EF \tag{3.9}$$

Example

Calculate the downward force of a hydraulic cylinder with a 5 in. OD, a 4 in. ID, a piston OD of 3.985 in., and a piston rod diameter of 2 in., with a power-pack that produces 4000 psi hydraulic fluid pressure. Assume 90% efficiency.

From Eq. (3.9),

$$F_D = 4000 \text{ x } 0.7854 \left(4^2 - 2^2\right) \text{ x } 0.9$$

$$F_D = 4000 \text{ x } 0.7854\,(16 - 4) \text{ x } 0.9$$

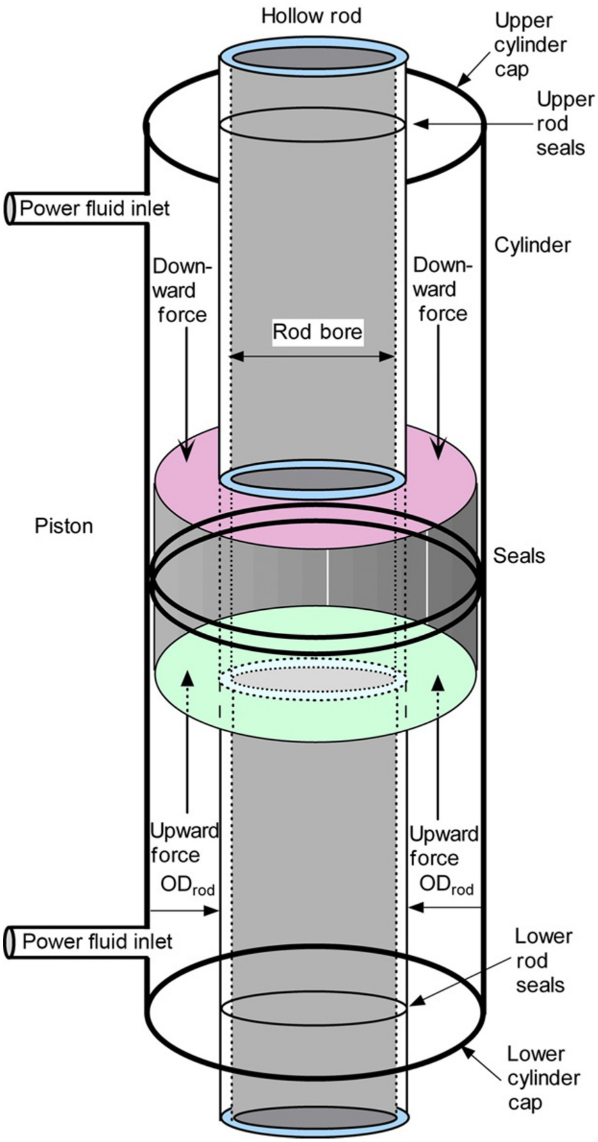
$$F_D = 33{,}929\, lb_f$$

3.2.2 **Concentric Snubbing Unit**

One snubbing unit design involves a piston and a hollow rod. The rod bore is large enough for pipe or BHA components to be run through its center. It is a single-cylinder design with traveling slips mounted on top of the large-diameter hollow rod (Fig. 3.4).

In this design, the rod (shaft) above and below the piston is enclosed with a cylinder endcap. The two volumes are separated by a piston. Power fluid directed into the upper part of the cylinder pushes the piston down along with the entire rod to snub or strip pipe in the hole, while return fluid flows out of the bottom port of the cylinder. Conversely, fluid pushed into the bottom fluid inlet of the cylinder causes the piston and hollow rod to move upward hoisting pipe out of the hole.

In this design, the upward (hoisting) force and the downward (snubbing) force exerted by the power fluid are identical since there is the same cross-sectional area available on both sides of the piston and the same "rod" area available across either the top or bottom seals. The force is



■ **FIG. 3.4** Concentric cylinder design.

calculated exactly like the snubbing, or pull-down, force of a double-acting cylinder as shown in Eq. (3.9).

This design has limited hoisting and snubbing capacity due to the bore of the rod. At this time, the largest concentric unit is classified as a 160 K rig-assist snubbing unit.

3.2.3 Snubbing Unit Sizes

A simple naming convention is used in the industry to classify snubbing unit sizes. Snubbing units are named by hoisting or lifting force. The length of the stroke has no bearing on the classification of the snubbing unit. Most of the hydraulic cylinders used in these units have a maximum stroke length of 10–14 ft.

A standard snubbing unit size, for example, is a 460 K unit. This means that the maximum hoisting capability for the unit is 460,000 lb_f. The rated snubbing, or pull-down, capacity of this same unit is about 220,000 lb_f, roughly one-half of the hoisting power. The same ratio is true of other standard snubbing units from 150 K to 600 K. Table 3.1 shows one manufacturer's hoisting and snubbing ratings for different size snubbing units.

Job planning requires the selection of a snubbing unit that will be capable of hoisting and snubbing the maximum anticipated loads including a safety factor. The safety factor provides a cushion between the rated capacity of the equipment and the actual anticipated maximum load. Say, for example, that the maximum "hook load" (buoyed weight) of a pipe string is expected to be 220,000 lb. Selecting a 225 K unit would be crowding the maximum capability of the unit at the maximum "hook load." Selecting a 340 K unit would be a better option. Similarly, if the maximum expected snub load on a snubbing job is expected to be 190,000 lb, a 460 K or 600 K unit should be chosen instead of a 340 K unit.

It is important to remember that all equipment ratings are based on brand-new equipment performance. This includes motors, pumps, wire rope, air conditioners, engines, and snubbing units. Once the item goes into service,

Table 3.1 Snubbing Unit Sizes and Capacities

Data Performance	Model HRS 150 K	Model HRS 225 K	Model HRS 340 K	Model HRS 460 K	Model HRS 600 K
Max pulling capacity	150,000 lb_f	225,000 lb_f	340,000 lb_f	460,000 lb_f	600,000 lb_f
Max snubbing capacity	66,000 lb_f	120,000 lb_f	188,000 lb_f	220,000 lb_f	260,000 lb_f
Horsepower	350	400	450	450	600
Tubing size range	1–2⅞ in.	1–5½ in.	1–7⅝ in.	1–8⅝ in.	1–8⅝ in.
Standard rotary torque	5000 ft.-lb	5000 ft.-lb	10,000 ft.-lb	10,000 ft.-lb	20,000 ft.-lb
Standard stroke	10 ft.	10 ft.	10 ft.	10 ft.	14 ft.

Courtesy of NOV Hydra Rig.

wear begins to reduce its capabilities. Older items with more accumulated wear are weaker than new ones.

3.2.4 Piston/Cylinder Sealing

In order for a double-acting hydraulic cylinder to work properly, there must be some kind of seal between its power end and its return end across the piston. Forces cannot be developed through hydraulic fluid without something to provide a high-pressure gradient across the piston. There are two important components of the piston seal segment and several types of materials and seals that can be used in these sections. Appendix C contains more information on the materials, usually elastomers, and other materials used in seals for both pistons and rods.

3.2.4.1 Piston Wear Sleeves (Wear Guides)

A wear sleeve is an expendable wrap that surrounds the piston. It has three main functions:

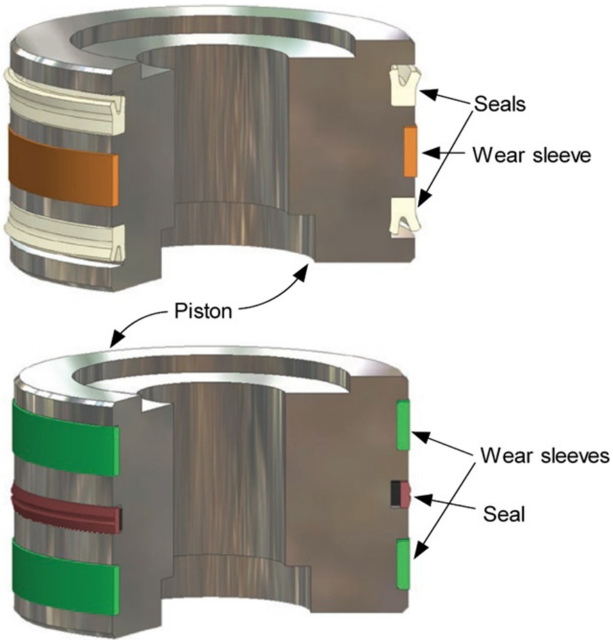
- Prevents metal-to-metal contact of the piston with the interior wall of the cylinder.
- Centers the piston within the cylinder to provide 360 degrees contact of the piston seals with an even distribution of side forces.
- Provides a "slick" bearing surface.

Metal-on-metal friction from a tightly fitting piston inside a cylinder is avoided by using the wear sleeve. There may be one or more wear sleeves installed on the piston (Fig. 3.5).

Several materials are available for use as wear sleeves in hydraulic cylinders. Each has its own set of advantages and disadvantages. Table 3.2 lists several of them.

When a hydraulic cylinder is overhauled, all of the wear sleeves and seals are usually replaced at one time. Shallow wear grooves in the piston accommodate both. The seals are flexible and can be stretched over the piston OD and snapped into their groove(s). Wear sleeves are far less flexible. They must be spread apart to get them into their groove(s) without deforming them to the extent that they would not perform properly once in place.

Wear sleeves are often cut or split to permit easy installation since they not intended to provide a seal. The cut can be vertical (perpendicular to the ring), at an oblique angle (usually 45 degrees), or step-cut (two vertical cuts spaced some distance apart and connected by a circumferential cut) (Fig. 3.6).

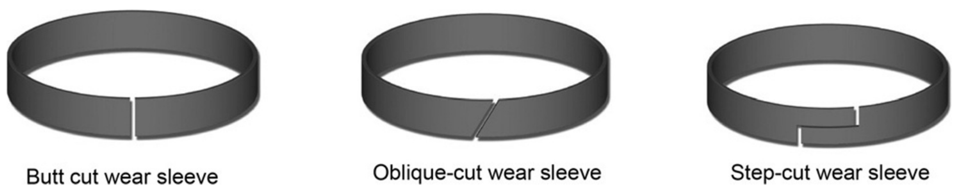


■ **FIG. 3.5** Piston wear sleeves and seals. *(Courtesy of Parker Hannafin.)*

Table 3.2 Wear Sleeve Materials and Characteristics

Material Type	Characteristics
Nylon, fiber reinforced	Good durability, low wear characteristics, high compressive strength
PTFE[a]	Low friction, high compressive strength
PTFE, bronze-filled	Low friction, nonswelling in moisture, corrosion resistant
Acetyl	Nonabrasive, nonswelling, good compressive strength
Phenolic	High-temperature resistance, high compressive strength, and low friction
PEEK,[b] graphite-filled	High-temperature resistance, high compressive strength, chemically resistant

[a] *Polytetrafluoroethylene (popular brand name, Teflon).*
[b] *Polyether ether ketone.*



■ **FIG. 3.6** Wear sleeve configurations.

3.2.4.2 Piston Seals

These seals provide the piston with the ability to slide along the interior wall of the cylinder with pressure trapped on one side of the seal or the other depending on cylinder travel and power requirements. They are installed on the piston and are held in place by a grove of a specific shape and depth. Selection of piston seals involves an extensive engineering analysis for the duty in which the hydraulic cylinder is expected to serve. Some materials and seal types are useful in low-temperature, low-pressure, and light-duty situations where others are intended to serve in high-temperature environments where heavy loads are anticipated (Table 3.3).

Some materials used to construct seals include Buna-N rubber, Viton, nitrile, silicone, PTFE, PEEK (bronze- or glass fiber-filled), neoprene, and polyurethane. Each has its own characteristics in terms of friction generation and temperature resistance. A listing and description of some of these materials can be found in Appendix C. A more complete list of seal shapes and types can be found in Appendix D.

Cylinder seals have varying capabilities for sealing under low-pressure conditions, the worst-case situation for sealing. The seals usually deform

Table 3.3 Piston Seal Types, Materials and Uses

Seal Type or Shape	Materials and Uses
V-ring, parachute stack	Neoprene (oil and water), butyl (phosphate ester). Low-temperature, light-duty
U-cup	Buna-N, urethane, EPM, EPDM, EPR, Fluorel, Viton, FKM Teflon. Low-speed, low-pressure applications
Asymmetrical unloaded U-cup	Urethane, HP urethane, Hytrel, nitrile, Fluorel, FKM, Viton, EPM, EPR or EPDM, improved stability (over U-cup), improved wear resistance. Low-speed, high-pressure
Loaded U-cup	Urethane, HP urethane, Hytrel, nitrile, Viton or EPOM. Rectangular seal, scraper lip, with nitrile O-ring or box ring. High-pressure, high-speed applications
PTFE-backed O-ring	Glass fiber-, moly-, carbon graphite- or bronze-filled Teflon. High-speed, low-friction, long service life, high-temperature
T-seal	Nitrile, Viton, EPDN, HNBR with Nylon, PTEF or PEEK backup. Square seal for stability, antiextrusion rings, dynamic sealing surface. High-pressure, high-temperature, low-speed
O-ring loaded	Urethane, HP urethane, Hytrel. Square seal, back beveled tip, energized seal, bidirectional sealing. Low-speed, high-pressure, low-temperature
Urethane	Urethane. Square seal, grooves prevent blow-by, energized seal. Moderate-speed, high-pressure, low-temperature
Capped T-seal	Nitrile, Viton, EPDM, HNBR with nylon or Detrin backup and PTFE, or filled PTFE cap. Long-life, low-friction, antiextrusion rings, dynamic sealing. High-temperature, very high-pressure, high-speed
Grooved O-ring	Nitrile; Viton; glass fiber-, moly-, carbon graphite- or bronze-filled Teflon. Bi-directional sealing, grooves prevent blow-by, energized seal. High-temperature, high-pressure, low-speed

to seal tightly under high fluid pressure. They seal less effectively at low pressure.

This has resulted in the design of loaded seal types in which the seal lip is backed by another material such as an internal O-ring. The thicker and more robust the seal lip, the greater its sealing capacity at low-power fluid pressures. The greater the sealing capacity, the more seal wear is involved (meaning, the more frequent the seal replacement) and the greater the friction created by the seal. All of these are design parameters. For snubbing and HWO service, the higher sealing capability is desired, so more robust seals are usually installed.

There are often multiple seals installed on pistons. The outermost seal, or wiper seal, has some type of “lip” that serves to remove sediment, debris, and corrosion products collected inside the cylinder away from the remaining seal pack. In a double-acting cylinder, this means that both of the outer seals are wiper seals with the lip facing in opposite directions.

Wiper seals are designed and made from soft materials that can “ingest” (absorb or capture and hold) particles that could score the piston interior if allowed to become wedged in the seal section. The wiper seals hold these particles until the seals are replaced. Sometimes, in very dirty situations, the particle concentration becomes so large that the wipers are unable to contain them, and they migrate into the other seals resulting in considerable cylinder damage from scoring.

The inner seals may be a single seal or something as complex as a “PolyPak,” a set of “V” or “W” cross-sectional shaped seals stacked one atop the other to provide a seal. In one design, “V”-rings alternate between 85 and 95 durometer stiffness. Their shape and hardness/softness help to expand these elements under pressure providing a tight seal even if the cylinder wall balloons slightly. Other seals have shapes that conform to the groove in the piston on one side and seal tightly to the cylinder wall on the other. These often have different shapes to effectively seal under a range of conditions.

The variety of piston seal shapes, thicknesses, materials, and uses make seal substitution very risky. The hydraulic cylinder manufacturer has specifications that apply to seal rings. Changing one type of seal out with another of a different type will probably not have a good outcome. For example, if a groove is cut in the piston to accommodate a capped T-seal, it is unlikely that an asymmetrical unloaded U-cup seal will work very well. Pressure/hydraulic fluid blow-by, spiraling seal failure, and excessive wear might reduce seal life to just a few minutes in oil field service.

Fortunately, the firms that overhaul hydraulic cylinders are very much aware of this fact. They will follow the manufacturer's specifications for piston seal replacement very closely. If an improved seal is available, they will usually check with the manufacturer before installing it during a cylinder overhaul.

Changing piston seals requires dismantling the cylinder. This is best done in a controlled environment inside a shop instead of in the field. Fluid must first be drained from the cylinder. Then, the rod endcap must be removed and the rod and piston pulled out of the cylinder. If a particular seal goes bad, the best option is to remove and replace all the seals and the wear sleeves at the same time. Then, the cylinder is reassembled.

Reusing piston seals, even if they don't look bad, is not a good idea. All seals have a life. If only a few of the seals on the piston are replaced, the old worn seals may not contribute to the overall sealing function after overhaul. The new seals will likely be doing all the work. This may lead to uneven wear and premature failure. The old seals will reach the end of their usable lives before the new seals do, so a second overhaul after a short service life might be necessary to replace all the seals. This is not economically prudent. All of the seals should be replaced by new ones as long as the cylinder is torn down anyway.

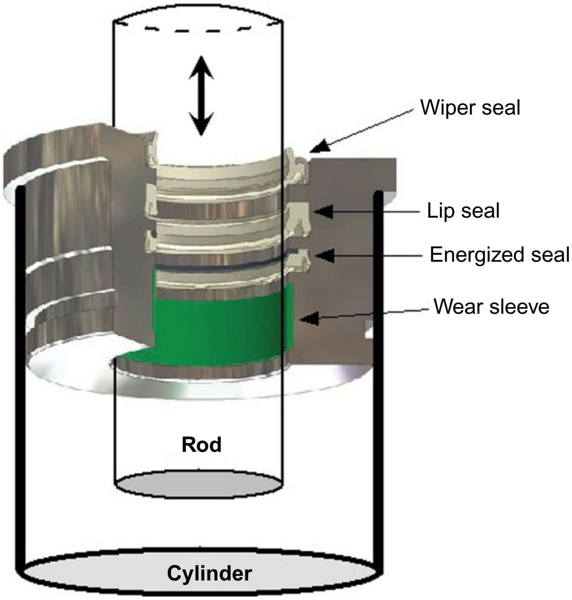
Again, if one cylinder on a snubbing unit is overhauled, all of the cylinders should also be overhauled even though only one has a problem. It is important that all the cylinders are sharing the hoisting and snubbing loads about equally. If only one cylinder is overhauled, it will work more effectively ("harder") than the others resulting in imbalanced loads on the traveling head at the same hydraulic pressure.

3.2.5 Rod Seals

For a double-acting hydraulic cylinder to work in snub mode, the cylinder cavity above the piston must be sealed. The hydraulic fluid pressure creates a differential between the cavity and the atmosphere. The wear sleeves and seals for this area are necessary to protect personnel working in the basket as well as the environment.

3.2.5.1 Rod Wear Sleeve (Wear Guide)

The rod wear sleeve performs the same functions as the piston wear sleeves. It centers the rod to allow equal contact by the rod seals and prevents metal-to-metal contact of the rod with the rod cap. It also catches metal and debris particles to prevent rod scoring.



■ **FIG. 3.7** Rod wear sleeve and seals. *(Courtesy of Parker Hannifin.)*

The rod sleeve is also an expendable item that is designed to take punishment while providing a bearing surface for smooth operation of the cylinder. Usually, there is only one rod sleeve where there may be two or more piston wear sleeves. Like the piston wear sleeve, the rod wear guide is usually made of "hard" elastomer-like glass-filled Teflon or an embedded fabric resin (Fig. 3.7).

Rod wear sleeve replacement involves removing only the top cap, removing the old wear sleeve, installing a new one, and then reinstalling the rod cap. The rod wear sleeve is probably split, so it can be replaced easily. Replacing the wear sleeve is frequently done in the field when the rod begins to get "floppy" (excessive lateral movement).

3.2.5.2 Rod Seals

Rod seals perform the same function as the piston seals. They trap hydraulic pressure inside the cylinder to prevent leakage to the environment. Fluid that gets through the rod seal will end up on the outside of the cylinder or in the air when it escapes in a fine mist going straight up out of the cylinder (Table 3.4).

Rod seals are installed in the top cylinder cap (i.e., the rod cap). They remain stationary, and the rod moves through them unlike the piston seals.

Table 3.4 Rod Seal Types, Materials, and Uses

Seal Type or Shape	Materials and Uses
V-rings, quad rings	Neoprene (oil), butyl (phosphate ester). Low-temperature, light-duty
Asymmetrical unloaded U-cup	Urethane, HP urethane, Hytrel, nitrile, Fluorel, FKM, Viton, EPM, EPR or EPDM, improved stability (over U-cup), improved wear resistance. Bump heel, film-breaking. Low-speed, high-pressure
Beveled loaded U-cup	Urethane, HP urethane, Hytrel, nitrile, Viton. Energized seal, back beveled lip, with nitrile O-ring. High-pressure, moderate-speed applications
Deep loaded U-cup	Urethane, Hytrel, Viton with nitrile box ring. Energized seal, improved extrusion resistance, improved stability. High-pressure, low-temperature, moderate-speed
Double lip U-cup	Urethane, Hytrel, nitrile, Viton, HNBR, low-temperature nitrile, carboxylate nitrile. Low compression set, secondary lip, extrusion-resistant base, low-temperature sealing. High-pressure, low-temperature, moderate-speed
Double lip U-cup with antiextrusion ring	Same as above with improved antiextrusion capabilities
Spring energized U-cup	UHMWPE, PTFE, PEEK, S/S spring. Low compression set, secondary lip, low-friction. Very high-pressure, wide temperature range, high-speed, heavy-duty use, corrosive fluid
Standard buffer	Filled PTFE, nitrile. Vents back pressure between seals, protects rod seal from pressure spikes, low-friction, long-life. Medium-duty use in combination with another rod seal
Premium buffer	Filled PTFE, nitrile. Vents back pressure between seals, protects rod seal from pressure spikes, low-friction, long-life. Heavy-duty use for large rod sizes
Crown seal	Urethane 95 with nitrile O-ring. Energized seal, minimal contact and friction, final seal below wiper seal. Low-pressure, low-speed

The piston seals are attached to the exterior surface of the piston, and they move inside the cylinder along with the piston.

The end of the rod exits the rod cap when the jack is "stroked out." It is exposed to rain, blowing dirt, and exhaust in the air. Once the jack is "stroked in," anything on the rod travels back down to the endcap. So, the upper rod seal is always a wiper seal. This cleans the rod and prevents debris from getting around the other rod seals and contaminating the hydraulic fluid inside the cylinder. Like the piston wiper seals, these seals are also made from a material that will capture and "ingest" particles that could damage the rod exterior.

Many hydraulic cylinders are also equipped with a rubber boot through which the rod travels. This boot is soft and conforms to the rod. The opening in the boot wipes the outside rod surface to prevent trash from getting into the rod seals. They also trap minor hydraulic fluid leaks or sprays preventing them from soaking personnel and the equipment in the work basket. The leaked fluid simply drains out of the boot and runs down the outside of the cylinder for later cleanup. Rod boots are inexpensive and can be replaced easily in the field when they get worn or damaged.

Rod seals may be the same or similar to the piston seals. They may be as simple as an O-ring (or several O-rings in different grooves along the rod). O-rings are one of the simplest types of seals available, and they are used extensively in hydraulic systems of all types. Small hydraulic cylinders in control systems for snubbing units use O-rings almost exclusively.

Replacement of rod seals is also fairly uncomplicated. Like replacing the rod wear guide, the endcap must be removed from the cylinder over the rod. Old seals are removed using a pick or some other tool. The new seals are gently folded into a “kidney” shape and inserted into the proper groove in the endcap and seated. The wear sleeve is compressed slightly and snapped into its groove. The seals are coated with clean hydraulic fluid, and the endcap is carefully lowered over the rod and reconnected to the cylinder.

This can be done in the field and is necessary when a rod seal begins to leak. Leaking rod seals result in a near-continuous low flowrate of hydraulic fluid that runs down the outside of the cylinder and drips onto the ground or deck. In dusty areas, the film of hydraulic fluid catches dirt causing the entire snubbing unit to become unsightly. Leaking rod seals are annoying, but they may survive the job until they can be replaced in the shop.

Complete rod seal failure results in a high flowrate “volcano” of hydraulic fluid squirting out the top of the cylinder, fouling a large portion of the unit and wellsite. There is no question that a rod seal has failed when it occurs; everyone on the site knows it immediately. This type of failure requires a field replacement of the rod seals or replacement of the snubbing unit. Continuing the job with a blown rod seal is not practical since there can be no snub force exerted on the pipe (i.e., there is no pressure containment in the upper portion of the cylinder).

If a seal in one cylinder fails, it’s a good bet that the seals in the other cylinders are near failure as well. Most snubbing service providers change all the rod seals at one time to avoid failure in the others.

3.2.6 Cylinder Damage and Repair

Cylinder damage most often involves interior wear. This is due to the movement of the piston up and down the wall. Seals create friction. Friction always results in wear eventually. This wear usually involves some level of scoring on the internal polished cylinder walls. The scoring is always axial, aligned with the centerline of cylinder (i.e., the pistons don't turn inside the cylinders—at least, they're not supposed to turn).

Scoring is aggravated by tiny particles of abrasive materials present inside the cylinders that get trapped between the cylinder wall and the piston seal. Often, they are carried into the cylinder along with the hydraulic fluid that has not been adequately filtered. Sometimes, these tiny particles agglomerate into large particles. These larger particles can cause deep scratches in the cylinder walls, and they do so very quickly.

Piston seals are sufficiently flexible and can expand to contain pressure when there is only light scoring on the inner walls of the cylinders. Unfortunately, the damage is sometimes localized near the cylinder base. This is the area where most of the piston movement in snubbing takes place. In high-pressure snubbing, the jack is rarely extended all the way to maximum extent of the rod. Instead, shorter, smaller bites are taken with the traveling head only extended 2–4 ft. at a time. This avoids pipe buckling between the traveling and stationary slips.

Because only short "bites" are taken during most of the snubbing cycle on any well with the piston near the bottom of the cylinder, only a short section of the cylinder is exposed to piston travel. So, that's where most of the scoring occurs.

By contrast, full cylinder extension is used as the neutral point is approached and snub loads are reduced. When the end of the pipe is below the neutral point, full extension is used since the pipe is under tension along its entire length. Long strokes are also be used during low well pressure and low loading conditions and in pipe-heavy work with HWO units.

Piston seals can expand to compensate for light wear of the cylinder wall. They continue to seal effectively for some time. When the wear becomes excessive, oversized seals or a different type of seal can sometimes be installed. If the wear is localized, this is only a temporary fix.

When excessive wear or severe scoring occurs, the best solution is often reconditioning the cylinders. This can involve complete replacement of some components. In a worst-case scenario, the entire cylinder must be replaced. If this occurs, it is prudent to replace all the cylinders since the new one will likely perform far differently than the old cylinder(s) and could result in unbalanced loading on the traveling head.

Refurbishing hydraulic cylinders can involve a number of techniques to restore them to service. Several of these include the following.

3.2.6.1 Honing

The interior surface of modern hydraulic cylinders is clad, or plated, with a polished metal that is often harder than the steel from which the cylinder is made. This metal cladding provides a tough, resilient, smooth (low friction) surface that resists scoring and abrasion. Several materials are used for this cladding:

- Hard chrome, Rockwell Hardness (RC), 68–72
- Thin, dense chrome
- Electrolysis nickel, RC, 48–52
- Cadmium
- Low-hydrogen cadmium (LHE Cad)
- Titanium-Cadmium
- Vacuum deposited cadmium (cac-Cad)
- Zink-nickel

Light wear results in a number of small ridges and valleys in the interior surface of the cylinder. Where the peak distance between the ridges and valleys is not excessive, the cylinder can simply be honed and smoothed to restore a surface that is conducive to sealing.

The standard honed and polished finish for a hydraulic cylinder is 10–20 microinches (a microinch is one-millionth of an inch or one micron, μm). The difference between any remaining peaks and valleys anywhere on the surface of the cylinder after honing and polishing is between 0.00001 and 0.00002 in. (10–20 μm). For special service hydraulic cylinders (such as those used to dispense drugs and vaccines in the medical field), the finish is usually polished to 4–6 μm. The finer the finish, the less friction is involved. Friction for the standard finish (that used in oil field hydraulics) provides an efficiency reduction of about 5%–7%. The efficiency reduction for even more highly polished cylinders is even less than that. For oil field purposes, the standard finish is sufficient.

The problem comes in the depth of the valleys in case of severe wear or scoring. The thickness of the cladding has been compromised to this depth. Honing will remove the cladding to this depth, but it may remove enough of the cladding thickness so that the remaining cladding is no longer viable. This is the situation that often occurs when a single deep scratch or gouge damages the cylinder interior.

A significant failure mode is when a section of the cladding suddenly detaches from the cylinder interior. The old cladding plus the rough edges where it detached quickly cut the seals, so the pressure containment around the piston is no longer possible.

The cladding on a new cylinder is usually thick enough to permit honing and polishing once or twice without compromising the entire cladding. The very small added internal diameter is easily taken up by the seals, so there is no need for recladding the cylinder the first time or two it is refurbished unless there are deep gouges involved.

3.2.6.2 Replating

At some point, the cladding must be replaced when it becomes too thin, or it is scored too deeply to hone out. Applying the new cladding on top of the old, thin remaining cladding is not a good option since the new layer may not bond to the old layer properly. The best practice is to strip out the old cladding to the base metal, prepare the metal for a new coating, and replate the cylinder interior.

This requires special skills and techniques; it's not a task that snubbing service providers are usually capable of doing well. There is an entire industry that rebuilds hydraulic cylinders. They are the specialists that can do this job properly. They are often licensed by the original equipment manufacturer. They are expected to bring the cylinder back to "like new" equipment specifications.

The technique that is fastest and least expensive involves simply stripping off the old cladding, polishing the base metal of the cylinder, replating a new cladding onto the interior surfaces, and polishing the new surface to the desired finish. This process is abbreviated SPPP (strip, polish, plate, polish).

Plating involves electroplating of a metal from a salt solution. There are also powder coatings that can be applied using electric plasma welders or lasers. These processes coat the interior of the cylinder uniformly with the selected cladding.

Briefly, the base metal is cleaned to remove all contaminates such as grease, oil, dirt, dust, and other films that could cause the coating to pull away from the base metal surface. The cylinder is then equipped with anodes, usually lead or zinc, and filled with a metal salt solution. One technique involves a hexavalent chromium salt, CrO_3, in a low pH (acidic) solution with sulfuric acid. The solution is heated and placed inside the cylinder. In some electroplating operations, the cylinder exterior is coated with grease and the entire cylinder submerged. Only the interior is electroplated since the grease does not conduct the current keeping the greased outer surface from being electroplated.

A current is applied across the metal surface as the chromium bath is agitated to provide a uniform deposition of metallic chrome atoms from the solution onto the interior surface of the cylinder. In some electroplating operations, a primary coating of copper is plated onto the base metal, followed by a nickel coating, and followed by a topcoat of hard chrome. It is chemically "easier" for chrome to stick to a layer of nickel than to the steel base metal. It's easier to plate copper onto steel than it is to plate nickel onto steel. Some engineered coatings use other materials and processes to electroplate the cylinder interior.

For more severe damage such as deep scoring or gouging, another technique is used. Here, the old cladding is stripped off; the damaged groove in the cylinder wall is filled with base metal (welded) after which the weld is ground to the ID of the cylinder. The cylinder is then replated and polished. It is abbreviated SWPP (strip, weld, plate, polish).

In situations where a complete overhaul of the cylinder is required, the process involves grinding out the cladding and the interior of the cylinder, polishing the base metal, replating or depositing a new hard metal cladding using laser or electric plasma welding techniques, grinding the new cladding, and polishing the entire cylinder. This process is abbreviated GPGP (grind, polish, grind, polish). It is used for new cylinders or those that are worn or damaged beyond minor repair.

Cost for this last process may exceed the cost of a replacement cylinder. Sometimes, the damage is so severe that there simply is no economically feasible way to recondition the cylinder. Again, when one old cylinder is replaced on a snubbing unit, it is usually best to replace all the cylinders. Junking the old snubbing unit and replacing it with a new one in the fleet could be the best decision in this case.

3.2.6.3 Exterior Coating

The exterior surfaces of hydraulic cylinders are exposed to atmospheric corrosion (rust) and other external damage. Once a cylinder is refurbished and repaired, it must be protected by some type of coating on its exterior surfaces.

The existing exterior coating (usually paint or an external multicoat system) is usually removed before repairing, replating, honing, or polishing is performed. This ensures that there are no angular particles from sandblasting, for example, that would scratch the interior surface during the repair process. Once repairs are made and before the cylinder is reassembled, a second step is taken to prepare the exterior for recoating.

Openings in the cylinder are masked; the cylinder is then again sandblasted or bead blasted with a fine particle. Sometimes, walnut hulls or plastic beads are used as the particulate so that only the surface is cleaned without any metal loss. It is important that the masking remains in place throughout this process to ensure that no abrasive particles get inside the cylinder. The exterior is thoroughly cleaned with a solvent, and a primer is applied.

The final topcoat is applied after the primer coat cures. The type and thickness of this coating are usually specified by the customer. The contractor may apply the topcoat if the color is specified by the customer (or he supplies the paint). Sometimes, the cylinder is returned for the customer after priming to apply the topcoat. Regardless, the cylinder exterior must be protected from atmospheric corrosion.

3.2.6.4 Ovality Issues

Occasionally, a hydraulic cylinder gets "mashed" usually during transportation. These cylinders are quite robust, and they are protected from this type of damage. Sometimes, they do get damaged, however. Ovality must be corrected, or there will be a considerable increase in friction as the piston moves through the "egged" section of the cylinder. In some cases when the cylinder wall is pushed in too far, the piston cannot proceed past the damage, and the cylinder becomes unusable.

Single-point ovality issues, such as a dent in a cylinder, can often be repaired. This involves forcing a solid bullet-shaped expander through the dent pushing it back out. Another technique involves using an eccentric set of opposed rollers. Both of these damage the internal cladding to the point that the cylinder must then be replated using one of the techniques mentioned previously.

These same tools can also be used to remove ovality over a section of the cylinder, not just a localized dent. Again, the cladding must be replaced following this work.

Whether or not the ovality can be removed depends on the severity of damage to the cylinder. In cases where the cylinder is badly damaged, the base metal has become so deformed that it cannot be returned to its original dimensions (i.e., the base metal has been permanently deformed). Cylinder replacement may be the only viable option in these situations.

3.2.7 Rod Damage and Repair

The most exposed portion of a hydraulic jack is the rod. It extends through the top of the cylinder, and the polished exterior is exposed to the environment at the wellsite whatever that might be (seawater spray, dirt, blowing sand, rain, sleet, ice, etc.). It is also exposed to physical damage from collision with moving objects (power tongs, pipe, hand tools, dropped objects, swung objects, etc.) and from abuse including a lack of lubrication. Several types of damage can occur to the rod, and there are repair techniques available for most of them.

Wear is the most common damage mechanism for rods just as it is for cylinders. Particles can cling to the rod exterior and then carried down to the wiper seal on each stroke. If the wiper seal is ineffective in removing them or if there is a wiper seal failure, these particles can be pushed into the rod seal assembly. They may be introduced to the cylinder interior through dirty hydraulic fluid and be pushed up onto the lower seal section on each upstroke. Large particles can score the rod just as they can the inner wall of the cylinder. Deep scratches can allow fluid bypass (blow-by) through the seals on every stroke.

This damage can be along the entire length of the rod, but it is usually localized to the top portion of the rod during high-pressure snubbing where short "bites" of the pipe string are taken, and the rod reciprocates through the seals. In some cases, blow-by occurs in one section of the stroke, but it is sealed off and stops once the worn section goes past the seals, and the relatively smooth rod section below enters the seals. This problem can be solved by replacing the rod seals with a different type (backed) or a lip that extends further. When this solution is no longer practical, the rod must be refurbished.

3.2.7.1 Straightening

A bent rod carries side forces to both the rod and piston wear sleeves that can increase friction and result in premature cylinder wear. This may not result in a dramatic reduction in operating efficiency. It may not even be noticeable unless it becomes pronounced. A bent rod is more susceptible than a straight one to further bowing and possible buckling failure.

Once the jack is disassembled and the piston removed from the lower rod end, bowing can usually be seen visually. This is part of the prerefurbishing inspection process. A bent rod must be straightened or replaced.

Importantly, long rods in many hydraulic jacks used in snubbing are not actually solid rods. Rather, they are thick-walled, hollow pipe sealed on both ends. For example, a solid 3 in. steel rod 10–12 ft. long would be exceptionally heavy, so to make the unit lighter, hollow rods are used.

Both solid and hollow rods can be straightened using a number of techniques including sets of opposing rollers that slightly bend the rod back to a straight configuration. Sometimes, the rod is heated to facilitate this work. Once it is straightened, other repairs can proceed.

Rods, like any other metal component, can break due to fatigue at stress risers. These are the places where stresses are concentrated such as at threads or grooves cut into the rod for some purpose. Continual load reversals like those found in snubbing can cause the base metal to crack (along with the plating or cladding). Without repair, these areas will continue to fatigue until complete failure occurs.

3.2.7.2 Honing/Grinding

In the case of minor wear, the cladding on the rod can simply be honed or ground down a very small amount and repolished. This is simpler than the same work on the interior of the cylinder. The rod can be secured in a lathe and turned with a very fine polishing head that moves down the length of the rod. Final polishing is done along the rod centerline to ensure there are no circumferential marks left by turning the rod.

Like piston wear on the cylinder interior, this can only be done so many times before the plating becomes too thin and the rod must be replated. Deep scratches that cannot be honed out require additional repairs.

3.2.7.3 Replating

Like cylinders, once the cladding becomes too thin, recladding or replating becomes necessary. This process again is much less complex than that used for the interior of cylinders.

First, the old coating or cladding must be removed by grinding or turning the rod in a lathe. This also removes deep scratches in the cladding that might extend into the base metal. Deep gouges in the base metal must be welded, and the rod turned a second time to provide a uniform OD after welding.

Once the plating has been applied, it is measured for consistency, and the cladding is ground to specifications. Polishing is performed in a multistep process to the required finish level. The finish is, again, measured in microns from peak to valley.

3.2.7.4 Cladding

Cladding or recladding a rod is also less complicated than recladding a cylinder. Cladding can be performed by plasma-arc automatic welding equipment or by computer-guided lasers, just like cylinders. These processes deposit a layer of molten high-strength metal such as dense chrome, cadmium, or titanium onto the surface of the rod. These processes are generally used for abrasive, high-temperature, high-speed operations where a very hard surface is required. They last much longer than some of the softer coatings, but they are also quite expensive.

Some of these materials are difficult to hone and polish. Different materials and techniques are required to smooth a hard cladding, so abrasive polishing (with a very fine abrasive) is all that is required normally.

Like electroplating, the base metal must be prepared to accept the new cladding. Old cladding must be stripped or ground off. The new cladding must go on the base metal and not over the old cladding to prevent lamination and early detachment.

3.2.7.5 Replacement

Replacement of a rod can be an uncomplicated decision. If the old rod is cracked, severely worn, scored, or badly bent, it is unlikely that repairs would be less expensive than the cost of a new rod. Replacing the rod with a new one built to the manufacturer's original specifications is often the best option. Rods are far less expensive than cylinders.

The time required for rod repairs or replacement means that the unit will be out of service if the cylinders do not also require repair. The revenue loss for this downtime when added into the cost of repairs versus replacement usually tips the scale in favor of replacement.

Finally, a single rod can be replaced without the need for all the other rods. The replacement rod will likely have the same cross-sectional area as the old rod. Friction from the rod seals is much less than that for the piston seals. So, one newly polished replacement rod for only one of the snubbing unit's jacks will likely not result in imbalanced loading.

Replacement of all the rods may be necessary. If so, replacing them is not particularly difficult or expensive especially when downtime is factored in.

3.2.7.6 Twisted Unit

One particular type of rod damage that cannot be easily repaired involves a twisted, or torqued, hydraulic unit. This involves the traveling head being turned by some radial force so that the cylinder rods are no longer aligned with the cylinder bodies. All the rods are simultaneously bent out of alignment.

A snubbing unit or HWO unit can be twisted in high-torque situations literally in the blink of an eye. This can occur due to reverse torque applied to the traveling head while rotating the pipe or by any other torsional force applied to the traveling head. The unit is most vulnerable with the jack extended out (up) in full-stroke mode.

If the twisting is minor (i.e., the deformation remains in the elastic region of the stress-strain diagram), the unit should return to its original configuration once the torque is removed. Unfortunately, in most twisting situations, the damage extends quickly into the plastic region resulting in permanent deformation of all the rods at one time and to roughly the same extent.

A twisted unit suffers from extremely high piston-on-cylinder wall friction. The friction may be so severe that the centering capability of the wear sleeves is exceeded and there is metal-to-metal contact between the piston and the cylinder. The rod wear sleeve function can also be compromised resulting in the rod rubbing inside the cylinder endcap as well. This friction occurs in all the cylinders and is additive. The result is that a twisted snubbing unit is just about inoperable. Increasing the power fluid pressure to overcome the friction is usually not successful with a badly twisted unit.

There is no good way to “untwist” a hydraulic unit. Attempts have been made to apply reverse torque to a twisted unit. Alignment of the unit at the top and bottom of the stroke might be restored. However, there are usually sections of the rods that remain bent. In many twisted unit situations, there simply is no amount of rod straightening, turning, grinding, plating, regrinding, or polishing that will restore the rods to their original, straight configuration.

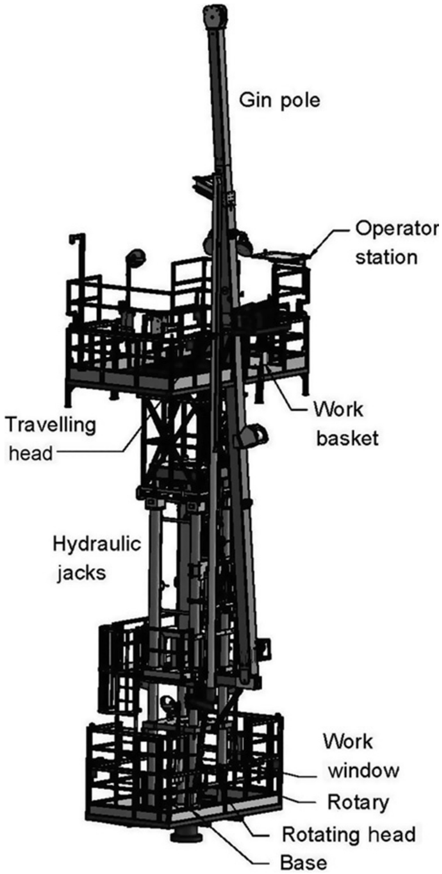
In short, a severely twisted hydraulic jack is, practically speaking, ruined, and it usually requires replacing all the rods (and possibly all the cylinders as well). This is a very large expense in a high-capacity snubbing unit with 2–4 large-diameter cylinders. Snubbing service providers are very sensitive to this type of damage. They take every precaution available to ensure that twisting a hydraulic unit never occurs.

3.2.8 Jack Configuration

The hydraulic jacks provide lift to the snubbing unit traveling head through the traveling frame (or plate). They are configured vertically to provide this motion with all the rods pushing upward or pulling downward on the traveling head simultaneously (Fig. 3.8).

In larger units, the cylinders provide the structural backbone of the snubbing unit. Their bases are rigidly attached to the unit baseplate so that the hoisting load and snubbing tension can be transmitted downward to the wellhead and casing. The tops of the cylinders are connected to an upper stationary deck that supports the stationary slips and the work basket.

In several designs, this upper plate also supports the jib and other equipment in the basket. In other designs, the jib is supported by the baseplate or some other portion of the unit.



■ **FIG. 3.8** Standalone jack schematic diagram. *(Courtesy of International Snubbing Services.)*

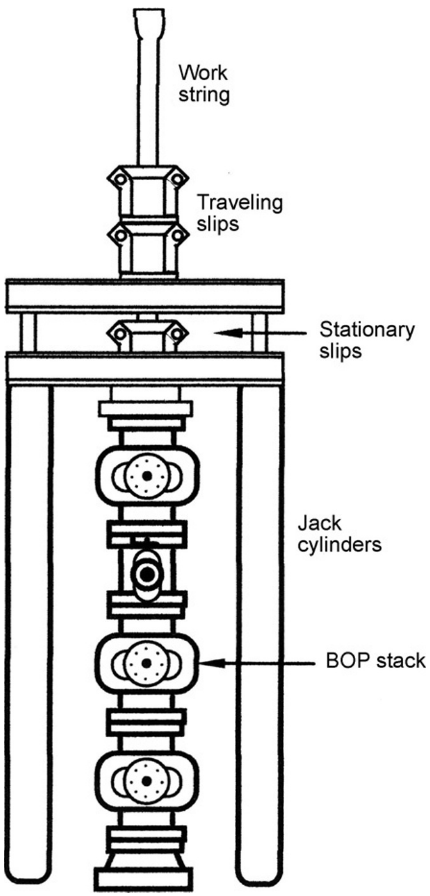
This means that not only do the walls of the cylinders have to be sufficiently thick to resist ballooning at high-power fluid pressures but also they have to support the weight of the unit and the applied forces by the unit on the BOP stack at their base. These cylinders are usually very robust.

Standalone units are usually guyed from the corners of the work basket and the guy lines are usually crossed over one another to resist cylinder twisting. Short bites are taken on the pipe to expose only a few feet of the cylinder rods.

The cylinder rods extend upward through holes in the top plate and are connected to the jack plate containing the traveling slips and hydraulic rotary table. If the traveling head is subjected to a significant torsional force, both the cylinder rods and the legs (i.e., the hydraulic cylinders) can be twisted all at the same time.

Maximum torque on the hydraulic motor turning the rotating head is set such that it will stall out before exerting significant reverse torque on the jack. If the rods are not sufficiently robust or if there is too much of each rod exposed above the top of each cylinder, the unit can still be twisted. That is the reason that the rotary tables supplied with most of these larger units are limited in peak torque capacity (see Table 3.1) and they are limited in operating speed to 50–60 revolutions per minute (RPM). At this slow rotating speed, the unit operator usually has enough time to catch the reverse torque and stop the rotary table if it doesn't stall out first.

In rig-assist units, the snubbing BOPs provide this structural support for the top plate where the stationary slips are mounted (Fig. 3.9).



■ **FIG. 3.9** Rig-assist snubbing unit schematic. *(Courtesy of Abel Engineering.)*

The hydraulic cylinders in these units only provide lift or snub force to the traveling head. They provide no structural support since the BOP stack supports the top plate and transmits all forces through the rig's safety BOP stack and down to the wellhead. The rods in a rig-assist unit can still be twisted by excessive torque on the traveling head. Few of the smaller rig-assist units are equipped with a rotary table since it is usually unnecessary. The cylinders can be bent, dented, or flattened due to mechanical abuse on the rig floor especially during initial rig up (hoisting).

Cylinders on small rig-assist units may be constructed with thinner walls than those in standalone units since they don't support the snubbing unit. They are usually shorter too. Both of these features reduce their weight, a desirable characteristic for a rig-assist unit.

3.3 TRAVELING HEAD

The traveling head is composed of several items that constitute the moving portion of the snubbing unit mounted on top of the cylinder rods.

The traveling head is often called by different names, some of which were used to describe the snubbing unit in patent applications. In some cases, local naming conventions or individual snubbing service provider names were given to this assembly. It has been called the jack frame, traveling frame, traveling plate, and traveling assembly in various areas. There is no universal naming convention for this assembly.

3.3.1 Jack Plate

The jack plate carries other devices such as the hydraulic rotary table and traveling slips. It is a robust structural member that is primarily intended to transmit force to the traveling slips. This is a simple rigid plate to which all the cylinder rods are firmly anchored. It transmits hoisting or snubbing forces to the traveling slip/bowl assembly across its face.

In the past, this was a single steel plate of given thickness with holes drilled in it to which the rods and the traveling slips were attached. Now, most have a different design to provide bending resistance from the rod connections to the slips.

Most of the jack plates are made from two plates with vertical members sandwiched and welded between the two plates. This permits the jacks to be connected to the bottom plate with the rotary table and traveling slips attached to the top plate. The internal members provide stiffness and strength to this "laminated" plate design. The distance between the plates is rather small, usually 2–4 in.

Also in the past, the jack plate had a single relatively small-diameter hole in the center through which pipe was run. This works well if a limited range of pipe diameters, such as production tubing, is being handled. If other equipment such as drill pipe, casing, motors, drill collars, stabilizers, or reamers must go through the unit, the hole must be large enough to accommodate these BHA components.

Many jack plates are now "U"-shaped with one side open. This allows access to the traveling slip/bowl assemblies. It also allows for some flexibility in running odd-shaped or odd-sized BHA components.

Regardless of shape, the jack plate must be designed to successfully handle the maximum hoist rating of the combined jacks plus a considerable safety factor. Bending, warping, or breaking a jack plate could result in unbalanced loading and significant damage to the end of the rods.

3.3.2 **Hydraulic Rotary Table**

A 1930 patent application by inventor James C. Fortune describes a hydraulic feed mechanism that is run inside of and attached to a rotary table on a drilling rig. It is composed of a short single-ram hydraulic cylinder operated by water with a hollow "rod" through which drill pipe or tubing is run. The piston-operated "hydraulic rotary table" design was used to snub or hoist drill pipe or tubing into or out of the well with low surface pressure. It is mentioned in several early papers for use in running tubing in pressured wells in California. The patent for this device was granted in 1933, but it was replaced by the early Otis snubbing unit that proved to be much faster and less complicated to rig up and operate.

Workovers and deepenings were performed on several old wells with pressure on the wellhead by rotating a drill string through the annular preventer using the rig's mechanical rotary table and traveling block swivel. This was only possible after the string became pipe-heavy and the slips could be dropped into the rotary table. Obviously, they had to be pulled frequently to allow drilling to proceed. Annular element wear precluded using the kelly. Even with pipe in the hole (not the kelly), numerous changeouts of the quickly worn annular BOP element were required, a common problem with early attempts to rotate pipe with pressure on the well.

The solution was a set of slips in the traveling head that could be rotated as the string was lowered by a hydraulic jack (similar to Fortune's early hydraulic feed design).

The earliest mention of a hydraulically operated rotary table on a snubbing unit involved a rotating plate mounted on top of the jack plate below the traveling slips. It had an external circular planetary gear driven by a pinion attached to a hydraulic motor. The motor was reversible so the rotary table could turn either direction, if necessary. It did not take long to realize that the exposed planetary gear could be easily damaged by dropped objects, and it was a hazard to operators (hand injuries, mostly).

Later designs inverted the planetary gear and enclosed it in a housing to prevent these problems, to keep the assembly clean, and and to prevent damage from dropped objects such as hand tools. Additional hydraulic motors and pinions were added to provide higher torque. One design had four motors. The number of motors is only limited by the size of the rotary table and the jack plate.

Modern hydraulic rotary tables use two or four motors both operating on an internal planetary gear (Fig. 3.10). Rotary tables are limited both in torque output and speed to avoid twisting the jack. Note that larger standalone snubbing units are equipped with a hydraulic rotary table provided by the

■ **FIG. 3.10** Hydraulic rotary table. *(Courtesy of Cased Hole Well Service.)*

manufacturers. Smaller units and rig-assist units are not usually equipped with a rotary table unless specified by the snubbing service provider. They are rarely used since there are better alternatives such as power swivels or the rig's rotary table once the string goes pipe-heavy.

The use of the snubbing unit's hydraulic rotary table has become popular for hydraulic workovers and for snub drilling. The rotary table allows the string to be rotated in either direction, and rotary table speed can be controlled using a volume regulator. This allows the fine control needed for, say, milling operations where the mill must be lowered gently while rotating the string to avoid snagging and overtorquing the pipe. In snub drilling applications, the rotary table can be used to make minor course changes while slide drilling. The rotary table allows the use of rotary steerable tools during continuous rotation drilling.

3.3.3 In-Line Power Tongs

An idea patented several years ago involved a set of power tongs mounted on top of the hydraulic rotary table and below the traveling slips. The device had a gripper that held the bottom of the connection steady, while an upper section gripped and turned the pipe to make up the connection to the proper torque. Similarly, the upper tong could be reversed to break out connections. Both grippers could be retracted to allow snubbing or pulling pipe through the bore of the power tongs.

The exact design was not provided in patent documents for this in-line power tong. It functioned much like the retractable power tongs used extensively in the industry today. It apparently did not gain much popularity since it was always in place and could not be detached and removed easily. Its size limited the unit operator's ability to visually monitor the traveling slips since it added about 2 ft. to the height of the equipment above the jack plate.

One other disadvantage to the original in-line power tong design is that there was no way to rotate the device without disconnecting the power fluid and return lines. Leaving them connected would cause them to twist around the tong when the rotary table was engaged.

There is a modern design of an in-line power tong that overcomes the problem with twisted hydraulic lines. It is used on an HWO unit as part of a permanent installation connected to the traveling head. Another design has a gin pole pipe guide that allows remote stabilization of the pipe while making a connection. This allows the HWO unit to operate under the same wind side-loading guidelines as conventional cranes.

Most snubbing and HWO units, however, still use the retractable power tongs for most jobs. More work is needed to perfect a hands-off robotic means to deal with connections without manual intervention.

3.4 SLIPS

Snubbing units are equipped with two different sets of slips and slip bowls, the traveling and stationary slips. These permit handing off the load, whether upward (snubbing) or downward (hoisting or stripping while pipe-heavy), so that the load is supported and firmly held while repositioning the jack head.

This type of motion with two sets of slips to alternately manage loads is often described in the literature as hand-over-hand snubbing. By contrast, coiled tubing units operate off opposing continuous chains with gripper blocks that hold the pipe securely regardless of travel direction. Hand-over-hand snubbing is required to work with jointed pipe.

The slips and bowls on any snubbing unit must be sized to have the proper capacity for the unit on which they are mounted. A light-duty set of slips mounted on a high-capacity snubbing unit such as a 600 K unit would not be prudent and could lead to failures that would endanger personnel, the snubbing unit, and the well. Conversely, putting a massive set of slips and bowls on a light-duty rig-assist snubbing unit makes no sense from either operational or economic standpoints. All components of a snubbing unit must be designed in concert with each other.

Early snubbing units, including the original Otis cable-style snubber, used common bowls and slips used on drilling or workover rigs. They were inverted for snubbing pipe in the hole under pressure in a pipe-light situation. When the string became pipe-heavy, the stationary bowl was placed in its normal position, and slips were dropped in just as they would be for drilling operations to keep the pipe from sliding down the hole. Obviously, knowing the point in the well where the string went from pipe-light to pipe-heavy (i.e., the neutral point) was, and still is, important. Something had to hold the pipe when it was run below the neutral point to keep it from sliding down the hole. With both sets of bowls and slips inverted for snubbing, there was nothing available to keep the pipe string from sliding down the hole due to its own weight.

The solution was fairly simple. A short stand fabricated from angle iron and secured to the rig floor was mounted to hold the stationary snubbing bowl and slip assembly some height above the rig floor. This left a gap above the rig's rotary bushings and below the stationary slips. The rig's slips could be dropped into the bushings as soon as the pipe showed any tendency to slide down the hole at the end of a "stroke."

Fortunately, at the neutral point, there is no upward or downward force affecting pipe movement (and therefore no friction). If the pipe was pushed below the neutral point, the string weight could pull the pipe in the hole. However, anytime pipe is moving, friction is generated, and the friction always acts opposite to the direction of pipe movement. So, when the end of the string was below the neutral point, there was a time when the pipe would not move due to friction even though the string had actually become slightly pipe-heavy.

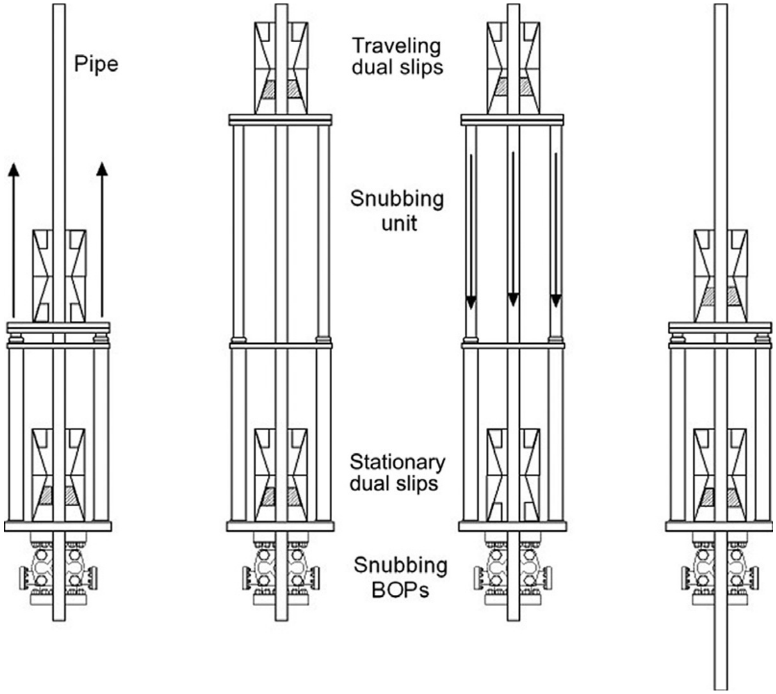
This allowed snubbers to invert only one set of slips, usually the stationary slips, as the pipe approached the neutral point going either direction (going in or coming out of the hole). In the barely pipe-light situation, friction kept the pipe from being forced out of the hole, while the jack was elevated to get another bite of pipe with the traveling slips. Later, in the barely pipe-heavy state, friction kept the pipe from sliding down the hole when the stationary slips were opened during the downstroke. The traveling slips were eventually turned over once the pipe showed a tendency to keep sliding down the hole at the end of a downstroke. Both bowl/slip sets remained in the normal position as the pipe became heavier and stripping operations continued.

Obviously, there were some anxious moments when the pipe suddenly decided to start sliding in either direction. Friction created when pipe starts moving through the snubbing BOPs usually stopped the pipe from moving near the neutral point. Some snubbers added another BOP to the safety stack with a slip ram that gripped the pipe and disallowed motion in either direction. Others wrapped a chain around the pipe and secured it to a portion of the traveling head in less sophisticated operations.

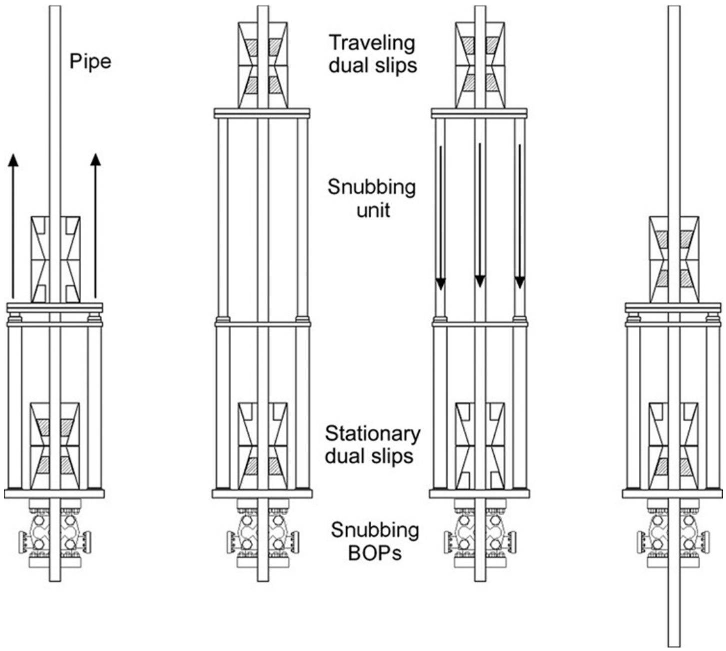
A solution to this situation was developed fairly quickly, double-acting slips.

Double-acting slips involve two bowls and two sets of slips in both the traveling head and at the stationary position. The slips are selectively activated depending on the direction of force and motion (Figs. 3.11–3.13). The slip bowls and slip segments are paired so that the four slip/bowl combinations work in tandem, two at a time. In all of these figures, pipe is going in the hole.

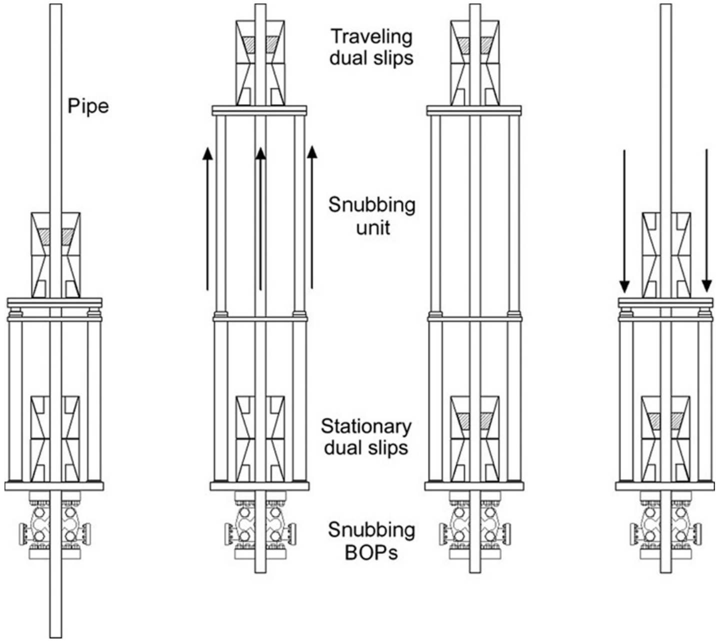
Paired sets of bowls and slips are used depending on the direction of the force on the pipe. Hydraulic controls for each slip set are interlocked such that both sets of slips in a working set cannot be open at the same time.



■ **FIG. 3.11** Slip activation sequence for pipe-light snubbing.



■ **FIG. 3.12** Slip activation sequence for snubbing at balance point.

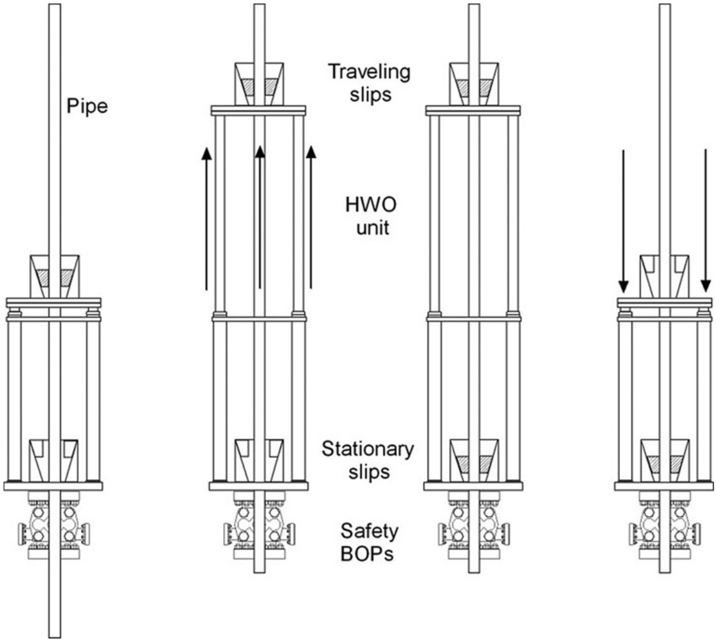


■ **FIG. 3.13** Slip activation sequence for pipe-heavy stripping.

When the other slip pair is not in use, it can be retracted to prevent the slips from rubbing on the pipe, wearing the slip dies, and scoring the pipe surface. The interlock system is disabled in the nonworking (open) slips. In some systems, the entire bowl/slip set is hinge-mounted and can be completely retracted when not in use. Only the slip/bowl pair being used surrounds the pipe at any given time.

At the balance point (Fig. 3.12), both pipe-light and pipe-heavy slips are closed to prevent the pipe from sliding down the hole or from being ejected due to wellbore pressure. Usually, friction from pipe moving through the snubbing BOPs is sufficient to stop the pipe from moving anyway. The two sets of opposing slips provide mechanical surety that the pipe will not slide.

By contrast, HWO units have only single slip/bowls since no snubbing is involved (i.e., dead well and pipe-heavy workovers). The slip/bowls are only arranged for hoisting the pipe while running or pulling the string (Fig. 3.14). Dual slip/bowls are not needed unless there is the possibility that pressure in the wellbore could increase during the workover. In this diagram, the pipe is being pulled from the well. The reverse sequence would be used for running pipe in the hole.



■ **FIG. 3.14** Slip activation sequence for HWO single slip/bowls.

3.5 SNUBBING BOPs

Three types of BOPs are used in snubbing and stripping: a stripping head (or stripping rubber), an annular preventer, and/or at least two conventional guillotine-style ram-type BOPs. The stripping head is similar to those used on early cable-style snubbing units like the Otis conventional snubber. Annular BOPs are also used for low-pressure snubbing and stripping. The annular BOP is used for stripping pipe by conventional drilling and workover rigs. Both stripping heads and annular preventers can close on various diameters and unusual shaped components of the string.

In ram-to-ram snubbing or stripping, two BOP rams are used to contain pressure. These fit around the OD of the body of the pipe (i.e., not an upset or a collar). Each must hold the well pressure while moving pipe through the ram, first one and then the other.

3.5.1 Stripping Head

These devices, often called stripping rubbers, employ some means of closing on the exterior of the pipe to hold low to moderate pressures and prevent wellbore fluids from leaking into the environment. Most use a flexible elastomer element that can be inflated, closed, or deformed around the pipe and still allow passage of an upset, a larger- or smaller-diameter pipe or some odd-shaped component of the pipe string.

Some systems are designed with a rubber element in a cavity that is inflated by pressure outside the element. These are normally called "bags" and are similar in function and operation to diverter elements on drilling rigs.

The height of the element and the cavity is normally about 5–7 times the diameter of the pipe. This provides sufficient contact area to prevent leakage while allowing some wear during low-pressure operations. Bag-type stripping heads have been used for many years.

Care must be exercised to avoid running sharp or very rough tubulars through the bag. These can cut the element resulting in seepage of wellbore fluids or immediate bag deflation and wholesale leakage. Nobody likes to be around the stripping head when a bag blows up.

Bag-type stripping heads usually cannot be closed completely on an open hole. There is not sufficient bag expansion to pinch the opening shut without rupturing the element. Other types of BOPs are needed for this situation.

Another type of stripping head uses a solid soft-rubber element housed in a rigid cavity. Well pressure or hydraulic pressure is used to push a piston upward crushing (deforming) the rubber onto the pipe for a tight fit. When an upset or collar goes through the rubber, the piston drops, and the rubber elements open a small amount allowing the upset to pass through the rubber that then closes back around the pipe.

Stripping heads also work as pipe wipers keeping wellbore fluids inside the well when coming out of the hole and dirt, debris, pipe dope, or other contaminants from entering the hole on the way in.

Eventually, all elements through which pipe is snubbed or stripped will wear to the point that they cannot contain either pressure or fluid. This requires changing out the element with a new one before the job can continue. The elements in stripping heads are far less expensive than annular BOP elements and less complicated to change out than ram packers on snubbing BOPs. Changing out a stripping head rubber is simple and fast. So, as long as something is going to be worn and changed out periodically anyway, it should be the cheapest element in the stack.

Most stripping heads are installed immediately on top of the annular BOP. This places the device in the work window below the snubbing unit base. This provides a convenient place for crewmembers to change out the element from time to time without interference from other snubbing or stripping operations. They are protected here from falling objects, and they are above the safety BOPs that are used to hold well pressure while the change-out takes place. Sometimes, stripping operations just swap over to the annular preventer, while the stripping head is repaired. The pipe only stops moving when necessary to mitigate risks.

In rotary operations, a rotating head or rotating BOP can be substituted for the stripping head. Rotating the pipe in the stripping head quickly wears the element, and failure occurs in short order. Some rotation can be tolerated, but not for long periods of time. The rotating head or BOP allows rotation without excessive element wear.

3.5.2 **Annular Preventer**

The annular preventer is usually the top BOP on the safety stack below the work window and snubbing unit. If the work window is not present, the hydraulic unit rigs up directly on top of the annular.

The annular preventer is usually rated at about 70% of the rated pressure of the ram BOPs in the safety stack. For example, if the safety ram-type BOPs are rated for 5000 psi, the annular is rated for about 3500 psi. It is also tested to this rated pressure. If a rig-assist unit is being used, the annular BOP rating may be lower if an overrated BOP stack is rigged up below it (say a 10,000 psi BOP stack for 5000 psi service). Regardless, the annular preventer should be rated and tested to at least the existing pressure on the well.

In some high-pressure situations, the use of an annular preventer is not practical or reasonable. In these situations, it is not nippled up at all. Instead, the snubbing unit is rigged up on top of the uppermost ram BOP in the safety stack. That ram could be a slip ram, a pipe ram, or a blind ram BOP. All of these must be rated and tested to a pressure greater than the maximum anticipated wellhead pressure during the job, usually to the rated pressure of the BOP.

Sometimes, the annular preventer can be operated from the BOP control panel in the work basket. The remote control panel on the accumulator skid, if one is present, will also has an annular control valve.

It is important that one remote operating panel for the safety BOPs be located somewhere on the site. If the controls for the safety BOPs were only located in the basket, there would be no way to function them if the unit operators must evacuate the basket during an emergency.

3.5.3 Snubbing BOPs

The snubbing BOPs (also often called "strippers") are those used for containing pressure while moving pipe through them. They are used for ram-to-ram snubbing. Both are rated the same and at a pressure higher than the well pressure.

A naming convention has been adopted by snubbing service providers. The upper snubbing BOP is termed the "number 1 stripper" with the lower one designated as the "number 2 stripper".

A safety factor is usually applied to the snubbing BOPs since they are required to hold the entire wellbore pressure while snubbing or stripping the pipe unless the well uses the stripping head or annular BOP for a portion of this work in low-pressure applications.

Most snubbing service providers apply a safety factor to the BOP rating since the snubbing BOP ram packers will suffer damage while snubbing pipe through them. One service provider uses a 90% cutoff for the snubbing BOP pressure rating. Say, for example, a snubbing BOP has a 5000 psi rating; anything at or above 4500 psi well pressure would require a higher rated BOP ($5000 \times 90\ \% = 4500$ psi).

Assume that a well has a 4400 psi wellhead pressure. A 5000 psi snubbing BOP set could be used. If the wellhead pressure was 4500 psi or more, a 10,000 psi-rated snubbing BOPs would be required. Similarly, if there was a 9000 psi wellhead pressure, 15,000 psi snubbing BOPs would be required instead of 10,000 psi BOPs. If the wellhead pressure was 8950 psi, the service provider would probably still use 15,000 psi-rated snubbing BOPs since the pressure could drift upwards during the job.

Often, the decision about the pressure rating for a set of snubbing BOPs is based on availability. If a 5000 psi-rated snubbing set was needed, but only a 10,000 psi-rated set was available, the 10,000 psi set could be used. If the opposite situation existed, the 5000 psi snubbing BOP set could not be substituted.

Snubbing BOPs are ram-type preventers. The ram packer elements are a bit different from conventional BOPs. The soft-rubber elastomer commonly used in conventional ram-type BOPs would wear so quickly with pipe running through them that almost constant changes of ram blocks and packers would be necessary. So, snubbing BOPs uses a hardened insert on the front of the ram packer. It is made from an elastomer (e.g., nylon) that will still seal but that is more resistant to abrasion than the soft elastomer commonly used (Fig. 3.15).

■ **FIG. 3.15** Snubbing ram blocks and ram packers. *(Courtesy of Abel Engineering.)*

3.5.4 Ram-to-Ram Snubbing

Managing pipe upsets and collars at connections using ram-type BOPs requires that one ram set is closed around the pipe body at all times. This requires that the connection be above, below, or between the snubbing BOP rams. The use of two BOPs allows this process to be performed safely using a technique called ram-to-ram snubbing.

When snubbing or stripping in the hole, the upset or collar is snubbed down to the top of the no. 1 stripper. The no. 2 stripper is closed on the pipe below the upset, and the no. 1 rams are retraced. The connection is then snubbed down to the top of the no. 2 stripper rams, the no. 1 rams are closed on the pipe above the connection, and the lower BOP rams are retracted. Thus, pressure control is maintained as the snubbing duty is handed off from one set of rams to the other. When snubbing or stripping out of the hole, the reverse procedure is used.

This obviously requires that there is enough room between the two sets of snubbing BOP rams to "swallow" the longest upset or tool in the string. Both strippers are single-ram BOPs. There would not be enough room in a double-ram BOP to allow the entire upset on most oil field pipe (tubing or drill pipe) to fit between the ram blocks. Most of the time, there is a flanged spacer spool between the two rams that is tall enough to ensure the proper distance between the two ram sets for ram-to-ram snubbing. This spool often has side outlets to accommodate the equalizing loop.

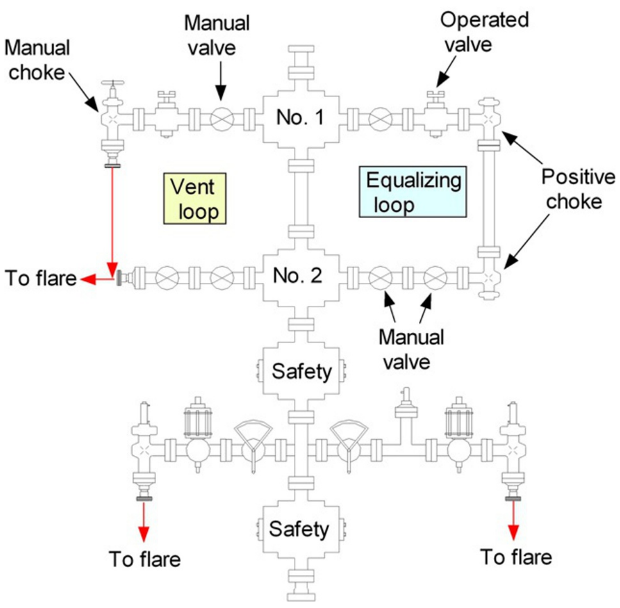
3.6 EQUALIZING LOOP

Ram-to-ram snubbing or stripping requires that pressure in the cavity between the BOPs, well pressure, and atmospheric pressure be equalized from time to time during the snubbing operation. The cavity must contain well pressure before opening the no. 2 stripper. If it remains at atmospheric pressure, the ram packers will be subjected to an almost explosive pressure increase when the no. 1 stripper rams are opened. Similarly, the cavity must be bled down to atmospheric pressure through a vent/flare system before the upper BOP rams are opened, or well pressure will blow straight up the snubbing unit bore and into the basket.

These two conditions require the use of an equalizing loop, a series of valves and piping that protect not only the sealing elements in BOPs but also the snubbing unit personnel working in the basket and the environment.

3.6.1 Configuration

An equalizing loop has two sides. One side is connected from a point on the stack that is connected to the pressured wellbore. The other side is connected to the cavity between the snubbing, or stripping, rams. This circuit is used to "equalize" pressure across the lower rams (no. 2). The other side of the loop is designed to vent well pressure out of the cavity between the rams. This side of the loop equalizes the cavity across the no. 1 stripper rams with atmospheric pressure (Fig. 3.16).



■ **FIG. 3.16** Equalizing loop schematic.

In Fig. 3.16, the snubbing BOP side outlets are actually situated below the rams on each BOP. The equalizing loop runs from below the no. 2 stripper rams to below the no. 1 stripper rams. This connects the wellbore to the cavity between the two snubbing BOPs.

Valves in both loops control the flow of pressured fluid from the wellbore into the cavity between the snubbers and also from the cavity to the vent or flare pit. The equalizing loop usually contains at least one in-line choke. The vent line to the flare pit can contain a manual choke, or it may be routed through a remote choke manifold. The cavity between the safeties also has some way to vent accumulated pressure. On rig-assist units, this may be the rig's choke line and manifold or some other vent system to prevent trapping pressure in an isolated section of the BOP stack.

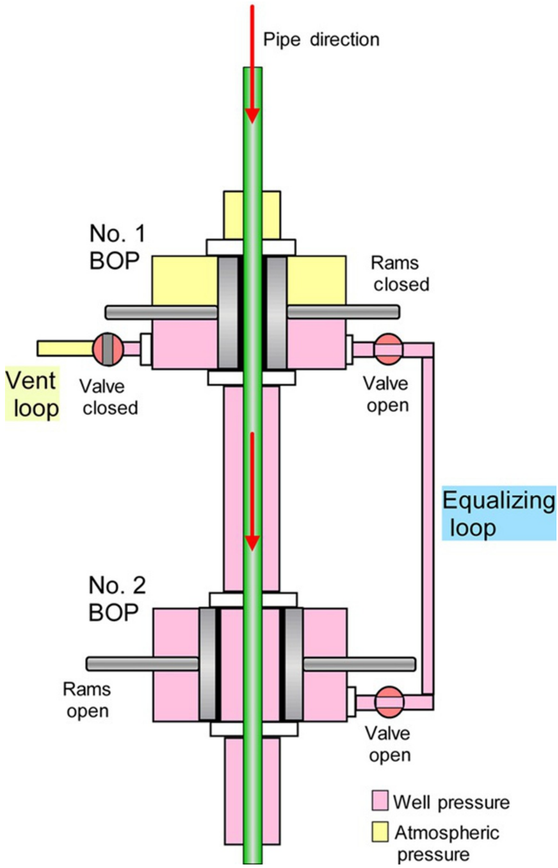
In Fig. 3.16, the valves coming off both side outlets on the no. 2 snubbing BOP are manual valves. When snubbing primarily on the no. 1 stripper, the valves on the equalizing loop usually remain open with pressure in the cavity between the BOPs. The control valves are functioned through controls in the work basket. On the vent loop, the valves coming off the bottom of the no. 2 stripper usually remain closed. Pressure venting is through the operated valve coming off the side outlet from below the no. 1 rams. The manual choke on the vent loop is usually set at a nominal value to prevent venting at a high flowrate. This avoids overloading the flare line and the BOP ram packers and icing below the choke.

3.6.2 **Operation During Snubbing**

Equalization across one set of snubbing rams or the other is crucial to safe and effective operation of a snubbing unit. The sequence of valve manipulation is not difficult as long as the operator pays attention. Recently, instrumentation (pressure and temperature gauges) and interlocking control systems have been developed to avoid opening both BOPs at the same time with pressure on the well. A set of simplified sketches help to illustrate how the equalizing loop operates both snubbing in or out of the hole.

3.6.2.1 Snubbing in the Hole

Figs. 3.17A–3.17F show the configuration and operation of an equalizing and vent loops on a simplified snubbing stack. In these figures, there are two snubbing/stripping ram-type BOPs, an equalizing loop, and a vent loop with a connection to a flare line. Actual equipment is more complicated than this simplified stack. It is used only to show how the equalizing and vent loops work while snubbing pipe.



■ **FIG. 3.17A** Normal snubbing/stripping operations going in the hole.

The first figure shows normal pipe snubbing or stripping operations with the no. 1 BOP as the primary snubbing BOP. In all of these figures, it makes no difference if the string is pipe-heavy or pipe-light. Ram-to-ram stripping is the same as snubbing. Stripping may use a stripping head or annular preventer that allows a connection to push through the sealing element, in which case neither the no. 1 and no. 2 strippers nor the equalizing or vent loops are used. Pressure is contained within the wellbore by the sealing element.

In this operation, the no. 1 (top) BOP is closed on the body of the pipe, and the bottom ram is open. The top ram is holding well pressure since the equalizing loop valves are both open with the vent loop line closed.

When a connection approaches the no. 1 ram, snubbing/stripping operations stop, and the lower rams are closed trapping well pressure between the two

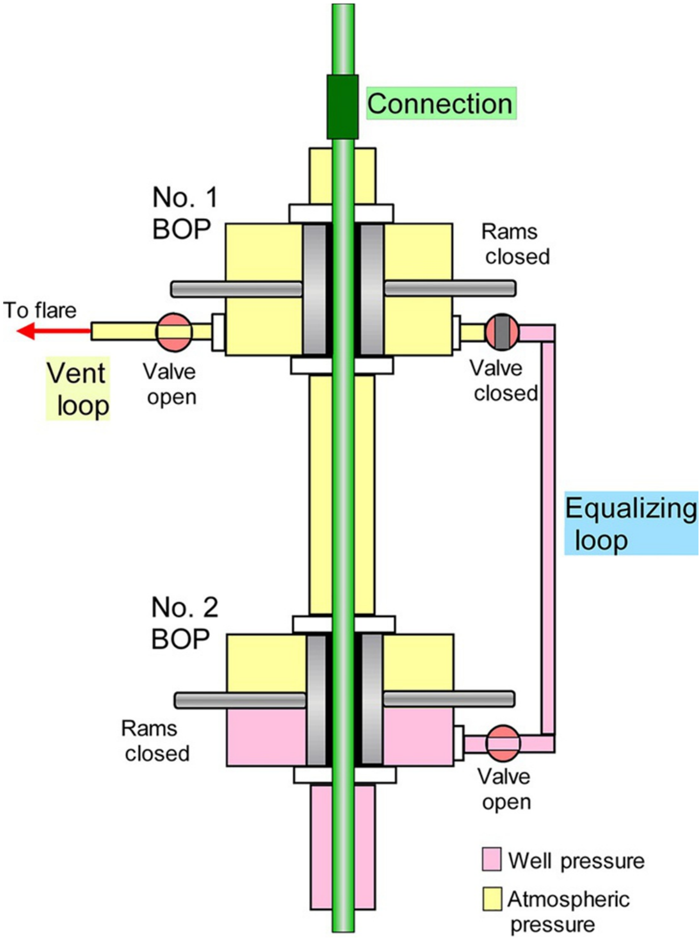
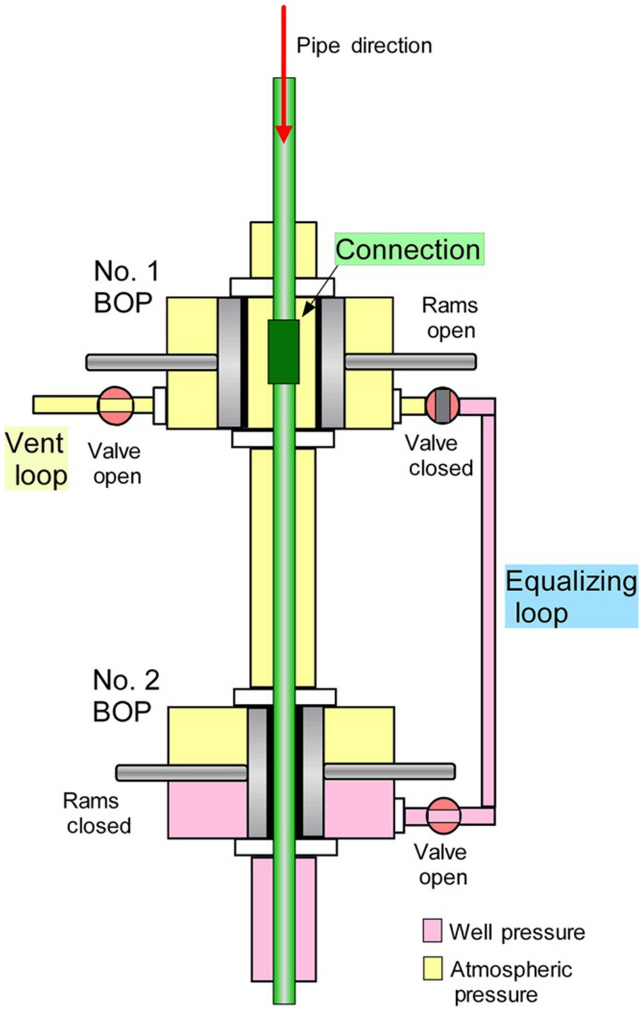


FIG. 3.17B Connection just above top BOP.

BOPs (Fig. 3.17B). The vent valve is opened, and pressure between the rams is vented to the flare.

Once the pressure between the two snubbing/stripping BOPs is vented and atmospheric pressure is below the no. 1 rams, they can be opened to allow the connection to progress down the hole (Fig. 3.17C). In this step, the no. 2 stripper holds well pressure as the pipe travels down the hole.

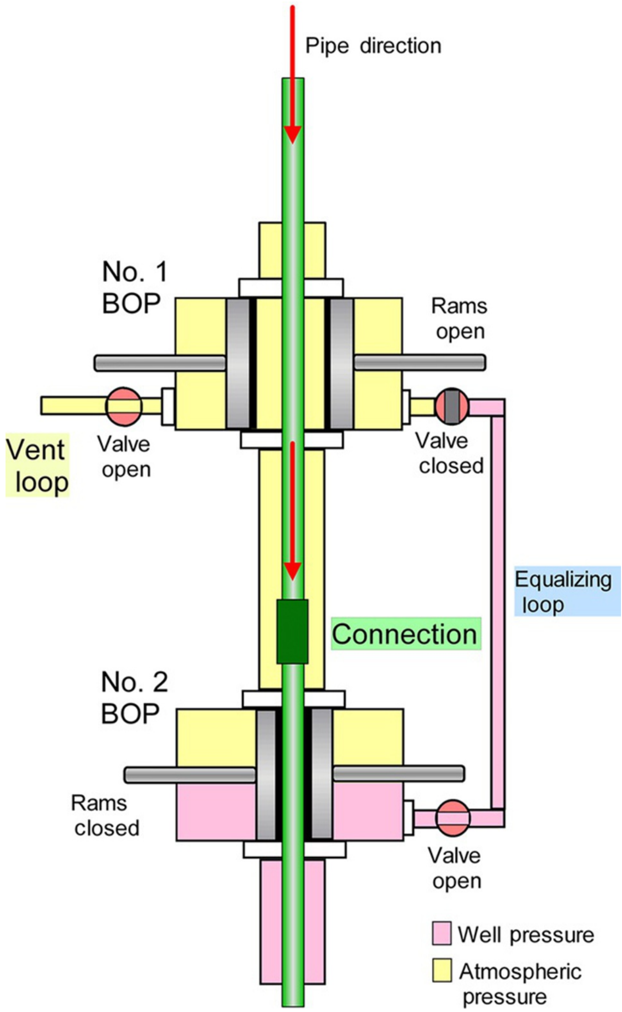
Snubbing/stripping continues until the connection is “swallowed” in the cavity between the two BOPs, usually just above the lower BOP rams (Fig. 3.17D).



■ **FIG. 3.17C** Snubbing/stripping through no. 2 BOP.

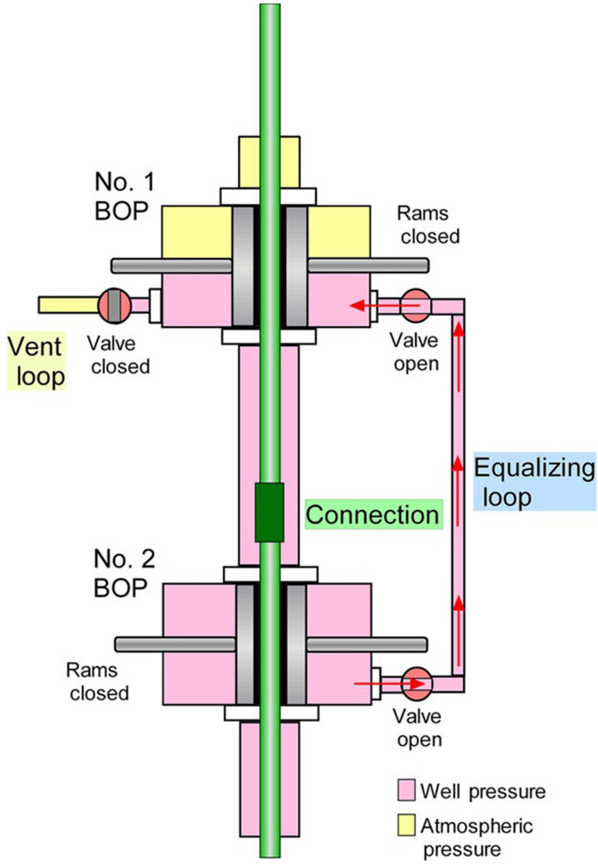
Once the connection is at the proper position, the upper rams are closed on the pipe body providing a seal above the connection. The vent loop valve is closed, and the equalizing valve is opened. This allows well pressure below the no. 2 stripper to flow around the loop and equalize across the lower BOP rams (Fig. 3.17E).

The bottom rams are opened once well pressure stabilizes in the cavity between the two BOPs; the connection is lowered through the bottom BOP. Normal snubbing/stripping operations resume (Fig. 3.17F).



■ **FIG. 3.17D** Pipe snubbed so connection is swallowed.

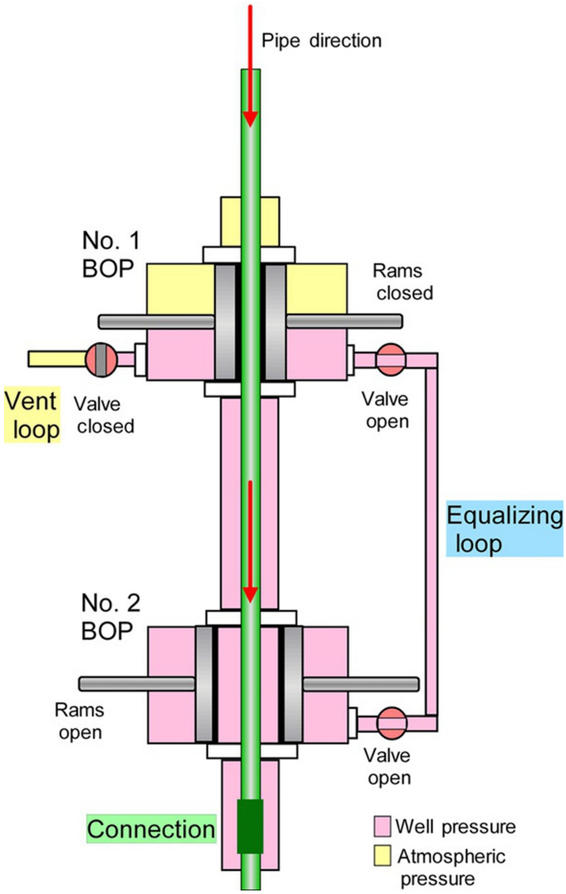
In this configuration, most of the wear and abuse is absorbed the ram packers in the no. 1 (upper) stripper since it closed on the pipe most of the time. This can result in frequent leaks and the need to change the ram packers often. Some snubbing service providers alternate between snubbing on the two BOPs to equalize the wear on the ram packers. They will intentionally leave the no. 2 (bottom) rams closed most of the time only closing the no. 1 rams to manage a connection.



■ **FIG. 3.17E** Equalizing pressure across bottom BOP.

When the no. 2 stripper is the primary for snubbing/stripping, the connection is run down to just above the top of the no. 2 rams. The no. 1 rams are closed on the pipe body above the connection, and pressure is equalized across the lower BOP (i. e., well pressure is introduced into the cavity between BOPs). The no. 2 rams are opened, and the pipe is snubbed/stripped through the no. 1 rams until the connection is below the no. 2 rams. Then, the no. 2 rams are closed, pressure in the cavity is vented to the flare pit, the no. 1 rams are opened, and the remainder of the pipe joint is snubbed down through the no. 2 rams.

Either method of snubbing/stripping is acceptable. The primary snubbing BOP is used most of the time with the other BOP used just for connections. Selection of the primary BOP may be based on the height of the unit after



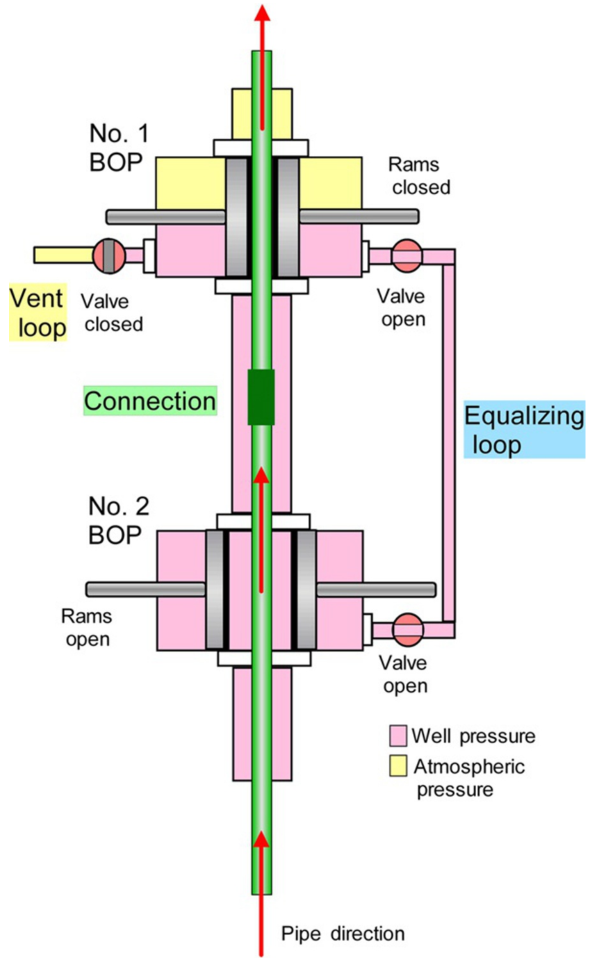
■ **FIG. 3.17F** Resumption of normal snubbing/stripping operations.

stack up and the work platform available for crewmembers to change out the primary stripper rams.

The same procedures are also used for pulling pipe out of the hole under pressure; the steps are simply reversed.

3.6.2.2 Snubbing/Stripping Out of the Hole

Figs. 3.18A–3.18D show the steps involved in snubbing/stripping out the hole on the no. 1 BOP. The connection is snubbed/stripped up until it is inside the cavity just below the no. 1 rams (Fig. 3.18A).

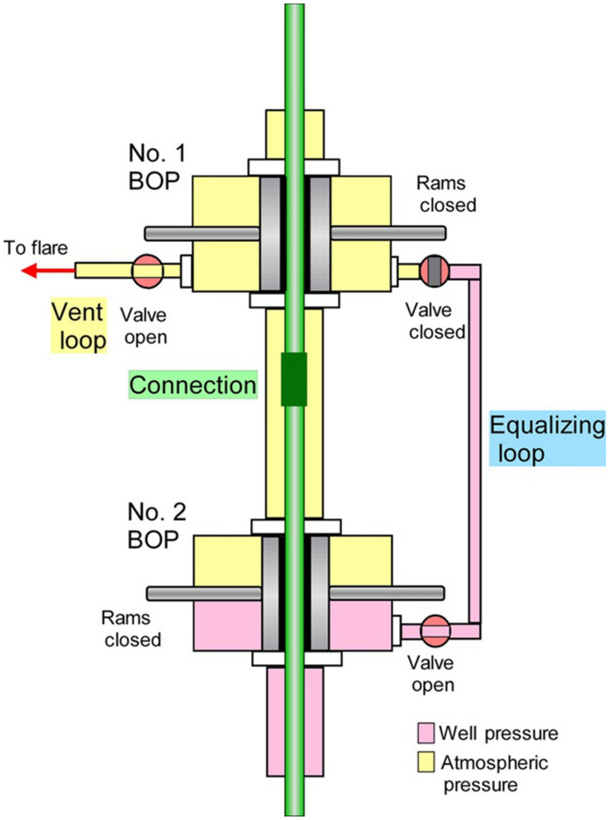


■ **FIG. 3.18A** Snub/strip connection inside cavity.

This allows the opportunity to close the no. 2 rams and vent the pressure between the BOPs in the cavity (Fig. 3.18B).

Pressure equalization between rams to atmospheric pressure allows the no. 1 rams to be opened safely and without damage to equipment, personnel, or the environment. The connection can then be snubbed above the no. 1 rams through the no. 2 BOP.

Now that the connection is out of the cavity, the upper BOP rams are closed and wellhead pressure equalized across the lower BOP (Fig. 3.18D).



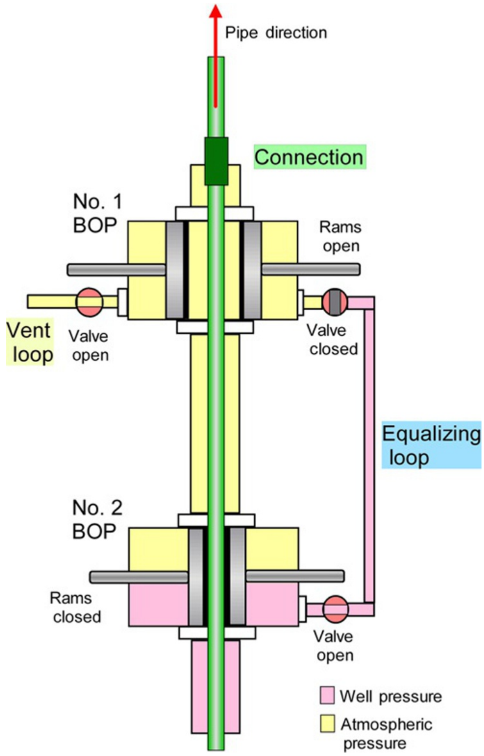
■ **FIG. 3.18B** Venting pressure between BOPs.

All that remains is to open the no. 2 BOP rams and continue normal ram-to-ram snubbing/stripping operations on the remainder of the joint until another connection is encountered (Fig. 3.18E).

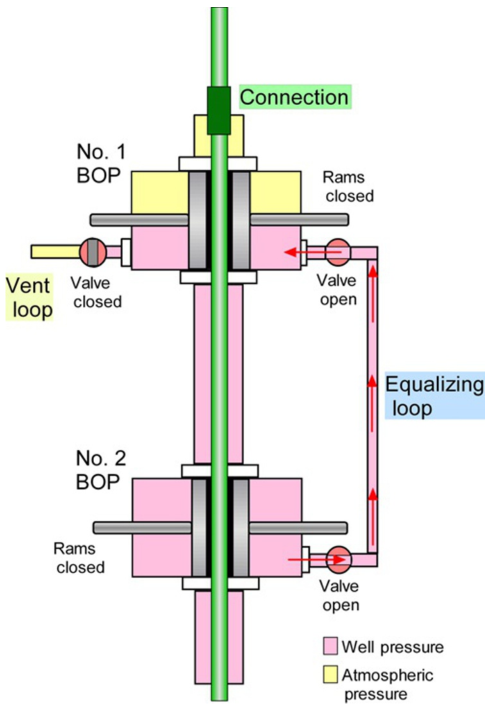
Again, the operator can snub/strip out of the hole using the no. 2 BOP as the primary control as an acceptable option. The steps in performing the procedure this way would essentially mimic the procedures shown in Figs. 3.17A–3.17F but in reverse.

3.6.2.3 Reversing Direction

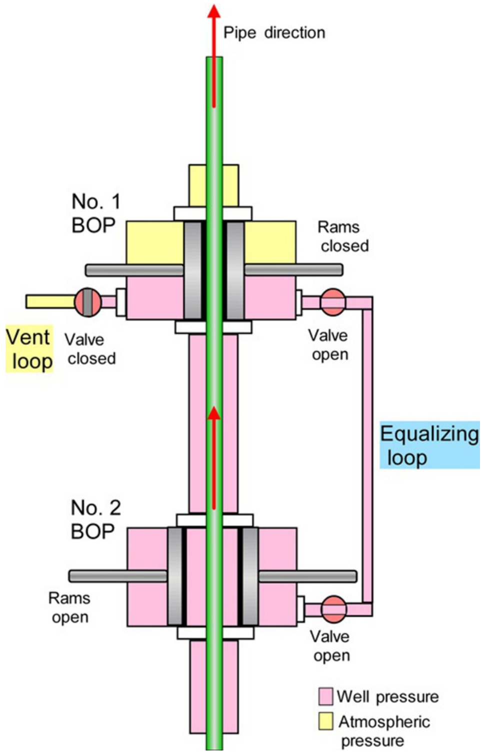
In many snubbing/stripping operations, the trip in the hole suddenly becomes a trip out of the hole. Examples include fishing operations, changes in wellbore pressure, lost circulation, management decisions, and equipment failures.



■ **FIG. 3.18C** Connection pulled above no. 1 rams.



■ **FIG. 3.18D** Equalizing pressure across lower BOP rams.



■ **FIG. 3.18E** Normal snubbing/stripping coming out of hole.

Humans are creatures of habit. If the equalizing circuit is set up for going in the hole, chances are that the workers will leave it that way even though the job calls for coming out of the hole.

When this occurs, it is vital that the operator change the operation of the equalizing loop at the same time that he/she changes the direction of pipe movement. There have been many instances in which the operator changed the direction of pipe movement but failed to change the operation of the equalizing loop. The results were catastrophic with high-pressure fluids and flammable gas blowing directly into the work basket.

Modern lockout control systems have been installed on many units that prevent this kind of operator error. These prevent, for example, opening a BOP with pressure across it (especially if there is pressure under the no. 1 BOP). Other controls prevent both BOPs from being opened at the same time. Still, these cannot prevent a determined worm (green hand) from opening the wrong valve, pushing the wrong lever, or deciding to ignore the very signal on the control panel that could avoid the issue. No oil field safety system is completely weevil-proof.

The best course of action is usually to stop the job, bring everyone down to ground level, and discuss the job requirements, including safety, in a short toolbox talk.

The notion of a temporary job shutdown is compelling. It requires that everyone stop and think about what's next on the agenda including operation of the equalizing loop. Psychologically, it allows a mental reset. The brain gets a new set of orders. In short order, most snubbing unit operators adjust their thinking, and the potential failure is avoided.

3.7 POWER-PACK

The power-pack, also called a hydraulic power unit (HPU), provides pressured fluid to all other components of the hydraulic unit. Without a supply of power fluid, a hydraulic cylinder is just a long tube with a rod inside. It cannot lift or snub unless there is an adequate flowrate of pressured hydraulic fluid supplied to it. The same is true of every other hydraulic device on the site including controls, valve actuators, slip set/release devices, and the snubbing BOPs (safeties sometimes have an independent pump to supply pressured hydraulic fluid that is then stored in accumulator bottles).

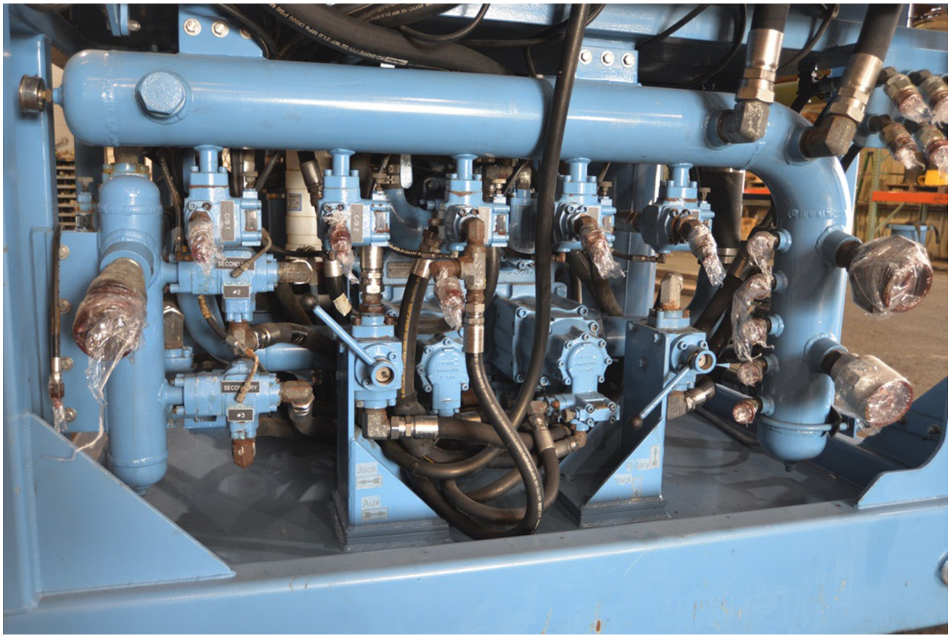
The power-pack is more than an engine- or electric motor-driven hydraulic pump. The components of a power-pack include shutdowns and tattletales, a hydraulic fluid reservoir, filters, heat exchangers for both the engine and the hydraulic fluid, a fuel tank, and a means of controlling both the pump flowrate and pressure. Usually, these are skid-mounted and are connected to the snubbing unit by a system of high-pressure flexible hoses (Figs. 3.19 and 3.20).

In some small onshore rig-assist units, the truck engine provides the power to the power-pack from a power take-off (PTO) on the truck driveshaft. There is only one engine for these units; the same one that transports the load also provides power for the hydraulic unit.

The power-pack is manufactured to fit the unit. Some are interchangeable with other hydraulic units of a similar size or type. Most power-packs have several common features, however.

■ **FIG. 3.19** Diesel engine-driven power-pack. *(Courtesy of Halliburton.)*

■ **FIG. 3.20** Electric motor-driven power-pack. *(Courtesy of International Snubbing Services.)*



■ **FIG. 3.21** Hydraulic pumps. *(Courtesy of Cased Hole Well Service.)*

3.7.1 **Hydraulic Pump**

Hydraulic pumps for most units are of two types: vane and gear pumps (Fig. 3.21). The pump must deliver a sufficient supply of fluid at a pressure consistent with the demands and ratings of other components of the unit. For example, if the hydraulic pump is capable of pressuring the power fluid to 6000 psi and the hydraulic unit's cylinders are only rated to 2000 psi, there would be little reason to buy such a high-pressure and expensive pump.

The pump output pressure should be sufficiently high that it can manage the requirements of the job. A higher maximum pump pressure might be desirable to overcome pressure losses in the hydraulic lines from the power-pack to the hydraulic unit (say, 150–250 psi). It does not necessarily need to be oversized to the extent that it exceeds the maximum rating of the remainder of the unit components by several multiples, however.

All hydraulic units operate in cycles, not continuously. However, the pump must be consistently ready to deliver all the fluid needed by the hydraulic system and at the pressure required. So, power-pack pumps are equipped with two controls, an unloader and a release. These allow the pump to run continuously. Fluid volume (flowrate) that is not required is simply dumped back into the fluid reservoir that feeds the pump. When the unloader control valve senses a low pressure, the bypass valve closes so the pump output is delivered to the unit. When the unit stops moving and does not need the hydraulic fluid, a slightly higher pressure causes the control valve to open bypassing fluid to the reservoir.

The pressure release valve is an adjustable controller that only allows the maximum power fluid pressure from reaching the split block controls on the unit. This is usually set at the maximum pressure required to snub plus slightly additional pressure required to overcome fluid tfriction and to deal with pressure spikes when starting the unit from a stop. The release operates on a feedback system that senses power fluid pressure and bleeds pressure (fluid) to the reservoir to prevent the pumps from overpowering the jack.

Hydraulic fluid flowrate from the pump, which relates to engine speed, is usually established based on the desired speed at which the jacks raise the traveling head. The pressure of the fluid combined with the cross-sectional area of the cylinders provides the rated lift of the unit. Fluid friction in the hoses connecting the power-pack to the cylinders must be taken into account along with all the other devices that use pressured hydraulic fluid as a power source.

3.7.1.1 Hydraulic Pump Flowrate

Hydraulic pump flowrate is determined by the traveling head's desired maximum speed. Often, this speed is limited by the piston or rod seals in the hydraulic cylinders. A high-volume output pump is unnecessary if the seals can't manage high-speed operations. Slow pipe-running speeds result in costly inefficiencies. Most oil companies want high speeds to minimize time over the hole and job costs. There is an optimum design for power-packs just like there is with any other piece of equipment.

To calculate the hydraulic fluid volume required to provide a specific jack speed, the speed should be multiplied by the volume per unit of jack height (the cross-sectional area of the cylinder):

$$F_p = S_c \text{ x } vol_c \tag{3.10}$$

where

F_p = hydraulic pump flowrate, gal/min
S_c = cylinder speed, ft./min
vol_c = cylinder area, in.^{2}

Example

Assume that a hydraulic cylinder has an ID of 5 in., and that an operating speed for the hydraulic cylinder is 52 ft./min. What hydraulic fluid flowrate would be required?

From Eq. (3.8) and converting units appropriately,

$$F_p = 52\frac{\text{ft.}}{\text{min}} \times 12\frac{\text{in.}}{\text{ft}} \times \frac{\pi d^2}{4} \times \frac{1\ \text{gal}}{231\ \text{in.}^3}$$

$$F_p = \frac{52 \text{ x } 5^2}{24.51}\ \text{gpm}$$

$$F_p = 53\ \text{gpm}$$

The same equation, written in reverse, can be used to calculate the speed of the jack if a specific flowrate of hydraulic fluid is available to it. Rewriting Eq. (3.8),

$$S_c = \frac{F_p}{vol_c} \tag{3.11}$$

Example

Assume that a hydraulic pump in the next building can supply a steady stream of pressured hydraulic fluid at 37 GPM. How fast will the rod in a 4 in. ID cylinder on the shop floor stroke out?

From Eq. (3.11) and converting units,

$$S_c = \frac{37 \text{ x } 24.51}{4^2}$$

$$S_c = 57\frac{\text{ft.}}{\text{min}}$$

In these two examples, only one cylinder is considered. Snubbing units usually have either two or four cylinders. There are some concentric snubbing units with large-diameter hollow "rods" that are actually single-cylinder units. In some of the four-cylinder units, two of the cylinders have one diameter, and two others have a different diameter (e.g., some 400 K units).

If a number of cylinders are operated off of the power-pack, the speed of the cylinder set is reduced since all of the cylinders require fluid in an equal volume to operate. Eqs. (3.10), (3.11) must add the number of cylinders in the set to provide the correct answer:

$$F_p = S_c \, \mathrm{x} \, vol_c \, x N_c \tag{3.12}$$

$$S_c = \frac{F_p}{vol_c \, x N_c} \tag{3.13}$$

where N_c = number of cylinders.

Example

A four-cylinder snubbing unit having cylinders each with an ID of 5 in. has a hydraulic pump that can deliver 246 GPM to the control console in the work basket. At what maximum speed can the traveling head be expected to hoist the pipe from the hole?

From Eq. (3.11) and converting units,

$$S_c = \frac{246 \, \mathrm{x} \, 24.51}{5^2 \, \mathrm{x} \, 4} \frac{\mathrm{ft.}}{\mathrm{min}}$$

$$S_c = 60.3 \frac{\mathrm{ft.}}{\mathrm{min}} \approx 1 \frac{\mathrm{ft.}}{\mathrm{sec}}$$

3.7.1.2 Snubbing Unit Speed

Snubbing unit speed is often criticized as being a weakness in the use of standalone units versus conventional rigs. Pipe cannot be run into or pulled out of the hole once the string is pipe-heavy as fast with a snubbing unit as it can be with a conventional rig's block and tackle hoisting system. Most snubbing units are therefore constantly run as rapidly as possible within acceptable safety limitations.

Power-pack volume flowrate is generally controlled by a dump valve that is pressure controlled. This is a feedback system that relies on minor changes in discharge pressure on the power fluid manifold. If the unit is not taking power fluid (i.e., the jacks have stopped moving the traveling frame), the dump valve controller senses a slightly higher pressure in manifold pressure and opens the valve dumping all or a portion of the pump output back to the hydraulic fluid reservoir.

Part of this fluid pressure reduction is due to a loss of fluid friction (i.e., pressure loss) in the large high-pressure power fluid line running from the power-pack to the control module. This is usually a 1½–2 in. hydraulic line designed to minimize pressure loss due to fluid friction. There will be some fluid friction pressure loss anyway. When the jacks are slowing, for example, there is less pressure loss in the line, the pressure at the power-pack drops slightly, and the dump valve controller opens the valve and dumps power fluid back to the reservoir. The opposite occurs when the operator demands fluid from the power-pack. Pressure drops slightly, and the valve closes to deliver more fluid to the snubbing unit.

This means that the power-pack prime mover operates at a constant speed. In diesel engines, the throttle provides this speed. In electric-motor-powered units, this speed is determined by the variable speed controller if the power-pack is so equipped. Otherwise, it is determined by the speed of the electric motors and is constant if the motors are provided with the proper voltage and current frequency.

In many power-packs, there are several pumps connected to the prime mover(s), usually 2–4. If the maximum demand for power fluid flow is limited by the snubbing unit and the job involved, it may be that only one or two pumps are needed instead of all of them. Split transmissions on engine-driven power-packs allow the other pumps to simply be taken off line by not engaging the transmission. For electric units, motors are simply left shut off and the pumps bypassed. This technique also allows one power-pack to be available for use on different hydraulic units or for sharing with other hydraulic equipment such as coiled tubing units.

Hydraulic units with four cylinders are generally slow because of the volume of hydraulic fluid required for each cylinder to operate. Large capacity units (e.g., 600 K units) require the fluid to create the power needed for hoisting or snubbing. They need of all the cross-sectional area provided by the four cylinders when loads are heavy. However, when either snub or hoist loads are reduced during the job, only two cylinders instead of four may produce the necessary force to move the load.

A simple solution to gaining speed is to "cripple" two of the cylinders. Crippling involves simply not sending pressured fluid from the power-pack to two of the cylinders. Both sides of the cylinder are connected to the low-pressure return system, so while the two power cylinders are handling the work, the other two "coast" doing no work at all.

Crippling can only be done when the two remaining cylinders are capable of handling the loads involved. If a 600 K unit is involved, crippling could only start when the hoisting load on the well was less than about 300,000 lb_f. Crippling half the cylinders cuts the load rating of the unit in half. Similarly, if the maximum snubbing capacity for a 600 K unit is 260,000 lb_f, crippling two cylinders could only occur when actual snub loads were less than 130,000 lb_f.

If the power-pack delivers a constant flowrate of hydraulic fluid, the impact of crippling two cylinders is that the speed of the snubbing unit doubles. If there is more flowrate and more pressure available from the power-pack, crippling can be done before the loads reach 50% of the rated capacity of the unit as long as the cylinders can manage the additional power fluid pressure.

Another way of increasing speed on some snubbing units is to use a "regenerative" circuit. Fluid is rerouted from one side of the cylinder to the other providing more volume than just the power fluid in the system. This increases jack speed and has the effect of putting the snubbing unit into "high gear" since there is a greater fluid flowrate to the working hoisting cylinders than the power-pack can deliver by itself.

3.7.1.3 Parasitic Devices

A number of other pieces of equipment on a hydraulic unit operate off power fluid supplied by the power-pack. These include the power tongs, the snubbing BOPs (and the annular preventer on HWO units), the stripping head, and the rotating head if installed. Each of these devices requires a certain fluid volume flowrate and pressure from the power-pack to function properly. Some function when the jack is not moving (i.e., the power tongs and snubbing BOPs), so the fluid demand switches from the jacks to the other device with no penalty in terms of jack speed.

Many hydraulic rigs have accumulator bottles to provide a pressured standby supply of power fluid for their operation. The accumulator capacity is inadequate on most units to provide all BOP functions as the accumulator system on, say, a drilling rig is required to maintain. The accumulators recharge usually on every stroke, so they are taking some flowrate away from jack operation. Usually, the volume is fairly small, however. The stripping head and rotating head or rotating BOP may demand power fluid while the jack is in operation.

Many safety BOP rams also charge their accumulator bottles from the power-pack. Some snubbing service providers have their own safeties and accumulators. Some of them have no standby hydraulic pumps specifically for the safety BOP accumulator skid. The accumulator system is just a set of bottles of sufficient capacity to close one or more of the safety BOPs if the power-pack should fail and go down.

The entire volume flowrate of all parasitic devices in the "spread" must be determined when selecting the power-pack for a particular snubbing unit or job. Failure to do so could result in unacceptably slow cylinder operation and hidden downtime (inefficiency).

3.7.1.4 Pump Pressure

Section 3.3.2 reviews the force supplied when power fluid acts on the cross-sectional area of the cylinder interior for hoisting or snubbing. The larger the cylinder ID, the greater the force that can be generated at a given hydraulic pressure. Conversely, the lower the pressure, the less force is generated at any given cylinder ID.

Maximum hydraulic power fluid pressure must be selected for the proper size hydraulic cylinders on the unit as well. For example, the piston seals on a large-diameter cylinder have a lower maximum pressure than those for a smaller-diameter one. A 7½ in. cylinder may only be capable of managing a few hundred psi where a 3 in. cylinder can handle a few thousand.

Fortunately, maximum pressure is selective. The maximum system pressure can be changed to meet conditions. In some high-pressure situations, the maximum pressure can be increased at the power-pack. It is not a good practice to change either the power-pack rate or pressure from the work basket. There are often other issues that should be determined before changing the maximum power fluid pressure.

Note that hydraulic power fluid pressure regulation is not necessarily related directly to volumetric flowrate. Pressure is determined by pump clearance and type. Pump flowrate is determined by engine speed and dump valve controls. Two controls are required on the power-pack instead of just the unloader. If the unloader was the only control and it closed completely to supply maximum flowrate to the snubbing unit, the entire power fluid system is exposed to the maximum pump pressure. If that maximum pressure is greater than the equipment can tolerate, seals and/or hoses might rupture and fail completely.

The pressure release controller is used to maintain the selected maximum pressure on the power fluid system. This safety device is usually located on the power-pack. It is not available for adjustment from the basket. There may also be an overpressure emergency control that will bypass the entire system and immediately dump all fluid back to the reservoir. This is similar to the pump discharge pop-off valve on a drilling rig. The loss of all fluid cripples everything attached to the power-pack (it does not render the safety BOPs inoperable since they have their own accumulator backup supply).

In electric motor-driven units, the pressure relief system may also be coupled to the motors themselves. The motor speed on many of these power-packs cannot be changed. So, if an overpressure event occurs, the safety devices on the power-pack control panel may shut off electric current to the motors. This, again, cripples the snubbing unit since it now has no source of power fluid. An electric shutdown normally requires a reset of the motor controller(s).

3.7.2 Prime Mover

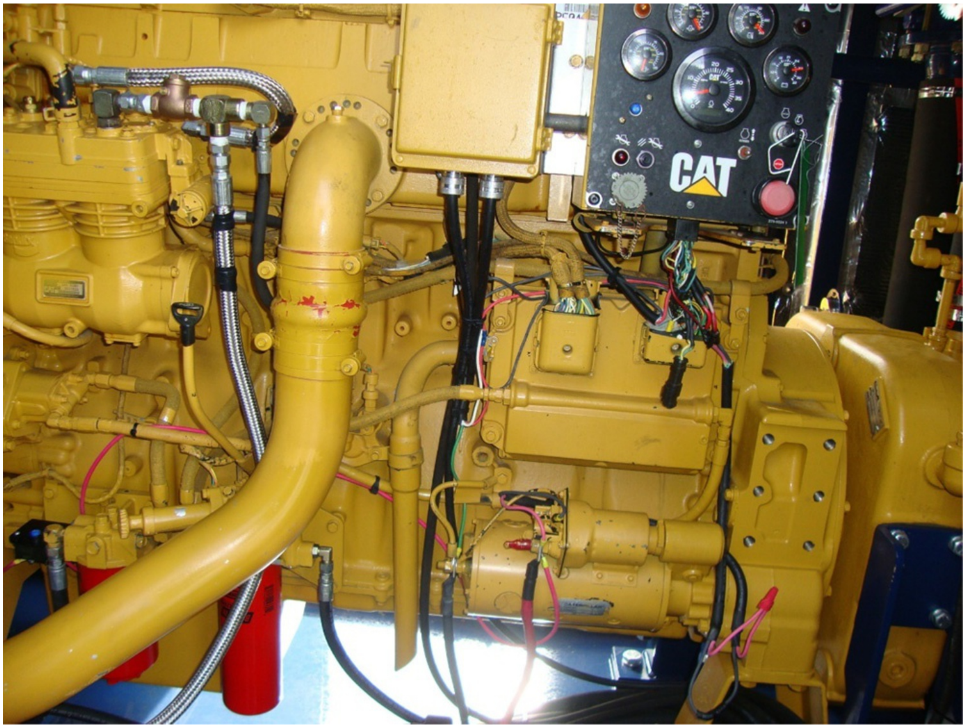
The prime movers and pumps are not simple plug and play devices. They are the heart of the system where mechanical energy is converted to hydraulic pressure. They are designed by engineering specialists that must match the prime mover to the pump based on the demand of the hydraulic equipment they operate.

Onshore units usually employ diesel engines to drive the hydraulic pumps (Fig. 3.22). Gasoline engines may be used along with natural gas and dual fuel units such as gasoline over liquefied natural gas (LNG). The latter engines, by requiring a more volatile fuel, may be prohibited on some onshore sites. Most snubbing service providers prefer diesel fuel because of its lower volatility.

Offshore units may be required by regulation to use explosion-proof electric motors operating off rig or platform power. In some areas, diesel-motor-driven units may be permitted. Electric motor size may be limited by available power and current frequency. In some areas, such as the North Sea, 280 V, 50 cycle power may be the only power source available. It would not be wise to attempt using a 240 V, 60 cycle motor set in this application without a converter pack.

Both onshore and offshore rigs generally employ multiple hydraulic pumps. Some older units may still have a large single pump. In most jobs, the loss of the only hydraulic pump in the power-pack ends the job unless there is a separate power-pack available. A unit with multiple pumps may be able to continue operating even with the loss of one pump although at a reduced speed due to limited power fluid volume output.

Onshore diesel units usually have a multitake-off transmission that allows selection of which pumps are actually used during jobs. It could be no. 1 or no. 3 on one job followed by no. 2 and no. 4 on the next to maintain even wear over time. In some cases, all the pumps may be needed or one may be



■ **FIG. 3.22** Power-pack diesel engine prime mover. *(Courtesy of International Snubbing Services.)*

kept in reserve in case of the loss of one of the other pumps. In most critical jobs, a second power-pack is also rigged up as a standby unit.

Single engine power-packs for snubbing service are usually in the 250–450 HP range with a “day” tank for fuel mounted at an elevation above the engine to ensure good fuel supply during operations. There are always fuel filters on the feed line. Sometimes, there is only one; often, there are two manifolded together. There may also be a separate water trap in the fuel line.

An air cooler (radiator) for engine coolant is usually present. Offshore diesel units may have a heat exchanger that uses seawater for cooling. Often, the radiator also has a coil for engine oil cooling and perhaps coils for hydraulic fluid cooling as well. Shared radiators are usually powered off the engine driveshaft. Some units have separate oil coolers and hydraulic fluid coolers with fans turned by small hydraulic or electric motors.

Engine exhaust is routed upward and away from the unit. The exhaust must have a cap to exclude rainwater accumulation during shutdowns. Air intakes are equipped with filters and intake shutdown valves to prevent ingestion of flammable gases into the engine resulting in a runaway engine speed event.

Most engines are now electric start except where prohibited for safety reasons. These require air start equipment and normally rely on rig or platform compressed air. Some power-packs must carry their own supply of gas (usually nitrogen in bottles) to start the engine in this situation. Obviously, the area must be free of flammable gases or liquids before starting the engine.

In offshore electric-motor-driven units, each pump is usually connected by direct drive to its own motor. Manifolding motors into a transmission of some type usually means that one motor may pull at an uneven load. So, each pump has its own motor, its own controller, and its own safety devices. There is usually a small hydraulic fluid cooler powered by its own separate fan with a motor controller (on-off or variable speed) that senses temperature from the return hydraulic fluid.

Offshore units are generally smaller and lighter than onshore units to facilitate hoisting. They are crash cage-mounted and are constructed to meet offshore regulatory requirements and standards (e.g., NORSOK and DNV) including those for hoisting loads from a boat to the platform or rig.

In cold weather environments, the units are enclosed and insulated. Engine or motor controls are usually situated on panels that are readily available to operating personnel. These units generally require a warm-up period after shutdown if they are not kept warm during shipment. Low-temperature impacts can also affect some components of the hydraulic rig and not just the power-pack.

3.7.3 **Instrumentation**

Instrumentation for hydraulic power-packs is widely varied because there are many manufacturers of hydraulic power-packs worldwide. There are no known standards for instrumentation packages on power-packs. Also, special instrumentation may be required by one Operator and not another depending on experience and regulatory requirements.

Normal instrumentation for engine-driven power-packs includes a number of gauges for monitoring engine conditions and shutdowns (Fig. 3.23). These include gauges for hydraulic power fluid pressure and temperature, engine oil temperature, engine speed (RPM), engine oil pressure, engine run hours, coolant temperature, and others depending on manufacturer. Shutdowns and tattletales normally include those for engine overspeed,

■ **FIG. 3.23** Power-pack instrumentation. *(Courtesy of Cased Hole Well Service.)*

engine coolant temperature, engine oil temperature, and engine low oil pressure. Often, the control panel employs a computer screen to display messages. Hydraulic circuit pressure gauges can be displayed on a separate panel to ensure that the snubbing unit crew can spot a problem quickly.

Indicators for monitoring electric-drive units generally involve electric current supply and usage, hydraulic oil pressure and temperature, motor speed, and other indicators. Shutdowns and tattletales are dependent on these variables such as motor overspeed, power fluid over/under pressure, and temperature.

3.7.4 Power Fluid Maintenance

All power-packs have a system to collect hydraulic fluid from the low-pressure side of hydraulic devices and condition it for reuse on a continuous basis. The means to accomplish this is discussed below, but first a discussion about the fluid itself.

3.7.4.1 Hydraulic Fluid

Several types of hydraulic fluid are available for use in hydraulic units. Clearly, every component in the hydraulic system from control lines to seals must be compatible with the fluid selected.

The two major families include hydrocarbon-based oils (usually mineral oils) and water-based fluids. All hydraulic fluids must have basic properties:

- *Lubricity*—hydraulic fluids lubricate all components and hydraulic devices including cylinders and hydraulic motors. Hydraulic fluid lubricity also reduces fluid friction inside lines on both the power and return sides., In pneumatic systems (compressed air) by contrast, a lubricant (tool oil) must be added to the air to avoid tool seizing. A dry device will lock up quickly.
- *Film stability*—a light film of the fluid remains on every portion of the system even after the bulk fluid continues its travel. It is important that some film remain in place, even if only a few molecules thick, to prevent sticking and device damage (e.g., seal damage).
- *Viscosity*—the fluid must retain some viscosity under work conditions to allow for filming and lubricity. If the viscosity of the fluid is reduced too far, there is little carrying capacity to sweep contaminants out of the system; however, higher viscosity can lead to increased fluid friction in hoses and devices.

- *Limited compressibility*—because the fluid transmits pressure from the pump to the end device, it must not be too "puffy" (i.e., compressible). Water-based fluids are especially good for this.
- *Emulsion tolerance*—every hydraulic fluid system will eventually become contaminated with another fluid at some point in its life (one of Murphy's laws). It is important that the fluid retain its properties and not become highly emulsified "chewing gum" when this occurs. It must be able to release the noncontinuous fluid readily when treated.
- *Antifoaming*—air or some other gas will probably invade the hydraulic system at some time (another of Murphy's laws). Hydraulic fluid must be able to release entrained air to prevent foaming.
- *Thermal stability*—hydraulic fluid heats as it performs work. It must not break down chemically or physically when heated. There are some very high-temperature systems that use specialized hydraulic fluids for work, in nuclear facilities and missile systems, for example. Chemical decomposition leads to reduced viscosity, reduced lubricity, and poor filming.
- *Noncorrosive*—the fluid must not promote corrosion in any portion of the system that would lead to deterioration of any component or the creation of corrosion products in the fluid that would lead to erosion and wear.
- *Compatibility*—elastomers are not all the same. Some seals and hoses are compatible with water-based fluids, but they will swell, shrink, or melt (deteriorate altogether) in oil-based fluids. The proper fluid to fit the system is crucial just as the aftermarket selection of replacement components must conform to the fluid used in the system.

Most hydraulic fluids are actually specialized fluid blends that include corrosion inhibitors, viscosity stabilizers, defoamers, thermal stabilizing chemicals, and other compounds. There are multiple sources of hydraulic fluids, and of course, each is touted by its manufacturer as being better than any other. Often, equipment manufacturers specify certain hydraulic fluids or families of hydraulic fluids that can be used safely in their equipment.

Fluid selection is often a matter of cost and availability. Selection of the cheapest fluid generally results in false economy. Expenses to overhaul cylinders and motors, replace pumps, and repipe a snubbing unit are usually far greater than the savings from using a cheap hydraulic fluid. Selecting and using the proper fluid even when it is more expensive is generally the best bet.

Hydraulic fluid is a consumable in hydraulic rig operations. Some hydraulic fluid will be lost due to minor leaks, drips, and small volume losses during rig-up and rig-down operations. Each quick connect on each hose will dribble some fluid out of the system. Replacement fluid must be completely compatible with the fluid already in the system. Additions of an incompatible fluid will result in early replacement of the entire hydraulic fluid volume and possibly cause serious equipment damage.

Another issue that is often ignored is the damage of a potential hydraulic fluid spill in a sensitive environmental area such as certain offshore areas, bays, estuaries, freshwater lakes or streams, and watersheds. In some areas, hydrocarbon-based hydraulic fluids are prohibited by regulatory authorities. Only low-impact water-based fluids are allowed. All the fluid additives must be "green" additives, like water-based BOP fluids, such as monoethylene glycol instead of diethylene glycol (common antifreeze).

Some service providers have switched to biodegradable oils for work in these areas. Many of the snubbing units are set up for an oil-based hydraulic fluid system instead of water-based systems. Instead of switching over to a "green water-based" system, these units substitute a less-damaging "green" hydraulic oil for the hydrocarbon-based oils. These substitutes include vegetable oils and certain seed oils (like rapeseed oil or canola). Any additives for these systems must also be "green," or the use of the environmentally friendly biodegradable base oil is defeated.

All hydraulic fluids will eventually begin to lose their favorable properties with use (Fig. 3.24). Filtering and polishing will maintain the fluid for a

■ **FIG. 3.24** Comparison of fresh versus used hydraulic fluid. *(Courtesy of Cased Hole Well Service.)*

time. Eventually, however, there may be a need to replace all the fluid when it loses its properties and cannot be reconditioned.

3.7.4.2 Hydraulic Fluid Cooler

Hydraulic fluid heats during work due to fluid friction through hoses and through the devices it operates. Regulators that control flowrate and pressure to certain devices also increase hydraulic fluid temperature as it is squeezed through needle valves and chokes (again, fluid friction).

Mechanical horsepower is transmitted to working devices such as hydraulic cylinders and motors where pressure is dispelled as work is performed. Warm and sometimes hot low-pressure fluid is returned to the power-pack for repressuring and reuse in a closed cycle operation. Well fluids, hopefully, never contact and mix with power or return hydraulic fluid.

Heat gradually causes hydraulic fluid to lose its viscosity and lubricity. Additionally, heat causes certain components of hydraulic oils to separate and plate out on internal portions of both the power fluid and return systems. This material is generally referred to as varnish. The more varnish inside the hydraulic system, the less effective it operates. Excessive heat in water-based systems may result in fluid boil-off.

Most units have a hydraulic fluid cooler located on the low-pressure return. In land units, it is usually a radiator (fin fan air cooler). In offshore units, a seawater-cooled heat exchanger may be provided. The fan or coolant pump may be driven by the engine driveshaft, or it may have a separate hydraulic or electric fan motor. If so, temperature is controlled so the fluid does not get too cold causing an unwanted increase in viscosity and more system fluid friction. The objective is to return fluid to a reservoir sufficiently cooled for reuse without suffering excessive pressure drops through the hydraulic system.

The hydraulic fluid from the pump discharge is also heated due to adiabatic fluid compression when hydrocarbon-based fluids are used. The heating is generally not excessive, and it dissipates through the piping system. One unit routes this high-pressure warm fluid through a heat exchanger with fluid that has been cooled. In water-based hydraulic fluid systems, there is essentially no compressive heating as the fluid is pressurized.

3.7.4.3 Hydraulic Fluid Reservoir

The hydraulic fluid reservoir is usually located above the hydraulic pumps. It is usually an atmospheric pressure container with a nonsealing cap equipped with a filter to prevent the introduction of dirt or silt into the tank.

It also allows expansion or contraction of the tank volume without collapsing or bursting the tank. It is important to keep the cap clean to allow this "breathing" to take place throughout the job.

The cap also allows the addition of fresh hydraulic fluid during the job to replace volume lost due to seal leaks, burst hydraulic hoses, leaking connections, or other losses. Obviously, the fluid added must be compatible with the fluid in the reservoir. Water should not be added to a hydrocarbon-based system just to make up the additional volume and *vice versa*.

The suction from each pump is connected to a manifold that allows the pump to be fed continuously when it is in use. Gravity is used instead of a charge pump since most hydraulic fluids are not highly viscous and the main pumps are at little risk of cavitation.

Some older onshore power-packs were equipped with split reservoir/fuel tanks. One side of the tank held diesel fuel and the other hydraulic fluid across a central partition. Most power-packs now have two separate tanks. It was found that the warm hydraulic fluid heated the diesel fuel in the other side of the split tank across the partition. In one instance, a weld in the center partition cracked allowing hydraulic fluid to mix with fuel, and the engine flatly refused to run on this mixture.

The hydraulic reservoir size depends on the overall size and power-pack design limitations. They are usually in the 50–75 gallon volume range although they can be larger to allow for some residence time (for cooling or for particulate fallout).

3.7.4.4 Hydraulic Fluid Filtering and Polishing

The greatest enemy of hydraulic fluid systems is particulates. This is true in both oil- and water-based systems. Particulate abrasion can reduce the life of the power-pack pump, hoses, cylinders, seals, hydraulic motors, and controls. The wear they cause can reduce system efficiency and result in unexpected failures.

Entrained or dissolved water in oil-based systems can increase corrosion, reduce lubricity, and generate particulates.

Most power-packs include a cartridge filter system on the discharge sides of the pumps. Some have an additional filter on the suction side. The cartridges are usually effective in removing most large particulates. Removing the filter cartridge to improve flowrate and/or reduce back pressure across the filter is not recommended. The hydraulic fluid may get so "dirty" that a wholesale fluid changeout becomes the only solution and an expensive one at that, especially when considering unit downtime to make the swap and internal damage to unit components.

On some power-packs, a large-diameter suction pipe or low-pressure armored hose exits from the side of the reservoir near its base. Fluid flows by gravity feed through a filter system usually with two or more large-diameter filter cartridges. Each may be large enough to filter the entire fluid flowrate. In some high-capacity power-packs, they only filter a side stream. Full-stream or side-stream filtering are both effective in reducing particulate matter. Many of the multiple cartridge systems are piped so that one pod can be bypassed and the filter changed out without interrupting operations.

Similarly, many units also have a filtration package for the hydraulic fluid on the high-pressure side of the pumps. This prevents debris and particulates generated by the pumps from being piped into hydraulic cylinders and hydraulic pumps under pressure where they would naturally collect at seals. Cylinder pistons and rods can be badly scored by this debris, so there is ample reason to ensure that the high-pressure power fluid is as clean as possible before it goes to the hydraulic rig.

Some systems can tolerate more contaminants than others. For examples, cylinders and rods coated with hard metal claddings such as hard chrome or titanium can manage dirtier fluid than those items with softer coating such as nickel. Some cylinders are equipped with wear sleeves and seals that are designed to ingest and entrap contaminants preventing them from damaging seals or claddings. The filtering system must be designed with these issues in mind. The smart money is on keeping the hydraulic fluid as clean as practical for all hydraulic operations.

Cartridge filters will always pass a certain number of very small, microscopic particles that concentrate (increase) over time. Eventually, the entire fluid system will require "polishing," a cleaning process that removes all the particulates and other contaminants such as water in an oil-based system. This requires special equipment that can be leased or purchased by the snubbing service provider.

One system has filter cartridges that remove most of the fine particulates. It takes the fluid stream as it is pumped through the hydraulic unit (all devices) and passes it through the filter packs at the optimum flowrate. Several passes, usually no less than five, are made so that the entire fluid volume is filtered numerous times.

Another system is equipped with an electrostatic precipitator. The small particles are passed through an electric field with some of the particles receiving a negative charge and others receiving a positive charge. When the two streams are mixed together, the particles agglomerate into large particles that are then filtered out.

Water removal from hydraulic oil uses one of two methods and possibly both. The fluid stream is passed through a desiccant pack that absorbs the water out of the hydraulic fluid reducing its concentration to a manageable level. Often, these desiccant packs release particulates into the fluid that must then be filtered out.

The second method takes a portion of the hydraulic fluid and, in a batch operation, reduces pressure by pulling a vacuum on the fluid causing the water to flash out of the oil. Heat cannot be used for this process because heating the fluid to the boiling point of water would destroy the integrity of the hydraulic oil resulting in an unusable fluid. The vacuum process causes the water to flash off and it is removed in vapor form. The cleaned fluid is returned to the hydraulic system, and another batch is drawn into the vacuum vessel. The process is repeated until almost all of the water is removed from the oil. No particulates are generated using this system.

In water-based hydraulic systems, homogenized oil is often the most serious fluid problem. Water systems contain lubricants and chemical slickners that can be adversely affected by an oil-in-water emulsion. Further, the emulsion traps particulate matter that cannot be removed easily by filtering. Foaming may cause additional issues.

Oil can be removed by adding demulsifiers such as low-molecular weight alcohols and moderate heat. This causes the discontinuous oil phase to separate from the water. The fluid is then passed through an oleophilic (oil-liking) fabric filter pack that adsorbs and traps the oil. The water phase is then filtered, and chemical additive concentrations are returned to the proper levels to ensure proper viscosity, lubricity, film strength, defoaming, and thermal stability.

Polishing is usually performed in a controlled shop environment. It may take several hours to completely recondition all the hydraulic fluid. This process may be done as routine maintenance after a number of jobs depending on experience. Many companies take hydraulic fluid samples during or after each job and send them in for laboratory analysis. Lab results are often the basis for when system hydraulic fluid polishing is performed.

Sometimes, wholesale fluid replacement is a better option than fluid polishing. When small-volume hydraulic systems are contaminated or degenerated to the point that the entire fluid is unusable, fluid replacement may be the least expensive option.

Some service providers routinely drain and dispose of a portion of the system fluid volume and replace it with new fluid. This dilution method may also be a cost-effective method of dealing with dirty or old, “worn-out” fluid. Still, other service providers purchase their own fluid polishing equipment and recondition the fluid after every few jobs.

Regardless of which method is used, an adequate supply of clean high-quality hydraulic fluid is the key to operating any hydraulic system successfully.

3.7.4.5 Hose Systems

High-pressure power fluid must leave the power-pack and be piped to the hydraulic rig on the well, and low-pressure fluid must return to the reservoir. This requires a minimum of two hydraulic lines on each unit. Generally, there are several more.

- Power fluid line

Pressured fluid from the pump is generally piped through a relatively large-diameter hydraulic hose to the control package on the snubbing unit. This hose is usually 1½–2 in. in diameter with a rating that is at least that of the maximum pump output pressure plus a considerable safety margin.

Often, this line is an armored flexible pipe reinforced to avoid crushing, pinching, abrasion, or other damages especially near the power-pack. A high-pressure spray of hydraulic fluid from a punctured power fluid main line that can quickly result in a considerable loss of fluid onto the jobsite. Because of its lubricity, a hydraulic fluid spill can lead to a number of hazards.

One particular hazard in oil-based hydraulic fluid systems where an engine-driven power-pack is used is fire. Should a hydraulic fluid leak occur in a pressured line, the fluid is usually atomized into a fine spray. When the spray encounters an ignition source, a large, very hot fire can occur quickly.

Obviously, it is important for operators to check the power fluid line as part of a hazard assessment prior to each job and during the job if an event occurs that would threaten the integrity of the line (such as a heavy vehicle driven over it). Usually, visual checks can reveal any weaknesses in this line by identifying external damage.

- Return fluid line

This line is usually a bit larger in diameter than the power fluid line, often 2–2½ in., to reduce fluid friction. The lower the friction in this line, the less back pressure is applied to the nonworking side of the device on the snubbing unit.

This back pressure reduces the power available to the working component by lowering the pressure differential across it. For example, if a cylinder is operating at a maximum power fluid pressure of, say, 700 psi but there is a 150 psi back pressure on the return fluid, there is only 550 psi worth of work being accomplished across the seal area.

There must be some pressure on the return side of a device, or there is no pressure gradient to cause the return fluid to go back to the reservoir. It is important that this pressure be minimized. The reservoir is almost always at atmospheric pressure, so only enough pressure at the fluid outlet is required to push the fluid down the return line and into the reservoir.

The return line may or may not be armored. It may be equally as susceptible to damage, but a leak normally only causes a spill and not a high-pressure fountain of hydraulic fluid like a burst power fluid hose would cause. Still, it must be inspected and repaired or replaced if there is damage to the line.

- Additional lines

Both the main power fluid line and the return line connect to manifolds on the control package. Other devices may or may not be connected to the main manifolds, such as snubbing BOPs or control valves on the equalizing or vent loops. These may go to a smaller control panel located on the ground or deck away from the work basket.

A worker on the deck might manually control some components of the equalizing loop (like the vent circuit or choke manifold) instead of the snubbing unit operator. This might be the case when the snubbing stack is tall and the unit operator can't see the equipment as well as a second operator located closer to the equipment involved. Another situation occurs when the jib hoist and counterbalance circuit are operated from the deck or ground.

A separate power fluid line (usually small diameter, ½–¾ in.) and a return line back to the power-pack are required in these situations. These devices become separate hydraulic units and must be supplied hydraulic power just like the jacks and snubbing BOPs. This requires considerable work to make all the connections necessary and run all the hydraulic hoses to the devices.

On complex systems, the hoses and receptacles are numbered or lettered to ensure that the correct hose is connected to the right device. These are commonly labels or attached tags that must be match with a corresponding tag on

■ **FIG. 3.25** Hose basket. *(Courtesy of International Snubbing Services.)*

the connection. Sometimes, even with these safety and labeling tools, connections are not made properly especially when inexperienced personnel are involved. Good supervision and job control are necessary to prevent this from occurring.

A considerable efficiency savings come from preassembled units with a "backbone" structure supporting the bulk of the components of the snubbing unit. These are preconnected with most of the hydraulic hoses bundled so that they do not need to be disconnected between jobs (Fig. 3.25).

In most small rig-assist units, all the devices are preconnected, and the hose bundle is spooled onto a reel. When the unit is picked up and mounted on top of the rig's BOP stack, there is no need to connect each device to the control panel. They are already connected, and the unit is ready to work.

- Connections

Most snubbing units use hydraulic quick connects on both power and return lines. These connections have some type of mechanism to release and to connect/lock the hose into a receptacle. Almost all of them also include check valves that prevent fluid from flowing from the hose or from the receptacle unless the two are connected properly.

There cannot be a significant pressure on the line when attempting to make or break a connection. The pressure will resist opening the check valve. Pressure across a connection effectively locks the connection.

Regardless, there will always be a small volume of hydraulic fluid lost from the cavity inside the connection whenever a connection is broken. Snubbing company workers understand this and realize that there will like be a small cleanup on every connection at some point during the job.

A problem can occur when the hose check does not hold. This occurs when there is a worn ball or seat inside the check or when debris holds it open. This usually results in a spill accompanied by many curse words. Often, a quick tap of the connection on a stationary object or with a hand tool allows the check valve to seal, but the cleanup still remains.

Some hydraulic units use screw-type connections particularly on larger lines (Fig. 3.26). The snap-type quick connects for these large lines would be too difficult to install or remove. So, a screwed connection is made up using a wrench. This connection often contains no check valve or other internal restriction allowing maximum fluid flow. These are very robust and resist damage. It may require more than one worker to make the connection, however. Smaller lines almost all use quick connects (Fig. 3.27).

The direction of the quick connects is important. Return hoses have lower pressures than supply (power) hoses. Most of the hoses on the unit have the

■ **FIG. 3.26** Power fluid hose connection. *(Courtesy of Quick Coupling Division, Parker Hannifin Corporation.)*

■ **FIG. 3.27** Small-line quick connect. *(Courtesy of Quick Coupling Division, Parker Hannifin Corporation.)*

same high-pressure rating so any hose can be used for any purpose. Sometimes, one-half of a quick connect contains a check valve, and the other does not. The direction of fluid flow and hence the configuration of the connection provide a clue about how fluid moves in the control line hose and through the connection. It also prevents incorrect hookup.

For example, if a power fluid connection is required on a device or control panel, it usually has a receptacle that will only allow a hose from the power fluid side of the system to be connected. A low-pressure hose or return fluid hose can't be connected because the quick connect configuration is reversed. Similarly, if the connection is a return outlet, only a return hose can be connected. This helps to prevent high-pressure fluid from entering a return outlet. Thus, the fluid only flows in one direction depending on how it is connected.

- Spares

Spare hoses and connections, plus repair kits, are often required on snubbing jobs. Some jobs are performed in remote locations where the loss of a hose due to leakage or outright rupture can cripple the entire unit. In these cases, it makes sense to have a number of spare hoses including the large power and return fluid hoses.

Some snubbing units carry a basket or tub with a number of hoses of differing lengths and diameters with a variety of connections in an attempt to have a substitute hose that can be used for any eventuality. In offshore operations, for example, a spare hose basket is almost a necessity.

Often, repairs can be made to hoses in the field in the unusual situation. Some hydraulic connections can be made, but they are usually suitable only for return lines. High-pressure connections for power fluid lines are possible, but most snubbing service providers would rather just replace a leaking or broken hose with a tested spare.

3.8 SNUBBING UNIT CONTROLS

Operating a hydraulic rig requires routing power and return fluids through various devices under a variety of well conditions. The unit operator is a highly qualified, experienced individual who can maintain continuous operations using a hydraulic unit to snub, strip, run, or hoist pipe while simultaneously supervising a crew of several workers.

For this reason, the controls on most hydraulic units have been simplified so that the operator can maintain good situational awareness without unnecessary distractions.

Hydraulic control circuits are complex and require considerable understanding of how these systems are designed and operated. Some of the circuits on a snubbing unit are directly controlled by a joystick or needle valve. Most of the hydraulic circuits are pilot-operated, particularly the ones requiring high volumes of hydraulic fluid delivered, for example, to all the jacks simultaneously. The control provides a small volume of hydraulic fluid to a shuttle valve that shifts to direct fluid from the power fluid manifold to the cylinders. The joystick for jack-up/jack-down operates the pilot circuit; the shuttle valve shifts one way or the other to operate the jacks.

Hydraulic control theory and design are beyond the scope of this book. A few features of the hydraulic control circuitry are included, however.

3.8.1 Control Panels—Standalone Units

There are usually two control panels in the work basket; although on new standalone units with large work baskets, there may be as many as four. One panel, and perhaps both, are in a single area and are run by the operator. Clearly, both must be far enough away from the traveling frame to avoid collision and in an area that allows enough room for the operator. In remotely-controlled units, this requirement is removed since there is no work basket, and the operator is situated in a control cabin somewhere away from the traveling frame altogether.

Other control panels in the work basket can be either permanently installed or set up on a temporary basis for a specific job. For example, there may be a small control panel located on the other side of the work basket for a second experienced crewmember to operate the jib main winch and counterbalance winch, the rotary table, and a stripping head or rotating head in the work window. The operator handles the jack and BOPs, and the other crewmember manages other devices. Supervision of certain individuals on the crew may be split between the two operators as well.

3.8.1.1 Gauges

Control panels may have a wide variety of gauges showing various operating parameters to the operator. There are no industry or regulatory standards for which gauges are required, which are optional or which may be placed elsewhere such as those on the power-pack panel.

In older units, these are generally all analog gauges. In newer units, many are digital with direct readouts. Some of these are backlit for easier reading under low-light conditions. Some also include warning indicators that can be manually set or that respond automatically if the value exceeds some preset limit. These may include a color change in the readout or a colored border (such as a red outline on a high-pressure reading).

The number, placement, style, and type of gauge vary significantly between panels on hydraulic units. These are designed by different manufacturers. The size and type hydraulic rig may dictate how large a panel is available limiting the number of gauges. Other factors include local regulatory requirements and the specifications provided by service providers based on their experience.

Some of the more common ones include the following:

- Pipe-heavy weight gauge
- Pipe-light weight gauge (may be combined with pipe-heavy weight gauge)
- Slip operating pressure
- Slip/bowl pair selection
- Slip position indicator (set/open)
- Snubbing BOP operating pressure
- Snubbing BOP ram open/close position indicator (no. 1 and no. 2)
- Annular operating pressure
- Well pressure
- Power fluid manifold pressure

Other gauges may include the following on the master panel or a remote panel:

- Tong pressure
- Rotary table pressure

- Rotary torque
- Counterbalance pressure (jib hoist)
- Accumulator pressure for safeties

Most panels also include a kill switch for the power-pack. This may be either hydraulic or pneumatic that closes the air intakes on the engine or trips the main power breaker on electric units.

3.8.1.2 Jack Operating Panel

The jack operating panel contains controls for hydraulic unit cylinders, traveling slips, stationary slips, and snubbing BOPs. It also has gauges for monitoring power fluid pressure, temperature, and other operating variables. It is usually located just adjacent to the traveling frame so the operator can manage the controls while also watching the jack run without having to look too far away from either. Fig. 3.28 shows a typical jack operating panel.

Most of the controls are simple levers or joysticks. The less complicated the control, the easier it is for the operator to keep track of the position of each device leading to better situational awareness and shorter operator reaction time. For example, if the operator gets confused about whether a stationary slip is open or closed, all he has to do is look at the position of the operating lever. Open is back; closed is forward.

Several of the more common controls on standalone units are discussed below:

- Jack-up/jack-down

This joystick is normally located near the base of the control panel and is separated from other controls. It is a three-position joystick. When the operator wants the jack to move up, the handle is pulled back. Down is forward (or vice versa). For the jack to stop, the operator returns the joystick to the central position.

This is a pilot-operated control to the travel of the joystick that also regulates the amount of fluid that moves into the cylinders. The hydraulic hose connected to the joystick is actually a small-diameter hose that carries a small volume of hydraulic fluid to a shuttle valve on the power fluid manifold.

The pilot operates the shuttle valve that opens in one direction or the other to shift fluid from the manifold to each cylinder lower fluid inlet (jack-up) or upper fluid inlet (jack-down). When the handle is in the center position, the shuttle valve is also in its center position with no power fluid going to either power fluid inlet. The amount of travel of the shuttle valve also regulates how much fluid goes to the cylinders.

■ **FIG. 3.28** Snubbing unit control panel. *(Courtesy of Cased Hole Well Services.)*

Operator observation is required whenever the jack is moved especially near the balance point. Slips must be properly engaged around the pipe to prevent sliding and pipe damage as the jack is moved in either direction. It doesn't take the operator long to notice that the pipe is moving but the jack isn't, or that the jack is moving and the pipe is too when it should be set. Even in remotely-operated units, the operator must sense an unusual situation and react quickly. That reaction is usually to stop the jack immediately.

In some operations, very closely controlled jack movement is required. These include fishing operations, milling, sidetracking, installing downhole devices such as packers, and snub drilling. Fine control of jack movement requires that the jack be raised or lowered at slow speeds. There are generally two ways to provide this slow jack movement.

One method is by throttling the power fluid volume flowrate to the jack using the jack-up/jack-down joystick. In this method, the operator moves the joystick only slightly in one direction or the other so that the jack only moves at a controlled slow speed.

A second method involves a circuit that allows a certain low flowrate of pressured hydraulic fluid into the proper power fluid inlet on the cylinder. A needle valve that controls the power fluid volume to the cylinders is closed. Then, the up/down joystick handle is pushed all the way forward or backward. The needle valve is then cracked open supplying a small power fluid volume to move the jack slowly.

Other circuits have been used in the past to provide this fine jack control including a special jack-up/jack-down control lever that allows only limited flow by using a small-diameter choke nipple in the line. This would be analogous to the low gear in an automobile.

- Slip open/closed

These controls are usually simple levers with two positions only (no neutral position). This is a binary control. The slips are either open or closed with no "halfway" position. Usually, the lever is pulled back for the "open" position. It is pushed forward for the "closed" position.

There are either two or four of these levers depending on the number of slip/bowl devices. Most units have four slip/bowls with two positioned for pipe-light operations and two for pipe-heavy conditions. They are paired, so the levers may also be paired, or they may be positioned a short distance apart with both traveling slips on one side and both stationary slips on the other.

The slip/bowls that are not being used are normally held in the open position to prevent the slip segments from rubbing the pipe and dulling. So, when snubbing in a pipe-light condition, both of the pipe-heavy slip/bowls are kept in the open position until the neutral point is reached. Once the string goes pipe-heavy, the pipe-light slip/bowls are placed in the open position, and the pipe-heavy slip/bowls are used.

Some older snubbing unit still only have one set of slip bowls and only two levers on the control panel. Once the neutral point is reached, the two slip/

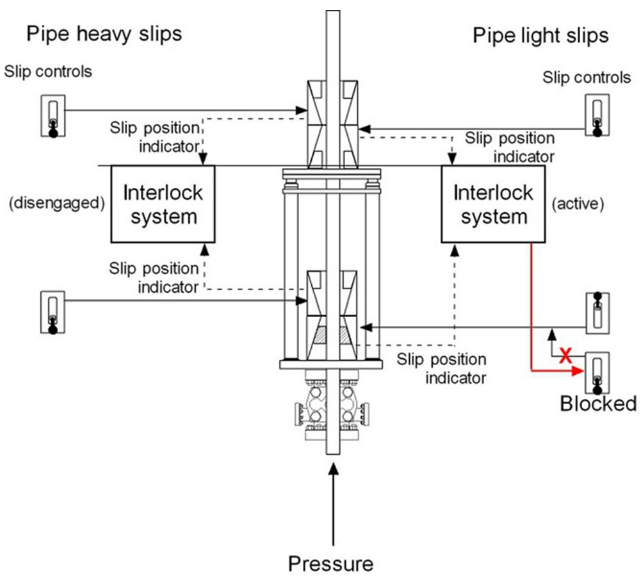
bowls must be manually inverted to switch from pipe-light to pipe-heavy operations.

Obviously, the worst-case scenario from a pipe movement standpoint is to have both the stationary and traveling slips open at the same time. This allows the pipe to either come out of the hole or go into the hole unrestricted. Neither is a good situation. Both will eventually lead to an open wellbore with the blind ram on the safety stack being the last protection against the well flowing to the environment.

Many snubbing units therefore have an interlocking system that prevents this situation from occurring. The system involves a position indicator for both slip sets. If either one is open, the hydraulic circuit to the other is disabled. No matter how hard the operator pulls on the lever, the slips won't open. The fluid in that circuit simply bypasses to the return side of the system. Fig. 3.29 shows how this interlock system functions in a pipe-light snubbing operation.

In a four slip/bowl system where two of the slip/bowls are not in service (pipe-heavy or pipe-light), the interlock system is disabled allowing both slip/bowls to be open at the same time.

The operator cannot disable the interlock system. In fact, most of these are controlled remotely by the snubbing service job supervisor. The interlock



■ **FIG. 3.29** Slip interlock schematic diagram.

control is located on the ground, on the platform deck, or in some other remote location, so the unit operator cannot disable it. This is a fail-safe system that prevents dropping the string or allowing it to be expelled from the hole (i.e., system failure causes both sets of slips to set). Power fluid pressure is required to open either slip set.

- Snubbing BOPs

Controls for the snubbing BOPs, or strippers, are usually located on the jack operating control panel. They may be located on the nearby BOP panel that controls the safety BOPs. If they are located on a separate panel, they must be close enough so the unit operator can function them, and the equalizing loop valves, without moving away from the jack controls.

These are three-position levers or rotating controls so that the BOPs can be in the close, open, or neutral position (with the ram either open or closed). Closed position is usually with a lever pushed forward, and open is with the lever pulled back (just like the slip/bowl control so there is no confusion). The neutral position is in the center position, but these controls are not spring-loaded to return to the center position like the jack-up/jack-down control.

Some snubbing BOPs have an internal ram locking device to keep the BOP in the closed position once it is activated. BOP operating pressure must be applied to release the lock allowing the rams to open. This allows hydraulic pressure to be released on the ram operator (usually, hydraulic pistons that move the rams into the closed position).

Some snubbing service providers do not want the BOP operating lines to have pressure on them all the time when the rams are in one position or another. Pressure is taken off the lines by moving the control into the neutral position. Other companies want positive pressure to be applied to the ram operators at all times as a safety measure. Their BOP control levers may not have a neutral position at all.

One advantage to *not* having a neutral position on the snubbing BOP controls, or not using it, is that the operator can see the ram position of each BOP just by looking at the lever position. If the rams are closed, the lever is pushed forward. If open, the lever is pulled back. If it is centered in the neutral position, the operator must remember the last position of the rams.

- Rotary table rotation

A control handle or dial may be present on the jack control panel to operate the rotary table below the traveling slips if the unit is equipped with one. The rotary table can be turned in either direction but usually clockwise looking from the top down. The control may simply be an on-off device, or it may be a more sophisticated control that also controls speed by adjusting the flow-rate to the hydraulic motor(s) that turn the rotary table.

During continuous rotary operations, the unit operator is usually watching the rotary table pressure and torque gauges very closely. If the downhole pipe string "snags" something, it is important that the rotary table be shut down quickly. Often, there is also a control that limits the maximum torque that the table will be allowed to place on the pipe. Sometimes, this limiter catches the high torque and dumps power fluid to the rotary table hydraulic motors, and they simply stall out (i.e., stop turning).

In snub drilling operations, the rotary table turns as the jack is slowly lowered. Reliance on the maximum torque limiter is more frequent in these dual operations, but the unit operator still must be ready to stop the rotary table quickly to avoid twisting a jack.

The rotary table controls are sometimes located on a remote panel, and the device is operated by another operator in the basket to avoid overloading the unit operator.

Some smaller standalone units are not equipped with a rotary table. Obviously, the controls for them would not be present on a control panel. On some units, there may be a control handle or dial on the panel that is not connected to anything. It is left in the panel in case a rotary table is added for a particular job. If so, the control is usually marked as being disconnected or disabled.

- Equalizing loop valves

Two controls are usually located on the jack panel or the BOP panel located nearby. These are simple two-position levers or other binary controls. There is no neutral position. The valves are either fully open or fully closed. These valves are not used to bleed or choke pressure. In-line chokes perform that function.

Positioning these valves on the jack panel or nearby allows the unit operator to manage both the snubbing BOPs and the equalizing loop while performing ram-to-ram snubbing or stripping. This also prevents a loss of coordination if someone else on the crew were operating the BOPs or valves. Only the unit operator or a second worker in the basket can activate the valves.

The lever position shows the operator the position of the valve to prevent accidental activation. He/she knows the valve position without needing a separate valve position indicator.

- Jack brake

Some older units are also equipped with a jack brake and a set/unset lever on the control panel. This is essentially a valve that prevents fluid from leaking back to the reservoir. This prevents the jack from moving at all (regardless of piston seal leakage). The cylinder simply becomes a closed container.

The jack brake is normally used as a static device like the parking brake on an automobile. Once the jack stops moving, the brake prevents further movement, sometimes as a backup for the hydraulic counterbalance circuit. In normal operations, it is not set except when the jack will not be moved for an extended time or in an emergency situation such as a power fluid line break requiring work on the unit.

In a dynamic situation with the jack in motion, activating the brake could result in a pressure spike due to jack momentum that would blow out seals or lines. This may be a risk worth taking in an emergency situation, however. If a BOP begins to leak badly requiring immediate emergency escape from the basket, the operator will usually push all levers forward at the same time including the jack brake if so equipped.

- Slip and snubbing BOP pressure regulators

Circuit operating pressure for these and other devices does not always need to be as high as the power fluid pressure delivered by the power-pack. There is little need to throw the extra pressure into the circuit if a lower pressure is all that is required to operate the device. This is important if the higher pressure of the power fluid could damage the device.

These regulators allow the operator to control the power fluid in the circuit to the optimum value for the device during the job. The regulators hold the pressure constant despite heavy power fluid usage by the hydraulic cylinders. If the devices get dirty, sticky, or cold during the job, the operator can simply raise the circuit pressure slightly to ensure proper operation.

3.8.1.3 Remote BOP Control Panel

This is a control panel found on some older units that contains the controls for the safety BOPs and other devices such as a rotating head, stripper rubber, or rotating BOP. It is located just beside the jack operating panel within easy reach of the unit operator. In most newer units, this panel is not present. The safety BOPs are operated only from the ground or deck so preserve fail-safe operations. If the snubbing unit operator is injured or has to make an emergency exit, there may be no opportunity to close the safety BOPs. Damage to the control lines could negate operation from the ground. So, most snubbing units no longer require the unit operator to manage the safety BOPs at all.

If the remote safety BOP panel is available in the basket, it contains the following controls:

- Ram BOP controls

The safety ram controls involve three-position, four-way valves to provide open, close, and neutral positions, just like the controls on the snubbing BOPs. The neutral position allows pressure to be removed from the internal ram operators after they are in the proper position (open or closed) to avoid damage or leakage from a pressured hydraulic control line.

During pipe running/pulling, with pressure on the well or not (such as during hydraulic workovers), these rams are kept in the open position to avoid ram packer wear that might prevent the BOP from sealing. These rams and BOPs are kept in reserve during the bulk of the unit's work. After testing, they are often not used except when the snubbing BOP ram packers require changing out.

The power source for the safety rams is sometimes provided by a remote accumulator skid and not the power-pack. The operating pressure is set by a regulator on the skid, so there is not a separate regulator on the BOP panel for the operating pressure in most panel designs.

- Annular BOP control

This control is a two-position valve that allows the annular element to be in the closed or open position only. This provides a means to hold annular pressure when there is an unusually shaped or oversized pipe segment across the snubbing BOPs.

Unless the annular is being used as an extra snubbing BOP, the annular normally stays open for running or pulling the pipe string.

When it is being used for snubbing or stripping pipe in low pressure or dead well applications, the closing pressure is reduced to allow the pipe and connections to pass through the element without significant wear. In this mode, a control is usually mounted on the jack operating panel so the operator can manipulate the annular pressure regulator from the basket.

It is noted that the annular element cannot close as fast as a ram-type BOP. The element is usually activated by a piston that requires time to move through its full stroke. As a "safety" BOP, the annular is used for those situations where closure speed is not an issue. Also, because it is slow, there is a good chance that the element will be eroded by high flowrate wellbore fluids during the time it takes to close in a blowout situation. For flowing well situations, the rams in the safety BOPs are used more often than the annular.

- Annular closure pressure regulator

This pressure regulator allows the unit operator to control the pressure on the closing line to the annular preventer allowing a "loose" fit around the pipe. The loose fit allows slight leakage of wellbore fluids to lubricate the pipe on trips in the hole to prevent excessive element wear. When pulling out of the hole, the loose fit prevents the entire fluid film from being stripped off the outside of the pipe. This also helps to prevent excessive element wear.

Sometimes, pipe is stripped through the annular using long strokes once the string becomes pipe-heavy in low-pressure applications. In this type of job, both snubbing BOP rams are retracted. This same technique can employ another device such as a stripping rubber or rotating head. If so, the annular remains open and in reserve since it is not needed for stripping pipe.

Sometimes, this regulator is positioned on the jack operating panel instead of the BOP panel. This allows minor closing pressure changes to be made while the jack is being moved. The unit operator does not have to look away to the BOP panel to make minor adjustments with this regulator control on the jack operating control panel.

- Stripping element pressure regulator

This is a regulator that has the same basic function as the annular pressure regulator. It controls the stripper element sealing pressure such that a small amount of leakage is permitted around the pipe while going in the hole. A tight fit will cause the element to wear quickly. Fortunately, these devices are designed such that the expendable elements can be changed out quickly and easily (much more so than the annular BOP element). They are also a fraction of the cost of an annular element.

A stripper is preferred if running or pulling pipe when ram-to-ram snubbing is not required.

3.8.1.4 Counterbalance Control Panel

This panel controls the jib and both of its winches for hoisting light loads, usually less than 5000 lb, on standalone units (Fig. 3.30). There are only limited controls and gauges on this panel, but operations are crucial to successful hydraulic rig work.

■ **FIG. 3.30** Counterbalance control panel. *(Courtesy of International Snubbing Services.)*

- Gauges

The number of gauges often depends on the number of functions operated by this panel. At a minimum, there is normally one gauge for system power fluid pressure (i.e., the pressure of the fluid available for the circuits on the panel), winch motor pressure, jib rotation motor pressure (if so equipped), and a weight indicator. Another gauge is the counterbalance circuit pressure or tension (sometimes both) that is also included. Other gauges may be present as well depending on manufacturer.

- Main winch in/out control

The main winch is usually configured with two lines and a traveling block to hoist heavy loads such as BHA components. The winch is a direct-drive hydraulic motor-driven winch. It is positioned such that its top sheave does not interfere with the counterbalance winch line(s).

The winch control for the main winch is usually a three-position joystick that has the winch taking up wire rope or paying it out with an important neutral position involved in the control circuitry as well. Pulling the handle back makes the winch take up line, and the whip end of the hoist line goes up. Pushing it forward takes line off the winch, and the load goes down.

The main winch often has a friction brake that is controlled by the operator. It is often used when rigging up or down and installing certain equipment in the basket such as the power tongs and other heavy loads. It is not necessary to stop and suspend a load during hoisting.

This circuit may be direct- or a pilot-operated. For either one, the joystick controls winch speed and direction. Pushing the joystick forward, a small amount causes the winch to pay out line slowly. If the lever is pushed further forward, more fluid is transferred to the winch motor, and the line goes out faster. The same is true when the line is being taken up.

- Counterbalance winch control(s)

The counterbalance winch is a single-line direct hoisting system used for light loads such as picking up a single joint of tubing or drill pipe. It does not have the doubling effect of the two-line main winch system with its traveling block.

The counterbalance winch control is also a lever- or joystick- type control that controls both direction and speed. It is usually a pilot-operated circuit, and the joystick is spring-loaded to return to the neutral position, thereby suspending the load without the use of a static brake (although the winch may be equipped with one as a backup).

The counterbalance circuit is so named because it contains a hydraulic brake that is a counterbalance valve. It contains a check valve that allows free flow of oil to the motor in the take-up direction and a pilot-operated spool valve that blocks the flow of oil out of the motor when the control valve is placed in neutral.

When the control valve is placed in the payout position, the spool valve remains closed until sufficient pilot pressure is applied to the end of the spool to shift it against a preset pressure and open a passage. After the spool valve cracks open, the pilot pressure becomes flow-dependent and modulates the spool valve opening that controls the lowering speed.

Two types of hydraulic counterbalance valves are available, poppet- and spring-styles. Each is adjustable. Winch operation using the joystick allows the winch to move loads to and from the basket with suspension possible during the hoist without dropping the load on personnel below.

Some units are equipped with two counterbalance winches. If so, the controls on the remote panel are duplicated and properly labeled (Fig. 3.31).

- Counterbalance circuit speed control

This circuit applies a certain volume flowrate to the hydraulic motor powering the jib winch. This allows the operator to be able to operate the counterbalance winch at high speed or to allow it to creep without using the joystick to throttle flow to the winch motor.

- Jib extension/retraction

■ **FIG. 3.31** Dual counterbalance winch. *(Courtesy of Halliburton.)*

Many jibs are telescoping devices that allow the unit to be rigged up easily in its retracted position. Sometimes, loads like power tongs and other equipment are hoisted using the main winch with the jib in a retracted or partially retracted position. Later, when it is necessary to hoist whole joints or even stands of pipe, the jib is extended and raised, and the counterbalance winches are used.

The hydraulic jib extension/retraction is a simple three-position lever. Forward is up, and backward is down (or *vice versa*) with the center position being neutral. The circuit has an internal hydraulic brake that prevents accidental extension or retraction during the job. It also has a bypass so that hydraulic pressure to extend or retract the jib is limited to the maximum pressure of the seals in the telescoping tubes.

- Jib rotation

Most jibs are fixed with the jib crown set vertically above the jack center when the jib is extended. One jib, however, is designed to rotate slightly allowing the jib crown to be directly over the well at one point and over the side of the basket at another to facilitate pipe handling. This is a rare feature and is used for special applications.

Jib rotation may be manual, or it can be done using a hydraulic motor operating a planetary gear attached to the base of the jib. Motor direction is reversible to move the jib in either direction.

The jib position control is usually located on the counterbalance control panel. The worker that operates the jib winch can also change the position of the jib just using a three-position lever with the forward position used to turn the jib to the right (or left) and the backward position as the opposite direction. The circuit locks the motor with the lever in the neutral position, and the jib stays where it was last placed.

This is usually a slow speed operation, so speed control is unnecessary. The jib rotation motor only operates in "creep" mode due to a limited amount of fluid being available to the motor. High-speed jib rotation is discouraged.

3.8.1.5 Auxiliary Panels

Some newer hydraulic units have larger work baskets. These may have additional control panels that behave as slaves to all or portions of other control panels. For example, the operator of the jib main and counterbalance winches may be able to watch pipe-handling operations more clearly in an alternate position than by standing behind the primary counterbalance control panel. Some manufacturers will place a small, slave control panel at the alternate position allowing the worker to hoist pipe using the winch and engage the counterbalance circuit without being behind the primary control panel.

Other manufacturers place a remote safety BOP control panel at the opposite end of the control basket away from the unit operator. Still, others have a power-pack kill switch on a single function control panel in a remote location to back up the one on the unit operator's jack panel.

Hydraulic rig service contractors may also mount a small panel to control a specific function or device somewhere else on the unit other than in the work basket.

There is always one remote operating panel outside the basket, usually on the ground or deck, for the safety BOPs. This is often mounted on the accumulator skid in case the basket must be evacuated in an emergency. The remote operating panels allow all functions of the safety BOPs to be actuated with nobody in the work basket.

3.8.2 Control Panels—Rig-Assist Units

Rig-assist units, unlike standalone units, rely on part of the job functions to be handled by the rig and its crew. Certain equipment may not even be available on the rig-assist snubbing unit that is not only present but also crucial to successful function of a standalone unit. One of these, for example, is the jib, hydraulic winch, and counterbalance circuit.

The control panel for a rig-assist unit is usually much smaller and simpler than a standalone unit as a result (Fig. 3.32). Some of the controls are identical to those on a standalone unit. When a unit can be used as either standalone or

■ **FIG. 3.32** Rig-assist control panel. *(Courtesy of International Snubbing Services.)*

rig-assist service, the control panel is not changed, but several of the controls may be disconnected or locked out if they are not used on the job.

3.8.2.1 Jack Control Panel

- Panel gauges

The jack control panel on a rig-assist snubbing unit is usually smaller than that on a standalone unit. So, the number and size of gauges are usually reduced. There are several gauges that are necessary including a weight gauge (hoisting and snubbing loads usually on the same gauge), power fluid pressure, jack speed, well pressure, and snubbing BOP operating pressure. Other gauges may indicate hydraulic oil temperature, return line pressure, and equalizing valve operating pressure.

An engine kill switch for the power-pack, either air- or electric-operated, may be present as well.

Backlighting gauges on a rig-assist panel may not be necessary. Rig lights usually provide sufficient illumination to permit the use of standard gauges, either analog or digital.

Other gauges may be present depending on unit manufacturer or service company design. Some pressure gauges may also be present but not active—spares for special purpose monitoring depending on the job such as tong operating pressure if the rig-assist unit employs its own power tongs.

Annular BOP operating pressure gauge may or may not be present. On some jobs, a line is run from the rig's remote BOP operating panel to the basket if a significant amount of stripping is planned through the annular under pipe-light conditions using the rig-assist unit. This allows the snubbing unit operator to determine how much pressure is present on the annular element to avoid pipe or element damage. More often, the annular BOP operating pressure and control is managed by the rig's driller or completion unit operator.

- Jack-up/jack-down

The jack control joystick is essentially the same on a rig-assist unit as that on the standalone unit. It is located on a small panel near the jack frame in a small work basket where there is little room for the unit operator and helper to work.

The joystick is a spring-loaded control that is pulled back for hoisting and pushed forward for snubbing or lowering the jack head. When it is in the neutral position, the jack stays at its last position being held in place by the hydraulic counterbalance circuit.

- Slip engage/disengage

These controls function like those on the standalone unit control panel. They have two-position levers with forward being closed and back being open.

The interlock system preventing opening both sets of slips may or may not be present. The rig's elevators remain connected to the pipe string almost all the time, and the rig is capable of supporting the entire load of the string in pipe-heavy operations. Once the string becomes pipe-heavy, it is often stripped through a stripping head or the annular preventer, and both sets of snubbing slips are opened since neither set is needed except when making a connection.

- Snubbing BOP controls

Snubbing BOP controls mimic those on a standalone unit. The two BOP controls have the same open, close, and neutral positions that are present in other BOP controls, and they function the same way during ram-to-ram snubbing/stripping.

- Equalizing loop valve controls

These two levers are two-position controls that fully open or close the valves on the equalizing loop. These are usually not a valve position indicator on the panel other than the lever handle position. The equalizing loop is generally situated just below the work basket floor, and the operator can easily look through the floor grating to see if the valve is open or closed if the valve has a mechanical position indicator.

- Jack brake

The jack brake handle, if present, is a simple engaged/disengage two-position lever with engaged being forward and disengaged being backward. Again, the position of the lever tells the operator whether the jack brake is engaged or not.

3.8.2.2 BOP Panel

The BOP panel is not usually present in rig-assist units. The safety BOPs (safeties) are usually the rig's BOPs, and they are controlled by the driller from the remote BOP operating panel on the rig floor just behind the driller's station. These BOPs use the rig's accumulator skid and its controls in case the floor, including the rig-assist snubbing unit, must be evacuated.

On small rig-assist units, the snubbing unit operator is just a few feet away from the driller, so voice or hand signal communication between them is often sufficient for job coordination. For example, if the snubbing BOP ram packers must be changed out, the snubbing unit operator shuts down the jack and requests that the driller close a pipe ram or the annular on the string. Once pressure is bled off through the equalizing loop vent line, it is safe to work on the snubbing BOPs. The snubbing unit operator is still responsible to ensure that the safety BOPs are closed and stay closed throughout this work. Once the job resumes, pressure on the stack is equalized, the driller opens the safeties, and snubbing continues.

In this scenario, there is no need for a safety BOP operating panel in the work basket. Besides that, there is little room for another operating panel in the work basket, so using the rig's remote BOP operating panel makes much more sense.

3.8.2.3 Counterbalance Panel

This panel is not present in most rig-assist snubbing jobs. If it is present, it is usually deactivated since it serves no function. All pipe-handling functions are provided by the rig (picking up, laying down, or racking the pipe in the derrick). The jib is not present, nor is the hydraulic winch. Also, there is very little room in the work basket, and having an unnecessary panel simply congests the work area.

The counterbalance circuit is also unnecessary. The rig's blocks and elevators support pipe in the derrick. Once a connection is made with a new length of pipe (a single joint or a stand from the derrick), the elevators remain attached, and the weight of the blocks keeps the pipe from bending over. The derrick itself only allows the pipe to bend so far, usually not enough to damage it.

The driller either raises or lowers the blocks to "follow" the jack operations. The elevators are usually having square shoulders that latch underneath a tubing collar, or they are bottleneck elevators that hold the drill pipe connection upset. So, both can slide a short distance down the pipe to prevent putting excessive tension on the string. So, for example, when pipe is being run in the hole, the driller lowers the block enough to keep the blocks a foot or so below the connection.

Obviously, the counterbalance circuit is not being used in this type of operation to strip or feed line off or onto the jib winch. There is no need for tension to be kept on the pipe above the jack head. There is a need, however, for good verbal communications between the snubbing unit operator and the driller.

3.8.3 Control Panels—HWO Units

HWO units are often snubbing units or former snubbing units that have been designated for dead well workovers. Many have the same gauges and controls as a snubbing unit, but some of the control joysticks are not connected to equipment that is not rigged up on the unit such as snubbing BOPs.

Most HWO unit control panels have an upper annular closing pressure regulator. In dead well or low-pressure well workovers, the pipe is still stripped through the annular, or at least, that capability is preserved in the event that well pressure increases during the job. The annular BOP closing pressure can be adjusted to permit stripping in either direction without ram-to-ram snubbing capability in low-pressure applications.

Another control that may be present is the stripping head closing pressure regulator or the rotating head closing pressure if either of these is rigged up on top of the annular preventer in the work window.

Obviously, if well pressure is capable of increasing rapidly such as in a recompletion, the unit must include full snubbing capability. It is likely that a snubbing unit would be rigged up instead of an HWO unit in this eventuality. One low-pressure configuration uses two annular preventers below the jack with an equalizing loop instead of ram-type snubbing BOPs. The controls for both annular preventers in this workover and the equalizing loop controls were positioned on the unit control panel so the operator could perform annular-to-annular snubbing.

Some compact HWO units have much smaller work baskets and control panels. These are necessary for space and weight savings and are required for some jobs such as those in remote swamps or jungles where the HWO unit must be flown in by helicopter. The control panels have only those gauges and controls necessary for the job and little more. There may only be one winch, for example. Its controls are located on a single-lever auxiliary counterbalance panel. There is no main winch on some of these units, but the counterbalance winch can be configured with two lines or a traveling block to hoist heavier loads.

3.8.4 Control Panels—Push-Pull Units

Push-pull units, small purpose-built snubbing units, are generally used only in the beginning of a job and at the end of a job when pipe-light conditions exist in low-pressure applications. They are, by definition, rig-assist units. They often operate off rig hydraulics, electric motors, or pneumatics.

Pipe is almost always snubbed through a stripping rubber or the rig's annular preventer. These units are not used for ram-to-ram snubbing, and there are no snubbing BOPs in the stack.

The driller or another crewmember on the rig floor controls the push-pull device. Controls are rather simple, one lever or other type of control to resist expulsion force (going up) or snubbing pipe in the hole (going down). There is also a neutral position for stopping the unit.

There are many designs for small push-pull units. Some are marketed commercially; others are field constructed. The control may be on the unit to operate the hydraulic motor(s) or cylinders that move the gripper head. It may be located at some small remote panel on the floor, or it may be something as simple as an extra lever on the driller's panel.

3.8.5 Power Tong Controls

Most hydraulic units include a set of power tongs for making and breaking pipe connections. These are usually supported from a mechanical arm or davit that allows the tongs to be swung into position around the pipe and then retracted to move them away from the jack and other devices. They are infrequently used (only when making connections), so they are not required to be positioned around the pipe constantly.

The control for operating the power tong is usually on the tong itself with no separate control panel or remote device used to control the tongs. One older snubbing unit with which the author was acquainted in the past had a foot pedal to operate the tongs, but the direction (forward or reverse) was still situated on the tong itself.

The process of stabbing a new joint into one going in the hole or disconnecting one coming out involves the help of a second worker in the basket. The unit operator is hard-pressed to operate the jack and make up/break out connections and handle pipe too. Often, both the unit operator and the second worker in the basket team up to perform these functions.

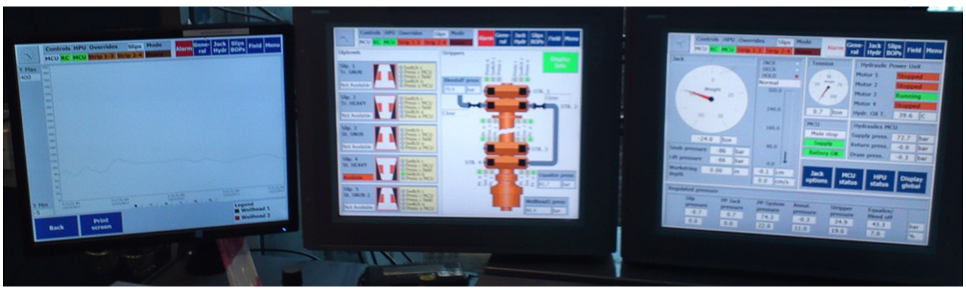
The second worker almost always operates the power tongs, however. They are usually situated on the side of the basket opposite the unit operator. Stabbing, starting the threads, clamping the backup head around the joint in the jack, and engaging the turning head to make up/break out the connection require a fair amount of coordination. It's only logical that the tong controls be located on the tongs themselves to avoid thread damage and hand injuries to both persons involved in the operation.

3.8.6 Data Acquisition Systems

A relatively recent addition to modern snubbing units is the placement of devices on the unit to read and transmit operating data to a computer. These systems may be wired or wireless depending on the technology employed. The data can be recorded for postjob analysis, and it can be displayed for real-time monitoring (Fig. 3.33).

Data acquisition systems allow for real-time monitoring from a remote location. Recent regulations require this capability in US offshore drilling operations. Where practical, hydraulic rig data can be fed to the Internet for remote monitoring on a laptop in an office completely remote from the job site.

Data acquisition permits decision-makers to be able to watch the job without the distractions associated with actual field operations. In the past, the job



■ **FIG. 3.33** Data acquisition system screens. *(Courtesy of International Snubbing Systems.)*

supervisor (usually not a member of the snubbing services crew) had to climb up into the work basket to watch some of the data available on control panel pressure gauges and to observe physical operations. This added congestion in the work basket and limited the space available for evacuation in an emergency situation. Now, data are collected by electronic devices and transmitted to a receiver allowing the company man or snubbing supervisor to see what the snubbing unit operator is seeing without climbing up the unit and getting into the basket.

One recent type of data acquisition involves the use of digital cameras. These provide a visual record of job operations and allow persons not in the basket to see, often with little delay, what's happening in the basket through streaming data feeds. Often, this helps to explain how the job is progressing without calls to the rig or explanations. In some cases when weather conditions prohibit ongoing operations, someone with a camera feed can actually see the reason for job stoppage without being anywhere near the jobsite.

Some snubbing unit operating personnel dislike having "big brother" looking over their shoulder. Usually, operating personnel develop an attitude that it doesn't really matter whether or not someone is watching them work. They quickly begin to realize that having a camera on the job does not mean someone is trying to catch them in an error. In fact, most video feeds support the work of these personnel, so they learn to ignore the camera.

Video feeds are important for remotely-controlled operations. There is nobody in the basket during these snubbing operations. There is often no work basket at all. So, cameras provide the visual cues needed to ensure that the equipment is functioning properly, such as slip/bowls seating properly.

3.9 VERTICAL PIPE RACKING SYSTEMS

One of the greatest criticisms of snubbing and HWO unit operations involves slow tripping speeds. Both types of operations often require that each joint of pipe being snubbed, stripped, or run into and out of a well be picked up from the ground or deck individually and laid down the same way. Obviously, this requires a great deal of repetitive motion and inherent risk to workers through their exposure throughout the process.

The simplest remedy is to pick up the pipe in singles one time, run it in the hole, and then pull out of the hole standing the pipe vertically instead of laying it back down on the deck or ground. Only rig-assist units had this capability prior to the late 1990s.

There are several advantages to vertically racking pipe for snubbing/HWO jobs:

- Handling and risk for picking up and laying down each joint individually are reduced. This reduces risk to crews from drops, pinching, or hand injuries from the actions required to pick up and lay down each joint on each trip.
- Pipe management time is reduced that, in turn, increases overall trip speed. The pipe can be run/pulled essentially at the speed of the jack instead of waiting on pipe handling. When the pipe is racked in doubles, one connection is eliminated per stand, also reducing pipe-handling time.
- A pickup and laydown area for handling individual pipe joints on the platform deck is eliminated once the pipe was racked vertically. It is eliminated altogether on some jobs in which the pipe is picked up from a barge or boat and racked vertically. These features further reduce the snubbing/HWO unit footprint.
- Most systems include drip pans for the racked pipe that contain any fluids adhering to the pipe. This reduces the incidence of minor spills, cleanup time, and materials.

A few disadvantages also exist with any racking system:

- There can be some additional time required to rig up the racking system, depending on type, at the beginning and end of each job. Some systems are skiddable between wells on the same platform or well pad.
- The snubbing/HWO service provider may charge a fee for the system. This may be part of the job contract negotiations with the operator.
- The platform deck or location near the well must support the weight of the vertically racked pipe. Most systems include bases with beams or pads that spread the load to avoid deck loading limitations. Note that the pipe in the laydown area for a job that is not supported by a vertical racking system must also be supported by the deck structure or location.
- Some racking systems may require an elongated jib to manage stands instead of single joints. Often, these are telescoping jibs that can manage the reach required for either. Certain weather conditions such as high winds may limit the use of a tall, extended jib. Dual counterbalance winches are required for these extended jibs to ensure that the next stand is in position as soon as the last one is in the hole. This obviously implies that the jib must be designed to safely hoist the combined weight of two pipe stands when extended (one going in the hole, one being picked up). The option is to resort to handling singles instead of doubles for heavy-pipe stands.

These racking systems often allow the pipe to be snubbed, stripped or run, and pulled at the speed of the jack itself. This is still slower than the pipe can be run or pulled using a block and tackle hoisting assembly on most jobs.

Tripping speeds on some jobs are restricted by well conditions such as swab and surge. In these jobs, the pipe can be tripped just as fast using a snubbing or HWO unit as it can be using a conventional rig.

3.9.1 Basket-Connected Fingerboards

The earliest design for a vertical racking system attached two sets of fingerboards, similar to those on a drilling or workover rig, to either side of the work basket on a snubbing unit (Fig. 3.34).

The pipe string stands near vertically in this design alongside the snubbing unit for easier handling and faster makeup/breakout. The basket height is

■ **FIG. 3.34** Fingerboards attached to unit. *(Courtesy of Abel Engineering.)*

governed by spacer spools in the stack selected to ensure that the pipe is properly racked. The system can be configured for racking pipe both in singles and double pipe stands.

Dual baskets are included so the lateral force of the pipe "leaning" back in the fingerboards on one side can be balanced by pipe on the other side of the basket. Usually, stands (or singles) are placed alternately on one side and then the other. This avoids excessive side-loading and guying requirements for the lateral weight component of the racked pipe. Guying requirements are increased slightly to manage the racked pipe and any associated wind loading.

The extendable jib can manage either pipe length, and the dual counterbalance winches have the next joint in position before the last joint/stand is completely in or out of the hole. The jib is strengthened to manage the loading requirements for handling doubles and for lateral and variable wind loading.

An extra crewmember often works in the basket to handle the pipe since he/she was not needed to manage it from the ground. The larger, extended basket including the dual fingerboards facilitates the extra man power.

3.9.2 Basket-Attached Structure

Another design includes a structure that supports the snubbing/HWO unit stack that can also be used for racking singles back vertically (Fig. 3.35).

In this design, the structure is sufficient to resist side-loading such that guying is not required. This allows the snubbing stack to be disconnected from one well and skidded to another one on the same platform or drilling pad without rigging either one down.

Pipe handling is by the same jib that would normally handle the pipe in singles without the supporting structure in place. There is no need for additional jib height or strength.

In this design, pipe stands back ready for running even if the stack and basket are taller than the structure. It is not necessary to lay the pipe down and pick it up in singles once racked.

3.9.3 Free-Standing Rack

A free-standing pipe racking system allows the snubbing/HWO unit to pull pipe from a structure that is not attached to the unit at all. The racking system is a standalone structure. It does not support the snubbing unit or any loads

■ **FIG. 3.35** Basket-attached structure. *(Courtesy of Halliburton.)*

except stand back side loads and wind loading. The entire weight of the vertical pipe and the rack itself is supported by the deck.

One design involves two separate racks that can feed the unit from either side to allow complex pipe strings to be isolated and monitored without mixing stands.

This system is only for offshore use, but pipe can be racked in singles or doubles. The unit basket is located near deck level, and the racking system provides pipe-handling capability including racking the pipe initially. This also means that the snubbing/HWO unit does not require a jib or counterbalance winch to hoist the pipe. The stack must be short enough, however, for the work basket to be at or near platform upper deck elevation.

An older version of this concept had a sloping surface used to pull pipe into the snubbing/HWO unit going in the hole the first time. The same structure stored the pipe in singles to be picked up and run in the hole without laying down. The jib and counterbalance winches were used for all pipe handling.

3.10 WORK BASKET EMERGENCY ESCAPE DEVICES

Escape from the elevated work basket may be necessary in an emergency situation. Some of these baskets can be quite high above the ground depending on the stackup of BOPs, spacer spools, and the hydraulic unit. Often, these are 60 ft. or more in elevation, and simply jumping out of the basket would not be wise.

A small rig-assist unit might allow jumping out of the basket onto the rig floor for escape, but any injuries sustained in this escape tactic could prevent the worker from getting off the floor unaided.

The parallel situation is when the derrickman on a rig needed to evacuate from the board. He/she could simply climb down the derrick leg. Exposure to fire and escaping wellbore fluids would make this slow descent impractical if not outright foolish. Other escape methods had to be developed.

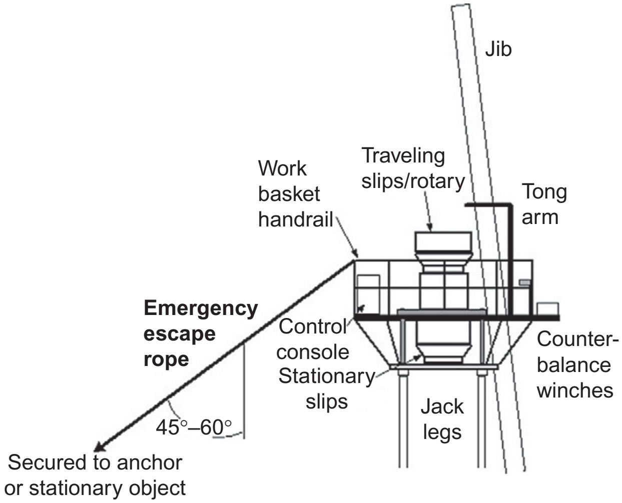
There are specific regulations regarding hydraulic unit work basket escape devices in Canada and perhaps other countries. These address ease and effectiveness of use in an emergency situation, construction, protection capability, and capacity. In general, there must be at least one escape device for every person working in the basket. This capability may be provided with a single, multiuser escape device.

Several escape devices are discussed below. They vary depending on the snubbing unit age and type, the service provider, and the type of well being serviced. In general, the escape devices have become more effective and more robust with time.

3.10.1 Escape Rope

This is probably the oldest escape device for personnel in the elevated work basket on a snubbing unit. It is a simple large-diameter (1–1½ in.) hemp or cotton rope attached to the top guardrail on the basket. It is usually run to a stationary point on the ground some distance away from the snubbing unit (Fig. 3.36).

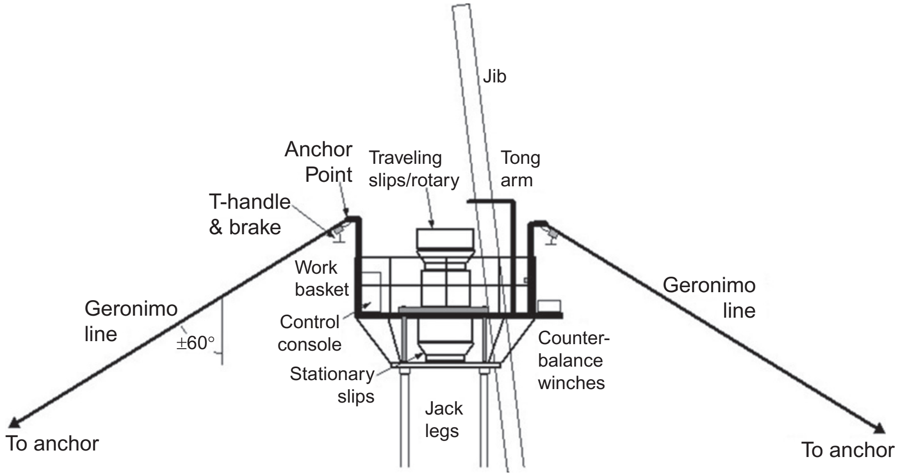
Personnel in the basket climb over the handrail, grip the rope with gloved hands, and slide to the ground controlling speed by their grip on the rope.



■ **FIG. 3.36** Work basket escape rope.

This system is simple and requires no specific training, but it has several drawbacks:

- Protection from rope burn is provided by gloves. Some personnel in the basket, such as the snubbing unit operator, may not be wearing gloves at the time of the escape. Sliding down the rope causes severe rope burns that almost always cause the person to turn loose of the rope and drop to the ground shortly after escaping the basket. This has resulted in significant fall injuries on several occasions.
- Speed control is determined by grip. Ropes that are slick due to accumulations of hydraulic fluid or from rainfall, snow, ice, or seawater spray make slowing the descent very difficult. Rapid descents have also caused significant injuries at the end of the ride.
- Injured personnel cannot escape using this technique depending on where and how badly they are injured. A seemingly insignificant hand injury could cause an early rope release or rapid descent with additional injuries involved. With some injuries, such as a broken hand or arm, there may be no possibility of escape at all using the rope.
- In fires, the rope burns through rapidly. Personnel that are descending on the rope at that time are dropped to the ground or deck without warning with the same results as an early release.
- There is no protection for personnel using the rope. They are exposed to fire, heat, explosion, flying obstacles, and other threats as they are escaping.



■ **FIG. 3.37** Work basket Geronimo line.

Many snubbing service providers have abandoned the escape rope because of these drawbacks. In some cases, the risk of sliding down the rope is greater than simply climbing down the stack below the outlet of escaping well fluids and fire. Some older snubbing units still use the rope, however.

3.10.2 **Geronimo Line**

This is an improvement on the escape rope. It is intended to serve the same purpose as an escape line for derrickmen on drilling rigs and has the same name (Fig. 3.37).

This is a small-diameter (e.g., ½ in.) wire rope extending from a post secured to the work basket on one end and to a stationary anchor point on the ground or deck some distance from the well on the other end. A carrier of some type is strung on the line that includes some type of brake to control the speed of the descent. This could be as simple as a "T" bar gripped by personnel that has a lever on one side to operate a simple brake (that may or may not function). It could have a seat or a stand included. Designs vary from unit to unit.

Personnel must reach up or climb up, position themselves on the carrier, release the device, and control the speed of the descent using the brake. This sounds easy, but in an emergency situation, there is very little time available for escape. Further, each braking device can only be used once. There is no reliable means to return the bar, stand, or basket up the line to the next person still in the basket awaiting escape.

The more complicated the evacuation system, the less likely it is that personnel in an emergency will actually use it. They may simply jump out of the basket in panic mode and risk a long fall rather than take any extra time to use the escape device.

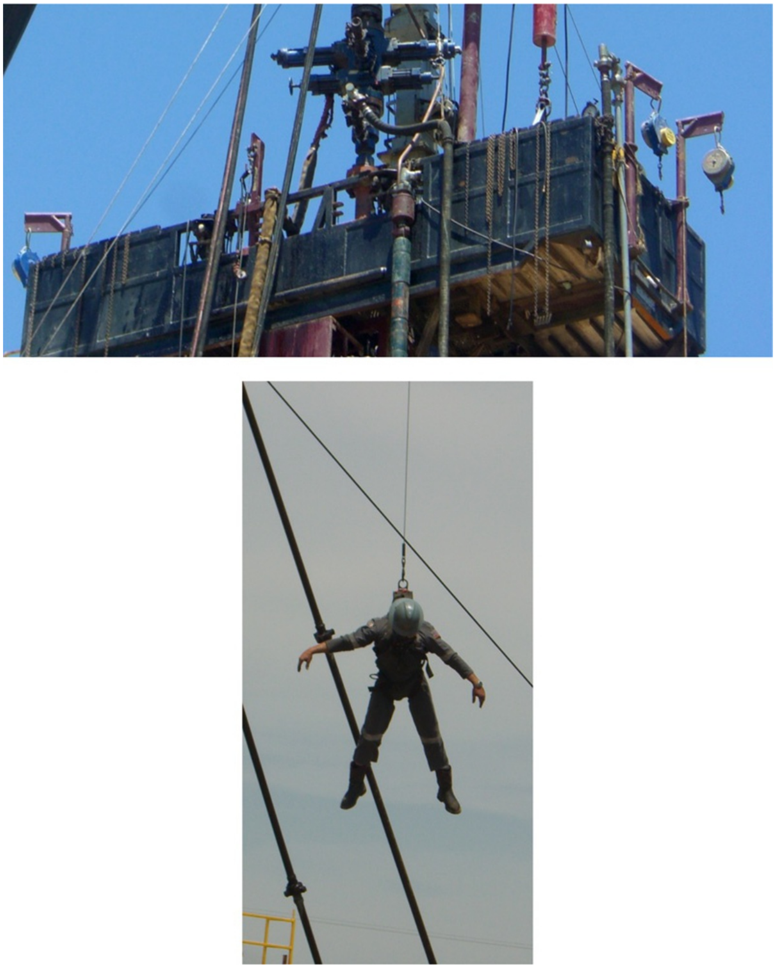
The Geronimo line has many of the same flaws of the escape rope:

- There must be a separate carrier and line for each person working in the basket. Obviously, if there is only one carrier and the first person uses it to descend, it is not available to anyone else. This means that anyone else left in the basket must figure out some other means of escape.
- Each carrier must be maintained ready for use with a brake that is functional at all times. Also, each line must be strung and anchored independently. This requires time and increases the footprint of the unit.
- The carriers must operate under all conditions of line lubricity, angle, temperature, and wind condition. Accumulated ice on the Geronimo line cannot collect under the pulley or brake causing the device to stall on the line leaving the person literally dangling in midair.
- There is no provision for evacuating injured personnel using this line.
- There is no protection for personnel during the descent.
- Improper brake operation during the emergency can result in a rapid descent with the same unhappy impact event at the bottom as that with a slick rope.

3.10.3 **Controlled Descent Device**

These are spring-loaded or fluid-filled devices that feed out a small-diameter cable from a spooling device hung from a point on the work basket. This device feeds the cable out at a given rate by holding a back pressure on the spool such that the person suspended from it falls at a predetermined speed (Fig. 3.38). The top photo shows three davits holding the controlled descent devices (reels) over the side of the work basket. The bottom photo shows how a worker (here a simulated injured worker) would escape from the basket during a controlled speed descent.

Obviously, this requires that each person has their own device and that they are connected to it at all times while they are working in the basket. They are usually required to wear a full-body harness with a “D” ring in the back to which the cable is attached. The spool and controlled descent device are suspended over the side of the work basket by a rigid arm or davit so that the cable does not rub on the side of the basket during the descent.



■ **FIG. 3.38** Controlled descent device. *(Courtesy of Abel Engineering.)*

All that is actually required in an emergency event is that the person in the basket jumps over the top handrail. The device then lowers him/her to the ground or deck at a controlled speed for a relatively soft landing. Many personnel have some difficulty trusting the device to deliver the controlled descent when personnel simply “bail out” of the work basket. Training is usually required with multiple jumps involved before personnel develop both familiarity and trust of this type device.

Like other devices, the controlled descent device has several drawbacks and limitations:

- Many of these devices have weight limitations. A large, heavy individual may require a special device, or they may not be able to work in the basket at all. Some of these devices are adjustable for heavier persons. Others manage a range of weights. If the individual's weight falls outside this range, they may not have adequate protection from a fast fall. Conversely, a light, small individual may have a slow fall. In certain emergency situations, that may not be an attractive alternative.
- Proper connection of the device to the support arm or davit and to the harness "D ring" is absolutely required. Connection to the support must be checked visually on every job, and it must be pull-tested to the maximum "spike" weight of a large individual hitting the end of the cable when he/she jumps out of the basket. Often, this spike load is several multiples of the person's actual weight. A safety snap or carabiner with a latch that cannot self-release is required to make the connection to the "D" ring. It must remain connected at all times while the person is in the work basket.
- Injured personnel may not be able to jump over the top handrail of the basket. They may need help. Once they are out of the basket, there is nothing left for the injured person to do but fall. This is an important issue for an unconscious worker. If the other worker(s) can roll him/her over the top, the person is simply lowered to the ground or deck with no further problems (at least until they hit the ground).
- There is no protection against fire, explosion, flying objects, etc. for personnel during the descent. They are completely exposed.
- In the event of an extreme temperature event such as a fire or extreme cold, the rate of descent can be impacted. Most of the controlled descent devices are shielded, and the cable is very strong (usually braided stainless steel aircraft control cable). A fire in the basket could "cook" the device quickly or burn through the cable resulting in a nasty face-down fall for the person depending on the device.
- There is little, if any, lateral displacement away from the well. Most emergencies are specific to the basket such as an upward leak from the no. 1 stripper and fire. However, if the focus of the emergency is lower on the stack, jumping over the side may result in the worker being lowered directly into a fire or leak exposing them to injury that might be worse than if they attempted evacuation using some other method. For example, if a line leak and fire occurs in the equalizing loop, jumping over the side using a controlled descent device would result in the worker being lowered into the fire instead of away from it.

3.10.4 Escape Pod

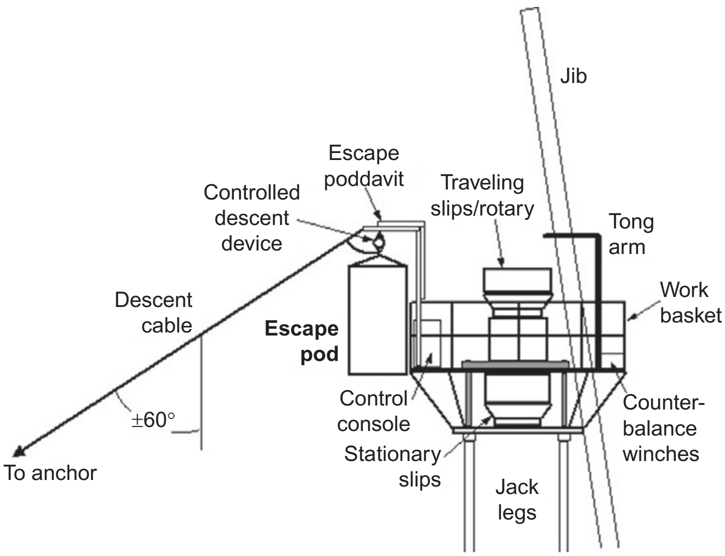
These are specially designed baskets designed to protect the worker(s), while it descends at a controlled speed down a Geronimo-type line to a point some distance away from the wellbore. The worker simply jumps or dives into the pod, his/her weight releases the device, and it travels at a controlled descent rate down a prestrung cable at a ±60 degrees angle to the ground or deck (Fig. 3.39).

One design has a fire/flame/heat-resistant outer cover that prevents burns during the descent. It also has an inner bag made of a material such as woven Kevlar that prevents penetration from explosion. The combination provides protection for the worker and allows for the evacuation of injured workers.

The escape pod is equipped with doors that open easily and close securely behind the worker. These doors provide protection during the descent. Once the person enters the pod, however, nothing else is required on his/her part. The release and descent are controlled without human intervention.

This represents a considerable improvement over previous systems that provide no protection to the worker. Still, it has some drawbacks:

- There can be one pod for all persons in the work basket since the pod is large enough to control a few workers. However, when multiple workers are positioned in the basket, another pod or two must be available with a



■ **FIG. 3.39** Escape pod.

line strung to a different anchor point on the ground or deck. Since there are usually at least two workers in the basket, even the one-pod configurations require each person to move from his/her work station to the pod to make the escape, and some time may be required.

- All pods, their release mechanisms, and braking devices must be maintained and tested frequently. They must be easy to hoist back into their "safety" position and reset, so they will be available when needed on the next job or the continuation of the current one after the emergency.
- There must be an elevated support arm or davit to which the "Geronimo line" is attached. This also serves as the anchor point for the releasing mechanism.
- The worker must be able to get into the basket through the doors. This requires him/her to get over the top handrail either by gripping a horizontal bar above the door and swinging his/her feet into the basket or by diving headfirst over the handrail through the doors and falling to the bottom of the pod. Injured personnel may require help to get in the pod. In some designs, this is overcome by having a hinged door or chain segments in the work basket guardrails, so workers don't have to climb over the top handrail to enter the pod.
- The Geronimo line is exposed to fire and/or explosion that could result in a rapid burn through or line severing, neither of which is likely during the time required for a quick descent.
- The worker inside the pod never knows exactly when the pod will reach the deck. There are no windows in the pod, so hitting the deck will likely come as a surprise to the rider, and the pod will likely tip over when it does.
- The claustrophobic worker may have some reservations about entering a closed pod for escape. Generally, the realization that injuries resulting from the emergency, such as burns, will convince the worker that a short claustrophobic ride to the bottom is far better than staying in the work basket and risking injury (or selecting another escape technique such as jumping over the side and falling to the ground or deck).

The advantages of this type device are obvious: (1) lateral displacement away from the well, stack, and any type of emergency located near the well; (2) protection during the descent; (3) the ability to get injured or unconscious workers down from the basket; and (4) no requirement for human intervention during the descent. The only thing left is for the worker to get out of the pod once it is on the ground or deck that may require other crewmembers to help. This, of course, takes place some distance away from the well in a safer area.

3.10.5 Slide

These are simple devices intended to get personnel from the basket to the ground or deck with no mechanical devices involved at all (Fig. 3.40).

The slide entry is at the floor level of the work basket, and the exit is at a height of 12–18 in. above the ground or deck. The slide, obviously, displaces the worker some lateral distance away from the wellbore and snubbing stack. Some versions are encircled with a protective covering that shields the worker from fire and injury due to penetration (Fig. 3.41).

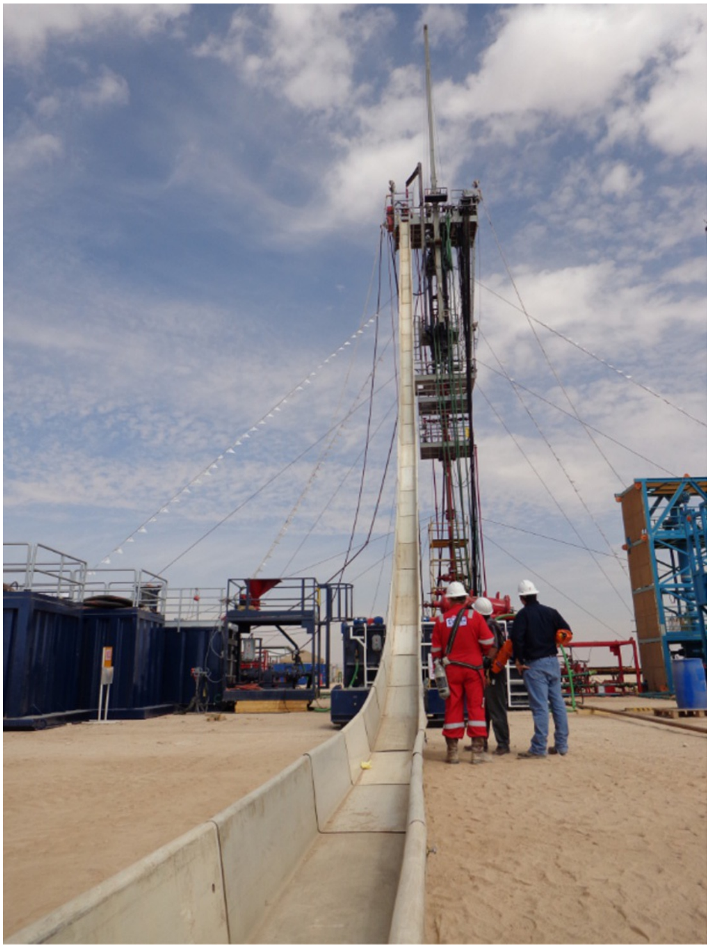


FIG. 3.40 Escape slide. *(Courtesy of International Snubbing Services.)*

■ **FIG. 3.41** Escape slide winterized. *(Courtesy of Snubbertech Manufacturing.)*

The worker can gain considerable velocity while making the descent. The material used to construct the slide can be "roughened" somewhat to slow the descent, and most slides have a short horizontal section at the end to slow the worker before he/she exits the slide.

The slide can be used to evacuate injured personnel. A hand or arm injury does not defeat the function of the slide. Personnel with more serious injuries can simply be pushed into the slide for recovery at the bottom in a safe area.

There are only a few disadvantages to slides:

- There is usually only one slide for all personnel in the basket. This means that all personnel must get to the slide entrance and they must enter the slide one at a time. In an emergency escape, the time gap between each person entering may be quite short.
- Entry is usually feet first so that the worker ends up on his feet at the slide exit. This requires only slightly more time than diving headfirst into the

slide. Obviously, the headfirst entry means that the worker will exit the slide headfirst as well.

- Escape time in a fire or explosion event will likely be fairly short. This time is generally long enough to allow evacuation of all personnel in the basket, however. The supporting structure of the slide will still allow evacuation even if the protective cover is burned away.
- Again, for those systems in which the slide is covered by a protective covering, a claustrophobic worker may have some reservations about entering an enclosed tube to escape the basket. In the case of a slide, or any other system in which escape is sequential, a hesitant worker could stall others. This is usually a self-correcting problem. The other workers will either go around the hesitant worker or shove him/her ahead of them down the slide. Snubbing unit personnel are rarely shy about escaping quickly in emergency situations regardless of obstacles (including fellow crewmembers).

The slide allows for rapid evacuation of all personnel in the basket. Operation of the jack may only require two workers, but three or more may be in the basket with one there for observation, training, or helping with certain tasks such as making up and breaking out connections. Other personnel such as tool operators and supervisors may also be present especially where the work basket is large. The slide construction is sufficiently robust to support all of them at one time without buckling or collapsing. Residence time inside the slide is very short.

Large, heavy personnel can evacuate using the slide as long as they can fit inside the protective "tube." The slide protective covering is intentionally large, so most workers can fit through the slide with no problems.

Protected slides have so many advantages that the few drawbacks to them are rarely a limiting factor in their use. Slides are the preferred escape device for Canadian snubbing operations.

3.11 REMOTELY-CONTROLLED SNUBBING UNITS

A relatively recent development in the snubbing industry is the remotely-controlled rig-assist snubbing unit. The control panel is located in a cabin, a small skid-mounted building on the rig floor, and all components of the snubbing unit are connected through hydraulic lines to the control panel. Pipe is managed by the rig's robotic pipe-handling system. Makeup and breakout involve the iron roughneck. Steaming video feeds supply the unit operator with the necessary visual cues to operate the unit without being in the work basket.

The remotely controlled snubbing unit makes extensive use of data acquisition systems and both analog and digital gauges for job monitoring. The system also uses the slip interlock system to prevent dropping or releasing the string by having both slip/bowl sets open at the same time. Job functions can be divided as much as they are when the unit operator has a helper in the work basket with one worker managing pipe-handling duties while the unit operator manages the jack and equalization loop. In this case, the rig's assistant driller remotely operates the pipe-handling system as he usually does anyway. Another worker might be charged with handling operation of the safety BOPs (Fig. 3.42). Note the use of both data acquisition screens

■ **FIG. 3.42** Remotely-controlled snubbing unit console. *(Courtesy of International Snubbing Services.)*

(bottom row) and video feeds (top row) to monitor and control operations from the remotely controlled operator's console.

Most importantly, the remotely operating snubbing unit removes the unit operator and his helper from the basket. Workers in the basket are no longer exposed to a plume of gas coming up through the floor. There is no need for escape devices since there is nobody in the basket. In fact, the work basket is usually empty except for maintenance and inspection work when the unit is inactive. There may not be a work basket at all.

The remotely-controlled snubbing unit makes complete sense from both operating and safety standpoints. Coiled tubing units are remotely operated as are many modern drilling rigs. The operator for each is located in a remote location, and all devices are joystick controlled from an ergonomically friendly chair. It is amazing that it took almost 100 years to develop a remotely-controlled snubbing unit.

CHAPTER 3 QUIZ 1

Sections 3.1 and 3.2

1. A snubbing or HWO unit is a collection of hydraulic and mechanical devices each working to achieve a particular part of the snubbing job.
   A. True ______
   B. False______

2. A hydraulic cylinder converts fluid pressure acting on a piston/seal cross-sectional area into a force.
   A. True ______
   B. False______

3. What is the hoisting force exerted on a hydraulic cylinder rod with a 3 in. OD from 3000 psi hydraulic fluid acting on a piston with an OD of 4.875 in. inside a hydraulic cylinder with an ID of 5.0 in. (efficiency factor is 0.9)?
   A. 50,397 lb_f
   B. 53,015 lb_f
   C. 55,997 lb_f
   D. 58,905 lb_f
   E. None of the above

4. What hydraulic fluid pressure would be required to lift a 30,000 lb load with a 4 in. ID hydraulic cylinder having a piston OD of 3.9 in. and a 2 in. OD rod? Assume 85% efficiency.

A. 2387 psi
B. 2511 psi
C. 2809 psi
D. 2954 psi
E. None of the above

5. What piston diameter is required to lift a 40,000 lb weight inside a 5.25 in. ID cylinder with a 3.5 in. rod using hydraulic fluid with a pressure of 1848 psi ignoring friction (i.e., efficiency factor = 1.0)?

A. 5.073 in.
B. 5.125 in.
C. 5.168 in.
D. 5.215 in.
E. None of the above

6. What are three things that require additional hydraulic pressure to start a lift using a hydraulic cylinder compared with steady-state pressure in the middle of the lift?

A. Rod seal friction, piston seal friction, and hydraulic pump startup
B. Metal-to-metal adherence, choke pressure, and power fluid line size
C. Seal friction, rod diameter, and return fluid line size
D. Seal friction, rod/piston acceleration, and breaking static friction

7. The operator of a well wants to install a hydraulic lift so he can work on a pumping unit. The unit weighs 30,000 lb. He has a hydraulic pump that will produce 2000 psi power fluid. How large will be the cylinder ID necessary to lift his pumping unit? Assume an efficiency factor of 0.9.

A. 2.150 in.
B. 3.975 in.
C. 4.607 in.
D. 5.00 in.
E. None of the above

8. The pull-down force on a vertically mounted dual-acting hydraulic cylinder is determined by the hydraulic fluid pressure acting on the entire piston/seal cross-sectional area including the rod cross-sectional area.

A. True ______
B. False______

9. What is the pull-down force (snubbing force) of a 6 in. diameter cylinder with a 5.125 in. ID, a piston OD of 5 in., and a rod OD of 2.5 in. with hydraulic power fluid having a pressure of 3000 psi? Assume an efficiency of 90%.
   A. 39,761 lb_f
   B. 42,445 lb_f
   C. 44,179 lb_f
   D. 49,834 lb_f

10. A pulling unit has two hydraulic cylinders. Both are 6.5 in. OD with a 6 in. ID. One piston has an OD of 5.985 in., but the piston in the other cylinder is slightly undersized at 5.875 in., and it is equipped with oversized seal rings. Both cylinders have 3.0 in. rods. What is the snub force available for this unit if the power fluid has a pressure of 1000 psi? Assume an efficiency factor of 0.95.
    A. 39,049 lb_f
    B. 40,291 lb_f
    C. 41,104 lb_f
    D. 42,412 lb_f

11. The hoisting (upward) force and the snubbing (downward) force available in a concentric snubbing unit are theoretically identical.
    A. True ______
    B. False______

12. Snubbing units are named or classified on what basis?
    A. Maximum number of hydraulic cylinders (jacks) on the unit
    B. Maximum theoretical snubbing force with a power fluid pressure of 2000 psi
    C. The sum of the IDs of all cylinders in millimeters
    D. Maximum available hoisting force in thousands of pounds

13. Wear sleeves are installed on pistons in hydraulic jacks to provide which of the following?
    A. An expendable component that protects the piston and seals from excessive wear
    B. Centralizes the piston and seals inside the cylinder and prevents metal-to-metal contact
    C. Absorbs, or ingests, particulate matter that could damage the seals and/or score the cylinder inner surface
    D. All of the above
    E. None of the above

14. A wiper seal performs which of the following functions?
    - **A.** Prevents particulate matter from getting inside the seal pack damaging the seals and the cylinder wall
    - **B.** Places a film of hydraulic fluid onto the piston and seal pack to enhance lubricity
    - **C.** Removes all hydraulic fluid from the piston and seals to prevent the fluid from getting underneath the seal rings
    - **D.** All of the above
    - **E.** None of the above

15. Twisted snubbing units are not difficult to repair.
    - **A.** True ______
    - **B.** False______

CHAPTER 3 QUIZ 2

Sections 3.3–3.6

1. Three components of the traveling head on a snubbing unit include
    - **A.** Hydraulic cylinders, stationary slips, and stripping rubber
    - **B.** Cylinder rods, rod seals, and cylinder caps
    - **C.** Jack plate, traveling slips, and hydraulic rotary table
    - **D.** None of the above

2. All the cylinders on a hydraulic snubbing unit are attached to the jack plate.
    - **A.** True ______
    - **B.** False______

3. The hydraulic rotary table is positioned above the traveling slips on the traveling head.
    - **A.** True ______
    - **B.** False______

4. Hand-over-hand load transfers on a snubbing unit require which of the following?
    - **A.** Stationary and traveling slips
    - **B.** No. 1 and no. 2 snubbing BOPs
    - **C.** A stripping head or annular BOP
    - **D.** Safety BOPs

5. How does the snubbing unit translate between pipe-light and pipe-heavy snubbing with modern snubbing units?
    - **A.** The single traveling and stationary slip/bowls are inverted at the neutral point

B. Double-acting slips take over automatically, so there is no need for human intervention
C. The snubbing unit operator swaps one paired set of the dual slip/bowls for the other when the load direction changes
D. Only one set of slip/bowls are required for both pipe-light and pipe-heavy snubbing

6. Which of the following describe snubbing BOPs?
A. Guillotine or ram-type BOPs
B. Hardened insert for ram packers
C. Capable of sealing and holding well pressure
D. All of the above

7. The stripping head can be used in high-well pressure applications.
A. True ______
B. False______

8. What is the primary purpose of the stripping head?
A. Removes debris, dirt, and pipe dope from the pipe as it is being stripped in the hole
B. Allows snubbing or stripping pipe without the use of the snubbing BOPs in low wellhead pressure or dead well operations
C. Is conveniently located just above the stationary slips
D. Has an element that is very difficult and expensive to change out

9. Ram-to-ram snubbing is what?
A. A means to safely contain full well pressure while snubbing or stripping jointed pipe with connection upsets and collars
B. Traps the upset of connection between the snubbing BOP rams so that at least one is closed on the pipe body at all times
C. Is not necessary for flush-joint connections
D. All of the above

10. What is the purpose of the equalizing and vent loops on a snubbing unit?
A. They provide a means to have equal pressure across a snubbing ram before it is opened or closed
B. It allows equal snub loads to be shared by the stationary and traveling slips when pipe movement ceases
C. It provides a means for lowering well pressure by venting gas to a flare pit
D. All of the above

11. The equalizing loop allows the unit operator to snub or strip pipe into or out of the hole through the stripping head or annular.

A. True ______

B. False______

12. How is the equalizing loop configured?

A. From below the no. 2 snubbing BOP into the cavity between the no. 1 and no. 2 snubbing BOPs

B. From the cavity between the snubbing BOPs to a point above the no. 1 snubbing BOP

C. From below the no. 2 BOP to a point above the no. 1 BOP

D. None of the above

13. When is pressure bled from the cavity between the no. 1 and no. 2 snubbing BOPs?

A. Before opening the no. 2 BOP with a pipe connection trapped in the cavity

B. After equalizing well pressure and the pressure inside the cavity between the snubbing rams

C. After closing the no. 2 BOP rams and before opening the no. 1 BOP rams

D. Before closing a pipe ram in a safety BOP

14. Either snubbing BOP can be used as the primary BOP for snubbing jointed pipe into or out of the hole with the other BOP used only for dealing with connections in ram-to-ram snubbing.

A. True ______

B. False______

15. Why do the equalizing loop and the vent loop contain in-line chokes?

A. The chokes allow pressure buildup or venting to occur at a controlled rate instead of a high flowrate when the valves are opened

B. They prevent icing and plugging inside the piping

C. They allow the valves to be fully opened without using them as a choking device

D. All of the above

CHAPTER 3 QUIZ 3

Sections 3.7–3.11

1. A power-pack is being designed for a snubbing unit with a pressure limitation on both cylinders of 2250 psi. The maximum hydraulic pump output pressure at the power-pack should be limited to what pressure?

A. 1400 psi
B. 2400 psi
C. 4400 psi
D. 6000 psi

2. Power-packs are usually equipped with a flowrate control valve (unloader) and a release to control maximum pressure so the prime mover can operate at a constant speed during a snubbing job.

A. True ______
B. False______

3. A single hydraulic cylinder has just been reconditioned and is being tested in the shop. The cylinder has a 4.21 in. OD, a 4 in. ID, and a piston OD of 3.894 in. It is connected to a hydraulic pump that can deliver 40 GPM. How fast will the cylinder rod stroke out?

A. 55 ft./min
B. 61 ft./min
C. 63 ft./min
D. 65 ft./min

4. A power-pack can deliver 300 GPM of hydraulic fluid to a four-cylinder snubbing unit at 2000 psi. How fast will the traveling head rise if the snubbing unit of each cylinder has an OD of 4.5 in., a 4 in. ID, and a piston OD of 3.95 in.?

A. 91 ft./min
B. 115 ft./min
C. 118 ft./min
D. 230 ft./min

5. A snubbing service provider wants to pull tubing from a well with a slight pressure at the surface and compete with a conventional workover unit. This requires a traveling head hoisting speed of at least 150 ft./min. The snubbing unit has two cylinders each with an ID of 4.5 in. and a piston OD of 4.375 in. What power fluid flowrate must the power-pack deliver to achieve this required traveling head speed?

A. 124 GPM
B. 191 GPM
C. 195 GPM
D. 248 GPM

6. The hydraulic pump in a power-pack delivers 250 GPM power fluid to a four-jack snubbing unit. Each cylinder has an OD of 4.75 in., an ID of 4.25 in., and a piston OD of 4.125 in. The required load on the traveling head while coming out of the hole is about half of the peak snubbing unit capacity, so the operator decides to cripple two cylinders. How fast will the traveling head move now?

A. 170 ft./min
B. 180 ft./min
C. 260 ft./min
D. 340 ft./min

7. All power-packs have a single hydraulic pump regardless of whether that pump is run by a diesel engine or an electric motor.

A. True ______
B. False______

8. Desirable hydraulic fluid properties, whether oil- or water-based include which of the following?

A. Lubricity and stable viscosity
B. Thermal stability and film-forming capability
C. Antifoaming capability
D. Incompressibility
E. All of the above

9. A key to successful operation of any hydraulic system is an adequate supply of clean hydraulic fluid to all devices in the system.

A. True ______
B. False______

10. The unit operator's control panel usually includes controls for what devices or variables?

A. Power-pack hydraulic pump rate and pressure
B. Safety BOPs using the jack power fluid system
C. Jack direction, snubbing unit BOPs, and equalizing loop valves
D. None of the above

11. What device does the counterbalance panel operate?

A. Both snubbing BOPs
B. The jib main winch motor
C. The annular BOP or stripping head
D. The power-pack kill switch

12. The safety BOPs can only be operated from the work basket on a snubbing unit to prevent accidental activation of a BOP by someone on the ground or deck.

A. True ______
B. False______

13. Characteristics of data acquisition systems include the following:
  A. Operating data from the snubbing unit is transmitted to computers for analysis, monitoring, and storage
  B. May include video camera feeds
  C. Can transmit sensor data through wired or wireless telemetry systems
  D. All of the above

14. An escape device for rapid evacuation of the work basket is required for each person in the work basket during a snubbing job.
  A. True ______
  B. False______

15. The following describe a remotely operated snubbing unit:
  A. At least one operator is still required to work in the basket to ensure that controls are functioning properly and to perform minor maintenance
  B. A large, robust work basket is required on these snubbing units
  C. There is no need for visual observation of the snubbing stack during operations
  D. Operators and control panels are located in a protected enclosure located some distance away from the snubbing unit

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Chapter 4

Snubbing Theory and Calculations

CHAPTER OUTLINE

4.1 INTRODUCTION

Snubbing and stripping have always been unusual operations. Both involve a well with pressure at the surface whether it is there intentionally or not. In the past, all wells were drilled overpressured having a column of fluid inside the wellbore that imposed hydrostatic pressure on the formation greater than formation pressure. There was never pressure on the wellhead unless there was a problem. Workovers and recompletions required killing the well so that “dead well” procedures could be used. Pressure on the well was considered to be highly undesirable.

Hydraulic Rig Technology and Operations. https://doi.org/10.1016/B978-0-12-817352-7.00004-X

Now, many operations are done without killing the well. High-density fluids can damage formations so badly that the well may not produce after the well is killed. Kill fluids may fracture weak formations resulting in lost circulation. Sometimes, this lost circulation can result in a drop in the fluid column that allows another pressured formation to flow. Neither situation is favorable.

Knowledge of the physics involved in snubbing is essential to understanding how the snubbing process works and how hydraulic rigs in snubbing mode are used, their capabilities, and their limitations. This chapter involves those concepts and the mathematics associated with them.

4.2 SNUBBING FORCES

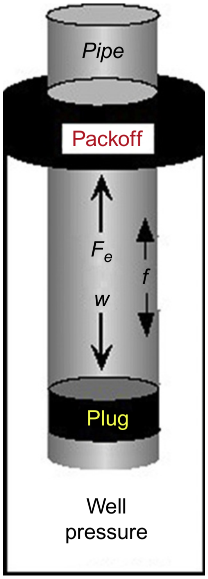
Well pressure provides the force necessary to eject drill pipe, drill collars, casing, tubing, or any other items by acting across its cross-sectional area at the sealing device. Sometimes, this pack-off seal is provided by a BOP ram or an annular BOP element. Sometimes, it is provided by a seal assembly mounted in a wellhead component. Regardless, the upward expulsion force always involves pressure acting on the cross-sectional area of some component at the surface.

Obviously, there must be a pack-off of some type around the outside of the pipe or other elements. Without a seal, the pressure is vented to the atmosphere around the pipe, and there is no upward force applied to the pipe. The pressure must be trapped below the seal to provide the force. A second requirement is that the interior of the pipe string must also be plugged. If it is open, the pressure is released through the inside of the pipe into the atmosphere, and there is no upward force acting on the pipe (Fig. 4.1).

If the expulsion force, F_e, is greater than the weight, W, of the pipe string hanging in the well (pipe-light condition), the pipe will try to move upward and out of the hole if not held. Similarly, if the weight of pipe is greater than the expulsion force (pipe-heavy condition), the pipe will slide down the hole if not constrained.

Unfortunately, most rigs operate using gravity and kill weight fluid in the wellbore to keep the string pipe-heavy. Their hoisting equipment, usually a block-and-tackle assembly, is unidirectional. The pipe string must be pipe-heavy at all times. Snubbing is required for pipe-light conditions and does not rely on a block-and-tackle hoisting system.

The following discussion describes basic snubbing theory.



■ **FIG. 4.1** Snubbing force diagram.

4.2.1 **Expulsion Force**

Well pressure acting on the cross-sectional area of the tubular item at the seal creates this force:

$$F_e = pA \tag{4.1}$$

where F_e = expulsion force, lb_f, p = well pressure, pounds per square inch (psi), A = area, square inch(es) or in.^{2}.

Notice that this equation is identical to Eq. (3–1) for hydraulic cylinders. In a very real sense, pipe in a well with pressure below it acts like a hydraulic cylinder.

In Fig. 4.1, well pressure is acting on the cross-sectional area, A, of the pipe in the pack-off section at the top of the "cylinder." The force, F_e, is transmitted upward trying to push the pipe out of the hole.

The pipe area is based on the OD of the pipe (the ID is not being impacted by well pressure—it is isolated by the pipe wall):

$$A = \frac{\pi\, OD_{pipe}^2}{4} \tag{4.2}$$

or

$$A = 0.7854\, OD_{pipe}^2 \tag{4.3}$$

By combining Eqs. (4.1) and (4.3), theoretical expulsion force can be calculated using Eq. (4.4):

$$F_e = p \times 0.7854\, OD^2_{pipe} \tag{4.4}$$

Example

A well has 2000 psi surface pressure trapped below a BOP that is closed around 2⅜ in. OD tubing. What is the theoretical expulsion force trying to push the pipe string out of the well?

Using Eq. (4.4),

$$F_e = p \times 0.7854\, OD^2_{pipe}$$

$$F_e = 2000 \times 0.7854\, (2\tfrac{3}{8})^2$$

$$F_e = 8860\, \mathrm{lb_f}$$

The expulsive force is calculated based on the OD of the pipe string component on which the pack-off is closed. If the pack-off is closed on a connection upset (obviously, the annular preventer), a pipe collar, or an oversized pipe string component such as a blast joint, drill collar, or liner, the expulsive force can be much higher.

Example

The same well as above has 2000 psi wellhead pressure trapped below the annular preventer that is closed on a 2⅜ in. EUE American Petroleum Institute (API) tubing collar. What is the theoretical expulsion force trying to push the pipe string out of the hole?

A 2⅜ in. EUE API tubing collar has an OD of 3.063 in. Again, using Eq. (4.4),

$$F_e = 2000 \times 0.7854\, (3.063)^2$$

$$F_e = 14{,}737\, \mathrm{lb_f}$$

Example

A well has 2000 psi at the surface trapped below an annular preventer closed on a 4½ in. casing collar with an OD of 5.0 in. What is the theoretical expulsion force trying to push the pipe out of the well?

$$F_e = 2000 \times 0.7854\,(5.0)^2$$

$$F_e = 39{,}270\,\mathrm{lb_f}$$

From these examples, it is clear that the expulsion force can become very high when the pack-off device closes on an OD larger than the pipe body. Because the pack-off may be somewhere down the stack in a snubbing operation, the stationary and traveling slips may be pushing down on small-diameter pipe while the well pressure is acting on a much larger OD component of the string. The additional force may exceed the safe snubbing limit for the small-diameter pipe in the slips. Preplanning to avoid this type of situation is a necessary part of any snubbing job.

Another important issue is involved in calculating the expulsion force: the actual OD of the pipe and **not** the nominal OD must be used for these calculations.

Naming conventions for small-diameter pipes are often based on the pipe ID and not the OD. For example, 1¼ in. tubing ordered from a vendor actually has an OD of 1.660 in. If the nominal pipe diameter is used instead of the actual OD, the calculated expulsion force will be less than the true value.

Another issue involves pipe tolerances. The API publishes reference specifications, such as API Specification 5CT (for casing and tubing) and 5DP (for drill pipe). Both allow pipe manufacturers to deliver "API" pipe with variances in pipe OD. These are summarized below in Table 4.1.

So, for nominal 3½ in. tubing, the actual OD could be as large as 3.531 in. For 5 in. drill pipe, the OD could be as large as 5.05 in. The expulsion force is larger because the calculation uses the square of the OD.

It is important to recognize that most pipe manufacturers of non-API and specialty tubulars also have tolerances for the OD of their pipe. They may be more or less restrictive than those shown in the API

Table 4.1 Casing, Tubing, and Drill Pipe OD Tolerances

Item	Size Range (in.)	OD Tolerance
Casing and tubing	$<4\frac{1}{2}$	± 0.031 in.
	$\geq 4\frac{1}{2}$	+1.0%, −0.5%
Drill pipe	≤ 4	± 0.031 in.
	>4	+1.0%, −0.5%

(Data from API Specs 5CT and 5DP.)

specifications for common pipe sizes, weights, and grades. The manufacturer's specifications should be used to calculate expulsion forces instead of the nominal ODs commonly used.

In other words, the maximum expulsion force calculation should use the nominal OD **plus** the maximum permitted tolerance to ensure that the worst case is defined. The snubbing operator cannot insure that the snubbing BOPs are *not* closing on the larger OD provided by the tolerance amount instead of the nominal OD. In snubbing jobs where the critical snubbing force to avoid buckling failure is approached, defining the worst-case expulsion force is necessary as an upper limit.

The term "theoretical expulsion force" is used here because that's what the traveling head senses when the jack stops. Maximum snubbing force to push pipe in the hole even with no appreciable pipe weight hanging in the well is significantly greater than the theoretical expulsion force because of friction created by the snubbing BOPs. Dynamic friction does not play a part in snubbing force when the jack is stopped. Neither does static friction. Friction forces only apply when the load is moving in one direction or the other. Friction force always acts opposite to the direction of motion. Friction is discussed later in this chapter.

4.2.2 Pipe Weight

The string weight, W, in Fig. 4.1 is composed of two parts, the buoyed weight of the steel and the weight of any fluid contained inside the pipe in a gas-filled well.

4.2.2.1 Gas-Filled Well

For a pipe string in a gas-filled hole with no fluid inside the pipe, the weight of the string is given by Eq. (4.5):

$$W_{pipe} = L \times W_{air} \tag{4.5}$$

where W_{pipe} = string weight (lb_m), L = pipe segment length (ft), W_{air} = air weight of the pipe (lb_m/ft).

Note that in this equation, the actual weight of the pipe, including upsets and connections, is used and not the tube weight. The upsets and connections may only add a little weight, especially in small-diameter tubing. This small additional weight applied to a long string could add several hundred or thousand pounds.

Again, API pipe has tolerances for IDs, the reason there is a nominal diameter and a drift ID for most oil country tubular goods (OCTG). For determining maximum string weight in snubbing mode, the lightest pipe weight should be used.

API allows a wall-thickness tolerance of $\pm 12.5\%$ for casing, tubing, and drill pipe. Combined with the minimum OD, this could result in a thinner wall and lighter weight over the entire string. Without measuring both ODs and IDs on every inch of the string, one would never know since the pipe was inspected at the factory according to API specifications, including the tolerances.

As an example, say that 3½ in. 10.2 lb_m/ft, or pounds per foot (ppf), tubing is being snubbed into a well. Its OD could be as small as 3.469 in. (3.5–0.031 in.), and its ID could be as large as 2.922 in. (nominal ID, drift ID is 2.797 in.). Under these assumptions, the maximum wall thickness would be 0.273 in. Calculating the volume of steel in a 1 ft. length of this tubing and adding the upset and collar weight provide an actual unit weight of about 9.6 ppf. The difference on a 5000 ft. pipe string would be about 3000 lb_m total weight using the maximum wall thickness for the entire string.

The "air weight" is used for the string weight here. Many snubbing companies use the shipping weight of the pipe string trusting the commercial scales to provide an accurate measure of the steel weight. In noncritical snubbing jobs, this may work satisfactorily.

Any fluid inside the tubing must also be taken into account in a gas-filled wellbore. The weight of the fluid is added to the weight of the steel in a gas-filled hole. The pressure that the fluid exerts on the bottom of the tubing is unimportant for weight calculations, but some operators prefer to have fluid in the well as a safety measure in case the internal tubing plug at the bottom of the pipe string fails. If the well begins to flow up the pipe, a fluid cushion provides the opportunity to install a stab-in safety valve in the top joint and shut the well in before the flow increases to an unmanageable rate. If the tubing is just filled with gas and the plug fails, there is little to stop the gas in the well from venting rapidly up the pipe (i.e., a blowout).

Other companies prefer to keep fluid inside the pipe to avoid collapsing it. In snubbing operations, well pressure is present in the annulus and providing a force on the exterior of pipe. A weak point in the tubing could collapse under this pressure, but the hydrostatic pressure of a fluid column inside the pipe will provide a force that will help resist pipe collapse.

Regardless of the reason for having fluid inside the pipe, the fluid volume (e.g., in gallons) multiplied by its density in pounds per gallon (lb/gal) provides the weight contribution of the fluid. This weight must be added to the pipe weight to get the total weight trying to pull the pipe into a gas-filled hole. It also affects the depth of the neutral point.

4.2.2.2 Fluid-Filled Well

The apparent weight of pipe in a fluid-filled well is less than that in a gas-filled hole due to buoyancy provided by the fluid. The fluid supports a portion of the pipe weight compared with the air weight owing to the difference in density of the fluids in which the weight is submerged.

This is normally expressed in the form of a buoyancy factor. To get a buoyed pipe weight, the weight of the pipe in air is multiplied by a buoyancy factor. The buoyancy factor is given by Eq. (4.6):

$$BF = \frac{65.5 - MW}{65.5} \tag{4.6}$$

where BF = buoyancy factor (dimensionless), MW = mud weight (fluid density) (lb/gal, ppg).

Note that this formula works for most pipe in the oil field because most of it is made from steel. The density of steel is ±65.5 ppg. Simply stated, the buoyancy factor is the reduction in the apparent density of steel due to its submergence in the fluid.

Note that if the fluid in the hole is a gas, its density is very small, usually less than about 0.1 lb/gal. The buoyancy factor is effectively 1.0 for steel submerged in a gas.

Example

What is the buoyancy factor for a pipe string suspended in a well filled with 10.0 ppg brine?

From Eq. (4.6),

$$BF = \frac{65.5 - 10.0}{65.5} = \frac{55.5}{65.5}$$

$$BF = 0.847$$

From the appearance of this formula, one can easily conclude that the buoyancy factor will be <1.0 for any commonly used fluid such as water, brine, drilling mud, or even aerated fluids. This equation also assumes that the pipe is filled with the same fluid in which the pipe string is immersed.

The reason this equation works is that the buoyancy actually supplies an upward-acting force on the pipe when it is submerged. This force, called buoyancy, is given by Eq. (4.7):

$$B = \frac{MW\,(A_o - A_i)}{19.25} \tag{4.7}$$

where B = buoyant force (lb/ft), A_o = outside area of pipe (in.^{2}), A_i = inside area of pipe (in.^{2})

$$A_o = \frac{\pi}{4} OD^2_{pipe} \tag{4.8}$$

$$A_i = \frac{\pi}{4} ID^2_{pipe} \tag{4.9}$$

Substituting, Eq. (4.9) can be rewritten as follows:

$$B = \frac{\pi\, MW\left(OD^2_{pipe} - ID^2_{pipe}\right)}{(4)19.25}$$

$$B = \frac{MW\left(OD^2_{pipe} - ID^2_{pipe}\right)}{24.51} \tag{4.10}$$

Here, OD and ID are in units of inches and the density is in pounds per gallon.

If two different density fluids are present inside and outside the pipe, buoyancy is affected by each fluid acting on the surface of the pipe to which it is exposed. In this situation, Eq. (4.10) can be written as follows:

$$B = \frac{\left(MW_o OD^2_{pipe} - MW_i ID^2_{pipe}\right)}{24.51} \tag{4.11}$$

where MW_o = outside fluid density (ppg), MW_i = inside fluid density (ppg).

In this equation, it is assumed that the density of the outside fluid is greater than the inside fluid density. If the opposite is true, the two terms inside the parenthesis must be reversed (or the absolute value of the equation must be used).

The weight of the pipe segment itself would be the following:

$$W_{pipe} = (W_{air} - B) \times L \tag{4.12}$$

where W_{pipe} = actual pipe segment weight in well (lb_m), W_{air} = weight of pipe in air (ppf), L = pipe length (ft).

Often, for simplicity, the expression ($W_{air} - B$) is simply expressed as W_b, the buoyed weight of the pipe per unit length in pounds per foot. In gas-filled wells, $W_b = W_{air}$ ignoring the very small value of buoyancy for the gas.

Thus, the weight of the pipe tubing submerged in a fluid inside the well is reduced by the calculated buoyancy. These equations can be for any fluid density. They can also be used for any pipe segment including those that are not in a fluid. This can occur if the top of the hole is filled with gas with a fluid level somewhere below the surface. The apparent weight of the pipe string is the same as the air weight to the top of the fluid. Then, the segment below the fluid level experiences a buoyant uplift. The actual string weight, W_{pipe}, is the sum of all the segments combined.

Example

What is the weight of a 2500 ft. string of integral, flush-joint 3½ in. OD tubing (2.992 in. ID) with an air weight of 9.2 ppf if the fluid level is located 1000 ft. from the surface. Assume a mud weight of 12.0 ppg in the well. The bottom 1500 ft. of the pipe has been filled with 9.4 ppg cut brine to prevent the pipe from collapsing. The well has an annular pressure of 2500 psi at the surface.

The weight of the top 1000 ft. of the string would be its weight in air because buoyancy is zero. So,

$$W_{pipe1} = 1000\,\text{ft} \times 9.2\,\text{ppf}$$

$$W_{pipe1} = 9200\,\text{lb}_\text{m}$$

The lower 1500 ft. of pipe is submerged in 15.0 ppg fluid with a water cushion inside the pipe. From Eq. (4.11), buoyancy on this segment would be

$$B = \frac{\left(MW_o OD_{pipe}^2 - MW_i ID_{pipe}^2\right)}{24.51}$$

$$B = \left[\frac{\left(12 \times 3.5^2\right) - \left(9.4 \times 2.992^2\right)}{24.51}\right.$$

$$B = 2.56\,\text{ppf}$$

The buoyed weight of the bottom 1500 ft. of pipe in the string would be (from Eq. 4.12)

$$W_{pipe2} = (9.2 - 2.56) \times 1500$$

$$W_{pipe2} = 9960\,\text{lb}_\text{m}$$

Total string weight is the sum of the weights of both segments:

$$W_{pipeT} = W_{pipe1} + W_{pipe2}$$

$$W_{pipeT} = 9200 + 9960$$

$$W_{pipeT} = 19{,}160\,\text{lb}_\text{m}$$

In a sense, fluid-filled pipe suspended in a gas-filled well can be thought of as being "negatively buoyed" since there is a vastly larger fluid density inside the pipe than outside the pipe. The fact that a gas cannot provide significant buoyancy makes Eq. (4.11) have a negative value. It is much easier to just add the weight of the fluid inside the pipe to the air weight of the pipe segment filled with the fluid to get the actual string weight.

This technique can be used to calculate the pipe segment weights of the BHA, any length of tubular in the hole and segments with differing fluid densities inside or outside the pipe. The segmented approach verifies the weight shown by the weight indicator on the snubbing unit when the pipe is not moving.

4.2.3 **Neutral Point**

The neutral point is defined at the depth of the end of the pipe string at which the buoyed string weight equals the expulsion force. In other words, this is the length of pipe in the well where the string weight and expulsion force are balanced. This is the point at which the string goes from pipe-light to pipe-heavy or vice versa.

Theoretically, if the pipe was snubbed to this depth, the slips could be removed, and the pipe would not move. Nobody would actually test that theory by opening both sets of slips on the snubbing unit. It's too easy to miscalculate the neutral point. Without some restraint, the pipe either could start sliding out of the hole or begin falling into the well. Neither is an attractive alternative.

The technique is fairly simple. The expulsive force, F_e, in Eq. (4.4) is equated to the buoyed unit weight and solving for the length of the pipe string in Eq. (4.12). This, of course, assumes a fluid-filled hole:

$$L\,(W_b) = p \times 0.7854\, OD^2_{pipe}$$

$$L = \frac{p \times (0.7854) OD^2_{pipe}}{(W_b)} \tag{4.13}$$

While this appears to be a simple calculation, it often becomes somewhat complex when there are other factors to consider. For example, if the well is gas-filled with no fluid inside the pipe, $W_b = W_{air}$, and the pipe length to the neutral point is easy to determine. Also, if the well is fluid-filled, as is the pipe, one only needs to calculate the buoyed unit weight of the pipe in pounds per foot using the pipe weight in air times the buoyancy factor (Eq. 4.6).

If there are multiple segments of pipe, some heavier than others, varying fluid densities in the hole and the top portion of the well filled with gas with a fluid level above the neutral point, the calculation becomes more complex. The string length to the neutral point is not known, nor is the length of the submerged pipe segment. Often, an assumption must be made; the buoyed weight of each segment is calculated and added together and compared with the expulsion force, the only known in the equation. The analysis is a segmented pipe analysis with the last segment having an unknown length.

The best way to illustrate these concepts is through several examples.

Example

Determine the neutral point if dry tubing with an OD of 2⅞ in. is being snubbed into a gas-filled well with a surface pressure of 2500 psi. The tubing weighs 7.9 ppf.

From Eq. (4.13) with $B = 0$ (gas-filled hole),

$$L = \frac{p \times (0.7854) OD^2_{pipe}}{W_{air}}$$

$$L = \frac{2,500\,(0.7854) 2.875^2}{7.9}$$

$$L = 2,054\,\text{ft}$$

Example

Using the same information as above, calculate the neutral point if 600 ft. of the tubing was filled with 8.3 ppg water after snubbing it into the hole (note that the capacity of 2⅞ in. 7.9 ppf tubing is 0.2202 gal/ft).

Water volume inside the tubing is $600 \times 0.2202 = 132$ gal.

Water weight for this volume is $132\,\text{gal} \times 8.3\,\text{lb./gal} = 1097\,\text{lb}$.

The expulsion force is partially balanced by this weight, so Eq. (4.13) becomes

$$L = \frac{p \times (0.7854)\, OD^2_{pipe} - \text{fluid weight}}{W_{air}}$$

$$L = \frac{16,230 - 1097\,\text{lb}}{7.9\,\text{ppf}}$$

$$L = 1916\,\text{ft}$$

Example

A well is full of 9.2 ppg brine and has 2000 psi at the surface. A string of 3½ in. 9.3 ppf tubing is being snubbed into the well. While it is going in the hole, the crew fills the tubing with the same 9.2 ppg brine from the tank. Calculate the neutral point.

From Eq. (4.6),

$$BF = \frac{65.5 - MW}{65.5}$$

$$BF = \frac{65.5 - 9.2}{65.5}$$

$$BF = 0.86$$

Eq. (4.13) can be written as follows:

$$L = \frac{p \times (0.7854) OD^2_{pipe}}{W_{air}\, x\, BF}$$

$$L = \frac{2000\,(0.7854)\,3.5^2}{9.3\, x\, 0.86}$$

$$L = 2407\,\text{ft}$$

Example

A decision was made to alter this planned snubbing job by filling the tubing with 8.3 ppg fresh water while it was being run. The ID of 3½ in. 9.3 ppf tubing is 2.992 in.

With one density fluid on the outside of the pipe and a different one on the inside of the pipe, the buoyancy must be determined from Eq. (4.11):

$$B = \frac{\left(MW_o OD_{pipe}^2 - MW_i ID_{pipe}^2\right)}{24.51}$$

$$B = \frac{\left(9.2 \times 3.5^2 - 8.3 \times 2.992^2\right)}{24.51}$$

$$B = 1.57 \text{ ppf}$$

From Eq. (4.13),

$$L = \frac{p \times (0.7854) OD_{pipe}^2}{(W_{air} - B)}$$

$$L = \frac{2000(0.7854)\, 3.5^2}{(9.3 - 1.57)}$$

$$L = 2489 \text{ ft}$$

Example

A well control situation has developed on a drilling well. The pipe string was being pulled for a bit change when a kick was taken. The 600 ft. BHA is still in the hole, and the well is shut in with a surface pressure of 2000 psi. The well is filled with 12.4 ppg drilling fluid. The weight of the BHA in the hole was measured by the rig's weight indicator to be 12,000 lb. The BHA will be snubbed back to the bottom on a string of 4 in. OD, 11.0 ppf tubing. The pipe has an ID of 3.476 in. It will be filled with 8.6 ppg seawater as it is being run. At what bit depth can the snubbing unit operator expect to be at the neutral point?

The buoyed weight of the BHA has already been determined by the rig's weight indicator. This weight can be removed from the expulsion force to determine how much pipe must be snubbed for the bit to reach the neutral point. Buoyancy must be determined for the 4 in. pipe with 10.4 ppg fluid outside the pipe and 8.6 ppg seawater inside the pipe.

From Eq. (4.11),

$$B = \frac{\left(MW_o OD_{pipe}^2 - MW_i ID_{pipe}^2\right)}{24.51}$$

$$B = \frac{\left(12.4 \times 4^2\right) - \left(8.6 \times 3.476^2\right)}{24.51}$$

$$B = 3.86\,\text{ppf}$$

From Eq. (4.13) and reducing the expulsive force by the weight of the BHA,

$$L = \frac{\left(p \times 0.7854 OD_{pipe}^2\right) - 12{,}000\,\text{lb}}{\left(W_{air} - B\right)}$$

$$L = \frac{(25{,}132 - 12{,}000)}{(11.0 - 3.86)}$$

$$L = 1839\,\text{ft}$$

This would be the depth of the end of the 4 in. pipe in the hole at the neutral point, but the BHA is known to be another 600 ft. long. So, the bit depth at the neutral point is actually 1839 + 600 ft. or 2439 ft.

The determination of the neutral point can involve multiple pipe segments and conditions of buoyancy (or the lack thereof), pipe sizes and weights, fluid densities, and other factors. Application of a single formula or rule of thumb can result in an erroneous conclusion, but one such rule of thumb, provided by H.C. Otis , has proven to be fairly accurate. He stated that 1 ft. of pipe of any diameter must be snubbed in the hole to reach the neutral point for every psi of wellhead pressure present on the wellhead. This still works for commonly-used oil field pipe.

Example

A snubbing unit is needed to snub 2⅜ in. 4.7 ppf tubing into a well with 2000 psi surface pressure. The well is filled with 10 ppg brine, and the tubing will be filled with the same brine, while it is being snubbed in the well. What is the neutral point?

The buoyancy factor for 10 ppg brine is 0.8473. From Eq. (4.13),

$$L = \frac{p \times (0.7854) OD_{pipe}^2}{W_{air} \times BF}$$

$$L = \frac{2000\,(0.7854)\,2\tfrac{3}{8}^2}{4.7 \times 0.8473}$$

$$L = 2225\,\text{ft}$$

Example

Using the same well information, assume that 3½ in. 10.2 ppf pipe is to be snubbed into the well:

$$L = \frac{p \times (0.7854) OD_{pipe}^2}{W_{air} \times BF}$$

$$L = \frac{2000\,(0.7854)\,3\tfrac{1}{2}^2}{10.2 \times 0.8473}$$

$$L = 2226\,\text{ft}$$

While admittedly not precise, this rule of thumb provides a reasonable starting point for calculating the neutral point. If the calculations for a common size and weight OCTG show that the neutral point is much higher or lower than this rule of thumb, perhaps the calculations should be run again. For example, in either of the last examples shown, if the calculated neutral point is, say, 5000 ft., there may be a problem with the math.

Note that in all the neutral point calculations, friction is not considered. The neutral point is a position in the wellbore at which the buoyed pipe string weight equals the expulsion force from well pressure acting on the cross-sectional area of the pipe with the pipe stationary in the hole. Because the pipe is not moving, there is no friction involved in this calculation.

4.2.4 **Friction**

Friction robs efficiency. In snubbing, this means that more force is required to do the work than it would in a frictionless system. Of course, there are no frictionless systems in the real world. Some unique systems may approach frictionless conditions, such as a dry-ice puck sliding over a Teflon® surface, but even in these, some friction is still there.

Friction in all well work, but particularly in snubbing, comes from several sources. These are discussed individually below.

4.2.4.1 Snubbing BOPs

A ram-type snubbing BOP has an elastomeric ram packer that closes around the pipe to contain pressure in the well whether the string is pipe-heavy or pipe-light. In some low-pressure jobs, the pipe may be run or pulled through a stripping head or an annular preventer. All of these add friction, and the amount is considerable.

Snubbing/stripping friction is unique to snubbing operations. It is not present in overbalanced or dead well work using a conventional rig although other friction sources are such as pipe-on-wall friction, buckling friction, and fluid friction. BOP friction provides a substantial portion of the friction in snubbing systems, however.

This type of friction is difficult to measure, and it changes with wear on the BOP ram packers and faces. New ram packers produce far more friction of ram packers that have been used and worn for a time. Snubbing friction increases by a considerable factor to somewhere around 40% with the new ram blocks installed.

At the neutral point, the force required to snub pipe into, or pull pipe out of, the hole provides a good approximation of snubbing BOP ram packer friction if pipe-on-wall friction can be calculated. This only applies during the steady-state movement (not during start-up or slowdown). If the jack is moving slowly at the neutral point, the weight and expulsion forces are essentially balanced Static friction and acceleration/deceleration are not acting on the pipe. So, only snubber friction and pipe-on-wall friction are at play on the pipe.

Note that there is still friction inside the jack from piston seal-on-wall and rod-seal friction. These are a relatively constant part of the friction profile. So, the only two added friction forces are pipe-on-wall and snubbing BOP ram packer friction. In most snubbing jobs on vertical wells, this is between 20% and 30% of the total force required to move the pipe.

This friction measurement is just a snapshot in time. With additional snubbing/stripping, the pipe-on-wall friction stays constant, but the snubbing BOP friction continues to decline due to continuing ram packer wear.

Once the ram packers are worn to the extent that they begin to leak a considerable amount of fluid or pressure, one or more safety BOPs are closed, and the snubbing BOP ram blocks are changed out with blocks having new ram packers and seals. The old ram blocks are then redressed by a crewmember with new packers and seals, and the process is repeated each time a set of snubbing BOP rams start leaking again.

4.2.4.2 Pipe-on-Wall Friction

This is the friction generated by the pipe being run into or pulled from the hole as it drags along the inside of the wellbore (uncased hole), casing, liners, or tubing already installed in the well. It includes the friction associated with the pipe rubbing on the bore of any wellhead segments, safety BOPs, spacer spools, pipe guides, and other surface equipment. It does not include the friction of the pipe rubbing on the snubbing BOP ram packers and seals.

This is the same type of friction for all other well operations such as running or pulling drill strings, running casing, running or pulling tubing and completion equipment, and installing production equipment such as power cables for electric submersible pumps (ESPs). It is also found in wireline and coiled tubing operations whether in live or dead wells.

The friction is caused by the pipe rubbing on the low side of the wellbore at the normal weight of the pipe. Pipe-on-wall friction acts along the axis of the pipe in the direction opposite to pipe motion:

$$F_p = W_n \times C_f \times L_p \tag{4.14}$$

where F_p = pipe-on-wall friction, W_n = pipe weight normal (perpendicular) to pipe axis (lb_f/ft), C_f = coefficient of friction, L_p = pipe length in contact with wall (ft).

The coefficient of friction varies depending on the material through which the pipe is moving and the fluid inside the wellbore. The existence of filter cake from drilling operations may provide slightly more or less friction than a clean surface. The following table shows how the coefficient of friction varies depending on the type of surfaces involved (Table 4.2).

Table 4.2 Coefficient of Friction for Various Surfaces

Surfaces	C_f
Water-wet steel	0.30–0.35
Lubricated steel	0.20–0.25
Oil-wet steel	0.15–0.20
Steel on rock	0.40–0.50

Vertical Hole Sections

In vertical holes, the side forces on the pipe, W_n, are very small. No well is completely straight so there is some side force due to gravity on every section of a vertical wellbore. Even at very small deviation angles up to about 10 degrees (vertical = 0 degree), the side forces on a pipe string are negligible, however. Most deviated wells have a vertical section that extends from the surface or mudline to the kickoff point where angle begins to build. Pipe-on-wall friction in this near-vertical hole section is very small.

The length of pipe in contact with the wall, L_p, is an important variable in snubbing operations. External/internal upset drill pipe, external upset tubing (with or without a collar), and nonupset pipe with a collar all have very short pipe contact lengths. The upset holds the pipe body off the wall by "centralizing" it in the hole. Only the upset or collar actually contacts the inner wall of the well whether cased or not. Friction due to side forces is localized on the short length of the upset or collar, not the pipe body (i.e., L_p is very short). So, friction is even further reduced versus that of integral-joint (flush-joint) pipe that rubs along its entire length.

So, in vertical hole sections, the snubbing BOP ram packer friction is the major friction source. Again, it is variable depending on the ram packer wear. The more wear, the less friction.

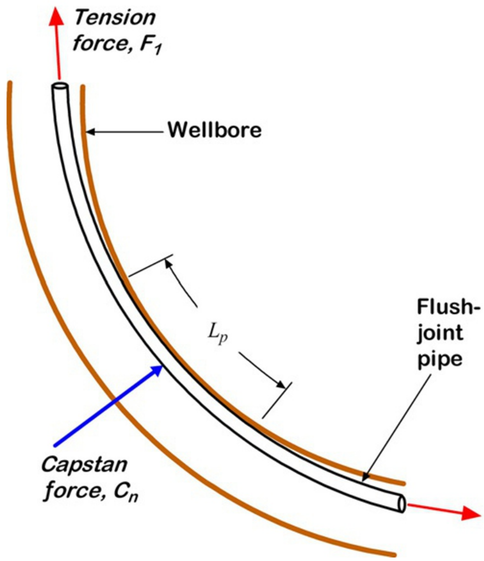
Curved Hole Sections

An additional force is imposed when otherwise straight pipe is forced to bend in a curved hole section. It is often referred to as a capstan force or belt effect, and it is normal to the centerline of the pipe. The vector sum of this capstan force and normal component of the buoyed weight, W_n, provides the total force for calculating friction in the curved hole section.

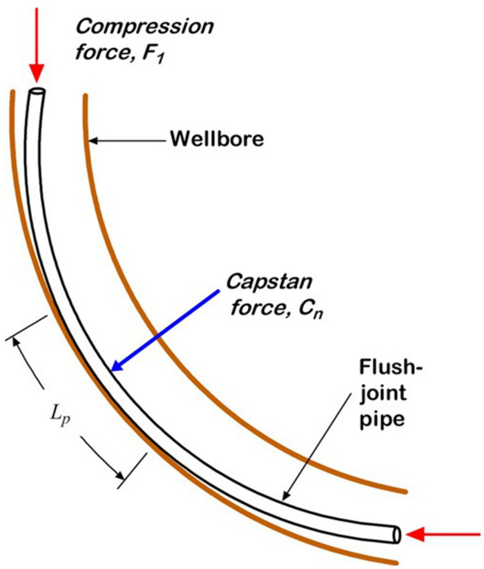
The effect is the same whether the pipe is being pulled in tension around the "high side" curved wellbore section or it is being snubbed under compression against the "low" side of the hole. The only difference is the sign of the normal component of the buoyed pipe weight. There are also calculations for determining the contribution of a change in course, or azimuth, that might accompany a change in deviation angle.

Integral-Joint Pipe. Calculating friction in curved hole sections for integral-joint pipe (i.e., flush-joint pipe without end upsets) is fairly straightforward (Figs. 4.2 and 4.3).

Change in Deviation. The term in the force equation that describes the impact of deviation change is a combination of the simple arithmetic average inclination of the flush-joint pipe segment, α_{avg}, and the local build rate, θ', in radians/unit length:



■ **FIG. 4.2** Curved section with pipe in tension.



■ **FIG. 4.3** Curved section with pipe in compression.

$$C_d = L_p\left[F_1\theta' + (W_b)\sin\alpha_{avg}\right] \tag{4.15}$$

Note that the second term in this equation is the normal force exerted at the average inclination angle due to the buoyed weight of the pipe or W_b.

Change in Azimuth. The contribution of the direction change is described by Eq. (4.15) and involves the local walk rate, or change in azimuth, ϕ', in radians/unit length:

$$C_a = L_p\left(F_1\phi' \sin\alpha_{avg}\right) \tag{4.16}$$

Effective Normal Force. Eq. (4.17) provides an approximation of the effective normal force, C_n, for a "short" segment of flush-joint pipe in a curved wellbore where the total curvature is <1 degree:

$$C_n = \sqrt{\left[C_d^2 + C_a^2\right]} \tag{4.17}$$

Substituting:

$$C_n = L_p\sqrt{\left\{\left[F_1\theta' + (W_b)\sin\alpha_{avg}\right]^2 + \left(F_1\phi' \sin\alpha_{avg}\right)^2\right\}} \tag{4.18}$$

Friction. In curved sections of flush-joint pipe, pipe-on-wall friction is generally higher than in straight sections, regardless of force direction, because the pipe is being bent and forced into the wall. The capstan force, C_n, is generally higher than the normal weight component. The axial force associated with friction from the capstan force is calculated using the same method as inclined or horizontal segments, however:

$$F_p = \left(C_n \times C_f\right)L_p \tag{4.19}$$

Coefficients of friction are the same as those included in Table 4.2.

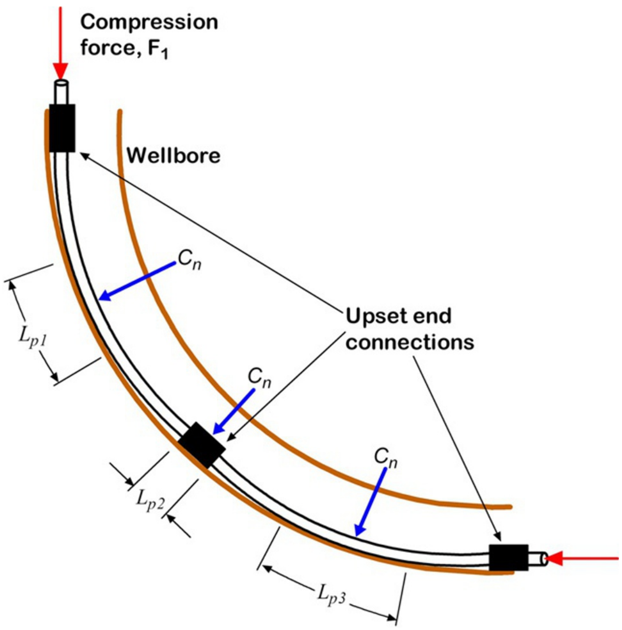
Friction from the capstan force can become very high in hole segment(s) with high dogleg severity especially if there are several doglegs in a relatively short wellbore length. The cumulative effect of friction in each section can provide enough friction to cause lockup and buckling above the doglegged section.

Capstan force friction can also increase rapidly as more pipes are snubbed or stripped below the curved section. The force shown as F_1 in Fig. 4.2 increases with the length of pipe that extends below the curved hole when pipe is going in the hole. Because pipe-on-wall friction below the curve reduces F_1 going in the hole, the pipe usually goes down easily. When the pipe is raised, however, the additional weight combined with pipe-on-wall friction forces the pipe hard against the wall in the curved section resulting in very high C_n values with considerable more friction added to F_1.

Pipe With Upset Ends. Friction calculations in curved hole sections with pipe having upset connections are very complicated. Not only do the connections (upsets or collars) rub against the inside of the well, but also the pipe "sags" between connections and makes contact with the wellbore too (Fig. 4.4).

The contact lengths, L_{p1}, L_{p2}, and L_{p3}, and the normal force along the connection and the sagged pipe sections depend on the flexibility of the pipe and the compression force being exerted on it. These, in turn, depend on the pipe diameter, the amount of hole curvature (the build or drop rate), the walk rate (change in azimuth), and the pipe's material of construction (its stiffness). Also, the capstan force varies along the sagged portion of the pipe in contact with the wall. This force is less where the pipe first contacts and where it lifts off the wellbore wall. It is greater in the middle of the sag.

In short, there are far too many variables to accurately determine the actual force acting normal to the pipe and therefore the friction generated at each point along the curve. It may be more or less than the friction in a curved



■ **FIG. 4.4** Curved section, pipe with upset connections.

hole section for integral-joint pipe depending on contact length and pipe flexibility (i.e., sag).

Inclined Hole Sections

In these hole sections, friction is also generated by the portion of the force that acts normal, or perpendicular, to the pipe centerline. This calculation technique uses a portion of the buoyed weight of the pipe laying on the bottom of the hole.

Integral-Joint Pipe. Fig. 4.5 shows integral-joint pipe laying on the low side of an inclined hole.

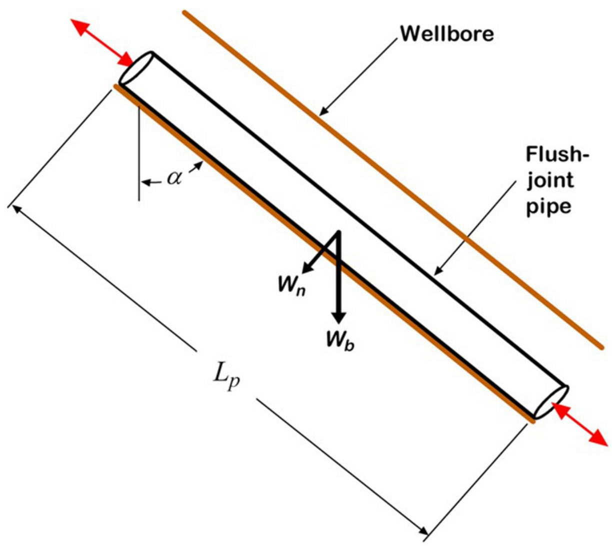
In this diagram, the weight normal to the pipe, W_n, is given by Eq. (4.20):

$$W_n = (W_b) \sin \alpha \tag{4.20}$$

Friction can be calculated from Eq. (4.14) using the same friction coefficients shown in Table 4.2:

$$F_p = W_n \times C_f \times L_p$$

Pipe With Upset Ends. Calculating friction for inclined wells with upset connections is also very difficult because of the number of sources of pipe-to-wall contact. In some situations, where the deviation of the well



■ **FIG. 4.5** Inclined well with integral-joint pipe.

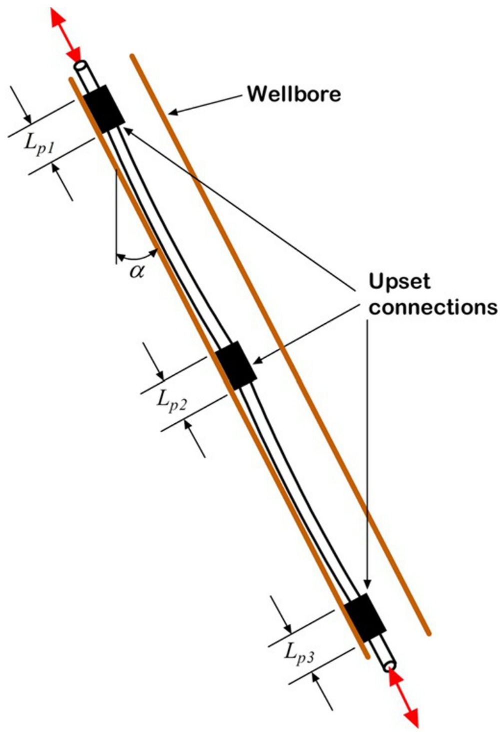


FIG. 4.6 Inclined well, connection contact only.

is low (i.e., almost vertical), the only portions of the pipe string contacting the wall are the upset connections (Fig. 4.6).

In this situation, the entire normal pipe weight, W_n, is supported only by the connections. The contact lengths, L_{p1}, L_{p2}, and L_{p3}, (which may be equal) over which that normal weight contacts the wellbore wall are very short, unlike the situation with flush-joint pipe shown in Fig. 4.5. So, the connections actually behave as bearing surfaces that minimize friction by holding the pipe body off the wall.

Example

A well was drilled to a target and has a straight inclined section with a deviation of 20 degrees (vertical = 0 degree). The well has 1000 psi surface pressure and is filled with gas. The operator does not want to kill the well. A snubbing job is planned, but a decision needs to be made whether to use a 4 in. 9.5 lb/ft integral-joint tubing string or an 11.0 lb/ft rental tubing string with external upset ends (EUE) and collars. At this low deviation, it is doubtful that the EUE tubing will sag between connections and contact the wall. Which work string should be used to minimize friction?

Integral Joint Tubing

Consider a single joint of pipe. A 30 ft. joint of 4 in. 9.5 lb/ft tubing weighs 285 lb_m (30×9.5).

From Eq. (4.20) with $B = 0$, the normal force would be

$$W_n = (W_{air}) \sin \alpha$$

$$W_n = (285) \sin\left(20^\circ\right) = 285 \times 0.342$$

$$W_n = 97.5\ lb_m$$

Friction force, F_p, from Eq. (4.14) with a coefficient of friction, C_f, of 0.325 from Table 4.2 for water-wet steel (there is always a film of water on the inside of a gas-filled well) is calculated:

$$F_p = W_n \times C_f \times L_p$$

$$F_p = 97.5 \times 0.325 \times 30$$

$$F_p = 951\ lb_f$$

External Upset Tubing

Again, consider a 30 ft. span of tubing (half a joint of tubing above the connection and half a joint of tubing below the connection). This 30 ft. span would weigh 330 lb_m (30×11).

Normal force from Eq. (4.20) with $B = 0$ would be

$$W_n = (330) \sin\left(20^\circ\right)$$

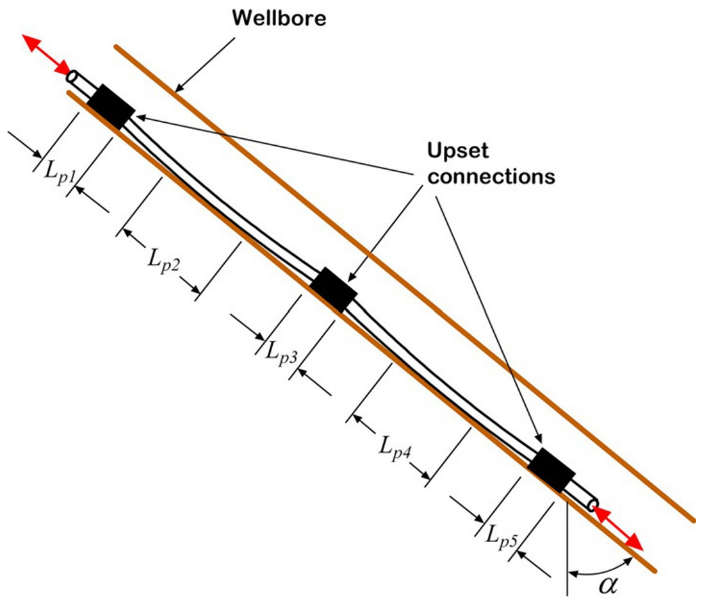
$$W_n = 112.9\ lb_m$$

Because the pipe does not sag and contact the wall between couplings for this pipe, the weight of this 30 ft. span of pipe is supported only by the 6⅛ in. (0.51 ft.)-long coupling rubbing on the inside of the wellbore. Friction force is therefore:

$$F_p = 112.9 \times 0.325 \times (0.51)$$

$$F_p = 18.7\ lb_f$$

Clearly, from this analysis, the decision would be to use the EUE collared tubing to reduce friction even though the pipe weighs more per joint.



■ **FIG. 4.7** Inclined well with both connection and pipe contact.

The same would be true if the pipe did sag between connections in higher deviation straight inclined hole sections. At least part of the normal pipe weight would be supported by the connections even though the pipe is also in contact with wall along part of its length (Fig. 4.7). The portion of the pipe that lifts off the wellbore wall does not generate friction force like flush-joint pipe would do in the same situation.

Horizontal Hole Sections

Horizontal holes are like inclined straight holes, but the entire weight of the pipe is normal (perpendicular) to the centerline of the well. In other words, the deviation angle, α, is 90 degrees and $\sin\alpha = 1$.

From *Eq*. 4–20,

$$W_n = (W_b) \tag{4.21}$$

Friction is calculated from Eq. (4.14) using the same friction coefficients found in Table 4.2.

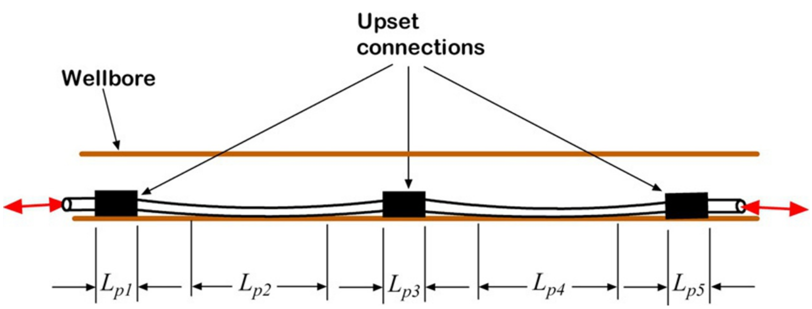
Integral Joint Pipe. Friction when using integral-joint pipe becomes very significant since all the buoyed weight of the pipe acts downward and normal to the well's centerline. This becomes particularly important if the tubular has a heavy weight, like drill collars or heavy-walled tubing. The friction can become so great that it becomes impossible to push the BHA to the bottom of the hole.

Pipe With Upset Ends. This type of pipe is preferred for horizontal wells for several reasons. The upset connections support at least a portion of the buoyed pipe weight along its length. More of the pipe will be in contact with the wellbore wall due to additional sag above that seen in inclined wells because the weight normal to the pipe is greater. Friction is greater than inclined well segments but less than horizontal wells using flush-joint pipe (Fig. 4.8).

In open-hole work, there is a greater tendency for flush-joint pipe to become differentially stuck than with EUE jointed pipe. The pipe lays in a trough in the bottom of the wellbore created both by the curvature of the circular cross section of the hole and the deposition of a layer of filter cake in permeable well sections. The pipe may be turning under the influence of a hydraulic rotary table or power swivel. That rotation must cease each time a connection is made. It is at that point that the differential between the wellbore pressure and formation pressure acting across the filter-cake "seal" around the pipe can cause differential sticking.

In underbalanced flow-drilling operations, this may not be as significant an issue. Here, the differential is in the opposite direction, and differential sticking cannot occur. In other managed pressure operations where surface pressure held on the well replaces hydrostatic pressure from a mud column, differential sticking can still occur if the imposed overbalance is significant.

Hole cleaning becomes an issue in many drilling, recompletion, and workover operations involving horizontal hole segments. Cuttings, scale, and debris will settle to the bottom of the hole in most operations. Mud properties can be adjusted to suspend cuttings during connections, and the rotating pipe can help to stir up the cutting beds. During slide drilling (directional



■ **FIG. 4.8** Horizontal well with both connection and pipe contact.

drilling without pipe rotation), the cutting beds simply build around the pipe if mud properties and flowrate cannot remove them.

Upset jointed pipe has the advantage in that the connections can be pulled or pushed down the hole, with or without rotation, to keep the cutting beds stirred up. This facilitates their removal by the mud that carries them out of the well.

Often, compression forces required to push the pipe to the bottom in any configuration well become so large that the pipe buckles. When the buckling becomes severe, there is additional friction added to the system from the unusual configuration of the pipe in the hole. More wall contact means more friction, so a knowledge of buckling is critical to understanding total friction acting on a pipe string.

4.3 BUCKLING

Buckling involves column theory. Columns have been used to support loads since antiquity. They have been used extensively in ancient buildings going back to the time of the earliest civilizations such as the Egyptians, Greeks, and Romans. Most of these involved brittle column construction with stone being the material of choice. Wooden columns are mentioned in ancient literature that had some flexibility, but they lacked permanence.

Brittle columns under compression can suffer from two distinct buckling failure mechanisms. One is a crushing failure in which the load placed on the column caused it to shorten where crushing took place. Obviously, the crushed section of the column is no longer able to support the load, and the column becomes unusable.

The second buckling failure mechanism was the departure of any portion of the column laterally from its centerline. Brittle materials bend or bow very little before suffering failure. The column simply shears and breaks.

Picture a column made of glass. Heavy loading of the column may cause the glass to deform slightly, but at some point, the glass will shatter. Brittle column bucking failures occur in the same manner. Failure is rapid and permanent.

Ductile materials like metals and plastics do not immediately fail when the compression force exceeds the ability of the column to resist crushing or remain straight. Most ductile materials "bend" or deform differently than brittle materials. They may simply return to their original form when excess force is removed. This is due to their chemical and physical properties.

4.3.1 Stress/Strain Behavior

Ductile materials react to forces applied to them by internally creating resistance to the force. This continues until the force exceeds its ability to resist after which the force deforms the material permanently. This is normally expressed in terms of stress/strain behavior.

Assume that a force is applied to a round column with area A (Fig. 4.9). The force can be a tensile or compressive force. The material will react by changing its length, ΔL, as it builds resistance to the force. The more force, the larger ΔL. These define the stress/strain relationship in the column.

For this diagram, the relationship between force and resistance is given by Eqs. (4.22) and (4.23).

$$\text{Stress}: \sigma = {}^{F}/_{A} \tag{4.22}$$

where σ = stress (force/length^2), F = force (usually lb$_f$), A = effective column area (usually in.^{2}).

Area in this equation is the cross-sectional area of the material resisting the load. For solid columns, the area is the cross-sectional area of the entire column face, πr^2. For hollow columns, it is based on the difference between the outside and inside radii, $\pi(r_o^2 - r_i^2)$.

$$\text{Strain}: \varepsilon = {}^{\Delta L}/_{L} \tag{4.23}$$

where ε = strain (dimensionless), ΔL = change in length due to force (usually in.), L = original length (usually in.).

Most pipes used in the oil field are made from steel. The steel may have a different chemical composition and be heat-treated in a manner that changes its properties, but most steel pipe products share a similar relationship between stress and strain (Fig. 4.10).

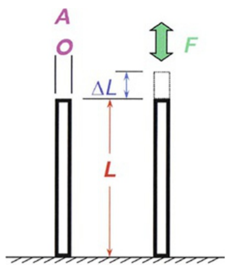
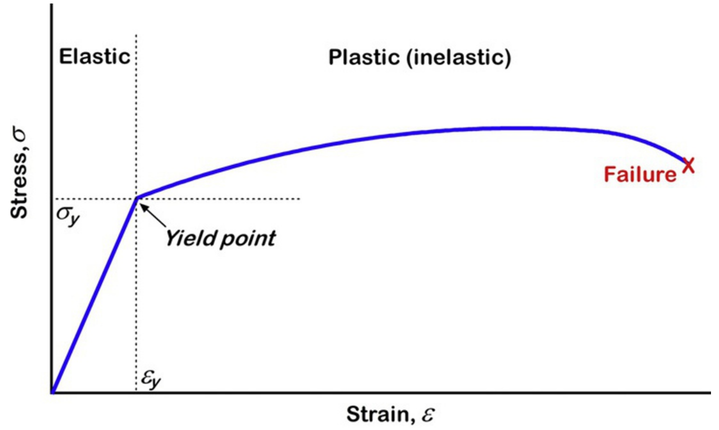


FIG. 4.9 Force diagram on a hollow circular column.



■ **FIG. 4.10** Typical stress-strain diagram.

Starting at the left side, with no stress on the steel, there is no strain. As stress is added, strain increases in a predictable fashion in direct proportion to the stress. If the stress is removed, the strain is reduced proportionately, and the material returns to its original dimensions. This is called the elastic portion of the curve, and it continues until the stress reaches the yield point.

Above the yield point, additional stress does not result in proportional strain development. The material deforms permanently in response as the additional stress "cold-works" the material. Once the stress is removed, the material never returns to its original dimension. So, this area is called the plastic or inelastic deformation region.

This behavior continues until the material begins to "neck down" (in tension) reducing the cross-sectional area of the material until it fails (pulls apart) at the failure point. The stress at this point has not increased appreciably, but the strain has continued to increase as the material is deformed to the point that there is not sufficient cross-sectional area to resist parting.

The precise shape of this curve varies for the material involved. Most steels have similar behavior. Other materials may have completely different stress-strain diagrams. For example, aluminum may have a steeper slope in the elastic region and a longer inelastic region to the failure point. Aluminum is softer than steel, and it is fairly easy to deform. Both the yield point and the failure point have much lower stress values than steel however. Some other materials, like graphite composites, are very flexible and have a very low slope in the elastic region. In fact, there may not be a yield point at all. The material simply behaves elastically until it fails. This makes graphite composites excellent materials for golf club shafts and fishing rods.

The slope of the elastic portion of the stress-strain diagram is important. This is provided by Eq. (4.24):

$$\sigma = \varepsilon E \tag{4.24}$$

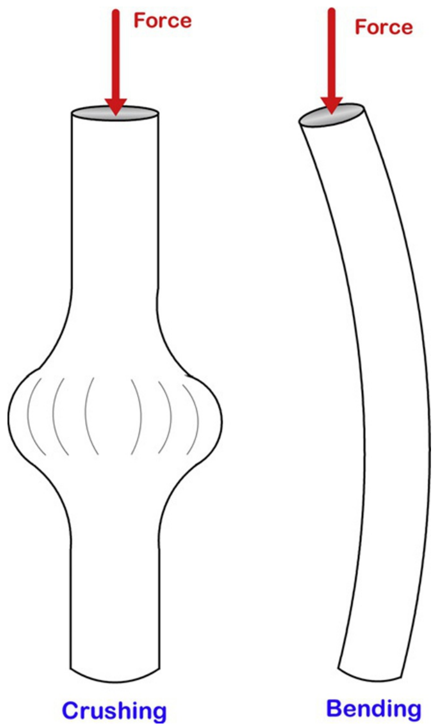
where E = slope of elastic region plot.

The slope of the plot, E, has the same units as stress since strain is dimensionless, force/length^2 (usually lb/in.^{2} or psi). This is also known as Young's modulus of elasticity. For most steels, regardless of the specific grade, $E = (27\text{–}30) \times 10^6$ psi.

4.3.2 Failure Modes

Ductile materials, such as steel pipe, can also buckle in two separate ways. Either type of buckling deformation can be elastic or plastic depending on where in the stress-strain relationship the failure occurs (Fig. 4.11).

Crushing failures under compression in snubbing operations generally involve large-diameter tubulars with thin walls. Some minor "swelling"



■ **FIG. 4.11** Ductile column failure modes.

of the OD may be present that largely remains undetected. This minor dimension change may be elastic, or it may remain in the pipe as an inelastic failure. Generally, crushing failures fall into the inelastic range and may be accompanied by pipe splitting, wholesale parting, and forcing one end of the pipe downward into the other end in a telescoping failure when the pipe body severs. Bending is the more common failure mode for pipe strings in the oil field. Again, the deformations can be elastic or plastic, but they usually fall in the elastic deformation range. Again, buckling is defined as any lateral deviation away from the pipe's centerline.

Buckling only occurs when the string is in compression. The pipe string may be in compression below the wellhead in either snubbing or stripping modes. The string may be pipe-heavy (tension) at the surface and not be buckled. However, it could still be in compression somewhere down the well. Similarly, during snubbing, the pipe is always in compression from the snubbing slips (traveling or stationary) to the BOP holding well pressure. This becomes a part of the analysis of critical snub force and the permissible unsupported length of pipe being snubbed.

Buckling can occur in two general provinces, constrained and unconstrained. Constrained buckling occurs when there is some barrier that restricts the lateral pipe movement (i.e., it only allows the pipe to move so far laterally away from its centerline). For example, if tubing is being run inside casing, it can only bend until it encounters the inner surface of the casing. If casing is being run in a hole, it can buckle only until it encounters the inside wall of the hole.

Unconstrained buckling occurs when there is little to prevent the pipe from buckling until it fails. This can occur at the surface in snubbing operations where there is no guide tube, casing, or hole to keep the pipe from bowing or bending

4.3.3 Unconstrained Buckling

Unconstrained, or unconfined, buckling can occur between the traveling slips and the first point somewhere in the stack where the pipe is held near the center of the stack. This length is known as the "unsupported length."

If some other constraining member is present, such as a telescoping pipe guide, the unsupported length becomes shorter. There will still be some length of unsupported pipe in snubbing operations between the stationary slips and some component of the stack. It is within this length that bending, folding, splitting, and eventual pipe parting can occur if snub force exceeds certain limits.

Similarly, if small-diameter pipe is being run inside a large-diameter casing string or a large wellbore, the effect is the same as unconstrained buckling.

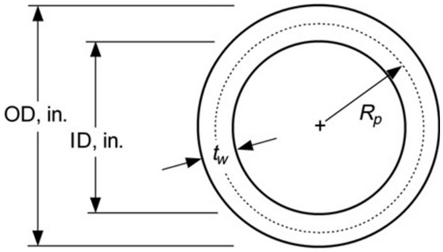


FIG. 4.12 Pipe cross section.

The internal wall is so far removed that the pipe can buckle as though it was not being run inside a constraining wellbore at all.

The key variables in determining the tendency of the pipe to catastrophically buckle in either situation are unsupported length and the net axial force acting on it. Slender column buckling theory determines how much buckling resistance the pipe will exert when placed under a compressive load. These calculations involve critical dimensions of the pipe as shown in Fig. 4.12.

In this diagram, the average pipe radius is defined simply by Eq. (4.25):

$$R_p = \frac{ID + t_w}{2} \tag{4.25}$$

where R_p = average pipe radius (in.), t_w = pipe wall thickness (in.).

Many snubbing service providers use the nominal pipe size and wall thickness for unconstrained buckling calculations. Recall that all manufacturers and API specifications allow tolerances in their pipe manufacturing processes. So, the snubbing companies that use nominal sizes are not considering the worst possible case. They compensate by using a safety factor, usually in the 70% range, to account for these dimensional tolerances when calculating the critical unsupported snubbing force.

A better option is to use the worst-case scenario taking the tolerances in the direction such that the calculated critical unsupported force is at its smallest value and then apply the safety factor. Refer to Table 4.1 for OD tolerances for both tubing and drill pipe. Also, recall that API allows for a wall-thickness variation of ±12.5%. The combination of the smallest OD and the thinnest wall should be used for determining the critical unsupported snubbing force.

Example

New API 3½ in. 9.3 ppf tubing is being run into a hole. What is the average radius of the pipe using both nominal pipe specifications and worst-case dimensions?

Nominal OD for this pipe is, obviously, 3.500 in. The nominal wall thickness is 0.254 in.

Nominal pipe ID is

$$ID_{nom} = OD_{nom} - 2(0.254)$$

$$ID_{nom} = 3.500 - 0.508$$

$$ID_{nom} = 2.992\text{ in.}$$

The pipe average radius using these dimensions can be calculated from Eq. (4.25):

$$R_p = \frac{ID + t_w}{2}$$

$$R_{pnom} = \frac{2.992 + 0.254}{2}$$

$$R_{pnom} = 1.623\text{ in.}$$

Minimum OD for 3½ in. tubing from Table 4.1 is

$$OD_{min} = 3.500 - 0.031 = 3.469\text{ in.}$$

Minimum wall thickness for this pipe allowed by API at −12.5% would be

$$t_{wmin} = t_w(1 - 0.125)$$

$$t_{wmin} = 0.222\text{ in.}$$

Maximum ID for this pipe, also the worst-case condition, would be

$$ID_{max} = OD_{min} - 2(0.222)$$

$$ID_{max} = 3.025\text{ in.}$$

Average pipe radius from Eq. (4.25) would be

$$R_{pmin} = \frac{3.025 + 0.222}{2}$$

$$R_{pmin} = 1.623\text{ in.}$$

While the R_p value remains the same in both cases, the minimum OD, maximum ID, and minimum wall thickness are different. These are critical variables when calculating other properties of the system that ultimately lead to the calculation of the critical buckling load.

The minimum dimensions for any pipe can change along the length of a joint. So, unless every inch of each joint of pipe is measured accurately, there is no way to know if the pipe has nominal dimensions or minimum dimensions considering tolerances. The pipe has all passed inspection at the factory since the tolerances are allowed. The buckling failure will occur at the minimum pipe OD and wall thickness, however. There is one more issue to consider, used pipe.

API does not have specifications for used pipe. So, if the pipe string being snubbed has a smaller OD and wall thickness due to wear or corrosion, internal or external, the calculated critical force for unsupported pipe buckling will also be smaller than that for new API pipe. Using the minimum OD and minimum wall thickness and then applying a generous safety factor will ensure that the upper snub force limit is set low enough to avoid a catastrophic failure. This is, by far, the safer option.

4.3.3.1 Moment of Inertia

Several equations are used to calculate the various loads on the pipe string due to buckling. One of these is the moment of inertia as shown in Eq. (4.26):

$$I = \frac{\pi\left(OD_{pipe}^4 - ID_{pipe}^4\right)}{64} \tag{4.26}$$

where I = moment of inertia, OD_{pipe} = outside diameter of the pipe (in.), ID_{pipe} = inside diameter of the pipe (in.)

Again, for critical buckling force calculations, the worst-case dimensions for the pipe OD and ID should be used including permitted tolerances.

The classic Euler equation is used to calculate buckling forces in most columns. There are limits on the use of the equation. The slenderness ratio is used as an indicator of which calculation should be used.

4.3.3.2 Slenderness Ratio

The general column slenderness ratio divides the distortion of a column of any material into the elastic and inelastic regions of the stress-strain diagram (Fig. 4.9). Slenderness ratio for a column is given by Eq. (4.27):

$$C_c = \pi\sqrt{\frac{2E}{\sigma_y}} \tag{4.27}$$

where C_c = column slenderness ratio (dimensionless), E = Young's modulus of elasticity (psi), σ_y = yield stress (psi).

For steels, Young's modulus of elasticity falls between 27×10^6 and 30×10^6 psi depending on temperature. A value of 29.5×10^6 psi is commonly used for critical buckling force calculations under ambient conditions.

The yield stress value depends on the material from which the item is made. For some steels, this is as low as 40,000 psi (H40 grade pipe). For others, it can be as high as 150,000 psi (V150) and even higher for newer alloys.

Example

Calculate the column slenderness ratio for 3½ in. N-80, 10.3 ppf EUE 8rt tubing that is to be snubbed into a well with 5000 psi surface pressure.

Using Eq. (4.27),

$$C_c = \pi\sqrt{\frac{2E}{\sigma_y}}$$

$$C_c = \pi\sqrt{\frac{2\left(29.5 \times 10^6\right)}{80{,}000}}$$

$$C_c = 85.3$$

Note that in this calculation, neither the weight per foot of the material nor the surface pressure on the well has any impact. The only variables are those having to do with the inherent properties of the steel in the column.

4.3.3.3 Radius of Gyration

The radius of gyration is defined as the resistance of a cross section of any material to bending. In pipes, this involves the walls of the pipe developing the stress necessary to resist deformation either elastically or plastically. The radius of gyration is given by Eq. (4.28):

$$r_g = \sqrt{\frac{I}{A_s}} \tag{4.28}$$

where A_s = steel area (in^2).

From the previous discussion on stress-strain relationships, in hollow columns, the cross-sectional area of steel in a pipe is defined by the differences between the outside and inside radii of the pipe, $\pi(r_o^2 - r_i^2)$, or as shown in Eqs. (4.29) and (4.30):

$$A_s = \frac{\pi\left(OD^2 - ID^2\right)}{4} \tag{4.29}$$

or

$$A_s = 0.7854\left(OD^2 - ID^2\right) \tag{4.30}$$

Obviously, with I (moment of inertia) having units of in.^{4} and A_s having units of in.^{2} and taking the square root of the ratio, r_g has units of in. The magnitudes of both of the components in this equation, I and A_s, depend on the dimensions of the pipe. The variables define the resistance to bending. So, large-diameter thick-walled pipe is less likely to buckle than small-diameter thin-walled pipe. This is what is usually seen in the field. There are a wide range of variations to this rule of thumb. For example, a small-diameter thick-walled pipe may buckle at the same force as a larger-diameter thin-walled pipe. It all depends on the material of construction, the physical dimensions of the pipe, and the effective slenderness ratio of the system.

4.3.3.4 Effective Slenderness Ratio Calculations

There are two methods of determining the effective slenderness ratio. The first is shown in Eq. (4.31):

$$SR_1 = \frac{kL_u}{r_g} \tag{4.31}$$

where SR_1 = effective slenderness ratio (dimensionless), L_u = length of unsupported pipe (in.), k = end connection constant (dimensionless).

The unsupported length of pipe in a snubbing unit is the distance from the top constraining device, usually the traveling slips, and the first constraining device in the unit. Where there is a telescoping pipe guide, this may only be a few inches. If there is no pipe guide, it could be the distance to the top stripping BOP. In some configurations, it could be the exposed pipe in the work window. In any case, it can be easily measured. Generally, the longer the unsupported length, the greater the tendency for the pipe to buckle (from Euler's equation for long-column buckling).

The constant, k, depends on how the pipe is held on each end. Connections can allow lateral displacement and/or rotation. The value of k varies depending on which range of motion is available to the pipe ends. Table 4.3 shows various connection types and values of k.

Table 4.3 *k* Values for Various Conditions

Top End Condition	Bottom End Condition	*k*
Rotation fixed Translation fixed	Rotation fixed Translation fixed	0.65
Rotation free Translation fixed	Rotation fixed Translation fixed	0.80
Rotation free Translation fixed	Rotation free Translation fixed	1.00
Rotation fixed Translation free	Rotation fixed Translation fixed	1.20
Rotation free Translation fixed	Rotation fixed Translation free	2.00
Rotation fixed Translation fixed	Rotation free Translation free	2.2

For other combinations of end connections, there would be other k values. In snubbing operations, a k value of 1.00 is most often used. This implies that the pipe can turn in both the snubbing BOPs, the stripper or the annular, and that the traveling slips can also turn slightly.

Example

A joint of 3½ in. 10.3 ppf N-80 tubing is being snubbed in a well. There is an unsupported pipe length in the snubbing unit of 36 in. Calculate the first effective slenderness ratio using nominal pipe dimensions.

The ID of 3½ in 10.3 ppf tubing is 2.922 in. From Eq. (4.28) and substituting values for I and A_s, the radius of gyration is first calculated:

$$r_g = \sqrt{\frac{\pi/_{64}\left(OD^4 - ID^4\right)}{\pi/_4\left(OD^2 - ID^2\right)}}$$

$$r_g = \sqrt{\frac{\left(3.5^4 - 2.922^4\right)}{16\left(3.5^2 - 2.922^2\right)}}$$

$$r_g = 1.14\,\text{in}$$

Eq. (4.31) can be used to calculate the first effective slenderness ratio assuming a k value of 1.0:

$$SR_1 = \frac{kL_u}{r_g}$$

$$SR_1 = \frac{1.0 \times 36}{1.14}$$

$$SR_1 = 31.57$$

The second effective slenderness ratio can be calculated using different variables (Eq. 4.32):

$$SR_2 = \left(4.8 + \frac{R_p}{225 t_w}\right)\sqrt{\frac{R_p}{t_w}} \tag{4.32}$$

Example

What is the second effective slenderness ratio for 3½ in. 10.3 ppf, N-80, EUE 8rt tubing. Use nominal dimensions.

For this pipe, $t_w = 0.289$ in. and $ID = 2.922$ in. The value of R_p can be calculated from Eq. (4.25):

$$R_p = \frac{ID + t_w}{2}$$

$$R_p = \frac{2.922 + 0.289}{2}$$

$$R_p = 1.6055 \text{ in}$$

The second effective slenderness ratio can be determined from Eq. (4.31):

$$SR_2 = \left(4.8 + \frac{R_p}{225 t_w}\right)\sqrt{\frac{R_p}{t_w}}$$

$$SR_2 = \left(4.8 + \frac{1.6055}{225 \times 0.289}\right)\sqrt{\frac{1.6055}{0.289}}$$

$$SR_2 = 11.37$$

A comparison between the last two examples shows that for the same tubing, the calculated effective slenderness ratio can vary depending on the equation used. The first effective slenderness ratio equation involves the unsupported pipe length. The second does not. If the unsupported pipe length is zero, $SR_1 = 0$. As the unsupported length increases, so does SR_1. Eventually, SR_1 will be larger than SR_2. These relationships can be used to calculate the maximum unsupported length for a system.

The larger of the two effective slenderness ratios must be used to determine the critical buckling force for unconstrained buckling, so both must be calculated.

4.3.3.5 Critical Unconstrained Buckling Force

This is the compressive force applied to the pipe by the snubbing unit that will just initiate buckling. At any force less than this force, the pipe will retain its original shape. At forces greater than this, buckling is initiated and can result in failure.

There are two ways of calculating this force. In *both* of them, the larger value of the effective slenderness ratio, SR_1 or SR_2, must be used.

If SR is **greater** than the pipe slenderness ratio, C_c, Euler-type long-column elastic buckling (bowing) dominates, and the critical force to initiate buckling is given by Eq. (4.33):

$$F_{c1} = A_s\left(\frac{286 \times 10^6}{SR^2}\right) \tag{4.33}$$

where F_{c1} = critical unconstrained buckling force, lb_f, A_s = area of steel, in.^{2}, SR = greater of the values of SR_1 and SR_2.

The second method of calculating the critical buckling force applies when the effective slenderness ratio, SR (i.e., the larger of the values of SR_1 and SR_2), is **less** than C_c. In this situation, local inelastic buckling is the dominant buckling mechanism, and the critical force to initiate this type of buckling is given by Eq. (4.34):

$$F_{c2} = A_s\sigma_y\left(1 - \frac{SR^2}{2C_c^2}\right) \tag{4.34}$$

This equation uses both the column slenderness ratio, C_c, and the effective slenderness ratio, SR, plus the yield stress of the material, σ_y. In the crushing-type failure, the yield strength of the material becomes important. Avoiding this failure mechanism may be as simple as changing out the snubbing string for one with a higher yield strength. Using a string with a larger diameter and a thicker wall can also help.

Example

From data in the last two examples for 3½ in. 10.3 ppf, N-80, EUE 8rt tubing being snubbed into a well with a 36 in. (3 ft.) unsupported pipe length and using nominal dimensions, calculate the critical force to initiate long-column bending in an unconstrained buckling situation.

The area of the steel in this size tubing must be calculated from Eq. (4.30):

$$A_s = 0.7854\left(OD^2 - ID^2\right)$$

$$A_s = 0.7854\left(3.5^2 - 2.922^2\right)$$

$$A_s = 2.915\,\text{in}^2$$

The critical buckling force for this example can be determined using variables calculated in the past two examples and Eq. (4.34) because SR at 31.58 is less than C_c at 84.6:

$$F_c = A_s\sigma_y\left(1 - \frac{SR^2}{2C_c^2}\right)$$

$$F_c = (2.915)80{,}000\left(1 - \frac{31.58^2}{2\times 84.6^2}\right)$$

$$F_c = 216{,}953\,\text{lb}_\text{f}$$

So, at a snub force of 216,953 lb_f, this tubing would start buckling in the unsupported length. It is noted that this is dependent on the yield stress of the tubing. So, changing the string out to a higher-yield-stress pipe, like P110 tubing, would impact the buckling force.

Three means of raising this critical snubbing force value exist:

- Increase the OD of the pipe
- Increase the wall thickness, t_w
- Use a higher-yield-strength pipe

Again, tolerances allowed by API specifications and the manufacturers can reduce the calculated critical force for unconstrained buckling.

Example

Calculate the critical snubbing force for the 3½ in. OD, 10.3 ppf, N-80 tubing shown above using the minimums related to allowed tolerances.

Minimum OD for 3½ in. tubing is 3.469 in. from the previous example (i.e., nominal OD less 1/32 in.). Nominal wall thickness for this pipe is 0.289 in.

First, the minimum wall thickness permitted by API Spec 5CT must be determined by reducing the thickness by the tolerance of −12½%:

$$t_{wmin} = t_w(1 - 0.125)$$

$$t_{wmin} = 0.289(0.875)$$

$$t_{wmin} = 0.2529\,\text{in.}$$

Next, the maximum ID must be determined for the worst-case scenario:

$$ID_{max} = OD_{min} - 2(0.2529)$$

$$ID_{max} = 3.469 - 0.5058$$

$$ID_{min} = 2.963\,\text{in.}$$

The steel area must be calculated from Eq. (4.30):

$$A_s = 0.7854\left(OD^2 - ID^2\right)$$

$$A_s = 0.7854\left(3.469^2 - 2.963^2\right)$$

$$A_s = 2.555\,\text{in.}^2$$

Radius of the pipe must also be determined from Eq. (4.25):

$$R_p = \frac{ID_{max} + t_{wmin}}{2}$$

$$R_p = \frac{2.963 + 0.259}{2}$$

$$R_p = 1.611\,\text{in.}$$

The radius of gyration also uses these minimums:

$$r_g = \sqrt{\frac{{}^{\pi}/_{64}\left(OD^4 - ID^4\right)}{{}^{\pi}/_{4}\left(OD^2 - ID^2\right)}}$$

$$r_g = \sqrt{\frac{\left(3.469^4 - 2.963^4\right)}{16\left(3.469^2 - 2.963^2\right)}}$$

$$r_g = 1.1405\,\text{in.}$$

Values for SR_1 and SR_2 can now be calculated:

$$SR_1 = \frac{kL_u}{r_g}$$

$$SR_1 = \frac{1.0(36)}{1.1405}$$

$$SR_1 = 31.57$$

$$SR_2 = \left(4.8 + \frac{R_p}{225t_w}\right)\sqrt{\frac{R_p}{t_w}}$$

$$SR_2 = \left(4.8 + \frac{1.611}{225x0.2529}\right)\sqrt{\frac{1.611}{0.2529}}$$

$$SR_2 = 12.16$$

Since SR_1 is larger than SR_2, it will be used in the equation for the critical buckling force. From the previous example, C_c was determined for N-80 tubing to be 84.6, which is obviously greater than SR_1 at 31.57. Therefore, long-column inelastic buckling dominates, and the formula for determining the critical force is given by Eq. (4.34):

$$F_{c2} = A_s\sigma_y\left(1 - \frac{SR^2}{2C_c^2}\right)$$

$$F_{c2} = (2.555)80{,}000\left(1 - \frac{31.57^2}{2 \times 84.6^2}\right)$$

$$F_{c2} = 190{,}162\,\text{lb}_\text{f}$$

These calculations are very sensitive to the number of significant digits in the variables. Here, rounding has lowered the calculated value of the critical snubbing force by 6.4% under those generated by a computer that stores up to 16 significant digits. These calculations are obviously more accurate when done on a computer than those done by hand and rounding to just two or three significant digits. In this calculation, the computer-generated value of the critical buckling force is 202,300 lb_f.

Note that the critical force for unconstrained buckling of an unsupported length with tolerances included is less than those using nominal dimensions.

In the last two examples, F_{c2} is 87.6% of the same force using the nominal dimensions for the same pipe (and rounding to three significant digits). Using the nominal dimensions and applying a 70% safety factor leave a **true** safety factor of only 17.6% if a thin-walled, reduced OD section of the tubing is encountered where both tolerances are allowed by API.

That level of safety factor may not be sufficient to protect the personnel, the equipment, the environment, and the well from a catastrophic failure if something unexpected occurs during the snubbing job (such as running into a downhole obstruction while snubbing near the critical force).

It is recommended that critical force calculations be made considering tolerances and *then* multiply the force by a suitable safety factor. This provides ample room between limiting forces to manage unforeseen circumstances. In this last example, the maximum allowable snub force is given by Eq. (4.35):

$$F_{c,\max} = F_{c,\min} \times SF \tag{4.35}$$

where $SF =$ safety factor.

The safety factor can be established at an experience-based level, or it could be related to a particular snubbing job. Most snubbing service providers use a 70% safety factor for routine jobs. If the job involves a toxic gas such as H_2S, the safety factor may be increased. In low-pressure applications, the safety factor might be decreased slightly.

Example

Using the previous example, determine the maximum snub force allowed on the tubing assuming a 70% safety factor:

$$F_{c,\max} = 190,243\ \text{lb}_f \times SF$$

$$F_{c,\max} = 190,243 \times 0.70$$

$$F_{c,\max} = 133,170\ \text{lb}_f$$

On the jobsite, the release control on the power fluid circuit would be set to deliver a pressure no greater than what would be necessary for the snubbing unit to provide this force depending on cylinder diameter, number of cylinders, and pressure losses through the power fluid piping. It should be recalled that this force is acting above the BOP stack, so snubbing friction, usually 25%–30% of the snub force, is added to the theoretical snub load necessary to push pipe into the well against wellhead pressure.

Setting the maximum pressure to provide this safe snub load at the power-pack prevents the operator from intentionally or accidentally increasing the pressure exceeding the maximum safe snub load. It is an operational safety control that is difficult to defeat. If the load needed to snub pipe in the hole exceeds the pressure associated with this safe maximum snub load, the unit simply stalls out and cannot move.

If the critical force is exceeded, the pipe may begin to bow in the unsupported length of the pipe and displace laterally out of the snubbing unit. If the force is increased somehow or if any of the variables change, even slightly, there is the very real chance that bowing cannot be stopped and the pipe will fold, shear, and break in a catastrophic failure. Obviously, this would all occur in or just below the work basket placing operating personnel in grave danger very quickly.

4.3.3.6 Unsupported Length

The maximum unsupported pipe length can be determined using these same equations as a function of geometry and maximum snub force. This can be done mathematically or graphically.

Note that from the formula for SR_2 (Eq. 4.32), repeated here, it is independent of unsupported length but relies only on the pipe geometry:

$$SR_2 = \left(4.8 + \frac{R_p}{225t_w}\right)\sqrt{\frac{R_p}{t_w}} \tag{4.32}$$

However, the formula for SR_1 shown in Eq. (4.31) is directly proportional to unsupported length:

$$SR_1 = \frac{kL_u}{r_g} \tag{4.31}$$

At low values of L_u, starting at zero, SR_1 remains smaller than SR_2, so the value of SR in the calculation of the critical buckling force for unsupported pipe is the value of SR_2. The unsupported length value increases to the point that SR_1 is greater than SR_2; then, the value of SR_1 becomes the larger of the two and becomes the value of SR. After that point, it is possible to back into the value of the unsupported length and the value of the critical snubbing load for unconstrained buckling. So, by equating SR_1 and SR_2 and solving for L_u, the point at which unsupported length becomes dominant can be determined:

$$L_u = \frac{r_g}{k}\left[\left(4.8 + \frac{R_p}{225t_w}\right)\sqrt{\frac{R_p}{t_w}}\right] \tag{4.36}$$

Note that the right side of this equation depends only on the geometry of the pipe and not on its metallurgical properties such as minimum yield strength.

Graphically, this can be done by preparing a table of values that relate unsupported length to critical snub force. Then, the actual snub force required can be entered to determine the allowable unsupported length for that force. This is shown in the following example.

Example

For 3½ in. 9.3 ppf, N-80, EUE 8rt tubing, determine the maximum unsupported length if the maximum snub force for a particular job is calculated to be 66,000 lb_f using minimum dimensions and including a 70% safety factor.

Prepare a table of critical snubbing force using Eqs. (4.33) and (4.34) at various values of unsupported length, L_u.

Using data calculated from previous examples (recall that $C_c = 84.6\ lb_f$), prepare a table of critical snub loads versus unsupported lengths for this tubing string (Table 4.4).

From these tabulated data, it is clear that the longer the assumed unsupported length, the lower the permissible maximum critical buckling force. Note that between 96 and 102 in, the buckling regime goes from local inelastic to long-column elastic buckling as the value of *SR* becomes greater than the column slenderness ratio, C_c. When the calculated critical buckling force, F_{c2}, becomes negative, the data are meaningless. It is shown here to describe how the equations work at high unsupported pipe lengths.

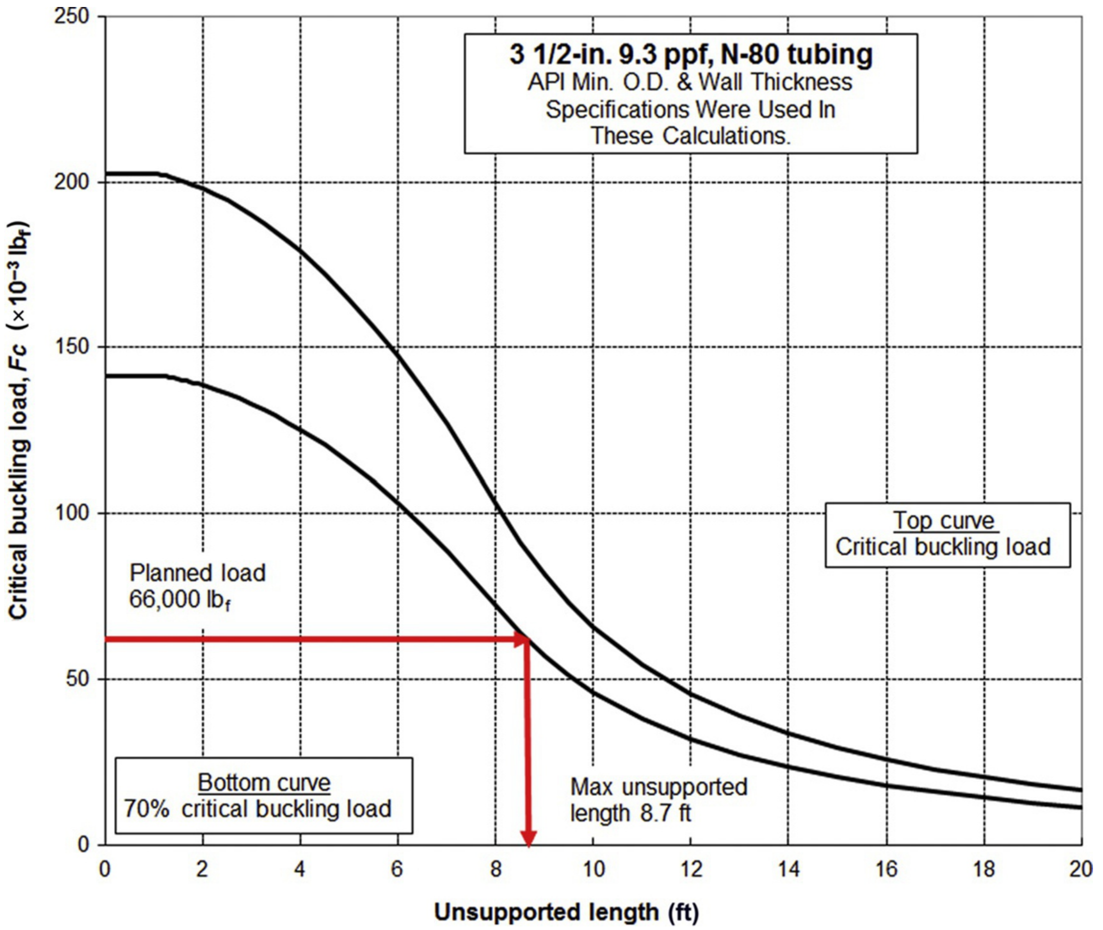
These data can be plotted after converting the unsupported length to feet to show how critical buckling load varies with unsupported length (Fig. 4.13).

This serves as a good example of how the tabular and graphic techniques work for field operating personnel. Note that the permissible unsupported length can be interpreted from the table or obtained directly from the plot. In this example, a maximum desired snub force of 66,000 lb_f relates to a permissible unsupported pipe length of 8.7 ft. using the lower curve, 70% of the critical load curve, and taking into account tolerances permitted by API.

Table 4.4 Critical Buckling Forces and Unsupported Lengths

L_u (in.)	SR_1 (in.)	SR_2 (in.)	SR (in.)	F_{c1}*	F_{c2}*	F_c*	70% F_c*
0	0.00	12.18	12.18	4929.2	202.3	202.3	141.6
1	0.88	12.18	12.18	4929.2	202.3	202.3	141.6
3	2.63	12.18	12.18	4929.2	202.3	202.3	141.6
6	5.26	12.18	12.18	4929.2	202.3	202.3	141.6
12	10.52	12.18	12.18	4929.2	202.3	202.3	141.6
18	15.78	12.18	15.78	2933.3	200.8	200.8	140.6
24	21.04	12.18	21.04	1650.0	198.1	198.1	138.6
30	26.30	12.18	26.30	1056.0	194.5	194.5	136.2
36	31.57	12.18	31.57	733.3	190.2	190.2	133.1
42	36.83	12.18	36.83	538.8	185.0	185.0	129.5
48	42.09	12.18	42.09	412.5	179.1	179.1	125.4
54	47.35	12.18	47.35	325.9	172.4	172.4	120.7
60	52.61	12.18	52.61	264.0	164.9	164.9	115.4
66	57.87	12.18	57.87	218.2	156.6	156.6	109.6
72	63.13	12.18	63.13	183.3	147.5	147.5	103.2
78	68.39	12.18	68.39	156.2	137.6	137.6	96.3
84	73.65	12.18	73.65	134.7	126.9	126.9	88.8
90	78.91	12.18	78.91	117.3	115.4	115.4	80.8
96	84.17	12.18	84.17	103.1	103.2	103.2	72.2
102	89.43	12.18	89.43	91.3	90.1	91.3	63.9
108	94.70	12.18	94.7	81.5	76.3	81.5	57.0
114	99.96	12.18	99.96	73.1	61.7	73.1	51.2
120	105.22	12.18	105.2	66.0	46.3	66.0	46.2
132	115.74	12.18	115.74	54.5	13.1	54.5	38.2
144	126.26	12.18	126.26	45.8	−23.3	45.8	32.1
156	136.78	12.18	136.78	39.1	−62.9	39.1	27.3
168	147.30	12.18	147.30	33.7	−105.5	33.7	23.6
180	157.83	12.18	157.83	29.3	−151.4	29.3	20.5
192	168.35	12.18	168.35	25.8	−200.4	25.8	18.0
204	178.87	12.18	178.87	22.8	−252.5	22.8	16.0
216	189.39	12.18	189.39	20.4	−307.9	20.4	14.3
228	199.91	12.18	199.91	18.3	−366.4	18.3	12.8
240	210.44	12.18	210.44	16.5	−428.0	16.5	11.5

* *Forces in* $lb_f \times 10^3$.



■ **FIG. 4.13** Critical load versus unsupported length for 3½ in. tubing.

4.3.4 Constrained buckling

There are two types of constrained buckling associated with running pipe of any kind into a well under compressive loading, sinusoidal and helical. In this type of buckling, the pipe can only travel laterally so far; then, it is constrained by some barrier such as tubing, casing, liner, or the inside wall of the wellbore itself. The first buckling mechanism, sinusoidal buckling, can occur at relatively small loads. Under heavier loads, the sinusoidal buckling advances into helical buckling.

At some point in helical buckling, pipe-on-wall friction (drag) becomes so great that the pipe cannot advance into the hole. This point is called lockup, and it can become problematic while snubbing small-diameter pipe into a well, particularly horizontal hole segments.

The pipe string shortens with both types of buckling. The degree of buckling and the consequential shortening of the string are based on the diameter of the pipe string and the size of the hole in which the pipe is being snubbed/stripped. If the hole diameter is small, buckling can occur, but a smaller-diameter hole limits the distance the pipe can deviate from its centerline.

In constrained buckling, the lateral distance the pipe can travel before reaching the inside wall of the hole is important. If the pipe is tightly constrained, the jump from sinusoidal to helical buckling is delayed. The pipe may never fully reach a helix in some configurations. This relationship is given by Eq. (4.37):

$$r_c = \frac{ID_{hole} - OD_{pipe}}{2} \tag{4.37}$$

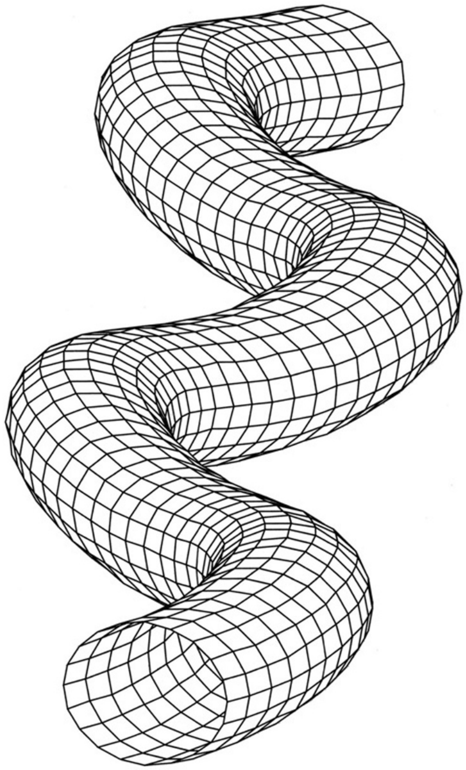
where r_c = clearance radius, in., ID_{hole} = inside diameter of the wellbore, in., OD_{pipe} = outside diameter of the pipe, in.

4.3.4.1 Sinusoidal buckling

Sinusoidal buckling occurs when the downward force on the pipe at a given point places that portion of the pipe in compression. It can occur anywhere in the string. So, the string can be pipe-heavy (in tension) at the surface and in compression down the hole somewhere. The compressive force causes the pipe to fold into a shape such that it touches the inner wall of the well. It may not extend all the way across the hole to contact both sides, but eventually, it advances to this state. When it does, the pipe-on-wall contact points are 180° apart, and the sinusoid is all in single plane forming a "snake" shape (Fig. 4.14).

Friction is generated at each point where the pipe contacts the wall over the buckled section. These points are spaced according to the period of the sine wave (the distance between contact points on the same side of the well).

Sinusoidal buckling occurs at very low compressive loads. Side forces are minimal, and because the pipe only contacts the wall at individual points, often along only one side of the wall, additional friction generated by this type of buckling is minimal. If flush-joint pipe is being run into the well (i.e., the only time there would be a net compressive force on the pipe), the friction due to sinusoidal buckling is less than the pipe lying on the low side of the hole with no buckling.



■ **FIG. 4.14** Sinusoidal buckling. (Courtesy of Watters.)

In many operations where pipe is run at an economically viable speed, sinusoidal buckling is considered to be the normal mode of operation. Because friction from this type of buckling is so small relative to other sources of friction in snubbing/stripping operations, it is often ignored. Buckled pipe can still transmit force to the BHA to a point. This is important during certain HWO and snub drilling operations.

Once the axial compression force is relaxed, the buckling ceases, and the pipe straightens out. All sinusoidal buckling occurs in the elastic portion of the stress-strain relationship. If the string experiences additional compression, the pipe configuration quickly changes from sinusoidal to helical.

The critical sinusoidal buckling force, F_{cs}, can be described by some fairly straightforward equations. This force in a curved hole section is more complex to describe, however.

Straight Hole Segments

Vertical Holes. The critical sinusoidal buckling force, or limit, for a vertical straight hole segment approaches the common Euler equation as shown by Eq. (4.38):

$$F_{cs} = EI\left(\frac{\pi}{L_s}\right)^2 \tag{4.38}$$

where E = Young's modulus of elasticity (psi), I = moment of inertia (in.^{4}), L_s = pipe segment length (in.).

In this equation, the product of Young's modulus of elasticity and the moment of inertia, often called the bending stiffness product or EI, is a measure of the flexural rigidity of the pipe. Young's modulus is about 29.5×10^6 psi for steel pipe. The moment of inertia described by Eq. (4.26) can be written as shown in Eq. (4.39):

$$I = \frac{\pi\left[OD_{pipe}^4 - \left(OD_{pipe} - 2t_w\right)^4\right]}{64} \tag{4.39}$$

where OD_{pipe} = outside diameter of pipe (in.), t_w = pipe wall thickness (in.).

Again, it is important to recall that API specifications and most manufacturers allow tolerances for certain dimensions in oil field pipe. Where these tolerances could impact buckling, the worst-case combinations of dimensions should be used. For example, if wall thickness and outside pipe diameter are critical to the determination of a buckling force, the thinnest wall and smallest outside diameter should be used in the calculation, not the nominal figures for each.

In 1950, Arthur Lubinski developed an equation for dealing with the critical sinusoidal buckling load in drill pipe in vertical wellbores shown in Eq. (4.40):

$$F_{cs} = 1.94\sqrt[3]{EIW_b{}^2} \tag{4.40}$$

Later, in 1993, Wu developed a relationship based on an energy balance model that has the same form but predicts slightly higher values (Eq. (4.41)):

$$F_{cs} = 2.55\sqrt[3]{EIW_b{}^2} \tag{4.41}$$

The difference between the two equations is insignificant in oil field operations. The critical sinusoidal buckling force for most pipes in vertical or near-vertical wells (up to about 15 degree inclination) is very low. Measured data show that sinusoidal buckling begins at a compressive load on the order of 2000 lb_f, a value that is quite small in most field operations.

Example

A string of 5 in., 19.5 ppf drill pipe is being snubbed into an 8½ in. hole filled with 15.8 ppg mud. The pipe is being filled with mud while it is being snubbed in the hole. The actual weight of the pipe in air including connections is 20.85 ppf. The drill pipe has an ID of 4.276 in. At what compressive force downhole will the pipe first begin buckling?

Initial buckling will be sinusoidal buckling due to pipe-on-wall friction somewhere in the wellbore. First, the buoyed weight of the pipe must be calculated:

$$BF = \frac{65.5 - MW}{65.5}$$

$$BF = \frac{65.5 - 15.8}{65.5}$$

$$BF = 0.759$$

Buoyed weight of the pipe is

$$W_b = W_{air} \times BF$$

$$W_b = 20.85 \times 0.759 = 15.82\,\text{ppf}$$

$$W_b = 1.318\,{}^{\text{lb}_\text{f}}/_{\text{in.}}$$

Next, the moment of inertia must be determined from the pipe dimensions using Eq. (4.39):

$$I = \frac{\pi\left(OD_{pipe}^4 - ID_{pipe}^4\right)}{64}$$

$$I = \frac{\pi\left(5^4 - 4.276^4\right)}{64}$$

$$I = 14.269\,\text{in.}^4$$

Using Lubinski's equation (4.40), the "critical" force to induce sinusoidal buckling can be calculated:

$$F_{cs} = 1.94\sqrt[3]{EIW_b{}^2}$$

$$F_{cs} = 1.94\sqrt[3]{29.5 \times 10^6 \times 14.269 \times 1.318^2}$$

$$F_{cs} = 1{,}748\ \mathrm{lb_f}$$

Inclined Holes. The critical sinusoidal buckling force for inclined straight segments above about 15 degree inclination was derived by work from the early to mid-1980s by several researchers. It includes a term to account for the nominal force exerted by the weight of the pipe against the conduit wall. The equation describing this limit is shown by Eq. (4.42). This equation has been verified by laboratory experiments:

$$F_{cs} = 2\sqrt{\frac{EI \times (W_b)\sin\alpha}{r_c}} \tag{4.42}$$

where W_b = buoyed weight of the pipe (ppf), α = hole inclination angle (degrees, vertical = 0 degree), r_c = radial clearance (in.).

In this equation, $(W_b)\sin\alpha$ is the component of the pipe weight acting on the inside wall of the conduit, or W_n (Fig. 4.5). Until this compressive force is reached, the pipe will remain straight in the hole.

The critical sinusoidal buckling force in an inclined well is higher than the same force in a vertical or near-vertical well because the low side of the hole forms a trough that resists the displacement of the pipe from its straight configuration. The normal force tends to keep the pipe in the trough. Also, the curving walls of the well form an elastic restraint. Both of these tend to delay the onset of buckling.

Work done by Mitchell in 1995 indicates that the pipe will stay in sinusoidal buckling until a larger compressive force results in the initiation of helical buckling. The problem Mitchell found was that there are not clearly defined boundaries at which one form of buckling or the other begins or ends. There are transitions between each. His work determined that the pipe will remain in sinusoidal buckling mode before the transition to helical buckling as long as the compressive force stays below the value as shown in Eq. (4.43):

$$F_{cs} = 2\sqrt{\frac{2EI \times (W_b)\sin\alpha}{r_c}} \tag{4.43}$$

By simplifying, this equation becomes *Eq.* 4.44:

$$F_{cs} = 2.83\sqrt{\frac{EI \times (W_b) sin\alpha}{r_c}} \tag{4.44}$$

This closely resembles the work done independently and published by He, also in 1995. His estimation of this maximum compressive force for sinusoidal buckling before the pipe transitions into helical buckling is given by Eq. (4.45):

$$F_{cs} = 3.75\sqrt{\frac{EI \times (W_b)\sin\alpha}{r_c}} \tag{4.45}$$

Again, in the low ranges of compressive force needed to sustain sinusoidal buckling, the difference between these two equations is insignificant.

Example

Using the same straight hole, pipe, and fluid properties in the previous example, determine the "critical" buckling force to initiate sinusoidal buckling if the well has a 40 degree deviation.

For this analysis, the clearance radius must be calculated using Eq. 4.37:

$$r_c = \frac{ID_{hole} - OD_{pipe}}{2}$$

$$r_c = \frac{8½ - 5}{2}$$

$$r_c = 1.75\ \text{in.}$$

From Eq. (4.42), the critical buckling force to initiate sinusoidal buckling in a straight inclined well can be calculated:

$$F_{cs} = 2\sqrt{\frac{EI \times (W_b)\sin\alpha}{r_c}}$$

$$F_{cs} = 2\sqrt{\frac{29.5 \times 10^6 \times 14.269(1.318)\sin(40)}{1.75}}$$

$$F_{cs} = 28{,}550\ \text{lb}_\text{f}$$

Using Eq. (4.44), the force predicted by Mitchell's work to *maintain* sinusoidal buckling before the pipe transitions into helical buckling is somewhat higher:

$$F_{cs} = 2.83\sqrt{\frac{EI \times (W_b)\sin\alpha}{r_c}}$$

$$F_{cs} = 40,399\ \mathrm{lb_f}$$

If He's equation is used (Eq. 4.45), the stable sinusoidal buckling force is even higher:

$$F_{cs} = 3.75\sqrt{\frac{EI \times (W_b)\sin\alpha}{r_c}}$$

$$F_{cs} = 53,532\ \mathrm{lb_f}$$

Comparing this result with the previous example shows that the axial compression force necessary to initiate sinusoidal buckling is considerably greater in inclined holes than in vertical holes. The reason is that the normal component of the pipe weight is bearing into the hole wall preventing the pipe from lifting off the wall forming the sinusoid.

Horizontal Holes. Eq. (4.42) for straight inclined hole segments reduces to Eq. (4.46) for a horizontal hole segment:

$$F_{cs} = 2\sqrt{\frac{EI \times W_b}{r_c}} \tag{4.46}$$

As α approaches 90 degrees, sin α approaches a value of 1. So, instead of a fraction of the buoyed pipe weight applying normal to the centerline of the pipe, all the buoyed pipe weight is acting downward.

Again, this downward weight tends to hold the pipe on the bottom of the hole. The elastic restraint due to the round pipe lying in the trough combines with this weight, and both resist the onset of sinusoidal buckling. The result is that more compressive axial force is required to cause the pipe to form the sine wave shape.

Example

Using the information on pipe and hole sizes, wellbore diameter, and mud density used in the previous two examples, what is the critical axial force required to initiate sinusoidal buckling in a straight horizontal hole section?

Using Eq. (4.46) and substituting variables previously calculated in the last two examples, the critical sinusoidal buckling force can be determined:

$$F_{cs} = 2\sqrt{\frac{EI \times W_b}{r_c}}$$

$$F_{cs} = 2\sqrt{\frac{29.5 \times 10^6 \times 14.269(1.318)}{1.75}}$$

$$F_{cs} = 35{,}610\,\mathrm{lb_f}$$

The compressive force to maintain sinusoidal buckling in a horizontal hole using Mitchell's work is given by Eq. (4.44) modified by substituting $\sin\alpha = 1$:

$$F_{cs} = 2.83\sqrt{\frac{EI \times (W_b)}{r_c}}$$

$$F_{cs} = 50{,}389\,\mathrm{lb_f}$$

The same force using He's analysis, Eq. (4.45), shows a slightly higher value after modification for use in a horizontal hole:

$$F_{cs} = 3.75\sqrt{\frac{EI \times (W_b)}{r_c}}$$

$$F_{cs} = 66{,}769\,\mathrm{lb_f}$$

Comparing these results to the same calculation for a straight inclined hole shows that a higher axial compressive force is required to initiate and maintain sinusoidal buckling because all the pipe weight is now normal to the pipe centerline, not a component of it.

Curved Hole Segments

In a curved hole section where the pipe string is in compression, the net compressive force tends to push the pipe into the curve with normal force, C_n (see Figs. 4.2–4.4). This replaces the buoyed weight term in the equation for straight hole segments. The mathematical treatment of this configuration introduces several variables that are not present in the less complicated equations for buckling in a straight hole segment.

Buckling in a curved hole section will not easily occur due to two unique effects:

1. The lateral or normal component of axial compression along the length of the curve tends to keep the pipe pushed against the wellbore suppressing buckling and lifting of the pipe off the wall. Recall that the capstan force, C_n, is due to the pipe being bent around the curve. This bending resists buckling.
2. The wellbore surface is longer on the outside of the curve than it is on the inside. Buckling is suppressed due to the added length of the outside curved surface. In fact, higher-order buckling calculations are required to compensate for this additional length.
   Like horizontal buckling, there is also an elastic effect of the pipe adhering (i.e., trying to "stick") to the trough created by the curved surface of the well segment. So, it is more difficult to buckle the pipe in a curved section than in any straight section of the wellbore with same ID.
   The net compressive force, F_1, is the force applied downward with the base of the segment anchored. The effective normal force, C_n, includes the effects of a deviation change coupled with a change in azimuth (Eq. 4.18).
   Qui et al. (1998) determined the critical sinusoidal buckling limit equation for curved hole segments based on prior work as shown in Eq. (4.47):

$$F_{CC} = \frac{2EI}{r_c R}\left(1+\sqrt{1+\frac{W_b \sin \alpha_{avg} r_c R^2}{EI}}\right) \tag{4.47}$$

   where R = borehole radius of curvature (in.).
   Experimental data showed that this was the point at which the sinusoidal buckling would just be initiated. With even minor reductions of this "critical" force, the buckling would collapse, and the pipe would once again lie along the inside wall.
   Eq. (4.47) was later modified by Qui to determine a force at which the sinusoidal buckling would remain stable in a curved hole section until the critical helical buckling force was reached at which time the sinusoid would flip into a helix (Eq. 4.48):

$$F^*_{cc} = \frac{(2\times 3.52)EI}{r_c R}\left(1+\sqrt{1+\frac{W_b \sin \alpha_{avg} r_c R^2}{3.52\,EI}}\right) \tag{4.48}$$

   where $F_{cc}{}^*$ = axial compression force needed to maintain a maximum stable sinusoidal configuration (lb_f).

This second equation shows that there is a transition between the initiation of sinusoidal buckling and the jump to helical buckling. The stabilized sinusoidal configuration adjustment provides an estimate of the higher forces involved in maintaining the sinusoid.

Example

Using the same pipe, hole, and fluid data as in the last three examples, calculate the critical axial force necessary to initiate sinusoidal buckling of the pipe in a curved hole section if the well's radial curvature is 1000 ft. and the average inclination at the point of calculation is 40 degrees.

From Eq. (4.47) as modified by Qui et al. (1998), the axial force necessary to initiate sinusoidal buckling can be calculated:

$$F_{CC} = \frac{2EI}{r_c R}\left(1 + \sqrt{1 + \frac{W_b \sin \alpha_{avg} r_c R^2}{EI}}\right)$$

$$F_{CC} = \frac{(2)29.5 \times 10^6 (14.269)}{1.75 \times (1000 \times 12)}\left(1 + \sqrt{1 + \frac{1.318 \sin(40) \times 1.75 \times (1000 \times 12)^2}{420.9 \times 10^6}}\right)$$

$$F_{CC} = 40{,}089\left(1 + \sqrt{1.507}\right)$$

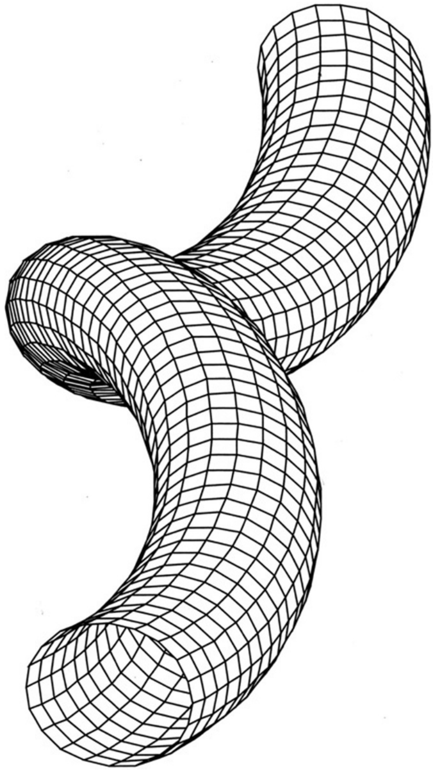
$$F_{CC} = 89{,}306\ \mathrm{lb_f}$$

While these equations show that there is a compressive force that will initiate sinusoidal buckling in a sharply curved hole segment, that force is so high that the pipe would likely already be in helical buckling above the curved section (and probably below it, as well).

4.3.4.2 Helical Buckling

When drag becomes high at a given axial force, the pipe assumes a helical (corkscrew) shape with the pipe exterior in contact with the well interior at all points along the helix (Fig. 4.15).

The stable sinusoidal buckling configuration persists until a compressive force is reached at which time the sinusoid rolls into a helix or corkscrew shape. As even more compressive force is applied, the normal force exerted on the walls of the conduit increases rapidly (with the square of the force). Each 360 degree wrap or period of the helix becomes tighter and more



■ **FIG. 4.15** Helical buckling. *(Courtesy of Watters.)*

closely spaced until the helix generates so much drag that any additional compressive force fails to reach the end of the pipe string, the length of the helix grows, and more pipe-on-wall friction is generated. Ultimately, the helical "spring" becomes so long and tight that all further downward motion at the pipe end ceases at a point known as lockup.

Even under this condition when the helix has just formed or only has a few coils developed, the helically buckled pipe can still transmit a certain amount of force to the bottom of the string.

This type of buckling also remains in the elastic region of the stress-strain relationship of the pipe except under extreme conditions like dropping the pipe string to the bottom. In that unhappy incident, the bottom portion of the pipe may be permanently "corkscrewed."

The period of the helix becomes important in two ways. It is defined in Eq. (4.49):

$$\sigma = 2\pi\sqrt{\frac{2EI}{F_e}} \tag{4.49}$$

where σ = period of the helix, F_e = effective force at a given point.

The effective force, F_e, in this simplified equation is just another name for buoyant weight of the pipe string above the helix. It corresponds to the surface weight of the pipe while at rest.

The period of the helix (i.e., the distance between two points that describe a 360 degree twist inside the wellbore) becomes smaller as the effective force increases. So, as additional pipe weight or pull-down force provided by the snubbing unit is applied, the helix becomes tighter (i.e., the period shorter), and pipe-on-wall friction becomes even greater.

Anytime pipe is buckled, the string becomes shorter. The change in string length is described by Eq. (4.50):

$$\triangle L_h = L\left\{\left[\sqrt{\frac{2\pi r_c}{\sigma}+1}\right]-1\right\} \tag{4.50}$$

where ΔL_h = change (shortening) in pipe due to helical buckling, L = length of pipe in the hole, r_c = clearance radius, σ = period of the helix.

The force at which helical buckling is initiated is also known as a critical helical buckling force. Here, the subscript CH denotes the force at which helical buckling is initiated. There are separate relationships for each wellbore configurations and segment lengths.

Straight Hole Segments

As with the sinusoidal buckling lower limit, there are several complex models used to describe the critical helical buckling force. The relationships included here are simpler and approximate observed in helical buckling behavior in laboratory experiments.

Vertical Holes. An energy analysis is used to predict the occurrence of helical buckling in vertical wellbore segments. The relationship is shown by Eq. (4.51):

$$F_{CH} = 5.55\sqrt[3]{EIW_b^2} \tag{4.51}$$

A comparison of this equation to Eqs. (4.40) and (4.41) shows that the force required to initiate helical buckling in a vertical well is about 2.2–2.9 times greater than that required to initiate sinusoidal buckling.

In the early days of snubbing, it was assumed that the critical helical buckling force in vertical holes was zero. In other words, the pipe would simply buckle helically as it went in the hole under its own weight. The energy analysis that led to Eq. (4.51) showed that this is not the case. It is a much smaller force than that required to initiate helical buckling in straight inclined wells, horizontal wells, and curved wells owing to the stabilizing tendency of the pipe weight acting normally to the centerline of the pipe string in these situations.

Vertical Holes With Doglegs. An important subset of vertical wells involve wells with short crooked sections of hole or doglegs. Doglegs have a rapidly increasing curvature over a short section that returns to an essentially straight hole section through reverse curvature at the bottom of the dogleg. If the length of the vertical hole segment contains one or more of these, there must be a way to account for the additional buckling force required by these short, sharply curved sections.

Dogleg severity is shown in Eq. (4.52):

$$DLS = \frac{18,000}{\pi R} \tag{4.52}$$

where DLS = dogleg severity (degrees/100 ft.), R = average wellbore radius of curvature at dogleg (rad/ft).

The critical buckling force associated with these doglegs is shown in Eq. (4.53):

$$F_{CHDLS} = \frac{EI}{4900 r_c} \times DLS \tag{4.53}$$

Combining Eqs. (4.51) and (4.53), the total critical helical buckling limit for vertical wells with doglegs is given by Eq. (4.54):

$$F_{CH}^{*} = 5.55 \sqrt[3]{EIW_b^2} + \frac{\mathrm{EI}}{4900\mathrm{r_c}} \times \mathrm{DLS} \tag{4.54}$$

Comparison of Eqs. (4.51) and (4.54) shows that more compressive force is needed to initiate helical buckling in crooked vertical wells than in straight holes. The curved sections of a dogleg tend to stabilize helical buckling, and it does, in fact, require more compression to change from sinusoidal to helical buckling in the doglegs.

Inclined Holes. Work by Mitchell in 1995 showed that buckling can flip between sinusoidal and helical buckling over a range of compressive forces in inclined holes. At the very onset of helical buckling, the system is unstable with samples subjected to the "critical helical buckling force" switching back and forth between the two buckling types. Also, the helix sometimes reverses going from clockwise to counterclockwise at this interface. In fact, the so-called critical helical buckling force better describes the helical "unbuckling" force as pipe is picked up to relieve compression.

Stabilized helical buckling begins at a force defined by Eq. (4.55):

$$F_{CH} = 4\sqrt{\frac{2EIW_b \sin \alpha}{r_c}} \tag{4.55}$$

At forces greater than this value, the helix begins to tighten. At values less than this and greater than F_{ch} defined by Eq. (4.32), the buckling form switches back and forth between sinusoidal and helical, and the direction of the helix may reverse.

Horizontal Holes. Like inclined wells, both theory and laboratory data confirm that there is a transition interval in terms of axial compressive force between sinusoidal and helical buckling in horizontal hole segments. Eq. (4.55) simplifies to Eq. (4.56) with all the pipe weight acting downward:

$$F_{CH} = 4\sqrt{\frac{2EIW_b}{r_c}} \tag{4.56}$$

Simplified, this equation is shown in Eq. (4.57):

$$F_{CH} = 5.66\sqrt{\frac{EIW_b}{r_c}} \tag{4.57}$$

This relationship describes the force required to form the first stable helical element (i.e., period). It also defines the initial force used to calculate friction in the first helical wrap.

Curved Hole Segments

Like sinusoidal buckling, a strange dichotomy exists when considering curved sections of the wellbore and helical buckling. Apparently, the curve stabilizes the pipe so that helical buckling does not occur in curved hole sections. This allows force to be transmitted to the section of the pipe below the curve as the pipe remains on the low side of the hole in the curve.

The other side of the coin involves additional pipe-on-wall friction while running the pipe through the curved section. Curvature increases drag that reduces the force that can be applied to the pipe below the curve. This increased drag pushes the helical buckling up the hole. Depending on how much force is reaching the BHA, the pipe may also be buckled below the curve as well.

One theory behind this behavior is that the curved well segment forms a "trough." Because the pipe is in compression, it lies on the bottom side of the curve, and the "trough" prevents the pipe from picking up off the wellbore to buckle in either sinusoidal or helical shapes.

Regardless of the reason, this behavior has been observed both in the field and in the laboratory.

Calculations of the critical helical buckling limit for curved hole segments are much more complex than that for straight hole segments, either vertical, inclined, or horizontal. Hole geometry and the interaction of the normal force resulting from buckling on the curved inner surface of the wellbore make the use of tedious mathematical manipulation of basic equations difficult.

Fortunately, these relationships have been simplified in several of the models such that they adequately describe the critical helical buckling in curved wellbores (Eq. (4.58)):

$$F_{CH} = \frac{8EI}{r_c R}\left(1 - \frac{r_c}{4R} + \sqrt{1 + \frac{r_c R^2 W_b \sin\alpha}{2EI} - \frac{r_c}{2R}}\right) \tag{4.58}$$

where R = borehole radius of curvature (in.).

The force provided by this equation is the point at which the stabilized sinusoidal buckling in a curved hole section shown by Eq. (4.48) converts to a stable helical shape and the first complete helical period is formed. At forces greater than this critical or limiting value, more helical wraps form, and pipe-on-wall friction increases.

4.3.5 Factors Impacting Buckling

Several factors regarding both the pipe and operating conditions determine if they have an influence over pipe buckling. Some of the factors do affect the onset of buckling; others do not. There is no information available on some factors. The following is a discussion showing these impacts.

4.3.5.1 External Upset Connections

The impact of external upset and collared connections on friction in straight pipe configurations has been discussed. The question then is what impact to external upset end connections have on buckling, both sinusoidal and helical.

It is unlikely that sinusoidal buckling is impacted by EUE connections. Points of contact are intermittent depending on the period of the sine curve. The period has been measured at 60–90 ft. long in some pipe configurations with low axial compression forces. It is unlikely that having a connection every 30 ft. or so would impact sinusoidal buckling where long periods are involved. The connection would probably not be making contact with the wellbore, or if it did, the side forces would be minimal. In either case, the formation of the sinusoid and any negative effects such as additional pipe-on-wall friction would be minimal.

Mitchell in 1999 examined the impact of EUE connections on helical buckling. He used a column model with connections in tangential contact with the inside wall of the well and compared that with the common helix model. One of the assumptions in his analysis was that bending moments were the same on either side of the connection and that the connections would contact the wall before the pipe would.

Mitchell's analysis showed that at low axial loads, the two models were in agreement especially with small-diameter pipe and short lengths. At higher loads, however, they did not match as well. This had to do with a property he called "sag" that mimics the weight-induced pipe sag between connections in inclined wells. As this "sag" increased, caused by additional side forces acting on the helix, more of the pipe contacted the inner wellbore wall and pipe stresses at the connections increased significantly.

Again, in this type of analysis, the amount of "sag" and the additional contact and friction from the helix are very difficult to determine. The impact on buckling-induced friction was even more difficult.

This is clearly an area for more research, as Mitchell concluded. The reaction of pipe with upset connections and collars in helical bending may have an impact on pipe stresses and, at high loads, may also have an impact on helix formation and pipe-on-wall friction.

4.3.5.2 Internal Pressure

Intuitively, if the pipe string tubing is pressured through a column of fluid that is more dense than the fluid in the well, the stiffness product, *EI*, should increase. Pressure inside the pipe should try to straighten the buckling and to provide additional support against buckling. Also, when pipe bends around a corner, such as a curved well segment, the round cross section becomes slightly oval-shaped. Again, if the pipe has a significant internal pressure, the pipe should try to return to a round profile as pressure removes the ovality.

Laboratory experiments were performed to confirm or refute this concept (Kuru et al., 1999). In one experiment, pipe was intentionally buckled by applying axial compression with no pressure inside the pipe in several configurations to establish a baseline. Then, the pipe was buckled again in the same configurations at varying internal pressures. The experiment was carried out under very precise monitoring in "wells" composed of clear walls (acrylic tubes) for visual confirmation.

Results of these lab data show that internal pressure has little impact on pipe buckling. Apparently, the bending stiffness is not altered sufficiently to increase critical buckling loads.

4.3.5.3 Applied Torque

Helical buckling forms a coil, or corkscrew, that can be either clockwise or counterclockwise, once the critical helical buckling axial compression load is exceeded. It would seem that torque applied to the pipe by the hydraulic rotary table or reverse torque by a downhole motor would cause the helix to form at a lower critical buckling load than the same situation without torque.

Models have been derived to determine the impact of torque on helical buckling near the BHA using the energy conservation method. These models show that torque slightly decreases the critical buckling force (thought to be through the stabilization of sinusoidal buckling that precedes helical buckling). This slight reduction in the critical helical onset compression is small enough to be negligible in field operations.

The models also show an increase in normal force applied to the constraining wellbore with a corresponding increase in friction once the helix is formed.

4.3.5.4 Bottom-Hole Temperature

It would be logical that the buckling tendency for any pipe run in a well would increase with bottom-hole temperature.

The bending stiffness product, EI, is critical to all buckling calculations. The moment of inertia, I, is determined by the geometry of the system and does not change significantly with increased temperature. Young's modulus of elasticity, E, decreases for all ductile materials with increasing temperature. For example, Young's modulus for carbon steels at normal field conditions is about 29.5×10^6 psi at 0°F, but it drops to 27.6×10^6 psi at 400°F, a reduction of 7%.

It may be important for some critical snubbing jobs to prepare a temperature profile of the wellbore (which may or may not match the geothermal gradient), then determine where in the wellbore buckling is taking place, and use the proper Young's modulus value for buckling calculations.

4.3.6 Pipe-on-Wall Friction Due to Buckling

The compressive force that establishes buckling is the net sum of the downward force on a pipe segment from weight or jack-supplied pull-down and the upward force acting on that segment. If the tool on the bottom of the BHA is off bottom (e.g., while running in the hole), this upward force is the result of pipe-on-wall friction.

Once the pipe is buckled, additional friction can be imposed by the configuration of the buckling in addition to the pipe-on-wall friction just from the pipe rubbing on the inside of the wellbore. Friction is an additive force, so buckling friction is added to normal pipe-on-wall friction. Thus, the string weight at the surface "feels" all the friction. This has the impact of reducing the net pipe weight at the surface, and it can change the actual neutral point. Once the buckling is released (i.e., once the pipe stops moving and all friction ceases), a pipe-light string can suddenly become pipe- heavy.

4.3.6.1 Sinusoidal Buckling Friction

As discussed above, sinusoidal buckling is minimal in vertical holes. For inclined holes, the reduced number and length of contact points provided by sinusoidal buckling may reduce pipe-on-wall friction. The bulk of the pipe is lifted off the pipe wall to make contact at discrete points, but not everywhere along its length even where the pipe contacts the top and bottom of the hole. Sinusoidal buckling may not exist in curved hole sections at all. The force necessary to initiate sinusoidal buckling in a curved section will likely result in helical buckling above and possibly below the curve. If so, the friction from the sinusoidal buckling in the curve would be masked by the helical buckling friction above and below the curve.

For these reasons, the friction attributed to sinusoidal buckling when snubbing or stripping pipe is not discussed further.

4.3.6.2 Helical Buckling Friction

Friction from helical buckling can be quite significant. At the onset of helical buckling, some force and motion can be transmitted through the buckled area to lower sections of the pipe string, but when the compressive force increases, the friction grows rapidly.

The helix contacts the inside wall of the well forming a coiled spring shape. Eventually, the length and normal force applied by the helix create so much friction that no motion is transmitted downhole. This point is known as "lockup." Further additions of compressive force simply result in more friction and a longer buckled section.

The normal force acting against the constraining wellbore by the helix is described by Eq. (4.59):

$$B_n = \frac{r_c F_1{}^2}{4EI} \tag{4.59}$$

where B_n = buckling-supplied normal force, r_c = clearance radius, F_1 = net axial force.

In this equation, the bending stiffness product, EI, or flexural rigidity defines how much of the net axial force is converted in the helix to a normal force acting against the inside wall of the wellbore.

Radial clearance is a simple distance between the outside wall of the pipe and the inside wall of the wellbore and is defined by Eq. (4.37), which is repeated here just as a reminder:

$$r_c = \frac{ID_{hole} - OD_{pipe}}{2} \tag{4.37}$$

Recall that the moment of inertia (Eq. 4.26) also involves both the OD and ID of the pipe:

$$I = \frac{\pi\left(OD_{pipe}^4 - ID_{pipe}^4\right)}{64} \tag{4.26}$$

Eq. (4.59) shows that the normal force due to helical buckling is proportional to the *square* of the axial force and inversely proportional to the bending stiffness. Later, it will become obvious that pipe-on-wall friction increases with the square of the compressive axial force once helical buckling is established. As B_n increases, friction due to helical buckling also increases very rapidly.

Straight Vertical Holes

Referring to the previous discussion for a straight vertical wellbore section, the normal weight against the pipe wall is essentially zero. Pipe-on-wall friction due to helical buckling is considered to be due to the normal buckling force, B_n. Pipe-on-wall friction due to helical buckling for a short vertical pipe segment is given by Eq. (4.60):

$$F_p = B_n \times C_f \times L_h \tag{4.60}$$

The length, L_h, is from the top of the first helical coil to the base of the helically buckled section. Friction factors, C_f, are the same as those shown in Table 4.2.

Straight Inclined Holes

For an inclined straight wellbore section, the effective total normal force for helically buckled pipe is $W_n + B_n$ where B_n is much larger than the normal force due to the weight of the pipe on the lower side of the hole, W_n. Drag, or pipe-on-wall friction, for a short pipe segment of length L' is given by Eq. (4.61):

$$F_p = (W_n + B_n) \times C_f \times L' \tag{4.61}$$

Net axial force on the upper end of a short helically buckled pipe segment in a straight inclined well is shown by Eq. (4.62). This shows that a portion of the string weight below the buckled section is being supported by the pipe-on-wall friction of the helix:

$$F_1 = (W_b \cos\alpha \times L') - C_f\,(W_b \sin\alpha + B_n) \times L' \tag{4.62}$$

Curved Holes

A short, curved hole segment in which the pipe is in compression has a total normal force for helically buckled pipe of $C_n + B_n$. In this situation, B_n is much, much larger than C_n to the extent that the net axial friction force can be approximated by Eq. (4.63) by ignoring C_n:

$$F_1 = \left(W_p \cos\alpha_{avg} \times L'\right) - C_f\left(W_b \sin\alpha_{avg} + B_n\right)L' \tag{4.63}$$

where α_{avg} = average deviation angle over the segment.

Horizontal Holes

In a straight horizontal hole section, W_p is the same as W_{air}. In Eq. (4.62) for a horizontal hole (i.e., deviation = 90 degree), $\sin\alpha = 1$, so the drag for a short segment of helically buckled pipe in a horizontal well reduces to Eq. (4.64):

$$F = -C_f \times (W_{air} + B_n) x L' \tag{4.64}$$

This equation describes the buckled pipe in very short sections, usually only a single period or 360 degree loop of the helix. Complex models based on laboratory experiments show that as the helix lengthens, the normal force of the helix, B_n, grows rapidly toward the "anchored" end of the helix. Thus, the pipe-on-wall friction, or drag, is much greater at the base of the helix. In short, each round of the helix becomes tighter applying more outward force against the constraining wellbore, so drag increases proportionately. Each coil wrap gets closer to the last one until the helix actually resembles a coiled spring. At some point, the drag becomes so great that no additional force can be transmitted through the helix. That point is known as lockup.

4.3.7 Transition Intervals

The calculations for the compressive force on a string of pipe where buckling starts have been the subject of debate for some time. Various mathematical and energy models predict where this "critical" force is located. Laboratory and field data show that there are transition intervals between sinusoidal and helical buckling configurations.

Mitchell's work in 1995 on inclined holes demonstrates this quite well. Results from Mitchell's work are summarized in Table 4.5.

This shows that there is a transition from the initiation of sinusoidal buckling to fully established helical buckling. In those portions of the pipe dominated by buckling, a continually decreasing amount of the axial force applied as buoyed pipe weight or snub force on the pipe actually reaches the base of the string (Fig. 4.16). The remainder of the force is converted through a force perpendicular to the pipe centerline (i.e., the normal force) against the inner surface of the well where it is converted to friction. Friction working opposite axial force reduces the force on the bottom of the string. In drilling terms, this would be the weight on bit, which goes to zero at lockup (Fig. 4.16). This is confirmed by field data where measuring devices have been run on BHAs.

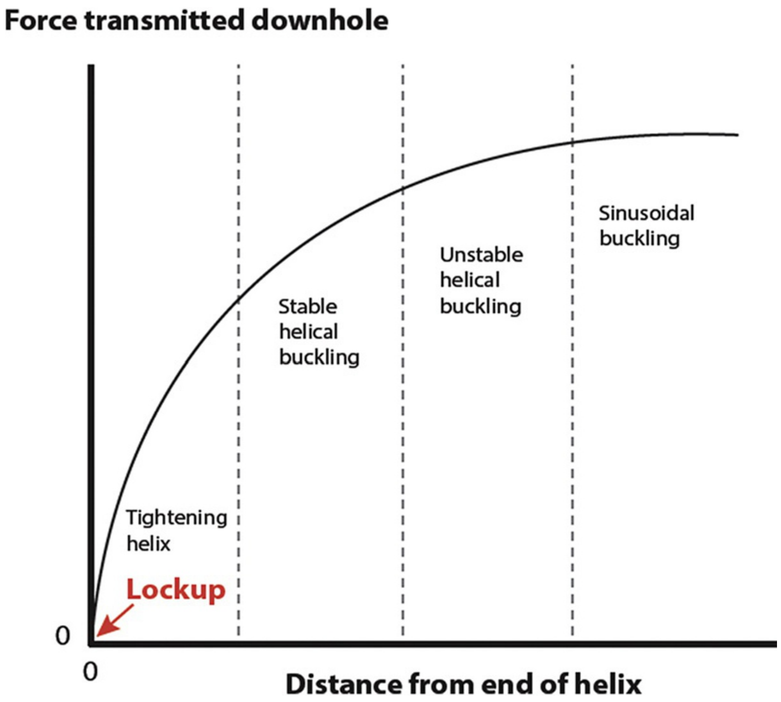
4.3.8 Triaxial Stress Analysis

Buckling-imposed stresses add to axial stresses acting on pipe in a well in a complex manner. Instead of a single-axis stress profile (say, tension only) acting on the pipe, there are multiple stresses acting simultaneously in other ways. In some situations, these stresses oppose each other. In others, the stresses are synergistic. These multiple stresses are shown in Fig. 4.17.

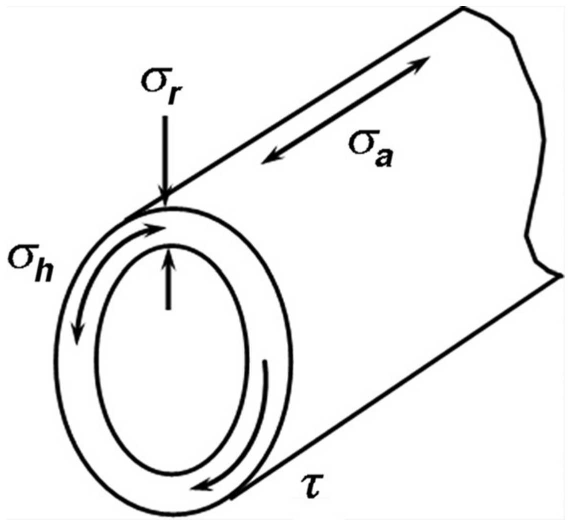
Table 4.5 Net Axial Compressive Force Versus Pipe Configuration for Inclined Holes

Compressive Force, F_1	**Pipe Configuration**
$F_1 \le 2\sqrt{\frac{EI \times W_b \sin\alpha}{r_c}}$	Straight (unbuckled)
$2\sqrt{\frac{EI \times W_b \sin\alpha}{r_c}} < F_1 < 2\sqrt{\frac{2EI \times W_b \sin\alpha}{r_c}}$	Sinusoidal
$2\sqrt{\frac{2EI \times W_b \sin\alpha}{r_c}} < F_1 < 4\sqrt{\frac{2EIW_b \sin\alpha}{r_c}}$	Sinusoidal or helical
$F_1 \ge 4\sqrt{\frac{2EIW_b \sin\alpha}{r_c}}$	Helical

(after Watters et al)



■ **FIG. 4.16** Force transference through buckled intervals.



■ **FIG. 4.17** Stresses acting on pipe segment.

In Fig. 4.17, σ_a is the axial stress, σ_r is the radial stress (most often caused by pressure), σ_h is the hoop stress, and τ is the stress associated with torsion. Torsional stress is usually ignored in snubbing operations since the pipe is rarely rotated while snubbing/stripping into or out of the hole (although it can be rotated).

4.3.8.1 Axial Stress

Axial stress is defined by Eq. (4.64):

$$\sigma_a = \frac{F_e}{A_s} + \sigma_b \tag{4.64}$$

where σ_a = total axial stress (psi), F_e = effective tension/compression (lb_f), A_s = cross-sectional area (in.^{2}), σ_b = bending stress (psi).

The first term in this equation is created by the tension or compression on the pipe string. In pipe-heavy strings, this term deals with tension in the top portion of the pipe. In pipe-light applications, this is the compression force. The sign of F_e is reversed to show that the force is compressive instead of tensile.

The second term is bending stress, the axial stress resulting from helical buckling. Sinusoidal buckling is insignificant when compared with the stress associated with the pipe tension or compression. So, the only bending stress here is associated with helical buckling as shown by Eq. (4.65):

$$\sigma_b = \pm \frac{r_c (F_e) OD}{4I} \tag{4.65}$$

where OD = pipe outside diameter (in.).

This equation takes into account both the "weight" of the pipe string and the effect of the helical buckling friction.

4.3.8.2 Radial Stress

This stress results from a pressure differential across the wall of the pipe. In some cases, it can be positive or negative depending on which pressure is higher, the internal or the external pressure. Eq. (4.66) shows this stress. This is also known as the Lame equation:

$$\sigma_r = \frac{(P_o - P_i) r_i^2 r_o^2}{r^2 \left(r_o^2 - r_i^2\right)} + \frac{r_i^2 P_i - r_o^2 P_o}{\left(r_o^2 - r_i^2\right)} \tag{4.66}$$

where σ_r = radial stress (psi), P_o = pressure on outside of pipe (psi), P_i = pressure on inside of pipe (psi), r_o = outside radius of pipe (in.), r_i = inside radius of pipe (in.), r = radius of investigation (in.).

In radial stress, the actual stress is the greatest on the outside or inside wall of the pipe depending on the direction of the pressure gradient. There is less stress at all points within the pipe body. The radius value, r, is the place inside the body of the pipe being analyzed (say, halfway through the pipe wall). Note that the sign of this stress can also be positive or negative depending on the relative sizes of the pressures and radii.

4.3.8.3 Hoop Stress

The hoop stress, or tangential stress, is the stress around the circumference of the pipe due to a pressure gradient. The maximum hoop stress always occurs at the inner radius or the outer radius depending on the direction of the pressure gradient. Like the radial stress, the hoop stress can be analyzed at any investigation point within the pipe wall at radius r. The Lame equation, Eq. (4.67), is also used to determine this type of stress:

$$\sigma_h = \frac{r_i^2 P_i - r_o^2 P_o}{\left(r_o^2 - r_i^2\right)} - \frac{(P_o - P_i) r_i^2 r_o^2}{r^2 \left(r_o^2 - r_i^2\right)} \tag{4.67}$$

where σ_h = hoop stress (psi).

4.3.8.4 Torsional Stress

In some snubbing jobs, the pipe may be rotated as it is being snubbed/stripped into the hole. This accomplishes several things: (1) breaks static friction, (2) reduces the tendency of pipe buckling in high-angle or horizontal holes by "working" the pipe down instead of just "pushing" it down the hole, and (3) reduces sticking tendencies in curved hole sections.

Like the hoop stress, torsional stress (or shear stress) varies across the entire pipe body. It can be analyzed at any radius; however, the maximum shear stress occurs at the outside radius. It is most often analyzed at τ_o, but it can be determined anywhere within the pipe wall using Eq. (4.68):

$$\tau = \frac{Tr}{J} \tag{4.68}$$

where τ = shear stress (psi), T = imposed torque (in. lb_f; ft. $lb_f \times 12$), J = polar moment of inertia = $2I$.

If torsion-induced shear stress is analyzed for the outside surface of the pipe (usually done to give a conservative estimate of total stress), Eq. (4.68) can be written as Eq. (4.69):

$$\tau_o = \frac{T\left(OD_{pipe}\right)}{4I} \tag{4.69}$$

4.3.8.5 von Mises Yield Criterion

Richard Edler von Mises was a scientist and mathematician who held the position of Gordon-McKay Professor of Aerodynamics and Applied Mathematics at Harvard University. He worked on solid and fluid mechanics, statistics, and probability theory, among other subjects. He was an Austrian-born immigrant who held positions with several universities in Europe prior to coming to the United States. The von Mises criterion was first formulated by James Maxwell in 1865, but it is generally attributed to work done by von Mises in 1913.

The von Mises criterion makes it possible to analyze the yield stress of any material under a multitude of forces resulting in multidimensional stresses. von Mises and others devised a method to deal with all the stresses to determine the yield of any material regardless of the number of dimensions and the degrees of freedom involved. In the case of pipe, the triaxial dimensional analysis (with or without torque) is often used to design drill strings, casing, jointed tubing, and coiled tubing. It is employed to set limits on pipe in snubbing, stripping, or pulling operations.

The basic form of the von Mises criterion is shown in Eq. (4.70):

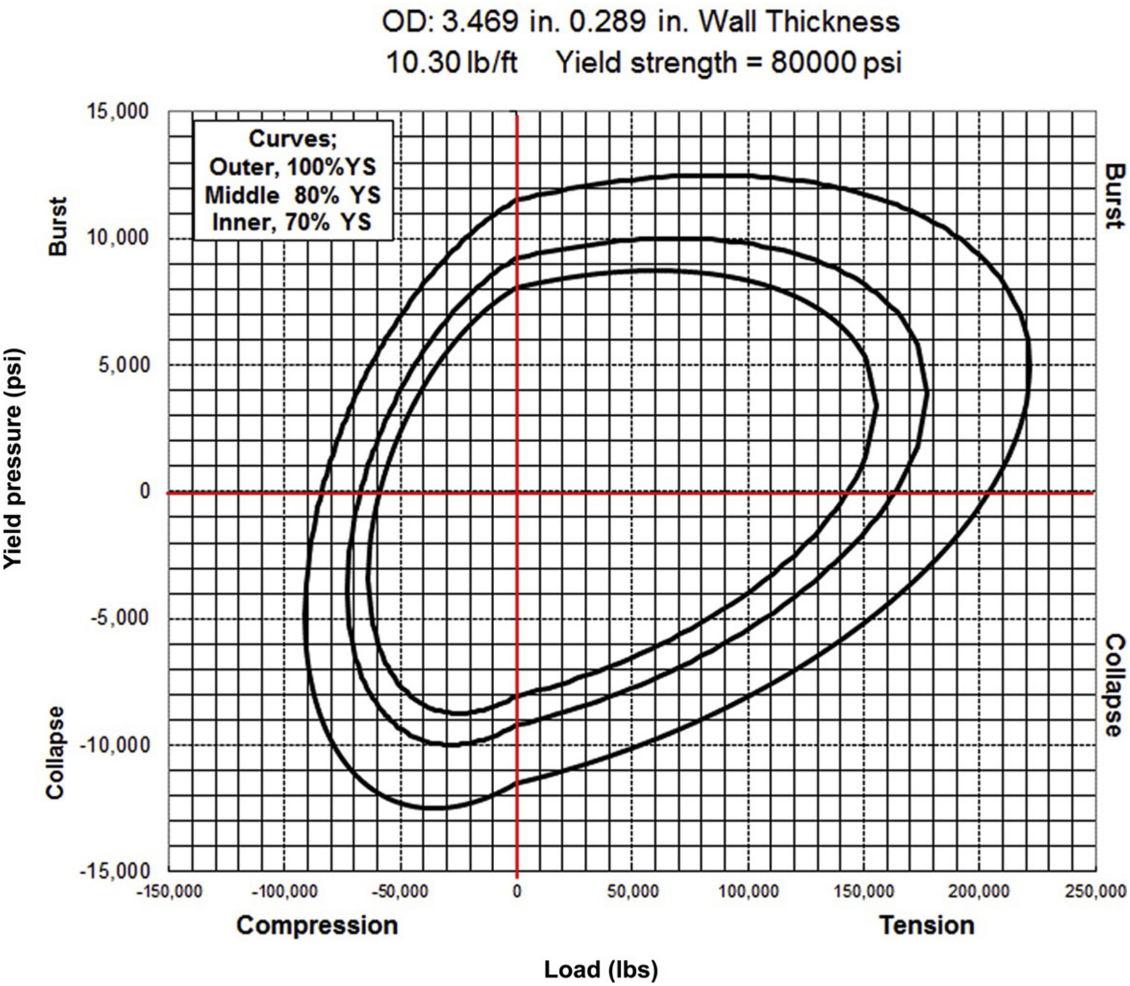
$$\sigma_{vME} = \sqrt{\tfrac{1}{2}\left[(\sigma_h - \sigma_r)^2 + (\sigma_h - \sigma_a)^2 + (\sigma_a - \sigma_r)^2\right] + 3\tau^2} \qquad (4.70)$$

where σ_{vME} = von Mises yield criterion.

Obviously, if there is no torque on the pipe while snubbing, the last term drops out since $\tau = 0$.

The triaxial yield stress of any pipe can be determined by setting the von Mises yield criterion equal to the yield stress of the material from which the pipe is made, σ_y, and solving for each of the stresses at r, the radius of investigation (usually the critical radius where failure would be expected). This provides a plot of pressures and axial forces for the pipe in burst and collapse and tension and compression modes such as the one shown in Fig. 4.18.

Note that the triaxial stress analysis illustrated here ignores the effect of upset connections and collars. It also ignores the so-called Bauschinger effect what deals with small pipe defects that impact total stress calculations by imposing stress risers. These defects can include rust, pitting, gouges in the pipe's surface, acid etching, and small damages such as dents. When all these are considered, the analysis becomes much more complex and probably requires the use of finite element analysis on the section of pipe being considered.



■ **FIG. 4.18** von Mises plot for 3½ in. N-80 tubing in 8½ in. hole.

Actual, measured, or planned conditions of load and pressure at a particular depth on the job can be used to determine if the prejob pipe and pressure plan would be acceptable. Those points within the maximum envelope selected would be considered safe even if buckling occurred while snubbing/stripping the pipe with pressure inside or outside the pipe. If those conditions fell outside the envelope on the von Mises criterion plot, a different sized pipe, a different material of construction, or a different pressure profile would have to be developed for a safe job.

CHAPTER 4 QUIZ 1

Sections 4.1–4.2

1. What is the theoretical expulsion force, ignoring friction, for 2⅜ in. OD tubing with a 1.995 in. ID in a well with 1400 psi surface pressure? Use nominal dimensions.
   A. 3325 lb_f
   B. 4376 lb_f
   C. 6202 lb_f
   D. 7897 lb_f

2. System friction does not need to be considered when calculating the actual maximum snubbing force based on expulsion force for the first joint of pipe being snubbed into a pressured well.
   A. True ______
   B. False______

3. A joint of 2⅜ in. EUE 8rt tubing has a collar OD of 3.063 in. What is the maximum expulsion force that could be seen on the snubbing unit jack weight indicator when snubbing the first joint of pipe in the hole using the annular preventer in a well with 500 psi surface pressure? Assume 20% friction.
   A. 2215 lb_f
   B. 2658 lb_f
   C. 3684 lb_f
   D. 4421 lb_f

4. The first joint of 3½ in. flush-joint tubing being snubbed into a well with 3000 psi has a maximum OD of 3.531 in. If the snubbing rams exert 30% friction, what is the snub force that the unit must exert to snub this pipe into the well?
   A. 28,863 lb_f
   B. 29,377 lb_f
   C. 37,522 lb_f
   D. 38,190 lb_f

5. A string of new 4½ in. API tubing is going to be snubbed into a well under pressure. What tubing diameter should be used to calculate the expulsion force?
   A. 4.469 in.
   B. 4.478 in.
   C. 4.531 in.
   D. 4.545 in.

6. What is the buoyancy factor for 12.2 ppg fluid?
   A. 0.814
   B. 0.850
   C. 0.875
   D. 0.900

7. A well is standing full of 13.3 ppg drilling mud. It has no surface pressure. A string of 2⅜ in. 4.7 ppf tubing with an ID of 1.995 in. is run in the well to 5000 ft. It is filled with 8.9 ppg produced water while being run. What is the buoyed weight of the tubing string using nominal dimensions?
   A. 15,305 lb_m
   B. 15,422 lb_m
   C. 43,000 lb_m
   D. 66,500 lb_m
   E. None of the above

8. The neutral point in a well is the length of pipe with a buoyed weight equivalent to the expulsion force including friction.
   A. True ______
   B. False______

9. Calculate the neutral point for a well with 2500 psi surface pressure that is full of 12.8 ppg drilling mud using 2⅞ in. 8.7 ppf, L-80 tubing that is filled with drilling mud as it is being run. Use nominal dimensions and assume friction of 30%.
   A. 1865 ft.
   B. 2319 ft.
   C. 2952 ft.
   D. 3015 ft.

10. Pipe-on-wall friction can be calculated using the friction factor times the length of pipe in contact with the wall times the buoyed weight of pipe in all wellbore configurations.
    A. True ______
    B. False______

11. What is the amount of pipe-on-wall friction associated with 2000 ft. string of 3½ in. 10.3 ppf flush-joint tubing being run in a straight vertical hole segment? Assume a friction factor of 0.35.
    A. Zero (negligible)
    B. 293 lb_f
    C. 697 lb_f
    D. 1021 lb_f
    E. None of the above

12. A straight well with a deviation of 48 degrees (vertical = 0 degrees) is 4000 ft. long and has 3½ in. 10.3 ppf flush-joint tubing in it being snubbed in an open hole at 60 ft./min. The hole and tubing are both full of 10.0 ppg brine. What is the upward friction force exerted on the pipe from this straight inclined hole section while going in the hole? Assume a friction factor of 0.45.

A. 11,674 lb_f
B. 18,322 lb_f
C. 25,943 lb_f
D. 29,726 lb_f

13. A string of 4 in. OD, 3.476 in. ID 11.0 lb/ft flush-joint tubing is being run to the end of a horizontal well segment that is 7500 ft. long. The hole is filled with 14.1 ppg drilling mud, and the tubing was filled with 8.7 ppg seawater while running it in the hole. What friction force can be expected from this hole section? Use nominal dimensions and assume a friction factor of 0.40.

A. 18,253 lb_f
B. 25,800 lb_f
C. 27,613 lb_f
D. 33,001 lb_f

14. A string of 2⅞ in. 7.8 ppf, P-105 flush-joint tubing is being snubbed through a curved hole section with a downward force of 8500 lb_f. The well at the point of wall contact has an average deviation of 45 degrees and a radius of curvature of 0.003 rad/ft. The hole and pipe are both full of 12.0 ppg fluid. What friction is being exerted over the 100 ft. contact section? Assume a friction factor of 0.35.

A. 34,118 lb_f
B. 42,012 lb_f
C. 68,236 lb_f
D. 84,024 lb_f

15. Upset end connections and/or collars have no impact on friction calculations in straight or curved hole segments.

A. True ______
B. False______

CHAPTER 4 QUIZ 2

Sections 4.3.1–4.3.3

1. New 2⅞ in. 8.7 ppf L-80 API tubing is going to be snubbed into a well with 4000 psi surface pressure. This tubing has a nominal wall thickness of 0.308 in. What are the worst-case dimensions for snubbing considering the tolerances allowed by API Specification 5CT for this pipe in terms of OD, wall thickness, and ID (inches)?

A. 2.875, 0.308, 2.259
B. 2.844, 0.308, 2.228
C. 2.844, 0.269, 2.305
D. 2.875, 0.269, 2.336

2. It is safe to use API used pipe specifications since they are conservative and will provide the worst-case scenario for job planning.

A. True ______
B. False ______

3. A special, non-API tubing string is to be snubbed into a well with 1500 psi surface pressure. The minimum pipe OD is 3.750 in. The maximum pipe ID is 3.30 in. The minimum wall thickness is 0.225 in. What is the radius of gyration for this pipe? Assume 20% friction.

A. 1.25 in.
B. 1.35 in.
C. 1.43 in.
D. 1.56 in.

4. The special pipe in the previous problem has Young's modulus of elasticity of 34×10^6 psi and a yield stress of 127,000 psi. What is its column slenderness ratio?

A. 13.532
B. 23.139
C. 51.403
D. 72.695

5. A string of new 4½ in. API tubing (ID = 3.958 in.) has a slenderness ratio of 35.4. It is pinned such that the k index is 1.2. What unsupported length is permissible for this pipe? Use nominal dimensions.

A. 44.2 in.
B. 53.0 in.
C. 66.2 in.
D. 176.8 in.

6. A planned snubbing job includes 2⅞ in. OD, 8.7 ppf, N-80 tubing with a nominal ID of 2.259 in. and an unsupported length of 10 in. at the snubbing unit. The column slenderness ratio for this pipe is 84.59. The first effective slenderness ratio is 10.93. The second effective slenderness ratio is 10.54. What is the critical force to just initiate unconstrained buckling in the unsupported length will occur? Do not apply a safety factor (i.e., 100% of critical buckling force).

A. 171,600 lb_f
B. 174,200 lb_f
C. 4,220,000 lb_f
D. 5,615,000 lb_f
E. None of the above

7. A string of 2⅜ in. J-55 tubing is going to be snubbed in a well. The column slenderness ratio for this pipe is 102.02. The calculated value of $SR = 108.79$. The pipe has a minimum wall thickness of 0.16625 in., a maximum ID of 2.01125 in., and a radius of gyration of 0.7721 in. What is the permissible unsupported length for this pipe in the snubbing unit? Use a k factor of 1.0 for this calculation.

A. 36 in.
B. 72 in.
C. 78 in.
D. 84 in.
E. None of the above

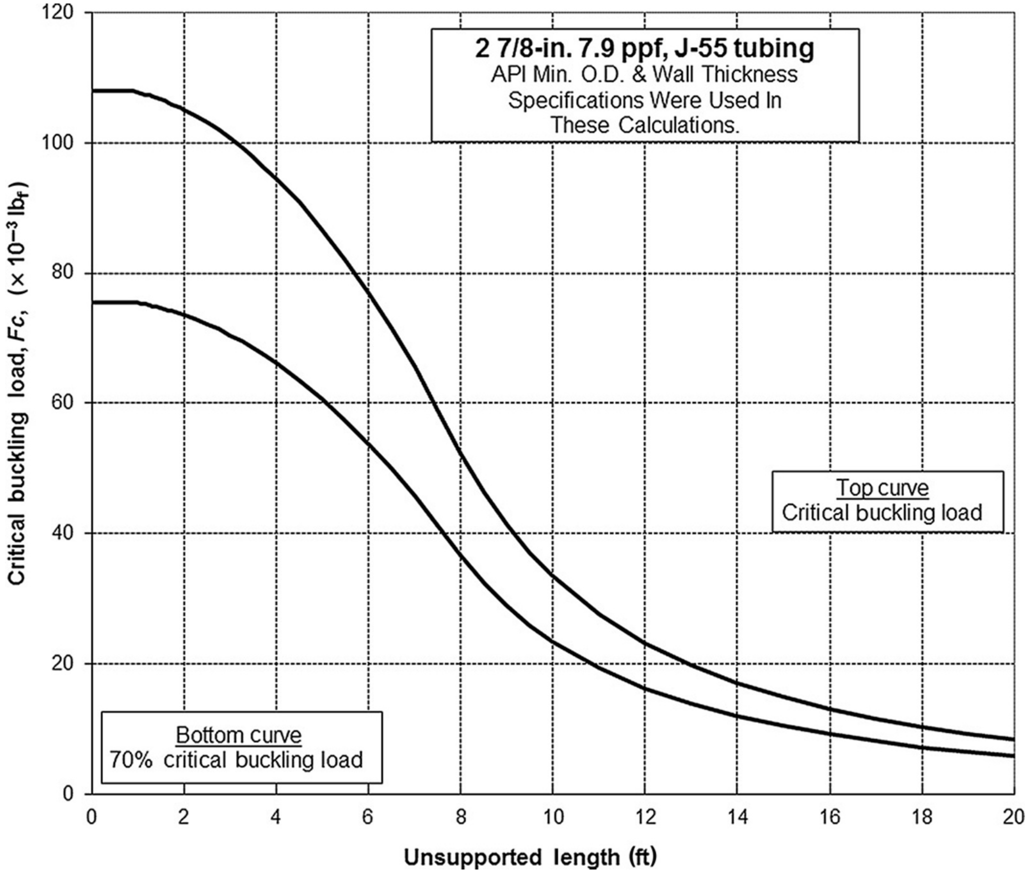
8. For the pipe in the question above, at what value of the unsupported length will the value of SR switch from SR_2 to SR_1 (i.e., at which value of L_u will the unsupported length become the dominate factor in the critical force calculation)?

A. 6.3 in.
B. 7.5 in.
C. 9.5 in.
D. 11.7 in.

9. The pipe in Question 7 has a column slenderness ratio of 102.019. What is the critical buckling force for unconstrained buckling if the unsupported length is zero?

A. 15,732 lb_f
B. 62,060 lb_f
C. 91,310 lb_f
D. 102,126 lb_f

10. Unconstrained buckling in snubbing operations is a serious threat because the pipe can fold, break, and part somewhere in the unsupported length.
    A. True ______
    B. False______
11. Using the following diagram, determine the maximum unsupported length permitted for normal snubbing operations using a 70% safety factor for a maximum snub force of 36,600 lb_f.
    A. 6.7 ft.
    B. 7.5 ft.
    C. 8.0 ft.
    D. 9.2 ft.



CHAPTER 4 QUIZ 3

Sections 4.3.4–4.3.8

1. Constrained buckling occurs where there is a conduit in which the pipe is being run that only allows the pipe to move laterally a certain distance before encountering the inner wall of the conduit.
   - **A.** True ______
   - **B.** False______

2. 3½ in. OD flush-joint pipe with a maximum OD of 3.531 in. is being run inside 8⅝ in. casing with a drift ID of 7.796 in. What is the clearance radius for this configuration?
   - **A.** 2.563 in.
   - **B.** 2.547 in.
   - **C.** 2.148 in.
   - **D.** 2.133 in.

3. Two types of constrained buckling are
   - **A.** Polar and axial
   - **B.** Rectangular and orthogonal
   - **C.** Sinusoidal and helical
   - **D.** Circular and triangular

4. A 2⅜ in. 4.7 ppf N-80 flush-joint tubing string with a nominal wall thickness of 0.190 in. is being run in a straight inclined 7 in. hole with a deviation of 51.3 degrees. Both the hole and the pipe are filled with 12.4 ppg drilling mud. What is the critical force to initiate buckling in this configuration?
   - **A.** 10,142 lb_f
   - **B.** 10,176 lb_f
   - **C.** 10,767 lb_f
   - **D.** 11,303 lb_f

5. Assume that the well in the previous problem is a horizontal hole (i.e., deviation = 90 degrees). What is the critical force to initiate buckling in this configuration?
   - **A.** 11,303 lb_f
   - **B.** 11,481 lb_f
   - **C.** 11,520 lb_f
   - **D.** 12,403 lb_f

6. A new API 4½ in. 11.0 ppf J-55 flush-joint tubing string (nominal wall thickness = 0.262 in.) is being run in an 8½ in. horizontal well. The well is full of 13.0 ppg drilling mud, but the pipe was filled with 8.8 ppg field produced water while running in the hole. According to Mitchell's (1995) work, what force will produce stabilized sinusoidal buckling until helical buckling tendencies begin to occur in this tubing string? Again, assume Young's modulus = 29.5×10^6 psi.

A. 50,297 lb_f
B. 71,387 lb_f
C. 73,979 lb_f
D. 86,678 lb_f

7. A string of J-55 tubing in an 8½ in. hole that has a radius of curvature of 1.984 in., a buoyed weight of 6.18 ppf, and a moment of inertia of 1.88 in.^{4} is being run into a curved hole with a wellbore curvature of 1000 ft. The average deviation of a short pipe segment in this curved hole is 48 degrees. Young's modulus is 29.5×10^6 psi. What is the force required to maintain stabilized sinusoidal buckling before the buckled section assumes a helical shape using Qui's modified equation?

A. 17,605 lb_f
B. 30,984 lb_f
C. 50,645 lb_f
D. 61,969 lb_f

8. A string of 2⅞ in. 8.7 ppf N-80 flush-joint tubing is going to be snubbed into a vertical 6 in. ID well. The tubing has a nominal wall thickness of 0.308 in. Both the hole and the tubing are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling? Assume nominal tubing dimensions.

A. 7939 lb_f
B. 8.140 lb_f
C. 8376 lb_f
D. 8866 lb_f

9. The same pipe in the question above is going to be run in a straight inclined 6 in. hole with a deviation of 54 degrees. Both the pipe and hole are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling using Mitchell's (1995) equation? Assume nominal tubing dimensions in all calculations.

A. 81,107 lb_f
B. 86,468 lb_f
C. 93,934 lb_f
D. 96,134 lb_f

10. The same pipe in Question 8 is going to be run in a straight horizontal 6 in. hole. Again, both the pipe and the hole are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling again using Mitchell's (1995) equation and assuming nominal pipe dimensions?

A. 86,468 lb_f
B. 90,174 lb_f
C. 96,134 lb_f
D. 104,435 lb_f

11. A string of 2⅞ in. 8.7 ppf J-55 flush-joint tubing with a nominal wall thickness of 0.308 in. is in a 7⅞ in. hole under a net force of 15,000 lb_f, a combination of buoyed string weight and imposed snubbing force. The pipe is suspected of being in helical buckling because the force exceeds the critical helical buckling force. What is the force normal to the well axis being applied to the tubing by the helix? Use nominal pipe dimensions.

A. 847 lb_f
B. 982 lb_f
C. 1108 lb_f
D. 1232 lb_f
E. None of the above

12. The pipe in Question 11 is located in a straight inclined hole with a deviation of 39 degrees. The hole and pipe are filled with 12.5 ppg mud. The net force being applied to the pipe is 3000 lb_f, and the pipe is helically buckled. This inclined hole segment is 55 ft. long. What is the friction applied upward while snubbing this pipe in the hole assuming a friction factor of 0.3?

A. 893 lb_f
B. 1003 lb_f
C. 1158 lb_f
D. 1274 lb_f

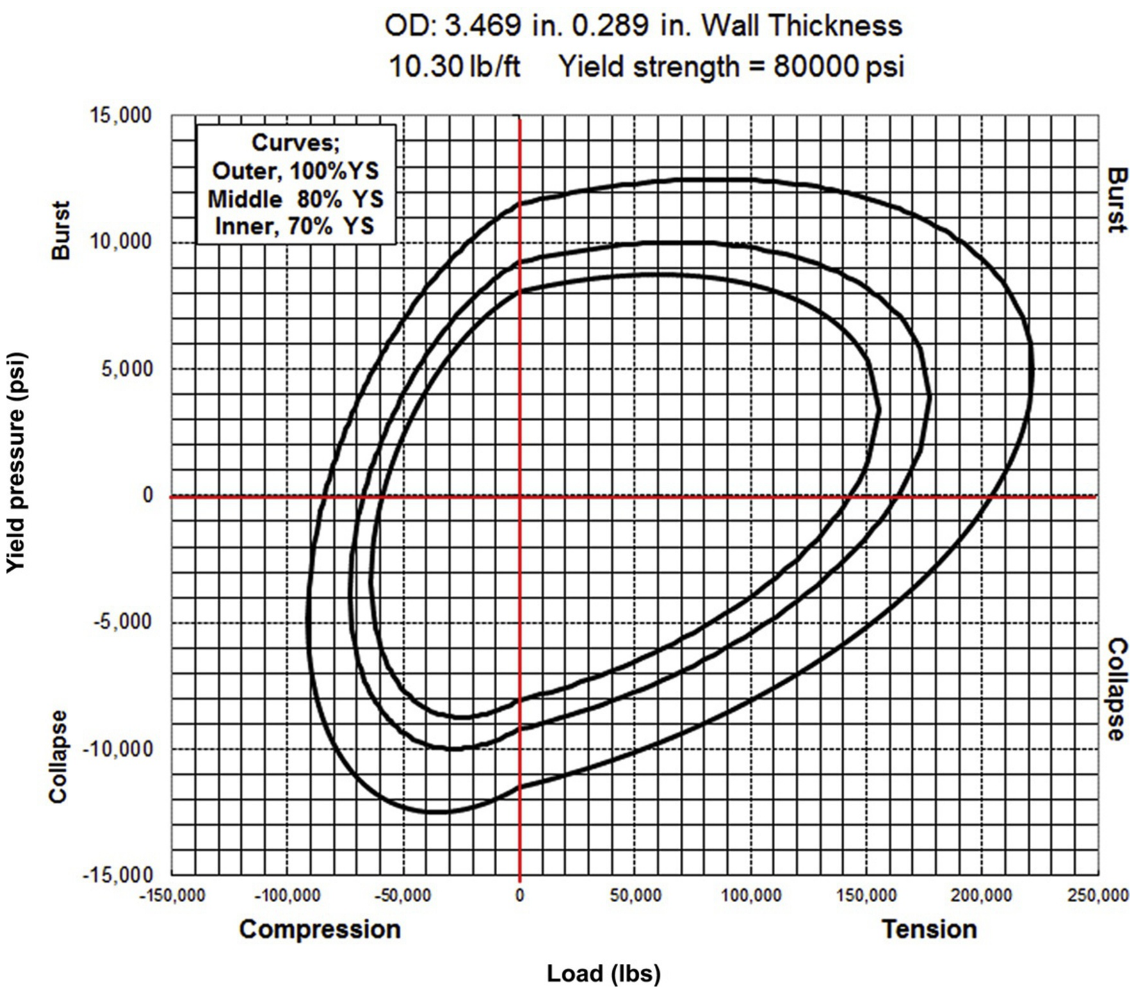
13. The von Mises failure criterion allows for the triaxial analysis of pipe under stress in compression and tension and burst and collapse modes.

A. True ______
B. False______

14. A string of 3½ in. 10.3 ppf, N-80 tubing is being planned for use in a snubbing job. It is expected that the pipe will be under a collapse pressure of 4000 psi with a compression load of 30,000 lb_f as snubbing begins. The conditions will end at an internal pressure of 5000 psi with a tension load of 100,000 lb_f, and the loading will proceed uniformly between these two end conditions. Using the plot below, can the job be safely done if a 70% safety factor is required?

A. Yes

B. No



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Chapter 5

Oil Field Uses of Hydraulic Rigs

CHAPTER OUTLINE

Hydraulic Rig Technology and Operations. https://doi.org/10.1016/B978-0-12-817352-7.00005-1

5.1 INTRODUCTION

Hydraulic rigs, including snubbing and hydraulic workover (HWO) units, have expanded into many areas of oil field operations. Almost any job that can be performed with a conventional drilling or workover rig can also be performed using hydraulic rig within certain limits. Conventional drilling and workover rigs use a block-and-tackle hoisting system that relies on gravity (pipe-heavy condition), whereas snubbing and hydraulic workover rigs employ large hydraulic cylinders to hoist or lower pipe and other equipment into and out of the well with or without pressure on the well.

One significant difference is that the block-and-tackle assembly cannot manage well pressure when the string becomes pipe-light. The rig's pipe-handling system is designed for pipe-heavy strings to keep pipe from falling into the well under the influence of gravity. Only a snubbing unit can push jointed pipe into a well under pressure.

Another difference involves the diameter limitations of hydraulic rigs. There is a maximum pipe diameter that can be run through the bore of a jack. Even the largest hydraulic units have bore size restrictions. Drilling rigs can manage large-diameter tubulars with their block-and-tackle systems to surprising sizes. If the pipe can get through the floor, or moon pool, it can be run by the unconstrained nature of a drilling or completion rig.

Yet another difference involves maximum hoisting loads. A drilling rig, for example, can add sheaves in both the crown block and traveling block, and the extra lines as required. These become load-hoisting multipliers that make multimillion pound loads manageable as long as the derrick and substructure are capable of handling the load. A snubbing unit is limited by cylinder diameter, the number of cylinders, and the maximum power fluid pressure available. A 600 K unit can safely manage a "hook load" of just over a half-million pounds.

Snubbing and HWO units are not intended to manage all problems. They are augments to conventional rig equipment with each having specialized capabilities. It is important that the proper equipment is selected for the job with the issue of safety being paramount in the decision-making process. Both physics and economics are important. Sometimes, it is better to use a conventional rig. Other times, it may be better to use a hydraulic jack.

Again, a distinction should be made here that HWO in this book is considered to be for dead well work (i.e., no pressure on the wellhead). Snubbing and stripping are used to perform work on live, or pressured, wells. Drilling with a hydraulic rig may involve live or dead wells.

The oil field uses of hydraulic rigs can best be explained by examining jobs that require snubbing as a way to manage the live well operations. For dead well operations, economics control the selection and use of a conventional drilling rig or completion unit versus an HWO unit.

5.2 WELL CONTROL—SNUBBING

The original snubbing units were designed with the intent of maintaining well control while running a work string in live wells in the late-1920s to fish drill pipe that had fallen into the hole. Another early use was for running tubing in pressured wells in California in the 1930s. Both involved doing the job on a live well by limiting the risk of a blowout and consequential damages while avoiding killing the well by pumping heavy kill weight mud (KWM).

There are many other uses for snubbing units to control pressure and prevent blowouts (or kill a blowout) using snubbing units.

5.2.1 Barriers

A primary assumption in snubbing/stripping work is that there is pressure at the surface inside the wellbore. The barriers to flow are therefore mechanical since hydraulic equilibrium provided by a column of mud is not a primary well control barrier. Hydrostatic pressure from a column of fluid in the well is not sufficient to balance or exceed formation pressure, or there would be no pressure at the surface. Fig. 5.1 shows the barriers inside the pipe being snubbed.

Work strings snubbed or stripped into wells under pressure are equipped with at least one working downhole check valve or plug that prevents pressure and fluid from entering the bottom of the pipe and flowing out at the surface. Two checks or plugs are recommended as a minimum. Often, a third is used in high-pressure, high-temperature (HPHT) operations. It might be a specialized plug (e.g., X, XN, or similar plug) set in a profile nipple that is wireline or slickline retrievable. The check valves may be flapper-type checks as shown in Fig. 5.1, or they may be of a different type (spring-loaded sliding sleeve, dart-type, etc.). Often, they employ metal-to-metal sealing surfaces.

These downhole check valves constitute the primary inside barrier in snubbing/stripping operations. They are the first defense against an upward flow from the pipe.

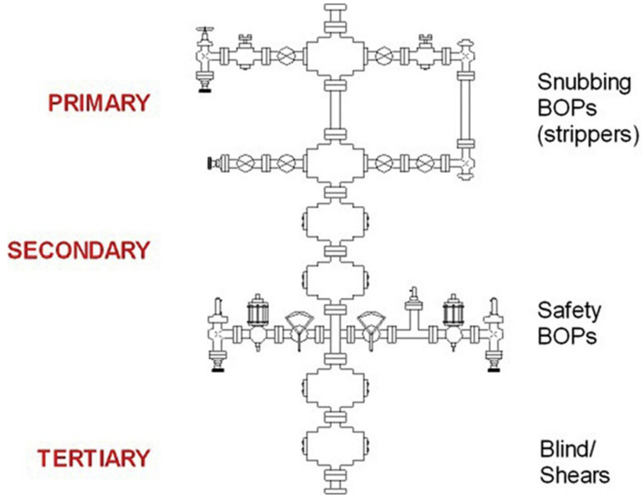
A secondary barrier is provided at the surface by a stab-in safety valve, often called a "TIW" valve after one early manufacturer, Texas Iron Works. This

■ **FIG. 5.1** Well control carriers, interior.

valve is kept in the basket near the traveling head so it can be quickly inserted into the pipe in the open position and then closed by a worker to stop the flow. Clearly, this would only be required if all the downhole check valves failed or if a leak developed somewhere in the work string above the checks.

There must be one stab-in safety valve for each pipe size and thread type in the string. Often, this requirement is met by having multiple TIW valves in the basket with the proper thread for each pipe segment. It can also be met by having one (or two) safety valve assemblies with different crossover subs made up on the bottom of the valve. The subs can simply be changed out as a new pipe diameter and/or thread type in the pipe string is encountered during the job.

A final tertiary barrier is shared with the annular flow barriers, the blind-shear rams in the bottommost BOP (if installed). This device cuts the work string and seals the entire well. Should an event occur in which the stab-in safety valve could not be inserted, this tertiary barrier safely shuts off the



■ **FIG. 5.2** Well control barriers, annulus.

flow although a fishing job to recover the dropped pipe string would be required.

The primary annulus barrier is provided by the snubbing BOPs, or strippers, as shown in Fig. 5.2. These are used as the working well control devices while snubbing or stripping pipe ram-to-ram in a pressured situation. The ram packers must be changed periodically due to wear, the primary stripper more often than the secondary stripper. For example, if pipe is being snubbed on the no. 1 (upper) stripper with only connections snubbed with the no. 2 (lower) stripper, the ram packers in the no. 1 stripper will wear much faster and require changing more often.

The secondary annulus barrier is provided by the safety BOPs. In Fig. 5.2, the configuration used for HPHT operations, there are three ram-type BOPs. There may be a different configuration for other operations. Regardless, the safety BOPs provide the backup barrier to the snubbing BOPs.

The tertiary barrier is provided, again, by the blind/shear rams (if installed), usually the lowest BOP in the stack. Some onshore operations do not require blind/shear rams, but in an emergency event, they are quite useful. When, for example, the work string is compromised due to a leak, pipe part (breakage), or other failure, the entire wellbore is charged with the same pressure. There may be no means to shut off flow other than actuating the blind shears.

The installation of blind/shear rams in one of the ram-type safety BOPs is recommended.

In rig-assist operations, the snubbing BOPs (primary barrier) are a part of the snubbing unit. However, the rig's BOP stack constitutes the safety BOPs, the secondary barrier. Blind/shear rams may or may not be installed.

In low-pressure wells, the pipe is often stripped through an annular preventer situated on top of the BOP stack and below the snubbing BOPs. This is used in certain pipe-heavy applications when ram-to-ram snubbing is not required. When this occurs, the annular or stripping head becomes the primary annular barrier with the ram BOPs in the stack below the annular preventer providing the secondary barrier. When the annular BOP element, or stripper head element, wears to the point that it can no longer contain pressure, a safety BOP is closed on the pipe, and the element is replaced. Note that all pressure inside the stack must be safely vented before opening the annular to change the element.

The importance of maintaining operative and adequate well control barriers, both interior and annular, during snubbing operations cannot be overemphasized. Dealing with pressure and flammable wellbore fluids requires that special attention be given to these barriers. In normal overbalanced drilling operations or HWO operations, the absence of pressure often results in crew complacency. In snubbing where pressure is as common as a morning cup of coffee, complacency cannot be tolerated. The well is ready to blow out at any moment, and rigorous well control barrier maintenance is an absolute requirement at all times.

5.2.2 **Kick Control**

A kick is defined as an unexpected and unwanted influx of reservoir fluid, oil, water, or gas, into the wellbore due to an underbalanced condition in which pressure inside the wellbore or bottom-hole pressure (BHP) is less than formation pressure. Gas kicks are riskier than fluid kicks because of their high mobility in the wellbore.

Formation water kicks may be troublesome, but they rarely constitute a significant threat to the safety of the crew, the environment, the rig, or the wellbore. A saltwater kick may trigger an emergency response since an influx will be identified through an increase in fluid volume returning to the pits. A saltwater kick can be circulated out of the hole using fairly benign methods and the well pressure increased through a drilling fluid density increase to prevent further saltwater kicks. This increases BHP inside the wellbore to balance reservoir pressure.

Gas kicks are much more troublesome. The gas not only invades the wellbore but also begins to migrate upward due to the density difference between drilling fluid in the well and the gas "bubble." In other words, it can migrate upward even if there is no further influx from the formation. As it moves upward, it retains the same pressure it had when it entered the wellbore.

Good kick control requires that some fluid at the surface be bled off to allow the gas to expand as the hydrostatic pressure on the bubble decreases (i.e., there is not as much drilling fluid above it as it moves up the hole). Without this pressure reduction and expansion, the bubble simply brings reservoir pressure along with it as it moves up the hole.

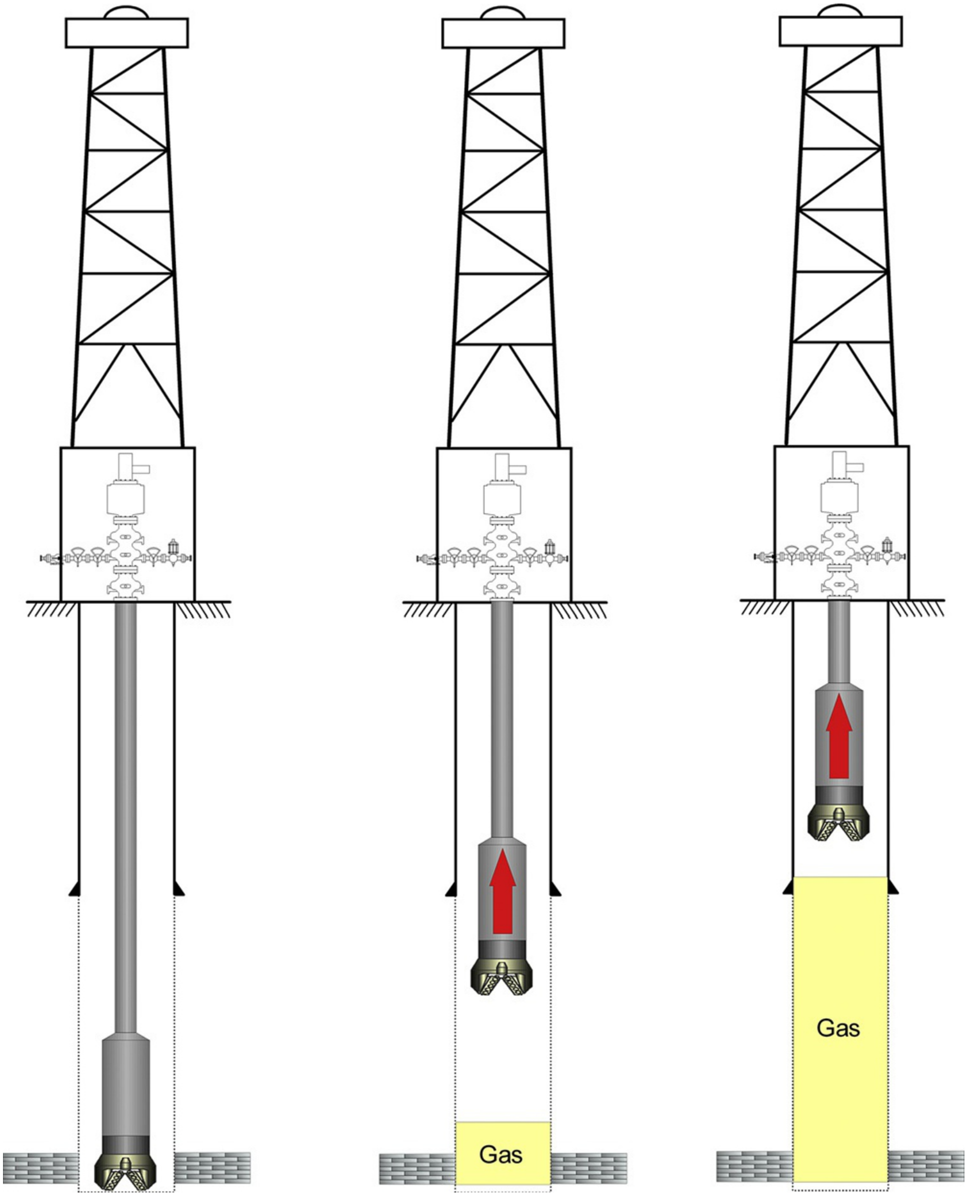
In some situations, the gas bubble is not allowed to expand as it moves up the hole. It will eventually migrate to the surface with high pressure. This assumes that some downhole feature of the well has not fractured under the pressure of the bubble at the surface plus the hydrostatic pressure from the column of mud below it. Even if the job was planned using a dead well drilling or workover procedure, this situation may require the unplanned use of a snubbing unit to prevent the pipe from being expelled from the well.

An oil kick can have some of the impacts of a gas kick. The oil influx will probably be circulated out of the hole during normal mud circulation. Under certain circumstances, it can migrate upward in the wellbore. Eventually, it will reach a shallow depth in the well where the hydrostatic pressure from the drilling fluid column above it is low enough to allow gas dissolved in the oil to bubble out of solution forming a gas kick. The pressure at which this occurs is called the bubble point of the oil.

In oil-based mud (OBM) systems, small gas kicks can behave the same way. Because oil (crude oil, refined oil, or synthetic oil) is the continuous phase in these mud systems, any formation gas will dissolve readily in the mud. As the mud makes its way to surface, the OBM reaches its bubble point, the gas flashes out of solution and it becomes a gas kick that can present a significant threat. Handling this type of kick requires quick thinking and decisive action since these events usually occur near the surface.

Many kicks occur as a result of swabbing. This effect occurs during the upward movement of pipe and the BHA as it is being pulled from the hole. Pulling pipe out of the hole requires that mud in the wellbore flow from around the BHA to fill the void below it created by the absence of the BHA. If the pipe is pulled too fast for this to occur, a slight suction is created on the formation each time a joint or stand of pipe is pulled from the well. In effect, the pipe and BHA behave like a plunger unstopping a drain. The pipe movement literally sucks reservoir fluids into the well.

Here, mud in the hole usually has sufficient density to control the well under static conditions. It is not sufficient to control the reduced density of the fluid column caused by unwanted formation fluid in the wellbore, however. Unfortunately, in many cases, the BHA is located above the “bubble” as shown in Fig. 5.3.



■ **FIG. 5.3** Swabbing schematic diagram.

The best way to manage a kick is to return the pipe to the bottom of the well and circulate all the "bubble" to the surface under controlled conditions. If the end of the pipe is above the kick, it must be run back down the hole. Unfortunately, for conventional rigs, surface pressure and expulsion force can create a pipe-light condition that makes it impossible to go back to the bottom.

So, in comes the snubbing unit to handle the problem. It can manage forces in both directions whether the string is pipe-light or pipe-heavy. It can safely return the pipe to the bottom for a circulating kill without risking the loss of well control. Upset end connections and collars can be managed through ram-to-ram stripping. Once the string becomes pipe-heavy, it can be stripped through an annular preventer or stripping head using the rig's hoisting equipment simply by opening the snubbing BOPs and both sets of pipe-light slips. This is one of the primary uses of a rig-assist snubbing unit.

Snubbing units have been required numerous times to push the pipe back to the bottom for kick circulation. On numerous occasions, an unexpected kick has resulted in a high surface pressure, and the string has become exceptionally pipe-light. Crews have been forced to chain the pipe string down to the rig floor to prevent it from blowing out of the well. Some tubing strings have been completely expelled from a well during high well pressure situations.

Snubbing pipe back to the bottom is often preferable to bullheading mud down the well to lower the pressure. Even bullheading is better than doing nothing, which could allow the situation to escalate into a major failure including a blowout.

5.2.3 Blowout Control

Another use of a snubbing unit is to control a blowout. A blowout is the uncontrolled flow from a well with limited means of stopping the flow. Obviously, the snubbing unit cannot rig up on top of a well that is blowing hydrocarbons into the air, often on fire. The well must first be capped and shut in, or capped and diverted allowing flow to some remote point like a flare.

Snubbing pipe into the blown out well provides a good way to regain well control without making the situation worse. Circulating out the kick remaining inside the capped well in a controlled manner is far better than bullheading. Bullheading applies considerable stress to the well that could result in a loss of wellbore integrity. In some wells, this stress causes a casing string to rupture or the cement at the base of the casing to fail. In these unhappy situations, the blowout flow can exit the wellbore, come up beside the casing string, and fracture its way through soft sediments to the surface in a process known as "broaching."

Once broaching occurs, the entire site becomes unsafe. The only solution to a broached well is to drill a relief well to pump kill fluid into the blown out well. Snubbing would be far too risky.

5.2.3.1 Kill String Installation

Once a well begins to flow uncontrollably, the "kick" is already moving rapidly up the hole, or it's already at the surface. There are no more options for blowout prevention and no more kick control. These events often involve fire that consumes and destroys the rig and its blowout preventers. Getting pipe back to the bottom for blowout control becomes more complex than just running it using a conventional rig.

First, the flow must be controlled by capping the well. Blowout specialists may simply cap the well without killing it. In some situations, the well is capped, and the flow is diverted away from the wellhead, but it cannot be halted if doing so would cause the well to broach. In either situation, the wellhead is now safe enough to permit pipe to be snubbed into the well under pressure. Several kill techniques are available once the pipe has been run back into the well. Two of these are used on wells that are still flowing.

Dynamic Kill

The dynamic kill is, quite simply, pumping some fluid at a high rate to the end of the kill string where it commingles with produced fluid as the well continues to flow. The combined fluid stream flows up the annulus between the wellbore, or casing, and the pipe creating fluid friction. At some pump rate, enough friction is developed in the annulus to match reservoir pressure at which time continued flow into the wellbore from the reservoir ceases.

The kill pump rate must be maintained for some time to ensure that all hydrocarbons, especially gas, are flushed from the annulus. Fluid friction must be maintained by pumping at some critical pump rate if the dynamic kill fluid has a density lower than the KWM density. Usually, a final circulation with KWM is all that is needed to bring the well and reservoir back into pressure equilibrium.

This technique is often used when there is a limited volume of KWM available, but there is an abundance of a lighter fluid, such as seawater. The kill is actually made using a sacrificial fluid, and then the well is stabilized with a single circulation of kill weight mud.

Obviously, this technique requires that there is pipe in the hole to serve not only as the conduit for pumping kill fluid but also as the obstruction inside the wellbore around which fluid friction can be developed (i.e., the pipe creates an annulus inside the well). Since the capped well will have pressure at the surface, even if the flow is diverted, a snubbing unit is required to get the pipe into the hole.

The pipe may not be snubbed all the way to the bottom. There is a minimum length of pipe that will be necessary for the dynamic kill. There must be enough pipe in the hole to ensure that sufficient friction can be developed in the annulus while pumping the sacrificial fluid out the end of the string at the kill rate. The longer the string in the well, the easier the dynamic kill. If the pipe is on the bottom, any additional kicks that might be experienced during kill operations can be circulated out of the hole using conventional techniques.

For this situation, a standalone snubbing unit is used. There is no rig available to use a rig-assist unit. The snubbing unit is installed on top of the safety BOP stack often in one or two lifts. This means that work can begin quickly to control the well even if it has been capped and there is no further flow. The speed in reacting to an "emergency situation" is often demanded by the public and regulatory agencies who view pressure on a capped well, with a measure of fear, even though the well may be completely secure.

Circulating Kill

This type of kill is similar to the dynamic kill, and it applies to flowing wells that have been capped. Here, instead of a light sacrificial fluid, KWM (or denser fluid) is used in the same technique as the dynamic kill. Fluid is pumped to the end of the pipe where it mixes with wellbore fluids.

Fluid friction is developed in the annulus between the pipe and hole. The friction is usually increased because of the additional KWM viscosity rather than the sacrificial fluid, such as water, used in the dynamic kill. Another benefit is that additional hydrostatic pressure is gained more quickly in the annulus for each volume of the dense kill mud pumped. The combination of added fluid friction and the ever-increasing hydrostatic pressure often kills the flow faster and at lower pump rates than the dynamic kill method.

This is advantageous from several viewpoints. Firstly, less total fluid is required for the kill. The downside is that all the kill fluid must be mixed, weighted up, and stored ready for pumping before the kill begins. That means that this type of kill can be more expensive than the dynamic kill and there is a need for more equipment. One would not want to run out of mud in the middle of a kill operation, so several multiples of the theoretical kill volume, usually 3–4, are mixed, stored, and maintained. This means tanks, mixing and agitation equipment, and personnel to do the extra work.

Secondly, fewer pumps are required since a lower pump rate is required. However, there is additional fluid friction pumping viscous, weighted fluid down the pipe. Pump pressures may be higher.

One should expect to lose about half the operating pumps during any high-pump-rate kill operation (including dynamic kills). So, it's a very good idea to have multiple spare pumps (usually 100% of the theoretical pump capacity) for the kill. This again requires pumps, operators, fuel, communications, and more people.

Thirdly, if small-diameter pipe is in the hole such as production tubing, this may be the only way to kill the flow since there would be too much friction pumping fluid down the pipe at allowable surface pressure to perform a true dynamic kill. There simply would not be enough flowrate to generate the required fluid friction in the annulus. In other words, it might not be possible to pump fast enough for the dynamic kill to work. Replacing the small pipe with larger-diameter pipe may not be possible due to restrictions in the wellbore. The only solution would be a circulating kill using heavy mud in this case.

The snubbing unit again comes into play by getting the pipe in the hole or getting it further in the hole if some pipe is already in the well. Just like the dynamic kill, the circulating kill won't work without pipe in the hole. The length of the string, again, is dependent on the flowrate from the well and the required minimum kill pump rate down the pipe. This tricky tradeoff is usually analyzed by computers running sophisticated dynamic kill models.

Lost Circulation Solutions

In many wells, especially high-pressure/high-temperature (HPHT) wells, a weak zone cannot support the hydrostatic pressure of a column of KWM. This results not only in kicks but also in uncontrolled fluid losses. Sometimes, flows come out of one interval and go into another open zone with little or no surface pressure. This is called an underground blowout.

Underbalanced (flowing) operations resolve this situation by intentionally not balancing the formation pressure with a column of mud. The well is allowed to flow to the surface rather than into a downhole zone under controlled conditions.

If the well must be killed, restoring hydrostatic balance will require curing the lost circulation problem to halt the underground flow and to prevent further kicks. Spotting lost circulation pills of various types provide a solution that can involve snubbing.

Unlike dynamic and circulating kills, lost circulation pills are usually more effective if the well is not flowing when they are placed. In some situations, this can be done by simply shutting in the well. In the case of an underground blowout, other techniques are required.

Some of these techniques require working on the well under pressure. This can involve pulling or running a pipe-light string or dealing with a bypassed well that is still flowing while being flared.

Lost circulation pills. These are relatively small volumes of mud, or other fluid, mixed with lost circulation material (LCM). The term LCM encompasses many types of materials. Some are fibrous, usually from vegetable or other plant sources, and include cedar fiber, paper, nut hulls of various kinds (e.g., cottonseed, walnut, and peanut hulls), and hemp. Others are mineral-based (e.g., calcium carbonate and mica flakes). Still, others are chemically based (e.g., plastics and shredded rubber products).

They are all intended to bridge across zones that will readily take fluid under pressure including fractured intervals, underpressured zones, and high-permeability zones such as sands, gravels, and conglomerates.

Some BHA components such as motors, measurement-while-drilling (MWD) and logging-while-drilling (LWD) tools, and the small downhole turbine that powers them have clearances that limit the concentration and type of LCM that can be pumped through the tool string. Drill strings must be pulled and the BHAs removed before running back in the hole with open-ended pipe if high-concentration LCM pills are needed to control lost circulation. When there is a kick in the hole and surface pressure on the well, this task must be performed using a snubbing unit after the string becomes pipe- light.

There are several general methods for curing lost circulation. One is to mix and circulate a pill with a high concentration of LCM, say ±50 pounds per barrel (ppb). This pill can be included with drilling fluid in a continuous circulation method hoping that the LCM will selectively plate out on the formation taking fluid (the thief zone) and plug off the losses.

In other situations, LCM is simply mixed into the entire mud system at a lower concentration. Sometimes, this is used as a preventative measure against anticipated lost circulation. Of course, when the fluid is circulated back to surface, LCM is removed at the shakers and must be replaced.

Another method is to spot a pill sufficiently large enough in volume to cover the thief zone. Then, circulation is stopped, and the LCM is allowed to "heal." This is thought to provide more robust bridging. A variation of this technique is to close off the annulus and pressure up on the well to "squeeze" the LCM pill. In some loose or fractured formations, this can force LCM into the formation where it can bridge off behind the exposed formation face. Any LCM that is not squeezed away will simply be swept off the formation face by drill collars and drill pipe connections when the drill string is moved.

For a well that has pressure at the surface, pipe often must be snubbed or stripped in the hole to place an LCM pill. If the well is flowing downhole in an underground blowout, the LCM pill must be pumped with the end of the pipe below the thief zone and above the flowing interval. This provides the same impact as an LCM squeeze except that the LCM is placed in a dynamic situation.

Circulation is restored as the LCM plates out on the surface of, or inside, the thief zone. However, the well may continue to flow to the surface until it is brought into hydraulic equilibrium with formation pressure. Often, a small kick is circulated to the surface. The kick must be properly managed, but this does provide a means to cure the lost circulation problem as long as the LCM bridge is sustained.

Another problem with some LCM is that it contains a high bacterial concentration. This is the case with most of the fibrous LCM. The bacteria become active when resaturated in a water-based mud system. They multiply and consume part of the mud chemicals, such as polymers, generating H_2S and other wastes. This results in the entire mud system turning sour. Bactericides and H_2S scavengers are needed to control the bacterial activity. These add costs that can quickly become burdensome. Continuous LCM use may not be an attractive, or lasting, solution to the problem.

Sometimes, the only solution for lost circulation is steel filter cake (i.e., a string of casing or a liner). Again, if there is pressure on the well, it might be necessary to snub the liner or casing into the well to place and cement it properly across the lost circulation zone.

Gunk squeezes. Gunk is an unusual lost circulation material that can be used in some situations to seal off a thief zone even under dynamic conditions. Gunk is often used because it can be mixed using materials that are readily available and inexpensive. This gelatinous material can also plug BHA components such as motors, downhole tools, and bit jets. In many cases, the drill string must be tripped out of the hole, the BHA removed, and the pipe run back in open-ended before pumping a gunk pill. This task often requires snubbing when there is pressure on the well.

Recipes for gunk vary depending on the mud system and the circumstances of the lost circulation event. The simplest description of gunk is that a clay is mixed in a fluid dissimilar to that being used in the well. When the two fluids mix, a viscous mass is formed. The gelled mass also forms inside the thief interval as the gunk pill invades and plugs the zone.

In water-based mud (WBM) systems, the gunk is made by mixing clays (often just bentonite) in oil (e.g., field crude oil, diesel, or base oil) and pumping it down the pipe. In oil-based mud (OBM) systems, the gunk is made by mixing organophilic clays (e.g., kaolinite) in a slug of gelled water.

Gunk placement is an art. It involves both skill and luck. In a dynamic situation, such as an underground flow, the pipe end is positioned just above or below the flowing zone depending on the direction of flow. The gunk pill is spotted around the bottom of the string using drilling fluid. Then, the pipe is pulled several hundred feet above the thief zone, and the well is shut in. The downhole cross flow carries the gunk into the thief zone where it gels and, hopefully, stops the flow.

In a static situation, with or without pressure at the surface, the end of the pipe is above the thief zone. The gunk is displaced out the end of the pipe. A BOP is closed, and drilling fluid is pumped down the pipe and the annulus simultaneously to displace the gunk into the thief zone. Then, the well is shut in for a time period sufficient to allow clays in the gunk to seal off the thief zone.

Multiple gunk squeezes may be needed to seal off a particularly bad lost circulation problem. Sometimes, other materials such as cement and silica flour are added to the gunk mixture for a more robust plug. Regardless, restoration of circulation depends on the formation of a thick, gelatinous mass with the look and consistency of peanut butter to halt fluid losses into the lost circulation zone.

While this sounds rather simple, if there is pressure on the well and insufficient wellbore integrity to support a fluid column, the pipe must be manipulated using either stripping (the most common method) or snubbing (in pipe-light situations) to place the gunk pill. Leaving the drill string immersed in the gunk after it gels is not wise, so repositioning the pipe to some point well above the thief zone is important. Again, pipe manipulation under pressure is often best performed using snubbing units.

Barite plugs. Barite, barium sulfate or $BaSO_4$, is a finely ground inert weighting material often used to raise mud density. It is readily available on most drilling rigs. It can also be used for creating a solid, nearly impenetrable plug when it settles and packs off inside a wellbore. It is quite useful for sealing off thief zones that occur in the bottom of a well.

Barite plugs have also been placed in wells where underground flows are active. They are best suited for static situations where the cross flow has ceased or the fluid level in the well has fallen to the point that the thief zone can support the column's hydrostatic pressure. Unfortunately, when this occurs, upper producing zones may start flowing resulting in a kick.

Barite plugs can be pumped through most BHAs including bit jets, motors, and drilling tools. Reverse circulation following plug placement may not be possible since most drill strings contain floats to prevent cuttings and debris from coming up into the string while running in the hole. These could easily plug the drill string or tubing. They could also damage downhole measurement devices such as MWD, LWD, and pressure-while-drilling (PWD) tools. Most of the time, setting a barite pill is best done through open-ended drill pipe or tubing using normal circulation. Tripping out of the hole with pressure on the well requires snubbing capability at some point.

Barium sulfate is unusual from a chemical standpoint. It has a chemical formula of $BaSO_4$. Its molecular structure has a nucleus containing both the barium (a metal ion) and sulfur (a nonmetallic ion). The molecule has the shape of a tetrahedron, a three-sided pyramid with each face of the pyramid an equilateral triangle of the same size. This is one of a very few perfect stacking shapes in nature. Each of the little pyramids exactly fits every other pyramid on all its faces so that the molecules stack together in a perfect mass with few disruptions (except for contaminates).

This stacking is enhanced by another atomic curiosity. Each of the points of the pyramid is occupied by an oxygen atom. Oxygen is a very unhappy, lonely atom. So, it is constantly looking for another atom with which to combine. Often, that is another oxygen atom. Free oxygen in the atmosphere comes as a combined molecule composed of two oxygen atoms, for example, O_2.

In barium sulfate molecules, not only do the molecule faces match when stacked, but also the corners interact with each other in a process known as oxygen bonding. The attraction of the oxygen atoms creates an adhesion that makes the barite mass very stable.

These properties make barite an excellent plugging material. Placement of the barite in the wellbore can be a challenge, however.

Again, without getting into precise recipes, a barite pill is simply a high-concentration, weighted solution of barite in a limited volume of loosely gelled mud. It is designed to allow the barite to settle out after placement.

Placement techniques vary. In one technique, the pipe is lowered to the bottom of the hole; the barite pill is displaced outside the pipe using the balanced plug technique leaving an equal height of the pill inside the pipe. Then, the pipe is pulled out of the pill. The pill inside the pipe fills the void created by the missing steel of the pipe. This leaves a continuous pill in the hole (i.e., there is no hole in the middle of the pill left by the missing pipe).

Another technique involves raising the pipe to a point off the bottom, circulating the barite pill down the pipe, and then bullheading a volume of mud between the end of the pipe and the bottom of the hole into the thief zone leaving a portion of the barite pill inside the wellbore above the thief zone.

The final step in barite plug development is allowing sufficient time for the barite to settle out on the bottom of the wellbore. Barite settling is controlled by Stokes' law, so the settling time can be estimated, but rarely accurately. Often, the waiting time is extended to ensure that a dense plug has set up in the well. This can be from 12 to 24 h or longer in some cases. A good part of the settling time depends on the gel strength and longevity of the pill in which the barite is mixed. Sometimes, the gel breaks quickly at bottom-hole temperature allowing the barite to settle within a short time frame.

Obviously, the pipe must not be inside the plug when the barite settles out or it is likely to get stuck. So, the pipe is usually raised several hundred feet above the calculated top of the pill. In dead well situations, when there is no float inside the pipe, reverse circulation is used to clear the pipe and hole of any remaining barite. In live well situations, the best solution may be to trip out of the hole completely. Pressure on the well means that the string will become pipe-light at some point. Again, snubbing will be required in these situations.

One advantage to a barite plug is that it can be circulated out of the hole anytime. It does not harden like cement forming a permanent plug. Assume that the decision is made to set a string of casing or a liner across a series of producing sands above the thief zone. The barite plug can remain in place through this work and then be removed to continue drilling using a less dense fluid. Barite plugs are not permanent although they can be left in the hole indefinitely.

Cement squeezes. Cement is often used as the first choice for stopping lost circulation in the hope that one squeeze to seal off the thief zone will be successful. In a dynamic flow situation, a cement squeeze should be the last option, since cement rarely gels and cures properly when it is moving or when fluid is moving through it.

If the flow involves gas, the cement squeeze attempt is rarely successful. As blowout specialist and well control pioneer, Bob Cudd, once told the author, "When the words gas and cement are used together, there is going to be a failure."

In static well situations, cement can be used to set a permanent plug across a lost circulation zone or to squeeze cement into it. Often, both techniques require multiple attempts. If the thief zone cannot support a fluid column, it is unlikely to be able to support an even heavier cement column. Again, placement is the key to a successful job.

Cement should never be pumped through a BHA if there is any alternative (assuming the BHA is not being abandoned in the hole). Cement, once set up, is very difficult to remove from BHA components. So, even if the BHA can be recovered, it probably could not be salvaged economically.

Most operators pull the drill string and remove the BHA before setting cement plugs or performing squeezes. Snubbing is required in live well situations at some point in this process.

More on cement recipes, plug placement and squeeze techniques can be found in other resources.

5.2.3.2 Kill String Cleanouts

When the kill string in a well is plugged, whether drill pipe or a designated work string, circulating a kick out of the hole, setting a plug, or any other similar work is impossible.

The best way to deal with a blowing well is to kill it by circulation using any of the techniques above depending on circumstances. First, however, the conduit to the bottom of the well must be open.

Wehrenberg and Baxter (2010) mention several case histories in which a small-diameter pipe was snubbed into a plugged drill string in a blowing well. Once the pipe was cleaned out, the well was killed. Some of these involved small (1¼ in.) jointed pipe to clean out the drill string. Snubbing was required to run the jointed pipe into the drill string.

In some situations, the snubbing unit and cleanout string are used to fish obstructions such as wireline tools or coiled tubing from the work string. This was followed by well control operations including kick circulation.

Coiled tubing is often used for some of these jobs, but snubbing higher-strength jointed pipe can provide a better way to clean out wells in some situations. This pipe can also provide lower pump pressures since only the pipe in the hole generates fluid friction while pumping through it.

The entire string of CT, including that still on the reel, will generate more fluid friction, higher pump pressures, and lower pump rates than the jointed cleanout string.

In several cases, snubbing units have been used to manipulate the kill string once it was cleaned out. In other cases, particularly in fishing work, a connection was made to the drill string fish in the hole using a sealing overshot. The cleanout string was then run to remove fill from the fish using the same snubbing unit. The fish then became part of the kill string, and fluid was pumped to the end of the fish to kill the well.

5.2.3.3 Relief Wells

One of the primary issues with relief well drilling and interception of a blowing well is the potential of the blowout flowing backwards into the relief well causing it to experience surface pressure. Usually, the first indication of an intercept between a relief well and a blowout is the immediate loss of circulation as the overbalanced fluid column in the relief well contacts an underbalanced situation in the blowing well. From a fluid dynamics standpoint, the blowing well begins to "gas lift" fluid out of the relief well once the two wells are hydraulically connected.

The result is that most relief wells go on a vacuum when the intercept is made. Blowout specialists understand this phenomenon and immediately begin pumping fluid down the annulus of the relief well at high rate. The relief well drill string is used to monitor downhole pressure since it contains a full column of drilling mud of known density. However, if kill pump rate is not high enough, the fluid level in the relief well annulus may drop due to the suction of the blowing well.

The loss of mud from the relief well is the gain of mud in the blowing well. Unless that mud loss is immediately replaced by pumps, the kick can reverse directions and come up the relief well. The worst-case situation is the reservoir blowing out through both the original well and the relief well simultaneously.

There are several case histories of using hydraulic unit drilling to make the intercept between the relief well and the blowing well. Fine control of the jack means that drilling near the intercept point can be as slow as needed to ensure that directional requirements are met. The hydraulic unit in drilling mode can place the bit at the intercept point with a degree of precision that may not be easy, or even possible, using a conventional drilling rig.

The hydraulic unit also provides the means to continue drilling even if there is pressure on the relief well. The unit can contain the pressure and still rotate the drill string using the hydraulic rotary table or a power swivel. Again, hydraulic rig crews are familiar with pressure, and dealing with it is well within their expertise envelope.

Once the blowout is dead, the hydraulic unit can be removed, and follow-up operations such as abandonment can continue using the conventional rig that drilled the relief well.

5.3 LIVE WELL OPERATIONS

The definition of "live well" implies that there is pressure on the wellbore at all times. It also implies that this pressure is from an intentional continuous underbalanced condition or from an unplanned temporary event. One live well event is the unintentional kick as discussed above. Another live well event might be drilling with a fluid that intentionally provides a fluid hydrostatic column pressure less than formation pressure, known as managed pressure or underbalanced drilling, discussed in Chapter 6.

5.3.1 Casing/Liner Installation

Pressured casing and liner installations can be performed with hydraulic unit in snub mode, usually with small-diameter casing/liner less than about 9 in. OD. Larger-diameter casing installation is possible, but there may be some maximum diameter limitations.

5.3.1.1 Large-Diameter Casing

Large-diameter casing snubbing could be needed in areas where there are known pressured shallow gas zones. Water flows and shallow lost circulation zones can also result in pressure at the surface when it's time to run casing. Having snubbing capability for large-diameter casing is attractive in some situations, but there may be several limitations for this type of work.

Expulsion Force

From Eq. (4.4),

$$F_e = p(0.7854)\mathrm{OD}^2$$

When casing diameters increase even moderately, the expulsion force increases dramatically with the square of the pipe diameter. The difference in expulsion force between, say, 4½ and 9⅝ in. casing at the same pressure, is the multiple, 4.6.

So, for example, if there is a moderate pressure of 500 psi on the well, just holding 4½ in. casing would require a downward force of about 8000 $\mathrm{lb_f}$.

Actually, snubbing it would require 25%–30% more force to overcome friction for a total downward snubbing force of around 10,300 lb_f. If the same conditions existed and 9⅝ in. pipe was being snubbed in a well, the downward force to snub the casing in the hole, including friction, would be over 47,000 lb_f.

The reason for this example is to show what would be required for the largest-bore snubbing unit to push large-diameter casing in the hole. The through-bore ID of a 600 K unit is 13⅝ in., the same as the bore of the unit's snubbing BOPs (drift ID, 13.595 in. per API Specification 16). The largest-diameter collared API casing that can be run through a BOP of this size is 11¾ in. OD (collar OD = 12¾ in.). The largest-diameter casing that can be reliable handled in snub mode, even with specialized slips and snubbing rams, is only 10¾ in.

Snubbing BOPs

At low surface pressures, casing of this diameter would likely be snubbed through two annular preventers instead of snubbing ram-type BOPs. This allows for snubbing float equipment, especially centralizers, into the hole on the casing string. The operating (closure) pressure of the annulars can be adjusted to avoid crushing large-diameter casing while still containing well pressure.

Snubbing ram-type BOPs can be used, but there is little clearance between casing collars and the BOP bore. Misalignment of the pipe could result in casing damage when the rams are closed. The BOP bore may not have sufficient clearance for centralizers to travel through without hanging up and damaging the rams or the casing.

Friction

Total system friction while snubbing any pipe is composed of pipe-on-wall friction, friction through the BOPs, and jack friction. Hydraulic unit friction includes seal friction and the hydraulic friction of the power fluid and return fluid systems. All of these combine to require additional snub force above the theoretical force to push the pipe in the hole against well pressure.

Running large-diameter casing increases both pipe-on-wall friction and friction through the stripping BOPs. The larger the diameter of the pipe, the more outer pipe wall area is involved per unit length.

For example, if 4 in. OD casing is being run in the hole, the pipe has an external area of 12.6 in.^{2} for every foot of pipe. For 9⅝ in. OD casing, the external area is 30.2 in.^{2}/ft. Actual friction force involves the coefficient of friction times the area of contact. So, both the pipe-on-wall and BOP friction increase significantly because of the greater area of contact.

For smaller-diameter pipe, the additional friction is usually about 25%–30% of the snubbing force. For large-diameter casing, the additional friction could amount to a much larger add-on, possibly in the 60%–70% range. Filling the casing and running it in a fluid-filled hole would reduce the weight of the pipe due to buoyancy adding more snubbing duty to the hydraulic unit.

Fortunately, the neutral point in low-pressure situations would be reached fairly soon when snubbing casing. The pipe weight would then begin to impact the hook load and not snub force. The force required to overcome friction would remain, meaning that snubbing might still be required for some time after the true neutral point is reached just to overcome friction.

Snubbing unit selection should be made with this additional snub force in mind.

Jib and Winch Capacity

Pipe handling while snubbing large-diameter casing strings may also present a limitation that deserves consideration. Some large-diameter thick-wall casing is quite heavy for a full range 3 (±40 ft.) joint. This weight, if hoisted by a fully extended jib, can create significant bending moments on the jib mast, the shear stresses on its anchor points, and the counterbalance winch system.

The heavy casing weight may exceed the hoisting capacity of the counterbalance winch even if the jib is capable of handling the weight. This would require the use of the main winch that is often not hydraulically counterbalanced (assuming that the jib can be extended high enough). The main winch uses a traveling block as a force multiplier, so handling the casing would be slower than using the single counterbalance winch line.

The main winch would also be required to hold some tension on the casing to control sway at the top. The winch operator would have to be skilled at "following" the jack-down as the pipe is going in the hole to avoid excessive line tension and applying even more bending stress to the jib.

Some large-diameter casing jobs would not be possible using the hydraulic unit's jib and winch system. The pipe would simply be too heavy to manage safely. A crane would be required increasing the cost of the job and adding congestion to the wellsite.

These risks are not involved when snubbing large-diameter pipe with a rig-assist unit in a live well situation. The pipe handling is done using rig equipment. It is doubtful that the rig-assist unit would have a jib at all. Casing connection makeup with hydraulic casing tongs elevated above the snubbing unit is always riskier than making up the casing at rig floor level, however.

Other Considerations

Push-pull units or rig-assist jacks may be capable of moving the large-diameter pipe down the hole in many applications. Limitations involve the availability of large slip/bowl assemblies and the means of handling large casing tongs in the basket. There is always the issue of having stab-in safety valves of the proper size, and light enough, to be handled by personnel in the basket as opposed to having them available on the rig floor.

5.3.1.2 Small-Diameter Casing/Liners

Small-diameter casing strings can be installed readily by snubbing units. Some of the casing and liner sizes and joint weights are the same as those of drill pipe or tubing handled in the regular course of business for a snubbing services provider. So, slip/bowls and BOP rams are usually available.

The snubbing unit and BOPs for snubbing casing must be selected after calculating maximum pressures and force demands.

Casing Equipment

Crossovers, float collars, landing collars, liner hangers, external casing packers, liner top packers, polished bore receptacles (PBRs), and other components of the casing/liner string must be considered when snubbing/stripping pipe. Some of these odd-shaped items may not be conducive to snubbing.

There must be adequate points in the string for both sets of slips to set on the solid casing body as these devices are snubbed into the hole. Sometimes, it is necessary to place blank casing pup joints within the casing string to allow places to set slips and also to close BOP rams on solid pipe.

BOPs must be spaced so that these attachments can be snubbed ram-to-ram. Sometimes, one of the safety BOPs is used for snubbing some of these items. The snubbing BOPs may be too closely spaced to control pressure when long oversized or odd-shaped items are installed in the string. Alternatively, spacer spools that can swallow the entire length of the long item may be added to the stack. This increases the length of the stack and the height of the basket significantly.

External Casing Attachments

Most attachments such as centralizers are installed in the work window below the stationary slips and above the snubbing BOPs. A short work window may be used for rig-assist units. This may be the only place available to install a large-diameter centralizer while still maintaining pressure control.

The distance between the snubbing BOPs must be sufficient to include the centralizers in ram-to-ram snubbing. Note that if a centralizer is installed in the middle of a casing joint using a stop ring, it too can be snubbed using common ram-to-ram snubbing techniques.

Stack ID clearances must be taken into account for any external attachment. Small-bore snubbing BOPs and safety BOPs may not allow for the passage of certain large-diameter attachments like bowspring centralizers. There may be so much friction created while pushing these items through the BOPs and spacer spools that the snubbing unit's maximum pull-down capacity is exceeded. There is always the problem with these items hanging up on a shoulder or minor ID obstruction within the stack. These might have no impact on running pipe at all, but an external attachment could hang up on them causing significant difficulties.

Care must be taken during casing design to consider centralizer type when snubbing pipe. Instead of bowspring centralizers, another type of centralizer, such as a full-body rotating or nonrotating centralizer, might be a better choice for snubbing.

External Wireline, Cable and Power Lines

Several new technology proposals have been made that involve attaching sensing devices and cables, such as common wireline logging lines or fiber-optic lines, to the exterior surface of casing as it is being run in the hole. These would allow monitoring the casing string on a continuous basis and reporting production-related variables, such as pressures and temperatures, to the surface.

One proposal involves the permanent installation of an electric submersible pump (ESP) power cable on the outside of the casing string. This would allow ESPs to be pulled and rerun without power cable attached to the production tubing. There is a proven system for this type of installation with the power cable permanently installed. The small-diameter ESP is wireline or coiled tubing retrievable, and connection to the power source is a wet connect in a special receptacle at the base of the tubing string.

Another proposal is the permanent installation of a second, twin casing or liner string in a side-by-side arrangement. A directional hole could be drilled out of each one after cementing both simultaneously.

While intriguing, some of these ideas are not currently practical for snubbing. Side-by-side tubing strings have been run with dual slips and BOPs with dual pipe ram cutouts. Some dual and triple tubing strings have been run on dead wells by HWO units. ESP power cable can be attached to the outside of tubing in the work window. This can be done because there is no need for stripping the pipe in the hole ram- to-ram in a dead well scenario.

There are no available means, as yet, for a ram or annular BOP to seal effectively on the ODs of both the tubing and the ESP cable when they are run together in a well. Practically speaking, there would rarely be a well with surface pressure that would require an ESP (except if the well pressure built up during the shut-in period). Most are dead wells, or they would not need an ESP in the first place. The well must be killed or any surface pressure vented for the unusually shaped tubing or casing/cable combination before they can be run using current technology.

Future installations could involve snubbing odd-shaped casing strings in the hole possibly using encasement technology like CJS Engineering's FlatPak system for coiled tubing. This would require some type of special connection (a round threaded connection probably would not work), special slips, and BOP rams.

There is no reason that casing has to be round. Dual casings with an egg-shaped cross section having two compartments separated by a central wall could provide significant capabilities not currently available with single casing strings. Snubbing these unusual shapes would require modification of current BOPs, slips, and procedures.

5.3.2 **Production Tubing Installation**

One of the earliest recorded uses of snubbing equipment was for installing production equipment in live wells. These jobs involved running small-diameter tubing jet strings in gas wells in Louisiana for water removal without killing the well or pulling the production tubing. The other early use was for installing production tubing in pressured wells in California. In both cases, the Otis cable-style conventional snubbing unit was used.

In these jobs, the wells had already been perforated and flow-tested. In the Louisiana wells, dry gas had been produced for some time before water production started, probably the result of coning. The wells developed a column of water in the bottom of the well that produced a back pressure on the formation from hydrostatic pressure. Running a jet string using dead well techniques would have required killing the well. Instead, snubbing permitted running the jet strings without killing the wells or pulling the production tubing. Gas was injected down the jet string that lightened the water column allowing it to be expelled from the well, and gas production increased as a result.

In the Elk Hills Field (Elk Hills Naval Petroleum Reserve) in California, most of the wells' production tubing and packers were reconfigured without killing the wells. Regulatory requirements made it advantageous to hang a flow restrictor sub below the packer. Killing the well could have resulted in the perforations being covered by weighting material (barite) settling out over time. More importantly, the formation could be damaged by the kill fluid requiring long cleanup times. This work, performed in the 1960s, used conventional snubbing units along a completion rig. The jobs were fast and economical.

In both California and West Texas, wells were drilled into high-pressure formations below intermediate casing. The wells began to flow so they were completed by snubbing production tubing and a packer into the well. Once the tubing hanger was set and locked in at the surface, the packer was set, and the internal plug was pulled allowing wells to flow up the tubing. Killing the wells with weighted mud was not practical. An exposed thief zone would simply take the mud and the well would begin to flow again if killing was attempted.

There are numerous case histories in the literature in which similar work was done under pressure using snubbing units. In fact, one of the most common uses of snubbing units today involves the installation of production equipment in pressured, live wells. These installations include not only the tubing but also all the equipment needed for production such as seal assemblies, profile nipples, perforated nipples, screens, packers, sliding sleeves, and the tubing hanger seal assembly at the surface.

This type of work on new wells often requires wellbore preparation prior to running the production equipment. This work can involve casing scraping, debris cleanout, displacement with clear completion fluids such as weighted brines, and other similar work. These jobs are necessary to ensure that the production tubing and jewelry make a single trip into the hole to initiate production. Each time this hardware is made up and broken out, there is the possibility of thread damage and leakage.

Usually, the production tubing is hydrostatically tested going in the hole to isolate any leaks in the tube or connection after makeup. This job is expensive and time-consuming, so it's important to limit tubing testing to the final trip in the hole.

This section discusses those steps necessary for successfully preparing a completed (open-hole or perforated) well to receive production equipment and for running the equipment in the hole.

5.3.2.1 Hole Preparation

Drilling operations rarely leave a clean hole suitable for long-term production. Cuttings, fines, mud weighting materials, low-gravity solids, mud filter cake, mud rings, salt accumulations, and other materials are often left behind inside a wellbore when the drilling operation is complete.

"Evil" solids pushed into a formation can block pore throats adding skin that suppresses optimal production flowrates. Skin is near-wellbore damage that acts as a barrier to fluid flow from the formation into the well. Old dehydrated mud chunks can plug surface production equipment and flow lines. Silt collections may be difficult to remove. Perforation gun debris and formation/cement fines routinely plug chokes. Burrs left inside the casing from perforating can cut packer elastomer elements resulting in failures when a packer is run through a perforated interval and set below it. It is prudent to remove as many of these potential problems as possible before making the final production tubing installation.

In many wells, this preparation work is done prior to perforating when there is no pressure on the well and it cannot flow. Well preparation when there is no pressure on the well can be done with a conventional drilling rig, a completion or platform rig, or an HWO unit since no snubbing is involved. This may be the best and most cost-effective way to clean up the well making it ready to receive production equipment.

Sometimes, clear weighted brines are used to provide hydrostatic pressure to balance formation pressure, and all the completion work, including production tubing installation is done on a dead well. Other times, the well is not perforated until the production tubing is already in place and tested. Again, dead well techniques and equipment are needed without snubbing capability, at least until there is pressure on the surface for some reason.

In live well preparation work, snubbing is required.

5.3.2.2 Open Holes

Open holes are uncased sections of wells drilled into productive reservoirs. These are intentionally left uncased, or at least uncemented, to expose more formation for fluid flow into the wellbore without perforating individual zones.

An open hole can develop pressure at any time due to gravity segregation of drilling mud left in the hole at the end of the drilling operation. Gravity segregation is the process by which weighting materials such as barite settle to the bottom of the mud column leaving an unweighted fluid near the top. Eventually, the loss of overall hydrostatic pressure from the mud column allows formation pressure to exceed hydrostatic pressure. The well may not flow since it is full of fluid. It will develop pressure at the surface, however, and just opening a valve at the surface can initiate flow from the now underbalanced well.

Cleanout strings are routinely snubbed into these completions to clean both the open-hole and the cased-hole sections of solids and debris.

Open Hole Cleanup

There will be some debris left in every open-hole section after drilling especially horizontal and high-angle laterals. This debris can include drilled cuttings and fines; low-gravity solids; weighting material from the mud; and possibly metal shavings, rust, scales, and other materials deposited during drilling operations. Drilling mud is traditionally dirty (in terms of completion work) no matter how well mud cleaning equipment on the rig performs.

This debris usually settles to the low side of the hole beginning soon after the drill string is pulled for the final time. Mud plastic viscosity lasts only a brief time under quiescent conditions as wellbore temperature recovers back to its original geothermal level. Solids drop out quickly since there are no viscous forces to keep them suspended in the fluid.

Collections of these materials can simply lay dormant, “cooking” in place before completion work starts. There could be a considerable delay lasting from weeks to months if the drilling rig is not used for the completion. By the time completion operations begin, there may be a nasty accumulation of hardened cement-like material lying along the low side of the hole with pressure at the surface. In some cases, these solids can form solid plugs or rings that must be drilled out before the well can be completed.

This job usually requires a pipe work string, tubing or small-diameter drill pipe, fitted with a cleanout bit and one or more stabilizers. It is snubbed into the open hole (if there is pressure on the well) and rotated to break up and circulate out the fill using a “clean” completion fluid of some type. This can be WBM or OBM that is heavily gelled to provide lifting capacity for circulating the debris out of the hole.

The bit may be a conventional bit, but sometimes, the hole is reverse circulated to provide higher fluid velocities. The bit will probably be center bored or have no jets installed to avoid debris plugging. There is no need for additional drilling, so jets are not needed anyway. Special subs with side jets may be included in the work string and simple pressure-activated underreamers be used to scrape the open-hole walls removing mud filter cake and LCM accumulations.

Usually, the open hole is circulated until no further debris is seen on shaker screens. This may involve several hours to ensure complete hole cleaning during which time the work string is rotated and reciprocated to keep the debris stirred up, especially in horizontal open holes.

At the end of the cleanup in vertical holes, a series of pills may be circulated. These can be viscous pills interspersed with ungelled mud pills followed by additional gelled, weighted pills, each having different mud properties. All of them are designed to remove various types of debris from the wellbore. The final pill is usually a highly viscous pill often made from clean fluid.

The use of cleanup pills is neither effective nor recommended in horizontal or high-angle holes. Mechanical stirring of the cuttings by rotating and reciprocating the pipe is far better and much less expensive.

Some wells are also intentionally allowed to flow briefly during this cleanup to remove mud filtrate and solids from the formation. There is a risk in allowing wellbore fluids to enter the well. The flow could cause the well to kick adding risk from oil or gas in the fluid system.

Following the open-hole cleanup, the work string is usually pulled from the hole.

Cased Hole Cleanup

Debris accumulations in the cased section of the well may also require cleanup especially in directional wells. There may be mud cake coating the walls, salt, or adhered formation fines that will eventually end up in the bottom of the hole unless removed. Mill scale, varnish, rust, pipe dope, and trash left inside the pipe could also be present.

Usually, a single or tandem casing scraper is run on the work string to the base of the casing. Then, the casing scraper is pulled up the hole and worked over certain areas of the pipe, such as planned perforation intervals and packer setting depths, to ensure the cleanest casing possible. If the well has both a casing and a production liner, two sets of scrapers are run with the upper large-diameter scraper spaced out so it does not enter the liner. Both are used to clean the casing as they are pulled out of the well while circulating.

Sometimes, the casing is cleaned before cleaning out the open hole. This is to ensure that no debris from the casing falls into the exposed open hole. It all depends on experience in the area and the operator's preference.

Sand Control Equipment/Preperforated Liners

In many wells, sand control equipment is run into the open hole following cleanout. These may include wire-wrapped screens or prepacked screens. When the screens are to be gravel-packed, a variety of other equipment is required. Screens are needed to prevent sand from entering the wellbore due to viscous forces and plugging the tubing and surface production equipment. These can be snubbed safely into a live well.

The same is true of preperforated or slotted liners. These are often run to prevent caving and the wholesale loss of entire hole sections due to insufficient borehole stability. They can be combined with some types of sand control equipment such as small-diameter prepacked screens.

Snubbing these "porous" pipe segments in the hole requires several features. First, there must be a blank pipe (solid wall pipe with no openings) between individual sections of the screen or liner. These provide the place to close snubbing BOPs and/or safety BOPs isolating the perforated sections between them. Obviously, there must be spacer spools in the stack long enough to contain the joints or screens.

Secondly, there must be some type of plug inside each of the blank pipe segments or in the connections where they make up to the screen or preperforated pipe. These plugs are usually a baffle or drillable plug instead of a flapper or dart check valve. These plugs provide the primary internal barrier. The snubbing BOPs provide the primary external barrier.

A landing joint is commonly used to snub the screen and a solid pipe section into the hole such that the screen is completely below the BOPs. They can close on the plugged solid pipe to ensure that no flow is possible from the "porous" pipe section completely encased in the riser below it. This also ensures that the slips will not close on either a screen body or a section of the liner weakened by the drilled holes or slots in the preperforated section. Once the screen or liner is snubbed down to the stationary slips, the "landing" joint is backed out of the blank pipe, and another screen or liner joint is added, and the process is repeated using the same landing joint.

An alternative technique is to run a short pup between screens or liner joints that will remain permanently in the hole. The pup is preequipped with a drillable, millable, or retrievable plug. Where fracturing is anticipated, these are often drillable or dissolvable ball-activated check valves. The entire screen or perforated liner joint is snubbed into the hole in one pass with a sufficiently long spacer spool between the top and bottom snubbing BOPs to swallow the entire joint.

Usually, the screens or liner joints are hung off from inside the casing. They may be permanent or retrievable. It is necessary to drill out or recover any plugs inside them left from snubbing work. A second run with the work string is necessary to do this drill out unless the job can be done better, faster, and less expensively with coiled tubing or small-diameter jointed pipe.

5.3.2.3 Cased Holes

Like open holes, there is usually a need to clean up cased holes before completion. Cased holes are generally not perforated before the final cleanup is performed, but on occasion, some cleanup is necessary after perforating and before running the production tubing and jewelry (flow control nipples, profile nipples, packers, seal assemblies, etc.).

In some cases, multiple zones are perforated. Cleanouts or other preparatory work may be needed between perforations. The initial cleanout can be done before the first zone is perforated, but subsequent intervals must be cleaned or prepared with pressure on the well. Another example is when a sidetrack has been performed below existing perforations in a well.

Cased Hole Perforating

There are many completion variations that require cased-hole preparation after the initial completion with pressure on the well. One includes adding perforations and production equipment between them and the existing perforations.

Take, for example, the situation in which the lower zone in a multizone reservoir has been perforated and tested below a test packer set on a work string. The packer can be released, perforating fluid spotted over the next zone up the hole and the work string snubbed from the hole under pressure. This is not possible except with the use of a snubbing unit unless the well is killed.

Burrs from the added perforations must be removed before an isolation packer can be run. These burrs can cut packer elements resulting in the packer not setting or the seal failing prematurely. So, a casing scraper, mill, or hone must be run over the newly perforated interval. Usually as a part of this work, the end of the pipe is lowered to a point below the original perforations, and any debris from the perforating guns is also circulated from the hole to prevent choke plugging.

If another zone is to be added and tested up the hole, again, perforating fluid can be spotted as the scrapers/hones are snubbed out of the hole along with the work string, and the process is repeated.

Sand Cleanout

Sand accumulated in the wellbore during production can limit flow from the interval. This solid material must be removed before running production tubing and other equipment.

Sometimes, sand can be cleaned out by reverse circulating around a test packer to "vacuum" the sand from the hole. Other times, a separate trip must be made to remove the sand after pulling the packer. If the well has pressure on it, and there is a desire not to kill the well, the pipe-handling work must be done by a snubbing unit.

Cement Squeezing and Cleanout

Cement squeezing of existing perforations is often required to isolate a zone. There are several techniques to perform this work, most of which leave some cement inside the wellbore. Clearly, if existing perforations are to be returned to production, the cement must be cleaned out before production equipment can be installed.

Snubbing units can clean out cement and other equipment, such as drillable retainers left from this work with pressure on the well. This requires snubbing in the hole with a cement mill or bit on a work string. Snubbing, instead of a dead well HWO procedure, is used if there is the risk of a pressure increase once the cement plug is penetrated exposing lower perforations. Otherwise, the work must be performed with kill weight mud to ensure that the lower reservoir pressure cannot flow once the plug is penetrated.

5.3.2.4 Packer Fluid Placement

In many older wells, drilling mud was left in the hole when the packer was set above a perforated interval or open-hole section. This was done to avoid surface pressure until the production string could be installed. In other instances, the operator believed that the mud would provide a safety cushion to prevent high annular pressures by maintaining a hydrostatic head from the mud column in the annulus. A tubing leak would simply be a minor inconvenience since the mud column would keep the annulus from pressuring up.

Experience has shown that gravity segregation occurs in the annulus within a few months of initial packer setting and the initiation of production. A dense mass of weighting material, usually barite, collects on top of the production packer in the annulus with unweighted fluid in the top of the annular fluid column. Tubing leaks can create high pressures within the annulus due to this gravity segregation because there is limited hydrostatic pressure above the solid mass in the annulus (i.e., just unweighted fluid). Releasing and recovering the packer are complicated by the barite plug above the packer.

Now, most operators use a clear weighted fluid, often specially formulated heavy brines, containing a variety of chemicals in the annulus to protect the tubulars and to avoid expensive washovers to recover the packer in the event of a tubing leak or packer failure. These chemicals include the following:

- Corrosion inhibitor—a chemical, usually a filming amine, that avoids rust on the tubing exterior or the casing interior, wellhead components, and jewelry above the packer
- Oxygen scavenger—a sacrificial chemical designed to react with oxygen and consume it leaving an inert product behind that will remain suspended in the packer fluid
- Biocide—a compound that prevents the growth of bacteria, either aerobic or anaerobic, which avoids souring
- Fungicide—a compound that prevents the growth of fungus or mold in the packer fluid

There may be other proprietary components such as dyes (for tubing leak identification), slickners (friction reducers), and viscosifiers (used during initial displacement to ensure plug flow).

It is usually desirable to keep the packer fluid from being displaced into the producing formation. Many of these chemicals can create emulsions, scales, paraffins, and precipitates in reservoirs with incompatible fluids. These can add skin and have, in some cases, shutoff production entirely. Unwarranted, expensive secondary stimulation treatments may be required to remove the near-wellbore damage.

The best method of circulating packer fluid is to set the packer first, open a port sub with a sliding sleeve positioned above the packer, and circulate the fluid in a dead fluid annulus with no pressure. If circumstances dictate circulating packer fluid in a pressured situation, the simplest method is to hold only enough back pressure on the annulus to be sure that the packer fluid is not pumped into the formation. Fluid friction through the system at the displacement pump rate can be calculated easily. This is added to the shut-in surface pressure, and that pressure can be held on the annulus throughout the displacement. Complex fluid friction models involving complex downhole configurations are not necessary.

Obviously, to pump anything down a tubing string that has been snubbed into a hole under pressure, either the plugs inside the pipe must be check valves or the plugs must be pulled prior to pumping. If there is pressure on the tubing after pumping the fluid, the plugs must be closed or be reset to continue snubbing the pipe. Most production tubing strings are equipped with short nipples having internal grooves, or profiles, in which plugs can be set by wireline or slickline so the tubing pressure can be contained.

5.3.2.5 Tubing Hanger Landing

Landing the tubing on a hanger inside the tubing head at the surface in a pressured well may be desired for some completions. The tubing hanger has a larger diameter than the tubing body. The string could go from pipe-heavy (stripping) until the tubing hanger enters the tubing head and then suddenly become pipe-light as the expulsive force increases the moment that the initial seal is made. This can push the "donut" out of the tubing head and buckle the landing joint with no prior warning in high-pressure situations.

The snubbing unit operator must be aware that the snub load could increase significantly when this event occurs. In some situations, this could require the use of a thick-walled landing joint, such as heavy-weight drill pipe or even a blast joint, to successfully hold the tubing hanger down until the set screws are run in and locked.

This same situation can occur when a packer element is set but the slips do not hold. The force acting across the casing interior is now driving the net snub force and not the pressure differential across the tube body in the snubbing BOPs.

Obviously, in both situations, there is a pressure differential across the larger-diameter member. For the tubing hanger, this implies that there will be no increase in expulsion force as long as well pressure is trapped in the BOP stack above the hanger. The screws are simply run in to lock the tubing hanger down before bleeding pressure off the stack.

In the case of the slips not holding on the packer, bleeding off the annulus pressure is possible, but the packer may still slide up the hole buckling the pipe above the packer. A simple casing collar locator wireline log is all that is needed to determine if the packer is still where it was placed. Fortunately, this is a rare event. Usually, when the slips do not set, the packer rubbers will not expand properly and hold pressure. So, the annulus simply will not bleed down, and the packer will not take weight, or the tension cannot be pulled in the string. The only alternatives in this situation are to attempt setting the packer a second time or to pull the pipe string and replace the defective packer.

5.3.2.6 Initiating Production

One of the most significant advantages of live well completions is that nothing additional must be done to initiate production than to open the production tree valves and flow the well. There is no need to jet, unload, or swab the well to make it flow. A pressure underbalanced already exists, so flowing the well is simple. This, of course, requires that the hydraulic unit has been rigged down and a production tree has been installed.

Snubbing is not required from this point forward. Positive pressure on the well allows the well to flow once plugs required for snubbing are removed or disabled.

Sometimes, however, a jet string of small-diameter pipe must be snubbed into the hole to remove accumulated fill, heavy mud accumulations, or to jet the well with a light fluid. Often, this function is best performed using coiled tubing.

In certain circumstances, the snubbing unit can do the same job with small-diameter jointed pipe (“baby pipe”). One situation where this can occur, for example, is on a remote location with no access for a coiled tubing unit. Another situation is when there is a small platform with limited available space for additional equipment just to jet the well in. If the snubbing unit is already on the site and rigged up, it makes sense to kick off production by snubbing "baby" (small diameter) pipe in the hole to jet the well.

5.3.3 Recompletions

A recompletion is opening a zone in an existing well that is not currently available for production, injection, or monitoring. The operative term here is “opening” because there is some economic incentive to do so. It may be for regulatory purposes (protection of correlative rights), leasehold reasons (extend an existing lease through production), or to improve economics (increasing lease production). Stakeholder issues may require a recompletion for public relations purposes even though it may not seem logical from an operating viewpoint.

Recompletions apply to three basic categories of wells:

- Temporarily or permanently abandoned wells
- Shut-in wells
- Producing wells/active service wells

5.3.3.1 Abandoned Wells

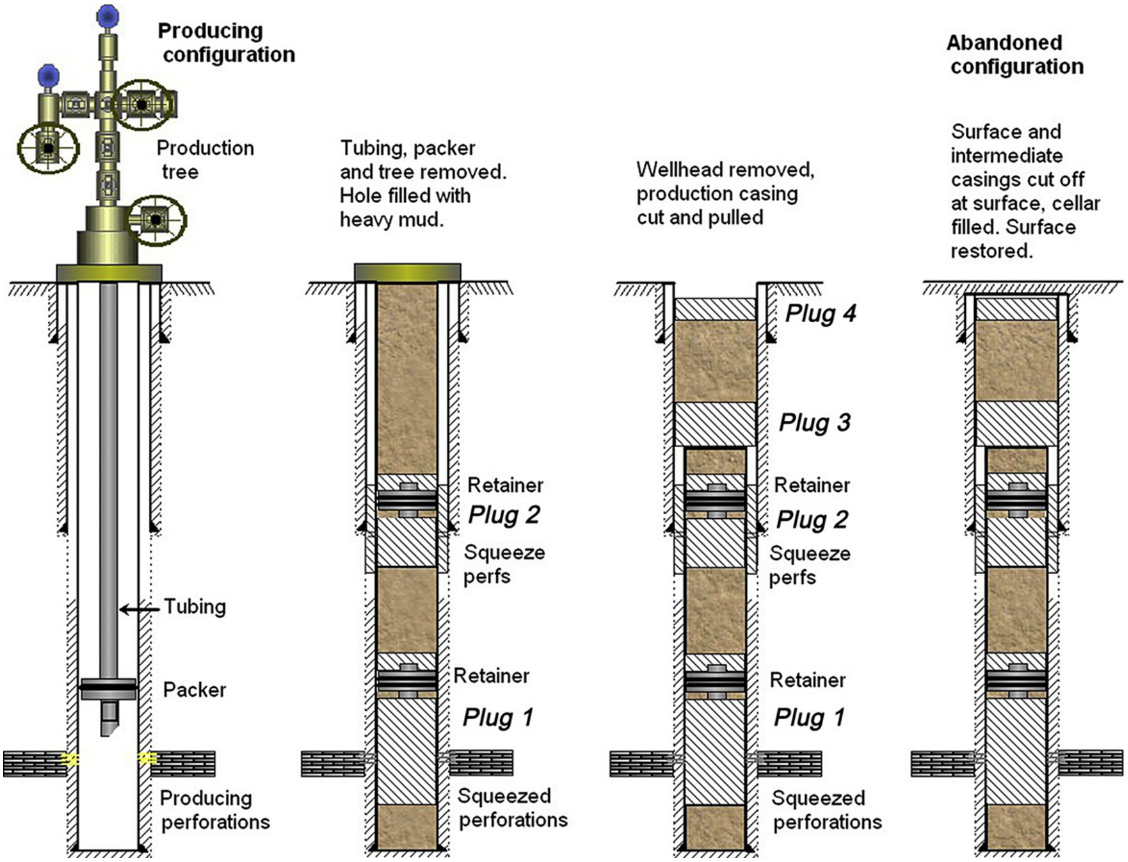
This term applies to three types of wells. One is a dry hole—a well that was drilled and did not discover hydrocarbons, at least in the quantities required to pay out drilling and completion costs.

Tax treatment for dry holes varies across the world. In many countries, a large portion of the drilling costs are completely deductible as expenses when the hole is unsuccessful. Drilling a dry hole is treated as a loss for tax purposes. If an interval was discovered but deemed to be of poor quality, it may never pay out the drilling cost or make a significant return on investment. The weak well might be worth more to the investors as a dry hole (i.e., a tax deduction) than a poor producer.

The second type is a well that produced successfully for a time, but its usable life ended when production fell below the economic limit. The economic limit is the point at which revenue from product sales is equal to lease operating expenses, taxes, royalty, and abandonment/cleanup costs. In short, production from the well was simply no longer economic.

Causes for this production shortfall can be numerous. There could have been simple depletion of the reservoir. The production drop could have been the result of a buildup of scales, paraffins, or asphaltenes in and behind the perforations. The well could have suffered a mechanical failure such as casing collapse, leak, wellhead component failure, or junk in the hole. Often, these wells are plugged and abandoned (P&A) without adequate analysis for recompletion possibilities in the interest of getting an old well out of the operator's inventory (Fig. 5.4).

Another type of well applies to a reservoir within an open wellbore that formerly produced but was plugged off to complete the well in another reservoir above or below the original perforations. Often, these are isolated below a permanent plug, or the original perforations were squeezed with cement. Regardless, the zone was abandoned for some reason. It may have been due to poor production rates, or the operator may have perforated another zone being produced by an offset operator to protect correlative rights (i.e., compete across a lease line).



■ **FIG. 5.4** P&A sequence diagram.

Any interval left behind in an existing wellbore can be recompleted if the wellbore condition is conducive to the job.

In permanently abandoned dry holes and plugged wells, wellbore re-entry is necessary. Initial steps in re-entering a plugged and abandoned (P&A) wellbore include nonrig activities such as the following:

- Excavating around the cutoff casing at the surface and constructing a cellar (onshore)
- Exposing the supporting casing or conductor by cutting back exterior casing stubs and removing cement between them, as required
- Extending the supporting casing to the surface or to the platform wellhead deck
- Installing a new wellhead with the proper size, strength, and pressure rating along with side outlet valves

- Testing the wellhead and casing extension with pressure sufficient to assure that the reconstructed well segment can contain expected surface pressure
- Nippling up and testing BOPs

While this sounds relatively simple, it may be very difficult depending on the condition of the old well at the surface, whether onshore or offshore. Some permanently abandoned wells simply cannot be re-entered.

It is at this point that a rig of some type must be selected. Most operators prefer to use conventional rigs because of perceived cost savings. These are usually smaller rigs than the one used to drill the original well since heavy casing string installation is not required. The original casing is still in place. Most of the re-entry work is dead well work (i.e., no pressure on the wellhead), at least at first.

Plugs in abandoned wells must be drilled out. This requires some rotary capability and a fluid circulating system. Often, small platform rigs offshore or completion/pulling units onshore are used for this work. They may or may not have all the components required, but much of the additional equipment needed for the job can be leased such as a power swivel, mud handling system, and circulating pump(s).

Surface plugs can usually be drilled out with no problems. Cement cuttings or other drillable plug debris can be circulated out easily. However, once the last plug is penetrated, there can be pressure trapped in the well just below the plug that is immediately liberated in the form of a kick.

CASE HISTORY

In 2003, an abandoned onshore well was found to be bubbling crude oil and gas from inside the previously plugged well. It was located in a state that requires a marker for dry holes and abandoned wells showing the lease name, the well's location, and the last well operator. Regulatory agency inspectors ruled that the well had to be replugged.

The Operator had his contractors excavate the old cellar and cut and strip back surface and intermediate casings to expose the original 5½ in. production casing. A 5½ in. casing riser was welded on the stub, and a new casinghead was installed and tested. A small workover rig was mobilized to the site, and an 11 in. ID 3000 psi BOP was installed on the wellhead flange. A power swivel and a single open-top tank and pump were rigged up. The unit picked up a short string of 2⅜ in. tubing for a work string. The intention was to simply drill out the old plugs and set new ones to satisfy regulatory authorities.

The surface plug was drilled out along with an intermediate plug at about 350 ft. Pipe was tripped in to the top of the next plug at about 2400 ft., a cast-iron bridgeplug (CIBP) capped with 10 ft. of cement above a 150 ft. open-hole section. The cement was drilled out, and the bit began drilling on the CIBP.

After a few minutes, the tubing started moving up the well pushing the power swivel into the rig's traveling blocks. The pipe continued being ejected from the hole at high velocity. Rig crews and the power swivel operator evacuated, while tubing was ejected from the well. The CIBP finally surfaced and lodged in the surface wellhead. The well began blowing oil and gas out of the wellbore with the remains of the mangled tubing work string twisted around the completion unit mast and the BOP stack.

The well stopped flowing as silt and cuttings bridged off around the CIBP. The rig operator managed to close the blind rams after the work string and bit were expelled from the hole. Pressure under the BOP increased to approximately 1800 psi.

The completion unit was rigged down, and a snubbing unit was rigged up. A work string of 2⅞ in. 8.7 ppf, P110, PH4 pipe was used to push the CIBP down the hole, and the well was successfully circulated with KWM.

The Operator decided to recomplete the well in the original San Andres open hole instead of replugging the well. The field had been under an active carbon dioxide (CO_2) flood for several years, and this well had responded as oil was swept to the wellbore from offset injectors. The 2⅞ in. tubing work string was hung off in the well, and the well flowed until pressure depleted. A permanent production tubing string and a pumping jack were installed. The well produced over 200 barrels of oil per day for several years.

Fortunately, there were no injuries and little environmental damage in this job. The Operator apparently did not account for the possibility that the old open-hole completion in this well could pressure up in response to the active CO_2 flood in the area. This was only discovered because of the failure of the original plugs placed a decade or more before the CO_2 flood began during the abandonment.

Here, the Operator benefited from a serendipity find due to leaking plugs. He also started a campaign to re-enter other abandoned producers in the field and found several that were producible. A snubbing unit was used in each re-entry to drill out plugs, recomplete the well, and equip them for production.

The outcome of this fortunate incident was that the Operator extended the life of his leases and made a considerable amount of money without redrilling the wells.

5.3.3.2 Shut-In Wells

A shut-in well is one that still has open perforations and possibly pressure on the wellhead, but the well is not actively producing.

There are many reasons why a well is shut in. Production from the zone could be at or near its economic limit, and stimulation/recompletion costs have not been budgeted in favor of more attractive prospects within the Operator's portfolio. Another reason could be that the shut-in well is holding a lease, and the risk of and unsuccessful workover of the well could result in the loss of the wellbore (and abandonment) and lease if the well had to be plugged. Another reason could involve disputes with other working interest owners (WIOs), the partners in the well, involving rework/recompletion procedures and costs. Some operating agreements require 100% approval before starting rework operations.

Some wells are shut in because the Operator is out of business. The former Operator may or may not have filed bankruptcy. If the Operator was an individual, the well may be tied up in an estate that has not been settled. Sometimes, wells are simply left as they were when the Operator walked away from them, with no intention of returning to rework or abandon the old well.

An orphan, or orphaned, well in Texas is defined as one that has been inactive for more than 12 months and/or the Operator has failed to file an organization report (implying that the business is no longer legally viable) for greater than 12 months. Most states in the United States and Canada have similar regulations. The plugging bond originally purchased by the Operator for each such well is forfeited to the regulatory authority, and the funds are then used to abandon the orphan well.

State and federal regulators are unconcerned about rework or recompletion prospects on old wells. Often, old wells suffer from a variety of mechanical problems. These could lead to surface leaks, spills, and freshwater interval contamination. So, regulators dislike leaving any well shut in too long.

Planning for a shut-in well recompletion involves several steps:

- Ownership of the current perforated interval or open hole must be ascertained to ensure that leaving the zone, if necessary, will not result in the loss of rights under the lease agreement.
- A complete well history must be developed including all previous attempts to stimulate or otherwise enhance production (e.g., installation of artificial lift). This assures that previous attempts to make the well's production economical have been made.
- Restimulation using modern materials and procedures such as fracturing (frac) should be evaluated before the zone is abandoned in search of a recompletion prospect somewhere else in the hole.
- Mechanical condition of the wellbore, both downhole and at the surface, must be determined before rigging up on the well and attempting any operations. The well may not be suitable for rework

or recompletion if it is plagued with holes in the casing, parted or collapsed casing, poor wellhead components, a fish or unrecoverable junk left in the hole, known thin-walled casing that will not withstand treating pressures, or similar mechanical issues. Permanent abandonment may be the only viable option without exposing the Operator to environmental or regulatory risks.

- Wellbore integrity in each prospective interval must also be determined. Some zones are damaged by exposure to fresh water, as an example. The water releases suspended clays within the reservoir that plug pore throats blocking production. Enlarged holes while drilling that were filled with cement, cuttings, or debris during casing installation may not be good candidates for recompletion.
- Obviously, there must be another zone in the well that has the potential to produce in paying quantities above the economic limit. Evaluation of uphole zones is often done by a team of engineers, geologists, and geophysicists working together.
- The possibility of commingling production from several intervals, including the shut-in zone, must be explored with regulatory authorities and WIOs. The well may not be a candidate for recompletion if rules do not permit combining production from several zones. It is unlikely that the WIOs would object to commingling. Making some money from the well is better than nothing, especially when they realize that the cost of abandonment could be the result.
- Planning should include the cost of the work and the anticipated production to determine if the recompletion is economically viable. There is little to be gained from spending money to recomplete a well for the "sake of science" unless information from a zone in the shut-in well would open a prospect on another well or lease. Only the government performs "sake of science" work; Operators do work to make a profit (at least those that intend to stay in business).

Snubbing can be used for recompletions especially if the procedure is to be performed without killing the well or abandoning the existing interval. This could be the case where commingling of several zones is practical. Some partially depleted zones may never be capable of unloading kill fluids such as brines that preferentially flow into the interval. There simply is not enough reservoir pressure left to expel the invading fluid. The incentive here would be to perform the recompletion underbalanced using a snubbing unit.

Snubbing units usually transmit any surface loads directly to the wellhead and surface casing. In some cases, the surface casing has suffered corrosion and cannot support these loads. The option is to install a frame that will transmit the load to the surrounding ground or platform deck (Fig. 5.5).

■ **FIG. 5.5** Snubbing unit support frame. *(Courtesy of Cased Hole Well Service.)*

Recompletion procedures are as widely varied as the wells and circumstances associated with each. One procedure successfully used on one well may not be the best one to use on the next well. Unfortunately, many operators believe in just doing the same thing to every well without examining the specific requirements for each well. This leads to false confidence.

In most recompletions, experience has proved that the cheapest option is not always the best option. Many operators believe that the lower the job cost, the better the outcome, which leads to a false economy in many cases, at least in this author's experience.

The procedure may be as simple as adding perforations using through-tubing guns and a wireline unit in the commingled zone option. This may not require pulling the completion at all and is often the least expensive option if wellbore configuration permits it to be attempted. The most expensive option could involve abandonment of a portion of the well followed by sidetracking and redrilling the well to the original or a new reservoir. Another expensive, but effective, option is to add horizontal laterals in an existing interval. Often, this work can be performed by a snubbing unit using underbalanced or managed pressure drilling techniques or an HWO unit equipped for drilling on a dead well.

The selection of equipment must be evaluated on shut-in wells to determine the best choice primarily from a safety standpoint. It makes little sense to open a new zone that would expose the well to high internal pressure using a platform rig or conventional drilling rig. This would require removing the platform rig and rigging up a snubbing unit to run the completion equipment with pressure on the well (or killing the well, in the alternative). Both of these options would be expensive and time-consuming. The entire recompletion could just as easily be done using a snubbing unit from the outset.

5.3.3.3 Producing Wells/Active Service Wells

Recompleting an active well presents a number of questions the first of which is, "Do I want to kill the well to perform recompletion?"

Often, this question is answered by the objective(s) of the recompletion. One objective, for example, might be to add perforations in another zone up the hole and commingle production with the active zone. Injection wells might require additional perforations to increase capacity. Sometimes, the well must be deepened to expose another formation not originally penetrated during drilling activities. Killing the well could damage both the reservoir in which the well is currently completed and the newly exposed zone. If so, recompleting using a snubbing unit and using underbalanced or managed pressure techniques may be the best option.

Other factors will probably influence the decision to recomplete an existing producer or service well to add production/injection capability:

- Economic analysis involves cost and risk, not just the increased revenue from enhanced well capability. Risk involves both mechanical risk (i.e., potentially junking the hole) and reservoir risk (i.e., damaging one or both reservoirs during the job). It's a matter of protecting existing production/injection capability or risking it in a potentially costly venture.
- The time value of reserves also involves a rigorous economic evaluation. Is it better to keep the reserves stored in an unexposed reservoir? Usually, economics are improved by producing available reserves as quickly as possible since the value of money from the sale of those reserves diminishes with time (not to mention higher anticipated future operating costs on any well).
- Leasehold may be shortened by recompleting and producing more reserves faster. A lease in an active area could be jeopardized by producing the reserves faster to improve the net present value of the wellbore if doing so would lead to premature well and lease abandonment. This could, in turn, lead to the loss of other opportunities on the lease.
- Regulatory approval may difficult to secure. Some regulatory agencies discourage commingling unless production from each interval can be accurately measured. Many do not permit downhole commingling unless all the commingled zones have essentially the same reservoir pressure or they are hydraulically connected somewhere outside the wellbore (e.g., a common aquifer).
- Protection of correlative rights is both a regulatory and legal issue that must be determined. Assume that one operator on one tract chooses to

commingle production from several intervals in a single reservoir by recompleting the well. The offset operator cannot do so for some reason. The commingling operator can drain reserves from the offset lease under this arrangement. This could result in regulatory and/or legal intervention, forced pooling, or revenue losses.
- WIOs may not approve the recompletion. When the well must be recompleted to protect the leasehold, the decision to fund the work is relatively simple. When the decision is discretionary, some WIOs may object to the recompletion, and others do not. Experience has shown that some WIOs are more conservative than others on certain operations that could increase production/injection capability. They would rather just keep the "bird in the hand."

Sometimes, the decision is not so complex:

- Competition for reserves across a lease or tract line can result in a decision to leave an existing production interval and recomplete in another reservoir to prevent drainage. Here, the intent is to leave an economically viable producing interval to prevent an offset operator from draining reserves from a zone up or down the hole. It may be that the offset operator has located an interval that produces more than the one in which the well is currently completed, so there may also be an economic incentive to recomplete the well and improve its net present value. The original interval in these cases is often squeezed, plugged off, or cased over until the new zone is depleted. Then, the well is recompleted a second time by re-opening the original producing interval.
- The need for additional injection capacity for continued lease operations may push the operator to recomplete an existing injector that has reached its maximum capacity. The operator would have to curtail production from producing wells on the tract without the additional injection capacity. So, while this may not result in additional production, it may be required to maximize income from production.
- An existing production interval may be approaching its economic limit as a single-zone well. Recompletion is required to keep the well and/or lease producing. Not doing so would require producing the well beyond its economic limit or shutting the well in.

The choice of the rig and procedure for the recompletion of an existing producing/injection well is rarely a simple decision. It is usually a multivariable optimization. Some of the components of this decision may be simple choices. For example, the cost of mobilizing a large conventional drilling rig to the jobsite may be too great to support the recompletion economically. It might be better to use a more nimble rig of some type.

CASE HISTORY

In 2010, a well located on a production platform in the Gulf of Mexico was producing at a low but economical rate from a Frio sandstone. An offset well was perforated in a deeper Frio sand and produced at an unexpectedly high rate flowing over 300 barrels of oil and 500,000 standard cubic feet (500 MCF) gas per day. The operator decided to recomplete the existing well to the new interval without damaging the original zone by bullheading KWM down the production tubing.

The job required pulling the production tubing and milling off the slips on the permanent production packer. Junk below the perforations had to be fished out of the hole before the new interval could be perforated.

Rig choices included a jack-up (a bottom-supported rig), a platform rig, or a hydraulic unit. Because the job was intended to eventually be a live well recompletion after perforating the new interval, a hydraulic snubbing unit was selected. Its daily spread cost was approximately $75,000/day. The jack-up rig would have required a mobilization cost of $500,000 and a daily spread cost of just over $350,000. The platform rig daily spread cost was over $125,000. So, even if the recompletion was intended to be a dead well workover, an HWO rig or snubbing unit would have been selected because of the cost differential between rigs.

The snubbing unit was rigged up, and the well was successfully completed in the new interval. Instead of killing the well with mud, two packers were set to "straddle" the old perforations. Profile nipples were installed in the tubing string above both intervals along with a wireline-actuated sliding sleeve between the zones. This allowed either zone to be produced selectively. Eventually, the two reservoir pressures approached each other, and the zones were commingled.

Procedures for live well recompletions vary considerably depending on wellbore and reservoir conditions. Care should be exercised in live well workovers when production packers are released to pull the tubing. The packer, if covered with silt, could act as a downhole piston with the full diameter of the well casing ID affecting upward force on the pipe. This could buckle the tubing and cause ejection of the string. Snubbing units are uniquely suited to avoid this situation where HWO units and conventional rigs are not.

5.3.3.4 Sidetracks

Sidetracking involves drilling a new hole section from an existing wellbore. In live well work, this involves the snubbing process to manage well pressure before, during, and after the new hole section is drilled. A hydraulic drilling rig equipped for snubbing is particularly well-suited to this type of work both onshore and offshore since it is not necessary to kill the well to drill the sidetrack.

Sidetracking may be required, for example, to go around a portion of the wellbore that contains irretrievable junk, collapsed casing or tubing, or to expose an undamaged portion of the reservoir to production. Live well sidetracking may be done to lengthen a horizontal hole segment or to add another lateral (or two, or three, etc.). Normal underbalanced (flow drilling) or managed pressure techniques can be used for this work to improve hole cleaning and avoid formation damage.

This topic is discussed in more detail in Chapter 6.

5.3.4 Live Well Workovers

Live well workovers involve maintenance work on an existing wellbore without killing the well first. These differ from initial completions and recompletions in that the original zone, which is often partially depleted, is returned to production instead of recompleting the well to another zone or to initiate production from a new well.

In the past, even the recent past, most wells were routinely killed before starting workovers to avoid a well control situation. Work was preferentially performed in dead well mode using conventional rigs. Many of these were never able to produce at the same level after the job as they were before the job because kill fluid invaded the depleted formation. In many wells, there was insufficient remaining reservoir pressure to expel the fluid from the zone. Some wells never produced again (i.e., they would not clean up).

Another issue involves relative permeability damage when water-based fluids are used in oil-producing reservoirs. Once the water invades the formation, the relative permeability to oil at the formation face is suppressed and cannot be restored due to a permanent damage mechanism called hysteresis. A similar problem involves wettability. If the formation, for example, is water wet and an aqueous completion fluid invades the zone, some of the water will be selectively "absorbed" by the formation, filling small pores and blocking oil or gas production. Removing the water is both expensive and complicated, if it can be done successfully at all.

In still other cases, water releases small clay platelets that plug pore throats resulting in permanent skin damage. Restoring the well to previous production levels involves fracturing through the damaged zone and packing the near-wellbore area with a proppant. This allows the formation behind the damage zone to flow into the wellbore unimpeded. Near-wellbore damage from dispersed clays cannot be removed. Often, the fluid used in fracturing is never recovered either.

Workovers must be economically viable. Obviously, one would not undergo the cost of a workover if there was a reduction in oil and gas production (revenue stream interruption) or suppressed injectivity in a service well.

Some operators have policies that set limits on economics for workovers. For example, one operator requires that workovers payout in 1 year with a net return on investment (ROI) of 3.0. Any job that is not predicted to meet these economic thresholds is required meet some other criteria (leasehold, wellbore life extension, recompletion prospects, etc.). If the well still cannot be economically reworked, it is shut in and warehoused for potential future use, or it is abandoned.

Operators with a number of wells will often evaluate wells in competition with each other for workover funding where budget and cash flow are limited. So, a well with the highest potential to pay out the workover cost quickly and return a high ROI gets the funding. Other wells are left to be worked over at a later time, or abandoned, depending on the amount of budget capital available.

Only three types of equipment can be used on live well workovers safely: coiled tubing, wireline, or snubbing units. Of these, coiled tubing and snubbing units are capable of pushing pipe into the hole against well pressure. Weight bars and tool weight are used to pull wireline into the pressured hole. The weight bars can overcome the expulsion force from well pressure because of the small diameter of the wireline. Wireline and slickline employ a lubricator that traps well pressure preventing fluids from escaping into the environment while still allowing vertical movement of wire into and out of the hole. Coiled tubing uses a stripping head to accomplish the same purpose.

Live well workovers are generally separated into three major categories:

- Downhole equipment replacement/repair
- Production restoration
- Stimulation

5.3.4.1 Downhole Equipment Replacement/Repair

Downhole production equipment is often worn or damaged during operations. Often, it is easier and less expensive to replace the defective piece rather than repairing it.

The job may be as simple as pulling and replacing a leaking tubing joint. Other jobs could involve replacing downhole pumping equipment, such

■ **FIG. 5.6** Dual stationary slips in window. *(Courtesy of International Snubbing Services.)*

as gas-lift mandrels, broken sucker rods, pumps, or leaking packers. Dual tubing string live workovers can be performed using dual slips and BOPs with cutouts for both tubing strings (i.e., ram blocks with two half-moon holes to accommodate and close on each tubing string). Fig. 5.6 shows one such arrangement.

One equipment replacement job that is **not** suitable for live well workover involves replacement of an ESP with the power cable strapped to the outside of the production tubing. There is no reliable means for a ram-type BOP or annular to close both on the tubing and around the power cable. These are often replaced during dead well workovers using HWO units or conventional rigs, however.

Some jobs may start as simple equipment repairs only to find that the issue was caused by another problem such as a casing leak up the hole or partial pipe collapse. At that point, it might be better to kill the well to perform other work with a conventional rig or an HWO unit rather than continue with a live well workover. Sometimes, this cannot be done, and the job must be done with pressure on the well.

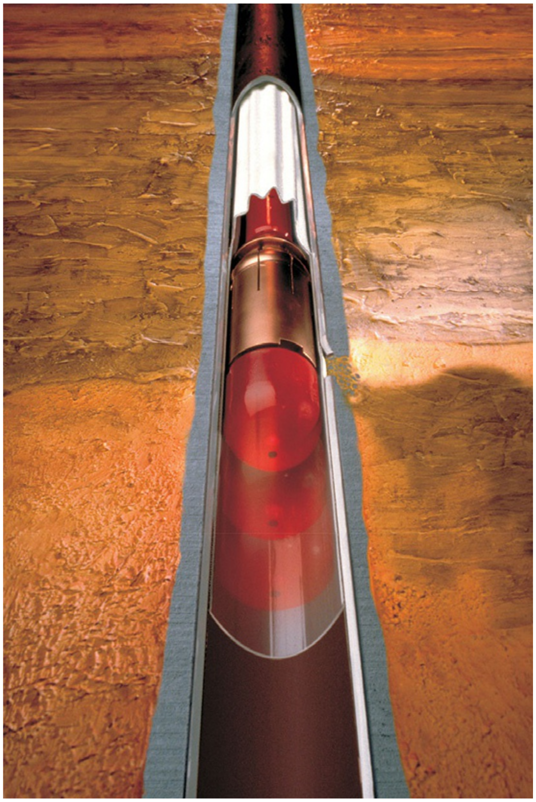
Casing Repairs

The general conditions define the type of casing repair necessary. One is a simple hole in the casing such that it cannot contain pressure or fluids. The other is a structural failure of the pipe where the casing separates in two. The pipe above and below this “part” may remain in alignment, or they may shift creating a very abrupt dogleg and sharp ledge. A third condition is a partial or complete casing collapse.

Any of these may result in pressure in the casing-tubing annulus that may require a live well workover using a snubbing unit. Sometimes, the repairs required are so extensive that the best option is to simply abandon the well that may, again, require snubbing capability for the abandonment procedure.

A casing leak with no other complication can be repaired in a variety of ways. One involves removing the production tubing and packer, setting some type of retrievable or drillable plug to protect the production/injection formation, and squeezing the hole with cement or some other permanent plugging material (such as an epoxy resin). After the squeeze cures, the remaining material must be cleaned out and the well restored to service.

Another type of repair includes the installation of an internal patch of some type. One service provider offers a patch that goes in the hole as a corrugated cylinder that is expanded firmly against the inside surface of the casing. This provides a "skin" of new steel to the inside of the pipe without reducing its ID significantly (Fig. 5.7).



■ **FIG. 5.7** Internal casing patch. *(Courtesy of Weatherford International.)*

The repair strategy using either of these techniques, or both, depends on several factors such as the depth of the casing leak, the number of holes involved, the cement integrity behind the casing at the hole depth (if any), the age of the well, and the cause of the hole, if it can be determined. If the hole is deep in the wellbore where there is good cement integrity around the casing, the less expensive cement squeeze may be the best option. If the holes are due to a packer slip punch-through or unwanted shallow perforations, the casing patch may be the best option.

Many shallow casing leaks in older wells are due to corrosion. Some shallow formations, such as San Andres in West Texas, produce H_2S, which can externally corrode casing at shallow depths resulting in both a leak and pressure in the annulus (not to mention toxic gas). This may require squeezing the hole with cement followed by a casing patch in a belt-and-suspenders approach. If several holes are involved, there is a good chance that the casing will eventually part and shift. The casing patch improves the odds against this type failure.

Casing parts can also be repaired using the casing patch if the pipe ends are still aligned or only slightly misaligned. The patch can "pull" the casing back into alignment and provide a bridge that may last for some time. This type of failure may require a stronger steel patch.

Another good option is an expandable liner. These liners are designed to run inside the casing. In some systems, the liner has expandable external seals and is coated with a temperature-set epoxy resin. The liner is run through the damaged casing, which aligns the casing. Then, an expander "bullet" or "cone" is hydraulically displaced up the hole. The liner is cold worked and expanded hard against the inside of the casing. The seals are extruded, and the resin is heated and flows between the two pipes creating a permanent long-lasting seal.

The ID of the expanded liner is smaller than the original casing. It is also smaller than the ID of the internal casing patch.

Unfortunately, both of these systems are quite expensive. They may still be more economical than other options, however. One of these expensive options is to abandon the leaking well and drill a replacement.

Another option is to simply install a small-diameter conventional pipe liner across the parted casing. This is a liner string run inside the casing, hung off, and cemented using normal liner installation techniques. This restricts the ID of the hole considerably and may require a different type of production tubing-/packer-type completion.

Collapsed casing repairs depend on how badly distorted the casing is. If it is simply a bit out of round (i.e., egged), a set of eccentric rollers on a central mandrel can be run into the collapsed area. Rotating this tool causes the rollers to successively push the wall of the casing back out and into a round cross-sectional shape. Casing rollers have been used for decades to round out partially collapsed casing.

Another option is to simply mill out the collapsed casing using a tapered mill or section mill. Then, an expandable casing patch or liner can be run and installed through the bad section using techniques described above. The problem with milling out a bad casing segment is the risk of the mill sidetracking and drilling a new hole. When this occurs, getting back into the original wellbore is often a lost cause.

In the worst-case scenario, the casing cannot be repaired using any technique, or the well is junked during the job. There are few economical options in an old well except to plug and abandon the hole. A replacement well can be drilled or the site abandoned if there are insufficient reserves to justify a new hole or continued recovery operations.

Fishing

A fish is an unwanted obstruction in a wellbore that interferes with production/injection or normal well maintenance operations. It may be recoverable or permanent.

Fishing is the act of recovering the fish using a variety of techniques and tools many of which can be run with pressure on the well. In fact, a snubbing unit is an excellent device for fishing because of its ability to turn the work string and the fine control of vertical motion and weight application using a hydraulic jack instead of a block-and-tackle hoisting system. Fishing with a snubbing unit under pressure is often referred to simply as "snub fishing."

Fishing is a unique type of live well repair workover. It is intended to restore mechanical integrity to an active well without killing the well. This may involve removing a restriction to ensure long-term service even if the fish is not reducing production. Sometimes, the fish must be removed to satisfy regulatory requirements, which are often as much an impediment to long-term production or injection as a mechanical or hydraulic problem.

Some fishing jobs require more than just attaching some tool to the fish and pulling it out of the hole. Often, some secondary problem has developed as a result of the fish being in the hole in the first place.

Take, for example, the situation in which tubing has parted in the hole above the production packer. Re-attaching to the tubing stub "looking up" in the wellbore might require cleaning fill from the top of and around the fish. Not only can a snubbing unit raise and lower the cleanout string (including wash pipe to swallow the top of the fish) with pressure on the well, but also it can turn the work string using the hydraulic rotary table.

The tubing might have been corroded to the extent that simply reattaching pipe to the top of the fish would not be a long-term solution to the problem. So, milling or cutting the pipe below the corroded section might be required to recover the remainder of the fish. Again, the snubbing unit is ideally suited for performing this work with pressure on the well.

These tubing recovery and repairs are performed quite often. Downhole repairs that involve fishing and tubing/injection strings are often the object of the repair strategy. Tubing, by definition, is not permanently installed (like casing). So, when it fails, recovering it for partial or total string replacement becomes both a cleanout and a fishing job.

The literature contains several case studies of snub fishing in conjunction with downhole repairs with constant pressure on the well.

In the case of a pressured injection zone, killing the well may not be possible or practical. The weighting material in the KWM could damage the injection zone impacting its future utility. If killing is necessary, it might involve the use of expensive heavy brines that will ultimately be lost to the formation. Economics might favor snub fishing under pressure rather than killing the well.

Another feature of a snubbing unit that facilitates fishing is the use of the pull-down feature of the jack. Some fishing tools require that weight be set on the fishing tool to attach it to the stub looking up. In shallow fishing jobs, this can be done using the pull-down (snubbing) capability of the hydraulic unit. It is unnecessary in this type of jobs to add drill collars or heavy-weight drill pipe/tubing to the fishing string for weight.

Several excellent books are available that discuss downhole tools and procedures for fishing work. Most of these assume that the job is being performed in a dead well scenario using a conventional rig. Not only is live well fishing possible using snubbing or coiled tubing units, it is desirable under certain circumstances. Obviously, if a conventional rig is not available or too expensive, a snubbing unit offers a good alternative for other specialty work.

Standard fishing tools can be used with snubbing and HWO units. There are no special "snubbing" fishing tools necessary as there are with coiled tubing, for example. The fishing string can be manipulated by the snubbing unit just as it can be with a conventional rig. One of these capabilities is the ability to rotate the pipe.

Obviously, there must be some type of plug inside the fishing string to prevent pressure and fluid from the well escaping through the work string at the surface. The requirement for a plug inside the string is often used as the excuse offered to justify why the well must be killed to fish, especially if wireline work is a necessary part of the fishing job. There are ways to avoid this apparent conflict.

One way is to snub the pipe and fishing tool into the hole, latch onto the fish, and then rig up a wireline lubricator on top of the pipe above the work basket. This allows the wireline unit to recover the plug from the fishing string or production tubing below the top of the fish. It can perform other wireline work as necessary. If the fishing string must be lowered or raised, the snubbing unit can manipulate the pipe with the wireline lubricator in place (for short distances, at least). The lubricator can be rigged down at any time after wireline tools are pulled out of the hole.

In wells with minimal pressure, or dead wells, the plug used to prevent flow up the fishing string can be altered to allow wireline and tools to be run through it. In this technique, the plug is open as long as there is no flow through it. It closes if the well should start to flow up the pipe, however.

The best way to achieve this is to remove the spring from a flapper-type check. This allows the flapper to simply hang down (dangle) inside its housing. A wireline lubricator is installed on top of the pipe, and wireline tools are run through the disabled check valve. The flapper will continue to hang down and remain out of the way without interfering with wireline operations. If pressure is encountered, the wireline unit can simply set another plug above it if the lubricator is still rigged up. If not, the wireline lubricator can be nippled down, and fishing work can continue.

The flapper will continue to hang open unless the well begins flowing up the fishing string. Then, the flow creates a vacuum due to Venturi effect, and the flapper is pulled upward and closes on the seat sealing the fishing string. Once closed, the wireline unit can again be rigged up to set a secondary plug above the closed flapper check. Snubbing work can continue normally.

Snub fishing also differs from dead well fishing in another significant way. Once the fish is brought to the surface, it too must be snubbed out of the hole under pressure. The snubbing and safety BOP rams must be configured to snub both. Sometimes, the fish is the same size as the fishing string (e.g., tubing or drill pipe fishing string and production tubing with the same body diameter). In other cases, the fishing string is snubbed out of the hole, and all the rams must be replaced with different size rams to fit the fish. Variable bore rams (VBRs) in the safeties can be used to avoid part of this reconfiguration problem. Changing the stripper BOP rams to fit the fish is usually the preferred option instead of using safety ram for snubbing. The VBR ram blocks are not well-suited for snubbing because the rubber elements wear quickly. VBR ram blocks are expensive too.

If the fish is not capable of holding pressure due to holes in the pipe or the absence of an effective internal plug, there may be the need to adopt special techniques to snub it out of the hole. One is to temporarily kill the well to pull the fish. This can require re-killing the well several times or pumping fluid continuously down the annulus at a slow rate until the fish is out of the hole. Another option is to set one or more plugs inside the fish, such as a magna-range bridgeplug, using a wireline unit. For other short fish without pressure-holding capability, such as an expended perforating gun, a stack with a sufficient spacer spool length is required to swallow the fish at the surface. The entire fish must be pulled above the blind rams and isolated before it can be removed.

Snub fishing has become more popular recently because of the increasing inventory of partially depleted wells coupled with the need to maintain maximum production for economic reasons. Many of these cannot be killed, or they simply will not recover and produce economically following the job.

CASE HISTORY

A Morrow gas well in the Delaware Basin of West Texas was depleted to the point that even the small fluid volumes required for minor-scale inhibitor treatments caused a production rate decline that required several weeks to recover. The load fluids from these small volume jobs were never fully recovered. The well produced only gas and a small volume of condensate. Morrow wells are historically sensitive to freshwater.

Pressure in the annulus led to the conclusion that the tubing had developed a leak. A wireline-conveyed multifinger caliper survey showed that the tubing had parted about 50 ft. above the production packer at 12,645 ft. The caliper also showed that the tubing had been eroded in the area of the failure probably due to early high-rate gas flows that drew sand into the wellbore along with gas.

Several options were considered for fishing and repairing the tubing string. One was to kill the well with brine, pull the tubing, and recover the tubing stub and packer using a conventional workover rig. The calculated BHP showed that the lightest commercial brine available was far too heavy to avoid significant losses to the formation even if the perforations were first plugging off with a diverting agent. Fluid retention in the thin Morrow sand could have caused the well to cease flowing altogether.

Coiled tubing was considered, but the well depth and the string to run fishing tools made the use of coiled tubing unlikely. Further, milling slips off the packer, if necessary, required circulating the well to operate the downhole motor.

A decision was made to work on the well under pressure using a snubbing unit. The snubbing unit was rigged up and pulled the production tubing from the well. The condition of the end of the pipe showed that the top of the fish would have a thin wall that might collapse if efforts were made to release the seal assembly from the polished bore receptacle (PBR) in the top of the packer. It would be better to cut the tubing just at the top of the packer leaving a 10 ft. fishing “neck” above the seal assembly hoping for more strength in the fish.

A work string of 3½ in. tubing was run in the hole with a short skirt and cut-lip guide to slide over the top of the fish. At the top of the skirt, a long-catch overshot was run with a grapple to fit the production tubing OD. A profile nipple with a plug was installed just above the overshot.

The overshot engaged the fish, and tension was pulled on the string. A wireline unit was rigged up on top of the work string using a crane. The wireline pulled the plug from the profile nipple exposing the interiors of both the fishing string and the fish. A magna-range composite plug was set in the fish just above the top of the seal assembly. Then, a chemical cutter was run, and the fish was cut 12 ft. above the seal assembly. The plug was reset inside the 3½ in. work string, and the wireline unit was rigged down.

The work string was pulled from the hole to the overshot. The snubbing BOP rams were changed out from 3½ to 2⅞ in., and the tubing fish snubbed out and laid down. An examination of the bottom of the recovered fish showed that there was sufficient wall thickness to support further work.

The work string was rerun with an overshot and a set of oil jars. The fish was engaged and latched. Tension was pulled on the fish, and the jars were fired one time. Tension was immediately lost back to the approximate weight of the work string. When the work string was pulled from the hole, it was found that the remaining tubing fish and the seal assembly were both recovered.

A hone was run on the work string, and the PBR was dry polished with the well flowing. A new seal assembly and locator sub were installed on the base of the production tubing, and new tubing was picked up to replace all the eroded pipe. The production string was snubbed in the hole, and the seal assembly was stabbed into the PBR. Pressure was bled off the annulus showing that the seal assembly was holding. The tubing was landed in the tubing head. A braided line unit pulled the plug from the profile nipple above the seal assembly, and the well was returned to production through the tubing string with no loss of rate due to fluid retention.

5.3.4.2 Production Restoration

Production restoration involves removing some restriction to continued production or injection from/to a zone allowing it to resume at the previous level. The three most common impediments involve the collection of paraffin, scale, or sand inside the wellbore.

Paraffin Removal

Paraffin is a catchall term that includes waxes and asphaltenes as well as long-chain hydrocarbons that have condensed and plated out inside production equipment downhole. The paraffin can also include silt, fines, and formation sand.

Paraffin accumulations can restrict tubing, packers, and wellhead equipment by reducing the ID of the conduit resulting in fluid friction back pressure on the producing formation.

Paraffin can be removed in some wells by heating the tubing in some manner to melt the material allowing it to be produced along with fluid from the well. Wireline (sand line) tools have been developed that can remove certain amounts of paraffin. These paraffin cutters are designed to penetrate through and loosen the paraffin layer inside production tubing and then pull the free paraffin from the hole.

When the accumulation is too thick to permit either of these methods from being used, the tubing is often pulled and replaced. Sometimes, the tubing is pulled and heated at the jobsite to remove the accumulated paraffin. It is then rerun, and production is reinitiated.

Wells are commonly killed to remove paraffin-blocked pipe. This can be done in a live well situation, however, as long as a plug can be set in the base of the pipe string (a difficult task in most badly plugged pipe strings). If the pipe can be snubbed out of the live well, the costs of recovering the kill fluid and kicking the well off to flow again are avoided.

Scale

Scale is another catchall term that includes the accumulation of a hard layer of material that is deposited inside production equipment, both downhole and surface, from physical changes to produced or injected water. Chemically, scales are inorganic and are composed of molecules having a positive metal ion combined with negative inorganic ion such as a carbonate, bicarbonate, sulfate, silicate, tungstate, or other chemical group.

Like paraffins, a scale accumulation reduces production equipment IDs, and the additional friction they create acts as a back pressure against the

■ **FIG. 5.8** Scale accumulations inside tubing. *(Courtesy of Schlumberger.)*

formation. In some cases, the scale can completely close off the production tubing. In injection wells, scale can restrict injectivity across the perforations or in the injection tubing (Fig. 5.8).

Usually, scales accumulate where there is a pressure and/or temperature change. This creates an oversaturation of the scaling material in produced water or injected water, and the scale plates out where the produced water contacts a surface. This could be inside the casing at the perforations; inside the tubing at any point; or inside surface wellhead equipment, valves, flow lines, or separators.

Some scales are relatively easy to remove. One specialized type of scale is salt. Most formations were once filled with ancient seawater. One component of seawater is sodium chloride, or salt. Salt rings and salt bridges are quite common. Both can restrict production and prevent wireline tools from going in the hole.

Fortunately, salt is quite soluble in fresh water. Removal of salt accumulations is simply to pump fresh water down the hole to dissolve the salt. This works well until the fresh water contacts a formation that is sensitive to it (clay dispersal) or incompatible with it (precipitation of solids in combination with formation fluids). Fresh water can sometimes trigger paraffin or asphaltene precipitation. So, the simple solution to salt removal may, in fact, cause more serious issues.

The two most common scale types in the oil field are carbonates and sulfates. Both may be present having been codeposited simultaneously along with paraffin, salt, and various corrosion products inside tubing and other production equipment.

Carbonates are the combination of an ion, such as calcium, in combination with a negatively charged carbonate radical that has the chemical formula $CO_3^{=}$. The metal ion and the carbon atom form the nucleus of the molecule with the three oxygen atoms forming the corners of the triangle-shaped molecule. The oxygen atoms force the molecule into a flat plane, which is then deposited inside the wellbore and serve as a "seed." As other scale molecules precipitate, they join the "seed" to form thin scale sheets.

Carbonates are fairly soft, and they can be removed easily from the inside of tubing by just drilling them out with a full-diameter scale mill. Carbonates react readily with common acids used in the oil field such as hydrochloric acid (HCl). Again, the problem may be that reaction products may not be compatible with formation fluids causing precipitation of other materials inside the wellbore and formation.

One very good solution is to mill out the carbonate scale while flowing the well so that formation fluid cools the mill and carries out the pulverized scale to be recovered at the surface. This live well workover involves the use of a snubbing unit. A small-diameter pipe work string and a mill or bit are snubbed in the hole. When scale is encountered, the pipe is rotated to mill out the scale. Circulating the hole is unnecessary as long as the well is capable of flowing underbalanced during the job although most workovers involve pumping some fluid at low rate down the pipe as it drills the scale.

The other common scales found in the oil field are sulfates. These are the chemical combination of a positive metal ion combined with a sulfate radical with the chemical formula of $SO_4^{=}$. Calcium and magnesium are two of the most common metal ions in this molecule. However, one very nasty scale includes barium as the metal ion forming barium sulfate (barite) inside the tubing.

All of the sulfates and their sister molecules, the silicates and tungstates, have a tetrahedral shape with oxygen atoms on the points of the three-sided pyramid. They are very hard and highly abrasion-resistant. They are also chemically very stable and do not react readily with common acids.

Milling out sulfate scale can be time-consuming and expensive. They are quite shear-resistant. Like the carbonates, sulfate scale deposits can be milled in an underbalanced flow-drilling scenario. Heavy accumulations may require numerous trips with the work string to replace worn mills.

There is always the chance that the least resistive path for the mill is through the wall of the production tubing.

Often, the better solution is to remove the tubing and production equipment from the hole and simply replace it. Once the pipe is on the surface, dealing with the scale is fairly simple. Despite their strength and shear resistance, sulfate scales are brittle. Shocking or rattling the pipe with an eccentric pneumatic tool is usually enough to break up the scale and blow it out of the pipe.

Snubbing scaled-up tubing out of a well is usually difficult because it may not be possible to run a plug inside the pipe and set it, especially in badly scaled pipes (similar to extensive paraffin accumulations). The plug simply won't go down due to the ID restriction caused by the scale. It might be necessary to kill the well to get the pipe out of the hole. If so, dead well techniques using an HWO unit or conventional rig might be the best option.

Removing scale is not without risks. One of these is the inclusion of naturally occurring radioactive material (NORM) within the chemical structure of the scale. This material originates from ancient formation water and is concentrated in the scale. So, as the scale is removed and collected, the NORM can become a hazard to crewmembers and to the general public if it is not disposed of properly. Most regulatory jurisdictions have some specific protection, handling, and disposal rules for NORM.

Sand

Sand is another catchall term that includes actual granular quartz along with other formation fines, drill cuttings, mud chemicals and weighting materials, scales, paraffin, wax and other materials. These are deposited inside the wellbore when formation fluid flow is insufficient to carry them out of the hole. They often form a bed that can cover perforations and fill open-hole sections. The sand plug constricts production resulting in less flow to carry additional solids out of the wellbore. In older wells, sand accumulations are an ongoing problem.

Fortunately, most of these beds can be removed by circulating a fluid or gas out the end of a jet string. In many situations, this does not require pulling the production tubing or packer. The jet string is often run in a live well. If the well has previously loaded up with fluid, jetting is often preceded by unloading the fluid allowing the well to flow. So, the workover may start as a dead well job only to become a live well workover at the end.

Coiled tubing units can be, and are, used quite often for this work. However, if the well is located in a remote area or on a platform without adequate deck loading capability to hold the large, heavy CT reel and other equipment, a snubbing unit can be used to run the jet string. The weight of the snubbing unit and all forces associated with the jet string are supported by the wellhead and not the platform.

If obstructions within the production tubing prevent running the jet string, the snubbing unit is capable of pulling the production tubing to clear the obstruction, a task that a coiled tubing unit cannot do. So, unless the nature of the job is known, having a snubbing unit over the hole might be the better option in some cases. Pulling the production string without killing the well is always a good option.

If a snubbing unit is used to run the work string, the pipe can be turned to facilitate sand recovery from the well during cleanouts in an underbalanced well. Coiled tubing cannot turn although small motors and bits can be added to the string to stir up the sand bed that requires circulating fluid continuously. This could kill the flow from the underbalanced well. Another technique uses concentric coiled tubing with fluid and sand returns in the annulus between the CT strings. Continuous fluid circulation is avoided using the technique. When a jointed work string is used, the pipe can be rotated, and a small mill, bit, or perforated bullnose on a bent sub can be used to stir up the sand bed. This allows flow from the well to lift most of the sand out of the hole.

Again, if the well is not killed during a sand cleanout job, there is no need to jet and unload the well at the end of the job. So, a flowing, live well workover using a snubbing unit might make good economic sense for this type of cleanout on certain wells.

5.3.4.3 Production Stimulation

Live well stimulation work usually involves two general types of workover, acidizing and hydraulic fracturing. Sometimes, fluids used for these stimulations are gas-boosted (or gaseated) to aid in recovering load fluid and initiating production from the well after the job. Injection wells can be treated to increase fluid disposal rates. Occasionally, they are back-flowed to recover reaction products and fines. Having live well capability to reposition tubing and packers in both types of wells is sometimes a desirable alternative to dead well workover techniques.

Well Preparation

Preparation steps for the wellbore and the zone of interest are as varied as the type of well and its current condition prior to performing any workover, especially a stimulation. Sometimes, no preparation work is needed at all.

In most wells, there is at least some work needed to ensure that the most efficient stimulation is performed. If the money required for the stimulation is going to be spent by the Operator, it only makes sense to do all the necessary preparation work to achieve the best result possible from the job. Most stimulations are not cheap, especially when one considers the loss of production or injectivity during the time the work is in progress.

Tubing, production packers, jewelry, and wellhead components are often set above existing perforations in preparation for a stimulation. These can be run and placed in live or dead well modes. Often, it was done by the conventional drilling rig that drilled the well. Obviously, in live wells the perforations are open, a snubbing unit will be involved to push the pipe and other components into the hole against well pressure.

Some of the same work described in previous sections might be necessary to prepare the well for a stimulation such as a fill cleanout, paraffin removal, and scale milling. In older wells, certain diagnostics might be necessary such as pressure tests, casing inspection logs, temperature/acoustic surveys, and tracer logs to ensure that the well is capable of withstanding the stresses of the stimulation.

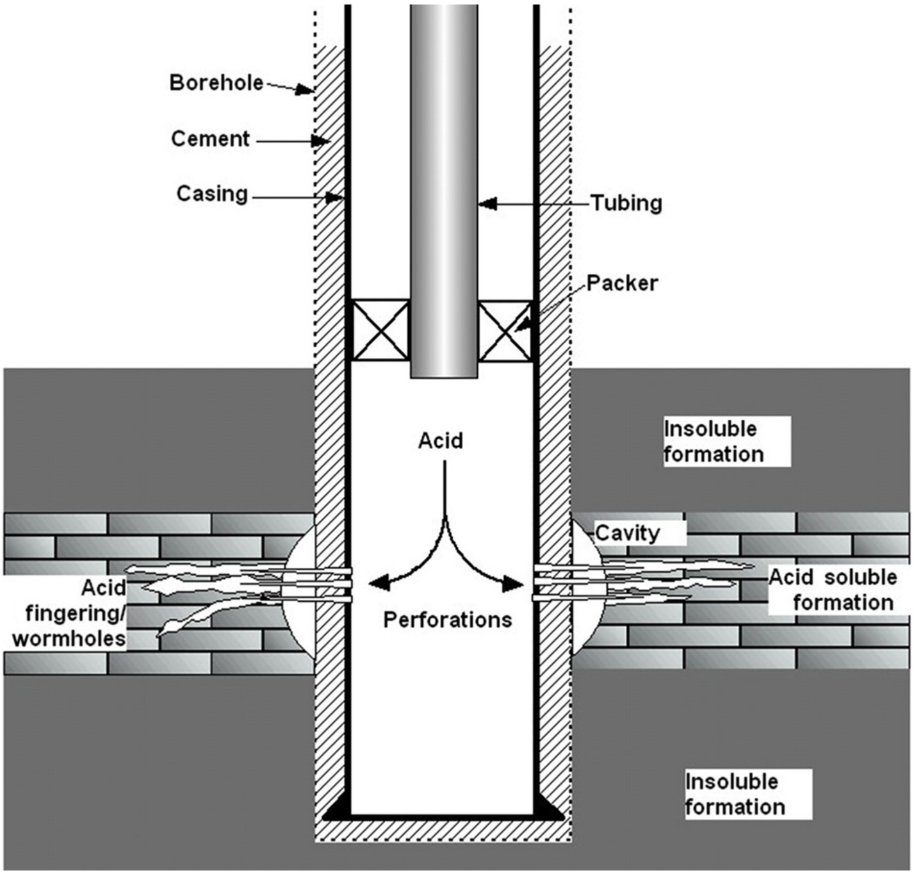
In other wells, perforations might be added, or the same zone might be reperforated to ensure good contact of the stimulation fluids with the reservoir.

Acid Stimulation

This stimulation technique was the first to be used in the oil field over a century ago, and it still used frequently to remove acid-soluble materials that interfere with production or injection. Acid-soluble materials involve soft scales (carbonates, primarily) and near-wellbore cementation materials holding grains together in the formation. Sometimes, these materials are interbedded with insoluble materials such as certain clays, other types of scale, paraffin, formation fines, pulverized formation, and perforating gun debris. In many cases, low-concentration acid is used as a washing fluid with only limited reaction in the wellbore or formation.

Originally, only hydrochloric acid (HCl) was used to open perforations during the initial completion, especially those in low-BHP reservoirs. This was primarily for perforating debris and mud solid removal (Fig. 5.9).

Later, stronger, more reactive acids were used to etch the formation creating "wormholes" that permitted production through skin at the formation face resulting in higher production rates. This, of course, required that the formation would actually react with the acid being used. In certain formation, like



■ **FIG. 5.9** Acid stimulation schematic.

sandstones, special acids were needed to create wormholes, such as hydrofluoric acid (HF). The less reactive HCl will not etch sandstones effectively.

Often, there is the perception that all acids will react with any rock. That is not the case. HCl will not react readily with dolomite, but it will react with limestone, for example.

Most acids will also react with casing, liners, and production tubing and its jewelry pitting their surfaces. This is especially true when reactivity is enhanced by elevated temperature at the bottom of the hole. Most acid solutions used in the oil field contain inhibitors to protect downhole tubulars.

Some acid solutions also include surfactants and wetting agents to enhance the reaction of the acid on the target material. Unfortunately, some of these chemicals can form emulsions with formation fluids that can adversely impact production from the well after the acid job is over.

Most acid reactions also create free gas, so-called acid gas, that in certain situations can behave like a kick. Unreacted acid combined with acid gas can pose a risk to crewmembers and production personnel once they come to the surface. Another source of a kick is any gas used to charge, or gaseate, the acid and flush fluids.

Finally, there is the need to recover acid reaction products and fluids used to flush the acid into the formation as quickly as possible. Acid can release fines inside the formation that can settle in pores and plug pore throats. So, getting the reacted acid and all the released material from the stimulation out of the well quickly is often the key to a successful acid job.

CASE HISTORY

A Clear Fork injection well in a West Texas waterflood was found to have most of its perforations plugged with scale from the injection of a mixture of produced waters and fresh water. The standard maintenance treatment for injectors in this waterflood was to bullhead 500 gal 15% nonemulsifying acid with an iron-sequestering agent (NEFE) down the injection tubing periodically.

A temperature log and injection profile showed that all of the injected water was going into the top set of perforations. The interval was approximately 115 ft. thick with select groups of perforations over the length of the zone. When preparing for a new acid job, it was thought that all of the acid would go into the top perforations leaving the remainder of the interval untreated if the standard procedure was performed on this well.

A slickline unit set a downhole check valve in a profile nipple above the injection packer. Then, a snubbing unit was rigged up on the well, and the packer was released resulting in a surface pressure of 520 psi.

The tubing hanger was pulled and removed, and internally plastic-coated injection tubing was added to lower the end of the injection string to the base of perforated interval. A slug of acid-insoluble diverting material was pumped and circulated to the top perforations. This effectively plugged off the uppermost “thief” (injection) zone. Then, acid was pumped while raising and lowering the tubing to contact the lower perforations with fresh acid. This resulted in the previously ineffective perforations taking the acid and reopening them.

The tubing hanger was reinstalled, and an overhauled injection packer was set. The snubbing unit was rigged down, and the pressure in the annulus was vented to a test tank. The check valve was recovered by slickline, and injector was then back-flowed to recover acid reaction products and the diverting material over the top perforations. The well was returned to injection with a vastly improved profile and injection rate.

Fracturing

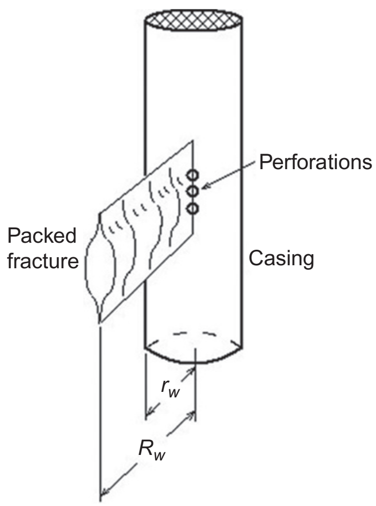
This process, invented and patented in 1946 by Standard Oil of Indiana (Stanolind), is designed to stimulate production by hydraulically rupturing the rock and inserting a proppant into the newly formed fracture. The newly created high-permeability proppant-packed pathway has the impact of increasing the wellbore diameter exposing more of the formation to flow to the wellbore (Fig. 5.10).

Consider Darcy's law in radial form:

$$Q = \frac{0.00708\,kh\,(P_e - P_w)}{\mu B_o\left[\log_e\left({}^{r_e}/_{r_w}\right) + S\right]} \tag{5.1}$$

where Q = flowrate (BOPD), k = permeability (millidarcies), h = reservoir thickness (ft., vertical wells), P_e = reservoir pressure at the drainage boundary (psia), P_w = bottom-hole pressure in the well (psia), μ = produced fluid viscosity (cp), B_o = oil formation volume factor (bbl/bbl), r_e = formation drainage area radius (ft.), r_w = wellbore radius (ft.), S = skin factor.

The smaller the value of any term in the denominator of this equation, the greater the flowrate, Q. So, if the wellbore radius is large, the natural logarithm of the ratio of the drainage area to the wellbore radius, log_e (r_e/r_w), is smaller. Similarly, if skin, S, is smaller, the flowrate is larger. Fracturing has an impact on both of these variables.



■ **FIG. 5.10** Fracturing schematic.

Assume an 8½ in. wellbore is drilled into a producing formation. It has a radius of 4¼ in. Even after perforating, the well has a radius of only about 8 in. (perforation channel tip). Acid can clean the perforating channels by removing gun debris and pulverized formation, but there is rarely a significant increase in wellbore radius just from acidizing, especially in rock that is not acid-soluble such as sandstone.

When the well is fractured, it now has an effective wellbore radius, R_w, of, say, 1000 ft. The increase in production would be almost sevenfold! The improvement in well economics would be obvious making the operator very happy as long as the job economics were favorable (fracturing is an expensive stimulation technique).

Now assume that the formation was damaged by mud solids during drilling leaving 400 psi skin. This would have a profound impact on the volumes of fluid "fighting" their way into the wellbore. Not only does fracturing punch through near-wellbore skin, it also provides a high-permeability propped channel through the damaged zone having flow capacity that exceeds native formation permeability. The result is actually "negative" skin, an improved wellbore condition. So, in this equation, S goes from positive to negative, and there is another significant production increase possible just by ridding the well of the effects of near-wellbore skin.

A variant of fracturing involves pumping acid at a pressure above the formation fracture pressure to rupture the rock and expose a crack subject to acid etching (wormholes). There may be proppant included for all or part of the job, but in most jobs, the fracture is not propped open. The acid is intended to provide the high-permeability channel from deep in the formation to the wellbore. Acid fracs can have good results in certain formations, such as limestones and some sandstones. Usually, if an Operator has the desire to open a conduit by fracturing, a nonacid propped frac is usually selected.

New wells are often fractured down the production casing after perforating with no tubing in the hole. This provides for maximum pump rate and minimum pump pressure. The only fluid friction generated is that developed on the inside wall of the relatively large-diameter casing (e.g., as opposed to the smaller diameter of a tubing string). Obviously, the maximum treating pressure is the rated burst pressure of the casing times a safety factor of around 80% (assuming new casing).

Another way to fracture wells is to install the tubing after perforating and pump down both the tubing and the casing annulus simultaneously. This provides a cleanup conduit inside the well (i.e., the tubing) for improved flowback and a selective conduit (the tubing) for delivering fluid and proppant to a specific set of perforations. Pump rates are similar to those with no tubing in the hole (i.e., a frac down the casing).

The third method is fracturing down tubing or a work string below a treating packer. Fluid friction is much higher due to the relatively small diameter of the tubing. The annulus is usually closed off. Often, pressure is trapped in the annulus to allow higher tubing pressures while pumping. In some jobs, the operator may reduce pump rates to avoid excessive pump pressure (and hydraulic horsepower cost). This type of job is often selected for high-frac-pressure formations where the maximum pressure would exceed the casing burst pressure (e.g., an old producer with questionable casing integrity that is being restimulated).

The use of snubbing units is limited in prefrac operations to positioning the frac string in the well under pressure. This may be the case when the well has already been perforated and tested or produced. Rather than pay the expense to kill the well to run the frac string, the operator may opt to run it in a live well situation.

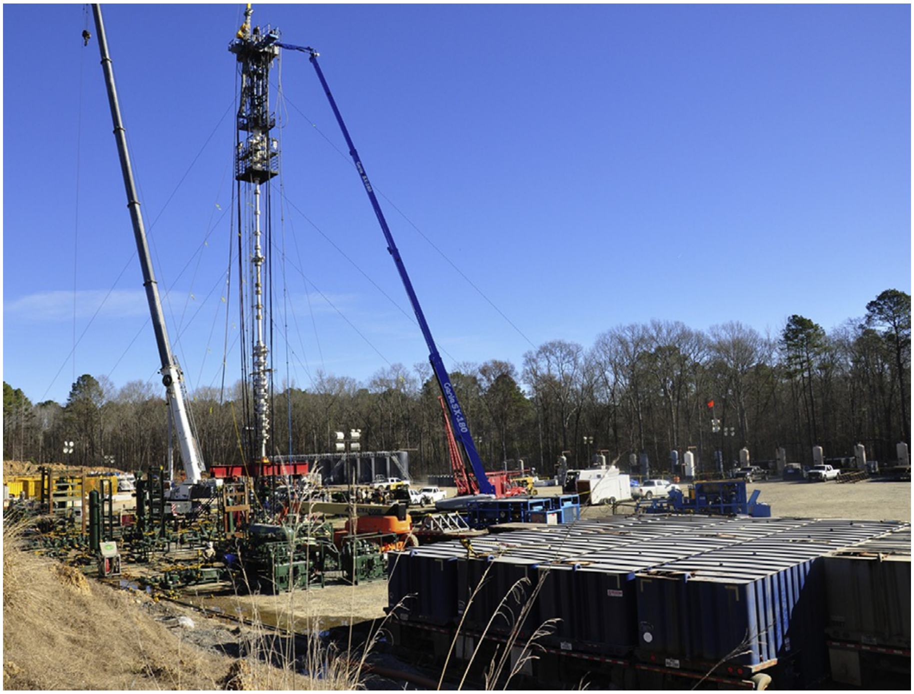
In almost all cases, the unit used to run the pipe, regardless of type, is rigged down and demobilized. A set of heavy-duty, abrasion-resistant frac valves are rigged up, and frac pumps are connected to it through manifolds. BOPs are no longer installed on the hole, and the frac string, if installed, has been landed in the tubing hanger.

Postfrac work using a snubbing unit may be required to properly run and position the completion tubing and production packer for long-term service. The well is usually shut in for only a relatively short time after the last of the proppant-laden fluid is pumped. The shut-in is needed to allow the fractures to close on the proppant. Leaving the well shut-in too long would allow all the surface pressure to leak off into the formation. So, there is usually pressure on the well when the flowback process begins. Fracture fluid is flowed to the surface under controlled conditions, which further allows the fractures to close on the proppant. Often, this results in some proppant being swept back into the wellbore.

Frequently, the well begins producing hydrocarbons during the flowback, and surface pressures increase accordingly. This is a highly desirable outcome. However, proppant or formation fines in the wellbore must be cleaned out to clear the perforations, and the frac work string must then be pulled under pressure. The packer and production string must also be installed in the well under pressure. The well is often allowed to flow underbalanced during this work.

The snubbing unit can perform these functions and successfully equip the well without killing the well. Drilling rigs, completion units, and HWO units cannot. Once the packer is in position, the well is usually shut in briefly to allow the packer to be set without flow past the packer's elastomer elements, and the tubing is landed in the tubing head. Plugs are run, a sliding sleeve is opened to circulate packer fluid, and the annulus is isolated. The well then flows up the tubing to recover remaining load fluid from the frac job (Fig. 5.11).

Each fracture stimulation is different. Some fracs are well-behaved and go just as planned. Some of them run into difficulty. One of those problems is an early screen out. This occurs when fluid leaks off to the exposed formation at a rate faster than the pumps can replace it.



■ **FIG. 5.11** Recently frac'd well. *(Courtesy of Cased Hole Well Service.)*

At this point, the fractures cease to extend (i.e., the cracks stop growing). Proppant literally stacks up inside the fractures until they are packed full. Proppant-laden fluids stack up in wellbore resulting in very high pump pressure very quickly. The job must be shut down immediately to avoid bursting the pipe. Any remaining proppant suspended in the well settles out plugging perforations, the casing, and the frac string. Attempts to flow the remaining fluid and proppant out of the well are usually unsuccessful. If leak off is rapid enough to result in a screen out, pressure bleeds off into the reservoir very quickly. A proppant cleanout is usually required.

Snubbing is used in most of these jobs to clean proppant out of the well (coiled tubing may be used if the screen out occurs inside the frac string). The proppant bridge can hold pressure underneath it. As soon as the plug is removed, there can be pressure that suddenly appears on the surface without warning. So, cleaning out the well with equipment that can manage surface pressures would be required whether there is pressure on the well at the beginning of the job or not.

5.4 WELL CONTROL—HWO UNITS

HWO units are configured differently from snubbing units because they are used only on dead wells (i.e., having no surface pressure at any point during the job). As such, they are no different from a well control standpoint than a conventional drilling or workover rig. They are equipped only to manage pipe-heavy situations. Most do not have inverted (snubbing) traveling or stationary slips, only pipe-heavy slips. They do not have snubbing BOPs or an equalizing circuit since ram-to-ram snubbing is not required.

For the most part, HWO is confined to work on offshore platforms or inshore wells working from a barge or lift boat. They can be used for onshore work, but conventional workover rigs are usually less expensive. Offshore, an HWO unit usually costs significantly less than a rig of any type including a platform rig.

Mobilization of a bottom-supported or platform rig is considerably higher than an HWO rig. An HWO rig can be hoisted and rigged up using most platform cranes since it can be broken into small lifts. Dredging a canal to install a posted barge rig on an inshore well could be quite expensive. Environmental restrictions may not permit mobilization of a large rig to a small inshore site. So, using an HWO unit on a keyway barge, for example, provides an excellent alternative to a conventional rig from a number of standpoints.

The use of an HWO in offshore or inshore wells still requires rigorous attention to well control. The barrier requirements for dead well work in these environments are the same as those for conventional rigs. The consequences of a spill onto the water are still serious regardless of whether there is an HWO unit, a conventional rig, or a jack-up over the hole.

5.4.1 Barriers

HWO barriers are identical to those required for conventional rigs. The primary inner and outer barrier is a column of fluid with sufficient density to provide hydrostatic pressure that exceeds formation pressure at all times, or the well would be flowing. A drop in the fluid level or density cannot be permitted, or this primary barrier system will be compromised.

Having a plug or check valve inside the string as a primary inner barrier is not necessary and often not desired. The pipe is open, unrestricted, and available for transporting fluids by direct or reverse circulation. Wireline tools or coiled tubing can be run without interference from the float.

The secondary inner barrier is a stab-in safety valve (TIW valve). Like a snubbing or drilling operation, there must be one stab-in safety valve available in the basket for each pipe size and thread type in the string. Again, this requirement may be met by having one valve with a set of crossovers that can be made up to the bottom of the valve as the pipe size or thread type in the string changes.

Many HWO units also have a screw-in side-entry sub for each size and thread type in the string that allows pumping fluid through a "kelly" hose and down the work string to ensure that the hole stays full especially while pulling out of the hole. This, of course, requires some type of plug or valve in the top of each joint. This requirement is often met by handling the pipe with pickup subs, or "nubbins." While not a true barrier, this side-entry fill line sub is often useful to avoid minor spills from fluid overflowing the top of the work string while running in the hole.

The secondary annular barrier is the blowout preventer. The rig is equipped with a BOP stack usually composed of one ram-type preventer for each pipe OD in the string (thread type is unimportant) and one annular preventer. The requirement for one ram in each pipe size can be satisfied by the use of variable bore rams that will close and seal on each pipe diameter in the string. This saves space and weight in the BOP stack. When VBRs are used, the HWO unit operator only has one set of pipe rams with which to be concerned. It's hard to forget which BOP ram should be closed in an emergency since there is only one ram that fits all the pipe.

The BOPs must be rigged up and tested to the maximum anticipated well pressure (MAWP) under the worst-case scenario. Regulations may and often do require that these BOPs be pressure-tested to their rated working pressure. Often, they must be retested periodically to ensure that they are still capable of managing MAWP. Most service providers pressure test the BOPs to the MAWP every week or so. They are usually function-tested even more frequently to ensure the closing/opening and ram lock mechanisms are working properly. For example, the blinds are usually closed every time the pipe is pulled from the hole even though there is no pressure on the well.

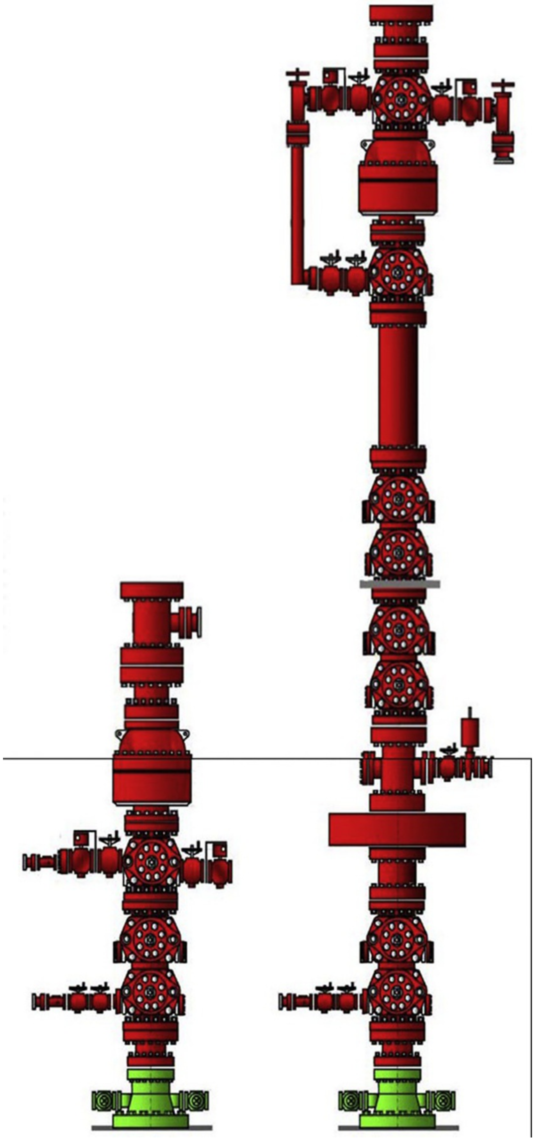
The shared tertiary inner and outer barrier is the blind ram. This ram must be capable of closing and sealing the open wellbore against flow. Often, the blind ram is combined with a shear ram, or blind/shear ram, that can cut any component of the string in the hole and still close on the well sealing it against flows of any kind (up the pipe or up the annulus). A shear ram may be used in a separate BOP housing with a blind ram in another to satisfy this requirement. Fig. 5.12 shows a typical HWO BOP stack arrangement as compared with a snubbing stack.

5.4.2 Kick Control

Kicks of all types are controlled on HWOs the same way they are controlled on conventional rigs. First, the well is shut in to obtain stabilized pipe and annular pressures. Then, one of two constant BHP methods is used to circulate the kick out of the hole. Fluid density must be increased and the well circulated again with KWM at some point in the procedure to ensure that the well remains overbalanced.

Maximum annular pressures during kicks on these dead wells rarely provide the force necessary to expel the work string from the well. They are usually pipe-heavy to the extent that a small kick cannot push the pipe out of the hole. However, it is possible especially when there is only a short length of pipe in the hole when the kick occurs.

Modern ram-type BOPs usually have automatic ram locks. Once the BOP is actuated and the ram closes around the pipe, the rams lock in place. Upset or collared pipe may be forced up the hole until they reach the closed ram. Then, the upset lodges against the locked ram, which stops the upward pipe motion. In critical situations when older BOPs are in use, the manual ram locks should be closed quickly to prevent the pipe from being forced out of the hole.



■ **FIG. 5.12** HWO unit BOP stack versus snubbing stack. *(Courtesy of International Snubbing Services.)*

A similar situation can occur if high-pressure pumping results in annular pressure sufficient to force the pipe upward and out of the hole. This pressure may be sufficient to “pump” the pipe out of the hole. So, if automatic ram locks are not available, the manual locks should be used to ensure the pipe can't be ejected from the hole. Recall that the HWO does not have hold-down (pipe-light) capability; both sets of slips are oriented only for pipe-heavy loads.

In some HWO jobs during which there could be an unexpected pressure increase, another ram-type BOP with slip rams is installed in the stack as an additional safety measure (see Fig. 5.12). These rams are designed to grip the pipe and keep it from moving in either direction. If the pressure increases for any reason, the slip rams can be closed to hold the pipe securely until the pressure subsides or a snubbing unit replaces the HWO unit.

5.5 DEAD WELL OPERATIONS

HWO units are configured to perform dead well operations, so they do not have snubbing capability. However, they are capable of doing almost anything that a conventional rig can do as long as the pipe string has a sufficiently small diameter to pass through the bore of the HWO unit. In any job, the working string weight (hook load) limit of the jack assembly cannot be exceeded.

One important difference between HWO and snubbing operations is that there is only pipe-on-wall and cylinder seal friction acting on the unit. There is no friction from pipe being snubbed through the strippers (snubbing BOPs) or a stripping rubber, and there is no expulsion force from pressure in the well. There is no need to hold pressure, so the additional friction going through a seal at the surface is not experienced. The friction is no greater for running or pulling pipe using an HWO unit than it would be for doing the same task with a conventional drilling or workover rig with block-and-tackle hoisting gear.

Also, because the string is always pipe-heavy, there are no concerns about unconstrained buckling at the surface. There may be normal work string buckling down the hole somewhere resulting from pipe-on-wall friction, but not unconstrained buckling at the surface from snubbing the pipe in the hole against pressure. This usually means that running the pipe is faster using an HWO unit since the entire stroke length can be used. There is no need for short bites to reduce the unsupported length as discussed in Chapter 4.

The use of pipe racking with an HWO unit means that the time for manual pipe handling from the deck to the basket is reduced. Risk due to exposure for pipe-handling injuries to crewmembers is minimized. Pipe running and pulling times are therefore competitive with conventional rigs if the pipe is racked standing up in single joints or doubles (two joints still connected to each other).

5.5.1 HWO v. Snubbing Unit Selection

One error made by some operators in the interest of saving money is to start a workover using an HWO unit when there is a probability of encountering pressure that cannot be balanced by the fluid column. HWO units cannot snub pipe. So, if a workover has the chance of exposing the wellbore to increased pressure, a snubbing unit should be used instead of an HWO unit from the outset (e.g., recompletion from a depleted interval to one with original reservoir pressure).

Daily cost for a snubbing unit does not differ significantly from that for an HWO unit. The HWO is not equipped the same way that a snubbing unit is, and it is often simpler to use. Snubbing equipment rig up and rig down may require more time than that needed to rig up an HWO unit, however.

HWO crews can be slightly smaller than snubbing unit crews by one or two crewmembers. Dead well operations, for example, may only require one rigger working on the deck to pick pipe up using the counterbalance winch system. A snubbing unit might require two. There are usually only two personnel in the basket on an HWO unit where there might be three on a snubbing unit to manage various aspects of the operation.

Some HWO jobs are packaged into groups of wells or platforms. The unit moves from well to well without rigging completely down in many cases using a skidding system. If a snubbing unit is needed for a particular well, this sequence could be interrupted and cost to the platform operator increased. If the snubbing work is anticipated early on, however, its additional cost has probably already been included in the package deal.

So, if there is the chance of encountering well pressure on the job, it is usually better to simply start with a snubbing unit instead of mobilizing one after the fact. This would trigger additional costs (not popular with the Operator) for such things as an extra boat to transport the snubbing unit to and the HWO from the platform, dock charges, surface (road) shipping to and from the dock, and idling the HWO unit (paying a standby fee), while snubbing work is in progress.

Note that the snubbing unit can operate in dead well mode simply by opening the strippers and the pipe-light slip/bowl pairs and closing all valves on the equalizing loop. The service provider may only charge the operator for an HWO unit during dead well operations even though a snubbing unit is actually performing the work. The idle "snubbing equipment" is not charged since it is not being actively used. In other cases, the service supervisor may charge a fee for not having the snubbing unit available for live well work on another jobsite. These charges are usually negotiable.

5.5.2 Dead Well Workovers

HWO units are frequently used for the following jobs:

- Wellbore cleanouts
- Junk milling
- Fishing
- Recompletions
- Sidetracks
- Stimulations
- Abandonments

Procedures used for these jobs follow those used on conventional rigs. The difference only involves the use of a jack instead of a block-and-tackle pipe hoisting system and pipe handling. Sidetracking/redrilling and deepening are discussed more fully in Chapter 6, "Hydraulic Rig Drilling."

Well abandonment using an HWO is growing in popularity as the offshore well inventory ages and regulatory requirements lean toward abandoning wells that can no longer produce instead of leaving them shut in or temporarily abandoned. This has also spawned several construction-related businesses involved in platform removal and seabed cleanup.

Several methods of setting abandonment plugs are available. However, if the production tubing must be pulled to satisfy plugging requirements, HWO units offer a low-cost alternative to doing this simple dead well job. The HWO is also capable of cutting and pulling inner casings for salvage or to meet regulatory requirements.

In many regulatory jurisdictions, the operator must cut off all casing strings, including the conductor, some distance below the mudline and recover the wellhead and all pipe stubs. An HWO is capable of handling the loads associated with this work although the recovered casing OD may be too large to be hoisted completely through the jack and BOP stack. Usually, the BOPs are not required at this point; the well has been plugged completely, and there is no pressure at the surface. Once the surface casings are cut, the wellhead is no longer capable of supporting the HWO unit. Most service providers have lift frames on which the jack can rest, supported by the platform deck. This allows the smaller-diameter, inner pipe stubs to be pulled after they are cut below the mudline. These frames are not used with heavy loads to avoid exceeding deck loading limits. Obviously, the platform crane or a special-use crane, like a bullfrog, would eventually be needed to pull the larger-diameter casings and conductor after the HWO is rigged down.

5.6 MOBILIZATION, RIG UP AND CREW SUPPORT

The cost to ship a conventional rig to a jobsite, rig it up, and make it ready for work is often greater than that required for the same tasks for a snubbing or HWO unit, especially offshore. Rigs may be bottom-supported, floating, or platform rigs. The cost to mobilize a conventional rig in a marine environment, spot it, rig it up, and make it ready for work is usually a complex series of tasks, all of which are expensive. Onshore, small mobile workover units make the cost much smaller for dead well work. A snubbing unit must still be used for live well work, however.

5.6.1 Onshore Mobilization

Onshore snubbing unit mobilization involves the use of trucks and haul trailers traveling over both public roads and lease roads. Public highway regulations control both combined weights and load sizes (height and width) of all truckloads. A heavy snubbing unit package with all BOPs, the jack, power-pack, accumulator skid, fuel tank, hose basket, and spacer spools can exceed highway limits if shipped in a single truckload. The solution is to break the equipment up into smaller, lighter packages with proper sizes and configurations for over-road hauls.

Onshore standalone hydraulic units also require a crane for rigging up, especially for very tall stacks. The crane is sometimes the only "permit" load in the equipment package. It must be large enough (lift capacity) with a tall mast to lift all the components in the stack and hold them stationary until they can be secured. This means that some jobs require a very large crane. Large crane mobilization over highways and roads may require oversize load permits and/or escort vehicles.

The crane may stay on site assisting with pipe-handling duties for short-duration snubbing jobs. It may be demobilized for longer-term jobs and be redeployed at a later time for rigging down the snubbing unit. Clearly, the location must be large enough to accommodate the crane and all rigging activities. In places with soft soils where the location must be reinforced with a dry material such as rock, caliche, or gatch, there may be an extra cost to the operator. For very soft sites, board roads and locations must be sufficiently robust to manage the crane weight and all loads without allowing the crane to tip.

One significant difference between conventional rigs and snubbing/HWO units involves stack stabilization. Most conventional rigs, including land rigs, jack-ups, and platform rigs, have freestanding derricks or masts. Most snubbing and HWO units require guying to stabilize the often tall, top-heavy stacks to prevent toppling.

On land locations or large multiwell platforms, there are usually a sufficient number of anchor points in all directions. If they are not available, they can be added. Some snubbing units carry large anchor blocks, concrete weights that can be placed around the onshore wellsite at strategic points. Other onshore locations have permanent anchors embedded in the ground. There is usually sufficient space on most onshore locations for all the anchors needed.

5.6.2 Offshore Mobilization

Mobilizing a snubbing unit to an offshore site requires the use of boats or barges and a crane capable of hoisting the unit components into place. Obviously, the snubbing/HWO unit components must first get to the dock, which usually requires transport over existing roads. Load sizes and weights must be in conformance to highway regulations. Oversize or overweight loads may require special permitting. Shipping days and times may also be restricted (e.g., no permit loads on weekends or holidays).

Dock cranes are usually large enough to manage all components of the snubbing/HWO unit while loading them onto, or off-loading them from, the transport vessel. Deck loading requirements must not be exceeded. Certain small, heavy loads must have spreader plates installed on the vessel to prevent deck punch-through. Loads must be adequately secured to prevent shifting during transport.

Once at the location, the snubbing/HWO equipment must be lifted by a crane onto the platform or wellhead. The crane must be capable of handling the entire weight of the component under dynamic loading conditions to account for transport vessel heave, pitch, and roll. Static loading limits apply once the load is on the platform or wellhead.

Many older platform cranes have been derated due to age and physical condition, usually corrosion. These old cranes may have insufficient hoisting capacity to manage some of the heavier loads associated with snubbing/HWO equipment. These can include large ram-type or annular BOPs and the jack itself. HWO units are all four-leg units, and their weights are significant. If the platform crane is incapable of safely managing the lifts, a portable crane may be required. These are cranes that can be hoisted by the platform crane in small lifts, assembled on the platform, and used for heavier lifts (e.g., a "bullfrog" crane). This capability may also be economically supplied by a crane barge in some situations.

Once the unit is hoisted off the transport vessel, rigging up involves continued use of the crane to hold the load in place, while it is secured. This may require continuous tension with the work stack tied to various anchor points using guy lines.

5.6.2.1 Guy Lines

An ample number of suitable guy line anchor points are usually available on large platforms with multiple wells, but on small platforms such as monopod, single-well platforms, there simply is no place available to tie off the guy line. There are several solutions to this problem.

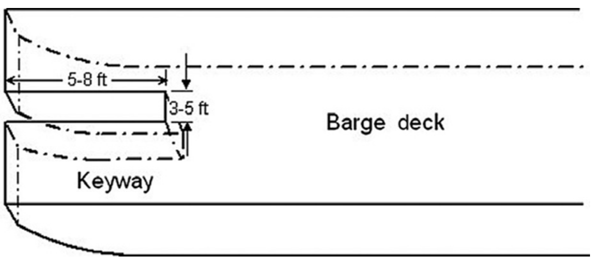
Bottom-Supported Vessel

One solution is to rig the snubbing unit up next to a bottom-supported vessel or barge in quiescent waters. A favorite for HWO and snubbing crews is a lift boat, a bottom-supported vessel that can transport equipment to the site and provide a robust crane as well (Fig. 5.17).

The vessel is not impacted by heave since it is normally lifted well above the waterline by its legs. It is only slightly rocked by wave motion. So, guying the snubbing unit off to the lift boat is practical and secure. Better yet, the crane can be tied to the unit high on the stack and used to continuously hold the load.

Keyway Barge

Another similar vessel is a keyway barge for inshore operations. The snubbing unit is rigged up on the wellhead after the barge is positioned with the well inside the keyway and the barge is anchored (Fig. 5.13). The barge is usually ballasted down into the water column to provide significant stability.



■ **FIG. 5.13** Keyway barge.

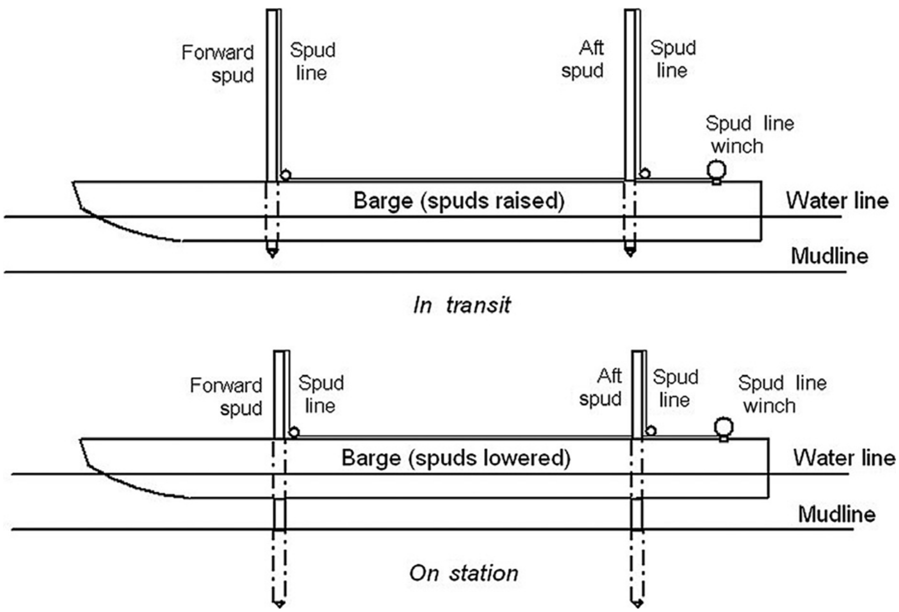
Spud Barge

In low-activity inshore areas, a barge is simply tied off to an anchor point such as a small wellhead structure or perhaps piling surrounding the well. It may be secured by dropping heavy weights such as concrete anchor blocks. Sometimes, the barge is anchored by lowering heavy steel pins, or spuds, housed in collars that penetrate the muddy, soft bottom pinning the barge in place (Fig. 5.14).

In the two-spud design, the spuds can be mounted on the port side, on the starboard side, or on opposite corners of the barge. A four-spud design has them on all four corners. For some high-current/rough water applications, there can be six or more spuds.

The spuds are usually surrounded by a loose housing that allows the barge to rise and fall with tides. There may be some barge movement when waves, such as the wakes of passing vessels, cause it to roll or pitch gently around the spuds. The barge cannot move off the well, however. It is, literally, pinned to the floor of the bay or canal. Clearly, this type of securing system will not work where the bottom is too hard for the spuds to penetrate.

Some caution must be exercised when lowering (dropping) the spuds. On one notable occasion in the author's experience, a spud was dropped, and



■ **FIG. 5.14** Spud barge.

the sharpened point penetrated a buried gas pipeline in Galveston Bay resulting in a shallow-water "volcano" of gas. The "blowout" immediately excavated a crater in the bay floor and activated a number of emergency services and regulatory vessels. Fortunately, there was no fire, but adverse publicity had an impact on the barge service and the oil company. After the gas line blew down, repairs were made, and the pipeline was returned to service at considerable cost.

Posted Barge

Another support vessel is the posted barge. This type of barge has an elevated deck held up by steel legs, or posts. Upon final positioning, the barge is intentionally sunk to rest on the bottom. The legs support the work deck that remains above the water level. Obviously, this bottom-supported barge is very stable and is unaffected by tides or waves (Fig. 5.15).

Outriggers

Another option that does not rely on a vessel or barge involves the use of outriggers. These are structural members attached to the wellhead or platform that extend some distance away from the well's centerline. Guy lines attached to these outriggers stabilize the HWO or snubbing unit (Fig. 5.16). They are not impacted by tides, currents, or wave actions. Attaching the guy lines to the ends of the outriggers may involve some fall risk, however.

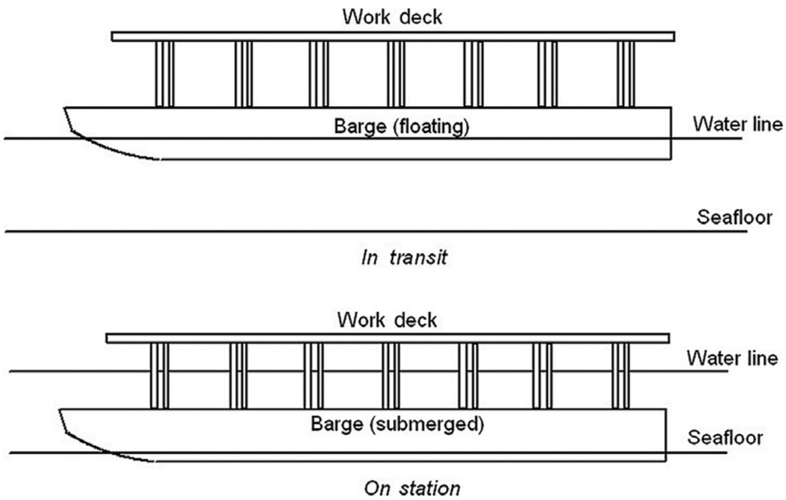
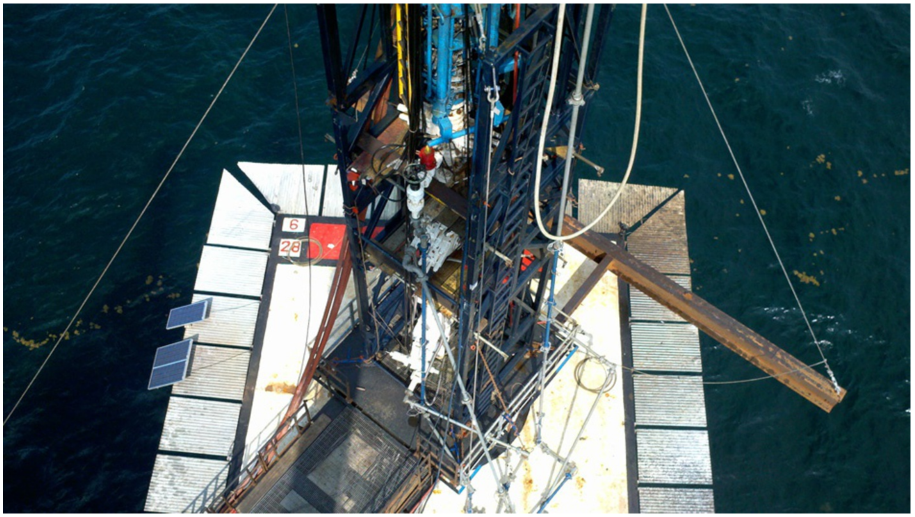


FIG. 5.15 Posted barge.



■ **FIG. 5.16** Outrigger supporting snubbing unit. *(Courtesy of Cased Hole Well Service.)*

5.6.2.2 Special Vessels

If these guying techniques, or combinations of them, cannot be used, special vessels may be necessary. For example, in shallow open waters, the snubbing/HWO unit may be guyed off to a set of outriggers and to a lift boat as well (Fig. 5.17).

5.6.3 **Crew Support**

This involves issues not associated with equipment or procedures. Crews are an integral part of the snubbing/HWO process, and they must be supported. The areas of support include transportation, housing, and messing.

5.6.3.1 Transportation

Transport to and from the jobsite varies depending on whether the location is onshore, offshore, or inshore. Onshore transport is usually by vehicle over existing roads. Obviously, the shorter the ride to the crew quarters, the better. Crews are often fatigued after a full day's work, so picking a local crew living at home or housing the crews near the worksite limits travel time and exposure. Accidents during road transport have been, and still are, the number one source of oil field fatalities.

Offshore, transport may either be by helicopter (if there is a suitable helideck on a platform) or crew boat. The crew-boat option always means time on a

■ **FIG. 5.17** Lift boat and outriggers. *(Courtesy of International Snubbing Services.)*

pitching vessel. Helicopter flights are much shorter and far less stressful to most workers.

Most Operators and regulatory agencies require special training to provide personnel with the skills necessary to escape a helicopter that goes down in water. This is known worldwide as Helicopter Underwater Escape (or Egress) Training (HUET). Another companion course is required for cold-water environments that involves survival training for immersion in frigid water. This cold-water survival training may not be required for tropical environments.

Sometimes, Operators ask crews to accompany the snubbing/HWO equipment on slow-moving supply boats or barges rather than spend the extra money on the faster and more expensive helicopter flight. This may require an extended transport time on a rolling deck, and crews are usually fatigued when they arrive to begin hoisting equipment onto the platform and rigging it up. This is the worst possible time to have a worn-out crew working on a well.

Transport back to the dock at the end of the job is also an area of concern. Once the job is over, crews are usually tired. A long boat ride to the dock, followed by off-loading equipment, followed by loading it onto trucks and securing it, followed by a long drive home, exposes crews to potential vehicular accidents with obvious negative consequences.

5.6.3.2 Housing

Quarters are usually not considered important by some operators for snubbing/HWO work for crews especially onshore. Many operators think that workover crews can just find adequate housing somewhere. In many remote onshore locations, that is not the case.

Crews should be provided with quarters that are conducive to sleeping and rest between tours. Often, this involves camp-style living while working on an onshore jobsite. "Crews" here include supervisors, engineers, special equipment operators, wireline loggers, the company site supervisor, and anyone else involved in the job, not just the snubbing unit crews (Fig. 5.18).

Suitable quarters might be found in a room at a local hotel. It could be at an onshore camp where no other facilities are available in the area. Offshore, it could be vacant rooms on a manned platform or temporary mobile quarter modules set on the deck. Quarters must include facilities for bathing and for washing work clothes. They must also include common areas for safety meetings and discussions. These may also include entertainment of some kind such as reading materials and a TV.

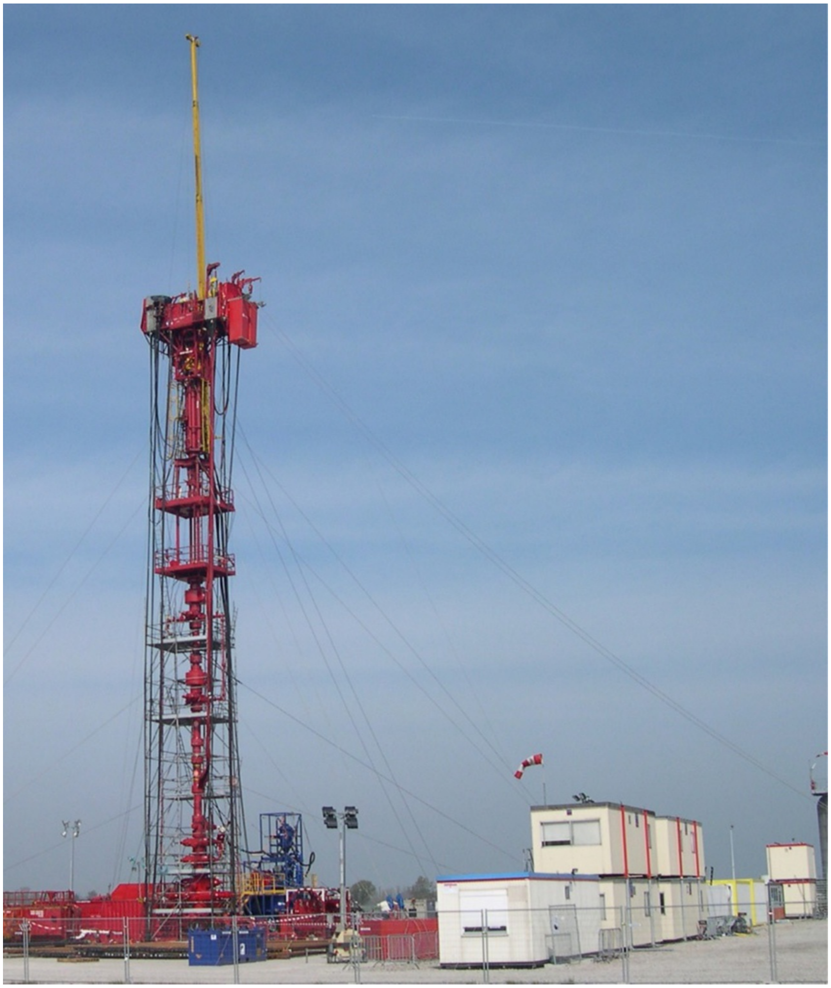
Sleep-deprived, grumpy crews do not perform well. Often, they make decisions that are poor or downright dangerous. Working crews until they drop is not an option. Tours should be limited to a maximum of 12 hr. Statistics show that the probability of personal injury, accidents, and fatalities increase dramatically after that time limit. Situation awareness becomes quite limited as fatigue creates complacency.

Most crews work better during daylight hours due to natural circadian rhythms. Some jobs require 24-hr operations. If so, there should be two full crews assigned to the job with half of them on duty at any time.

5.6.3.3 Messing

There is a saying that "an army marches on its stomach." This is equally true of oil field crews. If you expect them to work, you have to feed them and feed them well.

Manual labor tends to drain caloric reserves rapidly. Replacing those calories with nutritious, good-tasting food is often a challenge both onshore and offshore.



■ **FIG. 5.18** Stackable housing units. *(Courtesy of Halliburton.)*

Personnel working onshore usually bring a stock of food with them when they arrive on the location to begin their shift. Offshore and inshore crews must be supplied with meals. The logistics for providing meals is always challenging, particularly in bad weather.

5.6.3.4 Supervision

Adequate crew supervision is a necessary part of most jobs regardless of type. Supervision in snubbing/HWO work is also needed, mostly for coordination with the Operator and forward planning. Crews are normally deeply involved with the operation at hand (at least, they should be), and their forward planning abilities are limited by the duties in which they are involved. The supervisor is usually thinking about tomorrow's activity (and the next day, and the next day, etc.) and the logistics associated with equipment and personnel (at least, he/she should be).

Both the crewmembers and the supervisor should be prepared to manage the unexpected event such as a broken hose or control system failure. Most snubbing/HWO unit personnel are trained to deal with these incidents. The supervisor should be the look-ahead person, however.

If the supervisor must be in the basket or on the deck telling each crewmember how to do his job, he cannot be looking too far ahead. This is often a telltale sign that the supervisor is inexperienced or that the crew is. Personalities often play a large part in supervision. Fortunately, most supervisors on snubbing/HWO units are well-suited for the role, or they would not be in it.

There must be a clear distinction between the service provider and oil company supervisors regarding separation of responsibilities on the job. Usually, the service provider supervisor has the responsibility of operating the snubbing/HWO unit and support equipment and supervising the crews performing the work. The company man is responsible for the well, location (platform), and equipment other than the snubbing/HWO unit. This separation of duties prevents overlap and conflicting instructions.

One of the first lessons taught in supervisory management courses is that there is a one-to-one-to-one relationship between responsibility, authority, and accountability in a workable, efficient organization. As long as individual supervisors on the jobsite recognize that relationship, the operation normally runs smoothly. Violation of this principle often results in hurt feelings, territorial thinking, and a poor outcome. However, to protect individuals and equipment, there is sometimes a need for confrontation to sort out the lines of responsibility, authority, and accountability. These should never take place in front of crewmembers, but the supervisors should deal with them in a more private setting—sometimes completely off the location.

5.6.3.5 HSE Support

Health, safety, and environmental support is essential for the safety of all personnel working on the site. Operators are generally charged with providing a safe worksite by regulations. This implies that recognized hazards have been removed or there is a mitigation plan in place. A safety plan for the site should be in place, and a second one (or an addition to the site safety plan) for the job should be in place, as well.

Service providers are also required to maintain robust safety plans that deal with equipment operation, overhead work, hazard control, and other topics.

Often, the two plans overlap on certain topics such as well control. Sometimes, certain topics that are site-specific are not included in either general safety plan. Like supervision, there is a need for clear delineation of lines of responsibility.

Many operators and contractors prepare a bridging document that defines these areas and how they are to be managed in advance of starting the job. This avoids confusion at the time of the unexpected, unplanned event. Not having these lines clearly defined can lead to confusion, conflicting orders, and other negative consequences.

Sometimes, the contractor supplies an HSE representative on the jobsite to observe and manage risks. Sometimes, the Operator supplies an HSE rep as well. These professionals usually work well together and collaborate to provide the safest situation possible (e.g., daily hazard assessment survey, or "hazard hunt"). This is particularly important if simultaneous operations (SIMOPS) are in progress during the snubbing/HWO work.

Most operators and contractors now employ a safety policy known as "stop the job." Quite simply, each person on the jobsite is granted the authority to shut down the operation at any time if he/she notices a hazard that could threaten the safety of personnel working anywhere on the job. This authority comes from the realization that each person has a slightly different view and perspective of the job. Where one person might not recognize the hazard, another would. So, having the authority to shut operations down to avoid a safety-related incident is critical. Many regulatory authorities have recognized this principle, and they require "stop the job" authority on all jobs.

Note that this "stop the job" authority extends to everyone on the site even if they are not directly involved in the operation. Everyone from the teaboy to the barge master can call a halt to the work at any time. Experience has shown this to be an effective way to recognize hazards that may not be apparent to those actually involved in the job. If the hazard is not significant or real, it can be cleared quickly and the job resumed.

Another useful safety tool involves short safety meetings, so-called tailgate meetings or toolbox talks. Not only do these involve particular safety topics pertaining to the current or upcoming operations, they also serve the purpose of reinforcing safety concerns in general (especially during SIMOPS).

Often, when a hazard is recognized, the job is stopped, and a short tailgate meeting is held. This usually causes a reset in crew perception, which combats complacency, resulting in better situation awareness. It's also a good opportunity for a crew break. Both result in safer operations.

5.6.3.6 Crew Handover

In continuous 24 hr/day snubbing/HWO operations, there will be a crew changeout after some time interval. The oncoming crew must be informed of the job status and any problems encountered by the outgoing crew to make a seamless transition in both operations and safety aspects of the job. This is commonly called a "handover."

The time required for the handover is fairly short, usually 10 min or so. Longer times may be required based on activity level and problems encountered. The handover duration and content are usually left to the individuals and their counterparts in each crew. Tally books, job logs, notes, and other documents are normally passed along to the arriving worker during this brief meeting as well.

Often, the supervisors and HSE reps change out and do a handover at some time other than the one in which the crews change out. This avoids having "green" crews, a supervisor, and an HSE rep handing off the job to their counterparts at the same time and losing continuity in the process.

5.6.4 **Morning Report**

The morning report is a summary of the previous 24 hr activities, a current status report, and a forecast of planned work. There is a cutoff time used by all contractors on the location (snubbing/HWO, wireline, pumping services, support vessels, etc.) so that the company man can prepare a single report with all the components of the job showing the same 24 hr period each day.

Some operators use a cutoff time that corresponds to a calendar date (i.e., midnight). Others use a standard time regardless of where the job is located (e.g., Greenwich Mean time or Zulu time). This allows every job around the globe to have the same termination/start-up time. Still, others use a specific time (e.g., 6:00 a.m. local time).

This report is also the basis of the service provider's payroll and expense accounting system and invoicing to the operator. The daily activity report may be at one cutoff time and the service provider's report at a different time. Sometimes, the two are synchronized so that the operator's accounting staff can verify the reported activities on the signed daily ticket with those on the daily job report.

5.7 SPECIAL USES

The flexibility of snubbing and HWO units allows them to be used in ways that are unique in oil field operations. This can extend to nonwell work as well.

5.7.1 Motion-Compensate Well Work

Subsea work using snubbing or HWO units can be done from floating vessels by using motion-compensated snubbing systems. Unlike motion-compensated draw works or block systems, snubbing units cannot manage pipe movement due to roll, pitch, or heave without some type of system that will compensate for the motion of the floating vessel.

One motion-compensated snubbing system involved construction of a frame on which the snubbing unit was rigged up connected to a rig's motion-compensated traveling block (Olson patent, 2005). The snubbing unit was able to operate as though it was stationary relative to the seafloor using this system.

Another system has four hydraulic cylinders that provide compensation not only for heave, within the limits of the cylinder extension, but also for roll and pitch. The cylinders are connected to the base of the snubbing or HWO unit in a way that allows different cylinders to extend or withdraw keeping the unit vertical as the vessel moves. Fig. 5.19 shows this motion compensation frame (this frame also has four outriggers, complete with guardrails on walkways to connect guy lines, all of which are also motion-compensated).

Operation of a motion-compensated snubbing/HWO unit is just like an onshore unit except for one minor problem. Often, snubbing/HWO unit operators become seasick. The unit is stationary relative to the seafloor, subsea BOP, and wellhead, but the vessel providing support to the unit is subject to heave, pitch, and roll. The operator in the basket is actually stationary, but the vessel, his visual point of reference, is in constant motion resulting in severe seasickness.

In another case, a snubbing unit was rigged up on top of the drilling riser. The riser tensioners were used to support the weight of the freestanding HWO unit without contribution from the rig's motion-compensated blocks. The unit was actually rigged up below the floor, so there was no need to pull the rotary table or risk collision between the stationary jack and the heaving vessel. All pipe handling was done using the rig's equipment.

■ **FIG. 5.19** Motion-compensated system for snubbing/HWO unit. *(Courtesy of International Snubbing Services.)*

5.7.2 Production Riser Installation

In the past, welded pipe was used to ship production from platforms to central transport lines. The pipe was run to the seafloor and turned horizontal inside bent J-shaped conduit connected to the production platform. The production riser was forced to bend inside the conduit, and friction was considerable since there was no appreciable pipe weight to pull or push the pipe through the J-tube.

In a 1991 job, a decision was made to use 3½ in. jointed tubing for the flow line and snub it down through an existing J-tube previously installed on the platform. A temporary wellhead was rigged up on top of the J-tube, and a snubbing unit was used to "snub" the tubing down through the tube to the seafloor bending it along the way. The J-tube had an average deviation of 57 degrees/100 ft. The snubbing unit was used to provide the compressive force necessary to push the production riser through the J-tube. Once the pipe exited the J-tube, it was pulled by a hydraulic winch on a surface vessel to the pipeline connection some distance away from the platform with the snubbing unit feeding tubing down the J-tube.

The stationary and traveling slips had to be disassembled sequentially on several occasions to permit passage of large-diameter sacrificial anodes to the outside of the pipe. The production riser was successfully installed with no damage or leakage.

5.7.3 Pipeline/Flowline Cleanouts

Snubbing units have been used successfully to clean out flow lines and pipelines of paraffin and hydrate accumulations on deepwater projects. This was accomplished by pushing a jointed cleanout string down the line after disconnecting and bringing the platform end of the riser to the surface. There was no pressure on the pipeline, but hydrate accumulations were so severe that the pipe had to be pushed into the pipeline using a snubbing unit instead of an HWO unit or a conventional rig. Pigging or chemical cleanouts were not practical for this work. The ability to run cleanout tools and scrapers on the work string and rotate the pipe to clean out accumulations made the snubbing unit an ideal tool for the job.

In one 2008 job, chemical solvent and paraffin inhibitor failed to clear the blockages. Methanol injected into the line reacted with the paraffin inhibitor causing the paraffin to solidify complicating the cleanout process. Initially, coiled tubing was used to clean the paraffin blockages with some success. After a time, the blockages became so severe that this method failed and further attempts using coiled tubing were abandoned. A jointed work string was substituted for the CT and the cleanout job continued using a snubbing unit to clean out over 30,000 ft. of pipeline. Debris was flushed from the line, paraffin inhibitor was placed in the line, and gas production resumed.

In another job in 2009, coiled tubing initially used to remove hydrate and paraffin bridges from an umbilical on the Nansen Spar got stuck and parted inside the line. A snubbing unit and jointed 3½ in. work string fished out the CT, cleaned out the remaining hydrate and paraffin bridges, and allowed production to resume through the 13,000 ft. umbilical.

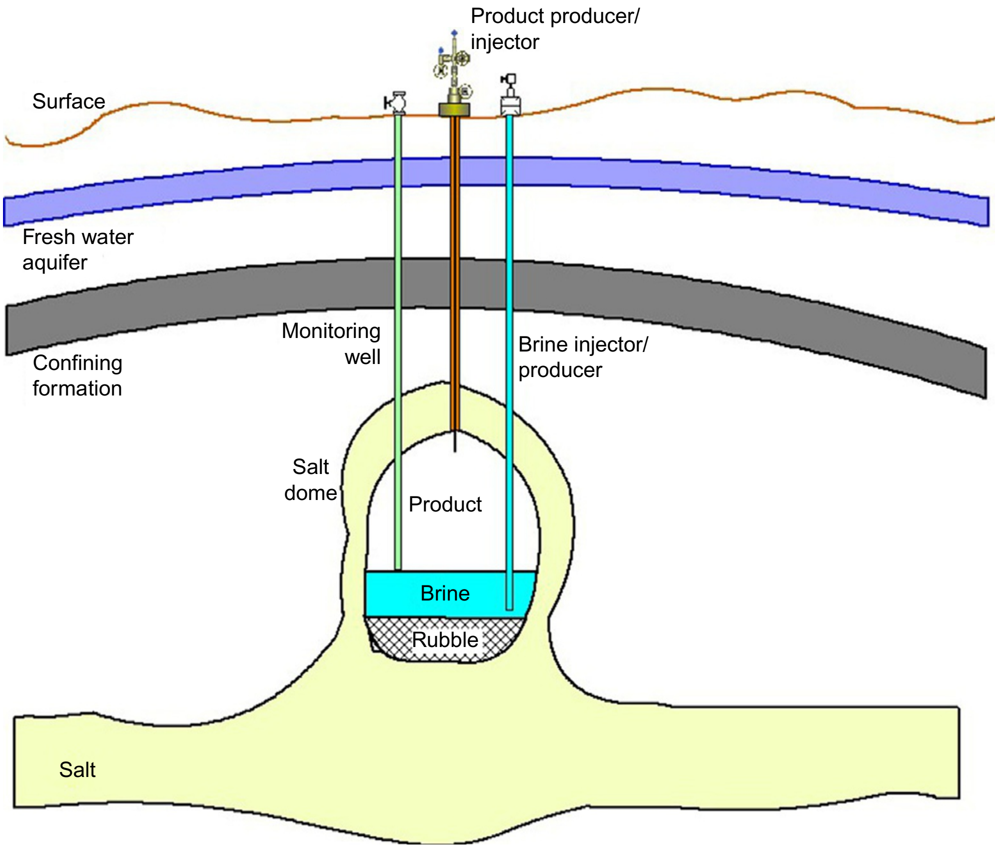
5.7.4 Storage Cavern Work

The notion that snubbing/HWO units can only be used on producing or injection wells was dispelled quickly in 1991 when butane in a storage cavity became trapped behind casing set at the original top of the cavern. Additional material fell from the roof of the cavern after it was originally constructed. This created a new roof 53 ft. above the original roof. Approximately, 100,000 barrels of butane had become trapped in this "new" cavity (Fig. 5.20). Live well work was required because pressure inside the cavern could not be killed using a fluid column. The cavern top was at a depth of only 1404 ft.

The 8⅝ in. production tubing was raised and reset 80 ft. above the original setting depth. A 2⅞ in. drill pipe work string was snubbed inside the tubing, and the 13⅜ in. production casing was cut mechanically at several points with individual pieces allowed to fall into the cavern (or so it was thought). A 5½ in. tubing "stinger" was run inside the 8⅝ in. production tubing and hung off using a conventional liner hanger. This allowed the operator to recover the trapped butane.

Two "firsts" were involved in this job. One was the use of nitrogen to purge the work string and tubing stinger during snubbing to prevent liquid butane from vaporizing and coming to the surface. The second involved the use of downhole camera to inspect the cuts made on the 13⅜ in. casing. Only one of the casing cuts was successful, but the casing did not fall as anticipated. It was still in place held by debris inside the cavern from the roof collapse. The cavern was returned to service for butane storage.

Other snubbing jobs have been performed using snubbing units to repair or reposition production tubing, clean out debris from the cavern floor, and perform other storage cavern maintenance work for several years.



■ **FIG. 5.20** Storage cavern schematic diagram.

5.7.5 **ESP Installations**

One use of HWO units has been the recovery and reinstallation of electric submersible pumps (ESPs) in offshore wells. In the past (prior to about 1991), jack-up conventional rigs or platform rigs were required to perform this work. ESPs have been proved to be an attractive form of artificial lift for offshore service, and the use of these pumps increased in the 1990s to replace traditional gas-lift systems. As reservoir depletion and water encroachment became more significant during that time, there was less gas available. ESPs presented a safer alternative after several incidents involving leaks of high-pressure gas-lift gas and fires occurred on offshore platforms resulting in considerable damage.

ESPs are often deployed on production tubing with the power cable attached to the outside of the tubing. Most of the cable is round, three-conductor cable that is armored to protect against damage. However, the portion of the cable that runs from the top of the pump to the motor is flat cable. Numerous failures of the flat cable resulted in the need for a faster replacement method than waiting on an available jack-up or platform rig, mobilizing the rig to the site, rigging up, and spending a whole day pulling and replacing an ESP. The HWO was selected as a faster, less expensive alternative.

It is not feasible to run both the production tubing and the power cable through the traveling and stationary slips on an HWO unit (nor can they be run together through the slips using a conventional rig). The solution was to install a work window below the HWO unit. The pipe was tripped using the HWO unit, but the cable was handled through the work window (Fig. 5.21).

HWO units are still used routinely for ESP replacement. They have also been used to pull and replace downhole hydraulic pumps, pressure monitoring devices, and production and injection packers and for a variety of other jobs including abandonments and reabandonments.

■ **FIG. 5.21** ESP power cable installation in work window. *(Courtesy of International Snubbing Services.)*

CHAPTER 5 QUIZ 1

Sections 5.1 and 5.2

1. For the purposes of this book and most of the industry now, HWO units are involved only with live well workovers, completions, and recompletions.

A. True ______

B. False______

2. What limits the diameter of equipment run through a snubbing or HWO unit?

A. ID or bore of the unit

B. ID or bore of the snubbing and safety BOPs

C. ID or bore of the wellhead and last casing string hung off in it

D. All of the above

3. Snubbing and HWO units can lift any load that a conventional rig with a block-and-tackle hoisting system can lift.

A. True ______

B. False______

4. What is the primary inside pipe well control barrier for a snubbing unit?

A. A fluid column of kill weight mud

B. The safety BOPs including the annular preventer

C. The downhole plug or float set in the work string

D. All of the above

5. What is the primary outside well control barrier for a snubbing unit?

A. A fluid column of kill weight mud

B. The no. 1 and no. 2 snubbing (stripping) BOPs

C. The safety BOPs including the annular preventer

D. All of the above

6. What is the shared tertiary inside and outside well control barrier for a snubbing unit?

A. Blind or blind/shear rams

B. A fluid column of kill weight mud inside and outside the work string

C. The safety BOPs including the annular preventer

D. None of the above

7. How will a gas kick entering a wellbore full of water-based drilling fluid behave?

A. Migrate up the annulus due to the density difference between the gas and drilling fluid

B. Bring bottom-hole pressure with it as it moves up the hole if not allowed to expand
C. Will retain its original volume if not allowed to expand
D. Will eventually collect under the BOP stack if not properly vented off and replaced by drilling fluid
E. All of the above

8. What causes swabbing?
A. Drill string is run in the hole too fast and causes some portion of the well to begin taking fluid
B. Pressure is held on the drill string while pulling out of the hole
C. The hole is not kept full of fluid while pulling out of the hole allowing gas to enter from the formation
D. The drill string is pulled faster than fluid above the BHA can flow around it creating a slight suction on the formation

9. In a dynamic kill, what causes the formation to cease flowing into the wellbore?
A. Fluid friction created by pumping the sacrificial fluid into the wellbore matches or exceeds formation pressure
B. Fluid friction is increased due to the higher viscosity of the pumped fluid
C. Density of the sacrificial fluid being pumped stops fluid flow from the formation
D. Tubing in the wellbore decreases fluid velocity causing the well to stop flowing

10. What characterizes a gunk squeeze?
A. Clays are mixed in a fluid that is dissimilar to the fluid in the wellbore
B. The gunk pill forms a viscous mass when it mixes with fluid in the well
C. Gunk is made from mud additives and chemicals readily available on most rigs during drilling, and it's easy to mix
D. All of the above

11. Lost circulation cannot cause a well to kick.
A. True ______
B. False______

12. Cement can always be used to stop lost circulation even when all other materials fail.
A. True ______
B. False______

13. Why are snubbing units often used to run small-diameter pipe to clean out kill strings?
   A. It is more economical to use a snubbing unit instead of running the small pipe using a conventional rig
   B. Snubbing units can handle small-diameter pipe easily where conventional rigs cannot
   C. There may be pressure on the kill string after cleaning it out that would expel the cleanout pipe from the well
   D. Snubbing units are faster than coiled tubing units performing the same job

14. What is the purpose of a relief well?
   A. To provide a means for pumping fluid into a blowing well to kill it
   B. To simply intercept a blowing well with another wellbore to sample and monitor flow while capping
   C. To provide a way to fracture the blowing well to kill the flow
   D. To satisfy regulatory requirements on a wild well situation

15. Snubbing units are not equipped to drill any portion of a relief well since they have limited inside diameters.
   A. True ______
   B. False______

CHAPTER 5 QUIZ 2

Section 5.3

1. When a snubbing unit installs large-diameter casing or a liner in a pressured well, what are some concerns?
   A. Expulsion force on the cross-sectional area of the casing/liner due to surface pressure
   B. Additional snub force necessary to push pipe into the hole against snubbing BOP friction
   C. Clearance available through slips, rams, and the jack bore for pipe collars and cementing tools
   D. All of the above

2. Where are centralizers usually installed when running casing or liners using a snubbing unit?
   A. On the ground before the pipe is picked up
   B. Between the traveling and stationary slips just below the jack plate
   C. In a work window below the jack and above the no. 1 stripper
   D. None of the above—centralizers cannot be installed on casing/liners when snubbed

3. It is easy to snub a conventional electric submersible pump (ESP) into a pressured well since the annular preventer can seal around both the tubing and the ESP power cable strapped to the outside of the pipe.
   A. True ______
   B. False______

4. Why must a high-angle or horizontal open-hole section be cleaned up after drilling and before beginning completion work?
   A. To make sure there is no pressure on the well
   B. To remove low-gravity solids, debris, cuttings, corrosion products, and other materials that could interfere with running completion equipment and/or damage the reservoir
   C. To replace drilling fluid with completion fluid
   D. It is not necessary to clean the open hole since it has just been drilled and it is clean enough

5. What is packer fluid?
   A. The liquid used to inflate and set the packer at the specified depth
   B. Liquid circulated in the annulus between the production tubing and casing with sufficient density to kill the well in case of a tubing or packer leak
   C. A liquid mixture circulated in the annulus between the production tubing and casing that contains chemicals to prevent corrosion and bacterial growth and protect the tubing and casing strings from leaks
   D. A workover fluid that is intended to be pumped into the formation to enhance production

6. When recompleting a well to a different zone above or below the existing perforations where original reservoir pressure is likely to be present inside the well after perforating, it makes more sense to use a snubbing unit instead of a conventional rig.
   A. True ______
   B. False______

7. What is an orphan, or orphaned, well?
   A. A well that has been shut in for an extended time and the previous owner cannot be located through filing proper regulatory forms
   B. A shut-in well on a lease that has reverted to the original mineral owner without being plugged properly after the previous owner walked away from it
   C. A well in which custody has reverted to the government for any reason such as bankruptcy, criminal proceedings, or death
   D. All of the above

8. Live well workovers can be safely performed using what types of equipment?
   A. Conventional drilling rigs of all types and completion units
   B. HWO units where conventional rigs are unavailable or too expensive
   C. Snubbing units, coiled tubing units, and wireline/slickline units
   D. All of the above

9. It is always better to kill a well to perform work on it without the risk of a blowout rather than perform the work on a pressured (live) well.
   A. True ______
   B. False______

10. What mechanical methods are commonly used to repair casing leaks in existing wells without squeezing the hole with cement or some other liquid?
   A. Internal casing patch
   B. Expandable liner
   C. Internal "scab" liner
   D. All of the above

11. Special fishing tools are required on live wells to prevent the loss of wellbore integrity and surface leaks.
   A. True ______
   B. False______

12. What materials can collect inside production tubing, surface valves, and separation equipment that curtail or impede production?
   A. Scale and sand
   B. Pressure and gas
   C. Artificial lift including gas lift
   D. Nitrogen, methane, and helium

13. What is NORM, and where does it concentrate?
   A. Normal wax, in paraffin deposits inside the tubing
   B. Nominal open radial flow, inside the reservoir near the perforations
   C. Native organic reduction material, in condensate produced from gas wells
   D. Naturally occurring radioactive material, in scales deposited in tubing and surface production equipment

14. Carbonate scales are fairly easy to remove using common acids to react with and dissolve accumulations in the tubing, Christmas tree, and production equipment.
   A. True ______
   B. False______

15. Common stimulations performed on existing wells include which of the following?
    A. Acidizing and fracturing
    B. Scale and paraffin removal
    C. Reperforating and cleanouts
    D. All of the above

16. Fracturing was invented and patented in what year?
    A. 2004
    B. 1996
    C. 1982
    D. 1946

17. How does a propped fracture increase production?
    A. By pumping contaminated drilling fluid and emulsions away from the wellbore
    B. By opening unperforated zones behind pipe as the fracture extends to the water table
    C. By increasing the wellbore radius exposing more formation to flow
    D. By etching the rock to form wormholes

CHAPTER 5 QUIZ 3

Sections 5.4–5.7

1. How are HWO units configured differently than snubbing units?
    A. They lack inverted slip bowls for pipe-light string handling
    B. They have no snubbing BOPs (strippers)
    C. They do not have an equalizing loop
    D. All of the above

2. Where are HWO units used most often?
    A. On some offshore and inshore locations
    B. At all onshore locations
    C. On all deepwater locations
    D. Everywhere that a rig can be used

3. What is the primary inside (pipe) well control barrier for an HWO unit during a workover?
    A. A fluid column with sufficient density to prevent flow up the pipe
    B. A plug or float in the bottom of the pipe string
    C. A stab-in safety valve at the surface
    D. The safety BOP stack

4. What is the secondary inside (pipe) well control barrier for an HWO unit during a workover?
   - **A.** A fluid column with sufficient density to prevent flow up the pipe
   - **B.** A plug or float in the bottom of the pipe string
   - **C.** A stab-in safety valve at the surface
   - **D.** The safety BOP stack

5. What is the primary outside (annular) well control barrier for an HWO unit?
   - **A.** A fluid column with sufficient density to prevent flow up the annulus
   - **B.** The BOP stack including the annular preventer
   - **C.** The blind-shear ram
   - **D.** All of the above

6. What is the secondary outside (annular) well control barrier for an HWO unit?
   - **A.** Blind or blind/shear rams
   - **B.** A fluid column of kill weight mud inside and outside the work string
   - **C.** The BOP stack including the annular preventer
   - **D.** None of the above

7. The well control barriers for an HWO unit are the same as those for a conventional rig (drilling, platform, completion, or workover).
   - **A.** True ______
   - **B.** False______

8. How are gas kicks controlled on an HWO unit relative to the way they are controlled on a conventional rig?
   - **A.** They must be bullheaded back into the formation instead of being circulated out of the well like they are on a conventional rig.
   - **B.** They must be allowed to migrate to the surface without expanding before they can be circulated out to avoid fracturing a formation.
   - **C.** The hole must be circulated with one barrel of mud for each barrel of mud coming out using kill weight mud to maintain hydraulic balance.
   - **D.** There is no difference; they are handled the same way.

9. HWO units are not equipped with a telescoping guide between the traveling and stationary rams. Why?
   - **A.** There is no unconstrained buckling requiring a telescoping guide
   - **B.** The pipe string is always in tension (pipe-heavy) at the surface except at points down the hole in some wells due to pipe-on-wall friction

C. There are no snubbing BOPs (strippers) imposing friction against the traveling slips, so there is no compressive force on the pipe

D. All of the above

10. What method is frequently used to stabilize an offshore snubbing or HWO unit on very small platforms?

A. Outriggers attached to the wellhead and guy lines

B. Guy lines to subsea anchors

C. Crane mounted on a floating vessel

D. Nothing—they are all freestanding

11. When considering HSE support for an offshore HWO, what does a bridging document do?

A. Provides the service provider a way to absolve the crew from all responsibilities for safe operations during the job.

B. Provides the Operator a way to absolve itself from any responsibilities for providing a safe worksite.

C. Allows both supervisors (company man and service contractor supervisor) the right to control all aspects of the job.

D. Clearly defines separation of safety-related and operational responsibilities and authority before the job begins to avoid conflicts during the job.

12. Who is responsible for preparing the job safety analysis for a snubbing or HWO job?

A. The Operator's representative (company man)

B. The service provider's supervisor (snubbing or HWO supervisor)

C. HSE representatives from both the Operator and the service provider

D. All of the above

13. Feeding and housing HWO unit crews offshore is not a significant issue for most jobs.

A. True ______

B. False______

14. Snubbing units are often required to perform work on storage cavern wells. Why?

A. It is easier to rig up a snubbing unit instead of a conventional rig due to space limitations inside the small storage cavern site

B. Snubbing units are needed to manage pressure in these wells since the well cannot be killed

C. Conventional rigs are too heavy and could collapse the roof of the storage cavity resulting in damage to both

D. None of the above

15. Pipelines and flow lines can only be cleaned out using chemicals or coiled tubing units.
 A. True ______
 B. False______

16. How is the power cable run and strapped to the production tubing when deploying an ESP using an HWO unit?
 A. In the work window below the jack
 B. From a reel feeding the cable above the traveling slips where it can be attached easily
 C. Through a side-door entry sub below the BOP stack
 D. None of the above—ESPs cannot be deployed by HWO units safely

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Chapter 6

Hydraulic Rig Drilling

CHAPTER OUTLINE

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6.1 INTRODUCTION

Drilling oil, gas, and service wells using snubbing and hydraulic workover (HWO) units configured for drilling is not often considered as a viable option during rig selection. Many operators believe the only equipment capable of economically drilling a well must have a derrick, crown, and traveling blocks; a rotary table or top drive; and massive pumps with huge drilling mud systems. The very idea of drilling with a hydraulic jack or coiled tubing (CT) unit seems rather nonsensical to them. Part of this notion comes from past history and experience coupled with the last seven words of any company, "We never did it that way before."

The fact is that using a hydraulic rig for drilling is a feasible, proven technique that can be used in many applications. In some situations, this type drilling is more economical than conventional rig drilling. Rig selection and drilling procedures must be evaluated on a case-by-case basis from safety, mechanical, hydraulic, and economic standpoints. Conventional drilling for all or part of a hole may be required because of the size and hoisting limitations of hydraulic units. There is no single "best" rig or drilling system for all drilling applications.

In some situations, a combination of the two rig types can provide the best alternative. For example, when employing underbalanced drilling (UBD) or managed pressure drilling (MPD), a snubbing unit must be used at some point when the string becomes pipe-light, the point at which the expulsion force exerted by well pressure on the string exceeds the buoyed weight of the pipe remaining in the hole. The hydraulic rig can also be used to drill the UBD or MPD hole section. This process is known as "snub drilling" (drilling underbalanced continuously using a snubbing unit to control surface pressure while advancing the bit).

True, continuous UBD or MPD is only possible by using a snubbing or CT unit for a portion of the job. If a conventional rig or HWO unit is employed, the only way to get the pipe-light portion of the string into and out of the hole without snubbing capability is to temporarily kill the well. This can result in problems restoring the underbalance once drilling resumes. It can also negate the positive benefits of drilling the well underbalanced or with MPD techniques. Snub drilling may be much better suited for this duty than conventional rigs or HWO units, especially when drilling laterals or sidetracking through partially depleted intervals. The overbalance required could damage the formation to the extent that production or injection rates would be permanently suppressed. If a snubbing unit must be used to avoid temporary overbalance issues, why not use it for drilling the well too?

The well manufacturing process involves the selection of the best rig for each hole segment. For example, drilling the surface and intermediate hole sections may be best performed by a conventional drilling rig that can handle large-diameter tools and heavy casing strings. Then, depending on economics, expected pressures, and the selection of UBD or MPD techniques, a snubbing unit or CT unit may be the better rig choice for the remaining hole segments. Keeping the large conventional rig over the hole just because it's already there may not be the best way to drill smaller-diameter holes and to complete the well, even though that may have been the traditional pattern for an Operator.

The hydraulic unit's drilling capability should be evaluated along with a comparison of advantages and disadvantages for each type of rig and hole segment before the final rig selection is made.

6.2 HYDRAULIC DRILLING OPERATIONS

A brief review of how a hydraulic unit drills new hole segments might be beneficial. Snubbing units are designed to perform work on live wells (wells with surface pressure) or those that have a reasonably high probability of becoming live during operations. Conventional rigs and HWO units are designed to work on dead wells only. Both snubbing and HWO units are capable of drilling, and most are equipped to do so (or they can be easily modified for drilling).

6.2.1 Pipe Handling

As we have seen from previous discussions, a hydraulic unit is capable of running and pulling drill strings, including bottom-hole assemblies (BHAs) within certain limits using hydraulic cylinders for the hoisting system instead of the block-and-tackle system employed by conventional rigs. Those limitations include the outside diameter (OD) of the item including bits, stabilizers, and reamers. They all have to fit through the bore of the unit and all of the blowout preventers (BOPs) in the stack. There must be blank pipe sections (those without perforations, slots, or screens) onto which the slips can connect and the BOPs can close to hold pressure in underbalanced, pressured wells.

Also included is the maximum hook load available in the drilling system. Hydraulic units can hoist loads up to the limit defined by hydraulic cylinder diameter, the number of cylinders, and power fluid pressure. Deep wells requiring long, heavy drill strings may be beyond the hook load limit for some hydraulic units.

The same restrictions apply to casing installations. Large-diameter casing strings may be too large to run through the bore and BOP stacks of a hydraulic unit. Casing weights may become extreme unless they are “floated” in (which places a collapse load on the pipe). At some point, the drilling system, whether a hydraulic jack or a conventional rig, must support the entire buoyed weight of the string until it is hung off in the wellhead. Large-diameter, heavy strings may exceed the hook load limit of the hydraulic jack even though the pipe has an OD that can be run through the unit bore and BOPs.

String weight and diameter limitations could shift the rig selection on some wells toward a conventional drilling rig for shallow, large-diameter hole sections. Other wells, especially those in which shallow gas features are present, might still be drilled better with a snubbing unit modified to manage larger-diameter drill strings and casing under pressure. This has been the case in some wells offshore in the Middle East where drilling with a snubbing unit was found to be better than drilling with a conventional rig through a shallow gas interval. The same might be true of remote areas, such as jungles and swamps, where a conventional drilling rig could not be mobilized easily. For example, in one remote area of South America, a snubbing unit was brought in by helicopter to drill the entire well.

6.2.2 Drill String Rotation

Most of the larger standalone snubbing and HWO units have a factory-installed hydraulic rotary table below the traveling slips. It allows the entire pipe string to be rotated when the string load is on the travelers although at a limited rotary speed of around 60 revolutions per minute (RPM). This still allows drilling and directional control especially if the BHA also contains a motor operating at 250–300 RPM. This rotational capability permits the use of rotary steerable directional tools. Rotary steerable tools are not used for coiled tubing drilling (CTD) where the string cannot be rotated. Rotary steerable directional control is possible for CTD through the use of pad-type steering tools using wireline equipped CT.

In some cases, installing a secondary rotary driver in the work window of a hydraulic unit, such as a power swivel or hydraulic rotary table to provide rotary motion to the string, might be the best decision. This addition can enhance hydraulic drilling in two important ways. First, higher rotary speeds can be applied to the drill string than those possible with the hydraulic rotary table on most units. Secondly, reverse torque is applied to a stationary portion of the stack and not the traveling frame. Thus, the prospect of a twisted jack is virtually eliminated. The addition of such a supplemental rotary device requires that the bearing pack below the traveling slips withstand higher rotary speeds than those available from the unit's hydraulic rotary table.

In pressured drilling applications, UBD or MPD, a rotating control device (RCD) is also required to trap pressure in the annulus while permitting continuous rotary motion. Rotating through a snubbing or safety BOP is possible, but not for long. Abrasion of the sealing elements will render their pressure-containing capacity useless in short order. The RCD can be a conventional rotating head with a drive bushing attached to the drill string or a rotating BOP. The RCD is usually installed in the work window just on top of the annular preventer.

6.2.3 Drilling Fluid System

Drilling fluid handling systems are not usually a part of a hydraulic unit spread; they must be added for drilling. These systems include mud pumps, tanks, solid separation equipment, mud cleaning equipment, and mud chemical mixing systems. There must be a means to connect the mud system to the drill string and annulus (Fig. 6.1). Special equipment, such as centrifuges, cutting handling, and drying equipment, may also be required for some drillsites.

Drilling fluid systems are commonly a part of the equipment spread on a conventional rig. They are usually quite large with sufficient volume to manage the worst-case scenario in terms of hole volume, residence time, and mud cleaning capability. In some smaller-diameter hole sections such as those drilled by hydraulic units, large drilling fluid capacity may not be needed. A smaller footprint, more portable, and more easily operated system may be sufficient. This can become a part of the rig selection process for a hole section or the entire well especially where remote, limited size locations are involved.

A well-functioning mud handling and circulating system is one of the most critical challenges of any successful drilling program. Systems that do not perform efficiently or effectively will likely result in additional cost and possible loss of a hole section due to borehole instability.

6.2.4 Crews, Support and Supervision

Personnel who operate drilling equipment, regardless of type, are crucial to successful operations. There must be a sufficiently sized crew with adequate training, support, and supervision to manage drilling equipment and the

■ **FIG. 6.1** Drill string swivel and kelly hose. *(Courtesy of Cased Hole Well Service.)*

processes required, including maintenance and minor repairs, when and as needed. By contrast, the best drilling equipment in the world cannot be used successfully without the proper manpower to operate it safely and efficiently. Many drilling operations have been torpedoed by inexperienced drilling crews sent to the wellsite without proper training and a clear understanding of plans, goals, and processes involved.

6.2.4.1 Crew Training and Experience

Snubbing unit crews are usually better trained and more capable of handling pressured-well drilling operations than some conventional rig drilling crews.

Often, as was this author's experience, a conventional drilling rig is the place where initial oil field training starts. Green hands, often unfamiliar with tools, pressure, loads, and processes, are commonly placed on a rig as roughnecks (floor hands) and trained on the job. They are often unfamiliar with handling pressure. In conventional rig operations, often only the driller and assistant driller have anything but cursory training in well control and kick handling; floor hands may not have any training in well control or pressure management at all.

The lack of training and experience dealing with surface pressure may be completely acceptable for dead well drilling operations. Some operations require intensive manpower to mix mud, handle drill strings, run casing, and cement pipe in large holes. The wells are usually dead with no possibility of flowing anyway. So, having inexperienced crews to manage these operations works well, and it provides them with training and experience to handle more complex drilling operations later on such as UBD and MPD.

Snubbing unit crews are familiar with pressure and how to handle it safely. They are generally comfortable managing wells with surface pressure, unlike drilling rig crews who may not have the same familiarity dealing with pressure. Many snubbing unit crews previously worked on hydraulic units and together as a crew for some time before they are dispatched to perform snub drilling duties. Pressure on the well is no surprise to a snubbing unit crew.

Well control training is a large part of a snubbing unit crewmember's job requirements. In pressured operations, there is a kick in the well with surface pressure at all times. Handling pressure on an annulus is nothing more than routine for most snubbing unit crewmembers.

6.2.4.2 Crew Size

Crew complements on hydraulic units, both snubbing and HWO units, typically include four persons per shift plus a snubbing supervisor. The four persons include two operators in the basket and two others to manage pipe handling, maintenance, minor repairs, and monitoring. The supervisor may or may not be directly involved in the operations. He/she generally performs duties similar to a toolpusher on a conventional drilling rig.

Sometimes, roustabouts or platform workers assist in hoisting and handling pipe, tools, bits, reamers, and other BHA components. Their continuous involvement in drilling may not be required, however. Specialists such as those involved with downhole data collection from measurement-while-drilling/logging-while-drilling (MWD/LWD) and pressure-while-drilling (PWD) tools may be on-site, but not necessarily directly involved in drilling operations. Tool makeup specialists may be in the basket to ensure that joints are connected properly. Packer specialists, fishermen, and other specialists may also occupy a place in the basket, but their involvement in the drilling job is usually sporadic.

Drilling operations are carried out 24 h/day with only minor interruptions. Some preparatory steps, such as setting a whipstock and milling a window in the production casing, may be daylight operations only, but when drilling a new hole, it is usually a bad idea to shut down operations overnight. Doing so could result in a loss of borehole stability.

Some smaller hydraulic unit service providers have found a poor means of providing 24 h/day crews. They will work one crew during daylight hours, then bring another crew from a rig where they have worked all day, and make them the night crew. On the following evening, they bring in a different crew to work nights, and a different crew the evening after that.

The primary issue with this rotation is that the new "night" crew has already worked 12 daylight hours before they report for another 12 hours of night duty. Further, they will work another 12 daylight hours the following day. Thus, they are required to work 36 straight hours before getting any rest.

Experience has shown that the crew is usually fatigued, sleepy, and mentally fatigued at some point during any night shift due to normal circadian rhythms. Our bodies like to sleep at night. This can lead to poor decisions, poor situation awareness, accidents, injuries, or just poor performance. Not having a fresh night crew is likely to lead to excessive fatigue, risk, and discontent.

If this prolonged 36 h schedule is the only way the service provider can do the work, the job should be delayed until dedicated crews are available. Otherwise, the operator needs to find a different service provider having adequate crews.

6.2.4.3 Housing and Messing

All crewmembers must have adequate housing for rest and sleep during off-hours. They must also have access to clean clothing and recreational activities in a controlled environment. Crews must be fed properly and regularly. There is no better way to create a mutiny than to feed crews poor tasting food in small quantities. These hardworking folks are burn thousands of calories per day. Failure to replace those calories with decent food usually results in poor crew attitude and performance.

Crew quarters, change rooms, and a robust galley are usually present on offshore drilling rigs on large, manned platforms. Some onshore conventional rigs have these features, as well, especially in areas where off-site crew housing and messing facilities are not available. In some areas, a nearby crew camp is provided since crews cannot return home at night or to a local hotel. Most hydraulic unit spreads do not have these facilities as part of their normal equipment spreads. They should be added when the snubbing or HWO unit is involved in 24 h/day continuous operations.

6.2.4.4 HSE Support

Health, safety, and environmental (HSE) support in current oil field operations is a critical component of most jobs to protect crewmembers, equipment, the well/platform, and the environment from injury or damage. Most crewmembers are aware of the requirements for a safe job, but sometimes, those are set aside in the interest of completing the task at hand. The crewmembers develop a type of myopia (tunnel vision) that causes them to miss subtle cues that would ordinarily alert them to potential risks during the job.

Many service contractors and operators provide one or more safety specialists whose function is to maintain a high level of situation awareness, check continually for newly developed hazards, and ensure that all personnel involved in the operation are reminded about existing and potential hazards.

There is usually a short safety meeting for all personnel involved in the operation, from crane operator to hydraulic unit supervisor at the beginning of each shift. Anytime there is a change in the operation or the introduction of a new hazard, such as well pressure, a short safety meeting should be conducted to discuss the situation and plans for handling the job. These meetings are highly beneficial.

6.2.4.5 Communications

Operators and service providers usually understand the need for adequate communications for business purposes. These include daily progress discussions with the office (usually the morning report); status updates periodically during the day; and the ability to order parts, equipment, supplies, and repair personnel. It is also a requirement of most regulatory agencies involved with health and safety to request emergency services in response to injuries, criminal activities, or other problems such as a fire.

Unfortunately, some companies involved in a long job fail to understand the importance of providing personal communications for crewmembers. Each person on the crew has a need to stay in touch with his/her family, especially if there is an existing or impending problem they are facing. The family of every person on the hydraulic unit wants to hear from the worker periodically. On long-duration jobs, this capability is particularly important. Having some type of private communication for crewmembers to contact their families is essential for a smoothly functioning operation of any type.

In remote locations, such as swamps, forests, or deserts, communicating may require a strong Internet connection for e-mail or video calls (e.g., Skype, WeChat, and Facetime). Sometimes, satellite phones provide the only means of communication. Cell phones may provide this capability. However, cell phones may not have service in some locations, especially offshore. Open communications such as FM or single-sideband radios may be adequate for business conversations but poor for personal ones where others can listen in.

Crewmembers, on the other hand, must be careful not to "hog" the Internet or satellite connection. Time restrictions may have to be imposed to make sure that everyone has an opportunity to call home. Playing games on the platform computer, for example, may use so much bandwidth that some individuals can't use the Internet at all.

6.2.4.6 Crew Rotation

Nobody can work forever without relief. Hydraulic unit crews are no different. After a period of time, crews simply quit caring about their performance or safety issues. They go about their duties in a standard routine with little concern about anything except making it to the next meal in the galley. Complacency kills; so does fatigue.

Crews are (or should be) rotated on a set schedule. This may be every 4 weeks (28 days on/28 days off) or more frequently depending on circumstances. The author has worked for as many as 5 months on one project without returning home. Long or indeterminate assignments are not recommended for crewmembers.

Sometimes, crewmembers must be substituted in the middle of a normal assignment (hitch). Family illness; injury; or personal issues, such a death in the family, a wedding, or a child's graduation, require that there be an adequate number of substitutes available for his/her replacement. Transportation must be available to manage these personnel transfers, and there can be no loss of crew continuity. Substitutes must be available to fill in for crewmembers on temporary leave.

6.2.4.7 Crewmember Compensation

Hydraulic unit crewmembers are generally compensated well, compared with many conventional drilling rig crews, because of their advanced skills and training. This provides the incentive for crewmembers to remain technically competent, welltrained, hardworking, and compliant.

Most service providers add bonuses of some type to their employees' salary when they are assigned to jobs that require them to be away from their home base. Most also receive generous expense reimbursements for housing and meals for remote onshore jobs. This extra compensation often causes crewmembers to stay past their normal rotation, especially when replacement crews are difficult to locate. They may end up working their normal hitches plus one extra in the middle of the schedule. This, of course, means they are on location for three hitches in a row. This is not a recommended schedule, no matter how attractive the compensation package.

Like all other jobs, compensation must be adequate for the duties and difficulties endured during the job regardless of whether a hydraulic unit, conventional rig, CT unit, or wireline unit is involved. If not, crews can become sullen and develop poor attitudes, which almost always result in poor job performance and, even worse, relaxed HSE compliance.

Operators (the oil companies) usually realize that crew compensation is a necessary part of a successful drilling operation, and many provide daily bonuses apart from the service provider's salary and bonus programs. These bonuses are usually both performance- and safety-based, so there is always an emphasis on the HSE aspects of the job. This avoids the "hurry up" operating method in which normal steps in any procedure are done at a frenetic, hectic, unsafe pace just to earn the performance bonus. It is replaced by safe, well-managed operations performed at a determined pace. The same type of bonus program is often provided to crewmembers on other types of drilling rigs.

Total crew compensation on a hydraulic drilling operation may be no greater than that for a conventional drilling rig. Some hydraulic drilling rigs employ fewer workers than conventional rigs, so the overall compensation and bonus package may actually be lower to the Operator; however, on some jobs, the conventional rig may outpace the hydraulic unit in performance (e.g., tripping pipe) making the total crew compensation package higher for hydraulic unit drilling than for conventional drilling. Obviously, this is one of the cost variables that should be analyzed before rig type, and selection is made. Cheaper is not always better.

6.2.5 Transportation and Rig-up

Mobilization and rigging up are two labor- and time-intensive processes that are involved with any drilling operation. Moving and rigging up in hydraulic drilling operations are no less complicated and costly. Logistics and equipment selection are often a large part of the total job cost. Actual drilling can be somewhat boring compared with getting the unit inplace and rigged up.

Mobilization differs depending on where the operation takes place. This can vary significantly from one site to another.

6.2.5.1 Onshore

Transporting onshore snubbing equipment (HWO units are rarely used onshore) usually involves commercial over-the-road trucking. Sometimes, the trucks and trailers are the property of the snubbing services provider, and they are driven by the snubbing company's employees. Other times, all transportation is provided by third-party commercial trucking companies. Cost of transportation may be borne by either the snubbing service provider or the lease Operator depending on contract terms.

The best way to arrange for transportation is to allow the snubbing services and the trucking company to collaborate on positioning the load on the trailer or truck bed, managing load sizes, and securing the load for transportation. It is usually better if the operator is not directly involved in this process unless the Company Man is skilled and experienced in trucking. The snubbing supervisor and the truck pusher are usually better at managing load out and transportation.

Other portions of the onshore snub drilling spread may be transported differently. These include mud pumps, mud tanks, mud cleaning equipment, cutting boxes, crew quarters, trailers, or skid-mounted quarters and offices for the Company Man, directional drillers, and mud loggers. These are also transported by truck. The loading and hauling may be performed by the same third-party trucking company handling the snubbing unit, or it may be done by a different one. Here, the truck pusher may be working with the Company Man or with the snubbing supervisor.

Placement of the snub drilling equipment spread is usually predetermined depending on the demands for the snubbing unit, especially anchoring, and the scope of the job. One job, for example, may only require a single mud tank and two small pumps. The next may require four to six mud tanks, complete with all mud cleaning equipment, and three large pumps. Laying out all this equipment requires forethought and sound reasoning.

Many conventional drilling rigs have a location layout available for all the equipment in their rig spread. The truck pusher can simply refer to a diagram when setting equipment on the location for these rigs. Snub drilling spreads are usually purpose-designed and do not have a uniform pattern. So, close coordination between contractors is required for a proper initial installation. Once the trucks leave, it's hard to move the equipment around on the jobsite.

Rigging up is equally purpose-driven. The job may require a considerable number of spools and spacer subs in the stack to hold the components of the drill string that cannot be snubbed ram-to-ram. Sometimes, the snub drilling stacks are quite tall, over 100 ft. This drives the size, mast height, and weight capacity of the crane used for rigging up the snubbing unit. The crane can become the largest and heaviest load transported over the highway. It may be, and often is, an oversized load requiring special signage, caution lights, and escorts.

Snub drilling units and stacks are usually assembled one piece at a time. However, in some remote locations when transporting within the field where highway regulations do not apply, large "chunks" of the equipment may be transported in a single piece, such as the entire safety BOP stack.

In some areas, such as desert locations, a conventional rig may be skidded with the mast still assembled on the substructure. This is a bottom-heavy load that can be safely moved as a single piece. Snubbing stacks are usually top-heavy with the hydraulic jack assembly being the top-most piece in the assembly. Guying and anchoring to prevent toppling is not possible during skidding, so snubbing units are rarely skidded while erect, if ever. They may be broken into smaller "chunks," but even these are normally laid down for transport to the next site.

The crane may remain on-site for short-duration jobs once the snub drilling unit is rigged up. The crane is often used to assist in nippling up lines and for supporting the top of the unit. The cost of transporting the crane to the site, erecting it, rigging it down, and transporting it back to the yard twice is often more expensive than simply leaving it on the edge of the location and paying standby charges while it's not working.

6.2.5.2 Offshore

Transportation from the dock to offshore sites relies on boats, usually supply vessels or transports, with sufficient deck space and loading capacity to manage the loads secured to them. Heave, roll, and pitch can cause unusual loading patterns on decks that must be addressed.

The number of vessels must also be addressed when estimating costs and determining proper rig selection. The entire spread must be considered, not just the snubbing or HWO unit. When comparing rig types in the selection process, the cost of transporting ancillary equipment to the platform must be considered. For example, some of the required equipment, such as mud tanks, mixing, mud cleaning, and cuttings handling equipment, is in the inventory for a platform rig. However, they may or may not be included in the drilling or workover contract with the Operator. They must be transported to the platform just like they would be for hydraulic unit drilling. The cost of transporting them to the site must be considered for both types of units in the rig selection process.

Some Operators and regulatory jurisdictions require standby boats for rescue and fire suppression during all offshore work. It is likely that these boats would be required regardless of rig type, so in the rig selection process, this cost is not considered. However, for capital expenditure (CAPEX) estimations, the cost of the standby boat must be included.

Loads involved with offshore hydraulic drilling are usually transported from storage facilities to the dock over highways. So, road and highway regulations with regard to load size and weight still must be within the permitted limits (just like trucking the same items to onshore sites). The same is true with equipment for conventional rigs as well.

Hoisting the hydraulic unit and its ancillary equipment requires a crane sufficient to manage the individual lifts under dynamic conditions. In most offshore applications, the transport vessel is subject to heave. So, hoisting is not the same as it was in quiescent waters at the dock. Higher-capacity cranes are usually required for offloading. Some platform cranes are not rated for these hoisting requirements.

A portable crane, such as a bullfrog crane, must be first transported to the site, assembled, and used for hoisting the hydraulic drilling unit spread onto the platform. This extra cost probably applies to a platform rig (but not a self-contained bottom-supported rig).

Rigging up and assembling the hydraulic unit, including the safety BOP stack and jack, require a crane mast with sufficient length and hoisting capacity to manage the loads. Sometimes, this crane is also used for handling heavy items such as drill collars, BHA components, and casing joints instead of the hydraulic winches on the snubbing/HWO unit. A supplemental crane normally stays on the platform for short-duration drilling programs since it will be needed at the end of the drilling work to rig down and off-load the equipment back onto the transport vessel. In longer programs, it is dismantled and returned to save rental fees and to provide additional free space on the platform deck, assuming that the platform rig can support drilling operations.

6.2.5.3 Inshore

Inshore hydraulic rig drilling differs from offshore work since most of the equipment spread is positioned on support vessels at the dock. The equipment is usually transported to the wellsite on the same vessel that will support it during the job. This vessel can be a lift boat, barge (keyway, posted, or semisubmersible), or similar vessel. Tugs or push boats push or tow vessels that are not self-propelled.

There may be more than one such floating vessel involved. Once arriving at the site, the vessels are lashed together to allow some movement. They are usually equipped with gangways providing access to each other and to support vessels, such as tugs. Other support vessels might include crew boats to transport workers back and forth to a dock at the end of a shift, unless there are crew quarters and messing facilities included on a floating vessel at the wellsite.

Again, the individual loads for an inshore hydraulic drilling spread must be transported over highways to get to the dock for onloading and securing. So, the loads must each be within the requirements dictated by highway regulations. A large crane may or may not be needed on the job.

Often, barges with permanently mounted cranes are selected since these barges are frequently used for construction work. Again, the crane must be sufficient in capacity and mast reach for rigging up the stack and snubbing/HWO unit. Because it is permanently installed, it usually assists in drilling operations and handling other loads during the job, essentially taking the place of a platform crane on an offshore site.

Rigging up the hydraulic drilling rig usually involves hoisting and assembling the BOP stack and the snubbing/HWO unit. All the other equipment items, such as tanks, pumps, lights, and other kits, are already installed and usually tack-welded in place on the barge deck. If more than one barge is involved, flexible hosing or other piping must be connected before drilling operations begin. Much of the preparatory work, such as laying lines on each barge, installing pump suction lines, and filling tanks with water, can take place during transport to the site.

6.2.6 Initial Wellbore Assessment

Borehole stability and well integrity must both be maintained in any drilling operation to ensure safe operations with risks mitigated sufficiently for a successful operation. Failure to do so can result in costly failures and risks to humans, the environment, the drilling equipment, and the wellbore itself. Reserve and CAPEX losses are unwanted, expensive outcomes of a failure in well integrity, and they can result in poor economics due to added costs and lost reserves if the job must be terminated.

Good prejob planning can help prevent the borehole stability and well integrity failures. Sometimes, failures in equipment, barriers, mechanical competence, and the hole itself occur anyway due to the nature of drilling. Reservoir properties and conditions can only be inferred through a variety of measurements and extrapolations until a bit penetrates the formation. So, it's important to make the best estimate of what can be expected during operations early on.

6.2.6.1 New Wells

Many hydraulic drilling operations are performed on existing wells, both live and dead wells. A well that is to be drilled entirely using a hydraulic unit must have some type of supporting structure on which to rig up the snubbing or HWO unit. This might only be a conductor or perhaps surface and intermediate casing set by an earlier conventional rig. In other cases, these upper casing strings may still remain after the original well has been abandoned with inner casings cut and pulled from the well.

If there is no wellhead of any kind, hydraulic unit service providers can provide a stand with a flanged connection that can support the weight of the jack and all hoisting loads, including casing strings, from the ground or platform deck. Obviously, the surface or the deck must be carefully analyzed to ensure that the stand is adequately supported. Once the first casing string is installed and cemented, the hydraulic unit and BOP stack can be rigged up on the wellhead flange and the stand removed. All future loads will be transmitted to the conductor, surface casing, and any subsequent casing string cemented back to the surface.

Shallow drilling using a jack is almost the same as drilling these sections with a conventional rig. There is rarely surface pressure involved since most operations are performed overbalanced. Surface pressure may be difficult to control since there may only be a limited length of casing set and the fracture gradient at the casing shoe is often quite low. Trapping pressure under a blowout preventer might simply result in a shallow casing shoe failure with broaching to the surface or mudline.

One exception involves drilling shallow gas or water flow zones. A snubbing unit is well suited for this type of drilling because low pressure can be held on the wellbore instead of subjecting the new hole section to kill weight mud while drilling the interval slightly underbalanced. It is not necessary to kill the well, if doing so is even possible. Obviously, this requires that there is at least one string of shallow casing set at a depth with a fracture gradient sufficient to handle the surface pressures involved.

Mechanical well integrity issues are rare with new wells, since all the barriers are newly installed and tested. Usually, new casing (or inspected used casing) is installed and cemented in new wells. The most common well integrity issue involves casing collar leaks and internal drill pipe wear on casing strings. This same issue exists regardless of rig type.

Barrier maintenance is an absolute requirement. These barriers include casing, cement, wellhead segments, and any external casing barriers such as liner top packers. The snubbing and safety BOP stacks must be maintained and tested frequently to ensure that they are functional and can hold anticipated pressures while drilling. The additional control made possible by using a snubbing unit to run and cement casing or liner strings enhances barrier installation and integrity.

6.2.6.2 Existing Wells

Hydraulic drilling on existing wells usually involves deepenings, sidetracks, and replacing segments of an existing wellbore for a number of reasons. One of these is to penetrate and expose a new reservoir. Another is to bypass a damaged wellbore section. Another might be to drill around unrecoverable junk that blocks a portion of the wellbore or to place a new hole in the reservoir at a different place (e.g., updip).

Regardless of reason, a good assessment of well integrity is a requirement that cannot be overstated. It is both costly and embarrassing to start a drilling job on an existing well only to discover that drilling is neither possible nor economically viable due to some pre-existing condition such as shallow collapsed casing. An assessment of the wellbore condition is essential to proper planning for a redrilling job (or any other task, for that matter).

Several issues can be investigated before dispatching equipment to the jobsite such as surface pressure, well history, and unexpected conditions.

- **Surface Pressure**

  Pressure on the production or injection tubing and all annuli is important in determining safety and equipment issues in a drilling operation. The primary inside barrier in all live well snubbing jobs is one or more check valves or plugs inside the pipe. Pressure on the tubing normally requires setting a downhole plug before nippling down the tree unless the well is first killed by bullheading or by bleeding off the pressure. Even then, setting a downhole plug is still recommended. The production tree might be safely removed by installing a back-pressure valve (BPV) in the tubinghead receptacle, but most snubbing service providers will still require a downhole plug inside the string if there is pressure on the well.

  Surface pressure in any annulus is an indicator of a barrier failure of some kind unless the well is not equipped with a packer or the pressure was intentionally imposed by the operator. One example involves an annulus used for gas lift. Here, the pressure is operator-induced and does not represent a barrier failure.

  Some operators apply pressure to an annulus so the annulus integrity can be monitored. A zero pressure at the surface is not an indicator of annular integrity. The casing could have a leak and downhole crossflow, for example, and still show zero surface pressure.

  Sustained annular pressure (i.e., pressure that cannot be bled off) on outer annuli may indicate that the cement sheath around the casing above some pressured reservoir has failed (cracked) or channeling occurred shortly after initial cementing. Another source of this pressure could be a leak at the surface in the wellhead through compromised seals.

  Increasing annular pressure due to rising temperature in a sealed annulus does not indicate a barrier failure. In fact, it is an indication that the barriers are not compromised since the temperature-induced pressure could not build in a compromised annulus (i.e., it would just leak off). This pressure can be bled off and it usually will not return.

  Pressure inside the "A" annulus (in the nomenclature of API Recommended Practices 90-1 and 90-2) between the production or injection tubing and the innermost casing string that follows changes in the tubing pressure can be an indicator of a hole in the tubing or production packer. The casing may be intact (especially if there is no pressure on the "B" annulus). This situation would have little or no impact on snub drilling. It would have a significant impact on preparations for drilling including snubbing out of the hole with the tubing string under pressure. If a hole in the tubing or packer leak is indicated, a multiarm caliper survey could show the location of the hole in the tubing. Setting plugs to isolate the hole would be necessary prior to tripping out of the hole to reduce the possibility of the well flowing out of the tubing unexpectedly.

Sustained casing pressure on the outer casing strings may also have little or no impact on drilling. The pressure can simply remain trapped in outer annuli in many cases. Mitigations for monitoring the pressure and protecting pressured surface structures such as side outlets on the wellhead may be sufficient to provide a safe work environment.

This type of prejob well integrity assessment can be done without the drilling spread on the jobsite. A wireline or slickline unit can set downhole plugs and/or run surveys to determine the existence of hazards. One example would be to run a noise/temperature log to check for crossflow behind pipe and to locate the fluid level inside the tubing. Setting plugs in downhole profile nipples to facilitate tubing removal with pressure on the annulus using a slickline unit is very efficient and cost-effective.

- **Well History**

  A thorough analysis of well history and that of nearby wells can often provide insight into situations that could impact snub drilling operations. Most wells have an extensive file that goes back to original drilling. A check of early drilling records can provide information necessary to determine if well integrity is likely to have been compromised or if wellbore stability issues might be expected while drilling through a particularly troublesome interval.

  Analysis of offset wells is important if records are available. If, for example, every offset well developed a casing leak in a sour water-producing zone after one year, it is likely that the well on which drilling operations are planned has one too (or will develop one soon). If an active fault in offsets resulted in partially collapsed casing, the probability of a similar problem in the planned well might be elevated.

  Some zones within intact wells might be sensitive to various drilling fluids. One example is the Morrow sand interval in West Texas and Eastern New Mexico. These sands were co-deposited with clays that are highly sensitive to fresh water. When the sands are contacted by fresh water (or just about any other water-based fluid system), the clays become dispersed inside the formation, and they can plug small pore throats resulting in excessive skin and consequential flowrate reductions. The drilling fluid chosen for this section might be an oil-based mud or a nondamaging brine. Drilling through the sand with fresh water would not be prudent.

Production history might also provide valuable information on what might be expected downhole. For example, if a well has been producing green oil for some time and suddenly starts producing brown oil with a different gravity, a compromise in an old perforation squeeze job might be indicated. A former well that began making water fresher than what would be expected from the original formation might indicate a shallow casing leak.

Repair and maintenance history of the well on which drilling is planned may also indicate problems that will require special attention. These could include such things as casing leak squeezes, partially collapsed casing, high water cuts in producing wells, or injection pressure fluctuations that cannot be unexplained. Wells with unrecoverable junk in the hole such as tubing, wireline tools, expended or live perforating guns, sucker rods, downhole pumps, or other obstructions might complicate drilling operations.

Some wells do not have complete or adequate well records. Ascertaining the history of the wellbore in these cases might not be possible. This can occur when the well was purchased from a previous operator and the well file has been misplaced. In some cases, the only well records are those kept in field notebooks or forms filed with regulatory agencies. Some jobs may be too risky to pursue with drilling of any type without some type of diagnostic work being performed in advance. The results of the diagnostics may be the only guide available for planning drilling procedures and not the well history.

- **Anticipating the Unexpected**
  Many blowouts through the history of the oilpatch have occurred because the operator drilled into a pressured reservoir that should not have been present or should have been depleted. Fortunately, snub drilling is particularly well-suited to handling unexpected events, one of the primary reasons it is often selected as the drilling method of choice.

  Planning for the unexpected is an integral part of preparing a drilling procedure. Once the original barriers in an existing well are penetrated, such as a sidetrack through a slot in a casing string, drilling risks and hazards can become realities in short order. The possibility that these hazards exist should be part of the original well assessment.

  Examples are numerous. One might be drilling through a disposal zone that has been behind pipe for decades. The prospect of a water flow with significant pressure should be anticipated. Drilling into a secondary gas cap in an undersaturated reservoir could result in taking a gas kick with no easy means of killing the well. Again, snub drilling underbalanced would be a good way to manage these prospects, but the snubbing unit must be configured and equipped to handle this possibility.

In some areas, all produced gas must be injected into the formation from which it was produced. Oil production results in reservoir pressure reductions, but injecting the gas partially compensates for this pressure loss. In those areas where there is no gas market, reinjection provides the means to deal with the gas other than flaring it (which is now banned in many jurisdictions). Drilling into a formation subject to this type pressure maintenance could result in an unexpected kick. The snub drilling unit, if selected, must be equipped so that it can handle the kick safely.

In these examples, there may be nothing in the well history or from offset wells that would indicate that the issue exists. So, anticipating these types of problems is part of the predrilling preparation for any job including snub drilling.

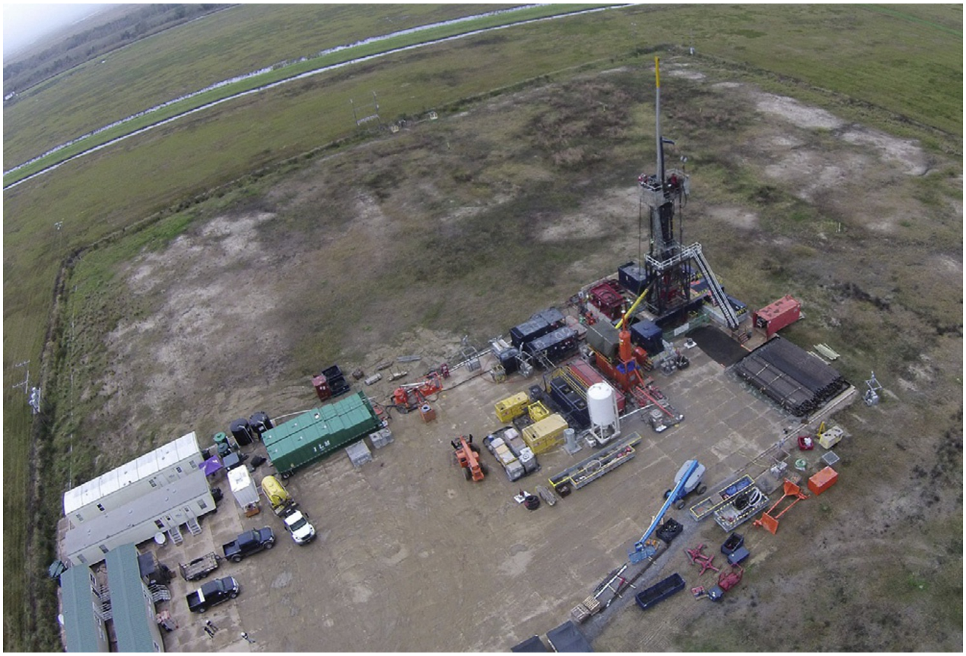
6.2.7 Hydraulic Drilling Unit and Equipment Layout

There are few prepackaged snub drilling equipment spreads available. Most are combinations of the snubbing/HWO stack with ancillary equipment procured and configured for the best fit on a particular wellsite. There is considerable flexibility in how the equipment is placed on the site, one of the greatest strengths of a hydraulic unit drilling spread in comparison with a conventional drilling rig. Onshore, the equipment can be set just about anywhere as long as the location is large enough to accommodate it. Offshore, the spread must be configured to the platform or support vessel on which it is assembled. Inshore, the support vessels (usually barges) dictate where and how the equipment is placed so it can be manifolded together with other components.

6.2.7.1 Onshore

Fig. 6.2 shows a typical layout for an onshore snub drilling unit equipment spread. This is, of course, only one such diagram. There are many layouts, each depending on the location configuration and the equipment needed to perform the job.

For many drilling jobs, only one or two mud tanks may be required. These may be small tanks (e.g., 125 bbl capacity) because smaller holes are often drilled using a snub drilling unit and total mud volume requirements are much smaller. There must be sufficient tankage for mud cleaning, degassing, and mixing chemicals in the drilling fluid. A small pill pit (20–30 bbl) is usually included.



■ **FIG. 6.2** Typical onshore snub drilling equipment layout. *(Courtesy of International Snubbing Services.)*

Other authors have emphasized that all the fluid for use in drilling and side-tracking operations must be consistent in density and fluid properties. This is no less important in snub drilling than it is in conventional drilling. Having poorly-mixed mud, with heavy and light “spots” in the column or with inconsistent properties, can provide significant risks, especially those involving well control.

It is also important to have sufficient fluid in the suction tank, usually 2–3 times the entire drill string volume, to ensure that losses to the hole do not deplete the available supply resulting in a premature shutdown. This entire volume should be clean, processed drilling fluid ready to pump downhole.

For most jobs, only two pumps are required. A third pump could be added, however. Tanks may include charge pumps, but usually, main pump suction comes directly off the bottom of the final tank. Because there is usually a smaller total volume tank requirement, there is often no trip tank used in snub drilling. A gain or loss can be detected from the sum of all the tanks accurately owing to their lower combined volume. Accurate total pit volume monitoring in a small tank setup would make a small-volume trip tank redundant.

A reserve pit and flare pit are usually located outboard from the mud tanks. The flare pit allows the safe handling of gas that collects during ram-to-ram snubbing in live well operations and from flow testing. The reserve pit may be replaced with aboveground cutting storage and handling equipment depending on specific site requirements.

A small pipe pickup and laydown area is usually all that is needed instead of the large area for pipe racks and a catwalk on conventional drilling rigs. Drill pipe sizes are usually smaller, and sometimes only heavy-weight drill pipe is needed instead of drill collars.

The power-pack and generators are usually diesel engine-powered and are located upwind or crosswind from the snubbing unit. Pumps may either be electric-motor-driven or have their own diesel engine as a prime mover. Again, these are generally located upwind or crosswind from the snubbing unit.

Quarters and office buildings are usually located upwind of the well. These can include quarters for the Company Man, snubbing supervisor, directional driller, MWD/LWD technicians, and geologist. The mud logger shack is usually located near the shaker pit to reduce the length of lines from gas trap in the flow-line possum belly.

Location lighting for nighttime operations is often supplied by diesel engine-driven light towers located about the location. They are needed to provide lighting for the snubbing unit and operations, since there are usually no derrick lights in the stack or basket.

A snubbing unit must be guyed to provide stability. Either ground anchors or anchor blocks are set in a square pattern with spacing defined by the height of the stack. The snubbing unit must be guyed to provide stability. Spacing is usually on the order of 100–125 ft. from the well centerline.

An area "in front" of the snubbing unit stack must be provided for the crane used to rig up and rig down the stack. The crane may or may not stay on the site during drilling operations depending on the time required for drilling and equipping the newly-drilled hole section.

The area outboard of the pipe racking area is usually reserved for wireline and cementing equipment. This provides sufficient room to rig up and operate either one without interfering with other equipment on the location.

6.2.7.2 Offshore

Most hydraulic unit drilling offshore, using either snubbing or HWO units configured for drilling, takes place from multiwell platforms with sufficient deck space for the assembly of the equipment spread. Configuration of the drilling equipment spread is based entirely on how the platform is configured and whether or not some of the equipment can be placed on a lower deck. This equipment might include pits, mud pumps, the power-pack, and cutting handling gear that are not immediately required on the top deck.

Offshore locations often require that equipment be crowded closer than it would be at an onshore site. Quarters may be located away from the well template for safety with only small "shacks" provided for supervisors, safety men, the directional drillers and MWD/LWD personnel, and equipment near the stack (wellbore). This makes the equipment spread congested with a number of hazards.

There is usually no tank for drilling water (nonpotable water) since the platform's seawater supply system is used to provide water for mud systems and for washdown. It is important to collect all used washdown water since minor leaks can carry drilling fluid, hydraulic fluid, and other contaminants into the sea. This wash water is usually handled by the platform's wastewater facilities, with contaminants such as hydraulic fluid collected in the slop tank.

Most operators require that environmentally safe fluids be used on offshore drilling and workover jobs. This includes the snubbing/HWO unit's hydraulic fluid, BOP fluid, and all drilling fluids used during the job. Small spills must be collected and cleaned. Environmental damage from accidental spills to the sea, if any, is mitigated by the "green" nature of the fluids used in the job.

The crew and supervisor may be housed in the platform's living quarters, in temporary quarters in containers, or in a moored housing unit near the platform (i.e., "flotel"). Quarters facilities also contain a mess hall and laundry facilities.

In some areas, regulations prohibit the use of diesel engine-driven pumps and power-packs. Only explosion-proof electric motors and intrinsically safe controls are permitted in the wellhead area. The power-pack should be located as close to the hydraulic unit as practical to limit power losses and return line fluid friction from reducing efficiency. This, of course, means that the power-pack must also be electric-motor-driven. The same may be required of main drilling fluid pumps depending on where they can be positioned.

The platform's electric power generating facilities are rarely large enough to supply power for hydraulic unit drilling spreads. This requires that two large diesel-powered generators (one main and one standby) be situated in safe areas on the platform with power cables run to equipment in the spread. This requirement often complicates the equipment layout and reduces the attractiveness of hydraulic drilling in some offshore areas versus a self-contained conventional drilling rig such as a jack-up.

The engines, generators, mud tanks, and other equipment required for hydraulic unit drilling are sometimes large, heavy, and awkward to handle during placement on the platform. A fairly large crane is required for off-loading and rigging up this equipment including the BOP stack and the snubbing/HWO unit.

Fuel for engines and generators usually comes from the platform's diesel tanks that must be resupplied often to provide fuel for both the platform and for the snub drilling equipment. Additional crew support also requires frequent restocking of potable water.

6.2.7.3 Inshore

Inshore sites, including those in bays, estuaries, and swamps, require the use of vessels on which the drilling spread is carried to the site and used during operations. In some areas, large barges can be placed. These are typically twice as large as typical inland barges with sufficient room for the entire equipment spread although much of the kit is crowded. In most areas, however, multiple barges are used with each barge selected for its size; weight capacity; and ability to ballast down, be submerged (e.g., posted barges), or be spudded for stability.

The single large barge approach involves an equipment layout similar to an onshore location although the spread size is usually smaller. Provisions must be made for collecting wastewater, slops, and cuttings (which may require a second smaller barge).

Single-deck barges may be added to the barge supporting the hydraulic unit as needed. Often, the mud tanks and mixing system, power-pack and generators, and cutting handling equipment are located on remote barges. Quarters with sleeping facilities and a galley may be situated on a different barge positioned some distance away from engines and the wellhead. Other equipment including pipe storage and BHA components may be located on yet another barge along with the crane for hoisting them and for rigging up other equipment.

Marine support for an inshore hydraulic drilling rig spread is often supplied by one or more tugs or pusher boats. Overall spread supervision may be provided by the Operator through the Company Man (wellsite supervisor), a marine service supervisor similar to an offshore installation manager (OIM), or a barge master, usually the captain of one of the tugs. Requirements differ depending on custom and regulatory requirements.

Often, the actual equipment layout depends on the size and number of vessels supporting the drilling operations. The snubbing/HWO unit, pipe handling area, offices, and crew quarters might be on one vessel; mud mixing and solids control equipment, extra tankage, and pumps on a different vessel; and casing/equipment stores on yet a third vessel.

6.3 ADVANTAGES OF HYDRAULIC UNIT DRILLING

There are several reasons to consider drilling with a snubbing or HWO unit configured for drilling. There are also several reasons to drill with conventional rigs or CT units in some situations. The primary drivers for the selection of one or the other depend on safety (the ability to manage pressure) and economics. A listing of the advantages for drilling with a hydraulic unit and a discussion of some of them are included below:

- Smaller footprint and fewer emissions
- Reduced fuel requirement for engines/generators
- Usually, fewer crewmembers
- Lower mobilization and rig-up cost
- Smaller lift sizes and weights for hoisting equipment from transports and spotting them on-site
- Vertical stack weights and hoisting loads are usually transmitted to wellhead and casing, not the ground or platform deck
- Can drill continuously underbalanced or with managed pressure techniques
- Can trip pipe with pressure in the annulus without killing the well (i.e., live well work)
- Most snubbing crews are adept at managing pressure in live well situations including those encountered during kicks
- Faster kick control
- Can avoid lost circulation by lowering drilling fluid density and/or reducing backpressure at surface
- Can run jointed pipe including casing
- Can rotate entire pipe string (unlike CT)
- Capable of making minor course changes by turning the drill string slightly in either direction while slide drilling
- Space available for RCD and external rotary device in work window
- Space available for installing external devices on casing (e.g., centralizers) in work window
- Usually involves smaller hole sizes with commensurately small diameter, light drill strings and BHA sizes
- Weight-on-bit can be all or partially provided by pull-down capability of hydraulic cylinders instead of just string weight (this places the drill string in compression)

- Very fine vertical and rotary motion control possible
- The same hydraulic unit that drills the final hole section can also complete the newly drilled well

6.3.1 Equipment Spread Size

Generally, a hydraulic drilling equipment spread has a smaller footprint than a conventional drilling rig. This is, in part, because hydraulic drilling usually involves smaller hole sizes requiring smaller drill string diameters, smaller OD and lighter BHAs, and smaller mud systems and pumps that require only the circulation rates necessary to clean the hole. All of this means less areal space is required on the wellsite for the equipment spread.

Less equipment, lower pump rates, and smaller horsepower requirements also mean less fuel consumption and fewer air emissions. There is less equipment on the location, so exposure risk to leaks or spills is reduced. Smaller hole sizes also mean that a smaller cuttings volume must be handled, and the risk of a cuttings spill is also reduced.

The snub drilling spread may be required to drill the same size holes as the conventional drilling rig. It does not have a substructure and mast, however, and most of the other equipment is smaller. So, the snub drilling spread will usually have a smaller footprint than a conventional drilling rig.

Some items on the snub drilling site may be the same size as those on a conventional drilling rig such as the mud logger's shack, the MWD/LWD and computer facilities, and supervisors' offices. Pipe will still be staged, picked up, and run in the hole. On most rigs, each joint must be pulled and laid down on a trip out of the hole as well. Some racking systems allow the drill string to be stood back in singles or doubles. This further reduces the footprint of the snub drilling equipment.

The weights of most of the individual pieces of equipment are usually less than those on a conventional drilling rig. So, offloading and spotting them requires smaller lift equipment and is less complicated. For packaged rigs, such as an offshore jack-up rig, this does not apply. Onshore, much of the work in spotting equipment is done by tandem-axle gin pole trucks, so the crane comparison does not apply. Inshore equipment spreads still require a crane to load and position equipment on barges, however.

Most onshore conventional drilling rigs are designed to be self-contained and sized to manage the deepest, largest-diameter hole and casing string that the derrick and substructure are rated to handle. Because onshore rigs may not have to deal with compressed locations, there is little need to place the equipment items close together.

Often, the mast and substructure require extra lifts and truckloads. This is not the case with snub drilling equipment since there is no heavy substructure and mast involved in snub drilling. Many conventional rig substructures are self-elevating and most of the derricks are raised by the drawworks. However, a crane is sometimes required to erect both. A crane is usually required to assemble the unit and BOP stack in a hydraulic unit drilling spread.

Mud systems on conventional rigs are also sized for the largest and deepest hole capable of being drilled by the rig. On many conventional rigs, over 1,000 bbl total mud system capacity is required where snub drilling rigs may only require a quarter of that volume. Similarly, conventional rigs need pumps that can clean large-diameter holes. Some have two large pumps; others have three. Usually, only two smaller-capacity (and lower-horsepower) pumps are required for hydraulic unit drilling.

The result of the smaller equipment package for hydraulic unit drilling often means that there are fewer mobilization and rig-up costs associated with this type drilling. Mobilization cost for an offshore jack-up rig is quite expensive. The rig must first rig down, deballast, and free itself from the seafloor at the previous location before moving to the new well, either under its own power or towed by large tugs.

Once the jack-up is spotted, the spud cans and legs must be jacked down to lift the rig above the waterline while avoiding punch-through (penetrating the sea floor unexpectedly). The rig must be preloaded with seawater pumped into the ballast tanks to place weight on the spud cans. This is commonly done to ensure stability before the rig is raised to the proper height to drill. Then, the drilling package must be cantilevered out to the well centerline above the wellhead deck. Only then can the drilling package be extended and rigged for drilling. Several days or even weeks may be required to perform this work depending on weather and sea conditions. The hydraulic unit package is rigged up on the platform floor, and aside from hoisting individual lifts from the transports, rigging up and drilling is sea-state-independent. Costly delays are unnecessary.

Inshore locations normally use canals to reach existing wellsites in marshes or swamps. Shallow draft barges can navigate these canals with little difficulty. A large, bottom-supported conventional jack-up drilling rig might require widening and deepening an existing canal that has partially filled in over time. A dredging permit is often required. All dredging is expensive especially when one considers the cost of spoil disposal.

Environmental concerns may delay or prohibit securing a dredging permit from regulatory agencies especially when the routes to the well or the well itself are in sensitive areas. In some cases, these areas became sensitive after the original hole was drilled. Securing a dredging permit in these areas is improbable, at best, even though there is an existing well at the end of the canal. So, new drilling operations on old inshore wells may not be possible at all using a conventional rig. The smaller footprint of a hydraulic unit drilling spread mounted on barges is certainly attractive in these situations.

6.3.2 **Crew Size and Support**

Crews for hydraulic drilling operations are usually limited to four individuals plus a supervisor per tour. Their duties vary depending on the operation at hand, but the limited size of the crew makes the operation very cost-effective.

Other individuals may be present to perform special services such as a fisherman, liner installation specialist, cementing crewmembers, mud engineer, directional driller, mud logger, and MWD/LWD operator. These are the same individuals that would likely be required using any other rig type (e.g., conventional rig and CT).

In general, a hydraulic unit drilling crew is smaller than a conventional drilling rig crew that also includes mechanics, motormen, electricians, roustabouts, and other individuals needed to operate and maintain the larger equipment set on a rig. Some smaller conventional rigs have about the same number of people working on the rig as a hydraulic drilling rig. On large conventional rigs, especially offshore bottom-supported rigs, there is also a marine staff.

Self-contained conventional rigs in remote and offshore areas also include cooks and galley crews plus staff to clean quarters and wash clothing, bedding, towels, etc. These support functions must also be provided to hydraulic unit drilling crews, but the number of personnel involved is usually smaller due to the smaller crew size on the drilling spread.

6.3.3 **Fine Drilling Control**

Hydraulic fluid pressure and rate are used to control the vertical and rotational motion of a hydraulic unit in drilling mode. Conventional rigs use the motion of the drawworks taking in or feeding out wire rope that is passed through a series of pulleys (sheaves) on the crown (stationary) and traveling (mobile) blocks to produce vertical motion. A large, high-torque top drive unit or rotary table supplies rotary motion. Both systems are designed to manage heavy, large loads, and they may not be capable of supplying the fine vertical and rotary motion control needed for certain drilling functions.

Weight control capabilities also differ between conventional rigs and snubbing units. Weight gauges on a conventional rig usually have a large range consistent with loads that could be handled by the rig under different conditions. Normally, the weight indicator such as a Martin-Decker weight gauge, and even digital gauges, cover the range up to the maximum rated load of the derrick and substructure. The weight range of the width of the needle on an analog weight indicator might be 10,000–20,000 lb or more. Digital gauges may be more accurate, but the nature of the equipment and the calibration of these devices infer that they may be too coarse to measure small weight differences under light loads.

Weight control on a snubbing or HWO unit is provided by hydraulic pressure acting on hydraulic cylinders. Adding or removing several hundred to several thousand pounds of weight on the bit, for example, may require operating a needle valve on the control panel to decrease or increase hydraulic power fluid pressure by 20–30 psi. This means that the snubbing unit operator can alter drilling conditions in tiny amounts and then be able to monitor them with a high level of accuracy.

The same is true of rotary motion. A hydraulic unit can use its smaller rotary table in slide drilling to alter the azimuth of the wellpath by rotating the drill string a few degrees in either direction. This type of fine control may not be possible using the large, robust, high-torque top drive unit or rotary table on a conventional drilling rig.

In some drilling situations, having this fine control is attractive and may shift rig selection toward the hydraulic unit for some hole sections.

6.3.4 Continuous Annular Pressure Control

Snubbing units are capable of live well drilling and tripping pipe at all times unlike conventional drilling rigs. This facilitates and enhances UBD and MPD operations. It is not necessary to kill the well, reducing annular pressure to zero, when the string becomes pipe-light. Thus, UBD and MPD operations can be maintained at all times, a desirable property for sensitive formations. If they weren't sensitive to some degree, they would not require drilling using UBD or MPD techniques in the first place. This, of course, requires the use of an RCD to hold pressure on the annulus while rotating the pipe, just as it would when using a conventional drilling rig.

By contrast, conventional drilling rigs would be required to pump kill weight fluid down into the annulus at some point when tripping pipe, so the string would be pipe-heavy. This is a requirement for block-and-tackle hoisting assemblies; they only operate on pipe-heavy strings. Also, there would be no means to prevent the pipe from being ejected from the well since the slips and elevators on a conventional drilling rig also only work in pipe-heavy mode.

Snubbing equipment is also capable of faster and more efficient well control. Kicks that would render the string pipe-light can be managed without chaining the string down to the rig floor. The strippers can be used to trap the pressure and the snubbing slip/bowls used to manage pipe movement. Constant kick control is available using the strippers. These BOPs prevent the well from taking a kick (flowing) at any time. If a kick should occur for some reason, the string can be snubbed into the hole to circulate the kick out with no interruption in operations.

6.3.5 **Weight and Load Management**

The weight of the entire BOP stack, work window and its contents, and the snubbing/HWO unit are transmitted down to the wellhead in most jobs. Extra weight from the drill string and other tensile loads such as pulling on stuck pipe, running casing, or cyclic tripping forces are also supported by the wellhead and, in turn, by the conductor, surface casing, and intermediate casings strings.

The weight of a conventional onshore drilling rig and a platform rig is spread by the substructure and transmitted to the pad (earth) or the platform deck. On some onshore locations where limited surface support exists (e.g., compressive soils or muddy sites), extra provisions are required such as thickened rock bases or board locations to spread the load. In those situations where the ground under the substructure is compromised, the rig usually tips a few degrees moving the derrick's crown block off the centerline of the well. Jacking and leveling are required to realign the derrick with the well centerline. Offshore platforms with limited deck loading capability and those where age, corrosion, and damage have reduced the deck loading capability. In some cases, it may not be able to use a platform rig at all. In these situations, a bottom-supported rig such as a jack-up may be the only alternative for conventional rig drilling.

Hydraulic unit drilling, with its smaller footprint and lighter deck loading, is a good alternative in these situations. The platform only has to support the ancillary equipment and fluid handling pits. Those loads can usually be spread about the platform sufficiently to avoid point loading on the deck. Some single-well platforms in shallow water or inshore wells can only support the snubbing unit and BOP stack. There is no room available for the ancillary equipment such as pits, pumps, powerpack, generators, and housing units. These must be placed on floating vessels, such as barges, or bottom-supported vessels like lift boats. Again, the alternative is a bottom-supported conventional drilling rig with its higher mobilization cost and larger footprint.

6.3.6 Completion With Snubbing or HWO Unit

In some new wells, a conventional drilling rig runs the completion (packer, jewelry, and production tubing string). In others, the rig is removed, and a smaller, less expensive rig performs the completion work including running the final completion. If testing of multiple zones is involved, the well must be killed between tests and before running the final completion when using conventional platform rigs or HWO units. Then, the well must be unloaded to initiate production.

Killing a recently perforated interval often adds skin to the formation face resulting in reduced flowrates, long clean up times, and poor long-term performance. Some wells can be better completed using a snubbing unit and doing the work with pressure on the well.

Snub drilling in these situations allows the use of the same snubbing unit to complete the well that drilled the last hole section and ran the last liner. This avoids the delay and cost for rigging down the conventional rig or HWO unit, moving it out, moving in a snubbing unit, and rigging it up to complete the well underbalanced. In some remote locations and offshore/inshore wells, this remobilization can be time-consuming and costly. If the snubbing unit used to drill the hole is still rigged up, why not just use it to complete the well and do so under pressure?

6.4 DISADVANTAGES OF HYDRAULIC UNIT DRILLING

There are some drawbacks to drilling with a snubbing or hydraulic workover (HWO) unit like there are with all other drilling systems. Some of these impact job costs considerably. Others add to job complexity especially in logistics when compared with some other drilling options. All should be considered when selecting a drilling rig for the job:

- Tripping the drill string and BHA is slower with a hydraulic unit than that achievable with a block-and-tackle hoisting system or with CT.
- Maximum hook load is often less than a conventional drilling rig depending on mast and substructure rating.
- Hole and casing diameters are limited to the snubbing/HWO unit bore and BOP diameters (including provisions for upset connections and collars).

- Penetration rates may be slower than conventional drilling rigs in larger hole sizes due to lower pump rates, smaller mud pit volume, and reduced mud cleaning capacity.
- Rotary speeds are often slower than a conventional rig's top drive or rotary table when using the snubbing/HWO hydraulic rotary table only.
- Hydraulic units are not normally heave compensated, so they are used in situations where this capability is not required (i.e., they are rarely used from floating vessels).
- Long or unusually shaped BHAs may require tall stacks with several spacer spools to "swallow" the BHA when snubbing on live wells.
- Hydraulic units rigged up on top of wellheads usually require that the wellhead flange is level and aligned with the wellbore centerline.
- Controls and operators are usually positioned in a work basket that is situated immediately above the no. 1 stripper (snubbing BOP) adding an element of risk in the event of an emergency.
- Crewmembers in the basket must be provided with a means of rapid egress in the event of an emergency; self-rescue options may be limited.

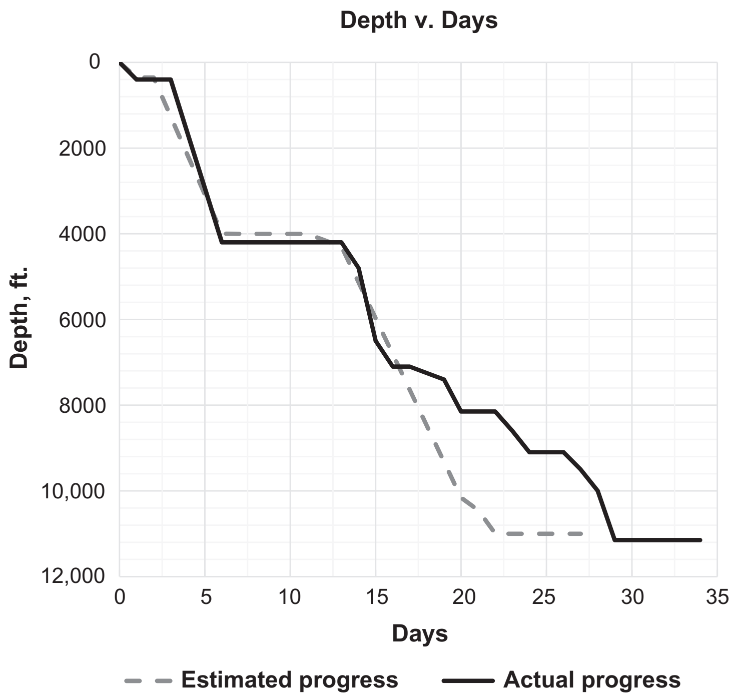
6.4.1 Tripping Speeds

Perhaps the mostoften quoted drawback to snubbing/HWO operations, in general, is the speed at which the work string can be tripped in and out of the hole. Much of the inefficiency of any drilling system involves time spent for tasks not associated with penetrating new rock with a bit. This time is often called "flat time" as it refers to sections of a depth versus time plot when hole is not being made (Fig. 6.3).

Obviously, the longer the flat time portions on this drilling progress plot, the longer it takes for the bit to reach the desired objective. It should be noted that in all drilling, there is a maximum tripping speed for both coming out of the hole with the BHA and going back in. This speed is defined by the tendency of the hole to swab or surge. In small-diameter holes with viscous mud systems, there may only be a limited difference between tripping speeds allowed by swab/surge and the maximum operating speed of the jack. In large-diameter holes with looser mud properties, the tripping speed advantage is clearly in favor of conventional rigs.

Another mitigation for slow tripping speeds is the use of racking systems that stand pipe back in singles or doubles depending on the jib height (see Chapter 3). If pipe does not have to be picked up and laid down as single joints, pipe handling is faster making tripping the bit faster as well.

Using the entire stroke length for pipe-heavy strings while stripping in the hole is also a plus. In wells with considerable surface pressure, the traveling



■ **FIG. 6.3** Typical drilling progress plot.

frame is normally short-stroked to reduce the unsupported pipe length above the strippers when snubbing under pipe-light conditions. Once the string is sufficiently pipe-heavy, the entire stroke length can be used.

Regardless of these mitigation measures, tripping pipe with a snubbing or HWO unit is usually slower than it is with a conventional rig or CT unit. Note that this limitation only applies when the pipe is being tripped. When the bit is on the bottom making hole, tripping speed is irrelevant. Only penetration rate is important, and it is not dependent on rig type. The bit cuts at a given rate if all other drilling parameters are the same.

Some of the flat time applies to planned operations other than drilling such as logging, running casing, and cementing. Trip speeds are irrelevant during these operations, as well.

In a well manufacturing process, the rig best suited to drill each hole section is selected and used for drilling only a portion of each well. It may well be that a conventional rig is best suited to drill the upper, large-diameter hole sections. It completes its work and then moves to the next wellsite. Another rig or drilling system is moved in to drill the next portion of the well, and so on. This can involve as many as three separate drilling rigs and a different rig yet for the completion, such as a completion rig. If hydraulic unit drilling is selected for one of these portions of the total well, then tripping speeds in the other hole sections that require more tripping can be maximized depending on the rig selected (e.g., large-diameter and shallow holes).

Where UBD or MPD is involved in drilling a particular hole segment, snub drilling may be the best type of drilling to maintain continuous underbalance or careful control over bottom-hole pressure to avoid overbalancing the formation. If there is to be pressure on the well during tripping, a snubbing unit must be used at some point anyway. So, snub drilling may be indicated regardless of trip speeds.

One case in which continuous underbalance is desirable involves air drilling dry gas wells. The objective is to avoid contacting the gas-producing zone with any fluid. Again, snubbing system of some kind is required during pipe-light operations for this type of drilling. Killing, or even temporarily killing, the well to trip the drill string is not an option. A rig-assist snubbing unit or a push-pull machine is required on these wells. The question becomes, “Why not drill the gas-producing zone with a snubbing unit instead of a conventional rig if snubbing capability is going to be required anyway?” Several gas wells in Canada have been drilled using either snub drilling or CT drilling specifically for this reason.

6.4.2 Drilling and Casing Large-Diameter Holes

Hydraulic unit drilling and CT drilling are both often restricted to smaller hole diameters since conventional drilling rigs are better suited to drilling and casing large-diameter hole sections. These rigs can be configured by adding lines (i.e., stringing the blocks through empty sheaves in both the crown and traveling block) to manage heavy drill strings and BHAs along with large-diameter thick-wall casing. Note that these are not just heavy hook loads, but provisions must be made for considerable over-pull in case it is needed for some reason, such as freeing stuck pipe.

A conventional drilling rig can drill just about any diameter hole and run any casing size as long as the BHA and casing strings with their collars can go through the rotary table and BOP stack. If the BOP stack becomes a constriction, a large bore BOP can be used for that hole segment and then replaced after the casing is cemented. The bore of the hydraulic unit is set and becomes a limitation to running some larger BHAs and casing strings.

Restricting hydraulic unit drilling to smaller hole sizes does not imply that it cannot be used with good effect on some hole sections with larger diameters.

One excellent use of hydraulic unit drilling is sidetracking existing wells from inside the production or intermediate casing strings. Hydraulic units are is especially effective for milling windows in casing or for section milling casing due to the fine motion and weight control available. So, not having large-diameter hole drilling and casing capability may only be a limitation for some sections of some wells.

6.4.3 Reduced Penetration Rate

The rate of penetration (ROP) of some hole segments may be lower using hydraulic unit drilling than conventional drilling. This is due to reduced rotational speeds using the hydraulic rotary table situated below the traveling slip/bowls and to reduced pump rate available on many hydraulic unit spreads.

Conventional drilling rigs are usually outfitted with several large, high horsepower pumps. The cylinder liners and pistons on the fluid end of these pumps can be changed depending on need. For shallow large-diameter holes, the pumps are usually equipped with relatively large-diameter cylinders and “swabs” to pump fluid at high rate and low pressure. Later in the drilling process as the well gets deeper, these are changed to smaller-diameter inserts to provide higher pump pressures (with consequentially lower flowrates).

Hydraulic unit drilling spreads usually have smaller, lower-horsepower pumps designed with small fluid end cylinders and pistons to provide limited flowrates and higher pressures. Drilling large-diameter holes with these smaller pumps results in poorer hole cleaning below the bit, reduced impact force or hydraulic horsepower at the bit, and lower annular fluid velocity. The result is that ROP suffers. In small-diameter holes, the pumps in a hydraulic unit drilling spread are usually sufficient. Penetration rates in these small-diameter holes are comparable with those achievable using conventional drilling rigs.

Rotary speeds on hydraulic units can be improved. The addition of a secondary rotary driver of some type, either hydraulic or mechanical, replaces the low-speed hydraulic rotary table on the snubbing unit to provide rotary speeds comparable with those using a conventional rig’s top drive or rotary table.

When a mud motor or turbine is included in the drill string, the addition of the supplemental rotary drive becomes unnecessary. The snubbing unit’s hydraulic rotary table turns the drill string at 50–75 RPM (slow rotation) with the motor adding 250–300 RPM to the bit, for example. Turbines provide even higher bit rotary speeds (1000–1200 RPM). Turning the drill string at 200–300 RPM, in addition to the motor or turbine speed, for even better penetration rate is not required and is unwanted to avoid overheating the bit's cutting structure.

Using either the unit's hydraulic rotary table or a supplemental rotary drive permits the use of rotary steerable tools just like those used on conventional drilling rigs. CTD cannot employ these tools because the string does not turn. Rib-steered tools are available for motor drilling on CT that mimics the performance of rotary steerable pad-type tools, however.

6.4.4 Tall Stacks

Some drill string assemblies cannot be snubbed easily on live wells. These can include such items as reamers, hole openers and underreamers, stabilizers, motors (especially bent ones), downhole logging and monitoring tools such as MWD/LWD/PWD tools, and other BHA components such as spiral cut drill collars. If they cannot be snubbed into and out of the hole safely, these must be fully contained within a pressured envelope before they can be run in a hole. This requires a tall stack composed of flanged pipe spools with the same or similar pressure rating as the BOPs. The long BHAs are contained within these tall "lubricators" for running and pulling them under pressure (Fig. 6.4). In this example, two snubbing units are stacked on top of each other with a lubricator for handling 40 ft.-long equipment sections below the bottom snubbing unit.

BHA tools are often interspaced with short, slick (not spiral cut) drill collar pup joints or blank sections of drill pipe to avoid the tall stacks. These blanks are positioned across the strippers, and they can be handled by the unit's slip/bowls. In some BHAs, heavy-weight drill pipe is substituted for drill collars. Heavy-weight drill pipe can be snubbed just like conventional drill pipe—they have the same OD and similar connections.

Provisions must be made to stabilize tall stacks, some in excess of 100 ft. tall, when the components must be snubbed. The most obvious solution is guying the stack and snubbing unit back to the ground or platform deck. Properly sized guy wires and anchor points become important design parameters. Conventional drilling rigs with freestanding masts do not share this requirement. However, their block-and-tackle hoisting assemblies cannot snub pipe in the hole against pressure. Snub drilling may be the only option for certain live well segments, so provisions must be made to deal with the height and weight of the tall stack.

■ **FIG. 6.4** Tall stack example. *(Courtesy of International Snubbing Services.)*

Tall or heavy snub drilling stacks usually require that the wellhead flange on which the BOPs are mounted be level so that the stack will be vertical when rigged up on it. Some old wellheads may have bent over due to side forces or casing corrosion immediately below the head at the surface. Installing a tall, top-heavy stack on top of an already compromised wellhead would apply a mechanical moment to the head that could result in failure and toppling of the stack no matter how well it is secured. The alternative is to use a stand of some type that would support the weight of the hydraulic unit and hoisting forces by the platform deck or ground surface. Straightening the head just by bending it into the proper level position is usually not an option—the casing below the head may break or split.

Some single wells and entire platforms have been damaged during hurricanes and typhoons. Usually, the conductor and all casing strings are bent at the seafloor or just below it. The entire platform may be listing at a considerable angle. Rigging up a snubbing unit to pull production tubing and to perform any drilling-type services might not be practical in these situations. Usually, the well is abandoned by bullheading mud and cement through flexible lines down the production tubing. Once the well is plugged, all casing strings and the production tubing are cut off below the mud line, and the platform is decommissioned and removed.

An unlevel or crooked wellhead would provide a severe dogleg at the surface. Any pipe running through the dogleg would rub on the inside of the curve. This could wear the casing or damage it in other ways. Some components such as long, stiff motors or drill collar strings might not be able to get through the dogleg.

A conventional rig or platform rig would not be useful in these damaged well situations anymore than a hydraulic unit would be. A CT unit injector might be able to rig up on the bent wellhead and run flexible coiled pipe past the dogleg. It might even be able to drill or sidetrack an existing well depending on downhole tool length and stiffness. Pulling production tubing with the CT unit would not be practical or even possible in most cases. This limits the use of CTD to sidetracks through both the production tubing and casing, a procedure that has been done with success in the past.

6.4.5 **Crew Safety**

Hydraulic unit crews working in a small basket on top of the stack are at more risk than crews on conventional rigs when the well is pressured. A large-volume, high-pressure leak in a snubbing BOP or anywhere else in the stack can drive fluids and hydrocarbons directly upward into the basket. The rotary table and floor on a conventional drilling rig can shield personnel somewhat giving them more time to escape if this situation should occur.

More importantly, the floor of most conventional drilling rigs has more room and more escape routes than the basket of a hydraulic unit. Drilling rig floorhands and the driller may be able to self-rescue just by running in one direction or another. Both the derrickman on a conventional rig and the operators in a hydraulic unit must be provided with some means of escape from an elevated work station. Traditionally, this has been through the use of an escape rope or a Geronimo line. These have been largely replaced by safety enclosures of various designs (escape pods) and slides.

It is noteworthy that hydraulic unit operators (and the derrickman) must also be tied off by a lanyard from their full-body harness to an anchor point in or near the basket. This is required by regulation in most jurisdictions, and it makes sense as a necessary safety precaution to prevent falls. Unhooking from the anchor point slows escape, however. Self-rescue can become problematic for persons working at elevation if they have sustained an injury.

In dead well drilling, neither the derrickman on a conventional rig nor operators in a snub drilling unit basket are at any more risk than they normally would be from the nature of their elevated work positions (primarily falls). However, when snub drilling on live wells, a significant risk is introduced for the snubbing unit operators and others in the basket. Additional training, rehearsals, and escape device rig up may be required above that necessary for conventional drilling rigs.

It is anticipated that the future will bring more remotelycontrolled snubbing units into play for snub drilling operations. In this type of unit, the operators do not work in an elevated basket. They are on the ground or platform deck inside a protected environment. As such, they are fully capable of self-rescue. Risks from fire, explosion, and escape-related injuries are reduced. Many conventional rigs now employ robotic pipe handling systems that eliminate the need for a derrickman to be in the derrick to trip pipe. Both of these improve overall safety for crews working in elevated platforms.

6.5 COMBINATION RIGS

Testing has been performed on at least three combinations of CT and hydraulic units for special-purpose drilling. The use of both equipment types together takes advantage of the strengths of each and compensates for their individual weaknesses. Two of them are described in the literature. The systems were used in the field apparently with good results. The other system was patented but never fully developed.

Both of the hybrid CT/hydraulic rig combinations have a CT injector mounted in the top of the stack complete with its own BOPs. The injector is mounted on a trolley that allows it to be retracted from the centerline of the hydraulic unit allowing collared pipe to be run and retrieved without interfering with CT operations. The CT is used as the drill string in "normal" operations, but the hydraulic unit is available to run and pull collared tubulars, such as BHAs and casing, when needed. Both of these units have the capability to drill, and both can be used in horizontal hole sections until the CT locks up.

In one of these systems, wired composite CT was used. This CT string had the capability of transmitting downhole sensor data to the surface in real time. This system also included a structural tower (mast) for use in handling collared pipe. It could also support the entire stack using the production platform as its base instead of transmitting loads to the wellhead. Both the hydraulic unit BOPs and the CT BOPs were rigged up on top of the wellhead for pressure containment, however.

The third system was conceived as a way to combine hydraulic unit drilling with the fast tripping capability of a CT unit. In this design, joints of large-diameter CT up to 50 ft. in length with a connection on each end could be delivered to the location in baskets along with BHA components. The BHA would then be assembled and run in the hole by the hydraulic unit. Then, the long drill pipe (CT) joints could be picked up out of the basket and run in the hole individually by screwing them together at a flush-joint connection, again using the hydraulic unit. Once on the bottom, the hydraulic rotary table on the hydraulic unit, along with a downhole motor where practical, would drill the new hole.

When the motor, bit, or downhole MWD/LWD/PWD tool wore out or ceased functioning, the last "drill pipe" joint (CT segment) would be broken off (unscrewed) and laid down. The next joint in the hole would then be connected to a large reel and the entire "spoolable drill pipe" string recovered by the CT unit. The BHA was pulled out of the hole using the hydraulic unit so it could be modified or replaced, as necessary. Then, it would be rerun by the hydraulic unit and reconnected to the flexible drill string on the spool and rerun to the bottom by the CT injector. The pipe would be disconnected from the spool, reconnected to a swivel for the introduction of drilling fluid, and rotated using the hydraulic unit's rotary table drilling ahead.

At the end of the job, the drill string would be pulled out of the hole by the hydraulic unit through a reverse bender to remove residual curvature imposed by the spooling process. Each joint would then be laid down in the baskets for transport back to the dock. The CT reel and injector would then be rigged down along with the hydraulic unit and stack. The entire assembly would be returned to the transport vessel or trucks in relatively small, light loads.

This concept was patented, but economics did not permit its development or deployment in the field. Further, there were no flush-joint CT connections at the time that could withstand the coiling process without leaking. Those connections were the subject of considerable research by the CT/snubbing service provider and at least one major oil company. The connection was never fully developed due to budgetary restraints, and system development was never completed.

6.6 RIG SELECTION

The drilling rig selection process, when done properly, is a complex comparison of physics and economics with an eye toward maximizing recovery from the objective reservoir. This applies to hydrocarbon-producing, injection, geothermal energy, and even freshwater wells. The analysis also involves logistics and rig availability—not just the drilling process. Manpower requirements, crew support facilities, and the desired pressure regime (overbalanced, underbalanced, managed pressure, etc.) often make one drilling system or even a particular rig more attractive than another. There is no single drilling system that is the best choice for all wells.

Cost is often the major issue in rig selection. Sometimes, out-of-pocket cost is the primary issue when CAPEX is limited. Experience has shown that the cheapest deal is not always the best deal, however. The more expensive option may result in faster drilling, higher production or injection rates, and a better return on the drilling investment than a less expensive option.

Some operators, especially those with long-standing operational habits, may reject a change of any kind from its normal drilling methods. These folks often believe that wells should always be drilled by conventional rigs using overbalanced drilling techniques. Full strings of casing, not liners or liners with tie-back strings, must always be used. Cementing is only necessary to cover the bottom 500 ft. of each casing string. Block squeezes are performed before perforating any zone. Only seamless casing can be used because all seamed pipe is weak and will split.

It is difficult, if not impossible, to change this mind-set and corporate culture when it is deeply embedded. It is for this reason that hydraulic unit drilling and CTD are routinely shunned by some Operators. Some think that if the hole can be drilled by a hydraulic unit, it can be drilled just as easily by a conventional rig. That may not be the case.

Other operators seize on only one aspect of the drilling process. Mud type (WBM or OBM) is always used because of past history, for example. One operator may only use conventional rigs because of tripping speed. Hydraulic units are too slow; CT units are too fast. Conventional drilling rigs are just right. These concepts rarely look at the entire process—only a single piece of it.

Many accountants and young engineers often minimize the cost of each component of the drilling process expecting that the lowest total drilling cost will be achieved. This method of cost saving is only effective if all of the variables are independent of each other. That is rarely the case.

The drilling system selected should be viewed systemically. It is a unit, not a collection of individual pieces. Minimizing the cost of one component may result in an increase in the cost of other components actually making the total drilling system more expensive. An example involves drilling fluid selection. Water (fresh water or seawater) or a water-based mud is often the least expensive alternative when compared with oil- or synthetic-based mud. Some shales can be hydrated returning them to a thick, viscous gumbo or causing them to become unstable and slough into the wellbore. The extra cost of borehole stability management in this situation is far greater than the savings in drilling fluid cost.

Rig selection is not always just a simple choice between two or three alternatives. It is usually a multivariable optimization. One of many variables in the process is certainly cost. It is not the only variable in most cases, however. Too many operators have learned the sad lesson that the lowest drilling rig cost frequently reflects poorest drilling performance. A bad result rarely justifies just contracting the cheapest rig in the fleet. Some of the other variables require more discussion.

6.6.1 Fit for Purpose

This issue involves the use of oversized or undersized rigs regardless of type (conventional drilling rig, CT, or hydraulic unit), the proverbial attempt to drive the square peg into the round hole. Nobody would want to pay the cost of a rig capable of drilling a 30,000 ft. well to drill a 5000 ft. "posthole." The cost of contracting such a large rig would not be prudent unless it was the only rig available and there was some sort of time requirement that could not be met without using it. Obviously, it would be capable of drilling the shallower well.

Of greater concern would be contracting a small rig to drill a deep hole, again regardless of rig type. There is no justification for getting the drill string to the bottom and then not being able to get it out of the hole because of the rig's limited hoisting capability. There should always be some margin of overdesign such that the rig can manage the worst-case scenario with respect to hoisting capability.

Condition of the rig is also an important issue when selecting a rig for the anticipated drilling conditions on a well. All equipment ratings are based on new or like-new conditions. The substructure and derrick on a conventional rig may be old, corroded, and cracked due to age, usage, and previous abuse. If the sub and mast have not been sandblasted and inspected for several years of hard service, the rig's actual capabilities for hoisting heavy loads may not be reflected by the drilling contractor's literature. The same applies to the remainder of the hoisting system and to the engines or motors providing power to the drawworks. This is an incentive for a thorough inspection of any rig before it is contracted (including hydraulic and CT units).

This capability issue is much more critical when considering well control equipment, particularly BOPs. Several wells have suffered blowouts from the failure of underrated BOPs in high-pressure kick situations. The author was involved in serious blowouts on two wells when 5000 psi BOPs were used by the drilling contractor. The maximum anticipated wellhead pressure on both wells exceeded 7000 psi. A hard gas kick migrated to the surface the BOPs began leaking at just over 6000 psi. Eventually, the leaks resulted in blowouts and fires in both cases. Clearly, a minimum of 10,000 psi-rated BOP stack was indicated, but the operator and the drilling contractor chose the lower rated BOPS never anticipating that the wells would kick as hard as they did. The scant cost savings from using the lowerrated BOPs was spent many times over by the cost to control the blowouts.

Wells in fields where lost circulation is anticipated might be candidates for either snub drilling or CT drilling rig along with UBD or MPD techniques during rig selection. Drilling with a conventional rig in these situations could result in excessive mud costs to control the lost circulation or to deal with kicks resulting from it. Much of the extra cost due to slower tripping speeds with snub drilling can be absorbed by lost time and lost circulation material (LCM) costs necessary to drill using a conventional rig in these situations.

The ultimate goal is to provide the best, highest-rate producer or injector at the end of the day. If drilling with pressure at the surface using UBD or MPD methods would accomplish that goal, using a snubbing or CT unit makes more sense than trying to drill the well overbalanced using a conventional rig. The risk of dealing with kicks would also be reduced by using snub or CT unit drilling. If there is likely to be pressure on the surface at some point, why not use the drilling equipment designed to manage that pressure from the beginning? This becomes a very important issue if the potential for a toxic gas kick exists (e.g., H_2S).

6.6.2 Mobilization

The cost of mobilization should be considered during the rig selection process. This cost, when coupled with the fit for purpose issue, may point to the selection of one drilling type over another. This also assumes that drilling units of all three basic types are available in the area.

Conventional onshore drilling rigs are typically moved by trucks over existing highways and road systems. The rig must be broken down into sufficiently small loads to meet highway size and weight restrictions. This results in as many as 65–100 truckloads, or more, being required. Large rigs require more loads than smaller rigs. Some large pieces of the rig (e.g., the derrick) might be moved in a single piece during an infield rig move. The substructure and derrick might be moved while still erected in a rig skidding operation from one location to the next. Other rig equipment can be moved in big chunks if the rig is not required to leave the field and enter the highway system.

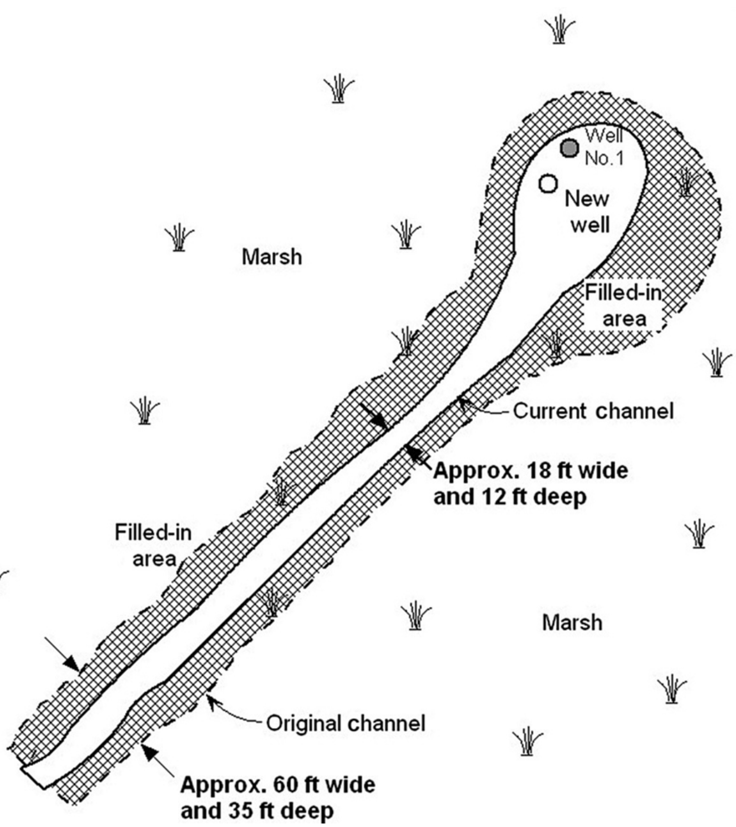
Offshore, a platform rig may require a number of loads to be transported on floating vessels such as supply boats or barges. The loads may not meet size requirements for highway transportation if they are moved from platform to platform, but they must be small enough to be hoisted onto the platform deck by a crane under dynamic loading conditions associated with vessel heave.

Bottom-supported rigs require transport to the site under their own power or by tow vessels. Once at the platform, they must be jacked up, preloaded, and jacked into position and the drilling package cantilevered over the slot in the wellhead template. Equipment must then be made ready to drill. Hoses and lines, for example, must be hooked up to the drilling package before the rig is ready to drill.

In times of low rig utilization, mobilization of a suitable jack-up rig may only require a few days depending on how far it must be moved. In times of high rig activity, there may not be an available jack-up anywhere in the vicinity. During industry downturns, most of the jack-up fleet may be mothballed and stored inside a protective anchorage near shore. The rig must be warmed up, manned, supplied, and then moved a considerable distance to reach the jobsite when needed.

A CT or hydraulic unit drilling spread must be collected and moved to a dock for transport by supply boat or vessel. Costs for loading and trucking to the dock, offloading onto transport vessels, moving the pieces of kit to the platform, and offloading and spotting must be considered. These are usually lower than those for mobilizing a self-contained conventional drilling rig (platform- or bottom-supported) to the worksite.

As discussed previously, inshore mobilization of a bottom-supported drilling rig requires adequate water depth and canal width. This may require dredging a previously existing canal or wellsite to provide the water depth and size requirements (Fig. 6.5).



■ **FIG. 6.5** Inshore well at end of old canal.

In areas that are or have become environmentally sensitive, getting a dredging permit may be difficult or impossible. There must also be a means of disposing of spoil from dredging. Costs for this work, in addition to actually mobilizing the jack-up to the worksite, may be prohibitively excessive in those areas where dredging is permitted.

All of the projected mobilization costs must be considered as part of the total cost of drilling regardless of rig type. The mobilization cost for a jack-up rig may be considerably higher than those for a hydraulic or CT drilling spread, but drilling may be so much faster that it is less expensive in the long run to use the jack-up. In other cases, especially when surface pressure is expected or there is only a short hole section to be drilled, snub or CT drilling may be more practical.

Take, for example, the situation in which an existing producing offshore producing well is to be deepened, say, 300 ft.The well will probably have pressure on the production tubing. This pressure must be killed to use a conventional rig or HWO unit, since the tubing would eventually become pipe-light with pressure on the well. A snubbing unit would be required to pull the tubing. Then, the drill string would be snubbed into the well to deepen the well using snub drilling. The snubbing unit would then run a short liner and cement it inside the new hole segment. Completion would follow.

If the well was drilled overbalanced, provisions for initiating flow would have to be made. This could involve jetting requiring additional equipment such as a CT unit and nitrogen pump. If all operations were conducted underbalanced using a snubbing unit, the well would be ready to produce as soon as the tubing and production packer were landed.

In this hypothetical situation, the mobilization cost alone for the jack-up could hardly be justified when compared with the cost of the job using a snubbing unit. Daywork cost would also be much lower. The difference in tripping speeds would be likely absorbed by the higher mobilization and daywork costs for the jack-up during the short duration of the job. It would probably not be practical to move a fully-contained, large jack-up to the site for simply deepening the well 300 ft. This is the same reasoning used to justify using snubbing and HWO rigs for workovers on offshore platform wells instead of conventional rigs.

6.6.3 **Daily Drilling Spread Cost**

The total cost of all equipment and personnel involved in the drilling process is referred to as the "spread cost." For self-contained conventional drilling rigs, this price is the rig's day rate. It may or may not include fuel and time for daily maintenance (often 1 h) to lubricate, to perform other maintenance, and to slip and cut drilling line. The cost usually includes supervisor (toolpusher) and crew quarters, messing, supplies, and spare parts.

Hydraulic unit drilling spread costs include the day rate for the hydraulic unit that may or may not include fuel, filters, and other supplies. Not usually included are costs for supervisor quarters, messing, and other crew support unless the snubbing services contractor provides these instead of the operator.

Some costs may be the same for both types of drilling rigs: quarters for the Company Man (rig site supervisor), mud logger and his/her quarters, quarters for the MWD/LWD/PWD personnel and their equipment, and quarters for the directional drillers. Often, the containers, trailers, or shacks for these services are connected to a freshwater supply system and a sanitary sewer system at onshore locations. The quarters and service contractor quarters are often provided with potable water and sanitary sewer connections by the offshore platform, as well (unless the platform is unmanned and does not have these facilities).

The total cost of the entire equipment and personnel set is important for estimating job costs. For comparisons between rigs or rig types, only those items that are not the same for both rigs need be considered. For example, if directional drillers are required for drilling the well, these professionals would be contracted whether a conventional rig or a snub drilling spread is contracted. Presumably, the daily cost for the directional drillers would be the same. Their quarters, water supply, and food could be an added cost on one rig type but not the other.

At many offshore locations, a standby boat is required for safety and emergency support if anyone is working on the platform. If so, the vessel cost would be the same for both drilling spread types, and it could be ignored for comparative purposes.

Assume that the daily rig cost for a jack-up rig is \$300,000 including fuel. The daily cost for a hydraulic unit equipped for drilling, including the crew but without all the same features such as quarters, communications, office space, and galley, is \$75,000. All of the rental items required for supporting the snub drilling rig would be added to the hydraulic unit day rate. If all the rentals together cost another \$75,000, the comparison would be a difference of \$150,000 (i.e., \$300,000 − 2 × \$75,000). Then, the comparison comes down to mobilization cost for each rig type and the number of days on-site to complete the job. Granted, drill string tripping time may be faster with a conventional rig than the hydraulic unit, but penetration rates should be about the same. The additional time for tripping and other limitations could easily be absorbed by the difference in daily cost between the two spreads.

Further, if the intent is to drill underbalanced or using managed pressure drilling techniques, how much additional time would be required to temporarily kill the well to prevent pipe-light conditions on trips into and out of the hole? This time would be required for the conventional rig but not a snub drilling rig. The risk of damaging the reservoir during these temporary kill events should also be a consideration when making the comparison.

Rig selection for the one-off job may involve only an economic comparison between costs between rig types. Often, however, other issues such as contractual requirements, regulations and permitting, and rig availability make the rig selection much more complicated.

In one situation in the Middle East, a pressured gas reservoir was present at about 3300 ft. (Huesecken, 2009). Conventional rigs had been used to drill and complete the wells originally. A campaign was initiated to sidetrack existing wells and drill 1,500–2,000 ft. horizontal laterals using an 8½ in. bit. HWO units had been used in the past for dead well workovers and to drill small-diameter (3¾–4⅛ in.) laterals in this partially depleted gas reservoir.

The Operator decided to sidetrack and drill the 8½ in. laterals in this shallow gas reservoir and run a 7 in. liner using an HWO unit (dead well hydraulic unit drilling) supported by a lift boat in shallow water. The results of the first three jobs were economical primarily because the cost of the HWO spread was only about one-third the cost of a jack-up. Lower tripping speeds and other technical limitations were overcome by the reduced mobilization and daywork costs using the HWO unit instead of a jack-up.

6.6.4 Rig Availability

The availability of a suitable drilling system and support equipment may dictate the choice of one system over another especially if there is a time limitation on the work. This is best illustrated by example.

Assume that a jack-up conventional rig is under contract for an Operator that needs to redrill a portion of a well on a nearby platform. Limited production and continuous development contract requirements make drilling this hole segment a priority. The well segment could be drilled by either the conventional rig or a HWO unit.

Organizing, transporting, and rigging up the hydraulic unit drilling spread could require some time, possibly several weeks. Moving the jack-up to the next platform could be done in a few days. The time requirement and the contractual obligations could easily swing the decision toward the jack-up and away from the HWO unit drilling spread even though the job could be done less expensively. Here, the economic analysis is trumped by availability.

Now assume that all suitable conventional rigs were occupied on other jobs with none available until those jobs were completed. The same time limitation exists. A hydraulic unit drilling spread can be organized and rigged up on the platform before a jack-up became available. Now, the pendulum would shift toward the hydraulic unit and away from the conventional rig. The economic analysis, the contractual terms, and the hydraulic unit drilling spread availability would trump using the conventional rig regardless of pipe tripping speed using a block-and-tackle hoisting system.

6.6.5 Crew Availability and Experience

An adequate number of crewmembers for any drilling rig is a necessity regardless of rig type. That they have adequate training and experience may be highly desired, but these individuals are not always available. Many crewmembers are lightly-trained and have little experience, but they receive on-the-job training as they work on the rig. This can become an issue in the rig selection process.

Conventional drilling rigs use a block-and-tackle hoisting system that has considerable flexibility. The derrick is usually tall enough to manage three or four joints of range 2 (±30 ft.) drill pipe in stands. The derrick must also be tall enough to accommodate the traveling blocks and top drive, if the rig is so equipped, with additional room for overtravel.

A minor error in judgment or procedure on a conventional drilling rig may be absorbed by the drilling line, the drawworks, and the equipment in the hoisting system because the hoisting system is not rigidly connected to the drill string. However, in a hydraulic unit drilling system, the drill string is directly connected to the slips with little or no “play” (i.e., slack). This hard connection is unforgiving and the consequences of even minor errors are immediately realized.

Conventional drilling rig crews are often less well-trained and skilled as hydraulic unit crews. There are always a few novices on a conventional rig. Often, the crew contains recent hires that are in the process of being trained. There are rarely novices involved in operating hydraulic unitsand snubbing or HWO units. Most of the crewmembers have worked in other oil field jobs and some on conventional drilling rigs, and they have often been on the same hydraulic unit crew for some time. Only experienced operators and supervisors are qualified and allowed to operate the hydraulic jack. Less experienced crewmembers are relegated to handling pipe, maintaining equipment, and other noncritical tasks.

Hydraulic unit drilling crews are also very well versed in well control theory and procedures. They are familiar with managing pressure on wells, and they understand the consequences of an unplanned and unwanted pressure release. As a result, they are very cautious as a group. They are cognizant of potentially catastrophic results when even a minor error is made in a well control situation.

In some cases, a conventional rig, a hydraulic unit, or a CT unit drilling spread may provide the best choice for drilling a particular hole section. If the conventional drilling crew is inexperienced or it has just been cobbled together from a group of oil field workers for a particular job, the crew may not have the proper training, certification, or experience to handle the job properly. A hydraulic or CT unit drilling crew may be much better suited for drilling the hole.

In any case, crew training and experience should always be considered when evaluating the rig and not just the way it is equipped.

6.6.6 Rig Selection by Hole Section

Operators for years have used a single conventional rig over the hole to drill all hole segments regardless of hole size, depth, or drilling conditions. The primary driver involves the cost of rigging down one rig type and rigging up another even when the second rig might be better suited for drilling a particular hole segment. So, the "big" rig is used even when a smaller rig would be better suited for the intended service.

The advent of UBD and MPD drilling techniques has led to the development of a variety of tools and equipment to maintain pressure while drilling with a conventional drilling rig. The use of rig-assist snubbing units and push-pull machines allows annular pressure to be maintained even though it results in pipe-light conditions at some point when tripping pipe or running casing.

In the recent past, some operators have adopted the well manufacturing process in which a different rig is used to drill certain hole sections for which it is ideally suited. Once its tasks have been completed, it is rigged down and moved or skidded to the next wellsite. Another rig, better suited for the next hole section, is moved in and rigged up (or skidded) to drill subsequent hole section(s). A third rig might be moved in after drilling ceases to complete the well.

This has led to dramatically-reduced overall drilling and completion costs in many cases since the operator has taken advantage of the strengths of each rig for the hole sections drilled and for the final completion. The primary advantage is that the tradeoff in rig day rate compensates for the additional cost of moving one rig off the hole and replacing it with a rig better suited for the next hole section.

Many rigs are equipped with substructures and derricks that are self-elevating with BOPs on skid rail systems so they can be nippled up quickly and with less risk to crews than old methods (i.e., one BOP at a time stacked on a wellhead). These units can be rigged down quickly and skidded or walked to the next well with little downtime. Some desert and arctic rigs are equipped with massive wheels and tires that make skidding the rig as simple as lowering the wheels and pulling the entire rig, with the derrick still standing, to the next well.

Optimum rig utilization should be considered for each well even though traditional methods have been used in the past (i.e., one rig for all drilling and for completion). In some areas, this may be the only option since the "right" rig for drilling a hole section or completing the well simply may not be available. In some offshore and inshore areas, this may very well be the situation.

Where there are multiple rig options and good availability, the operator should consider the well manufacturing process to optimize drilling and to minimize costs. The option of drilling using a snubbing or HWO unit is certainly one that should be considered along with conventional drilling using different rig sizes.

Assume that a well must have three casing strings: large-diameter, shallow surface casing; intermediate casing also set relatively shallow; and production casing set at total depth (TD). Rather than drilling all the hole segments with a conventional rig sized for the deepest hole or the heaviest, deepest casing string, a smaller rig might be suited for drilling the top two hole sections, running and cementing surface casing, and installing the required wellhead segments. Then, it could be rigged down before bringing in another rig to drill the deep hole and run a long casing string. If the cost difference in using a small shallow drilling rig offsets its demobilization cost along with the mobilization cost of the larger rig for the deep hole, overall costs can be optimized. Once the small rig has completed drilling the shallow hole segments, it would be available for doing the same tasks on the next well.

It may be practical to consider a hydraulic unit for drilling the deep hole segment in this example to further reduce costs regardless of tripping speed. Modern bits, especially polycrystalline diamond compact (PDC) bits, can drill for many more hours with good penetration rates at lower weights compared with older bits. Depending on deep hole length, there may only be a single trip during which trip speed would be an issue. Again, the hydraulic unit drilling spread cost would likely be a fraction of the large rig cost. For certain hole sections, CTD may offer the best option. Completion rig selection follows the same line of reasoning.

The important issue is selecting the rig and the drilling operation that provides the best combination of capabilities and cost optimization to the well construction process. Again, availability, timing, transportation, rig support, and other issues must be considered. In the past, it was assumed that one large conventional drilling rig met all the requirements, and therefore, it was obviously the best option. That may not be the case now.

6.7 SUMMARY

Hydraulic unit drilling has become a viable drilling option for certain hole segments on certain wells. It is not a panacea, and it is not recommended for all drilling. Under the correct drilling conditions, hydraulic unit drilling represents a viable option that could help to reduce overall drilling costs and both financial and physical risk, especially where UBD and MPD are attractive.

Drilling with snubbing or HWO units is currently the most underused market in the oilpatch. Many older drilling managers detest the sight of a hydraulic unit citing it as the least attractive option for anything. However, when it is needed, the same group grudgingly accepts its capabilities as necessary and useful. Hydraulic unit drilling has improved in both its capabilities and safety over the recent past making it a drilling option worth consideration.

CHAPTER 6 QUIZ

1. In some applications, snub drilling is more economical than drilling with a conventional drilling rig.
  A. True ______
  B. False ______

2. What limits the diameter of drill strings and casing run through a snubbing or HWO unit?
  A. Size of the slips and bowls
  B. ID or bore of the snubbing/HWO unit, the strippers, and the safety BOPs
  C. OD of the wellhead and seal assembly below the safety BOP stack
  D. All of the above

3. Rotary motion is applied to the drill string in snub drilling using what device?
  A. Hydraulic rotary table below the traveling slips
  B. Derrick-mounted top drive unit
  C. Rotating control device located in the work window
  D. All of the above

4. Why is a rotating control device (RCD) necessary for pressured snub drilling?
  A. It provides a bearing surface to help support the weight of the drill string while it is rotating
  B. It is not necessary at all—the entire drill string can rotate throughout the drilling process with the strippers, the annular, or the safety BOPs closed on the pipe to provide an annular seal

C. Provides a means to rotate the drill string with pressure on the well while sealing the annulus
D. None of the above

5. Drilling fluid cleaning and pit systems for snub drilling spreads are needed for what purpose?
A. To remove drill cuttings, metal shavings, and other debris from the drilling fluid to avoid plugging and bridging
B. To control low gravity solids that can gradually accumulate in an untreated mud system
C. To provide a means to mix mud chemicals that will maintain drilling fluid properties
D. All of the above

6. Snub drilling crews are often smaller and better trained in well control management than conventional drilling rig crews.
A. True ______
B. False ______

7. How do costs for mobilization of an offshore bottom-supported rig (jack-up) compared with those same costs for a snub drilling equipment spread?
A. Snub drilling costs are greater because there are more pieces involved that must be loaded on vessels and hoisted to the rig
B. Jack-up conventional drilling rig costs are greater because of the steps necessary to rig down, jack down, move, jack up, preload, cantilever the drilling package over the hole, and hook it up
C. There is never a significant difference between the two—they are about the same
D. Sometimes a. and sometimes b.—either one may be higher than the other depending on circumstances

8. Assume that an old well at the end of a long canal must be deepened. How could the mobilization costs for a jack-up conventional drilling rig compared with a barge-mounted snub drilling spread to do this job?
A. The snubbing unit spread mobilization cost will be higher because several barges must be used to transport all the equipment
B. The jack-up mobilization cost will probably be higher if the canal must be dredged deeper and wider to accommodate the jack-up
C. Crew quarters will be required on the snub drilling spread making mobilization cost much higher than the jack-up rig
D. None of the above

9. Why are borehole stability problems in the original hole important when sidetracking an existing well?

A. To select the proper drilling fluid for the problem hole interval
B. To ensure that sufficient pump pressure and rate are available for good penetration rate and hole cleaning
C. To select the proper downhole tools including bits, reamers, stabilizers, and measurement devices
D. All of the above

10. Well integrity issues that can jeopardize snub drilling include which of the following.
A. Holes and leaks in casing, crooked casing, or partially collapsed casing
B. Bent wellhead or the entire well bent over from mudline due to storm damage
C. A leaking wellhead seal with sustained annular pressure on an outer annulus
D. All of the above

11. The size and configuration of a snub drilling spread on an offshore platform depends primarily on the size and configuration of the platform.
A. True ______
B. False ______

12. What are some of the advantages of a snub drilling unit over a conventional jack-up drilling rig in an offshore environment?
A. Smaller footprint, lower horsepower, and fewer emissions
B. Snub drilling rigs are supported by the platform instead of the ocean floor preventing can punch-through
C. Fluid handling and cutting handling are far easier on the snub drilling spread
D. There is no requirement for housing or support for the snub drilling crew

13. Snubbing capability of some type is required if pressure is to be maintained on the annulus at all times during underbalanced or managed pressure drilling.
A. True ______
B. False ______

14. What is the most significant disadvantage of snub drilling when compared with drilling with either a conventional drilling rig or a coiled tubing unit?
A. Snubbing units cannot steer the bit while drilling
B. Available hook loads are lower on snubbing units

- **C.** The maximum bit RPM is slower using a snubbing unit than with either a conventional drilling rig or coiled tubing unit
- **D.** Pipe tripping speeds are generally slower with snubbing units than with conventional rigs or coiled tubing units

15. Tall snubbing stacks are sometimes required in snub drilling operations. What is true of a tall snubbing stack?
- **A.** The snubbing unit must be hoisted to the top of the stack by a crane with sufficient hoist rating and a mast with sufficient reach.
- **B.** All spacer spools and other components of the stack must have the same working pressure as the snubbing BOPs (strippers) or at least be capable of holding the maximum anticipated surface pressure during the job.
- **C.** The tall stack, including the snubbing unit, must be supported to prevent toppling usually by guy wires.
- **D.** All of the above

16. All personnel working in the basket on a snub drilling spread must have access to an emergency evacuation device.
- **A.** True ______
- **B.** False ______

17. When comparing different types of drilling systems, what are some of the factors entering into the decision to choose one over the other?
- **A.** Mobilization cost and rig availability
- **B.** Suitability for purpose
- **C.** Daily spread cost
- **D.** Crew size and training
- **E.** All of the above

18. What does the term "well manufacturing" mean?
- **A.** All the items involved in drilling the well are fabricated in the country where the well is being drilled to avoid duties, taxes, and fees.
- **B.** A different rig is used to drill certain hole sections for which it is best suited and the most economical.
- **C.** Wells are all planned to be drilled the same way with the same rig, thereby lowering overall cost when considering the learning curve.
- **D.** There is no such thing as "well manufacturing." It is a bogus term.

19. The lowest cost option for any drilling project is always the best option.
- **A.** True ______
- **B.** False ______

20. What are the last seven words of any company?
- **A.** "You guys really are not very smart."
- **B.** "We can always plug back and redrill."
- **C.** "We never did it that way before."
- **D.** "The author is certainly a great guy."

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Appendix A: Acronyms and Abbreviations

AIME	American Institute of Mining, Metallurgical, and Petroleum Engineers
API	American Petroleum Institute
$BaSO_4$	barium sulfate, barite
bbl	barrel/barrels
BF	buoyancy factor (fraction)
BHA	bottom-hole assembly
BHP	bottom-hole pressure
BHT	bottom-hole temperature
BOP	blowout preventer
BOPD	barrels of oil per day
BPV	back-pressure valve
CapEx	capital expenditure
CCL	casing collar locator
C_f	coefficient of friction
CIBP	cast-iron bridge plug
CO_2	carbon dioxide
CO_3^-	carbonate radical
CrO_3	chromium trioxide
CT	coiled tubing
CTD	coiled tubing drilling
CTU	coiled tubing unit
DNV	Det Norske Veritas
DP	drill pipe
EPDM	ethylene propylene diene monomer
EPR	ethylene propylene rubber (also EPM)
ESP	electric submersible pump
EUE	external upset end
FKM	fluoroelastomer
frac	fracture stimulation
gal	gallon/gal
GPGP	grind, polish, grind, polish
GPM	gallons per minute
H_2S	hydrogen sulfide
HCl	hydrochloric acid
HF	hydrofluoric acid

HNBR	hydrogenated nitrile butadiene rubber
HP	horsepower, high-pressure
HSE	health, safety and environment
HTHP	high temperature high pressure
HUET	Helicopter Underwater Escape Training
HWDP	heavy-weight drillpipe
HWO	hydraulic workover
IADC	International Association of Drilling Contractors
ICoTA	Intervention and Coiled Tubing Association of SPE
ID	inside diameter
in	inch/in.
KWM	kill weight mud
lb_f	pound force
lb_m	pound mass
LCM	lost circulation material
LNG	liquefied natural gas
LWD	logging while drilling
MAWP	maximum anticipated well pressure
MCF	1000 standard cubic feet (of gas)
micron	one millionth of an inch (1/1000,000 in or microinch)
MPD	managed pressure drilling
MW	mud weight (fluid density)
MWD	measurement while drilling
NEFE	nonemulsifying iron sequestered (acid)
NORM	naturally occurring radioactive material
NORSOK	Norsk Sokkels Konkuranseposisjon
OBM	oil-based mud
OCTG	oil country tubular goods
OD	outside diameter
OIM	offshore installation manager
OTC	Offshore Technology Conference
P&A	plugged and abandoned
PBR	polished bore receptacle
PDC	polycrystalline diamond compact (bit)
PEEK	polyether ether ketone
pH	negative logarithm of para-hydronium ion concentration
ppb	pound per barrel
ppf	pound per foot or lb./ft.
psi	pounds per square inch or lb./in^2
PTFE	polytetrafluoroethylene
PTO	power takeoff

PWD	pressure while drilling
Rc	Rockwell hardness
RCD	rotating control device
ROI	return on investment
ROP	rate of penetration
RPM	revolutions per minute
rt.	round thread
SPE	Society of Petroleum Engineers
Spec	specification (API)
SPPP	strip, polish, plate, polish process
Stanolind	Standard Oil of Indiana
SWPP	strip, weld, plate, polish process
TD	total depth
TIW	Texas Iron Works
TPC	Technical Publications Committee of IADC
UBD	underbalanced drilling
UHMWPE	ultrahigh-molecular-weight polyethylene
VBRs	variable bore rams
WBM	water-based mud
WIO	working interest owner
WPC	World Petroleum Congress

Appendix B: Glossary

Abandon/abandonment	The process of safely plugging a producing, injection, service, or observation well at the end of its useful life to protect the environment and to comply with applicable regulations and policies
Accumulator, BOP	A pressured vessel or a series of these manifolded together usually charged with an inert gas such as nitrogen to store pressured fluid for operating emergency equipment in the event of a loss of power from an external source
Acid fracture/acid fracturing	A stimulation process in which low-pH fluid is pumped into a formation at a pressure that exceeds the fracture gradient to hydraulically rupture the rock and form channels to enhance production (Note: proppants are not usually pumped with the acid in this type stimulation)
Acidizing/acid job	A stimulation process in which low-pH fluid is pumped into a formation at low matrix rates and pressures to remove contaminates and to etch the pore throats
Aerate	Injecting gas into a stream of liquid to reduce its density (Note: fluids thus treated are either called aerated or gasified fluids)
Anchor	A fixed point at a particular datum to which a device, component of an equipment set, a chain, cable, deadline, wire, or other item is securely connected to provide stability
Annulus	The space between two strings of pipe or between the inside of a hole and the outside of a string of pipe
Artificial lift	Any of several methods to provide energy to the base of a producing well to cause fluids and gases to be produced following the depletion of initial pressure that resulted in the well flowing naturally (Note: artificial lift may be added to a well to enhance its natural flowing capabilities)
Azimuth/course	The direction in which a directional well is oriented at some point along its length measured in degrees and oriented like a compass with both 0 degree and 360 degrees at magnetic north

Back pressure	Pressure retained in a vessel, device, or wellbore resulting from the restriction of outflow from that component (Note: may be dynamic or static in the form of trapped pressure)
Back-pressure valve (BPV)	A check valve installed in a receptacle in a wellhead that serves as a barrier against fluid flow from a well while installing or removing a tree or blowout preventer through which fluid can be bullheaded down the well if necessary
Backup/backups	Holding one portion of a connection while making up or breaking out the other portion(s)
Balance point	See "neutral point"
Ballooning, tubular	The increase in tubular diameter, with consequential shortening, when a fluid is pumped into it under pressure (Note: this deformation is usually elastic in nature, and the tubular returns to its original dimensions once the pressure is removed)
Barite	Finely divided granular barium sulfate, $BaSO_4$, used as an inert weighting material to increase fluid density
Base	The major foundation of a piece of equipment; the lowest portion of an item on or inside of a well
Bend/bending/bent	Deflection of a tubular item, whether solid or hollow, in response to lateral or compressive forces causing it to be displaced from its centerline as defined by a straight line from the top to the bottom of the tubular good (Note: this type deflection may be elastic or inelastic)
Bent sub	A short section of pipe intentionally deformed to a specific angle often used to deviate the bottom-hole assembly from the centerline of a wellbore
Bentonite	Sodium montmorillonite clay with other colloidal materials that, when mixed with water, creates a slickened gel useful in drilling fluids (Note: when bentonite hydrates, it "takes" fluid but swells to replace the volume used for hydration)
Bit	A cutting element of various types affixed to the base of the bottom-hole assembly used to drill wells by either pulverizing rock (percussive) or cutting/scraping rock (shear) to advance the hole or to clean out the inside of a wellbore
Blowout	The unwanted, unexpected, uncontrolled release of fluids and pressure from a wellbore at the surface or into another zone within a wellbore (i.e., an underground blowout)

Blowout preventer (BOP)	A hydraulically or mechanically operated dual guillotine valve or elastomer ring on the surface that seals the annular space to prevent an unwanted flow from the well (Note: blowout preventers may include devices that sever the pipe before sealing the annulus)
Bottom hole	At or near the maximum depth of a wellbore or the portion of the wellbore of interest
Bottom-hole assembly (BHA)	The collection of tools including a bit or mill, motor or turbine, detection (logging) tools, drill collars, disconnects, check valves, connectors, and other equipment attached to the bottom of the drill string used to drill or mill inside a wellbore
Bottom-hole pressure (BHP)	Actual pressure inside the wellbore at its base or at some other position along the well length (Note: this can be the pressure inside the wellbore at the depth of a particular formation or feature)
Bottom-hole temperature (BHT)	Actual temperature inside the wellbore at its base or at some other position along the well length
Breakout	To unscrew or otherwise disconnect a previously completed connection (Note: applies to tubular goods most often, breaking out a stack is often called "nippling down")
Bridge	A complete obstruction in a wellbore or tubular created by some material filling a portion of the hole or formation such as sand, silt, paraffin, mud chemicals, or formation solids; also, a type of tubular repair that installs across damaged pipe to form a connection between the good pipe on both sides
Bridge plug	A tool set inside a wellbore or tubular designed to seal and mechanically isolate the well segment below the tool (Note: this type plug is usually constructed of a drillable material such as cast iron, pewter, or aluminum with rubber seals and slips)
Brine	A solution of a salt in relatively high concentrations dissolved in water having a density greater than water
Brittle	A property of metals and other materials that results in fracturing instead of deforming in response to applied stress
Buckle/buckling	*Traditional:* any deviation of a column from its centerline resulting from applied force; *in pipe:* the deflection of the lateral axis of the tube body from its centerline that results in permanent deformation

	and/or catastrophic failure (Note: bowing is a form of buckling)
Buckling, elastic	Deformation of a malleable body from its original shape due to imposed stress that returns to its original configuration when the stress is removed
Buckling, helical	Buckling of a tubular item constrained inside another pipe or the wellbore in which sinusoidal buckling converts to a corkscrew shape that then contacts 360 degrees around the internal circumference of the buckled pipe for a portion of its length (Note: this type of buckling produces high pipe-on-wall friction that limits the ability of force to be transmitted down the buckled section)
Buckling, inelastic	Deformation of a malleable body resulting from stress that does not return to its original configuration when the stress is removed but remains permanently deformed
Buckling, sinusoidal	Buckling of a tubular item constrained inside another pipe or wellbore that assume the shape of a sine wave in a single plane with contact points roughly every 180 degrees along the buckled length
Bullheading	Pumping fluid into a wellbore from the surface and into a formation under pressure without circulation
Buoyancy	The upward force exerted by a fluid that partially supports the weight of an immersed material (Note: buoyancy is proportional to the density of the fluid in which the object is immersed)
Caliper	To measure the diameter or size of an object; the tool used in measurement of the size of an object
Caliper, logging	Measuring the inside diameter of a wellbore or tubular using a mechanical or ultrasonic detection device run on wireline or pipe
Cap	An impervious rock layer above a porous reservoir; an accumulation of gas or oil overlying another fluid layer (e.g., a gas cap)
Capping	Halting the flow from a blowout by installing a device on the well at the surface and closing it
Casing	A tubular item permanently installed inside a wellbore (i.e., not retrievable) that extends to the wellhead (Note: casing is intended to seal off a section of the well to provide protection from pressure, lost circulation, or sloughing as the well is drilled)

Casing collar locator (CCL)	A logging tool through which a current is passed that induces a magnetic field in the casing that is disrupted, detected, and displayed at the surface (Note: this device is often run in combination with a gamma-ray detector, the results from which, when compared with original open hole logs, can be used to ascertain the depth of the tool string relative to the original formation evaluation tools)
Cement	Finely divided granular mixture of clays, burnt limestone, fly ash, activated aluminum silicate, and other additives mixed in a slurry with water that ultimately hardens into a waterproof, inert rock-like material
Cementing	The process of pumping a cement slurry into a well to fill an annulus using it as a mortar to mechanically support tubulars and seal the annular space between them or as an impermeable plug inside of a tubular
Cement squeeze	Displacement of a cement slurry into a portion of the well (perforations, annulus, etc.) by applying pressure to the slurry (Note: the mixing water from the slurry is assumed to be "squeezed" out resulting in a tougher, harder cement plug)
Check	A check valve: also, a verification of some fact or determination
Check valve	A device that only allows fluid flow in one direction
Choke	A flow-through device that reduces flowrate while increasing back pressure on a flowing fluid stream (Note: a choke is not a valve); also, the act of reducing the flowrate in a stream through a restriction
Choke line	The high-pressure pipe extending to the choke manifold from the valved side outlet of a wellhead, BOP, or other device in the stack
Choke manifold	An arrangement of high- and low-pressure piping, valves, fittings, and chokes used to route and control flowrate and back pressure on a stream exiting a well
Choke, manual	A device with an orifice size that can be manipulated at will to lower pressure in a flowing stream of fluid or gas while controlling pressure upstream of the device
Circulating kill	The practice of pumping kill weight mud (KWM) down a well and removing lighter-weight fluid to increase the hydrostatic fluid column pressure at the depth of a flowing interval to bring the BHP into equilibrium and stop an influx

Circulation	Movement of a fluid through a conduit to the end of a suspended tubular connected at the surface and then back up through an annulus to the surface or in the reverse flow path (down the annulus and up the tubular)
Coiled tubing (CT)	Continuously milled pipe without connections that is transported, deployed from, and recovered on a reel or spool, temporarily installed in a well for a variety of purposes
Coiled tubing drilling (CTD)	Drilling or sidetracking a new hole section using coiled tubing as the drill string and the conduit for drilling fluids
Coiled tubing unit (CTU)	A collection of equipment designed to safely transport, deploy, recover, operate, and monitor all critical functions required to use coiled tubing in a well
Collapse	Flattening of a tubular item due to excessive external pressure that may be aggravated by mechanical tension or bending
Collar	A device, usually threaded, used to join two pieces of pipe with threaded pins each of which is made up into the collar
Completion	Any of several activities intended to bring a well into working configuration either as a producer, an injector, or a service well; the collection of equipment run into a hole to affect a completion including tubing, profile nipples, valves, and packers
Completion tubing	A recoverable tubular string installed in a well that conveys formation fluids from the formation to the surface or injection fluids to the formation (Note: this is sometimes just referred to as the "completion")
Composite	Material composed of carbon or glass fibers embedded in a resin matrix
Composite plug	An easily drillable downhole plug composed of cementitious and fibrous materials
Compression	A force acting on pipe in a way that could crush it (Note: when acting along the central axis, this force can result in buckling)
Concentric hydraulic rig	A specialized hydraulically operated unit with a single, large double-acting cylinder having a relatively large-diameter central hollow "rod"
Connection	Any method of combining two pipe strings or a pipe and end device (Note: includes threaded and coupled,

	threaded, welded, or a device that connects to both portions)
Connector	Any of a group of devices that mechanically and hydraulically connect pipe to itself or to another device
Control cabin	A protected enclosure housing the control console for a remotely controlled hydraulic rig that also provides sensor readouts, video monitors, and a high-visibility position for the operator to observe and control the unit
Control console/control panel	A cabinet or panel equipped with various gauges, valves, handles, and other devices by which the operator manipulates the hydraulic rig (Note: control consoles differ from one hydraulic unit to another depending on the type unit and the duty in which it is being used; auxiliary control consoles can be added as needed)
Corrosion	Oxidation or electrochemical deterioration of metal by the environment in which it operates or is stored
Corrosion inhibitor	A chemical agent used to prevent corrosion on a metal surface by interfering with the oxidation/reduction process (Note: these chemicals may be organic or inorganic and work in different ways such as coating the metal surface to prevent a corrosive environment from reaching the metal—filming amines, varnishes, and paints are examples)
Counterbalance	A hydraulic system that uses a device to prevent hydraulic device movement until some threshold pressure is exceeded to initiate motion (Note: these are used extensively in hydraulic cylinders and hoists control circuits)
Crack	A stress-induced separation in a section of a metal item that can ultimately result in failure at that point
Cycle	A portion of a hydraulic rig stroke, either upward or downward; the frequency of alternating current in one second
Dead well	A well having no surface pressure
Defoamer	A chemical or chemical mixture added to hydraulic fluids to reduce surface tension and prevent foaming to cause them to break down returning to a liquid by releasing trapped gases
Density	The weight per unit volume of an object or fluid

Depth	The vertical length of a wellbore or fluid column measured from a datum along its path; the length of defect penetration into the wall of a cylinder, rod, or threaded connection (i.e., the "valley" of the cut thread into the pipe body)
Derrick/mast	A structure designed to support the upper block assembly for hoisting loads from a well, for holding jointed pipe standing on its end and for supporting devices used to manipulate the pipe and other tools used on the well (Note: a derrick may either be permanently affixed to the support around the well or be dismantled, removed, and reused at a number of well sites)
Deviation	See "inclination"
Differential pressure	The difference between two pressures across the barrier where they are joined
Differential sticking	Holding of pipe against the wall of a wellbore due to differential pressure between the wellbore and the formation across a filter cake
Displacement	Fluid volume required to replace the volume of pipe being run into or pulled out of a wellbore or another fluid inside the wellbore; the lateral movement of pipe away from its centerline due to buckling
Dogleg	An abrupt change in either azimuth or deviation or both at some point in a wellbore (Note: the abruptness of this change is called "dogleg severity" and is measured in degrees per 100 ft)
Drag	Frictional force exerted by the pipe as it is pulled from or run into a wellbore by contact with the constraining wall of the hole whether pipe or a bore hole
Drill	The process of boring a relatively small-diameter hole into the earth for a variety of purposes
Driller	A term to designate the individual operating the equipment drilling a well; the supervisor controlling the crew involved in such an operation
Drill pipe (DP)	Tubular used to convey the bottom-hole assembly into the well and to serve as the conduit for circulated fluids used in the drilling process
Drill collars	Thick-walled, heavy tubulars used for weight at some point along the drill string, often just above the bit, to provide a force on the bit face against undrilled rock to advance drilling

Drilling fluid	Fluid circulated down the drill string, through the BHA and across the bit, to power the motor, to lubricate and cool the bit or mill, and to remove cuttings from in front of the cutting device and return them to the surface for separation (Note: these fluids can include water, oil, muds, gases, or emulsions and combinations of these)
Drill string/drill stem	The entire collection of drill pipe, drill collars, and bottom-hole assembly components used to drill a well
Elastic deformation	An alteration of the pipe or other component that returns to its original configuration once the stress causing the alteration is removed
Emulsion	A heterogeneous mixture of two dissimilar fluids with one held in suspension, the discontinuous phase, as a dispersion in the other, the continuous phase (Note: the emulsion may be formed by mechanical agitation or chemical means when small volumes of fluids with high surface tension are entrapped within another phase)
Entrained	Gas or liquid suspended in another fluid phase in the form of bubbles, droplets, mists, or slugs
Equalizing loop/circuit	A manifold composed of manually or hydraulically actuated valves and fittings that control well pressure inside the snubbing stack; this circuit allows stack pressure to equalize with the well or to vent off the pressure to ensure that unrestricted emissions are avoided through the upper snubbing BOP (stripper)
Fatigue	Damage to a metal item resulting from inelastic cyclic stresses; also, the state of workers to be extremely tired and listless from overwork especially in a stressful environment
Fill	Accumulated material in a wellbore usually composed of formation, silt, mud solids, scale, fracture proppant, paraffin, or other solid or semisolid material that limits the well's utility
Filter cake	A tough layer of solids from the drilling fluid that plates out on the inside of the hole across porous sections where the fluid is injected into the formation leaving the solids behind
Filtrate	The liquid phase of the drilling fluid injected into a formation leaving behind solid particles inside the wellbore to form filter cake

Fish	Any unrecovered object left in a wellbore, including junk, either intentionally or unintentionally (Note: most fish must be recovered to clear the wellbore of the obstruction and to enable further work to be performed or for the well to be used in its intended service)
Fishing	The art of attaching to and removing a fish from a well
Flange	A type of connection between components in which each is equipped with a flat plate of given thickness, drilled with a number of holes of a particular diameter and pattern and a seal capable of containing pressure to a maximum working limit
Flat time	Sections of a depth versus time plot prepared while drilling a well when new hole is not being made
Float	A check valve run at some point along the length of a pipe string in a well
Fluid loss	Wholesale injection of fluid that escapes from the uncased wellbore into a receiving formation: also, the property of drilling and workover fluids that represents the ability of filtrate to leak off into a porous medium under pressure leaving filter cake behind on the formation face
Flush joint	Pipe with a nonupset end and a connection that has the same OD and ID as the pipe body
Foam	A heterogeneous, stable mixture of a liquid, solid, or semisolid material with the gas suspended inside of it in very small bubbles; a stable gas-in-liquid emulsion
Foam breaker	A surface tension reducing chemical such as a low-molecular-weight alcohol that causes the foam to lose its stability and separate into liquid and gas phases; a defoamer
Footprint	The areal extent and configuration of the surface space occupied by any piece of equipment; the total areal space and configuration occupied by the entire equipment collection or spread
Formation	A geologic deposit composed substantively of a single rock type of a given age and with specific properties, fluid content, and pressure (Note: a formation may or may not be porous and permeable)
Formation damage	The reduction of original rock permeability caused by filtrate or whole drilling fluid invasion, the introduction of treating fluids or other fluids incompatible with connate fluids in the rock matrix

Fracture/frac A crack or break in the rock matrix of a formation either natural or induced

Fracturing A stimulation process in which fluid carrying a proppant is pumped into a formation at a pressure that hydraulically ruptures the rock with the resulting cracks packed with an inert material so that they remain open when surface treatment pressure is reduced

Friction Resistance to motion caused by one item rubbing on another

Friction pressure Pressure created by a flowing fluid as a result of the fluid rubbing on the inside of a conduit

Friction reducer A chemical or chemical mixture used to reduce the force resulting from pipe-on-wall friction; a fluid slicker

Friction, static Resistance to motion resulting from the adherence of two surfaces to each other such as pipe to conduit or pipe to wall in a wellbore (Note: static friction is generally higher than dynamic friction)

Gas Matter that expands and fills the entire volume of the container in which it is confined (Note: gas is compressible, and its volume depends on both temperature and pressure inside the container)

Gas lift A form of artificial lift in which gas is injected into a fluid stream to reduce its density and therefore hydrostatic pressure on the formation allowing the well to flow

Gate valve A single-acting guillotine valve that uses a sliding gate to control flow usually from one direction (Note: some gate valves are dual acting meaning that they can control flow and pressure from either direction; valves are on-off binary devices, and they should never be used to choke flow)

Grab To obtain a friction grip on an item, such as pipe, using a specialized device

Grade The classification of steel pipe or other materials based primarily on the minimum yield strength and chemistry of the material (Note: this classification applies to coiled tubing, jointed tubing, line pipe, drill pipe, drill collars, HWDP, and other tubular goods)

Gradient The difference between levels of a certain property or condition in a system, such as temperature, hardness,

	and pressure; a change in a property expressed in per unit terms such as pressure per unit depth or height
Grapple	A device that grabs and holds around the outside of the pipe (Note: a grapple is contained inside another device that controls its expansion such as a connector or overshot)
Gripper	A device designed to selectively hold an item to initiate or to prevent movement
Grippers/gripper blocks	Machined blocks designed to provide a friction traction force on the outside of coiled tubing usually conveyed by endless counter-rotating chains the tension and traction pressure of which can be manipulated by hydraulic rams in the injector (Note: grippers provide the means to pull coiled tubing from the hole or snub it into a hole under pressure)
Guide	A device or system that steers an internal component into it or retains it in place during subsequent manipulation (Note: a telescoping pipe guide prevents the pipe from unrestricted buckling by constricting its lateral displacement)
Head	The top portion of a device that performs a particular duty such as providing a rotating seal, imparting hoisting force, providing an abrasive surface, or other function; the top portion of a vertical hydraulic cylinder
Heavy-weight drill pipe (HWDP)	A tubular item with drill-pipe connections having a thicker wall and therefore heavier weight per joint than normal drill pipe; commonly used as part of the BHA installed above the drill collars
Helical buckling	A form of pipe deviation under axial loading whereby the pipe forms a spiral or corkscrew shape inside a conduit with the outside of the helix contacting the conduit wall at all points along its length (Note: this type buckling produces excessive friction created by pipe-on-wall contact and can lead to lockup)
High-angle hole	A well with a deviation angle generally exceeding 50 degrees
Horsepower (HP)	A unit of measure for work performed by a machine originally based on the working capability of a single horse (Note: 1 HP = 550 ft-lb per second)
Hybrid rig	A piece of drilling or service equipment composed of two or more components with substantively different

	functions; a hydraulic rig coupled with a coiled tubing unit
Hydrate	To soak in water; hydrocarbon molecules trapped in a water crystalline matrix resulting in an ice-like material (Note: hydrates can exist in a stable form at temperatures greater than the freezing temperature of water)
Hydraulic horsepower	A unit of measure for the energy required to move fluid at a given pressure and rate
Hydrostatic pressure	Pressure exerted on the bottom of a column of fluid resulting from the weight of the fluid acting in the vertical direction (Note: in directional wells, the hydrostatic pressure applies through its vertical depth at any given point along its length)
Inclination/deviation	The departure of the wellbore from vertical at any given point along the well's length measured in degrees with zero being vertical and horizontal being 90 degrees
Inclusion	Impurities of various kinds suspended or trapped within the matrix of another material
Inelastic deformation	An alteration of pipe or other component that permanently alters the configuration of the item even after the force that caused the alteration is removed (i.e., the item retains all or a portion of its new configuration and does not return to its original shape)
Inhibitor	A chemical or solvent that, when added to a system in small amounts, prevents the formation of reaction products such as rust or unwanted deposits such as scale or paraffin
Injector/injection well	A well designated and equipped to provide a conduit from the surface for the pressured insertion of fluid, gas or waste (usually a liquid) into a subsurface formation
Injector/injector head	A device equipped with motors, chains, grippers, and other components used to deploy and recover coiled tubing from a wellbore
Inshore well	A well situated in shallow water within the coastal boundary but not onshore; these are often located in bays, marshes, estuaries, and other tidally influenced areas (Note: may or may not apply to impoundments in onshore areas, such as lakes, depending on local terminology)

Inside diameter (ID)	The diameter between the inner walls of a tube measured through the tube centerline
Inspection	The process of examining an object using a variety of means to identify defects and/or deviations from specifications
Interlock	A safety system designed to prevent actuation of a device if another associated device is positioned in such a way that actuation of the second device would create a hazardous condition
Intermediate casing/liner	A string of pipe permanently installed inside a wellbore to isolate formations below shallow surface zones to protect from unwanted flows, sloughing, or lost circulation (Note: there may be several intermediate casing/liner strings installed in a well depending on geologic and hydraulic conditions that may exist)
Intermediate plug	A temporary or permanent sealing obstruction in a well between the bottom and surface plugs in a wellbore (Note: there may be several intermediate plugs installed in a well for a variety of reasons)
Jar	A downhole device installed in a pipe string in a well that imparts a blow either upward or downward when activated (Note: jars must be run within a string of pipe that can withstand the force of the blow(s) without buckling or failing mechanically)
Jet	A stream of a given diameter and at some velocity created by fluid pumped through a nozzle creating backpressure; the process of removing liquid (especially water) from a producing well by injecting gas through a small-diameter tube at the bottom of the well
Jib	A crane with a small mast used to hoist and lower light loads on a hydraulic rig (Note: load manipulation is often controlled by the counterbalance hoist while running or pulling pipe)
Joint	A standard random length of pipe (Note: range 2 joints are approximately 30 ft long; range 3 pipe is approximately 40 ft in length)
Jointed pipe	Pipe of a specific joint length with a connection on each end of some type (Note: the connection may or may not include an internal or external restriction/enlargement)
Junk	Metal debris lost in a wellbore that often requires significant effort and cost to remove; the process of

damaging an item so badly that it cannot be economically repaired

Kick An influx of fluid that enters the wellbore because of inadequate hydrostatic pressure during well operations (Note: a kick, if not handled properly, can be a precursor to a blowout event)

Kick off To begin an event; to start the intentional deviation of a wellbore from its original path

Kickoff point The depth within a wellbore where a directional kick off occurs

Kill/killing Pumping fluid into a well that provides sufficient hydrostatic pressure to counteract wellhead pressure reducing it to zero; any means used to stop the flow from a blowout including surface capping

Laser/laser cladding A welding process in which a concentrated light beam creates temperatures in the metal pieces in excess of their fusion temperature used to deposit a layer of one metal on top of another

Ledge An incomplete obstruction in a wellbore or tubular created by an obstacle that extends toward the centerline of the hole, usually a ragged section of rock or pipe, that constitutes an uneven inner surface

Liner A tubular item permanently installed inside a wellbore (i.e., not retrievable) that is installed from the inside of a previous casing string or liner but does not extend back to the wellhead (Note: a liner serves the same purposes as casing to protect a portion of the well as it is drilled or completed)

Live well A well with surface pressure

Lockup The condition when the friction between a pipe and the wall of a wellbore exceeds the force pushing the pipe further into the hole (Note: in coiled tubing and thin-walled jointed pipe, this condition is preceded by the development of helical buckling and full-diameter contact of the pipe with the hole preventing further movement no matter how much force is applied on top of the helix)

Log Record of formation characteristics such as density, resistivity, radioactive emissions, and other properties of formations and fluids within them measured by tools lowered into a well following drilling or generated by tools run on the drill string and operated while drilling the well

Logging while drilling (LWD)	Using a set of downhole detection tools run in the BHA to measure specific reservoir properties such as gamma-ray emissions, density, porosity, fluid saturations, and resistivity while advancing the hole depth (Note: these tools are often run along with MWD tools that provide wellbore position and PWD tools that provide downhole BHP as the well is being drilled)
Lost circulation	The lack of returning circulated fluid from a well usually caused when formations fracture under the influence of excessive pressure or fluid is lost into a geologic feature such as a natural fracture or fault
Lost circulation material (LCM)	Any of a variety or a mixture of drilling fluid additives that bridge across the face of a portion of the wellbore suffering from lost circulation (Note: these materials may be fibrous, either natural or man-made, or they may be of mineral origin)
Lubricator	Length of pipe or other container with proper connections and valving installed above a well to contain fluids and pressure while running a length of tools into a well under pressure on wireline or pipe without having to kill the well
Make up	To screw together or to properly complete a connection of some type (Note: applies to tubular goods most often, making up a stack is often called “nippling up”)
Manifold	Assembly of valves, pipes, and connections that collects fluids from several sources and delivers it to other systems as directed by manipulation of the valves; the process of collecting streams using such an assembly
Maximum anticipated well pressure (MAWP)	Maximum pressure expected to exist at the surface of any well; the highest calculated pressure expected at the surface of a well capable of flowing usually assumed to be the well’s BHP less the pressure exerted by a full column of gas
Measurement while drilling (MWD)	A set of downhole tools run in the BHA that provides positional information regarding the well’s TVD, azimuth and deviation, often with respect to the surface location (Note: often used in combination with LWD tools to provide rock and fluid data and PWD tools that provide downhole BHP as the well is being drilled)

Mechanical properties	Characteristics of a material involving the relationship between stress and strain including ductility, elasticity, tensile strength, and fatigue limit (Note: also known as "physical properties")
Mill	A purpose-built bit equipped with a cutting surface suitable for removing metal, cement, junk, or other materials considered too hard for a conventional bit by grinding, cutting, or chipping action; the process of cutting a hard material using a mill; the facility where pipe and other materials are manufactured
Minimum yield strength	The lowest stress at which a material will permanently deform
Motor, downhole	A device carried on the drill string that imparts rotary motion and torque to BHA components below it (Note: positive displacement motors and turbines operate from fluid pumped down the drill string and through them; electric motors are operated by electric power supplied by a conductor)
Motor, electric	A device that converts electric current at some voltage into some type of work, usually rotary motion
Motor, hydraulic	A device that converts hydraulic fluid flow and pressure into some type of work, usually rotary motion
Motor, mud	A downhole motor that converts mud flowrate into rotary motion (Note: includes positive displacement motors and turbines)
Neutral point	The depth or pipe length in a live well at which the weight of the pipe hanging in the hole equals the expulsion force caused by surface pressure acting on the cross-sectional area of the pipe OD at the surface (i.e., a condition in which the string is neither pipe heavy nor pipe light)
Nipple	A piece of pipe shorter than a full joint
Offshore	Generally, located in waters away from a shoreline (i.e., not onshore); may or may not include inland waters depending on local terminology
Oil-based fluid	A liquid that employs petroleum-derived and/or synthetic components to provide certain fluid properties
Oil-based mud (OBM)	An emulsion in which oil is the continuous phase used as a drilling, completion, or workover fluid having properties conducive to working on the particular well (Note: OBM is considerably more expensive than water base mud in most cases)

Onshore	Generally, at elevations above sea level and inside the shoreline (i.e., not offshore); may or may not include inland waters depending on local terminology
Open hole	An uncased portion of a wellbore
Oriented	Configuration of slips for snubbing (pipe light) or stripping (pipe heavy) in a live well
Orphan/orphaned well	A well with no known ownership (Note: often a shut-in or temporarily abandoned well that is now a "ward" of the state)
Ovality	The property of pipe, with an otherwise circular cross section, in which a difference between the largest and smallest ID exists at one or more points along the pipe length (Note: also called "egg-shaped" or "egged" pipe)
Overbalanced/overbalance	The state in which the level of the pressure inside the wellbore exceeds the formation pressure at a point in the well (Note: this excessive pressure may result from a hydrostatic column or from induced surface pressure transmitted by a fluid column to a point in the wellbore); the degree or amount of this pressure difference on a formation
Overshot	A fishing tool equipped with a grapple designed to engage the outside of the fish and attach securely to it until it is intentionally released
PDC bit	Polycrystalline diamond compact bit composed of disks or plates of man-made diamond deposited onto a wafer of carrier metal fused in a particular pattern and at a particular angle to a substrate used to drill by shearing or cutting rock
Pack-off	To seal the annulus between concentric tubular strings in a well
Packer	A device, either permanent or retrievable, designed to seal the annular space between two tubular strings; the elastomer component on a BOP ram that provides the seal around a tubular item or the open hole when the ram is closed against the item (including another ram in blind or blind/shear ram set)
Packer, production/injection	A permanent or retrievable packer designed to be installed for the long term inside production casing to seal the annular space between the casing a production/injection tubing
Packer, treating	A retrievable packer used to seal the annular space between a work string tubular and casing/liner

	through which various fluids can be pumped to stimulate or otherwise treat a formation
Perforated	An item that contains a hole through its wall (e.g., perforated nipple—a short pipe section with perforations)
Perforating	The process of penetrating pipe at a certain point along the length of a wellbore using a variety of methods including shaped charges, mechanical punches or drills, and abrasive jet boring (Note: a perforation is the hole or pathway resulting from this action that allows fluid to flow through the wall of the pipe or device)
Permeability	The physical property of porous media that allows fluids to flow through connected pore throats within the material due to a pressure gradient (Note: this property is defined by Darcy's law and is expressed in units of measure known as darcies)
Pay	The process of allowing rope, cable, or other flexible line to extend from storage, usually a reel; to monetarily compensate for goods or services received
pH	The negative logarithm of the para-hydronium concentration in an aqueous solution used to show the acidity or basicity of the solution (Note: the pH scale goes from 1 to 14 with 7 being neutral; pH less than 7 is acidic—pH greater than 7 is basic)
Pill	A small volume of fluid mixed with particular properties and density used for a particular purpose in drilling, workover, and completion operations
Pipe heavy	A condition in live wells in which the weight of the pipe string hanging in the hole exceeds the expulsion force caused by surface pressure acting on the cross-sectional area of the pipe OD (Note: advancing the pipe further into the hole requires stripping)
Pipe light	A condition in live wells in which the expulsion force caused by surface pressure acting on the cross-sectional area of the pipe OD exceeds the weight of the pipe string hanging in the hole (Note: advancing the pipe further into the hole requires snubbing until the neutral point is reached)
Plasma/plasma-arc welding	A welding process in which a gas is ionized inside a chamber between an electrode and an oppositely charged housing with the ionized gas becoming an electric conductor at a temperature of over 50,000 °

F to fuse metals together without the introduction of a filler metal (Note: this concept can also be used for cutting metals—i.e., a plasma cutter)

Plastic deformation Permanent alteration of a metal object's shape under an applied stress

Platform, offshore A facility extending above sea level installed on legs or pylons supported by the seafloor used for drilling, production, fluid treatment, or housing offshore crews

Platform, work A structure above ground level suitable for crews to provide services or insert objects into a well

Plug Object, device, or material that completely obstructs or blocks a passageway

Plug back Using a plug to isolate the lower portion of a well for a variety of reasons

Pop-off A valve that opens automatically when pressure in the valve body exceeds a preset limit and then reseals when pressure falls below the set point (Note: these are often used to prevent internal pressure from exceeding the minimum internal yield pressure as a safety device)

Porous The property of a material in which holes, or pores, exist (Note: the amount of void space in the material is called "porosity" and is usually given as a fraction of the total volume)

Power fluid Pressured fluid used to operate any of a variety of hydraulic devices including downhole artificial lift pumps

Power pack A device that supplies pressured hydraulic fluid to other portions of a machine such as a hydraulic rig or a coiled tubing unit

Pressure The force exerted by a compressed fluid on the inside of a closed container

Pressure gauge A device that indicates the level of pressure inside a vessel or pipe either relative to atmospheric pressure or to an absence of such pressure (Note: atmospheric pressure at sea level is approximately 14.7 psi)

Pressure test A nondestructive test used to verify the adequacy of a pressure-containing system at a prescribed level

Pressure while drilling (PWD) A set of downhole detection tools run in the BHA to measure the bottom-hole pressure in the wellbore as the hole is advancing (Note: often used in combination with LWD tools to provide rock and fluid data

	and MWD tools to provide positional information as the well is being drilled)
Primary barrier	The principle control mechanism against unwanted flows or pressure releases in well operations
Production casing/liner	The final pipe string permanently installed in the well to provide a conduit for the production of hydrocarbons from the well or the injection of fluids into the reservoir
Proppant	Solid particle carried in fracture fluids used to support and hold the fracture open once pressure has been removed from the system providing a high-permeability conduit from fracture tip to the well
Push-pull machine	A small rig-assist snubbing unit situated on the rig floor designed to snub the bottommost portion of the drill string into and out of the well during underbalanced drilling (Note: this unit is usually not connected to the blowout preventer stack like other rig-assist snubbing units)
Rams, BOP, blind	Blocks inside the blowout preventer with flat elastomer surfaces that close on the open hole to provide a seal
Rams, BOP, pipe	Blocks inside the blowout preventer with half-moon-shaped elastomer surfaces that close around pipe in the well to provide an annular seal
Rams, BOP, shear	Blocks inside the blowout preventer with knife blades on their flat surface to sever the pipe (Note: these blocks do not seal unless they are also equipped with elastomer sealing elements—such combination rams are called blind/shear rams)
Rams, BOP, slip	Blocks inside the blowout preventer with half-moon-shaped inner surfaces usually scored, ridged, or checkered and case-hardened that hold the pipe securely when closed (Note: slip rams do not contain elastomer seals and then therefore cannot hold pressure)
Rams, BOP, snubbing	Pipe rams equipped with a layer of a hard, abrasive-resistant material used to hold pressure while advancing (sliding) the pipe through them during ram-to-ram snubbing
Reamer	A device run on a pipe string that enlarges a hole or wellbore by rotation or that removes minor ledges or sloughing material (Note: a reamer is often

	preceded by a guiding device such as a bit to ensure that it stays inside the original hole)
Recompletion	A major well intervention intended to open or connect a new source of supply or point of injection to an existing wellbore (Note: there are eight different types of common recompletions, four of which involve drilling a new hole section)
Reel/spool	A circular device used to store, deploy, and recover flexible lines including cable, wire, hoses, or other items
Reservoir, geological	Porous and permeable rock bed penetrated by the well at some depth in which oil, gas, or water are stored underground
Reservoir, surface	Storage container for fluid connected to the power pack (may be closed or open)
Rig, conventional	Generally, a collection of equipment and machinery including a derrick and block-and-tackle hoisting equipment used to drill, complete, or work over a well using jointed pipe
Rig, hydraulic	A unit composed of several devices that uses large hydraulic cylinders to lower or hoist a tubular string into and out of a wellbore
Retainer	An irretrievable, drillable packer set inside a wellbore equipped with a check valve set through which various materials such as cement can be pumped without returning into the pipe (Note: once cement is pumped, the retainer becomes a drillable metal plug that can be left in the hole)
Safety BOPs/safeties	Generally, the lowest BOP set in the stack that is held on standby to control unwanted flows and pressure from a well during a hydraulic rig operation (Note: these are BOPs not routinely functioned during snubbing or HWO operations as flow or pressure controls, like strippers, but are kept in reserve for emergency activation only if needed)
Secondary barrier	A device or system serving as a backup to the primary barrier to prevent the unwanted flow or pressure release from a well
Shut in/shut-in	Closing valves or installing other devices to prevent fluid flow or pressure releases from a well, a vessel, or a pipe string; the property of having experienced a shut-in

Side-track/side-tracking	Redrilling a portion of a well from a point to a new bottom-hole location/the portion of the well having been so redrilled
Slide drilling	Drilling using a downhole motor to impart rotary motion to the bit while holding the drill string above the motor at a constant position (Note: this is used exclusively for coiled tubing drilling since the drill string cannot be turned)
Slough	Delamination or partial collapse of a bore wall into the hole resulting from physical damage, chemical wetting along the bedding plane, or localized fracturing of a wellbore
Slug	A very small volume of fluid with particular properties introduced during drilling, workover, or completion operations for a specific purpose
Snubbing	The process of inserting or withdrawing pipe from a well under pressure
Snub force/snubbing force	Compression exerted on a pipe necessary to overcome expulsion force due to pressure inside the wellbore acting over the cross-sectional area of a tube OD plus friction
Snub/snubbing line	In a conventional snubbing unit, the large wire cable running through large sheaves (pulleys) at or near the rig floor that connects the rig's traveling blocks to the snubbing unit's traveling slips (Note: this line provides the force necessary to snub pipe into the hole under pressure by lifting the rig's blocks using its draw works)
Spool	A flanged pipe segment that serves as a spacer in a stack to add length or to provide a point for the introduction or removal of fluid or pressure (Note: some spools are equipped with side outlets)
Spud/spud barge	Tubular pins lowered to secure (pin) a vessel to the seafloor in shallow water; a barge or similar vessel that uses spuds to secure itself to a given position at a shallow-water site
Sour	A gas stream, fluid, or reservoir containing hydrogen sulfide
Stack	An assembled collection of devices and spacers below a snubbing unit used as a pressured lubricator including BOPs to control fluid flow and pressure from the wellbore

Stall	Condition in which the rotor of the motor ceases to turn under excessive loads due to insufficient pump rate and differential pressure (Note: this condition is often preset by limiting rate and pressure of the power source supplied to the motor)
Stand	A short structure used to support a load; two to four joints of drill pipe or tubing made up into a length from roughly 60 to 120 ft (Note: a stand made of two joints of drill pipe is called a “double”; three joints, a “triple,” etc.)
Stationary slips	The slip set anchored to the hydraulic rig base so that they do not move vertically along with the traveling head and traveling slip set
Stress riser	Any point in an object where imposed stresses are concentrated due to imperfection or shape at which fatigue is accelerated usually leading to brittle failure (Note: one example of a stress riser is a crack in the metal object)
String	The complete length of pipe and any attachments deployed in a well
Stripper	A snubbing BOP; a device with a body containing an elastomeric packing element that seals around the pipe sealing the annulus to prevent the loss of fluid or pressure from a well used in low-pressure applications
Surface casing	Shallow protective pipe permanently installed in a well to isolate fresh water-producing intervals and to avoid sloughing into the wellbore as drilling advances (Note: surface casing is often fairly large-diameter pipe set after the conductor and usually cemented back to the surface in onshore applications)
Surge	Increase in BHP in a wellbore when running pipe due to friction created in the annulus when the pipe and attached tools are run too fast for fluid in the hole to flow upward around the pipe creating a friction pressure below the base of the pipe string
Swab	Lowering BHP in a wellbore when pulling pipe and attached tools too rapidly for fluid in the annulus to flow beside the pipe to replace the pipe volume being pulled
Synthetic-based mud	An emulsion in which a synthetic oil-like fluid is the continuous phase used as a drilling, completion, or

	workover fluid having properties conducive to working on the particular well
Tensile force/tensile load	Pulling force acting axially along a pipe string in a well or at the surface; stretching force
Tensile strength	Maximum load a metal object can withstand without fracturing or tearing under stress
Tolerance	Maximum deviation allowed by an object's specifications; the ability of one material to withstand the presence of another in, say, an emulsion
Torque	Torsional moment that applies a twisting load to an object about its axis of rotation
Total depth (TD)	Maximum well length measured along the well path; maximum well depth
Traveling head/traveling frame	A heavy frame, usually steel, connected to the top of the hydraulic rods that reciprocates vertically carrying the traveling slips and hydraulic rotary table along with other traveling devices
Traveling slips	The slip set connected to the traveling head that reciprocate along with the motion imparted by the hydraulic cylinder(s) on a hydraulic rig
Trip	Deployment or retrieval of a string of pipe into or out of a well (Note: a round trip is the complete retrieval of the entire pipe string from the well followed by complete deployment of the string back to bottom)
Tubing	A retrievable tubular item installed in a wellbore for a variety of purposes, usually for the production of hydrocarbons or injection of various fluids into a downhole formation
Turbine	A downhole motor that uses vanes fitted at a precise angle to the axis of the device through which fluid is pumped to provide rotary motion to a central shaft
Twist	Turning of one item about another during rotation; the resultant rotary force from attempting to rotate pipe against friction
Umbilical	A collection of tubes, pipes, conductors, and control lines inside a polymer matrix surrounded by flexible steel armor used to connect surface and subsurface facilities and control panels
Unloader	A tool that bypasses fluid from the high-pressure to the low-pressure side of a device or system when pressure reaches a preset high-level limit and then returns

	to its original configuration when internal pressure falls below that set point.
Unloading	Removal of fluid from a well (see "jetting")
Underbalanced	The condition in which wellbore pressure is less than formation pressure
Underreamer	A device run in a BHA with expanding blades used to enlarge a hole behind a pilot bit or mill of smaller diameter usually below some restricted ID portion of the well such as a casing shoe
Valve	A binary, on-off device used to control the flow of fluid and pressure
Vane pump	A device using specially designed impeller components that provides high-pressure fluid at significant flowrates
Viscosity	The property of fluids that causes them to resist flow
Wall thickness	The finished difference between the tube OD and its ID
Water-based mud (WBM)	A drilling, workover, or completion fluid composed of water with both chemical and inert additives having the proper fluid properties and density for its intended use
Wear sleeve/wear guide	A hardened circular component surrounding the piston or rod in a hydraulic cylinder that centers the device inside the cylinder or head to assure adequate seal contact and to prevent excessive nonuniform seal wear due to side friction with consequential leakage
Weight indicator	Hydraulic or electric device used to measure the weight of a string of pipe suspended in a well (Note: when snubbing, the weight indicator must be capable of measuring the snubbing force and hanging weight)
Weight on bit	Downward force being applied to the cutting surface of the bit or mill whether from drill string weight, pulldown force, or other applied push on the bit face
Weld	Fusion of two metal parts at high heat with or without the introduction of a filler metal
Wellhead	Hollow metal cylinder equipped with shoulders or cavities for hanging casing strings and side outlets for installing valves to control fluid flow and pressure in various annuli created by concentric pipe strings in a well
Wellbore/well	A relatively small-diameter hole drilled into the earth's surface using any of a variety of means either percussive or rotary

Well, injection	A well designed and equipped to provide a conduit for the purpose of pumping pressured fluid into a formation for a variety of purposes to aid in hydrocarbon production from producing wells
Well, gas	A producing well designed to bring primarily gas and associated products such as condensate and water from the formation to the surface for processing and sale
Well, producing	A well designed and equipped to allow for the flow of hydrocarbons from the reservoir to the surface for sale
Whipstock	A metal wedge set in a wellbore used to increase deviation angle or to initiate sidetracking at a particular point within the well
Wireline	A general name given to a flexible line that can be lowered into and recovered from a well such as slickline (solid wire), braided line (strong cable with multiple solid wire strands woven together), or electric line (cable composed of multiple internal conductors surrounded by a polymer sheath protected by a woven wire outer wrap that may also be surrounded by flexible metal armor)
Work basket	An elevated platform surrounded by protective handrails mounted on top of the cylinders on a hydraulic rig containing control consoles in which the rig operators are located during operations (Note: each worker in the work basket must have access to an emergency escape device or system)
Workover	A major intervention into a completed well, usually involving a breach of the existing primary barrier envelope, to improve, restore, or sustain production or injectivity (Note: includes acidizing, fracturing, cleaning out, fishing, and all other such significant well work)
Yield point	The stress at which a significant increase in deformation occurs with a limited increase in stress loading; also, the point where permanent deformation occurs

Appendix C: Seal Materials and Elastomers

C.1 NITRILE (BUNA-N, NBR)

Nitrile rubber is the general term for acrylonitrile butadiene terpolymer. Buna rubber was originally developed during World War II by Phillips Petroleum Company and manufactured at their Bunavista copolymer plant north of Amarillo, near Borger, Texas. It was used as a substitute for natural rubber, primarily for automobile and truck tires, when mixed with carbon black. It is a copolymer of butadiene and styrene.

The acrylonitrile content of various nitrile seals varies considerably (18%–50%) and influences the physical properties of the finished material. The higher the acrylonitrile content, the better the resistance to oil and petroleum-based fuels. At the same time, elasticity and resistance to compression set are adversely affected. In view of these opposing properties, a medium acrylonitrile content is usually selected for O-rings and cylinder seals.

Nitrile has good mechanical properties when compared with other elastomers especially high wear resistance. It is one of the most popular materials for O-rings, hoses, and other rubber goods including BOP ram packers. Nitrile is not resistant to weathering and ozone. O-rings and seals must be stored in protected areas away from electric equipment (motors, switchgear, etc.).

C.1.1 Heat Resistance

- Up to 212°F (shorter life up to 250°F)

C.1.2 Cold Flexibility

- Depending on individual O-ring composition, between −30 and −70°F

C.1.3 Chemical Resistance

- Aliphatic hydrocarbons (propane; butane; and petroleum-based oils including hydraulic fluid, mineral oil, and diesel fuel), vegetable and mineral oils, and most greases
- Dilute acid, alkali, and salt solutions at low temperatures
- Water up to 212°F

C.1.4 Not Compatible With the Following

- Aromatic hydrocarbons (e.g., benzene and toluene)

- Chlorinated hydrocarbons (e.g., trichloroethylene)
- Polar solvents (e.g., ketone, acetone, acetic acid, and ethylene esters)
- Strong acids (e.g., HCL, HF, and H_2SO_4)
- Glycol-based hydraulic fluid
- Ozone, weather, and atmospheric aging

C.2 EPDM (ETHYLENE PROPYLENE DIENE, EPD, M-DESIGNATION)

Ethylene propylene diene (EPD) is a synthetic rubber, a terpolymer of ethylene and propylene, and a diene component (e.g., dicyclopentadiene and ethylidene norbornene). The "M" refers to its classification in ASTM standard D-1418. The "M" class of synthetic rubbers has a saturated chain of the polymethylene type. EPDM is particularly useful with phosphate ester and glycol-based hydraulic fluids ("green" fireproof fluids).

The ethylene content is around 45%–85% with the higher content improving loading, mixing, and extrusion properties. The terpolymer is often cross-linked with peroxide giving it a higher density. The diene content provides resistance to tackiness, creep, and flow during use. It is also resistant to ozone, atmospheric aging, and weather.

C.2.1 Heat Resistance

- Up to 300°F but can be formulated with higher densities for use up to 400°F

C.2.2 Cold Flexibility

- Down to approximately −60°F

C.2.3 Chemical Resistance

- Glycol and phosphate ester hydraulic fluids and silicone dielectric greases
- Many organic and inorganic acids
- Cleaning agents, soda, and potassium alkalis
- Chlorinated hydrocarbon solvents (e.g., trichloroethylene)
- Many polar solvents (e.g., alcohols, ketones, and esters)

C.2.4 Not Compatible With the Following

- Aliphatic petroleum-based products (e.g., lubricating oils, gasoline, kerosene, aromatic hydrocarbons, and greases)

C.3 NEOPRENE (POLYCHLOROPRENE, CR)

Neoprene refers to a family of synthetic rubbers produced by the polymerization of chloroprene. It was the first synthetic rubber developed commercially by DuPont in the 1930s. It was originally marketed as "DuPrene," but it contained by-products that produced a foul odor. Once these were removed, the material had a considerable number of advantages over natural rubber.

It has many uses including electric insulation, orthopedic devices such as braces, corrosion-resistant coating, and reinforced rubber products such as fan belts. It is also used for hoses and BOP ram packers in the oil field along with O-rings and other seals. It has good resistance to ozone, atmospheric aging (i.e., better than nitrile), and many chemicals and solvents. It also has good mechanical properties over a wide temperature range.

Neoprene can be foamed in either closed cell (waterproof) or open cell (breathable) configurations. One of the most common home products for foamed neoprene is the ubiquitous mouse pad.

C.3.1 Heat Resistance

- Up to 250°F in normal service. Burn point is 500°F.

C.3.2 Cold Flexibility

- Down to approximately −40°F

C.3.3 Chemical Resistance

- Paraffin-based (long, straight-chain petroleum) mineral oils
- Silicone oils and greases
- Water-based at low temperatures
- Carbon dioxide

C.3.4 Limited Compatibility

- Naphthalene-based mineral oil
- Low-molecular-weight aliphatic hydrocarbons (e.g., propane and butane)
- Glycol-based hydraulic fluids

C.3.5 Not Compatible With the Following

- Aromatic hydrocarbons (e.g., benzene and toluene)
- Chlorinated hydrocarbon solvents (e.g., trichloroethylene)
- Polar solvents (e.g., ketones, esters, ethers, and acetone)

C.4 SILICONE (VMQ)

The term silicone covers a large group of materials known as polysiloxanes in which vinyl-methyl-silicone (VMQ) is often the central ingredient. The silicone family was originally developed in 1901 to describe polydiphenylsiloxane. The "phenyl" component was actually ketone benzophenone that was copolymerized with the siloxane component to form the original material that was known as "silicoketone." The silicone group is often confused with the element silicon, a crystalline metalloid. Silicones may contain some silicon atoms along with carbon, hydrogen, oxygen, and other atoms added to the siloxane to alter its properties.

Silicone elastomers as a group have relatively low tensile strength and poor tear and wear resistance. However, they have good heat resistance, good cold flexibility, good ozone and weather resistance, and good insulating properties. They are physiologically neutral (inert in the human body), and they do not support microbiological growth.

C.4.1 Heat Resistance

- Up to 400°F (special silicones are resistant up to 450°F)

C.4.2 Cold Flexibility

- Down to −75°F (special silicones down to −175°F)

C.4.3 Chemical Resistance

- Most petroleum-based lubricating oils
- Animal and vegetable oils and greases
- Glycol and phosphate ester hydraulic fluids (green and fire-resistant)
- High-molecular-weight chlorinated aromatic hydrocarbons
- Dilute salt solutions

C.4.4 Not Compatible With the Following

- Superheated water steam over 250°F
- Acid and alkali solutions
- Low-molecular-weight chlorinated hydrocarbons (e.g., trichloroethylene)
- Aromatic mineral oils
- Hydrocarbon-based fuels
- Aromatic hydrocarbons (e.g., benzene and toluene)

C.5 VITON (FLUOROCARBON, FKM)

Viton is a family of elastomers comprising copolymers of hexafluoropropylene and vinylidene fluoride, terpolymers of tetrafluorine ethylene, vinylidene fluoride, and hexafluoropropylene. The fluorine content of the most common grades of Viton is between 66% and 70%. There are four families of Viton polymers with each having special properties and uses. Viton is a registered trademark of The Chemours Company.

Fluorocarbon synthetic rubber has excellent resistance to high temperatures, ozone, oxygen, mineral oil, synthetic hydraulic fluids, fuels, aromatics, and many organic solvents and chemicals. It has replaced Buna-N rubber goods in several applications such as O-rings in compressed air systems used in scuba diving and in surgical gloves. Low-temperature resistance is often limited to about −15°F. Gas permeability is very low, so explosive decompression is rare.

Special Viton formulations exhibit an improved resistance to acids, fuels, water, and steam. Viton has good ozone resistance and is not susceptible to excessive degradation due to weather and sunlight.

One special precaution is required. In a fire or very high-temperature service, Viton may release toxic hydrogen fluoride. Waste materials and old seals should not be burned without proper personal protective equipment.

C.5.1 Heat Resistance

- Up to 400°F

C.5.2 Cold Flexibility

- Down to −15°F (special formulations down to −40°F, useful for Arctic operations)

C.5.3 Chemical Resistance

- Mineral oils and greases
- Nonflammable hydraulic oils
- Silicone oils and greases
- Mineral and animal oils and greases
- Aliphatic (straight-chain) hydrocarbons (e.g., various fuels, butane, propane, and natural gas)
- Aromatic hydrocarbons (e.g., benzene and toluene)
- Chlorinated hydrocarbons (trichloroethylene and carbon tetrachloride)

C.5.4 Not Compatible With the Following

- Glycol-based hydraulic fluids
- Ammonia gas, amines, and alkali solutions
- Superheated steam
- Low-molecular-weight organic acids (e.g., formic acid and acetic acid)

C.6 POLYURETHANE (AU, EU)

Polyurethanes are polymers composed of organic units joined by carbamate (urethane) links. Polyurethanes may be thermosetting (these do not melt when heated) or thermoplastic (remain flexible). Obviously, O-rings, seals, and other parts belong to the latter group. Traditionally, these polymers were formed by reacting di- or polyisocyanate with a polyol. Isocyanates are highly toxic, so non-isocyanate polyurethanes were developed to mitigate health risks.

There is some confusion in the industry regarding what is in polyurethane. Another material, ethyl carbamate, is also called urethane. Polyurethane neither contains nor is made from ethyl carbamate. One must also differentiate between polyester urethane (AU) and polyether urethane (EU). AU type urethanes exhibit better resistance to hydraulic fluids. Both have a wide range of uses from foams to tires and wheels on roller coasters, elevators, and shopping carts. Microcellular foams are used for seals and gaskets and for adhesives. Other uses include coatings and sealants. Synthetic fibers are used for flexible clothing (e.g., Spandex), carpets, and hoses.

Polyurethane elastomers, as a class, have excellent wear resistance, high tensile strength, and high elasticity in comparison with any other elastomers. They are generally ozone- and weather-resistant.

C.6.1 Heat Resistance

- Up to approximately 180°F

C.6.2 Cold Flexibility

- Down to approximately −40°F

C.6.3 Chemical Resistance

- Pure aliphatic hydrocarbons (e.g., propane, butane, and most fuels)
- Mineral oils and greases
- Silicone oils and greases
- Water up to 125°F (EU type)

C.6.4 Not Compatible With the Following

- Ketones, esters, ethers, alcohols, and glycols
- Hot water, steam, alkalis, amines, and acids

C.7 FLUOROSILICONE (FVMQ)

Fluorosilicone rubber, or fluorovinylmethylsiloxane, is modified silicone rubber compounds. They contain trifluoropropyl groups next to the methyl groups found in silicone polymer chains. The material was developed by Dow Corning under the trademark Silastic® (a combination of "silicone" and "elastomer") in 1948.

Their mechanical and physical properties are very similar to silicone rubber. However, fluorosilicone offers improved fuel and mineral oil resistance and better cold flexibility. They have excellent resistance to ozone, oxygen, and weathering. Like the silicones, they have low tensile strength and poor tear and abrasion resistance along with high gas permeability. They are often used in the aerospace industry because of their resistance to most oils and their low-temperature performance.

C.7.1 Heat Resistance

- Up to 350°F max

C.7.2 Cold Flexibility

- Down to approximately −100°F

C.7.3 Chemical Resistance

- Aromatic mineral oils
- Most common fuels
- Dilute diester oils, aliphatic and aromatic fluorocarbons, and silicone oils
- Low-molecular-weight aromatic hydrocarbons (e.g., benzene and toluene)

C.8 AFLAS (TETRAFLUOROETHYLENE PROPYLENE, FEPM)

Aflas is a copolymer of tetrafluoroethylene (best known as Teflon) and propylene with a fluorine content of approximately 54%. It was developed in 1975 by Asahi Glass Co., Ltd. It is best known for its high-temperature resistance and is often used in engines and other similar uses. Its chemical resistance is excellent across a wide range of aggressive media. It also has high electric resistivity and low gas permeability making it useful as an insulating material in wires and cables.

C.8.1 Heat Resistance

- Up to approximately 450°F in continuous use

C.8.2 Cold Flexibility

- Down to about 25°F (but physical properties are maintained)

C.8.3 Compatible With the Following

- Strong acids and bases
- Phosphate ester-based hydraulic fluid
- Amines included in many corrosion inhibitors
- Petroleum-based engine oils and lubricants
- Hot water and steam

C.8.4 Not Compatible With the Following

- Aromatic fuels
- Ketones
- Carbon tetrachloride

C.9 KALREZ (PERFLUOROELASTOMER, FFKM)

The name "perfluoroelastomer" is somewhat misleading. An actual perfluorinated material with a high molecular weight is polytetrafluoroethylene or PTFE, which has the chemical formula "$(CF_2)_n$." Perfluoroelastomer is produced by the copolymerization of tetrafluoroethylene (trade name, Teflon) and a perfluorinated ether (e.g., perfluoromethylvinylether). Kalrez is a tradename of the elastomer family belonging to DuPont.

Kalrez is resistant to over 1800 different chemicals. The extraordinary chemical resistance is due to the fluorine atoms shielding the carbon chain and partially due to the vulcanization system. O-rings, gaskets and other seals, and diaphragms are composed of carbon black-filled products of Kalrez. They are widely used in the oil field and in the chemical manufacturing industry.

C.9.1 Heat Resistance

- Up to 600°F depending on specific compound

C.9.2 Cold Flexibility

- −40°F (Kalrez Spectrum 0040)

C.9.3 Chemical Resistance

- Aliphatic and aromatic hydrocarbons
- Chlorinated hydrocarbons
- Polar solvents (e.g., acetone, methylethylketone, and diethylether)
- Inorganic and organic acids (e.g., nitric and sulfuric acids)
- Bases (e.g., ammonium hydroxide)
- Amines (e.g., ethylene diamine)
- Aldehydes (e.g., n-butyraldehyde)
- Hot water and steam

C.9.4 Not Compatible With the Following

- Certain fluorinated refrigerants (e.g., R11, R12, and R13)

Appendix D: Seal Types and Shapes

(Courtesy Parker Hannifan Corporation)

Seals for Rods	
Profile	**Description**
BD 	Premium nonsymmetrical O-ring-energized rod seal with a knife-trimmed primary lip and knife-molded secondary lip. Preferred material is 4300. Additional materials include 4301 and 5065
	BD profile with positively actuated backup. Preferred material is 5065 with 4655 backup
BT 	Premium nonsymmetrical U-cup rod seal with a knife-trimmed primary lip and knife-molded secondary lip. Preferred material is 4300
BR 	Premium knife-trimmed buffer or secondary seal designed to work with a primary rod seal for heavy-duty or zero-leak systems. Preferred material is 4300
B3 	Nonsymmetrical U-cup with a knife-trimmed lip. Standard materials include 4300, 4700, and 5065
BS 	Nonsymmetrical U-cup rod seal with a knife-trimmed primary lip and a knife-molded secondary lip. Standard materials are 4300 family, 4700, and 5065
UR 	Standard nonsymmetrical U-cup with a trimmed lip. Standard material is 4615
E5 	Nonsymmetrical low-friction rounded lip pneumatic rod seal. Standard materials include 4274, 4180, 4208, and 5065
TR 	Bidirectional rod "T-seal" available in no backup, single backup, and two backup O-ring groove sizes. Standard energizer materials include 4115, 4274, 4205, and 4259. Backups available in Nylon, PTFE, and PEEK
ON 	Bidirectional, rubber energized PTFE cap rod seal. Full range of energizer and PTFE materials available
CR 	Bidirectional, low profile, rubber energized PTFE cap rod seal designed to fit standard O-ring glands. Full range of energizer and PTFE materials available
OC 	Standard bidirectional rubber energized rectangular PTFE cap rod seal. Full range of energizer and PTFE materials available
OD 	Unidirectional rubber energized PTFE rod seal, typically used as a buffer or secondary rod seal. Full range of energizer and PTFE materials available
V6 	Pneumatic cushion or check valve rod seal used to cushion the piston using internal pressure. Standard materials include 4622, 4180, 4181, and 4208

(Continued)

(Courtesy Parker Hannifan Corporation) *Continued*

Seals for Rods

Profile		Description
OR		Bidirectional rubber energized PTFE rod seal used in rotary or oscillating applications. Full range of energizer and PTFE materials available
SPP		Standard PolyPak. A square-shaped symmetrical squeeze seal with a knife-trimmed scraper lip. Standard materials include 4615, 4622, 4651, 4263, 4207, and 4266
DPP		Deep PolyPak. A rectangular-shaped symmetrical squeeze seal with a knife-trimmed scraper lip. Standard materials include 4615, 4622, 4651, 4263, 4207, and 4266
BPP		Type B PolyPak. A rectangular-shaped symmetrical squeeze seal with a knife-trimmed beveled lip. Standard materials include 4615, 4622, 4651, 4263, 4207, and 4266
8400 8500		Symmetrical rubber U-cups used primarily in pneumatic applications. 8400 series feature knife trimmed with a beveled lip. 8500 series feature a straight cut scraper lip. Preferred material is 4180. Additional materials include 4274 and 4208
SL		A dual lip seal created by the combination of a standard square PolyPak shell and a rubber lip seal/energizer. Standard materials are a 4615 shell and 4180 lip seal/energizer. Also known as SCL-Pak
US		Standard symmetrical U-cup with trimmed beveled lips. Standard material is 4615
AN 6226		Industry standard symmetrical U-cups per the old Army Navy (AN) specification. Standard material is 4295

Seals for Pistons

Profile		Description
BP		Premium bidirectional rubber energized urethane cap piston seal. Preferred material is 4304
PSP		Standard bidirectional rubber energized urethane cap piston seal. Preferred material is 4622. Additional material includes 4300
CT		Four-piece capped “T-seal” piston seal made from molded rubber energizer, PTFE cap, and 4655 backups
OK		Bidirectional rubber energized step-cut nylon cap piston seal
PIP		Bidirectional piston seal created by the combination of a PIP Ring pressure inverting pedestal backup ring and Type B PolyPak. Standard material is a 4615 PolyPak with a 4617 PIP Ring
B7		Premium nonsymmetrical U-cup with knife-trimmed lip piston seal. Standard materials include 4300, 4700, and 5065
UP		Standard nonsymmetrical U-cup with trimmed beveled lip piston seal. Standard material is 4615

(Courtesy Parker Hannifan Corporation) *Continued*

Seals for Pistons

Profile	Description
E4 	Nonsymmetrical low-friction rounded lip pneumatic piston seal. Standard materials include 4274, 4180, 4208, and 5065
BMP 	Low-friction bumper and round lip seal profile for use in pneumatic applications. Standard materials include 4283, 4274, and 4208
TP 	Bidirectional piston "T-seal" available in no backup, single backup, and two backup O-ring groove sizes. Standard energizer materials include 4115, 4274, 4205, and 4259. Backups available in Nylon, PTFE, and PEEK
S5 	Economical medium duty bidirectional O-ring-energized PTFE piston seal. Standard material is 0203 15% fiberglass-filled PTFE with nitrile energizer. Split option available
R5 	Medium to heavy-duty bidirectional lathe cut energized PTFE piston seal. Full range of energizer and PTFE materials available. Split option available
CQ 	Bidirectional three-piece lathe cut energized PTFE cap piston seal with an integrated quad seal for zero drift. Also available with dual O-ring energizer
OE 	Bidirectional, rubber energized PTFE cap piston seal. Full range of energizer and PTFE materials available
OG 	Unidirectional rubber energized PTFE piston seal, typically used as a buffer or secondary piston seal. Full range of energizer and PTFE materials available
CP 	Bidirectional low profile, rubber energized PTFE cap piston seal designed to fit standard O-ring glands. Full range of energizer and PTFE materials available
OA 	Standard bidirectional rubber energized rectangular PTFE cap piston seal. Full range of energizer and PTFE materials available
OQ 	Bidirectional rubber energized PTFE piston seal used in rotary or oscillating applications. Full range of energizer and PTFE materials available

Wiper Seals

Profile	Description
YD 	Premium snap-in wiper with OD exclusion lip and a knife-trimmed wiping lip. Preferred materials are 4300, 4301.
SHD 	Slotted heel snap-in wiper for pneumatics and light to medium duty hydraulics. Preferred materials are 4615 and 5065. Additional materials include 4263, 4208, 4207.
SH959 	An industry standard slotted heel Army/Navy (AN) wiper designed to fit MS-28776 (MS-33675) grooves. Standard materials are 4615, 5065.

(Continued)

(Courtesy Parker Hannifan Corporation) *Continued*

Wiper Seals		
Profile		**Description**
AH		Double-lip, press in place, metal canned wiper with knife-trimmed sealing lip for heavy-duty hydraulics. Standard materials are 4300, 4700, 4615.
J		Standard single-lip, press in place, metal canned wiper with a knife-trimmed lip for medium and heavy-duty hydraulics. Preferred material is 4700. Additional materials include 4300, 4615.
AY		Premium snap-in place double-lip wiper for hydraulic applications. Preferred materials are 4300, 4301. Additional material includes 4700.
H/8600		Standard snap-in place double-lip wiper. Standard materials for H wiper are 4615, 5065. Standard material for 8600 wiper is 4181.
AD		Double acting, double-lip, rubber energized PTFE wiper. Full range of energizer and PTFE materials available.
SHD		Slotted heel snap-in wiper for pneumatics and light to medium duty hydraulics. Preferred materials are 4615 and 5065. Additional materials include 4263, 4208, 4207.

Appendix E: Answer Keys for All Chapter Quizzes

CHAPTER 1

Chapter Quiz Answer Key

1. What is the definition of oil field snubbing?

   B. Pushing pipe into a well when expulsion for due to wellbore pressure exceeds the weight of pipe in the hole

   Snubbing only occurs during "pipe-light" conditions. Once the string becomes "pipe-heavy," the operation is called stripping.

   Distractors: Answer A. The use of a snubbing unit does not necessarily meet the requirement of pressure on the well or having pipe-light conditions. Answer C. When the string becomes pipe-heavy, additional pipe run in the well under its own weight is called stripping, not snubbing. There likely would not be much pushing involved. Answer D. Running pipe in the well implies no pressure on the well (i.e., a dead well job) where neither snubbing nor stripping would be involved.

2. How did oil field snubbing get its name?

   D. Nobody knows for sure

   The origins of this term have been lost over time and nobody can say for certain where the term came from. It could be a combination of all three of the distractors or it could have been from some other source.

3. What is the definition of stripping?

   C. Running pipe in the hole under pressure when the weight of the string exceeds the expulsive force on the pipe from wellbore pressure

   See explanation under Question 1. Stripping applies to pressured pipe running when the string weight in the hole exceeds expulsive force. The pipe is simply pulled into the hole under its own weight despite there being pressure on the hole. See discussion on distractors in Question 1.

4. Stripping requires the use of a snubbing unit.

   B. False___

   Stripping can be done without a snubbing unit at all because the conventional rig's hoisting equipment allows the pipe to be run under pressure with gravity providing the downward force on the string. This is often done in drilling operations to get the bit back to the bottom for kick circulation without rigging up a snubbing unit.

5. When was the first patent, also known as the Townsend patent, filed in the United States?

   A. 1924

   Townsend filed the first patent 5 ½ years before Otis filed his for the conventional, or cable-type, snubbing unit. It is not known whether Townsend's apparatus was ever built or used, but it was the first patent filed in the United States. Distractors are all fictitious.

6. The most important portion of the Townsend invention involved what device?

   B. The annular blowout preventer

   The multiple, metal-petal-supported rubber-coated fingers on Townsend's annular preventer would close on any shaped tubular of any diameter making it highly flexible in comparison to "pack-off" preventers that usually closed on one size of round pipe and had to be hand actuated using screws at the time. It also used well pressure below the closing piston. This design became the basis for the popular "Hydril-style" pressure-assist annular preventer still in use today.

   Distractors: Answer A. Hydraulic cylinders were used in the Minor patent but were not even required in the Otis patent. Answer C. Size of the apparatus was not mentioned in the Townsend patent as a reason for the invention. Answer D. While intended as a rig-assist unit, the Townsend invention could have been freestanding.

7. The first practical snubbing unit was invented, manufactured, and operated by whom?

   B. Herbert C. Otis

   Otis patented the first cable-style snubbing unit, manufactured it, and deployed it for use in the oil field. Otis became the "Father of Snubbing" as a result of his successful use of this snubbing unit.

   Distractors: Answer A. Townsend's apparatus was apparently not similarly deployed. Answer C. Minor's patent was later purchased by someone, possibly Otis, and deployed on wells. Answer D. It is not believed that Adair invented any apparatus involved with snubbing.

8. Work on two early Kettleman Hills North Dome Field wells clearly established snubbing as an attractive means for what overall purpose?

   C. Well control

   Snubbing was used on both of the early wells in the Kettleman Hills Field as a means to prevent flows while deepening and recompleting the two high-GOR wells to lower oil zones without killing the well. It was thought that killing would not be safe or practical on either well.

   Distractors: Answer A. Tubing could have been run in both wells using a conventional rig if the wells had been killed. Answer B. Both wells were drilled overbalanced, cased, and later perforated. They were not drilled underbalanced. Answer D. Regulatory intervention, if any, would likely have resulted in both wells being shut-in to avoid high-GOR production.

9. Using H. C. Otis' rule of thumb for snubbing to the balance point of a pipe string, how many feet of 2⅜ in., 4.7 lb./ft., EUE, 8rt tubing must be snubbed if well pressure is 5000 psi at the surface?

   C. 5000 ft.

   Otis' rule of thumb is that 1 ft. of pipe of any diameter must be snubbed for every psi of wellhead pressure to reach the balance point. It is still a good rule of thumb. Distractors are all fictitious.

10. Using H. C. Otis' rule of thumb for snubbing to the balance point of a pipe string, how many feet of 3 ½ in., 9.3 lb./ft., EUE, 8rt tubing must be snubbed if well pressure is 8000 psi at the surface?

B. 8000 ft.

See explanation on Question 9. Diameter is unimportant. Surface pressure is the only variable in Otis' rule of thumb. Distractors are all fictitious.

11. Ram-to-ram snubbing or stripping is a means to control well pressure while avoiding excessive wear to the upper ram packers.

B. False___

Ram-to-ram snubbing is used to move oversized portions of the string, including upsets and collared connections, through single-diameter rams in high-pressure operations. The process involves snubbing pipe into the hole until the upset is just above the upper ram (using the upper ram and causing more wear to the upper ram packer than the lower ram packer); closing the lower ram; snubbing the upset to the top of the lower ram, thereby "swallowing" the upset between the rams; closing the upper ram; and continuing to snub pipe until the next upset is encountered.

12. The Buck and Bangert patent for snub drilling filed in the early 2000s included the following significant features:

C. A hydraulic rotary table, rotating traveling slip, and a power tong for connections

This patent was the first to show the invention of a rotary table powered by four hydraulic motors on a planetary gear positioned below a set of traveling slips. This allowed the traveling slips to hold the weight of the string and still allow rotating motion. The patent also covered the use of a built-in power tong and a hydraulic backup tong for making connections as well.

Distractors: Answer A. Many early designs had a work basket so the unit operators could function slips, close BOPs, and observe slip sets and releases. This patent was not unique in that respect. Answer B. Jib poles have been in use for stand alone units since the 1960s. Answer D. The use of hydraulic cylinders for hoisting or snubbing pipe goes back to the Townsend patent in 1924.

13. When imparting rotary motion at the top of a hydraulic snubbing unit, the most serious concern involves

D. Twisting the hydraulic jacks due to reverse torque

This is one of the largest concerns because once a jack is twisted it can't be "untwisted." Damage to the alignment of the pistons, push rods, cylinders, and traveling head, even if only slight, prevents the hydraulic cylinders from moving through their entire range, and it may cause them to lock up entirely. The Buck and Bangert patent included four stationary alignment posts for vertical traveling head motion, thereby eliminating twisting motion.

Distractors: Answer A. The rotating equipment on most snubbing unit slowly rotates the string at 50–75 RPM. Answer B. Backing out over-torqued connections involves use of the power tongs or other devices and has nothing to do with the hydraulic rotary table under the traveling slips. Answer C. Rotary speed can influence penetration rate, but bit selection, hydraulics and lithology are often more important variables.

14. A rig-assist snubbing unit is required on a conventional rig for what reason?

A. To provide the capability for pushing pipe in the hole since the rig's hoisting gear usually cannot snub pipe

A conventional rig uses a block-and-tackle hoisting system that uses gravity to force pipe in the hole. It cannot pull pipe down into the hole, so a snubbing unit is required. It is not needed for the entire trip—only until the string becomes pipe-heavy. The rig can strip pipe without a snubbing unit.

Distractors: Answer B. The rig-assist unit is not needed to push pipe in the hole for the entire trip. Once the string becomes pipe-heavy, the rig can lower it by stripping through the BOPs, usually the annular. Answer C. This is a true statement, but that's not the primary reason the rig-assist snubbing unit is used. It is to snub pipe into and out of the hole with the string is pipe-light. Answer D. The rig-assist units are not operated by the drilling contractor's workers. It is a specialized piece of equipment that requires special skills and training.

15. A push-pull machine is a type of rig-assist snubbing unit.

A. True_____

Push-pull machines are used in low-pressure snubbing applications just for getting the pipe into and out of the hole using the rig's annular preventer for pressure containment. It generally does not have its own power supply but uses power supplied by the rig. The push-pull machine is not a stand alone snubbing device.

CHAPTER 2

Chapter Quiz Answer Key

1. What is one specific item that is required when using a snubbing unit?

D. An annular seal to trap pressure in the wellbore

If there is no annular seal, all surface pressure leaks off to the atmosphere, and there is no expulsion force acting on the pipe, so there is no need to snub the pipe. Distractors: Answer A. Hoisting of the traveling frame can be done without pressure on the well (e.g., an HWO unit). Answer B. Guy lines also may or may not be needed. They do not define why a snubbing unit is needed. Answer C. Dead well HWO units also have work baskets. This is also not a critical item for using a snubbing unit.

2. Two of the common components of a snubbing unit include

A. Traveling and stationary slips

Almost all modern snubbing units have one set of movable slips and one set of stationary slips. Distractors: Answer B. Some hydraulic snubbing units have four cylinders, not just two. Answer C. Many smaller snubbing units, especially rig-assist units, only have a single power-pack. Answer D. Neither an annular BOP nor a rotating head is required on every snubbing unit, and they are not common on every unit.

3. What is the name of the device used to prevent pressure and fluid from traveling up to the inside of the pipe being snubbed/stripped in the hole?

C. Float

A float is an internal check valve that allows fluid to be pumped down the pipe being snubbed, but it prevents fluid and pressure from moving up the pipe. There are usually *two or more floats installed in a pipe string during a snubbing job.* Distractors: Answer A. A bull plug will certainly prevent fluid from moving up the pipe, but it also cannot go down the pipe. Bull plugs are rarely run when snubbing pipe in the hole. Answer B. A packer seals the annulus between the pipe and the wellbore. It has no effect on pressure or fluid movement inside the pipe. Answer D. This is fictitious. The head could be any one of a number of devices, none of which impact the inside of the pipe.

4. In a conventional snubbing unit, the snubbing line is commonly strung from the traveling frame to what?

B. The rig's traveling blocks

The rig's traveling blocks hoist the power cable on a conventional snubbing unit. These blocks are tied through the "fast" line to the rig's draw works, but the rig's block-and-tackle hoisting system actually transfers the snubbing force to the power cable.

Distractors: Answer A. The traveling head is connected to the counterweights to keep tension on the system while lowering the rig's blocks. Answer C. The cable is indirectly connected to the draw works through the traveling and crown blocks, but it is not directly connected to the draw works. Answer D. There was one design considered for using a tugger for a stand alone snubbing unit that used a tugger connected to a frame above the snubbing unit. This is not the same as a conventional snubbing unit.

5. Traveling slips must be aligned with stationary slips to prevent slip lock.

A. True_____

Misaligned traveling slips caused by a tilted traveling frame (head) can cock the slips to one side making them very difficult to release, a condition known as slip lock.

6. Power is transmitted to the traveling frame of a hydraulic snubbing unit through which system?

D. All of the above

All of these are involved in producing the force necessary to operate the snubbing unit and allow it to hoist or snub pipe into or out of a well. The power-pack pressurized hydraulic fluid. The pressure is converted to a force by the hydraulic cylinders that moves the traveling head through a distance (work).

7. In remotely controlled hydraulic snubbing units, what function does the work basket perform?

C. None—it may not be present except for maintenance

In a remotely controlled snubbing system, there is no need for personnel to be located in a work basket since all the controls are in a van or trailer nearby. There may not even be a basket in a remotely controlled operation.

Distractors: Answer A. The operators are not stationed in the basket in a remotely controlled snubbing unit if there is a basket at all. Answer B. There is no need for escape devices since there are no personnel in the basket. Answer D. Again, no personnel in the basket, so all monitoring is done using video cameras and sensors.

8. The jib is a small crane with a mast attached to the snubbing unit base and hoist line powered by a hydraulic winch to lift relatively light loads.

A. True_____

Jibs lift light loads, usually <10,000 lb, during the snubbing job. They may not be able to handle heavier loads without exceeding their rated capacity.

9. What is a work window on a snubbing unit?

A. An open frame below the snubbing unit base and the safety BOP stack that allows access to pipe being snubbed into or out of the hole

The work window allows access to the string after it has been snubbed down by the traveling and stationary slips and before entering the BOP stack. It provides access to the pipe for inspection or attachment of external devices.

Distractors: Answer B. The elevated platform has a similar name, the work basket, where operators are stationed. Answer C. The work window and a weather window are two different things. The latter refers to the time in which favorable weather conditions exist for working on the well using a snubbing unit. Answer D. While there may be clear panels in the wind walls, these are not work windows.

10. Guy lines are used on tall snubbing unit stacks to provide a means of escape from the work basket (similar to the Geronimo line on a drilling rig).

B. False____

Guy lines secure tall snubbing stacks to ground anchors or pad eyes on the platform to prevent tipping and damage to these top-heavy units. The guy lines are not used for emergency escape. Other devices are used for this purpose.

11. What is the purpose of an equalizing circuit in ram-to-ram snubbing or stripping?

B. To ensure that the pressure between rams is the same and to vent pressure if the upper rams need to be opened

When snubbing out of the hole, the equalizing circuit allows pressure across the bottom snubbing BOP to be the same as well pressure to reduce flow across and damage to the lower BOP ram packer. It also provides a way to safely vent pressure below the top snubbing BOP to prevent venting fluids and pressure upward endangering personnel in the basket.

Distractors: Answer A. The equalizing circuit has nothing to do with pressure buildup inside the well. It's all external to the wellbore. Answer C. The hydraulic pressure is equalized by the power fluid circuit and the fact that all cylinders are connected through a manifold. Answer D. Same as Answer C. The equalizing loop is separated from the power fluid on the jack.

12. What features of the safety BOPs are necessary to provide the redundancy for safe snubbing operations?

A. Their rated pressure must be sufficient to control the highest surface pressure of the well encountered during snubbing operations.

Safety BOPs must have a rating that matches (less a safety factor) or exceeds the maximum pressure in the well. They may use pressured fluid from the power-pack to operate, but sometimes, they have sufficient stored pressured fluid in accumulator bottles. They are usually operated from a remote location instead of the basket in case all personnel evacuate the basket in an emergency. They are used on every snubbing job including rig-assist operations.

Distractors: Answer B. While the safeties may function from the snubbing unit's power fluid circuit, that has little to do with their purpose as standby safety devices. Answer C. Safeties are rarely operated from the basket to ensure that they can be operated if the basket must be evacuated in an emergency. Answer D. They are usually kept in standby mode except when needed for ram replacement or for closing on the stack as a safety device. They are not the primary device used in a snubbing job, but they are used.

13. Hydraulic rig-assist snubbing units have which of the following features?

D. All of the above

These rig-assist units have many of the same components and controls of a stand alone hydraulic snubbing unit except that pipe handling duties are performed by the rig in which the unit is installed.

14. A rig-assist hydraulic snubbing unit is used throughout the entire job to lower or to raise the pipe string even after the string becomes pipe-heavy.

B. False____

A rig-assist snubbing unit, whether hydraulic or push-pull, is only needed while the string is "pipe-light." Once the string becomes pipe-heavy, it is usually just stripped through an annular preventer without assistance from the snubbing unit. Sometimes, the rig-assist unit is dismantled and demobilized once the string goes pipe-heavy.

15. What components of a hydraulic rig-assist snubbing unit are NOT commonly deployed and used on a snubbing job?

C. A jib and hydraulic winch

A jib is not needed since pipe handling is done by the rig. There is no room for the jib inside the derrick anyway. All the other components exist on a rig-assist unit just like they are on a stand alone snubbing unit. They are required for snubbing pipe into or out of a well under pressure.

CHAPTER 3

Chapter Quiz 1 Answer Key

Sections 3.1–3.2

1. A snubbing or HWO unit is a collection of hydraulic and mechanical devices each working to achieve a particular part of the snubbing job.

B. False______

A snubbing unit is a carefully designed system, not a collection of parts each of which is doing an independent task. All the parts work together to perform the work much like an internal combustion engine. The snubbing unit must be considered systemically.

2. A hydraulic cylinder converts fluid pressure acting on a piston/seal cross-sectional area into a force.

A. True ______

The cylinder converts pressure to a force that acts through a given distance, called a stroke, to provide work. The power-pack converts mechanical or electric energy at a pump into pressure that is then transferred to the cylinders through the hydraulic fluid.

3. What is the hoisting force exerted on a hydraulic cylinder rod with a 3 in. OD from 3000 psi hydraulic fluid acting on a piston with an OD of 4.875 in. inside a hydraulic cylinder with an ID of 5.0 in. (efficiency factor is 0.9)?

B. 53,015 lb_f

The hoisting or upward force, F_u, is found in Eq. (3.7). The ID of the cylinder is the critical dimension, not the OD of the piston.

Distractors: Answer A. The actual force delivered requires multiplication by the efficiency factor (unlike Answer C). Answer D. The OD of the cylinder is unimportant.

4. What hydraulic fluid pressure would be required to lift a 30,000 lb load with a 4 in. ID hydraulic cylinder having a piston OD of 3.9 in. and a 2 in. OD rod? Assume 85% efficiency.

C. 2809 psi

Equation (3.7) can be rearranged to provide the pressure required to lift a given load using a hydraulic cylinder.

Distractors: Answer A. The efficiency factor must be included in the denominator of the equation or a low pressure will be calculated. Answers B and D. Piston OD is not the critical dimension; cylinder ID is.

5. What piston diameter is required to lift a 40,000 lb. weight inside a 5.25 in. ID cylinder with a 3.5 in. rod using hydraulic fluid with a pressure of 1848 psi ignoring friction (i.e., efficiency factor = 1.0)?

E. None of the above

Pistons are undersized, so they can travel inside the cylinder. A set of seals fill the gap between the piston and the inner cylinder wall. Pressure acts on both the piston and the seals. So the cylinder ID is the critical dimension, not piston OD. It doesn't matter what the piston OD is.

6. What are three things that require additional hydraulic pressure to start a lift using a hydraulic cylinder compared with steady-state pressure in the middle of the lift?

D. Seal friction, rod/piston acceleration, and breaking static friction

When the cylinder is stationary, there is no piston seal or rod seal friction. These are only generated when the piston/rod set is moving. Static friction, which is always greater than dynamic friction, must be broken to initiate movement. There is an acceleration of the piston/rod set when starting from a standstill. All three require a bit more hydraulic pressure to start the piston/rod from a standstill.

7. The operator of a well wants to install a hydraulic lift so he can work on a pumping unit. The unit weighs 30,000 lb. He has a hydraulic pump that will produce 2000 psi power fluid. How large will be the cylinder ID necessary to lift his pumping unit? Assume an efficiency factor of 0.9.

A. 4.607 in.

Rewriting Eq. (3.7) allows backing into the cylinder ID for a given load, pressure, and efficiency factor. Note that this equation provides the square of the diameter, d^2. The square root of this value is the correct diameter. Also, the efficiency factor must be applied.

8. The pull-down force on a vertically mounted dual-acting hydraulic cylinder is determined by the hydraulic fluid pressure acting on the entire piston/seal cross-sectional area including the rod cross-sectional area.

B. False_____

The cross-sectional area for the pull-down or snubbing force, F_D, given by Eq. (3.9), does not include the area occupied by the rod.

9. What is the pull-down force (snubbing force) of a 6 in. diameter cylinder with a 5.125 in. ID, a piston OD of 5 in., and a rod OD of 2.5 in. with hydraulic power fluid having a pressure of 3000 psi? Assume an efficiency of 90%.

B. 42,445 lb_f

Equation (3.9) is used for this calculation.

Distractors: Answer A. This is for the piston diameter and not the cylinder ID. Answer C. Ignores 90% efficiency using piston diameter. Answer D. Fictitious. The cylinder OD that is unimportant in the calculation of snubbing force. The ID of the cylinder is the critical dimension.

10. A pulling unit has two hydraulic cylinders. Both are 6.5 in. OD with a 6 in. ID. One piston has an OD of 5.985 in., but the piston in the other cylinder is slightly undersized at 5.875 in., but it is equipped with oversized seal rings. Both cylinders have 3.0 in. rods. What is the snub force available for this unit if the power fluid has a pressure of 1000 psi? Assume an efficiency factor of 0.95.

B. 40,291 lb_f

The problem states that there are two cylinders. The total snubbing force is the sum of the force generated by both cylinders since both are supplying the force simultaneously.

Distractors: Answer A. Fictitious. Answer C. This is the sum of the two cylinders using piston OD instead of cylinder ID. Answer D. Does not include 95% efficiency factor.

11. The hoisting (upward) force and the snubbing (downward) force available in a concentric snubbing unit are theoretically identical.

A. True______

The piston/seal cross-sectional area is absent; the rod area and the upper and lower seal areas are all the same. So, the upward and downward forces generated by this type cylinder configuration should supply the same force in both directions.

12. Snubbing units are named or classified on what basis?

D. Maximum available hoisting force in thousands of pounds

The hoisting force is used to classify a snubbing unit. The pull-down force is about half of the hoisting force. For example, a 225 K snubbing unit has a hoisting capability of 225,000 lb. and a snubbing capacity of 120,000 lb.

13. Wear sleeves are installed on pistons in hydraulic jacks to provide which of the following?

D. All of the above

Wear sleeves provide all of these functions

14. A wiper seal performs which of the following functions?

A. Prevents particulate matter from getting inside the seal pack damaging the seals and the cylinder wall

The wiper seal "wipes" particulate matter off the rod or piston and prevents it from lodging between the tight seals and the cylinder ID where it could score the plating and damage the cylinder or rod.

15. Twisted snubbing units are not difficult to repair.

B. False_____

It is extremely difficult to "untwist" a twisted snubbing unit. The rods and/or cylinders are bent to the extent that the metal is permanently deformed and cannot be straightened. Even if it is, the metal loses part of its strength in the straightening process. Usually, all the rods must be replaced. The cylinders may also require replacement. The snubbing unit will be down during the repairs because excessive friction makes it almost impossible to use the snubbing unit after it has been twisted badly.

CHAPTER 3
Chapter Quiz 2 Answer Key
Sections 3.3–3.5

1. Three components of the traveling head on a snubbing unit include

   C. Jack plate, traveling slips, and hydraulic rotary table

   These three devices comprise most traveling heads. Other devices may be added such as an in-line power tong, video camera, and various position indicators.
2. All the cylinders on a hydraulic snubbing unit are attached to the jack plate.

   A. True______

   Regardless of the number of cylinders, they all must be connected to the jack plate to ensure that the combined force generated by them is transferred to the traveling slips.
3. The hydraulic rotary table is positioned above the traveling slips on the traveling head.

   B. False_____

   The rotary table is below the traveling slips. The rotary table must turn the traveling slips to impart rotation on the string supported by the slips. So, the slips rotate along with the pipe.
4. Hand-over-hand load transfers on a snubbing unit require which of the following?

   A. Stationary and traveling slips

   Hand-over-hand snubbing requires the alternate loading of the stationary and traveling slips
5. How does the snubbing unit translate between pipe-light and pipe-heavy snubbing with modern snubbing units?

   C. The snubbing unit operator swaps one paired set of the dual slip/bowls for the other when the load direction changes

   Most modern snubbing units have two sets of traveling slip/bowls and two sets of stationary slip/bowls. One of each is oriented conventionally (pipe-heavy), and one is inverted (pipe-light). These slip/bowl pairs are switched at the neutral point when the loading changes.
6. Which of the following describe snubbing BOPs?

   D. All of the above

   Snubbing BOPs are ram-type BOPs rated to manage the maximum wellbore pressure (with safety factor). They have a hardened ram packer insert that resists wear better than the normal soft elastomers used on other BOPs.
7. The stripping head can be used in high-well pressure applications.

   B. False_____

   The stripping head is only used for low-pressure snubbing/stripping applications or dead well workovers. It is not designed to contain high pressures. High pressures are best managed by ram-type BOPs.

8. What is the primary purpose of the stripping head?

B. Allows snubbing or stripping pipe without the use of the snubbing BOPs in low wellhead pressure or dead well operations

While the stripping head does clean or wipe the pipe, that is not its primary purpose. It is usually positioned below the snubbing unit on top of the annular preventer in the work window. Changing the inexpensive element components is easy and fast.

9. Ram-to-ram snubbing is what?

D. All of the above

These all describe ram-to-ram snubbing. Answer C. Is a true statement that ram-to-ram snubbing is not required for flush-jointed pipe.

10. What is the purpose of the equalizing and vent loops on a snubbing unit?

A. They provide a means to have equal pressure across a snubbing ram before it is opened or closed

The equalizing and vent loops place equal pressure across a ram before it is opened to avoid blowing out a seal or shocking the system with a sudden pressure increase resulting in damage or injury. This has nothing to do with hydraulic cylinder loading. It is not a means to lower well pressure by venting it to the flare pit.

11. The equalizing loop allows the unit operator to snub or strip pipe into or out of the hole through the stripping head or annular.

B. False_____

The equalizing loop is not involved in low-pressure or dead well snubbing/stripping through the stripping head or annular. Neither are the snubbing BOPs. The loop and the snubbing BOPs are not used at all during this type operation.

12. How is the equalizing loop configured?

A. From below the no. 2 snubbing BOP into the cavity between the no. 1 and no. 2 snubbing BOPs

The equalizing loop allows well pressure to be piped into the cavity between the snubbing BOPs to equalize across the no. 2 rams.

13. When is pressure bled from the cavity between the no. 1 and no. 2 snubbing BOPs?

C. After closing the no. 2 BOP rams and before opening the no. 1 BOP rams

Pressure must be bled from the cavity before opening the no. 1 rams. This lowers cavity pressure to atmospheric pressure to prevent pressure from being vented straight up into the basket and atmosphere.

14. Either snubbing BOP can be used as the primary BOP for snubbing jointed pipe into or out of the hole with the other BOP used only for dealing with connections in ram-to-ram snubbing.

A. True______

The unit operator can use either the no. 1 or the no. 2 snubbing BOP as the primary during snubbing operations. Some companies prefer to use one of the other routinely. Others alternate between them during the job. Using either one as the primary is an acceptable practice as long as the operation of the equalizing and vent loops conforms to the selected configuration.

15. Why do the equalizing loop and the vent loop contain in-line chokes?

D. All of the above

The chokes permit wellbore pressure to move at a measured, low flowrate to avoid water-hammer effect, shocking the system and blowing out seals. The choke size is selected to avoid icing and plugging inside lines. Valves are binary devices; they are either fully open or fully closed. Valves should not be used as choking devices (except for certain small needle valves and control valves).

CHAPTER 3

Chapter Quiz 3 Answer Key

Sections 3.6–3.9

1. A power-pack is being designed for a snubbing unit with a working pressure limitation on both cylinders of 2250 psi. The maximum hydraulic pump output pressure at the power-pack should be limited to what pressure?

B. 2400 psi

This provides an additional 150 psi for friction loss in hydraulic lines going to the snubbing unit. The maximum pressure at the control unit power fluid manifold can be controlled to 2250 psi or lower depending on needs. A lower pressure cannot be regulated up. There is no need to have a significantly higher pump maximum pressure from either an operational or economic standpoint.

2. Power-packs are usually equipped with flowrate control valve (unloader) and a release to control maximum pressure so the prime mover can operate at a constant speed during a snubbing job.

A. True______

The control valve allows the power-pack prime mover to run at a single speed with power fluid delivered to the snubbing unit according to need.

3. A single hydraulic cylinder has just been reconditioned and is being tested in the shop. The cylinder has a 4.21 in. OD, a 4 in. ID, and a piston OD of 3.894 in. It is connected to a hydraulic pump that can deliver 40 GPM. How fast will the cylinder rod stroke out?

B. 61 ft./min

See Eq. (3.11).

Distractors: The cylinder ID provides the correct dimension to determine the area upon which the pressure acts (not cylinder or piston OD, as in Answers A. and D.). Answer C. Fictitious.

4. A power-pack can deliver 300 GPM of hydraulic fluid to a four-cylinder snubbing unit at 2000 psi. How fast will the traveling head rise if the snubbing unit of each cylinder has an OD of 4.5 in., a 4 in. ID, and a piston OD of 3.95 in.?

B. 115 ft./min

See Eq. (3.13) that includes the number of cylinders (four in this problem).

Distractors: Note that if only two cylinders were involved, the operating velocity of the traveling head would be Answer D. All other answers involve the use of an incorrect dimension for cylinder ID, the critical dimension for hydraulic cylinders.

5. A snubbing services provider wants to pull tubing from a well with a slight pressure at the surface and compete with a conventional workover unit. This requires a traveling head hoisting speed of at least 150 ft./min. The snubbing unit has two cylinders each with an ID of 4.5 in. and a piston OD of 4.375 in. What power fluid flowrate must the power-pack deliver to achieve this required traveling head speed?
   D. 248 GPM
   Here, two cylinders are involved instead of four.
   Distractors: All other answers involve wrong dimensions.
6. The hydraulic pump in a power-pack delivers 250 GPM power fluid to a four-jack snubbing unit. Each cylinder has an OD of 4.75 in., an ID of 4.25 in., and a piston OD of 4.125 in. The required load on the traveling head while coming out of the hole is about half of the peak snubbing unit capacity, so the operator decides to cripple two cylinders. How fast will the traveling head move now?
   A. 170 ft./min
   From Eq. (3.13) with only two cylinders (two are crippled and require no power fluid).
   Distractors: Answer B. Uses the piston OD. Answer D. Uses only one cylinder. Answer C. Fictitious.
7. All power-packs have a single hydraulic pump regardless of whether that pump is run by a diesel engine or an electric motor.
   B. False_____
   Most power-packs have multiple hydraulic pumps that can be activated/deactivated through a multioutput transmission or by adding/deleting electric motors.
8. Desirable hydraulic fluid properties, whether oil- or water-based include which of the following?
   E. All of the above
   All of these are desirable characteristics of all hydraulic fluids.
9. A key to successful operation of any hydraulic system is an adequate supply of clean hydraulic fluid to all devices in the system.
   A. True______
   Emphasis is on "clean." Dirty fluid robs efficiency, increases wear, and results in early component failure and repair/overhaul.
10. The unit operator's control panel usually includes controls for what devices or variables?
    C. Jack direction, snubbing unit BOPs, and equalizing loop valves
    Power-pack hydraulic pump rate and pressure are never controlled from the basket as a safety concern. The safety BOP controls are situated on a separate panel, not the jack operator panel. They are not even present on most rig-assist units.
11. What device does the counterbalance panel operate?
    B. The jib main winch motor
    The snubbing BOP controls and the annular BOP/stripping head regulator are operated from the operator's panel. The power-pack kill switch is usually located on the jack operating panel or from a remote location not associated with any of the winches.

12. The safety BOPs can only be operated from the work basket on a snubbing unit to prevent accidental activation of a BOP by someone on the ground or deck.

    B. False_____

    The safety BOPs must have a remote operating panel located somewhere other than the basket so they can be closed in an emergency event when all personnel in the basket have escaped. If these controls were only located in the basket, there would be no way to close the safeties in an emergency.

13. Characteristics of data acquisition systems include the following:

    D. All of the above

    These are all characteristics of a snubbing unit data acquisition system (and of similar systems on other units).

14. An escape device for rapid evacuation of the work basket is required for each person in the work basket during a snubbing job.

    A. True______

    There must be an escape capability for everyone in the basket. This requirement may be satisfied by a common system, such as a slide, that provides escape for everyone in the basket.

15. The following describe a remotely operated snubbing unit

    D. Operators and control panels are located in a protected enclosure located some distance away from the snubbing unit

    The advantage of a remote controlled snubbing unit is that operators are removed from the work basket to a site that is protected. There may not be a work basket installed on these units at all. Visual observation is supplied through video cameras and live streaming feeds to monitors in the operator's cabin.

CHAPTER 4

Chapter Quiz 1 Answer Key

Sections 4.1–4.2

1. What is the theoretical expulsion force, ignoring friction, for 2⅜ in. OD tubing with a 1.995 in. ID in a well with 1400 psi surface pressure? Use nominal dimensions.

    C. 6202 lb_f

    Using Eq. (4.4), expulsion force is $F_e = p(0.7854)OD^2$. For this pipe diameter and pressure, $F_e = 6202\ lb_f$.

    Distractors: Answer A. Calculated with OD × pressure. Answer B. Uses the ID instead of the OD (ID does not come into play here). Answer D. Involves OD^2 × pressure without the conversion factor of $\pi/4$ (= 0.7854).

2. System friction does not need to be considered when calculating the actual maximum snubbing force based on expulsion force for the first joint of pipe being snubbed into a pressured well.

    B. False______

Snubbing always involves friction. Theoretical expulsion force does not include friction. Maximum snubbing force does. It also includes additional forces required to break static friction and to accelerate the pipe from a static position. Many jobs are delayed because a unit with insufficient snubbing capacity is selected without considering all the friction forces involved.

3. A joint of 2⅜ in. EUE 8rt tubing has a collar OD of 3.063 in. What is the maximum expulsion force that could be seen on the snubbing unit jack weight indicator when snubbing the first joint of pipe in the hole using the annular preventer in a well with 500 psi surface pressure? Assume 20% friction.

   D. 4421 lb_f

   If the pipe is being snubbed through an annular, it could close on the tubing collar. So, the wellbore pressure would be acting on the collar and not the pipe body. The additional 20% force would be required to push the collar below the annular, so the maximum snub force would include an additional 20% of the theoretical expulsion force.

   Distractors: Answer A. 2⅜ in. pipe with no friction. Answer B. 2⅜ in. pipe with friction. Answer C. 3.063 in. pipe OD without friction.

4. The first joint of 3½ in. flush-joint tubing being snubbed into a well with 3000 psi has a maximum OD of 3.531 in. If the snubbing rams exert 30% friction, what is the snub force that the unit must exert to snub this pipe into the well?

   D. 38,190 lb_f

   Same as above with similar distractors. Must calculate on the basis of maximum pipe OD and include additional 30% friction. There may be additional friction factors involved, but the problem says that 30% additional friction is needed. Chances are it would be closer to 50% in a real-life situation.

5. A string of new 4½ in. API tubing is going to be snubbed into a well under pressure. What tubing diameter should be used to calculate the expulsion force?

   D. 4.545 in.

   Table 4.1 (API Spec 5CT) shows that for tubing greater than or equal to 4½ in., the maximum OD used to calculate the expulsion force can be over by 1%. 4.5 in. × 1.01 = 4.545 in.

   Distractors: Answer A. 4.5–0.031 in. (minimum OD). Answer B. 4.5%–0.5% (minimum OD). Answer C. 4.5 + 0.31 (maximum ID for tubing <4½ in. OD).

6. What is the buoyancy factor for 12.2 ppg fluid?

   A. 0.814

   From Eq. (4.6), BF = (65.5–12.2)/65.5 = 0.8137.

   All distractors are meaningless.

7. A well is standing full of 13.3 ppg drilling mud. It has no surface pressure. A string of 2⅜ in. 4.7 ppf tubing with an ID of 1.995 in. is run in the well to 5000 ft. It is filled with 8.9 ppg produced water while being run. What is the buoyed weight of the tubing string using nominal dimensions?

   B. 15,422 lb_m

   From Eq. (4.10), $B = (13.3 \times 2.375^2 - 8.9 \times 1.995^2)/24.51 = 1.615$ *ppf. 4.7–1.615 = 3.084 ppf. 5000 ft. × 3.084 ppf = 15,422 lb.*

Distractors: Answer A. OD × 13.3/25.41, wrong value used for "B." Answer C. Wrong "B" using 8.6 instead of 8.9. Answer D. Fail to divide by 24.51.

8. The neutral point in a well is the length of pipe with a buoyed weight equivalent to the expulsion force including friction.

B. False_____

Friction is not included in the calculation of neutral point

9. Calculate the neutral point for a well with 2500 psi surface pressure that is full of 12.8 ppg drilling mud using 2⅞ in. 8.7 ppf and L-80 tubing that is filled with drilling mud as it is being run. Use nominal dimensions and assume friction of 30%.

B. 2319 ft.

$B = 0.805$. $(2500 \times 0.7854 \times 2.875^2)/(8.7 \times 0.805) = 2319\ ft$. Note that friction is ignored in neutral point calculations.

Distractors: Answer A. No buoyancy included in calculation. Answer C. Did not include $\pi/4 = 0.7854$. Answer D. Meaningless. Note: Answer B. Could have been selected from Otis' rule of thumb that the neutral point will be about 1 ft./psi wellhead pressure. 2319 psi is closer to 2500 psi than any of the other answers.

10. Pipe-on-wall friction can be calculated using the friction factor times the length of pipe in contact with the wall times the buoyed weight of pipe in all wellbore configurations.

B. False_____

This only works for horizontal segments. For all others, the force normal to the centerline of the hole is used for this calculation. In inclined holes, this is the sine of the deviation with vertical = 0 degrees. In curved segments, the value for the calculation comes from the capstan force.

11. What is the amount of pipe-on-wall friction associated with 2000 ft. string of 3½ in. 10.3 ppf flush-joint tubing being run in a straight vertical hole segment? Assume a friction factor of 0.35.

A. Zero (negligible)

In a vertical section, there is no normal weight acting on the pipe so there is no friction. In reality, there are no vertical holes, but at deviations less than about 10 degrees, the pipe-on-wall friction is negligible. All the distractors are fictitious.

12. A straight well with a deviation of 48 degrees (vertical = 0 degrees) is 4000 ft. long and has 3½ in. 10.3 ppf flush-joint tubing in it being snubbed in an open hole at 60 ft./min. The hole and tubing are both full of 10.0 ppg brine. What is the upward friction force exerted on the pipe from this straight inclined hole section while going in the hole? Assume a friction factor of 0.45.

A. 11,674 lb_f

Buoyancy factor is 0.8473. W_b is $10.3 \times 0.8473 = 8.7275$ ppf. The normal force is $8.7275 \times \sin(48°) = 6.4858$ ppf. $F = W_n \times C_f \times \Delta L = 6.4858 \times 0.45 \times 4000 = 11{,}674\ lb_f$.
Distractors include answers with no buoyancy and no friction factor.

13. A string of 4 in. OD, 3.476 in. ID 11.0 lb./ft. flush-joint tubing is being run to the end of a horizontal well segment that is 7500 ft. long. The hole is filled with 14.1 ppg drilling mud, and the tubing was filled with 8.7 ppg seawater while running it in the hole. What friction force can be expected from this hole section? Use nominal dimensions and assume a friction factor of 0.40.

A. 18,253 lb_f

Here, $W_n = W_b$. $B = 4.9156$ *ppf.* $W_b = 11.0 - 4.9156 = 6.0844$ *ppf.* $F = 6.0844 \times 0.40 \times 7500 = 18{,}253$ lb_f.

Distractors: Answer B. Seawater buoyancy only. Answer C. No buoyancy. Answer D. Fictitious

14. A string of 2⅞ in. 7.8 ppf, P-105 flush-joint tubing is being snubbed through a curved hole section with a downward force of 8500 lb_f. The well at the point of wall contact has an average deviation of 45 degrees and a radius of curvature of 0.003 rad/ft. The hole and pipe are both full of 12.0 ppg fluid. What friction is being exerted over the 100 ft. contact section? Assume a friction factor of 0.35.

C. 68,236 lb_f

Requires calculation of $BF = 0.8167$. $W_b = 0.8167 \times 7.8$ *ppf* $= 6.371$ *ppf.* $Sin(45°) = 0.7071$. *From Eq. (4.15),* $C_d = L_p[F_1\theta' + (W_b \ \sin\alpha_{avg})] = 100[8500 \times 0.003 + 6.371 \times 0.7071] = 1949.6$ lb_m. $F = C_d \times C_f \times L_p = 1949.6 \times 0.35 \times 100 = 68{,}236$ lb_f.

Distractors are all fictitious.

15. Upset end connections and/or collars have no impact on friction calculations in straight or curved hole segments.

B. False_____

They do have an effect by either decreasing or increasing friction depending on how much sag there is between connections. There is a considerable bending stress increase due to the additional moment from the upsets/collars supporting a portion of the pipe normal weight.

CHAPTER 4

Chapter Quiz 2 Answer Key

Sections 4.3.1–4.3.3

1. New 2⅞ in. 8.7 ppf L-80 API tubing is going to be snubbed into a well with 4000 psi surface pressure. This tubing has a nominal wall thickness of 0.308 in. What are the worst-case dimensions for snubbing considering the tolerances allowed by API Specification 5CT for this pipe in terms of OD, wall thickness, and ID (inches)?

C. 2.844, 0.269, 2.305

Min OD = (nom OD − 1/32 in.), min wall thickness = (nom × 0.875), max *ID = (min OD − 2 × min wall thickness).*

2. It is safe to use API used pipe specifications since they are conservative and will provide the worst-case scenario for job planning.

B. False______

API does not publish used pipe specifications at all. The operator must select a safety factor that is sufficiently conservative to provide adequate safety margins while snubbing with used pipe.

3. A special, non-API tubing string is to be snubbed into a well with 1500 psi surface pressure. The minimum pipe OD is 3.750 in. The maximum pipe ID is 3.30 in. The minimum wall thickness is 0.225 in. What is the radius of gyration for this pipe? Assume 20% friction.

A. 1.25 in.

Using Eq. (4.28) for r_g with Min OD and Max ID for both I and A_s.
Distractors: Answer D. is simply A^2 (1.25^2) without taking the square root of the product. Answer B. and Answer C. are fictitious.

4. The special pipe in the previous problem has Young's modulus of elasticity of 34×10^6 psi and a yield stress of 127,000 psi. What is its column slenderness?
D. 72.695
Using Eq. (4.27) for C_c.
Distractors: Answer A. Wrong equation used for SR_2. Answer B. Failure to multiply by π. Answer C. Failure to multiply by 2 inside the radical.

5. A string of new 4 ½ in. API tubing (ID = 3.958 in.) has a slenderness ratio of 35.4. It is pinned such that the *k* index is 1.2. What unsupported length is permissible for this pipe? Use nominal dimensions.
A. 44.2 in.
Use Eq. (4.31).
Distractors: Answer B. Does not include $k = 1.2$. Answer C. Does not take square root of the term inside the radical. Answer D. Improper calculation of r_g.

6. A planned snubbing job includes 2⅞ in. OD, 8.7 ppf, N-80 tubing with a nominal ID of 2.259 in., and an unsupported length of 10 in. the snubbing unit. The column slenderness ratio for this pipe is 84.59. The first effective slenderness ratio is 10.93. The second effective slenderness ratio is 10.54. What is the critical force to just initiate unconstrained buckling in the unsupported length will occur? Do not apply a safety factor (i.e., 100% of critical buckling force).
B. 174,200 lb_f
The first effective slenderness ratio controls as the larger value, so SR = 10.93. A_s must be calculated using min OD, min wall thickness, and max *ID. Note that C_c is calculated using Eq. (4.27) to be 84.59. SR is less than C_c, so Eq. (4.34) is used to calculate the critical force.*
Distractors: All fictitious.

7. A string of 2⅜ in. J-55 tubing is going to be snubbed in a well. The column slenderness ratio for this pipe is 102.02. The calculated value of SR = 108.79. The pipe has a minimum wall thickness of 0.16625 in., a maximum ID of 2.01125 in., and a radius of gyration of 0.7721 in. What is the permissible unsupported length for this pipe in the snubbing unit? Use a *k* factor of 1.0 for this calculation.
D. 84 in.
Equation (4.31) is used to determine the value of L_u at the conditions given. $L_u = SR \times r_g = 84$ in. since $k = 1.0$.

8. For the pipe in the question above, at what value of the unsupported length will the value of SR switch from SR_2 to SR_1 (i.e., at which value of L_u will the unsupported length become the dominate factor in the critical force calculation)?
C. 9.5 in.
Equation (4.36) is used here. The equations for SR_1 and SR_2 are set equal to each other and solved for L_u.
Distractors: All fictitious.

9. The pipe in Question 7 has a column slenderness ratio of 102.019. What is the critical buckling force for unconstrained buckling if the unsupported length is zero?

B. 62,060 lb_f

Both the calculations of A_s and R_p must be obtained from min OD, min wall thickness, and max ID. $As = 1.1373$ in.^{2}. $R_p = 1.08895$ in. Eq. (4.34) is used to calculate the critical unconstrained buckling load. All distractors are fictitious.

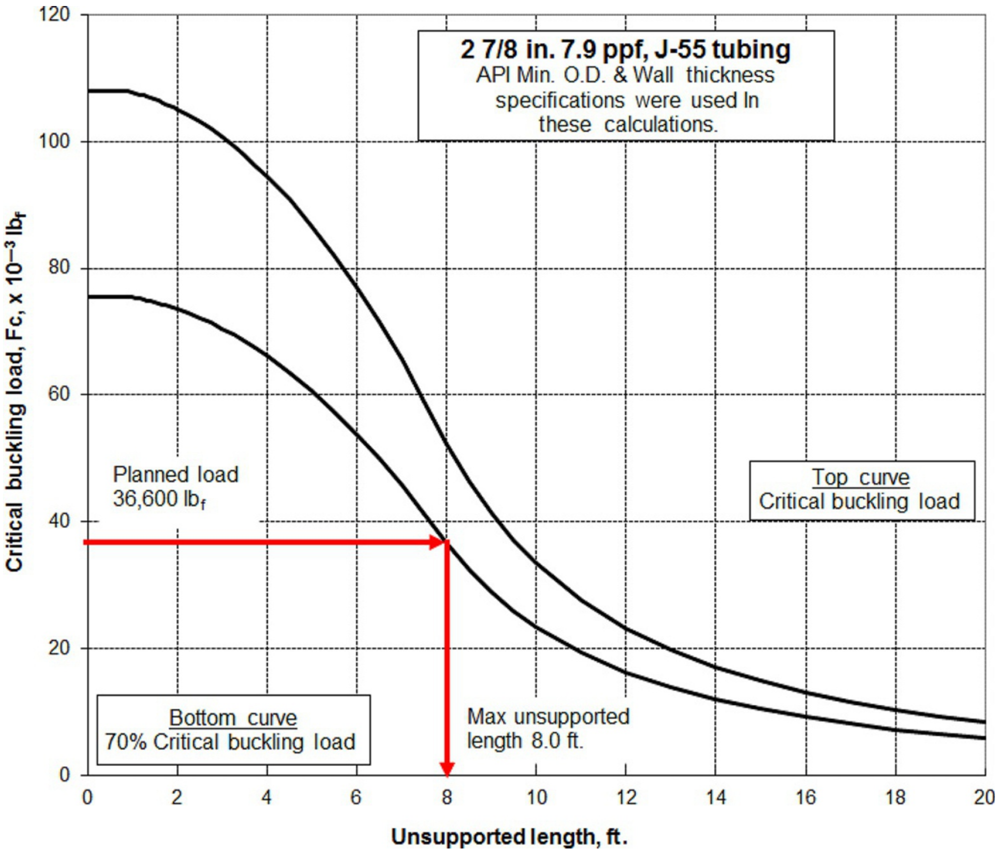
10. Unconstrained buckling in snubbing operations is a serious threat because the pipe can fold, break, and part somewhere in the unsupported length.

A. True______

Unconstrained buckling taken to failure can cause the pipe to fold, tear, break, and eject between the traveling slips and the no. 1 stripping BOP under high-load conditions. This endangers operating personnel, the environment, the surface equipment, and the well. If wellbore fluids escape during this event, there is a good probability of fire. If the well contains a toxic gas such as H_2S, personnel can be badly injured in a short time period.

11. Using the following diagram, determine the maximum unsupported length permitted for normal snubbing operations using a 70% safety factor for a maximum snub force of 36,600 lb_f.

C. 8.0 ft.



CHAPTER 4

Chapter Quiz 3 Answer Key

Sections 4.3.4–4.3.6

1. Constrained buckling occurs where there is a conduit in which the pipe is being run that only allows the pipe to move laterally a certain distance before encountering the inner wall of the conduit.

A. True______

The conduit provides the constraint. The only time this is not true is when small-diameter pipe is being run into a large-diameter hole. This can result in unconstrained buckling within a constrained environment.

2. 3½ in. flush-joint pipe with a maximum OD of 3.531 in. is being run inside 8⅝ in. casing with a drift ID of 7.796 in. What is the clearance radius for this configuration?

D. 2.133 in.

OD_{max} for 3.50 in. tubing is 3.5 + 1/32 or 3.531 from API Spec 5CT. Drift ID is 7.796 in. Must use these for correct constraint definition. From Eq. (4.37), $r_c = \frac{ID_{hole} - OD_{pipe}}{2} = 2.133$ in. Distractors: Answer A. Uses casing nominal OD (8.625, in., −3.5 in., for pipe OD)/2. Answer B. Uses casing nominal OD (8.625 in.−max pipe OD, 3.531)/2. Answer C. Uses casing drift ID, (7.796 in. −nom pipe OD, 3.5 in.)/2.

3. Two types of constrained buckling are

C. Sinusoidal and helical

Distractors: All fictitious.

4. A 2⅜ in. 4.7 ppf N-80 flush-joint tubing string with a nominal wall thickness of 0.190 in. is being run in a straight inclined 7 in. hole with a deviation of 51.3 degrees. Both the hole and the pipe are filled with 12.4 ppg drilling mud. What is the critical force to initiate buckling in this configuration? Assume Young's modulus of elasticity is 29.5×10^6 psi.

B. 10,176 lb_f

For this analysis, must calculate several variables including clearance radius, r_c; moment of inertia, I; and buoyed pipe weight, W_b. Factors in each of them require accounting for allowed pipe dimension tolerances:

$$OD_{max} = OD_{nom} + \text{tolerance} = 2.375 + 0.031 = 2.406 \text{ in.}$$

$$OD_{min} = OD_{nom} - \text{tolerance} = 2.375 - 0.031 = 2.344 \text{ in.}$$

$$t_{wmin} = t_{wnom} \times \text{tolerance} = 0.190 \times 0.875 = 0.166 \text{ in.}$$

$$ID_{max} = OD_{min} - 2(t_{wmin}) = 2.344 - 2(0.166) = 2.011 \text{ in.}$$

$$I = \pi\left(OD^4{}_{min} - ID^4{}_{max}\right)/64 = \pi\left(2.344^4 - 2.011^4\right)/64 = 0.678 \text{ in.}^4$$

$$BF = (65.5 - MW)/65.5 = 0.811$$

$$W_b = W_{air}(BF) = 4.7\,(0.811) = 3.81 \text{ ppf}$$

$$r_c = (7.0 - 2.406)/2 = 2.297 \text{ in.}$$

$$\sin\alpha = \sin(51.3) = 0.7804$$

From Eq. (4.42),

$$F_{cs} = 2\sqrt{\frac{EI\,\mathrm{x}\,(W_b)\sin\propto}{r_c}}$$

$$F_{cs} = 2\sqrt{\frac{29.5\,\mathrm{x}\,10^6(0.678)3.81(0.7804)}{2.297}}$$

$$F_{cs} = 10,176\,lb_f$$

Distractors: Answer A. Uses the nominal tubing diameter to calculate r_c instead of the $\mathrm{OD_{max}}$ including the 1/32 in. tolerance. Answer C. Uses the nominal pipe OD of 2.375 in. instead of the $\mathrm{OD_{min}}$ subtracting the 1/32 in. tolerance or 2.344 in. Answer D. Uses the nominal pipe weight/ft. of 4.7 ppf instead of the buoyed weight of the pipe in 12.4 ppg mud.

5. Assume that the well in the previous problem is a horizontal hole (i.e., deviation = 90 degrees). What is the critical force to initiate buckling in this configuration?

C. 11,520 $\mathbf{lb_f}$

Same equation as above but sinα = 1.0 for α = 90 degrees.

Distractors: Answer A. W_b = nominal pipe weight, 4.7 ppf, and includes sine (51.3 degrees) instead of sine (90 degrees) = 1. Answer B. Includes nominal pipe diameter in calculation of r_c. Answer D. Uses nominal pipe OD 2.375 in. instead of $\mathrm{OD_{min}}$ in calculation of I.

6. A new API 4½ in. 11.0 ppf P-105 flush-joint tubing string (nominal wall thickness = 0.262 in.) is being run in an 8½ in. horizontal well. The well is full of 13.0 ppg drilling mud, but the pipe was filled with 8.8 ppg field produced water while running in the hole. According to Mitchell's 1995 work, what force will produce stabilized sinusoidal buckling until helical buckling tendencies begin to occur in this tubing string? Again, assume Young's modulus = 29.5×10^6 psi.

B. 71,387 $\mathbf{lb_f}$

Again, several intermediate variables must be calculated first:

$$\mathrm{OD_{max}} = 4.5 + 1\% = 4.545 \text{ in.}$$

$$\mathrm{OD_{min}} = 4.5 - 0.5\% = 4.4775 \text{ in.}$$

$$t_{\mathrm{wmin}} = t_{\mathrm{wnom}} \times 0.875 = 0.262 \times .875 = 0.229 \text{ in.}$$

$$\mathrm{ID_{max}} = \mathrm{OD_{min}} - 2(t_{\mathrm{wmin}}) = 4.4775 - 2(0.229) = 4.0195 \text{ in.}$$

$$I = \pi\left(4.4775^4 - 4.0195^4\right)/64 = 6.9161 \text{ in.}^4$$

$$B = \left[\left(\mathrm{OD_{min}}^2 \times \mathrm{MW_o}\right) - \left(\mathrm{ID_{max}}^2 \times \mathrm{MW_i}\right)\right]/24.51 = \left[4.4775^2(13.0) - 4.0195^2(8.8)\right]/24.51$$

$$B = 4.8326\,\text{ppf}$$

$$W_b = W_{air} - B = 11.0 - 4.8326 = 6.1674\,\text{ppf}$$

$$r_c = (\mathrm{ID_{hole}} - \mathrm{OD_{max}})/2 = (8.5 - 4.545)/2 = 1.9775 \text{ in.}$$

From Eq. (4.44),

$$F_{cs} = 2.83\sqrt{\frac{EI \text{ x } W_b}{r_c}}$$

$$F_{cs} = 2.83\sqrt{\frac{29.5 \text{ x } 10^6(6.9161)6.1674}{1.9775}}$$

$$F_{cs} = 71,387\, lb_f$$

Distractors: Answer A. Correct variables but multiplied contents inside radical by 2 instead of 2.83 (i.e., calculated critical force to initiate buckling instead of sustaining it). Answer C. Uses nominal pipe OD, 4.5 in., to calculate I instead of OD_{min}, 4.4687 in. Answer D. Incorrect buoyant pipe weight calculated by averaging mud weight inside and outside pipe, 10.9 ppg; calculating BF; and multiplying by pipe air weight, 11.0 ppf.

7. A string of J-55 tubing in an 8½ in. hole has a radius of curvature of 1.984 in., a buoyed weight of 6.18 ppf and a moment of inertia of 1.88 in.^{4} is being run into a curved hole with a wellbore curvature of 1000 ft. The average deviation of a short pipe segment in this curved hole is 48 degrees. Young's modulus is 29.5×10^6 psi. What is the force required to maintain stabilized sinusoidal buckling before the buckled section assumes a helical shape using Qui's modified equation?

D. 61,969 lb$_\mathbf{f}$

$$EI = 29.5 \times 10^6(1.88) = 55.46 \times 10^6$$

$$r_cR = 1.984\,(1000 \times 12) = 23,808$$

$$r_cR^2 = 1.984\,(1000 \times 12)^2 = 285.696 \times 10^6$$

From Eq. (4.48),

$$F^*_{cc} = \frac{(2 \text{ x } 3.52)EI}{r_cR}\left(1 + \sqrt{1 + \frac{W_b \sin \propto_{\text{avg}} r_cR^2}{3.52\, EI}}\right)$$

$$F^*_{cc} = \frac{(2 \text{ x } 3.52)55.46 \text{ x } 10^6}{23,808}\left(1 + \sqrt{1 + \frac{6.18 \sin(48)285.7 \text{ x } 10^6}{3.52\,(55.46 \text{ x } 10^6)}}\right)$$

$$F^*_{cc} = 61,969\, lb_f$$

Distractors: Answer A. Does not include 3.52 in numerator of first term. Answer B. Does not include 2 in numerator of first term. Answer C. Inserts a 2 into denominator of term inside radical (i.e., 2×3.52 instead of just 3.52).

8. A string of 2⅞ in. 8.7 ppf N-80 flush-joint tubing is going to be snubbed into a vertical 6 in., ID well. The tubing has a nominal wall thickness of 0.308 in. Both the hole and the tubing are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling? Assume nominal tubing dimensions and Young's modulus $= 29.5 \times 10^6$ psi.

A. 7939 lb_f

This problem also requires calculation of variables. Using the same equations as above, BF = 0.8473, W_b = 7.372 ppg, and I = 1.8257 in.^{4}.

Using Eq. (4.51),

$$F_{CH} = 5.55\sqrt[3]{EIW_b^2}$$

$$F_{CH} = 5.55\sqrt[3]{29.5 \text{ x } 10^6(1.8257)7.372^2}$$

$$F_{CH} = 7{,}939\,lb_f$$

Distractors: Answer B. Uses nominal pipe OD, 2.875 in., to calculate I. Answer C. Uses both nominal pipe OD and nominal wall thickness, 0.308 in., to calculate I. Answer D. Uses nominal pipe weight, 8.7 ppf, instead of buoyed pipe weight, 7.372 ppf, to calculate F_{CH}.

9. The same pipe in the question above is going to be run in a straight inclined 6 in. hole with a deviation of 54 degrees. Both the pipe and hole are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling using Mitchell's 1995 equation? Assume nominal tubing dimensions for all calculations.

B. 86,468 lb_f

This calculation requires the radius of curvature for the pipe. Using the same equation as above,

$$r_c = 1.5625\text{ in.} = \left(\text{ID}_{\text{hole}} - \text{OD}_{\text{pipe}}\right)/2 = (6.0 - 2.875)/2$$

$$\text{ID}_{\text{pipe}} = \text{OD}_{\text{pipe}} - 2 \times t_w = 2.875 - 2(0.308) = 2.259\text{ in.}$$

$$I = \pi\left[2.875^4 - 2.259^4\right]/64 = 2.075$$

The critical force for initiation of helical buckling in straight inclined holes is given by Eq. (4.55):

$$F_{CH} = 4\sqrt{\frac{2EIW_b sin\alpha}{r_c}}$$

$$F_{CH} = 4\sqrt{\frac{2\left(29.5 \text{ x } 10^6\right)2.075(7.372)\sin(54)}{1.5625}}$$

$$F_{CH} = 86{,}468\,lb_f$$

Distractors: Answer A. Uses calculated $I = 1.8257$ in.^{4} from Question 8 without calculating it using nominal dimensions as instructed. Answer C. Calculates F_{CH} using nominal pipe weight instead of buoyed pipe weight. Answer D. Ignores sin(54°).

10. The same pipe in Question 8 is going to be run in a straight horizontal 6 in. hole. Again, both the pipe and the hole are filled with 10.0 ppg brine. What is the critical force to initiate helical buckling again using Mitchell's 1995 equation and assuming nominal pipe dimensions?

C. 96,134 lb_f

The equation and entries are the same as that for Question 9 with the exception that the term sin(54) is now sin(90)=1. Note that this answer was one of the distractors for Question 9. Distractors: Answer A. Repeats answer from Question 9 including sin(54) in numerator. Answer B. Uses the moment of inertia from Question 8 instead of recalculating using nominal dimensions. Answer D. Uses nominal weight of pipe instead of buoyed weight.

11. A string of 2⅞ in. 8.7 ppf J-55 flush-joint tubing with a nominal wall thickness of 0.308 in. is in a 7⅞ in. hole under a net force of 15,000 lb_f, a combination of buoyed string weight and imposed snubbing force. The pipe is suspected of being in helical buckling because the force exceeds the critical helical buckling force. What is the force normal to the well axis being applied to the tubing by the helix? Use nominal pipe dimensions.

D. 1232 lb_f

Again, this equation requires additional variables to be calculated. These include $r_c = 2.5$ and $I = 2.075$ in.^{4}.

From Eq. (4.59),

$$B_n = \frac{r_c F_1{}^2}{4EI}$$

$$B_n = \frac{(2.5)15,000^2}{4(55000)2.075}$$

$$B_n = 1,232\, lb_f$$

Distractors: All fictitious.

12. The pipe in Question 11 is located in a straight inclined hole with a deviation of 39 degrees. The hole and pipe are filled with 12.5 ppg mud. The net force being applied to the pipe is 3000 lb_f, and the pipe is helically buckled. This inclined hole segment is 55 ft. long. What is the friction applied upward while snubbing this pipe in the hole assuming a friction factor of 0.3?

A. 893 lb_f

Additional variables include $BF = 0.809$, $W_b = 7.04$ ppf, $\sin 39° = 0.629$, $W_n = 4.43$ ppf, and $Bn = 49.28$ lb_f.

From Eq. (4.61),

$$F_p = (W_n + B_n) \times C_f \times \Delta L$$

$$F_p = (4.43 + 49.28) \times 0.3 \times 55$$

$$F_p = 893\, lb_f$$

Distractors: All fictitious.

Note that for this pipe, 55 ft. calculates to be the period of the helix. In this configuration, the critical force to initiate helical buckling is 2544 lb_f. With the helix and buoyed pipe weight providing 893 lb_f in the first helical wrap (i.e., the first period), none of the pipe below this point where helical buckling begins would have any helical buckling. The downward force (3000) minus the friction from the helix and pipe weight (893) would mean that the pipe at all points below would not reach the critical force to initiate helical buckling (2107 < 2544).

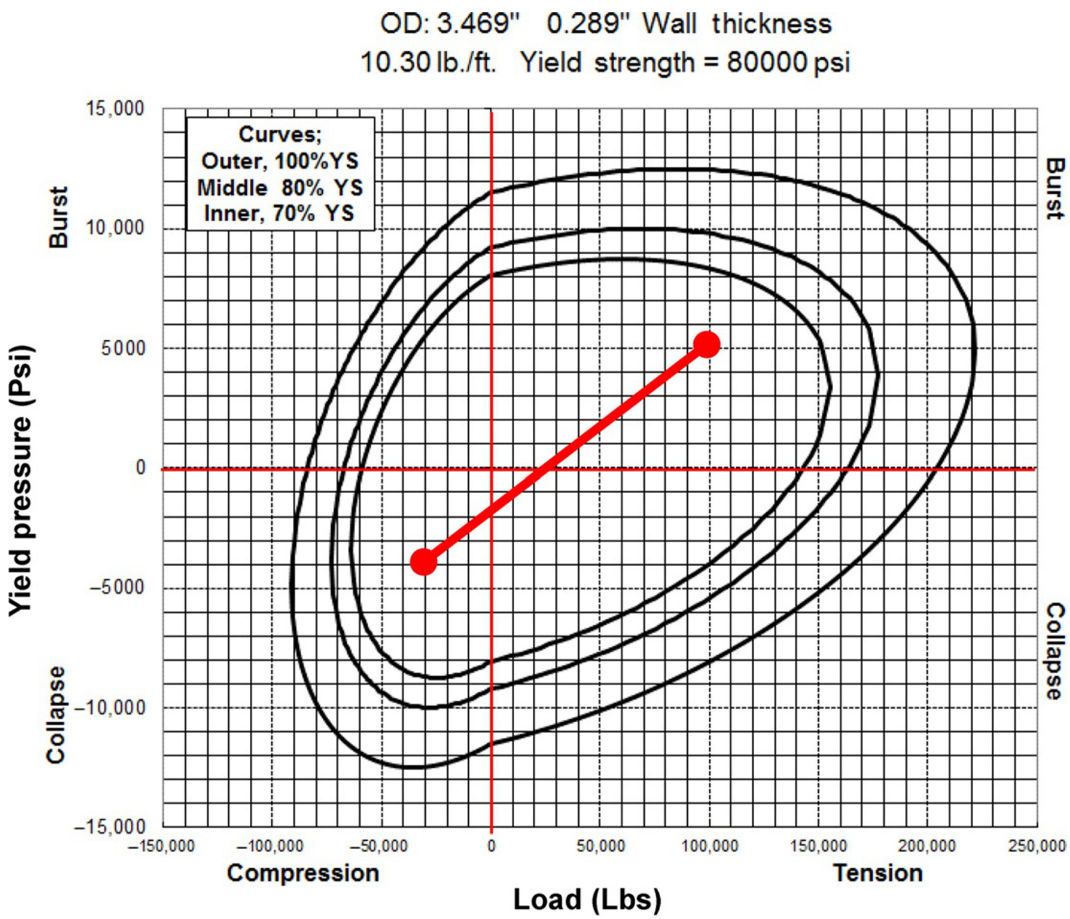
13. The von Mises failure criterion allows for the triaxial analysis of pipe under stress in compression and tension and burst and collapse modes.

A. True______

14. A string of 3½ in. 10.3 ppf, N-80 tubing is being planned for use in a snubbing job. It is expected that the pipe will be under a collapse pressure of 4000 psi with a compression load of 30,000 lb_f as snubbing begins. The conditions will end at an internal pressure of 5000 psi with a tension load of 100,000 lb_f, and the loading will proceed uniformly between these two end conditions. Using the plot below, can the job be safely done if a 70% safety factor is required?

A. Yes

All points along the force locus fall inside of the 70% envelope described by the von Mises plot.



CHAPTER 5

Chapter Quiz 1 Answer Key

Sections 5.1–5.2

1. For the purposes of this book and most of the industry now, HWO units are involved only with live well workovers, completions, and recompletions.

   B. False_____

   *HWO units are used on dead well workovers since they are not configured to snub pipe into a hole under pressure (*i.e.*, no pipe-light slips and no equalizing loop).*

2. What limits the diameter of equipment run through a snubbing or HWO unit?

   D. All of the above

   All of these limit the diameter of any item that can be run into the hole using a jack. Often, the bore of the snubbing or HWO unit and the BOP stack is the same. The wellhead and casing already installed in the hole also limit what can be run in the hole.

3. Snubbing and HWO units can lift any load that a conventional rig with a block-and-tackle hoisting system can lift.

   B. False_____

   Snubbing and HWO units are limited by the diameter and number of cylinders along with the power fluid operating pressure. The largest snubbing unit at this time can hoist a little over a half-million pounds. Some of the larger conventional rigs with block-and-tackle hoisting gear can easily manage loads over a million pounds.

4. What is the primary inside pipe well control barrier for a snubbing unit?

   C. The downhole plug or float set in the work string

   The primary inside barrier in a snubbing job is the downhole plug that prevents fluid from entering the pipe and exiting at the surface. Distractors: The well is, or may become, underbalanced at any time.

   Distractors: Answer A. Is incorrect. A fluid column is not a barrier in snubbing operations at all. Answer B. The safety BOPs have no impact on an inside barrier, so Answer B is incorrect. Answer D. Does not apply.

5. What is the primary outside well control barrier for a snubbing unit?

   B. The no. 1 and no. 2 snubbing (stripping) BOPs

   The snubbing BOPs provide primary annular or outside control against flow from an underbalanced well.

   Distractors: Answer A. The fluid column is already insufficient for annular control, or the well would not need a snubbing unit (i.e., there is pressure on the well). A fluid column is not a barrier in snubbing at all. Answer C. Incorrect because, while the safeties may provide protection against an annular flow, they are only secondary barriers. If both of the snubbing BOPs fail, the safety BOPs can become the primary barrier, but in normal snubbing operations, they are not. Answer D. Obviously does not apply.

6. What is the shared tertiary inside and outside well control barrier for a snubbing unit?

   A. Blind or blind/shear rams

   Once the work string is sheared or dropped in the hole, the blind rams become the barrier against flow from the entire wellbore.

Distractors: Answer B. Does not apply during snubbing operations—there is already pressure on the well, or snubbing would not be required. Answer C. Also incorrect since the safeties close on the outside of the work string and are considered a secondary barrier. If all the other primary and secondary barriers fail, both inside and outside, the blinds (with no pipe in the hole) or blind/shears can safely contain flow from the well. Answer D. Does not apply.

7. How will a gas kick entering a wellbore full of water-base drilling fluid behave?

E. All of the above

A gas kick in water-based fluids will migrate up the hole bringing BHP with it in a contained volume if it is not allowed to expand. This required bleeding off some of the fluid above the kick while it is migrating to maintain constant BHP in the wellbore.

8. What causes swabbing?

D. The drill string is pulled faster than fluid above the BHA can flow around it creating a slight suction on the formation

Swabbing involves a plunger effect with the drill string and particularly the BHA, providing the piston that sucks formation fluid into the wellbore while pulling pipe from the hole too fast.

Distractors: Answer A. Involves a similar effect called surging where the "plunger" pushes fluid downhole creating pressure that can result in formation fracture and lost circulation. Answer B. Nonsensical, because there is usually no way to hold pressure on jointed pipe as it is being run into or pulled out of the hole except by stripping or snubbing. Answer C. One way to initiate flow from the well is by allowing the fluid level in the hole to drop creating reduced hydrostatic pressure. Swabbing is a different effect.

9. In a dynamic kill, what causes the formation to cease flowing into the wellbore?

A. Fluid friction created by pumping the sacrificial fluid into the wellbore matches or exceeds formation pressure

Fluid friction due to high-rate pumping creates wellbore pressure to stop the formation from flowing into the well.

Distractors: Answer B. Not fully correct because the dynamic kill normally uses a fluid with little or no viscosity since it is a sacrificial fluid, usually water. Answer C. Not fully correct since the fluid flow from the formation must be stopped before the density of the sacrificial fluid becomes an aide in lowering surface pressure. Answer D. Incorrect—tubing inside the wellbore increased annular velocity and is used to provide a surface to develop fluid friction.

10. What characterizes a gunk squeeze?

D. All of the above

Distractors: Answer A. Correct. Clays are mixed in a fluid that is opposite that in the wellbore (i.e., oil for a water-based system and water for an oil-based system). Answer B. Also correct. When the dissimilar fluids mix a viscous mass if formed due to emulsification of one fluid in the other coupled with the surface interactions of clays on both fluids. Answer C. Also correct. Most of the materials for mixing gunk pills are readily available on most rigs. This is the source for their early and continuing popularity. Mixing is easy—placement often is not.

11. Lost circulation cannot cause a well to kick.

B. False_____

Lost circulation is often the primary cause of a kick because the well is unable to hold a full column of fluid resulting in a loss of BHP. This, in turn, can allow a formation with sufficient reservoir pressure to begin flowing into the wellbore.

12. Cement can always be used to stop lost circulation even when all other materials fail.

B. False_____

Cement, by itself, is a poor lost circulation material unless the well is static. Once a column of cement begins to set up, it supports its own weight and the hydrostatic pressure in that segment of the fluid column becomes the density of the mixing water only (usually fresh water). This can allow the well to start flowing, cutting through the cement in channels. If the fluid is gas, the cement column is literally destroyed as it becomes honeycombed with gas. Cement is useful as the final step in securing the well after the lost circulation is stopped by some other method and the well is static. Cement rarely sets up when it is moving.

13. Why are snubbing units often used to run small-diameter pipe to clean out kill strings?

C. There may be pressure on the kill string after cleaning it out that would expel the cleanout pipe from the well

Plugs in kill strings are often holding pressure that has collected below the plug. Once the plug is penetrated, the well immediately experiences pressure at the surface often inside both the kill string and the cleanout string. Anytime the potential exists for pressure to increase, it is better to already have the snubbing unit over the hole.

Distractors: Answer A. Incorrect. Snubbing units are often slower than conventional rigs running any pipe in a hole. These rigs cannot manage pipe-light situations, however. Answer B. Also incorrect. Pipe handling by some conventional rigs is as easy to manage as it is with a snubbing unit. The issue is pressure, not pipe diameter. Answer D. Also incorrect. Coiled tubing units are much faster running cleanout pipe than snubbing units can run jointed pipe. They can also manage pressure once the cleanout string breaks through the plug.

14. What is the purpose of a relief well?

A. To provide a means for pumping fluid into a blowing well to kill it

Relief wells provide the hydraulic connection with a blowing well to permit killing the flow using one or more techniques.

Distractors: Answer B. False because monitoring fluids, pressures, and flowrates are not needed in the emergency situation of a blowout—killing it is the focus, not monitoring it. Answer C. Also false. The intent is to never fracture the blowing well. A fracture makes it much more difficult to kill the flow. Answer D. Also false. Drilling a relief well may be part of a program that is helpful to satisfy the primary regulatory demand to kill the flow, but it is not the primary purpose. It helps the regulators and the public to see something being done in a blowout situation instead of just waiting for the blowout to deplete and stop flowing on its own.

15. Snubbing units are not equipped to drill any portion of a relief well since they have limited inside diameters.

B. False_____

Snubbing units can drill relief wells, especially the portion of the well near the intercept point. The snubbing unit has both the ability to rotate the drill string and the fine control *necessary to carefully drill into the blowing well. On rare occasions, the relief well becomes pressured from the blowout well. The snubbing unit can easily manage this pressure and still provide the means to drill into the blowing well providing the conduit for the kill.*

CHAPTER 5

Chapter Quiz 2 Answer Key

Section 5.3

1. When a snubbing unit installs large-diameter casing or a liner in a pressured well, what are some concerns?

   D. All of the above

   Distractors: Answer A. Is true. The larger diameter of the casing provides more cross-sectional area for which pressure to act on providing more expulsion force. Answer B. Is true. The BOP rams are larger, and there is more friction per unit length requiring more snub force than for smaller-diameter pipe. Answer C. Is also true. Jack, slips, and stack clearances become small when large-diameter casing is snubbed. It doesn't take much of an obstruction to jam the pipe resulting in thorny operational problems and many curse words.

2. Where are centralizers usually installed when running casing or liners using a snubbing unit?

   C. In a work window below the jack and above the no. 1 stripper

   The work window provides a place to install centralizers on the exposed pipe between the slips and the snubbing BOPs.

   Distractors: Answer A. Sometimes the centralizers are too large to go through the stationary and traveling slips without damaging the centralizer or rendering the slips incapable of closing on the pipe. Answer B. There is not enough room between the travelers and stationaries to install a centralizer. Again, there may not be enough clearance to get the centralizer through the stationary slips. Answer D. Centralizers can and are installed on casing strings when snubbing casing or liners in the hole.

3. It is easy to snub a conventional electric submersible pump (ESP) into a pressured well since the annular preventer can seal around both the tubing and the ESP power cable strapped to the outside of the pipe.

   B. False_____

   There is no known system for closing on both the pipe and the spiral armored power cable for an ESP. The annular preventer does not have the flexibility to seal in the small areas between these two side-by-side round items. Dual tubing rams might close on both, but sealing on the armored cable is quite suspect. Also, there would be no way to secure the cable to the tubing below these rams.

4. Why must a high-angle or horizontal open-hole section be cleaned up after drilling and before beginning completion work?

   B. To remove low-gravity solids, debris, cuttings, corrosion products, and other materials that could interfere with running completion equipment and/or damage the reservoir

Drilling usually leaves some accumulations of cuttings, fines, rust, scale, and other debris that settle out on the bottom of the hole sometimes forming complete bridges. This must be cleaned out to get liners, screens, and other equipment to bottom and to prepare the exposed reservoir for stimulation.

Distractors: Answer A. This process does not kill the well. It can be done with a low-density fluid keeping pressure at the surface to prevent the well from flowing. Answer C. The final step in the procedure to prepare the well for completion is to replace the drilling fluid with completion fluid, often solid-free brine, after the cleanout is complete. Answer D. Cleaning the hole leads to much better, more effective completions. Drilling is generally considered a "dirty" process that leaves way too much trash behind for a "clean" completion.

5. What is packer fluid?

C. A liquid mixture circulated in the annulus between the production tubing and casing that contains chemicals to prevent corrosion and bacterial growth and protect the tubing and casing strings from leaks

Packer fluid fills the annulus with a chemical mixture intended to protect the annulus during production.

Distractors: Answer A. It is not the fluid used to inflate the packer particularly in a mechanical or wireline set packer installed. Answer B. Packer fluid is usually made of a fluid with a density that is not sufficient to kill the well although some regulatory authorities require kill weight fluid in the annulus, usually expensive heavy brines. Note that this fluid will likely not kill the well at all since it will either be produced (gas lifted) out of the hole or the fluid level in the annulus will drop to the point that the hydrostatic pressure is not available in the remaining fluid column to kill the flow. Answer D. Packer fluid is not a stimulation fluid, and it is important to keep it out of the formation since some of the chemical constituents can form emulsions and scale inside the formation.

6. When recompleting a well to a different zone above or below the existing perforations where original reservoir pressure is likely to be present inside the well after perforating, it makes more sense to use a snubbing unit instead of a conventional rig.

A. True______

If pressure is anticipated, it is better to rig up and use the snubbing unit from the outset. Using a conventional rig is OK for the dead well portion of the job, but if pressure is encountered, the conventional rig must be rigged down to make room for the snubbing unit anyway. An exception would be the use of a rig-assist snubbing unit when pressure is encountered. Usually, if pressure on the well is anticipated, it's better to be rigged up to handle it from the outset.

7. What is an orphan, or orphaned, well?

D. All of the above

An orphan well is one without ownership except by the regulatory authority. In some jurisdictions, it is a well that has been shut in, and the operator has walked away from it for a variety of reasons. Many orphan wells are simply plugged to get them off the inventory without adequate analysis for workover or recompletion prospects.

8. Live well workovers can be safely performed using what types of equipment?

C. Snubbing units, coiled tubing units, and wireline/slickline units

Only these three types of equipment can perform work on the well and still contain pressure inside the wellbore. All others including conventional rigs and HWO units require that the well be dead since they have no snubbing capability. In actuality, only CT and snubbing units can push pipe into the hole under pressure.

9. It is always better to kill a well to perform work on it without the risk of a blowout rather than perform the work on a pressured (live) well.

B. False_____

Unfortunately, many people still operate under this delusion. Wells can be safely worked over with pressure at the surface. The risk of an uncontrolled flow is mitigated by using a method that can contain the pressure and still permit work. Often, wells cannot be killed at all but must be worked over by either flowing through some type of diverter system or performing live well workovers.

10. What mechanical methods are commonly used to repair casing leaks in existing wells without squeezing the hole with cement or some other liquid?

D. All of the above

These are the three most commonly employed mechanical means for dealing with casing leaks when cement squeezing either cannot be performed or has a low likelihood of stopping the leak.

11. Special fishing tools are required on live wells to prevent the loss of wellbore integrity and surface leaks.

B. False_____

The fishing tools used while snubbing are the same as those used by drilling rigs, completion units, or HWO units in dead well fishing jobs. The snubbing unit has the capability of turning the pipe unlike coiled tubing that requires nonrotating fishing tools.

12. What materials can collect inside production tubing, surface valves, and separation equipment that curtail or impede production?

A. Scale and sand

These are two of the major contributors to production impediments that also include paraffin. Usually, a combination of these collects in producing wells and surface equipment that must be removed.

Distractors: Answer B. Gas and pressure rarely curtail production and may, in fact, enhance it by gas-lifting liquids out of the tubing. Answer C. Artificial lift also enhances production by providing energy downhole to lift liquids out of the well. Answer D. These rarely accumulate in a wellbore, if ever.

13. What is NORM, and where does it concentrate?

D. Naturally occurring radioactive material, in scales deposited in tubing and surface production equipment

NORM is generally concentrated and collects in scales that plate out on the inside of production tubing and equipment. It comes from ancient seawater collected inside the

formations when the entire earth's environment was much more radioactive than it is today.
Distractors: All fictitious.

14. Carbonate scales are fairly easy to remove using common acids to react with and dissolve accumulations in the tubing, Christmas tree and production equipment.

A. True______

Most carbonate scales react with common acids used in the oil field, particularly HCl, and are readily removed. This is not the case with sulfate scales.

15. Common stimulations performed on existing wells include which of the following?

A. Acidizing and fracturing

These are common stimulations designed to increase production above the normal level for the well.

Distractors: Answer B. These procedures simply restore production back to the previous level after a production decline. They do not stimulate production from an existing interval. Answer C. Reperforating is intended to supply new holes for draining the reservoir, a production restoration technique that may or may not result in additional production from the well depending on whether or not the old perforations were still open. Sand and fill cleanouts also remove obstructions from the well restoring production from a zone. Answer D. Obvious.

16. Fracturing was invented and patented in what year?

D. 1946

Just after the end of World War II. This is not a newly discovered stimulation technique. It has been around for a long time, and it has been performed on hundreds of thousands of wells mostly with excellent results.

17. How does a propped fracture increase production?

C. By increasing the wellbore radius exposing more formation to flow

One term in Darcy's law involves the wellbore radius. The larger it is, the more area is available for fluid flow into the wellbore through a high-permeability fracture.

Distractors: Answer A. Fractures penetrate contamination near the wellbore. The fluid does not push damage away into the formation but provides a propped crack through it. Answer B. The frac may extend into unperforated intervals behind pipe, but this also opens more formation for leak off to occur. So far, no well has been able to extend a fracture up into the water table. Answer D. Frac fluids do not etch rock at all. Acids do, however.

CHAPTER 5

Chapter Quiz 3 Answer Key

Sections 5.4–5.7

1. How are HWO units configured differently than snubbing units?

D. All of the above

HWOs only handle pipe-heavy loads, so they are not equipped with inverted slip bowls, snubbing BOPs, or an equalizing loop. These are not needed for dead well work.

2. Where are HWO units used most often?

A. On some offshore and inshore locations

HWO units are used on some offshore and inshore wells where it is more economical to do so than to move in a conventional rig especially where mobilization costs are high.

Distractors: Answer A. HWO units are sometimes used for onshore work, but not often and certainly not on all onshore location. Answer B. HWO units may be used on some offshore deepwater locations where there is a tension leg platform or spar that limits heave, but not on all deepwater sites. Answer D. Sometimes, conventional rigs are a better choice than an HWO unit especially when heavy hook loads and large-diameter pipe are involved.

3. What is the primary inside (pipe) well control barrier for an HWO unit during a workover?

A. A fluid column with sufficient density to prevent flow up the pipe

HWO workovers require the same barriers that conventional rigs employ for dead well jobs. The primary inside pipe barrier is a column of fluid sufficient to keep the well dead.

Distractors: Answer B. A plug in the pipe string is not needed or desired in most HWOs. Answer C. The stab-in safety valve (TIW valve) is a secondary inside pipe barrier, not the primary. Answer D. The BOP stack does not protect against flow inside the pipe at all.

4. What is the secondary inside (pipe) well control barrier for an HWO unit during a workover?

C. A stab-in safety valve at the surface

See discussion on Question 3. This is just like the secondary inside barrier on a conventional rig.

5. What is the primary outside (annular) well control barrier for an HWO unit?

A. A fluid column with sufficient density to prevent flow up the annulus

Again, the primary barrier against flow for dead well HWOs is a fluid column with sufficient density and head to keep the well dead.

Distractors: Answer B. The BOP stack is the secondary annular barrier in a dead well workover regardless of rig type. Answer C. The blind shear ram is a shared tertiary barrier for both inside and outside the pipe. Answer D. Obvious.

6. What is the secondary outside (annular) well control barrier for an HWO unit?

A. The BOP stack including the annular preventer

See discussion on Question 5.

7. The well control barriers for an HWO unit are the same as those for a conventional rig (drilling, platform, completion, or workover).

A. True______

Unlike snubbing units, the primary, secondary, and tertiary well control barriers for HWOs are identical to those for conventional rigs.

8. How are gas kicks controlled on an HWO unit relative to the way they are controlled on a conventional rig?

D. There is no difference; they are handled the same way.

Kicks are handled during an HWO the same way they are handled on a conventional rig. Usually, the kick is circulated from the hole using one of two constant bottom-hole pressure techniques.

Distractors: Answer A. Occasionally, a kick will be bullheaded back into the formation, but not often, and certainly, not all kicks are handled this way. Answer B. Allowing a gas kick to migrate to the surface without expansion ensures that reservoir pressure will accompany it. The pressure combined with the hydrostatic pressure from the mud column below it may be sufficient to fracture a formation somewhere in the wellbore, usually the last casing or liner shoe. Answer C. The barrel in/barrel out circulating technique does not allow a gas kick to expand while circulating out of the hole. This technique has largely been abandoned by the industry.

9. HWO units are not equipped with a telescoping guide between the traveling and stationary rams. Why?

D. All of the above

*All of these are correct. There is no unconstrained buckling because the string from slips to the bottom of the pipe is always in tension (*i.e.*, pipe-heavy). There are no strippers through which the pipe must be pushed, so there is no compression on the pipe at the surface. There may be constrained buckling down the hole somewhere due to pipe-on-wall friction, but not at the surface where unconstrained buckling takes place. Thus, the entire stroke length of the HWO unit jack can be employed increasing the speed at which pipe is run into the hole.*

10. What method is frequently used to stabilize an offshore snubbing or HWO unit on very small platforms?

A. Outriggers attached to the wellhead and guy lines

The outrigger provides an anchor point from the guy lines extended some distance away from the centerline of the well. The outriggers are attached to the wellhead or some stable point near the wellhead, so they are not affected by heave or waves.

Distractors: Answer B. Subsea anchors in shallow water may be possible, but outriggers are far easier to transport and install. Answer C. A crane mounted on a floating support vessel is subject to heave and does not provide continuous support for the top-heavy snubbing or HWO unit. Answer D. Some snubbing/HWO units may be freestanding not needing stabilization, but certainly not all.

11. When considering HSE support for an offshore HWO, what does a bridging document do?

D. Clearly defines separation of safety-related and operational responsibilities and authority before the job begins to avoid conflicts during the job.

This is a document that ties the safety plans of the operator and the service provider together defining areas of responsibility, authority, and accountability.

Distractors: Answer A. and Answer B. Both false. The bridging document is never intended just to absolve a party of liability. It is to ensure that all areas of safety in the job are covered by one party or the other. Answer C. Also false. If both parties are considered to be in charge of all safety aspects of the job, there is bound to be conflict resulting in poor job and safety management.

12. Who is responsible for preparing the job safety analysis for a snubbing or HWO job?

D. All of the above

The JSA is prepared before the job and modified, as needed, through a daily or even hourly hazard assessment survey. This survey is normally conducted by representatives from both the operator and the service provider. Safety on the job is a jointly shared responsibility, and it is crucial to prevent accidents, injuries, and fatalities.

13. Feeding and housing HWO unit crews offshore is not a significant issue for most jobs.

B. False_____

This is often an overlooked area during job planning, but it is very significant. If crews are expected to work, they must have good quality housing and food. Failure to provide these basics can result in a crew mutiny if not managed properly.

14. Snubbing units are often required to perform work on storage cavern wells. Why?

B. Snubbing units are needed to manage pressure in these wells since the well cannot be killed

The capacity of a storage cavity is such that a sufficient volume of fluid cannot be pumped to kill the cavity or the service wells attached to it. Further, pumping enough kill weight fluid to ensure the absence of surface pressure would probably result in the loss of product inside the cavity and might make it unusable in the future. So, live service well work is the best option, and that requires snubbing.

Distractors: Answer A. While a small footprint service rig, like a snubbing unit, might be desirable, it is not a requirement. After all, the original service well was probably drilled using a conventional drilling rig, and the location is probably large enough to support one for workovers. Answer C. Conventional rigs are heavier than snubbing units that are supported by the wellhead of the service wells. It is unlikely that there will be sufficient weight from a conventional rig to collapse the roof of the cavity. Answer D. Obviously wrong.

15. Pipelines and flow lines can only be cleaned out using chemicals or coiled tubing units.

B. False_____

Snubbing/HWO units have been used to clean out flow lines, umbilicals, and pipelines offshore on several occasions. The small unit footprint, limited manpower needs, and cost savings are well documented. CT has also been used along with chemical washes, but snubbing/HWO unit work has also been successful.

16. How is the power cable run and strapped to the production tubing when deploying an ESP using an HWO unit?

A. In the work window below the jack

HWO units can be deployed and rigged up and pull production tubing along with the power cable and ESP in a fairly simple dead well workover. The cable is usually fed back down through a work window since it can be strapped easily to the tubing with the jack above the window managing the tubing loads.

Distractors: Answer B. The cable is usually stored on a reel, but it is fed into the well below the slips in the work window. This avoids the cable being crushed by the slips or the need for a slot within the slips to allow the cable to feed like those used on conventional workover rigs. Answer C. Feeding the cable through a side entry sub below the BOP stack requires another means of shutting in the well in case of a kick. Otherwise the well would simply blow out through the side entry sub. Also, using this technique would not allow the cable to be strapped to the tubing. Answer D. This answer is false. ESPs can be pulled and redeployed using HWO units.

CHAPTER 6

Chapter Quiz Answer Key

1. In some applications, snub drilling is more economical than drilling with a conventional drilling rig.

A. True______

When all factors are considered and total costs for all options determined, snub drilling is often more economical than a conventional rig especially for large offshore platforms. Even in onshore operations, snub drilling presents an option that may be economically attractive depending on rig availability and cost.

2. What limits the diameter of drill strings and casing run through a snubbing or HWO unit?

B. ID or bore of the snubbing/HWO unit, the strippers, and the safety BOPs

The bore of the snubbing unit and all the BOPs limits the OD of anything run through the stack. If the drill string, casing, or packer is too large, it simply cannot be run or pulled with the snubbing unit through the stack.

Distractors: A. Slips and bowls can be manufactured for almost any size drill string or casing. C. The ID of the wellhead and any seal assemblies in the wellhead must be large enough to allow drill string or casing components, including centralizers, to pass down into the well. D. Obviously incorrect.

3. Rotary motion is applied to the drill string in snub drilling using what device?

A. Hydraulic rotary table below the traveling slips

The drill string is turned by the hydraulic rotary table on the snubbing unit. It can be turned by an auxiliary rotation device such as a power swivel. The bit can also be turned by a downhole motor or turbine.

Distractors: B. There is no derrick on a snubbing unit nor is there a conventional top drive unit. D. The RCD does not impart rotary motion. It simply seals the annulus while the string is rotating. D. Obviously wrong.

4. Why is a rotating control device (RCD) necessary for pressured snub drilling?

C. Provides a means to rotate the drill string with pressure on the well while sealing the annulus

The RCD, whether a rotating head or a rotating BOP, seals the annulus trapping pressure inside the wellbore.

Distractors: A. The bearing pack on an RCD does not support the weight of the string in pipe-heavy situations or the upward thrust of the pipe during pipe-light conditions. B. The RCD is necessary to provide a secure, long-lasting seal during rotary operations. The strippers, annular, and safety BOPs will allow some rotary motion for a short time before they wear to the point of leakage and failure. D. Obviously incorrect.

5. Drilling fluid cleaning and pit systems for snub drilling spreads are needed for what purpose?

D. All of the above

The mud handling system on a snub drilling spread serves the same purpose as the one on a conventional rig or a coiled tubing rig. Cuttings removal and handling, mud conditioning, *and the ability to mix mud chemicals are all functions of the drilling fluid system on any drilling rig.*

6. Snub drilling crews are often smaller and better trained in well control management than conventional drilling rig crews.

   A. True______

   Snubbing crews are usually smaller than those required on large conventional drilling rigs when considering all the personnel involved such as motormen, electricians, mechanics, and instrument technicians. Snubbing unit crews are also better trained overall since they must handle pressure on a daily basis as a normal part of their work.

7. How do costs for mobilization of an offshore bottom-supported rig (jack-up) compared with those same costs for a snub drilling equipment spread?

   D. Sometimes A. and sometimes B.

   Either one may be higher than the other depending on circumstances, the equipment involved, and distances. Small, nimble jack-ups may be able to move faster and with less cost than a snub drilling spread in some cases but not in others. If the costs happen to be the same, it is a rare coincidence and not the norm.

8. Assume that an old well at the end of a long canal must be deepened. How could the mobilization costs for a jack-up conventional drilling rig compared with a barge-mounted snub drilling spread to do this job?

   B. The jack-up mobilization cost will probably be higher if the canal must be dredged deeper and wider to accommodate the jack-up

   Old wells in long canals typically imply that the canal may have silted in or partially collapsed over time. Dredging and spoil disposal costs to widen and deepen the canal to permit a jack-up to the site can be very expensive. Getting a dredging permit in some sensitive areas may require considerable time if such a permit can be obtained at all.

   Distractors: Answer A. The snubbing unit spread cost may not be higher due to the use of multiple barges to carry all the components of the spread. Answer C. Crew quarters are just another part of the spread requiring some type of transport. Answer D. Obviously incorrect.

9. Why are borehole stability problems in the original hole important when sidetracking an existing well?

   D. All of the above

   When redrilling a hole section from a sidetracked wellbore, all the initial problems encountered when drilling the original hole may become issues in the new wellbore. Having the old wellbore as a guide provides the opportunity to avoid the well stability problems if considered such as drilling fluid selection, pump rate and pressure, and BHA components.

10. Well integrity issues that can jeopardize snub drilling include which of the following.

    D. All of the above

    Barrier compromises can significantly jeopardize drilling with any equipment. Rigging up a snubbing unit or conventional rig over a bent wellbore or wellhead may not yield the best results. Leaking wellhead segments are problematic because the leak can result in unexpected pressure where it constitutes a considerable hazard.

11. The size and configuration of a snub drilling spread on an offshore platform depends primarily on the size and configuration of the platform.

A. True______

The way in which the equipment required for snub drilling depends largely on the shape and size of the platform on which it is rigged up. The same applies to platform rigs and coiled tubing unit drilling spreads. Bottom-supported drilling rigs do not share this issue since its drilling equipment is already configured aboard the rig from the outset and it does not have to be moved just to conform to the platform.

12. What are some of the advantages of a snub drilling unit over a conventional jack-up drilling rig in an offshore environment?

A. Smaller footprint, lower horsepower, and fewer emissions

Generally, snub drilling rigs and ancillary equipment occupy a smaller footprint than bottom-supported rigs or platform rigs. They may be about the same size and power as a coiled tubing drilling unit, however.

Distractors: B. Snub drilling rigs are only partially supported by the platform. The stack weight and hook loads are all supported by the wellhead under normal circumstances. C. Also false. The fluid handling and cuttings handling are either the same or more difficult on a snub drilling spread usually because they are not in a self-contained package. D. Also false. Snub drilling crews must be housed, fed, bathed, and supported just like all other crew members.

13. Snubbing capability of some type is required if pressure is to be maintained on the annulus at all times during underbalanced or managed pressure drilling.

A. True______

True underbalanced and managed pressure drilling requires that there is some pressure on the wellhead at all times. Sometimes, wells are temporarily killed to avoid pipe-light strings and to allow a large, complex BHA to be pulled from the well without pressure on the hole.

14. What is the most significant disadvantage of snub drilling when compared with drilling with either a conventional drilling rig or a coiled tubing unit?

D. Pipe tripping speeds are generally slower with snubbing units than with conventional rigs or coiled tubing units

Snubbing units can trip pipe at the speed of the jack only. In some cases, when high pressures are on the wellhead, short strokes must be used instead of the full stroke length. Conventional rigs can pull pipe using block-and-tackle hoisting equipment and rack it in a derrick in lengths of 3–5 joints on large rigs reducing the time required to break connections. Coiled tubing units can trip pipe at the speed of the injector with no connections at all until reaching the BHA.

Distractors: Answer A. Snubbing units can steer the bit using the same rotary steerable tools or bent motors just like a conventional rig can do since the unit is capable of turning the entire string (unlike a coiled tubing unit). Answer B. Conventional rigs may have higher hook load capability depending on the rig. Small rigs may not have any greater hook load capability than a large, high-capacity snubbing unit, however. Answer C. A snubbing unit with a downhole motor has the same bit rotary speed as a conventional rig drilling in rotating mode (as opposed to sliding mode). This is also true with coiled tubing units. If a supplemental rotary drive is added to the snubbing unit, there is no difference between the snub drilling equipment and a conventional drilling rig.

15. Tall snubbing stacks are sometimes required in snub drilling operations. What is true of a tall snubbing stack?

D. All of the above

These are all features of tall stacks. Often, the comparisons of different drilling equipment types fail to take the tall stack issue into account. If the well must be drilled with pressure at the surface, a tall stack may be the only option to handle certain drilling and completion equipment. This situation could lead to a decision to work on the well with no pressure (i.e., dead well work).

16. All personnel working in the basket on a snub drilling spread must have access to an emergency evacuation device.

A. True______

There must be at least one escape device for each person, or a common device for all personnel in the basket, to ensure rapid descent from the basket in an emergency situation. The same is true for the derrickman in a conventional drilling rig.

17. When comparing different types of drilling systems, what are some of the factors entering into the decision to choose one over the other?

E. All of the above

These are all variables for any type drilling system and between rigs of the same type. Not evaluating all of these in addition to several others could result in selecting the wrong rig and suffering the adverse consequences of that decision. Still other nonrig issues such as long-term drilling contracts and regulatory requirements must also be considered.

18. What does the term "well manufacturing" mean?

B. A different rig is used to drill certain hole sections for which it is best suited and the most economical.

This term was coined in Canada from attempts to use different rigs to drill specific hole sections for which that rig was ideally suited. This provided the most cost-effective way to drill a number of wells assuming that mobilization costs were overridden by savings in using the correct rig for purpose in each hole section. In snub drilling, especially on new wells, this can lead to the decision to use a conventional rig for part of the hole, snub drilling for another, and coiled tubing for yet another with completion work performed by yet another rig. Each hole section must be considered apart from the others in this type of analysis.

Distractors: Answer A. Well manufacturing has nothing to do with country of origin, duties, or fees although these can play a role in rig selection and should be considered. Answer C. The learning curve may also have a role in manufacturing wells, but it's usually the rig type, cost, and suitability that are far more influential. Answer D. Obviously incorrect. Well manufacturing does exist, but not necessarily in all areas and all well types.

19. The lowest cost option for any drilling project is always the best option.

B. False_____

Cheapest is not always best. It's just cheapest. Other variables must be considered with cost being only one of several considerations.

20. What are the last seven words of any company?

C. "We never did it that way before."

The other quotes here might well have been uttered at one time or another, and they may be true in some peoples' minds. However, the company that has become rigid and unwilling to use new or improved technology is usually the one that is quickest to fail.

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Note: Page numbers followed by *f* indicate figures, *t* indicate tables, and *b* indicate boxes.

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LES SKINNER, PE

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