# Well Control for the Workover Operator

First Edition

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WCS MAN-010

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# FOREWORD

This manual was compiled for use as the primary text for blowout prevention courses conducted around the world by Well Control School (WCS). Its scope is broad, and recommendations or suggestions of good practices are designed to meet the training requirements established by the International Association of Drilling Contractors (IADC), American Petroleum Institute (API) and other industry and government agencies, as well as to address the knowledge base necessary to competently perform many of the skills required by the International Well Control Forum (IWCF). Additionally, WCS hopes that field personnel will find the book a useful and practical on-site reference, covering a wide range of accepted well control practices.

Every effort has been made to use standard or universal terminology. Still, common usage varies among different segments of the industry. The drilling hand's drillpipe becomes the workover hand's tubing. Terms remain consistent throughout chapters and meanings should be apparent within the context of the topic discussions.

The mathematical formulas in the manual are presented lineally, that is, in the order in which values and operatives are entered into a hand-held calculator. In some cases this form of presentation may differ from accepted written mathematical formats. Our goal is for the learner to arrive at the correct answer in the simplest and most direct way possible, regardless of his or her educational background.

Although the manual is not intended to be a work of science, WCS is indebted to many engineers and scientists throughout the industry for technical advice and assistance. It is impossible to acknowledge on an individual basis all the companies and personnel who contributed materials to this compilation. It is our sincere hope that their thanks will come by way of the knowledge that in some way we have all helped to avert that greatest of all oilfield tragedies, the blowout.

# Acknowledgments

Well Control School (WCS) expresses thanks to all companies and individuals contributing to this text. Material contained here, by general consensus of those involved in the course development, is based on the best sources of knowledge available to the authors. WCS does not warrant or guarantee any procedures or information presented in the text.

By the very nature of the oil industry, procedures, equipment, standards, and practices vary widely. It is not the intent of WCS to endorse policies and procedures, but rather to communicate to readers generally accepted practices. This manual is intended for individual use and cannot be used to conduct a course without the express written permission of Well Control School.

# Abbreviations

| | |
|---|---|
| APL | annular pressure loss |
| bbl. | barrel(s) |
| BOP | blowout preventer |
| BTU | British thermal unit |
| bhp | brake horsepower |
| BHP | bottomhole pressure |
| CP | circulating pressure |
| CITHP | closed in tubing pressure head |
| cu. | cubic |
| $cm^3$ | cubic centimeter (in scientific context) |
| cc | cubic centimeter (in clinical context) |
| d./day | day |
| °C | degree Celcius |
| °F | degree Farenheit |
| Δ | delta |
| ECD | equivalent circulating density |
| ft. | foot/feet |
| fp | freezing point |
| gal. | gallon(s) |
| h./hr. | hour |
| hrs. | hours |
| hp | horsepower |
| HP | hydrostatic pressure |
| in. | inch(es) |
| K | Kelvin |
| L | liter |
| MAMW | maximum allowable mud weight |
| MD | measured depth |
| MPa | megapascal |
| mp | melting point |
| m | meter |
| min. | min |
| mo. | month |
| Ω | ohm |
| ppb | parts per billion |
| ppm | parts per million |
| p | pascal |
| ∏ | pi |
| lb. | pound(s) |
| lb./ft. | pound(s) per foot/feet |
| ppf | pound(s) per foot/feet |
| ppg | pound(s) per gallon |
| psi | pound(s) per square inch |
| PMW | present mud weight |
| rpm | revolutions per minute |
| sx | sacks |
| sec. | second |
| secs. | seconds |
| ∑ | sigma |
| sp gr | specific gravity |
| stk | stroke |
| spm | strokes per minute |
| sq. | square |
| sq. in. | square inch |
| sq. ft. | square foot/feet |
| temp. | temperature |
| TVD | true vertical depth |
| wt. | weight |
| yr. | year |
| yrs. | years |

# Chemical Elements

| | |
|---|---|
| Ac | actinium |
| Al | aluminum (US) |
| | aluminium (IUPAC) |
| Am | americium |
| Sb | antimony (stibium) |
| Ar | argon |
| As | arsenic |
| At | astatine |
| Ba | barium |
| Bk | berkelium |
| Be | beryllium |
| Bi | bismuth |
| Bh | bohrium |
| B | boron |
| Br | bromine |
| Cd | cadmium |
| Ca | calcium |
| Cf | californium |
| C | carbon |
| Ce | cerium |
| Cs | cesium |
| Cl | chlorine |
| Cr | chronium |
| Co | cobalt |
| Cu | copper |
| Cm | curium |
| Ds | darmstadtium |
| Db | dubnium |
| Dy | dysprosium |
| Es | einsteinium |
| Eu | europium |
| Fm | fermium |
| F | flourine |
| Fr | francium |
| Gd | gadolinium |
| Ga | gallium |
| Ge | germanium |
| Au | gold (aurum) |
| Hf | hafnium |
| Hs | hassium |
| He | helium |
| Ho | Holmium |
| H | hydrogen |
| In | indium |
| I | iodine |
| Ir | iridium |
| Fe | iron (ferrum) |
| Kr | krypton |
| La | lanthanum |
| Lr | lawrencium |
| Pb | lead (plumbum) |
| Li | lithium |
| Lu | lutetium |
| Mg | magnesium |
| Mn | manganese |
| Mt | meitnerium |
| Md | mendelevium |
| Hg | mercury (hydrargyrum) |
| Mo | molybdenum |
| Nd | neodymium |
| Ne | neon |
| Np | neptunium |
| Ni | nickel |
| N | nitrogen |
| No | nobelium |
| Os | osmium |
| O | oxygen |
| Pd | palladium |
| P | phosphorus |
| Pt | platnium |
| Pu | plutonium |
| Po | polonium |
| K | potassium (kalium) |
| Pr | preaseodymium |
| Pm | promethium |
| Pa | protactinium |
| Ra | radium |
| Rn | radon |
| Re | rhenium |
| Rh | rhodium |
| Rg | roentgenium |
| Rb | rubidium |
| Ru | ruthenium |
| Rf | rutherfordium |
| Sm | samarium |
| Sc | scandium |
| Sg | seaborgium |
| Se | selenium |
| Si | silicon |
| Ag | silver (argentum) |
| Na | sodium (natrium) |
| Sr | strontium |
| S | sulfur |
| Ta | tantalum |
| Tc | technentium |
| Te | tellurium |
| Tb | terbium |
| Tl | thallium |
| Th | thorium |
| Tm | thulium |
| Sn | tin (stannum) |
| Ti | titanium |
| W | tungsten (wolfram) |
| Uub | ununbium |
| Uuh | ununhexium |
| Uuo | ununoctium |
| Uup | ununpentium |
| Uuq | ununquadium |
| Uus | ununseptium |
| Uut | ununtrium |
| U | uranium |
| V | vandium |
| Xe | xenon |
| Yb | ytterbium |
| Y | yttrium |
| Zn | zinc |
| Zr | zirconium |

# Workover Operations

# 1

## Upon completion of this chapter, the student should be able to:

- Discuss well workover operations.
- Discuss and answer questions on remedial operations.
- List causes of kicks in remedial operations.
- List flaring and venting safe practices.
- List possible consequences of failing to clean up the well before completion.
- Calculate the differential between the tubing and annulus above and below any barrier.
- Calculate shut-in wellhead pressure.
- List the appropriate steps for a negative pressure test.
- Identify common subsurface equipment and its primary function.
- Line up the simulator for reverse circulation.
- Check the annulus fluid density.
- Perform the proper startup procedures.
- Maintain bottomhole pressure until the influx is out of the hole.
- Line up the simulator correctly for the exercise.
- Apply and trap pressure on the annulus.
- Monitor and record all pump rates and pressure changes, or unusual conditions.
- Shut in the well and ensure it is dead.
- Line up and relieve pressures.

*Excerpt from "Guide to Blowout Prevention Second Edition Revised 2011" manual by Well Control School*[1]

*Well completion* operations are the activities and methods used to prepare a well for production. Sometimes the system of tubular goods and the tool assemblies that provide the flow path from the formation to the surface is referred to as "the completion". The tools and techniques used in completion operations can vary widely depending on the local area and the particular reservoir(s) of interest. In some areas more than one reservoir is completed in a single well.

Figure 1.1.

*Workover operations* refer to one or more of a variety of activities performed on an existing well after it has been drilled and completed. Plug and abandon operations also fall under the category of workover. *Remedial operations* refer to any work done on a well after it has been drilled. Both completion and workover operations fall under the category of remedial operations.

The life of a producing well may extend over a period of many years and during that time the components that comprise the completion may be repaired or replaced several times as the well depletes and the components wear. Every well and its specific problems are unique. It is crucial that contractors and service companies gather as much information as possible before the work actually begins. Job sheets, sometimes called dispatch sheets, are used to organize well data and assist in planning the job. A sample job sheet can be found on page 1-34 of this text.

This chapter is divided into two sections. "Section One - Remedial Operations", discusses some of the most common reasons for doing remedial work on completed wells and the techniques employed to solve various problems. Section two lists and describes some of the common equipment used to complete or work a completed well over.

## *SECTION ONE – REMEDIAL OPERATIONS*

Although the basic concerns of well control are the same for both open-hole drilling and remedial operations, there are certain issues that apply more to one operation than the other. Almost all remedial work is done in cased hole. In remedial operations, the operators and contractors have access to information that is not available while the well is being drilled. The size of the casing and all the components in the completion are known. The formation pressure is known as are the depth and position of the perforations. But the very nature of remedial work, that is, dealing with open production zones can be dangerous from the standpoint of well control. Many tragic blowouts have occurred during seemingly routine completion and workover operations. Of the various causes of kicks discussed in chapter 4, five of those causes are especially important when considering remedial operations.

1. *Insufficient Fluid Density*

   The density of remedial fluids is usually maintained just high enough to balance, or slightly overbalance, the producing formation. A seemingly minor reduction in fluid density could allow unwanted formation fluids to flow into a well.

2. *Improper or Inadequate Monitoring on Trips*

   Many workover units are small rigs with fewer crew members than drilling rigs. Trip tanks and other sophisticated fluid measuring devices are not always available on workover rigs. The rig tank maybe used to monitor gains and losses on trips. The following formula can be used to find the volume of a rectangular tank in barrels per foot.

   Barrels per foot = $L_{ft} * W_{ft} \div 5.61$

   Where:

   L is the length of the tank in feet.

   W is the width of the tank in feet.

   5.61 is a constant that converts cubic feet to barrels per foot (bbl/ft)

   A tank is 12 feet long, 4 feet wide, and 6 feet high. What is the capacity of the tank in barrels per foot and barrels per inch (bbl/in)?

   $12 * 4 \div 5.61 = 8.6$ bbl/ft

   $8.6 \div 12 = 0.716$ bbl/in

3. *Swabbing/Surging On Trips*

   Tripping is much more frequent in remedial work than in drilling operations. Downhole clearances are often restricted and the density of remedial fluids is maintained as low as possible to avoid damaging the production reservoir. All of these things contribute to the likelihood of swabbing or surging on trips.

4. *Lost Circulation*

   Completion and packer fluids are often clear brine solutions with little gel strength or water loss control. Ideally, no fluid-borne solids are deposited across the face of the perforations. These clear fluids are easily forced into permeable formations if pressures are excessive.

5. *Obstructions in a Well*

   Many remedial jobs deal with obstructions in the annulus and sometimes in the tubing. Setting plugs in the tubing, setting and releasing packers in casing are both common workover tasks. Workover operations frequently require circulating sand and debris from the bottom of a well. Often a well is circulated by pumping down the annulus and up the work string (reverse circulation). The result is that bottom-to-surface circulating time is much shorter than when a well is circulated conventionally. The crew has to expect the gas to be at the surface quickly when reversing gas out of a well. It is essential that surface equipment, that is, manifolds, chokes, vent and flare lines are all correctly lined up before circulation begins.

## Live vs. Static (Dead) Wells

Live wells are wells that are flowing and producing fluids and/or gases to the surface, or wells that have been shut-in and have pressure at the surface. Wells are considered static, or dead, when they will not flow when open to the surface without some sort of stimulation or intervention.

## Workover Venting and Flaring

Petroleum regulations governing gas releases vary, depending on the workover location and on the venting or flaring duration. Gas releases are vented or flared, depending on whether the gas can be safely burned or vented. Regulations usually call for prior notification before venting or flaring. Always check local venting and flaring regulations prior to conducting workover operations. Portable flare stacks may be purchased or rented. Example petroleum regulations for South Australia are shown below.

### *PETROLEUM REGULATIONS IN SOUTH AUSTRALIA*

### *DISPOSAL OF PRODUCED OIL AND GAS*

Any oil or gas that is circulated out of, or produced from, a well during a drilling, testing or repair operation, and that is not flowed through the well's flow line to a gathering facility, must be flowed through an appropriate manifold and properly staked temporary flow line to a storage tank or flare.

### *VENTING OF FLAMMABLE VAPORS*

All process vessels, instruments and equipment, from which flammable vapor may be emitted, must be safely vented to the atmosphere.

All vent lines and drain lines from process vessels or storage tanks that are vented to flare pits or flare stacks must be fitted with flame arresters or other similar safety devices.

### *FLARES*

A flare pit or the end of a flare line must be located a safe distance from:

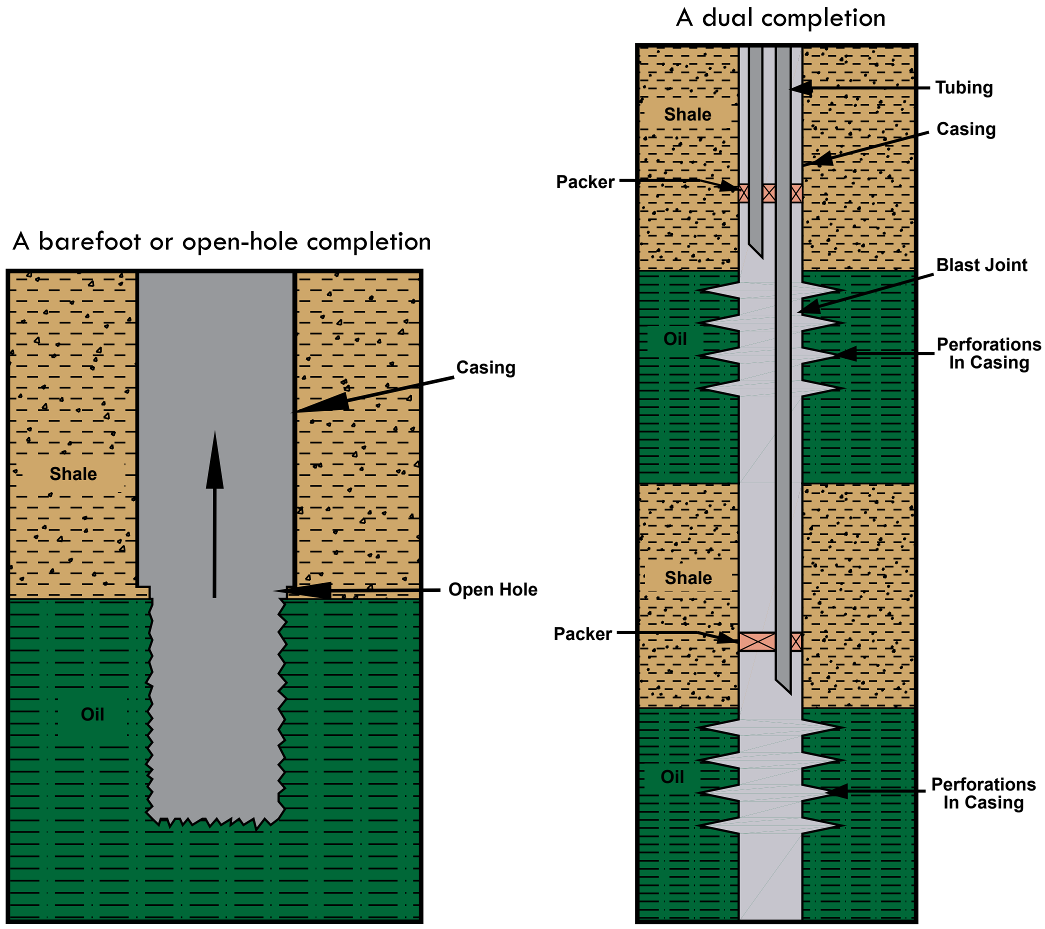
- The outside of a well, separator, pipeline, storage tank or temporary production facility
- An unprotected source of flammable vapor
- An unprotected source of ignition
- A road, railway or building.
- An access road must be sited a safe distance from a flare pit or the end of a flare line.
- A flare line must be constrained.
- Permanent flare installations must be fenced off and a safe method provided to ignite each flare.
- A flare pit must be sited and constructed so as not to create a hazard to persons or property.

## Completion Operations

Completion involves installing permanent equipment for producing oil or gas. Completion operations usually consist of bottomhole preparation, running in production tubing and downhole tools, perforating and stimulating (if it is required). Completion may also involve running in and cementing in casing.

There are many different types of completions ranging from simple open-hole (barefoot) completions to highly complex multi-zone completions. In an open-hole completion, there is no casing or liner across the producing formation. In the most common completion, casing is set and cemented through the pay zone. The casing is perforated at the production zone, and a packer is set in the casing above the zone. Production tubing is run and landed through the packer. Formation fluid is produced to the surface through the production tubing.

Figure 1.2.




## Horizontal Well Completions

Open-hole and cased well completions are used in horizontal wells. Open-hole completions are only used when producing from stable formations. Cased wells use relatively thin casing that is usually set in cement opposite the producing formation to keep the formation from caving and prevent inflow from other sections of the horizontal section. A perforated liner may also be used. The producing horizon is isolated with cement plug and/or packers and the casing is perforated.

## Potential Problems when Running a Completion String.

Potential problems when running a completion string include:

- Prematurely set packer
- Fluid losses

- Total losses due to surge, leading to a kick
- Sticking the string
- Tubing collapse
- Control line leaks
- Kicks with screens across the BOP
- Failure of SCSSV after landing
- Tubing connection leaks
- Sliding sleeve valve fails to open or close
- Starting running operations when the well not completely dead.

## Precompletion Cleaning

After the well is drilled to its total depth, the drilling fluid must be displaced and the well is cleaned before completion with completion fluids.

Figure 1.3a. Horizontal well completions types.

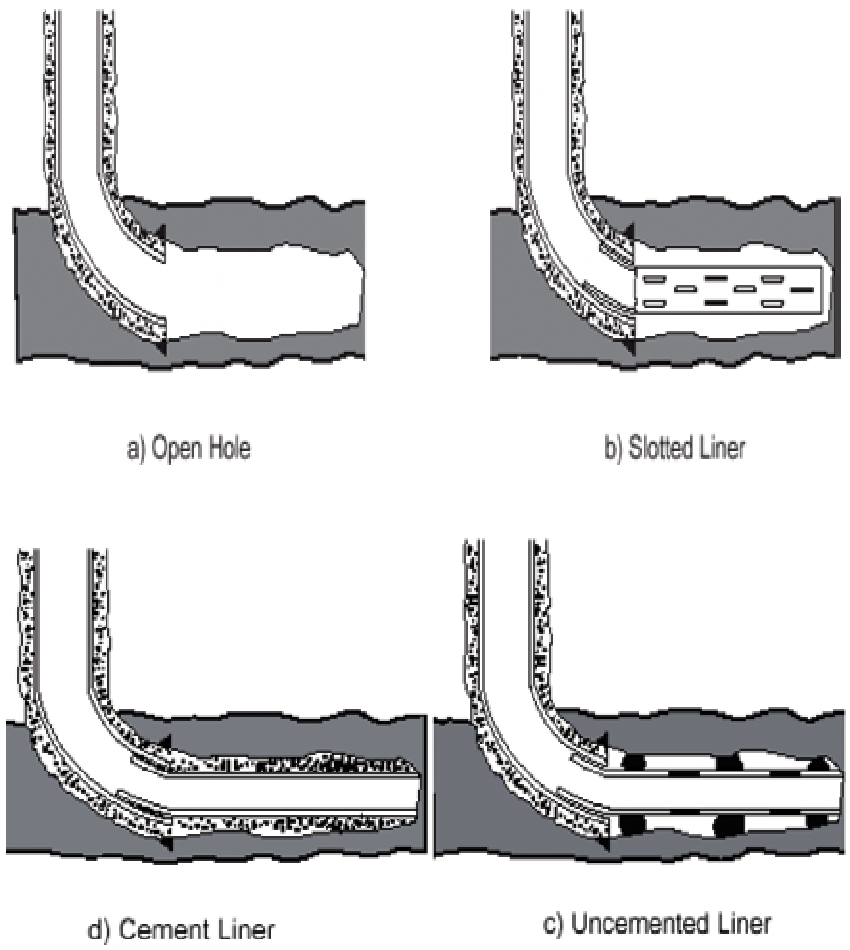
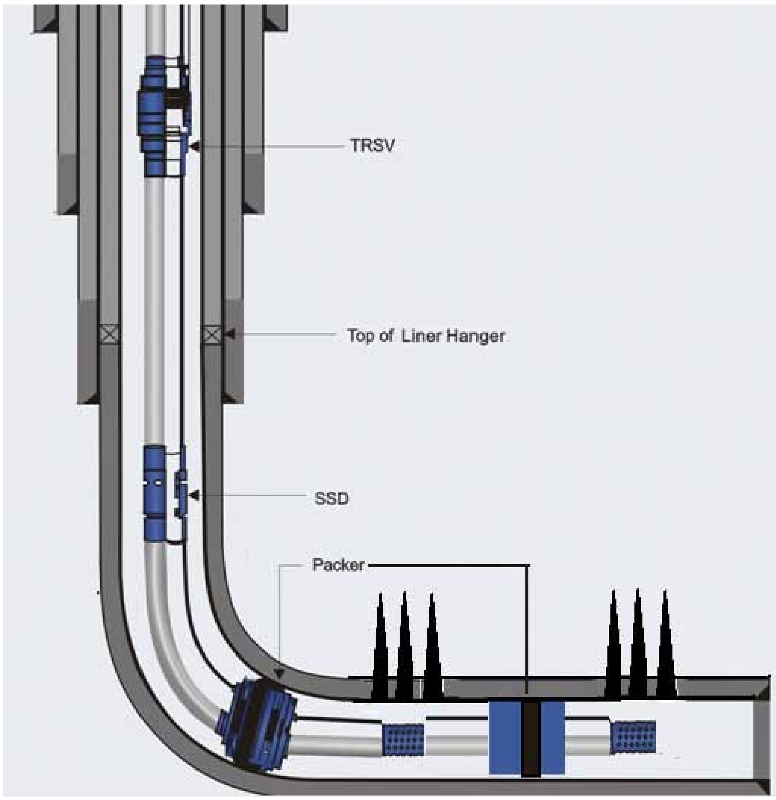


Figure 1.3b. An example of a horizontal completion.




Precompletion cleaning removes debris, mud and metal solids from the cased section of the wellbore, filter cakes and debris from the open hole. The wellbore must also be free from obstructions prior to running completions. Casing scrapers, brushes and pressure washing equipment can be run into the hole to help remove solids prior to displacing the drilling fluid.

Most drilling fluids are not compatible with completion fluids. Spacers are used to separate the displaced drilling fluid from the completion fluid. Viscous pills, solvents and surfactants are used to clean drilling fluid residue.

Cleanup consists of displacing the drilling fluids, using chemical spacers followed by completion fluid. Fresh water may be used for displacing and cleaning up water-based drilling fluids, if fresh water is inexpensive and its discharge has no adverse environmental impact. The hydrostatic pressure differential between the water displaced and drilling fluid must also be acceptable. The fresh water flushes out the drilling mud and is followed by completion fluids. Seawater may also be used for displacing oil-based drilling fluids. Spacers and solvents are pumped in advance of the seawater before displacing with completion fluids.

Precompletion cleaning has the following benefits:

- Increased productivity
- Increased mud recovery
- Reduced time setting completion equipment
- Reduced completion fluid filtration time
- Fewer downhole equipment failures

## PERFORATING

*Perforating* is the process of making holes in the casing, through the cement in a well to allow formation fluids to enter the well. Sometimes casing is perforated in order to introduce cement between the casing and the walls of the borehole.

Originally, perforations were drilled or cut into the casing before it was run. Then, hydro blast tools were used to cut holes in the casing. Next, wireline came along with perforating guns that shot bullets. Wireline-conveyed perforation (WCP) and tubing-conveyed perforation (TCP) are the two common perforation methods used today.

In a WCP operation, the perforation gun is lowered into the hole opposite the oil or gas producing formation by wireline. In a TCP operation, the perforation gun is lowered into the hole opposite the oil or gas producing formation, using tubing. Both operations use powerful shaped explosive charges that are detonated from a control panel on the surface. The explosive charges create a jet of high pressure, high velocity liquid that blasts a hole through the casing and casing cement into the formation. These perforations may be several feet deep, allowing the oil and gas to flow into the hole and up the well to the surface.

In certain areas casing is perforated in an underbalanced environment. A specified differential pressure (formation to casing) is created. When the casing is perforated, the pressure differential allows the formation to flow back immediately into the well, washing any junk or debris out of the perforations. The debris falls to the bottom of the well. The fluid in the casing opposite the zone to be perforated has usually been filtered to ensure that it is as free of solids as possible in order to prevent plugging the perforations. Nitrogen is sometimes used to achieve the desired underbalance because of its cleanliness and low density relative to liquids.

A water cushion is sometimes used as the perforating fluid in order to reduce the amount of hydrostatic head in the well and achieve the required pressure differential. Even with a water cushion, it may be necessary to swab a well in to initiate flow.

Assume that a well has an estimated formation pressure of 4,680 psi at a depth of 10,000 feet and that the well program calls for a 200 psi differential in the work string before perforating using 9.3 ppg saltwater. The height of the water cushion is determined by:

$$\boxed{\text{Water Cushion}_{ft} = (\text{Formation Pressure}_{psi} - \text{Pressure Differential}_{psi}) \div \text{Gradient}_{psi/ft}}$$

$$\text{Water Cushion} = (4{,}680 - 200) \div (9.3 * 0.052)$$

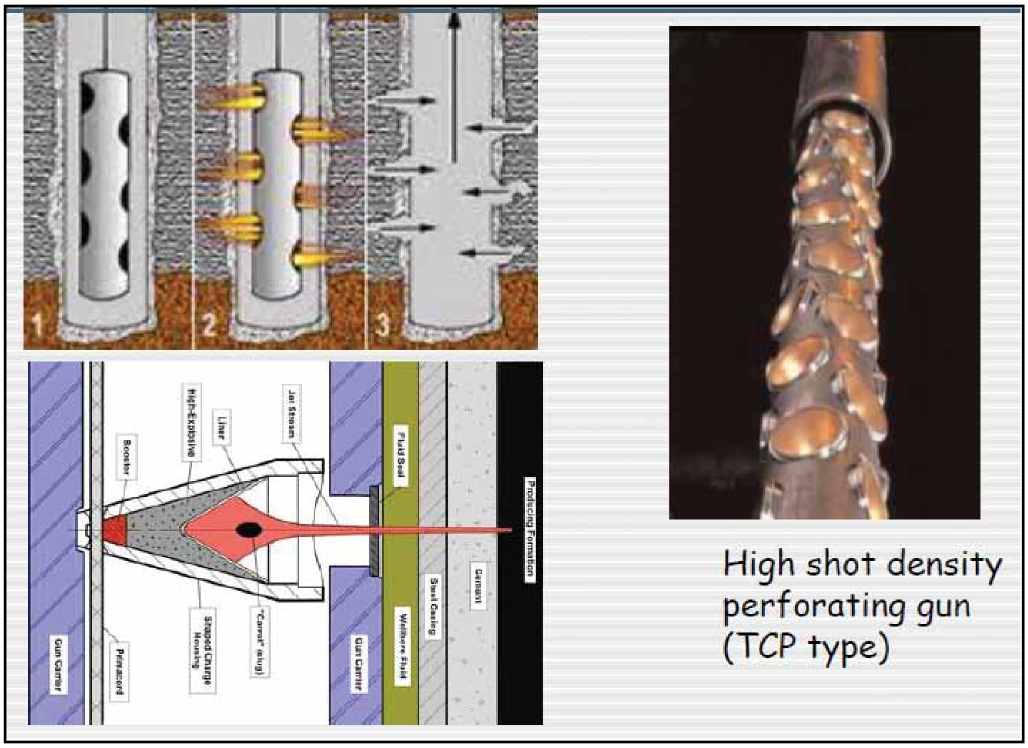
$$\text{Water Cushion} = 4{,}480 \div 0.483$$

$$\text{Water Cushion} = 9{,}275 \text{ feet}$$

Special safety precautions are considered when perforating equipment is on a rig site. The perforating equipment is handled by experienced service company personnel. All radios are turned off and welding activities are discontinued. Special radio restrictions are passed to work boats and helicopters in the area and most electrical equipment on the rig is shut down in order to reduce the likelihood of the guns being fired accidentally due to static electricity.

The various operations involved in bringing a completed well on line for production fall under the category of well *stimulation*. Almost all stimulation operations are supervised by service company personnel who have been trained in the use of their particular tools and techniques. Some common stimulation operations are briefly discussed below.

Figure 1.4. Examples of perforating.




## Fracturing (Frac Jobs)

*Fracturing* is the process of creating a crack or fracture in the rock that contains oil or gas. This crack is then filled with sand or an artificial proppant to allow the freer flow of oil or gas from the rock to the wellbore, thus improving the well's production. The fractures are usually horizontal at shallow depths and vertical in deeper wells. These fractures extend out away from the wellbore. The *proppant* most frequently used is sand but metal or glass beads are also used. The individual proppant grains should be as perfectly round as possible to ensure maximum compressive strength because they must hold the fracture open. Also, the proppant must be as clean as possible and contain no fine solids or clay.

Various fluids are used as proppant carriers during the pumping operation. A typical frac job will begin by filling the well (or tubing) with treated water. This is called the *pre-pad*. As the pre-pad is pumped into the well the pump pressure increases until the formation fracture pressure is reached. A steady injection rate is established and then a carefully measured "pad" volume is pumped. It is the pad that carries the proppant into the well. When the well is full, the pumping rate is stabilized and the proppant is added.

The amount of proppant is increased gradually until the required volume of fluid and proppant has been pumped into the well. When all the material has been injected, it is followed with more fluid to push it out of the wellbore and into the fractured formation. The final volume is carefully measured to ensure that the well is not overdisplaced. Overdisplacement can result in the fractures reclosing near the wellbore.

The very nature of fracturing operations, that is, long lines of hoses and pipe and high pumping pressures potentially make the jobs dangerous. Often radioactive sand is used so that the well can be logged in order to determine the height of the fracture. The use of radioactive material adds another dimension to the general personnel safety precautions.

Thorough planning is required prior to any frac job. Some of the common safety issues that must be considered are listed below.

- Personnel assignments, responsibilities and reporting procedures
- Pressure testing methods and limits
- Contingency plans in case of problems during the operation
- Required personnel safety equipment (PPE) including clothing, ear protection, safety glasses, rubber gloves, etc.
- Lines of communications
- Placement of signs and warnings
- Special precautions if radioactive material is to be used
- Emergency medical response in the event of a personal injury incident
- Site evacuation procedures

### Acidizing

A common method of well stimulation is to pump acid into a well to clean out the perforations or to increase porosity and permeability. There are two general acidizing techniques. *Matrix acid jobs* are done to clean out the face of the perforations but the pressure used to place the acid is less than the formation fracture pressure. The acid will travel about 6 inches into the perforations, after which the acid loses its strength. A variety of acids may be used depending on the type of material that is restricting flow. The selection of specific acid type(s) and strength, as well as the operational procedure, is developed by the operator in conjunction with service company representatives.

An *acid frac job* is done to enhance permeability when the damage is farther out from the wellbore. Acid is pumped out into the formation at pressures that exceeds the formation fracture limit. A larger flow area is created by the acid as it dissolves some of the bedding material of the formation. It is common to use hydrochloric acid (HCL) in limestone formations because the acid dissolves some of the limestone, leaving a channel in the rock. In some cases special additives are mixed with the acid in

Figure 1.5. Frac job preparations.

order to delay, or slow, the chemical reaction time. As with all acid jobs, each operation is designed for a specific well.

Corrosion inhibitors are used on acid jobs in order to protect tubular goods and downhole tools. *Surfactants* (*soaps*) and solvents are also used as additional aids in cleaning up the formation. They help prevent the gels and emulsions that form when fines or silts mix with the spent acid water. Diverting agents and devices are also available to improve the job. Once the acid solution has been held in place for the planned time, it is reversed or swabbed out of the well through the work string. Gas from the formation as well as any gas caused by chemical reactions with the acid may reach the surface quickly. An acid job could easily turn into a well control incident if the crew is not prepared for rapidly expanding gas at the surface.

Safety is a key point during all rig site operations. The combination of high pressures and acidic fluids make acid jobs especially hazardous. Some items included in a pre-job safety meeting include:

- Action to take in case of burns, eye injury, ingestion or fume poisoning
- Designation of essential and nonessential personnel
- Locations of wash stations in case of personnel coming in contact with hazardous material
- Location of respirators and other safety equipment
- Safety clothing (PPE)
- Danger inherent in breathing acid or other toxic fumes
- Procedure for mixing acid and water (i.e., acid is poured into water, not water into the acid)
- Warnings to prevent accidental mixing. Some material may cause an explosion. Some corrosion inhibitors can be fatal even if absorbed through the skin. In some instances, hydrogen sulfide ($H_2S$) and other toxic gases may be formed.
- Procedure for cleaning acid spills (i.e., acid spills should be cleaned up at once)
- Specification of hose material (i.e., all lines should be steel hoses)
- Procedure for securing lines (i.e., all lines should be securely tied down)
- Procedure for testing line pressure (i.e., all lines should be tested to pressures in excess of those to be used during the job)
- Pressure gauges should be checked for accuracy.
- A check valve should always be installed at the wellhead and there should be some means of releasing the trapped pressure between the wellhead and the check valve.
- Procedure for monitoring wind direction during the operation

## Workover Operations

The list of possible remedial operations taken to repair a producing well is nearly endless. Decisions as to whether to work a well over or to abandon it are based strictly on economics. Below, several of the most common remedial operations are discussed in a general way. From the standpoint of well control, it must be realized that all completed wells are potentially dangerous. There has been more than one case in which a supposedly dead well has come to life and control was lost. Invariably, the cause can be traced to human error.

Remedial operations require a workover rig. Through tubing equipment may be used if tubing does not need to pulled. Remedial operations include:

- Controlling water and/or gas when there is excessive gas or water production.
- Squeeze cementing, when remedial, or secondary, cementing is performed.
- Sand control
- Recompleting in a different reservoir
- Mechanical problems that require pulling the tubing string and its components, making repairs and returning the well back to production. Examples of mechanical problems include casing and tubing that is:
    - Damaged
    - Collapsed
    - Plugged
    - Eroded and corroded
    - Split or parted
    - Corroded

Other mechanical problems include damaged screens and leaking or malfunctioning completion equipment.

### Controlling Water and/or Gas

As oil is depleted from a pay zone, the gas-oil, or oil-water contact changes. This can result in gas or water being produced along with the oil. When an oil reservoir has a gas cap and the gas cap is being produced, the driving force that is, the gas, is being depleted, which in turn, reduces the volume of oil lifted by the gas drive.

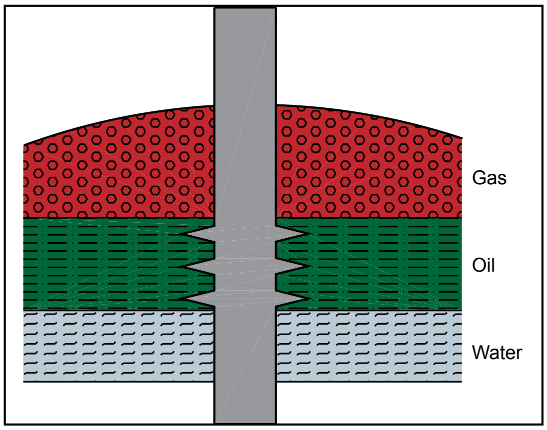
When excessive water is being produced, corrosion of well equipment may increase drastically and water disposal at the surface may become a problem. Often when too much water is produced, sand control also becomes a problem. However, it should be mentioned that sand entering the perforations can occur regardless of the amount of water which is produced. The metal erosion caused by producing too much sand will damage wellhead and production equipment, creating a serious hazard at the site.

Practically all hydrocarbon-bearing formations have water in the lowest portion of the reservoir and definition of the oil-water contact is a primary consideration in the development of any field. It is a mistake to assume that there is a hard line dividing oil and water or that the contact is horizontal throughout a reservoir. In reality, the oil-water contact is part water and part oil, and may range from 10 to 15 feet thick.

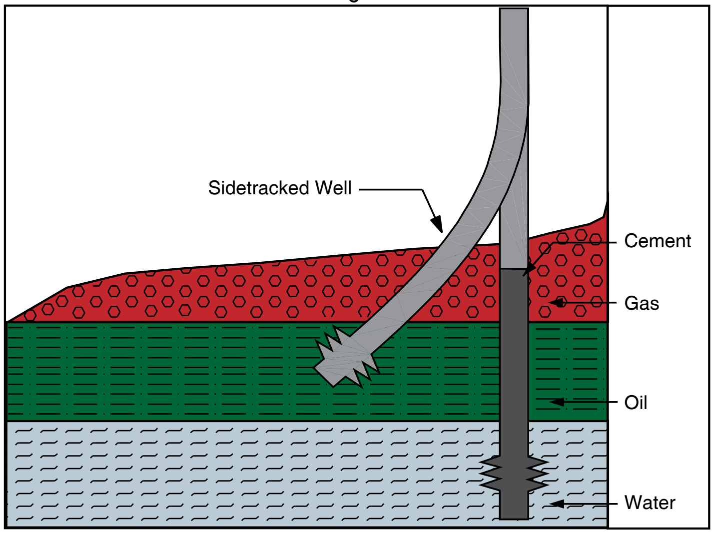
*Coning* is the term used to describe the natural tendency of reservoir fluids to move toward an area of reduced pressure. As the pressure in the area around perforations is reduced due to production, the fluids in the adjacent zone move up or down toward an area of lower pressure. Figure 1.7 represents simplified illustrations of coning. In the first diagram the well is static; no production has taken place. The second illustrates oil being produced at a low drawdown (production rate) and results in 100 percent oil. No water breakthrough has occurred at this point. In the third diagram, the operator has attempted to increase production. The increase in drawdown has caused a *cone* to rise and now water is produced with the oil.

Figure 1.6.

Ideally production occurs in the oil section using a gas cap as the reservoir drive.




If the gas-oil or oil-water interface changes, or if the drain area depletes the well can be sidetracked to the oil zone and/or new drainage area.




Coning will occur in any hydrocarbon reservoir if there is no barrier between the desired gas and oil and the unwanted water. The result is a decrease in the production of oil and an increase in the production of water or gas. The oil decrease occurs because the water or gas in the cone occupies part of the pore space that was once occupied by the oil. The amount of coning is related to the amount of vertical permeability, the mobility of the produced fluids, and the pressure differential. The difference in density between oil and gas also affects coning. The oil-gas contact is usually thinner and better defined than the oil-water contact.

If the rock and fluid properties are well known, the drawdown rate above which a water cone will develop can be accurately estimated. Attempts to reduce or eliminate water coning are often made by squeeze cementing and then re-perforating. These operations carry the same potential for a well control incident as the original perforation operation.

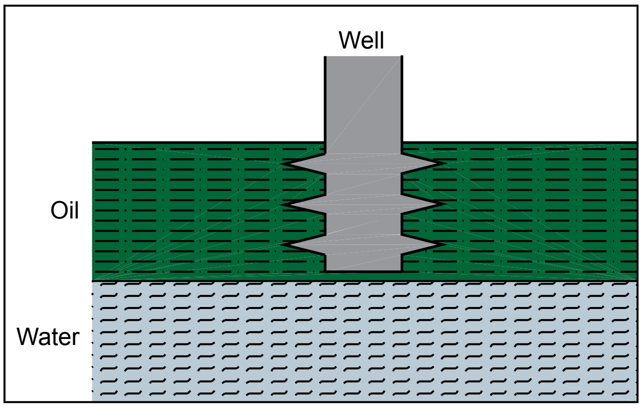
## Squeeze Cementing

Remedial, or secondary, cementing is performed to exclude water or gas from a well, to improve the primary cement job, to re-complete in a new zone, or to repair corroded or damaged casing.

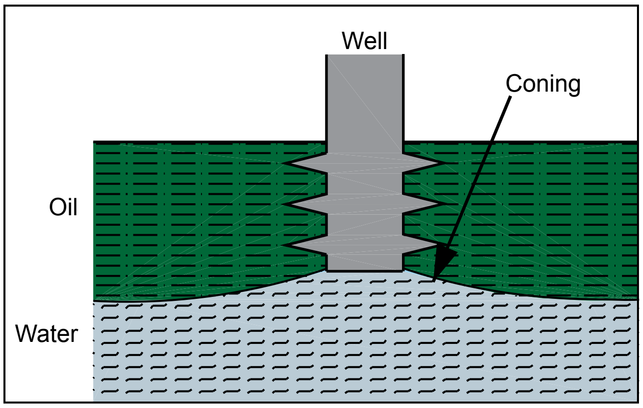
*Squeeze cementing* is accomplished by displacing cement at the desired point opposite perforations. Control is accomplished with the use of packers. Sometimes an existing permanent packer, already set in the casing, is used as the squeeze tool. Cement is then circulated down to the squeeze point. The tool is then set to isolate and protect the casing from high pressure. Next, cement is pumped into the area to be sealed off. Hydraulic pressure is applied to force, or squeeze, the cement slurry against the formation. This may be done either in open hole, or through perforations in the casing or liner. Excess cement can be reversed out of the well, or drilled out at a later date.

Figure 1.7.

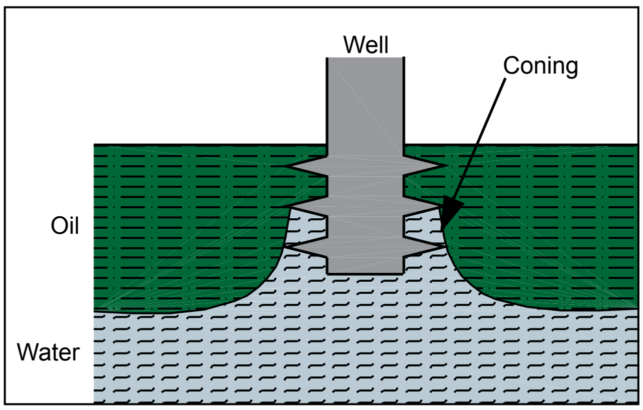
Static conditions,
where no producing has taken place




Oil produced at low drawdown (low production rates)
resulting in 100% oil, no water breakthrough




As higher production rates are attempted the increase in
drawdown has caused the cone to rise.

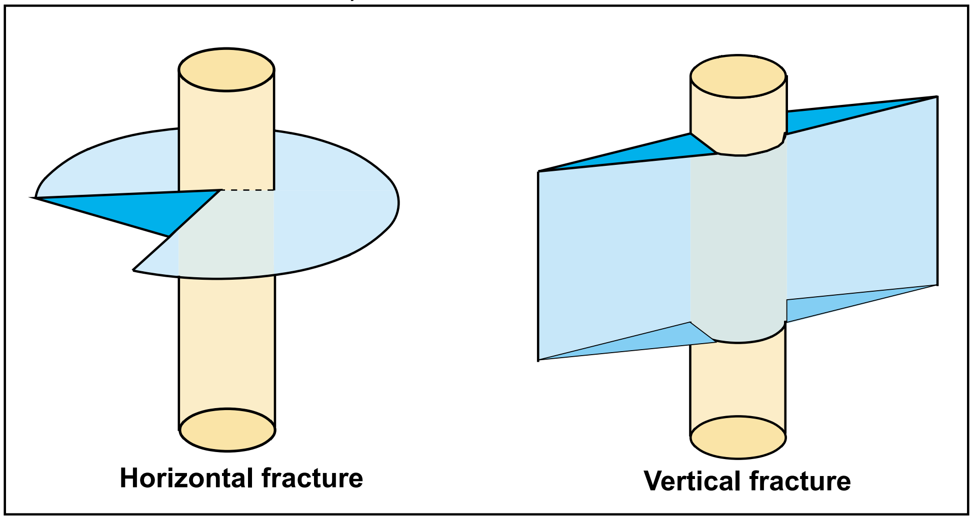


In almost every case, the cement goes up the hole between the formation and the casing. Once this annular channel is shut off, the producing zone can be squeezed. It should be noted that whole cement does not go into the pores of the formation. It is the water in the cement that goes into the formation's pore spaces. Water is forced into the formation under pressure, leaving the cement to plate out across the face of the formation, but often the formation will also take the whole cement. Ideally, the water leaves the slurry and the cement hardens in place. If enough pressure is applied to fracture the formation, then cement could enter the fracture lines of the formation.

Most jobs are successful when cement is left in the casing opposite the perforations or damaged area, and not drilled out after the squeeze operation. Therefore, plug back jobs have been the most successful. There have been poor results with so called "block squeezes" to shut off water. This is especially true in gas wells because fractures are often vertical, not horizontal "pancakes" which are layers of hardened cement radiating from the wellbore in a circle.

The most important prerequisites for a good squeeze cement job are clean perforations, clean channels, and cement slurry, which has been designed to meet the downhole conditions and type of squeeze to be performed. Minimal blockage and clean surfaces assure a better and more thorough bond. One of the cementer's primary concerns when squeezing is preventing water from entering the formation. The cementer must know exactly where the cement, including water cushions, is at all times.

Figure 1.8. Most induced fracture planes are vertical, however shallow formations may exhibit horizontal fractures.




Cement squeezes are accomplished in several different ways, depending on specific well conditions and the problem to be remedied. Some common squeeze techniques are discussed below.

In a *bradenhead squeeze,* the casing valves are closed and the well is pressured up on the casing and the work string during the operation. There is no packer set in the well. Gas migration can present a problem with bradenhead squeezes so pressure is applied to prevent potential flow. A bradenhead squeez*e* is a relatively low pressure squeeze because pressure is on the tubing as well as the casing.

When a packer is set above the perforations and all fluid in the work string is pumped into the formation ahead of the cement, the technique is called a *bullhead squeeze*. Sometimes pressure is isolated on the casing above the packer before the job begins. This is done to reduce the differential pressure across the packer. Well control issues are rare because the problem is usually a lost circulation zone.

A *hesitation squeeze* refers to a technique of pumping cement out through the casing perforations and into the annular area between the casing and formation. The pumps are then stopped. After a few minutes pumping is started and stopped again. The procedure is continued until the desired pressure is obtained. Hesitation squeeze techniques are often used on high-pressure jobs and low-pressure squeezes where the applied pressure may be as low as 200 psi. These operations are done to seal off the perforations without fracturing the formation.

A *circulation squeeze* is called for when there is communication between perforations in different zones. A retainer is set between the perforations. After circulation is established between the perforations, cement is pumped in through the lower and out through the upper perforations. When the cement is in place, the tubing is pulled out of the retainer to a point above the upper perforations. The cement in the work string is then reversed out to the surface. It is possible that a circulation squeeze could force formation fluids, especially gas, into the casing annulus above the retainer. In this case a routine cement squeeze job could easily turn into a serious well control incident.

Rig pumps are rarely used on squeeze jobs due to the high pressures required. The high-pressure/low-volume pumps on cement units are ideally suited for squeezing. Cementing service companies ensure that all fluids are in excellent condition prior to a squeeze job and that they are compatible with the cement and other fluids to be used. A buffer solution or spacer is pumped ahead of and behind the cement when fluids are not compatible.

### Sand Control

The production of sand with reservoir fluids is a major problem in some areas. It can cut or plug the choke and flow lines, cause equipment failure, complicate well clean-out, and cause downhole equipment to malfunction. Sand disposal can also be a problem on some locations. Methods used to control the production of sand include running screens or slotted liners, packing with gravel (specially prepared sand), and sand consolidation using a plastic resin.

Screens are the simplest to install in most cases. A slotted liner or wire wrapped screen is hung opposite the sand-producing interval. The *screen mesh* is too small to allow sand to flow into the wellbore, while still allowing the flow of formation fluids into the well.

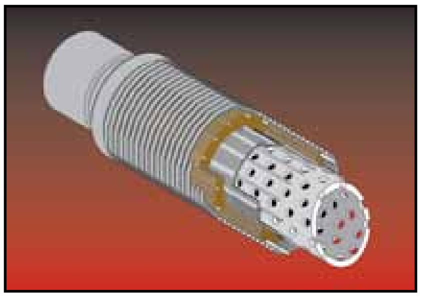
More than one serious well control incident has occurred due to swabbing. In one recent case, a gravel pack job had been completed and everything seemed fine as the crew started the trip out of the well. However, the combination of very small annular clearance plus excessive tripping speed led to disaster. One mistake led to another and eventually the entire unit was lost, having burned to the waterline.

### Recompleting In A Different Reservoir

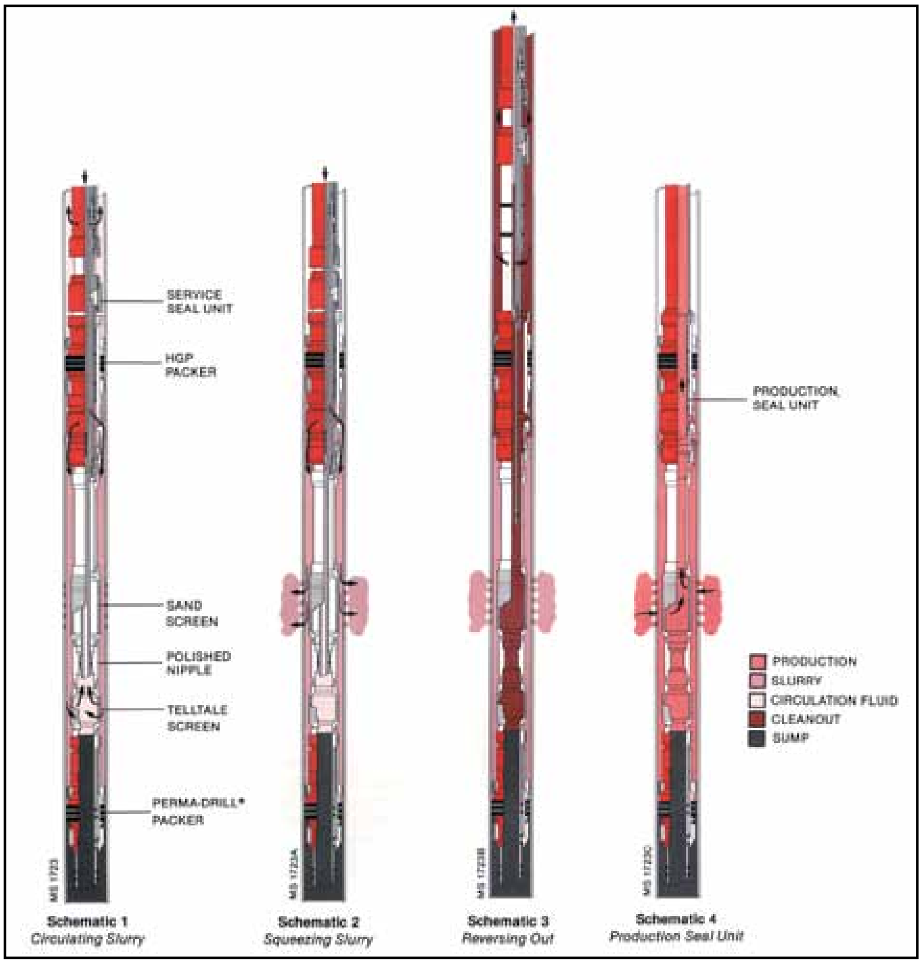
Wells with multiple production zones are usually completed in the lowest reservoir first. When the production of the lower zone becomes uneconomical, the well may be recompleted in a new, higher zone. Failure of casing or downhole equipment as well as cement problems can also require recompletion in a new interval. Plans for secondary recovery operations such as water or steam flooding often call for a well to be re-completed.

Moving the completion interval from a lower zone to a reservoir higher in the well is known as *plugging back.* A well is killed and the lower or older production formation is squeezed off. Sometime the squeeze is done through the old permanent packer. The packer seals are pulled, repaired or replaced,

Figure 1.9.



*Top*, screen.
*Bottom*, gravel pack.




and stung back into the packer. Always use original OEM parts when replacing seals. Cement is pumped down the tubing, through the packer and out into the perforations. The packer is then left in the well and a cement plug is set on top of the packer. Federal and/or state regulations require that the cement be tested either by applied pressure or by setting weight down on the plug. After isolating the lower section the new upper reservoir is perforated and put on production.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

## Differential Pressure Across a Mechanical Barrier

Often a well must be entered to remove a plug in the tubing string or bridge plug in the casing (mechanical barriers) that has been placed in a well for a period of time. At the time the barrier was placed, the pressure was most probably balanced across the plug or bridge plug. The well contained a fluid of known density. However, after the passage of time, the fluid below the plug may have seeped or otherwise leaked into a permeable zone or upward across the barrier. As a safety precaution, the potential differential pressure across the mechanical barrier should be estimated before it is removed. The maximum potential differential pressure can be estimated as follows:

The maximum reservoir pressure (RP) at the exposed perforations is known or estimated by reservoir engineers and provided to the team workover crew. The maximum possible pressure below the mechanical barrier is the reservoir pressure (RP), minus the hydrostatic pressure of a column of reservoir fluids between the perforations and the barrier. It is generally assumed the fluid column is gas (worst case condition).

Hence the pressure below the barrier is given by:

$$P\text{ (below barrier)} = RP_{psi} - HP_{psi}\text{ (top of perfs to barrier)}$$

$$P\text{ (above barrier)} = HP_{psi}\text{ (surface to barrier)} + \text{Shut-in wellhead pressure (if any)}$$

$$DP\text{ (across barrier)} = P\text{ (above barrier)} - P\text{ (below barrier)}$$

BSEE recommends the following when re-entering a well where there is a possibility of trapped pressure beneath a mechanical barrier:

- Thoroughly perform diagnostics to check for trapped pressure prior to re-entering a well.
- Develop operational procedures that account for the possible trapped pressure beneath a mechanical barrier.
- Consider using snubbing units for well servicing when there is any doubt of trapped pressure beneath a mechanical barrier.

## Shut-In Wellhead Pressure (SIWHP)

Wellheads must have a maximum allowable working pressure that exceeds the Shut-In Wellhead Pressure that may be anticipated during the life of the well, including both the drilling and production phases.

$$\boxed{\text{Shut-In Wellhead Pressure}_{psi} = \text{Formation Pressure}_{psi} - \text{Hydrostatic Pressure}_{psi}}$$

## Pulling Completion Equipment

The well is pressure checked by opening a downhole circulating device, using wireline. To make the well safe, a subsurface safety valve is closed (if present) or plugs are set in the tubing and locked into the landing nipple by wireline. A back pressure plug may also be set in the hanger to make the well safe.

The workover unit is rigged up. The workover operation begins by killing the well. The wellhead or Christmas tree is removed and replaced with a BOP stack. Plugs that were placed to make the well safe must be pulled and the subsurface safety valve (if present) must be opened, in case there is a kick while pulling the completion equipment. Full-opening safety devices must be available to contain any flow from the tubing. The tubing hanger is lifted from the casing head. When pulling completion equipment, take the same precautions that are taken during any tripping operation by keeping the hole full and avoiding swabbing.

The string is usually held in place by at least one production packer that must be released if it is retrievable. If the retrievable packer cannot be retrieved, the tubing can be cut above the packer and the upper tubing (above the packer) can be pulled out. The remaining tubing and the *retrievable packer* can then be pulled, using an overshot fishing tool.

If the packer is a permanent packer, the tubing is cut above the packer and then the tubing (above the packer) can be pulled out. The packer and the tubing left in the hole is then milled and fished out. Often a new completion is made by setting a new packer just above the old packer and new tubing is run down to the top of the old packer.

Two barriers must be in place when conducting any operation.

## Workovers in Open Hole

There are times when workover operations include work done in the open hole. In these situations, all the well control precautions and techniques discussed in previous chapters of this text come in to play. Since workover rigs are usually smaller than drilling rigs and may have less sophisticated well monitoring equipment, crews must be especially alert to changing hole conditions. Often operators will rent extra equipment for the job but this is not always the case.

Sometime operators choose to deepen their existing wells rather than go to the expense of drilling new ones and a workover rig is often hired to do the job. If the well has been on production prior to the project, it would be necessary to squeeze off the perforations. The cement is then drilled out, logged and tested. After the well has been drilled to the new depth, a liner may be run and cemented. The liner is then perforated and the well produced from the new zone. Data from the original well, including pertinent well control concerns, should be considered when the deepening program is designed.

There are times when it is necessary to abandon or bypass the lower portion of a well. The term to describe the operation is *sidetracking*. There are various reasons for sidetracking a well. Casing may be damaged or collapsed, junk may have been lost in the hole, or the production zone may have been damaged for some reason.

A cement plug is set above the planned kickoff point (KOP) and dressed with a bit. A window is cut in the casing, after which the directional hole is drilled through the window. Directional drilling service personnel use downhole motors or whipstocks to steer the bit according to the program. Depending on the type of completion to be performed, the new section of open hole may be logged, a liner run, and the new interval perforated and production resumed.

Whether sidetracking, deepening a well, or exposing the formation for any other reason, the supervisors and crew must re-adjust their thinking with regard to well control once the bit enters the open hole.

There comes a time in the life of every well when it will not be produced again or when it is uneconomical to continue production. Common sense and regulatory agencies require that wells are properly plugged and abandoned *(*P&A*)*.

After all perforations have been squeeze cemented, cement plugs are placed in the casing as the tubing or work string is pulled out of the well. Often the upper, unstuck casing is cut off and recovered and then cement plugs are set in the upper area of the hole. The wellhead is then removed as required by regulations.

If a well were to be left as is, even with the master valve closed, the casing would eventually deteriorate and fluid could migrate from one zone to another. Any high-pressure formation containing saltwater would eventually contaminate fresh water areas. There is the potential for future blowouts if gas is somehow trapped in the well. Offshore locations could become permanent hazards to navigation.

### *SECTION TWO - SURFACE AND SUBSURFACE EQUIPMENT*

Workover operations include repairing mechanical problems which may not be directly related to the formation. There are numerous of specialized tools designed to perform specific workover and completion operations inside a well. Some tools stay in a well throughout the productive life of the well. Others are used for special jobs and then retrieved. Tools with moving parts or that require setting and releasing at exact locations in a well may be operated by means of pump pressure, hydraulic pressure, or pickup/slack off weight. Some tools are designed to be used by wireline units.

Notice that some of the text in these discussions is printed in **boldface** type. The boldface print indicates a particular concern for a developing well control incident based on material gathered from the field.

## Christmas (Production) Tree

The *Christmas tree*[3] refers to the control valves, pressure gauges, and chokes assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed. It is used when reservoir pressure is sufficient to cause reservoir fluids to flow to the surface.

Although not strictly a part of subsurface equipment, installation of the Christmas tree represents the last phase of completion operations.

Good maintenance minimizes complications during production and leads to smoother repair and removal of the tree. The tree should be lubricated on a regular schedule. Extreme care must be taken when rigging up the tree. It is a good idea to function the casing valve prior to intervention activities in order to check for functionality, pressure and possible barrier failures such as a casing string or cement. Wings valves should be function tested to check for functionality and to ensure the well can be isolated from downstream equipment. The term wing valve is typically used when referring to the flowing wing.

The basic components making up the Christmas tree are:

- *Pressure gauge*. Pressure gauges allow well pressures to be monitored. Tubing pressure and casing or annular pressures are monitored with these gauges.
- *Gauge flange (cap).* The gauge flange provides a seal for the top of the tree and has provisions for a pressure gauge. When this flange is removed, it provides access to the tubing.
- *Crown valve (swab valve).* The crown valve is used to shut off pressure and allow access to the well for wireline, coil tubing, workover, etc. units to be rigged up.
- *Flow tee (cross, tee).* The flow tee is used so that tools may be run into the tubing without disconnecting the flow line.
- *Wing valve.* A wing valve is used to shut off the well for most routine operations. These are the easiest to replace in case of damage or cutting out of the valve.
- *Choke.* The choke controls the volume of flow from the well.
- *Master valves.* Master valves are the main shut off valves. They are open most of the well's life and are used as little as possible, especially the lower master valve.
- *Tubing hanger.* A tubing hanger suspends or supports the tubing string, seals off the casing annulus, and allows flow to the Christmas tree.

- *Casing valve.* The casing valve gives access to the annulus between the tubing and casing.
- *Casing hanger.* A slip and seal arrangement that suspends, and seals off, the casing in the casing bowl.
- *Casing.* Casing is a pipe string that supports the wellbore to prevent it from caving in and prevents communication from one zone to another.
- *Tubing.* A pipe string that contains and allows flow of fluid produced by the formation.

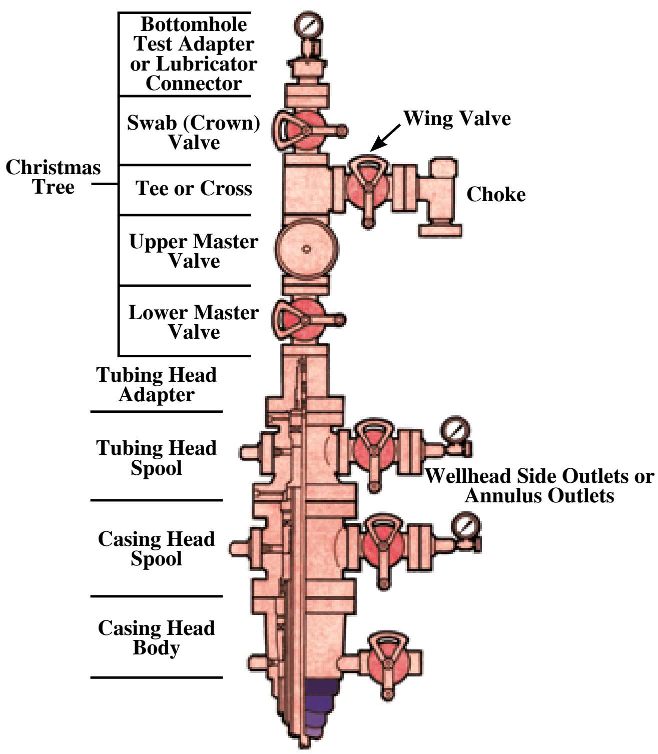
## Christmas Tree Removal

When planning to remove a Christmas tree and rig BOPs up on a well, several questions will be considered, for example:

- Will the tree be sent to a shop or serviced at the location, if necessary?
- Is the tree manufacturer service representative present and are there all the parts that may require replacement on site?
- Is the rig BOP equipment ready for immediate installation?
- Will the well be killed, or worked on under pressure?

If the well is to be killed by bullheading, several checks should by carried out before beginning the operation. The casing should be full of liquid and there should be no communication between the tubing and the casing. Kill fluid will be pumped until the produced fluid in the tubing has been displaced into the formation. Over-displacement can be major concern to avoid formation damage. After killing the well, a wireline plug is set in tubing, the wing valve is closed, and a back-pressure valve (BPV) is set in the tubing hanger. If there is no pressure buildup in the tubing or the annulus, the tree can be removed and the BOPs installed. Lockouts must be activated to ensure remotely activated valves are disabled.

Figure 1.10. A Christmas tree.



## Casing

*Casing*[5] is steel pipe placed in a well to prevent the wall of the hole from caving in, to prevent movement of fluid from one formation to another, and to improve the efficiency of extracting petroleum if the well is productive. A joint of casing may be from 16 to 48 feet long and from 4.5 to 20 inches in diameter. Casing is made of many types of steel alloy, which vary in strength, corrosion resistance, and so on.

*Casing is an integral component of the blowout prevention system. The internal yield (burst) rating is tested (usually to 70% of manufacturer's rating) after it is first cemented in a well. Caliper logs are run whenever casing wear is thought to be a concern and the internal yield limit is down-rated when the casing ID has been increased. It is common for companies to use the difference between the densities of the working fluid in the well and the fluid behind the casing to determine applied internal yield test pressure.*

### Conductor Casing

The *conductor casing* serves as a support during drilling operations, it helps prevents shallow gas flow during surface casing drilling and cementing. It prevents unconsolidated formations from collapsing near the surface. The conductor casing is the first casing on which a BOP can be installed.

### Surface Casing

*Surface casing* is used to isolate freshwater and hydrocarbon zones to prevent contamination, and to prevent loss of circulation during drilling and completion. It extends to the surface and is normally cemented to surface.

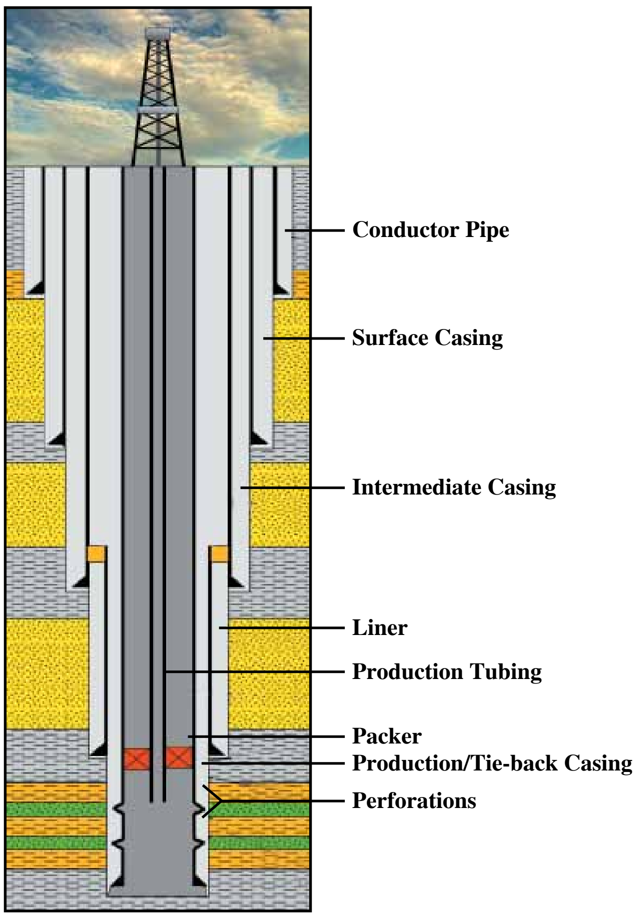
### Intermediate Casing

*Intermediate casing* is used in longer drilling intervals to isolate abnormally pressured formations, unstable shale sections, salt sections, lost circulation zones and where the drilling fluid density necessary to prevent blowouts may fracture deeper formations. It extends to the surface and is cemented in place.

### Production/Tie-back Casing

Production or tie-back casing forms the outer boundary of the annulus, which is run to the final interval (productive zone). It extends to the surface where it is hung off. The production casing is used to separate the productive zones from other reservoir formations. It may also be used for gas lift and killing the well.

Figure 1.11.



## Liner

*Liner*[6] is a string of pipe used to case open hole below existing casing. A liner extends from the setting depth up into another string of casing, usually overlapping about 100 to 300 feet above the lower end of the intermediate or the oil string. Liners are nearly always suspended from the upper string by a hanger device.

When workover units prepare to run liners they should make sure that the rig floor well control equipment, i.e., full opening safety valves, cross over subs, etc. are properly tested and readily available. If the liner float equipment should fail there must be a means of shutting off potential flow up through the liner.

## Liner Hanger

A *liner hanger*[7] is a slip device that attaches the liner to the casing.

Liner hangers may be set either mechanically or hydraulically and should be tested by applying pressure from inside and also tested negatively, that is by reducing the pressure at the hanger to a value below the estimated formation pressure at the hanger. The negative test is usually done by setting a packer above the hanger and then spotting light fluid into the string to reduce the differential pressure. Once the test is completed, the packer is released and the lighter fluid is allowed to U-tube out of the work string.

## Production Tubing

*Production tubing* is relatively small-diameter pipe that is run into a well to serve as a conduit for the well's produced fluids. It also protects the casing from pressure and corrosion. The tubing is normally run from the wellhead to the production zone. Tubing is classified by size, weight, and grade and there are a variety of premium connections used to couple joints of tubing together.

Old production tubing may be weak and develop leaks. There is potential for well control problems if formation fluids escape into the casing annulus.

## Work String

Depending on the type of work to be done, the tubing string is sometimes used to work over the well. However, in some instances it may not be desirable to use the production tubing and a work string with heavy-duty connections may be used. The production string is pulled and then a work string is picked up and used during the workover and then laid back down when the workover is completed. Using a work string avoids subjecting the tubing to unnecessary wear and damage.

The more the tubing is worked, the greater the possibility of failure. Wall thickness can be reduced significantly after many trips in and out of the well causing leaks or parting. Extreme forces such as when pulling or pushing the tubing can cause metal fatigue through elongation and compression and weaken the tubing. Pipe movement should be limited as much as possible. Downhole tools such as packers can be used to stabilize the work string and support some of the weight of the string thereby reducing compressive loading.

### Sliding Sleeve

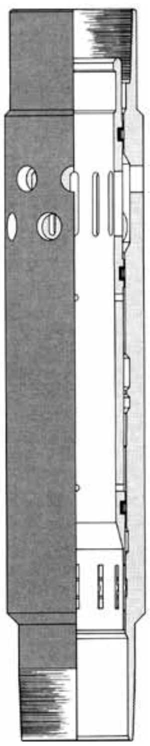
A *sliding sleeve*[8] is a special device placed in a string of tubing that can be operated by a wireline tool to open or close orifices to permit circulation between the tubing and the annulus (figure 1.12). It may also be used to open or shut off production from various intervals in a well.

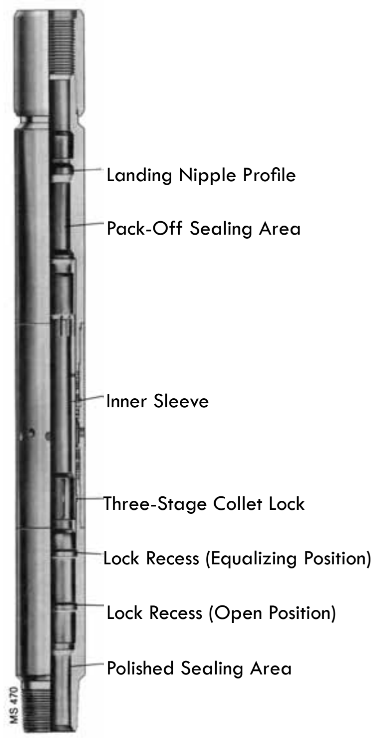
Any number of sliding sleeves may be run in a single tubing string and may all be opened or closed on a single trip or, individual sleeves may be opened selectively.

Sliding sleeves provide a nipple profile above the inner sliding sleeve and a polished pack-off area below as an integral part of the assembly. Ported nipples are sometimes used to provide additional access to the annulus. The profile provides locations for the additional landing nipples used for various flow control devices.

Sliding sleeves are sometimes difficult to shift due to differential pressure. Debris in a well may also prevent the tool from functioning properly.

Figure 1.12. Types of sliding sleeves.
*Left*, sliding sleeve.
*Right*, selective sliding sleeve.





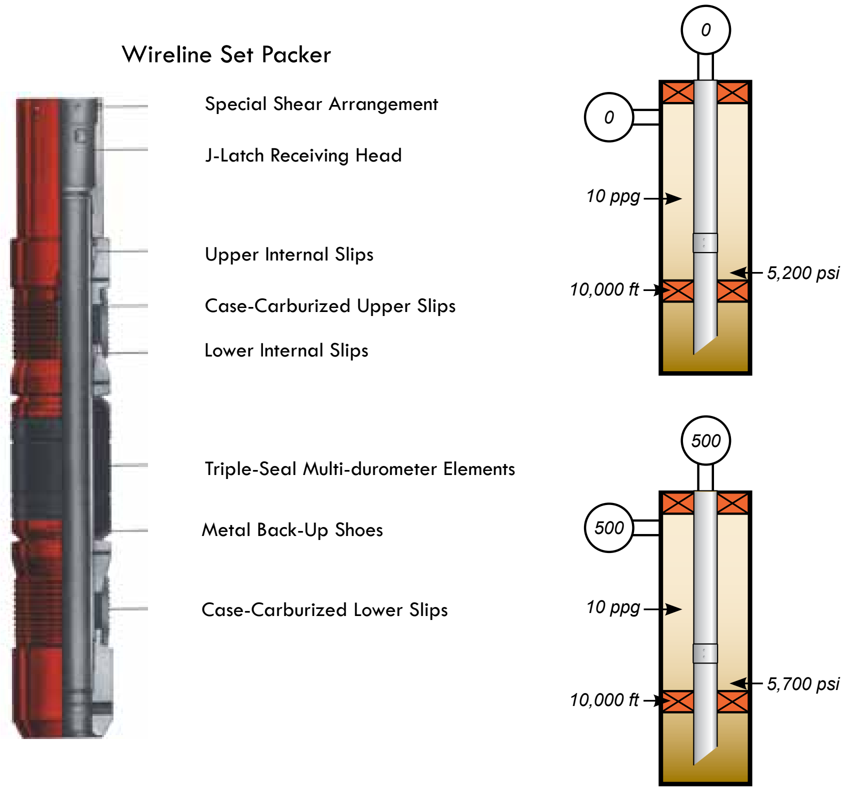

### Packers

A *packer*[9] is a downhole tool that consists of a sealing device, a holding or setting device, an inside passage for fluids. It is used to block the flow of fluids through the annular space between pipe and the wall of the wellbore by sealing off the space between them. In production, it is usually made up on the tubing string some distance above the producing zone. A packing element expands to prevent fluid flow except through the packer and tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (that is, whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed.

*From the standpoint of well control, releasing a packer is essentially the same as clearing any obstruction from a well. In the case of production packers there is always a dead spot, that is, an area that is not circulated, between the bottom of the packer and the tailpipe of the tubing. Gas that accumulates immediately below the packer will not be removed even though the well may have been killed by bullheading or any other means. Some packers may have a bypass valve which can be opened to allow circulation through the packer.*

*When testing packers and other downhole tools it is important to remember that the pressure exerted on*

Figure 1.13. Diagram of wireline set packer.




*the tool is made up of the hydrostatic pressure above the tool plus the pressure applied by the pump. For example suppose a packer was set at 10,000 feet and the annulus was full of brine with a density of 10.0 ppg. The hydrostatic pressure on top of the packer is 10 * 0.052 * 10,000 = 5,200 psi. If the pump was used to apply pressure on the annulus through a sliding sleeve until the standpipe gauge read 500 psi, the static pressure exerted on the annulus would be 5,700 psi (see figure 1.13).*

## Packer fluid

Packer fluid is used above a packer to provide hydrostatic pressure to reduce pressure differentials across the packer and production tubing. Packer fluids also lower the differential pressure on the wellbore and casing. They are formulated to be non-corrosive, stable (non-separating), and remain liquid so they may be pumped. Some commonly used packer fluids include combinations of brines like chlorides, bromides or formates.

## Seal Nipple Assembly

A *seal nipple assembly*[10] is a sealing member placed on the production tubing that is landed (placed) inside the seal bore of the packer (figure 1.14).

Figure 1.14. A locator seal nipple assembly.

The seal nipple assembly is used to prevent fluid and pressure from traveling between the tubing and packer into the casing or annulus. A latching type seal nipple locks into the packer so that tension may be pulled on the tubing if desired.

If the seals fail or leak for any reason it would expose the annulus to the pressures below the packer.

## Bridge Plug

A *bridge plug*[11] is a downhole tool composed primarily of slips, a plug mandrel, and a rubber sealing element that is run and set in casing to isolate a lower zone while an upper section is being tested or cemented.

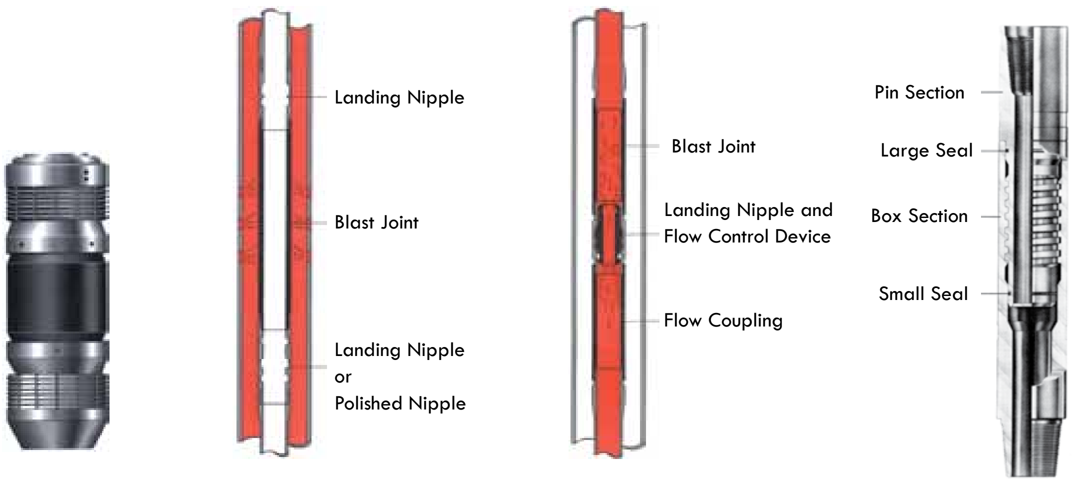
Bridge plugs may be permanent or retrievable and can be run either on the work string, or on wireline. They are set in the same manner as packers.

Bridge plugs should be tested after setting. Often they are only tested from above but if the plug is used to prevent flow from the formation, consideration should be given to performing a negative test also in order to make sure that the plug will also hold from the bottom.

## Blast Joint

A *blast joint*[12] is a tubing sub made of abrasion-resistant material. It is used in a tubing string where high-velocity flow through perforations may cause external erosion.

Figure 1.15.
*Left to right*, a bridge plug, placement of blast joint, flow collar placement, safety joint.



## Flow Coupling (Flow Collar)

A *flow coupling* is a tubing sub made of abrasion-resistant material and used in a tubing string where turbulent flow may cause internal erosion.

Flow couplings of hardened or special alloy steel are run along internal turbulent flow areas to prevent tubing damage or failure. They are a thicker section of straight pipe with proper tubing thread connections and full tubing ID.

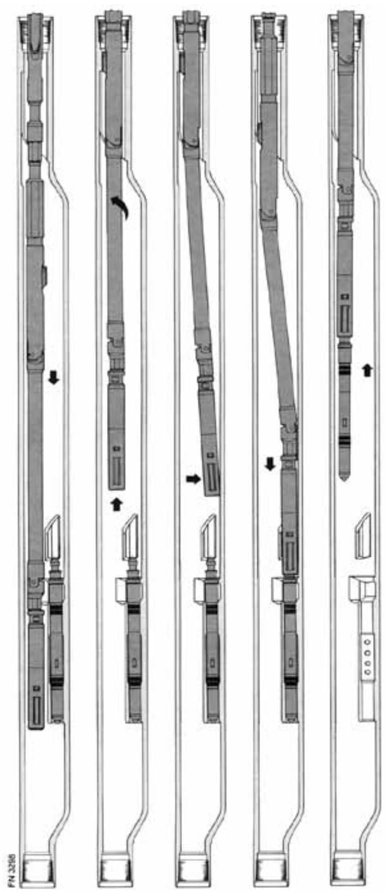
## Safety Joint

A *safety joint* is a large profile, threaded joint that allows quick and easy release of the tubing string from the downhole equipment by reverse rotation of the string or by shear force. Safety joints are run above tools that might easily become stuck in the hole. This allows a quick back off from the string so that fishing tools equipped with jars may be run in to retrieve the fish.

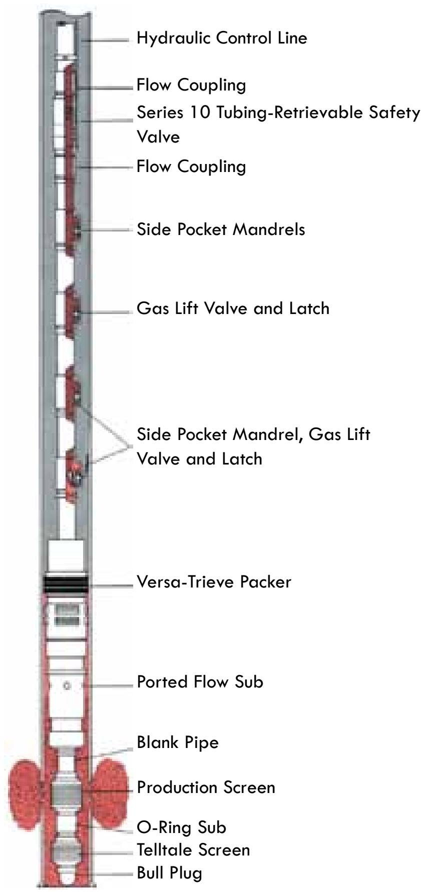
It is good practice to circulate bottoms up after releasing a safety joint in order to clear any gas that might be in the annulus.

Figure 1.16.

Mandrel valve pulling sequence



Placement of mandrels in production string



## Seating/Landing Nipple

A *seating nipple* is a special tube installed in a string of tubing, having machined contours to fit a matching wireline tool with locking pawls (figure 1.16). It is used to hold a regulator, choke, or safety valve; to anchor a pump; or to permit installation of gas-lift valves.

This equipment is sometimes used to set a plug in the tubing before nippling down the Christmas tree or to test the tubing.

## Gas Lift Valves

*Gas lift valves* are pressure-regulated check valves installed in a mandrel and run to lift reservoir fluid from the wells in which the formation pressure is insufficient and high-pressure gas is available (figure 1.16). High-pressure gas from the casing is allowed to enter the tubing through the valve ports and lift the well fluid by lowering the hydrostatic pressure inside the production tubing.

Dummy valves or circulation valves can also be installed in the mandrel. Dummy valves completely block flow and circulation valves can be used to circulate gas out of the annulus prior to pulling the tubing out of the well.

## Retrievable Cementer

A *retrievable cementer* is a packer (usually mechanically set) that is run for cement squeezes, high-pressure acid jobs and well tests (figure 1.17). Since it is retrieved after use, it is not a component of the permanent completion equipment.

As when releasing any packer, care must be taken that pressure is not trapped below the tool.

Figure 1.17. Cement retainer.

## Cement Retainer

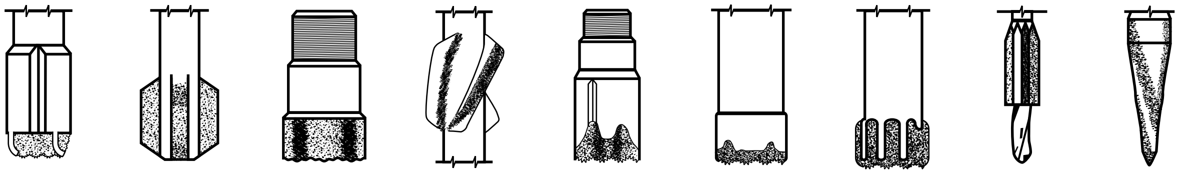
*Cement retainers* are wireline or tubing set drillable packers that are used during cement squeeze jobs (figure 1.17). They are usually drilled or milled out before perforating the casing. The retainer contains a flapper-type valve that is opened when the work string is stung into the retainer.

## Milling Tools

*Mills*[13] are downhole tools with rough, sharp, extremely hard cutting surfaces for removing metal, packers, cement, sand, or scale by grinding or cutting. Mills are run on the drill pipe or tubing to grind up debris in the hole, remove stuck portions of drill stem or sections of casing for sidetracking, and reaming out tight spots in the casing. They are also called *junk mills*, or *reaming mills*, depending on their use.

Caution must be taken when milling on junk so as not to accidentally cut a hole in the casing. If the job requires prolonged rotation, the casing should be pressure tested and/or callipered to determine if it was damaged during milling operations.

Figure 1.18. Milling tools.

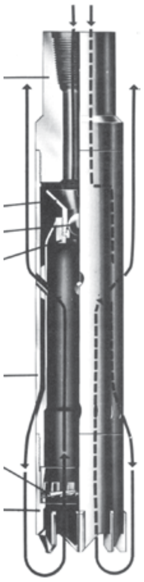


### Junk and Boot Baskets

The *junk and boot baskets* (figure 1.19) are devices that aid in the removal of milled or drilled material. A junk basket is run on or near the bottom of the string. By reverse or forward circulating (depending on the type of tool) cuttings are swept up into an inner chamber or basket. Heavy materials that cannot be circulated to the surface can be caught in the junk basket.

A boot basket is a bucket-like device run just above the mill or bit. Its OD is close to that of the wellbore. The fluid and milled cuttings circulate up the restrictive annular area and lose velocity when they reach the top of the boot, where the particles slip downward into the basket.

Figure 1.19. Circulating junk basket.




### Casing Scraper

A *casing scraper*[14] is a bladed tool used to scrape away junk or debris from inside casing. It is usually run on drillpipe or tubing above a bit or mill. Spring-backed blades that scrape the inside diameter of the casing provide the scraping action.

Prolonged rotation with a scraper may cause excessive wear and damage to the casing. It is not considered good practice to use a casing scraper in the string when drilling up cement. The scraper run should be made separately.

Figure 1.20. Casing scraper.

### Casing Roller

A *casing roller*[15] (figure 1.21, *below left*) is a tool composed of a mandrel on which are mounted several heavy-duty rollers with eccentric roll surfaces. It is used to restore buckled, collapsed, or dented casing in a well to normal diameter and roundness. Made up on tubing or drill pipe, and run into the well to the depth of the deformed casing, the tool is rotated slowly, allowing the rollers to contact all sides of the casing and restore it to roughly its original condition

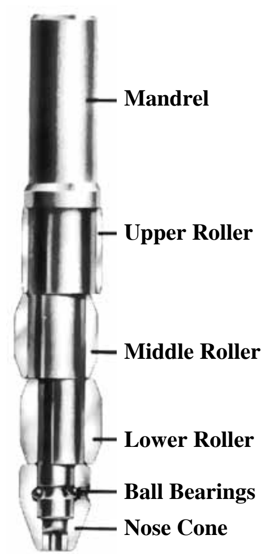
### Swage

A *swage*[16] (figure 1.21) is a solid cylindrical tool pointed at the bottom and equipped with a tool joint and the top for connection with a jar. It is used to straighten damaged or collapsed casing or tubing and drive it back to its original shape.

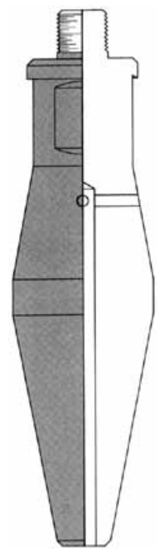
Casing rollers or swages are not often used. They are intended for casing or tubing that is only slightly dented. If the tubular is already deformed, it may remain in poor condition even after it has been rolled out. Good practice dictates that a set of jars be run in the string. If the tool should fall through a narrow portion of the pipe it may become stuck and have to be jarred out.

Figure 1.21.

Tubing and casing rollers




Swaging tool

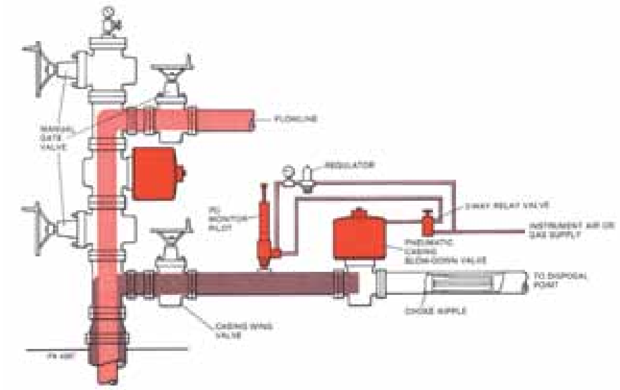


### Shutdown Systems

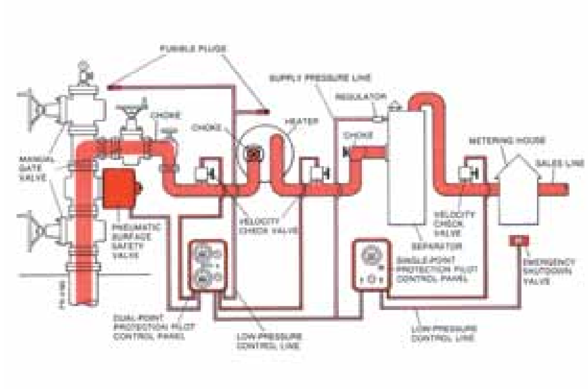
*Shutdown systems* include safety or automatic shutdown systems and emergency shutdown systems (ESDs). They provide a reliable form of safety insurance for the protection of our energy resources, property, environment, and especially human life. These systems are designed to shut in a producing well in the event of operational irregularities such as external heat, and other critical or hazardous irregularities. For example, abnormally high or low pressure, loss of the system's operational pressure supply, seal failure, or any other potentially hazardous system irregularity. These systems can be configured and operated in a variety of ways to shut down a live well. The shutdown can be accomplished by manual, automatic, direct, or remote control, and with surface or subsurface valves and tools.

Figure 1.22.

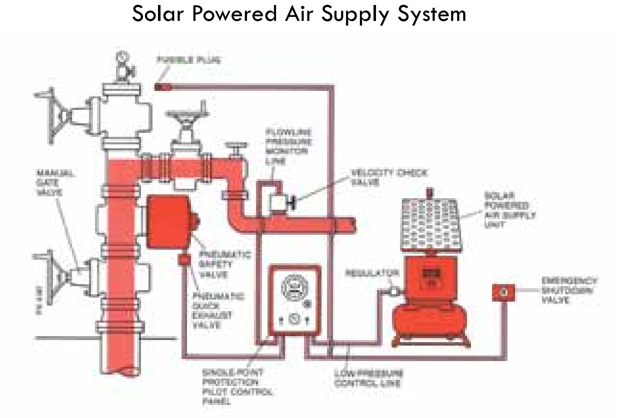
Casing Pressure Relief



Land Location Shutdown



Solar Powered Air Supply System



Remote Controlled System

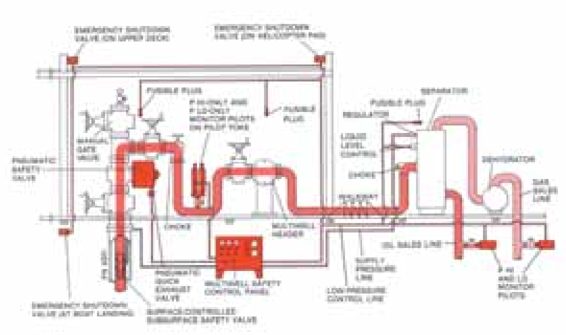
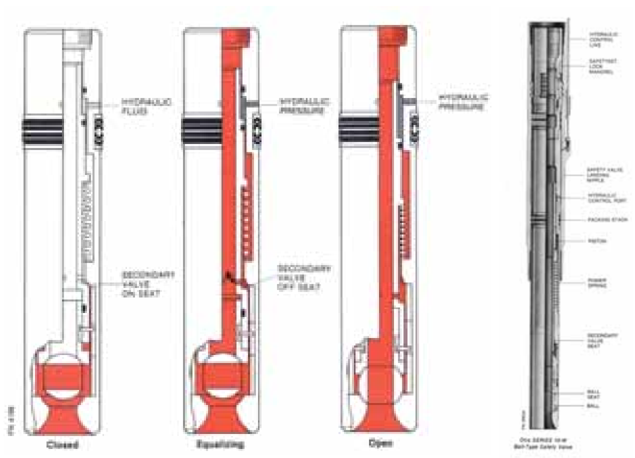
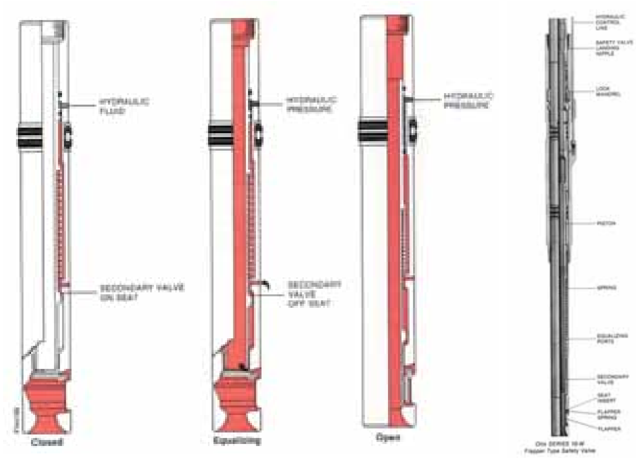


Figure 1.23.

*Left,* a wireline-retrievable safety valves, and *right*, bail-type safety valve.



*Left*, Series 10-w flapper valves and, *right*, flapper valve.



The systems can be very complex and vary greatly according to the specific well (and field) in which they are used. The basic components of an emergency shutdown system includes a safety valve, an automatic safety valve actuator, sensors (pilots and monitors), manifold(s), a source of pressure, and a control panel.

Monitor pilots may be installed at critical points to evaluate the system at any given moment. The function of the control or activator pilot is to sense a change (usually in pressure). Once the control pilot is activated, depending on the type, it may block or bleed pressure from an actuator. The actuator causes a valve to close due to loss of opening pressure (some induce a valve to open in order to dump excessive pressure). The systems are usually custom fabricated to each operator's requirements.

Many ESD systems are directly controlled surface-safety systems installed downstream of a choke and are controlled by line pressure or flow velocity fluctuations at the point of installation. These systems normally operate only with sudden drastic changes in operating conditions.

Remote controlled surface-safety systems are usually installed on the upper master valve of the tree and often on a wing valve upstream from the choke. Monitoring is usually done at high risk points throughout the well.

Design features of various downhole safety systems are listed below.

1. Retrievable
    - *Tubing retrievable* (TR) equipment is threaded into and becomes an integral part of the tubing string. To retrieve this equipment, the entire tubing string must be pulled. TR safety valves normally have a full open inside diameter. This permits wireline operation through the valve.
    - *Wireline retrievable* (WR) equipment is run into and out of the wellbore by conventional wireline operation. Most conventional WR safety valves require a tubing retrievable receptacle into which the valve locates. WR safety valves must be removed to perform wireline work below them.
2. Pressure method by which the pressure differential across the closure mechanism is reduced to permit opening.
    - Equalizing safety valves contain an integral equalizing mechanism (unloader). Before opening, the well must be shut in at the surface. Application of full open control line pressure opens the equalizing system. Surface pressure will increase under the closed surface valve because the high pressure held beneath the subsurface safety valve is now vented into the low pressure chamber above. After differential pressure across the ball or flapper decreases about 100 psi, the valve automatically opens.
    - Non-equalizing safety valves do not contain a self-equalizer and must be manually equalized before opening. This is accomplished by applying external tubing pressure on top of the safety valve. Once the operator has equalized the pressure across the valve, pressurization of the control line will open the safety valve.
3. Control
    - Surface controlled subsurface safety valves (SCSSV) are normally closed. They are hydraulically controlled and fail safe in design. These valves use a separate small diameter hydraulic control line run from the valve upward along the tubing string through the surface hanger, exiting through an exterior port in the wellhead for tie-in to the surface safety system. The valve consists of a hydraulic piston, a power spring, and a closure flapper

or ball. During flowing conditions hydraulic pressure is held on the valve to hold it open. Loss of control line pressure will cause the valve to close (fail-safe). To maintain hydraulic control line integrity, extreme caution must be exercised when manipulating the tubing string with the control line in the well.

- Subsurface controlled subsurface safety valves (SSCSV) are actuated by a change in flow characteristics of the well opposite the valve. This type of valve depends on an anticipated increase or decrease in pressure. The valves are normally an open type valve, and are not adjustable once they are installed downhole. The only way to test these valves is to flow the well more than the preset closure flow rate. Reliability and accuracy are subject to any change in the normal flowing characteristics of the well.

Formula for maximum fail safe setting depth:

$$\boxed{FSSD_{ft} = (FC_{psi} - FS_{psi}) \div MHFG_{psi/ft}}$$

Where:

FSSD = Fail-safe setting depth of valve (feet)

FC = Valve closing pressure (psi)

FS = Closing safety factor (psi) figured as 0.15 * FC, but never less than 75 psi .

MHFG = Maximum hydraulic fluid gradient (psi/ft).

Sample Job Sheet

Job No. ____________

Customer ______________________ Person Calling __________________ Ph. No. _____________

Time to be on the job ______________________ Date Job is to be done ________________________

Lease __________________________ Well No. ______________________ Field _______________

Type of Service ________________________________________________________________________

________________________________________________________________________________

Tubing Size ___________ Packer Depth _________ Approx. BHP _________ Safe Run Depth _______

Tubing End ___________ Type of Packer ______ Flowing _____________ Casing Pressure _______

Tubing Pressure ________ Perforations _________ Pumping _____________ Tubing Open In _______

Total Depth ___________ Perforations _________ Shut In _____________ Elevation ____________

Tree Connection ________________________________________________________________________

Direction of Location_____________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

Special Instructions to Operator ___________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

Job assigned to ___________________________

Employee receiving this job _________ Current Date Oper. _______________ Helper _____________

______________________________ ___________ ____________________ _________________

| Special Tools and/or Materials assigned to this job:** | Charged Customer* | Disposition (Check one) Returned to stock | | Left to Relief Oper. |
|---|---|---|---|---|
| | | Good Condition | Need Repairs | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

**The above tools and materials listed were issued to me and are my responsibility to care for and account for their disposition.

Operator ___________________________________

SIGN

*WLWO & OR No. _______________________________

Operator list addtional tools and materials assigned to job as it progesses.

MEMO FROM OPERATOR: (Pertaining to out of ordinary circumstances encountered on this job.)

________________________________________________________________________________

________________________________________________________________________________

# Well Control Principles 2

## Upon completion of this chapter, the student should be able to:

- Discuss and answer questions on hydrostatic pressure.
- Discuss and answer questions on abnormal pressure.
- Discuss and answer questions on fracture pressure.
- Describe the effects of pressure losses on surface pressure gauges and bottomhole pressure.
- Describe and calculate how changes in pump speed affect pressures.
- Describe and calculate how changes in fluid density affect pressures.
- Discuss and answer questions about primary well control.
- Discuss and answer questions about hydrostatic barriers.
- Discuss and answer questions on circulating pressure.
- Identify how pumping pressure affects well control.
- Determine hydrostatic pressure when fluids with different densities are pumped into a hole of known geometry.
- List the possible actions that can be taken to reduce pressure at the weak zone.
- Identify and explain contributors to bottomhole pressure.
- Perform calculations relative to pressure concepts using the WCS Formula Sheet (Appendix B):
    - Pressure gradient
    - Hydrostatic pressure
    - Capacity
    - Volume
    - Displacement
    - Equivalent circulating density (ECD)
    - New pump pressure at new pump rate
    - New pump pressure at new mud weight
- Describe the reasons for having a trip margin and the procedures to mitigate if it is not possible to maintain.

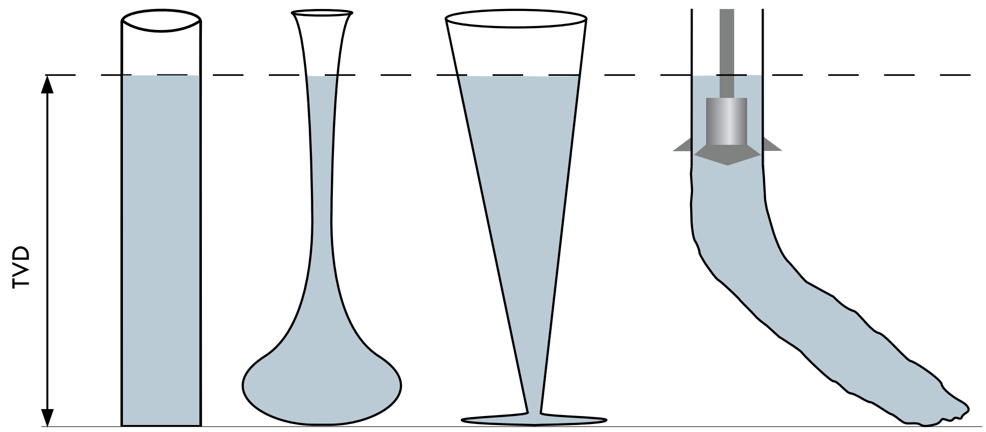
Understanding pressures and pressure relationships is important in understanding well control.

*Pressure is the force that a fluid (liquid or gas) exerts uniformly in all directions within a vessel, pipe, hole in the ground, etc.* Pressure is expressed in terms of force exerted per unit of area, for example, pounds per square inch.

$$\boxed{\text{Pressure} = \text{Force} \div \text{Area}}$$

It is important to remember that pressure is not a physical object; it is a measurement. The following is a discussion of the pressures acting within a drilled well.

Figure 2.1. Hydrostatic pressure varies with density and TVD.




NOTE: It is the vertical height/depth of the fluid column that matters; its shape is unimportant.

## Hydrostatic Pressure (HP)

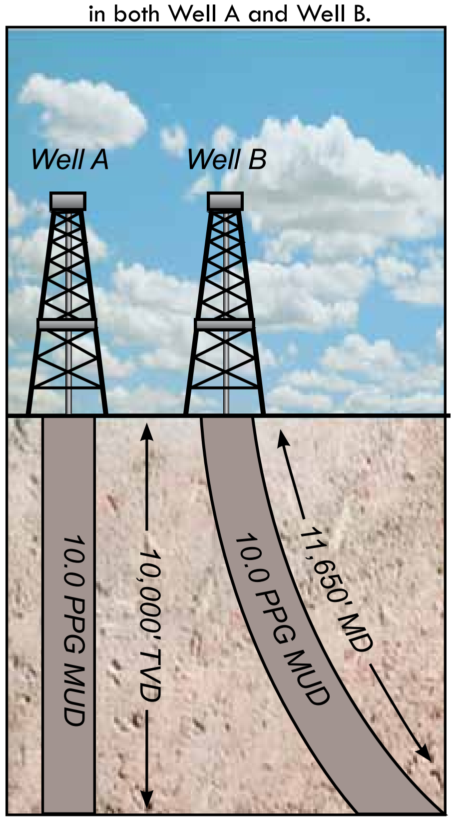
Hydrostatic pressure is the force, exerted by a body of fluid at REST. Hydrostatic pressure increases or decreases based upon the following two variables:

- *Mud weight*
- *Depth in relation to true vertical.*

Nearly all oilfield rig workers learn to check the *mud weight* (MW), but it is not really practical or even desirable to know the actual weight of all the fluid in a well. What we really want to know is the density of the fluid, that is, the weight of a given volume, often expressed as pounds per gallon (ppg) or specific gravity (sp gr). The density of the fluid is one of the two variables that affect hydrostatic pressure.

The other variable that affects hydrostatic pressure is the depth (the height of the fluid column). Since the weight of a substance is a measurement of the pull of gravity in an imaginary straight line to the center of the earth, it is the vertical or true vertical depth (TVD) of a well that must be used when determining hydrostatic pressure. The measured depth (MD) of a well is the length of the well. Think of highly deviated wells. In these wells the MD is much greater than the TVD. When considering hydrostatic pressure TVD must be used. Referring to the definition above, it can be said that as the fluid density or TVD varies in a well, the hydrostatic pressure will also vary and that hydrostatic pressure is controlled by adjusting the density of the fluid.

Figure 2.2
Hydrostatic pressure is equal in both Well A and Well B.



## WELL CONTROL MATH

If a decimal place is greater than or equal to (> or =) 5, round up, example 11.35 = 11.4

If a decimal place is less than (<) 5, round down, example 11.34 = 11.3

Barrels are rounded to the nearest tenth (0.1), example 1.26 bbl = 1.3 bbl

Capacities & Displacements$_{bbl/ft}$ carry five decimal places, example 0.00398 bbl/ft

Fluid Densities - Mud Weight$_{ppg}$, round to the nearest tenth, example 11.74 = 11.8 ppg

Kill Mud Weight$_{ppg}$ (KMW) is *always* rounded up.

Integrity Mud Weight$_{ppg}$ (MAMW) is *never* rounded up.

Feet are rounded to the nearest whole foot

Pounds per square inch (psi) is rounded to the nearest psi

True vertical depth (TVD) is used when calculating pressures

Measured depth (MD) is used when calculating capacities and displacements.

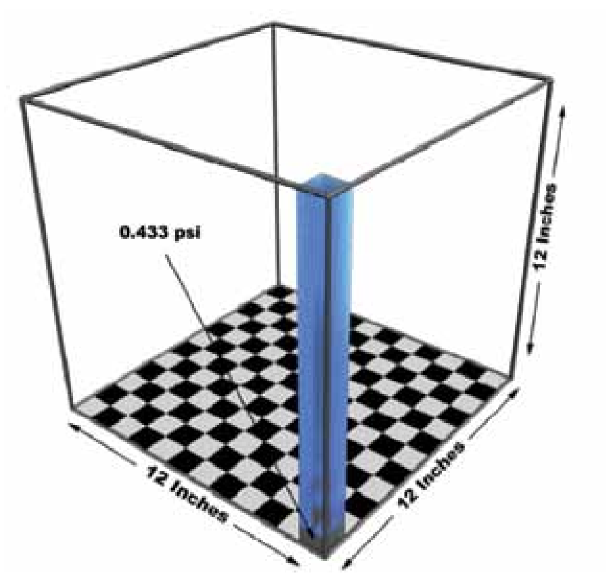
Hydrostatic pressure (HP) varies directly with fluid density and depth. The true vertical depth is multiplied by the density in order to determine the pressure. Consider the units of measure. If fluid density is measured in ppg, and TVD in feet, then it is obvious that these unlike values cannot be multiplied together in order to find pressure in psi. If the fluid density is converted so that it reflects a uniform change in pressure with depth, the results can be used to determine hydrostatic pressure at any vertical depth.

Since the pressure is measured in psi and depth is measured in feet, it is convenient to convert mud weights from pounds per gallon (ppg) to a pressure gradient (psi/ft). The conversion factor is 0.052. If the fluid density is converted so that it reflects a uniform change in pressure with depth, the results can be used to determine hydrostatic pressure at any vertical depth.

Imagine a column of fluid that is one foot high. Now imagine that the area of the fluid column is one square inch and that the fluid's density is 1.0 ppg. The weight of the column would be approximately 0.052 pounds exerted over the one square inch below the column as illustrated in figure 2.3. It follows that if a 1.0 ppg fluid exerts 0.052 psi per vertical foot (psi/ft), then a 9.0 ppg fluid would exert 9 times as much pressure or 9 * 0.052 = 0.468 psi/ft and a 9.5 ppg fluid would exert 9.5 * 0.052 = 0.494 psi/ft. The fluid density, measured in ppg, multiplied by 0.052 equals the pressure in psi exerted by a column of fluid one vertical foot high. This expression is the pressure (or fluid) *gradient* and is found by multiplying the fluid density in pounds per gallon by the conversion factor 0.052.

Figure 2.3.

A one-foot tall, one-inch square column of fresh water at 8.33 ppg exerts 0.433 psi of hydrostatic pressure.
8.33 ppg * 0.052 = 0.433 psi



$$\boxed{\text{Gradient}_{psi/ft} = MW_{ppg} * 0.052}$$

In order to determine the hydrostatic pressure at any given vertical depth, the pressure gradient is multiplied by the TVD.

$$\boxed{HP_{psi} = \text{Gradient}_{psi/ft} * TVD_{ft}}$$

Or substituting the $MW_{ppg}$ * 0.052 for gradient:

$$\boxed{HP_{psi} = MW_{ppg} * 0.052 * TVD_{ft}}$$

Example:

What is the hydrostatic pressure of a 500-foot TVD column of fresh water? Fresh water weighs 8.33 ppg.

$HP_{psi} = MW_{ppg} * 0.052 * TVD_{ft}$

$HP = 8.33 * 0.052 * 500$

$HP = 216.6$ psi

Example:

What is the hydrostatic pressure of a 6,750-foot MD well, filled with a 0.478 psi/ft pressure gradient fluid, which has a TVD of 6,130 ft?

$HP_{psi} = \text{Gradient}_{psi/ft} * TVD_{ft}$

$HP = 0.478 * 6{,}130$

$HP = 2{,}930$ psi

Example:

A 12,764-foot TVD well is filled with a 15 ppg fluid. What is the hydrostatic pressure at the bottom of the well?

$HP_{psi} = MW_{ppg} * 0.052 * TVD_{ft}$

$HP = 15 * 0.052 * 12{,}764$

$HP = 9{,}956$ psi

## Calculating Hydrostatic Pressure when using Multiple Densities

Hydrostatic pressure differences occur during workover operations when pumping fluids with different densities such as pills, slugs, washes, and spacers. It is easy to calculate hydrostatic pressure with two or more fluids in a well provided the depths (TVD) of the fluid interfaces are known. Using the same formula, the HP for each fluid section is calculated in the same way and the sum of the individual calculations gives the HP at the bottom of the well.

Example:

A 10,500-foot TVD well has two fluids in the well, a 15 ppg fluid from bottomhole depth to 7,125 feet and 8.33 ppg fluid to surface, what is the HP at the bottom of the well? See figure 2.4.

The formula for calculating the hydrostatic pressure for calculating a column with varying densities is:

$HP_{psi}$ = Fluid $Weight_{ppg}$ * 0.052 * $TVD_{ft}$

$HP_1$ = 8.33 * 0.052 * 7,125

$HP_1$ = 3,086 psi

$HP_2$ = 10,500 - 7,125

$HP_2$ = 3,375 ft

$HP_2$ = 15 * 0.052 * 3,375

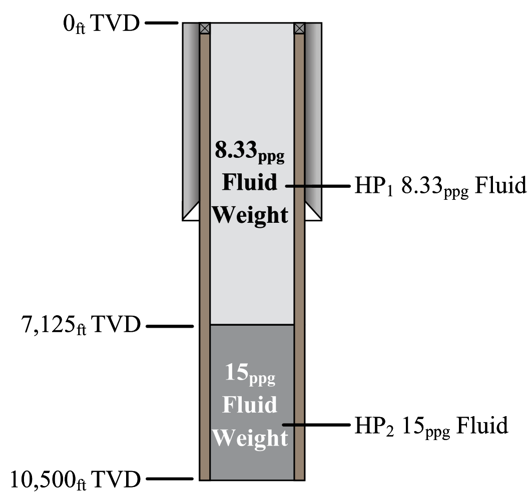
$HP_2$ = 2,633 psi

Total $HP_{psi}$ = $HP_1$ + $HP_2$

Total HP = 3,086 + 2,633

Total HP = 5,719 psi

Figure 2.4.




Example:

In figure 2.5, there are four different densities of working fluid in a 10,000-foot TVD well. For ease of calculation, each different density spans 2,500 feet of annulus. Hydrostatic pressures at 2,500 feet, 5,000 feet, 7,500 feet, and at the bottomhole depth of 10,000 feet are determined using the calculations shown on the next page.

The formula for calculating the hydrostatic pressure in a column with varying densities is:

$HP_{psi}$ = Fluid $Weight_{ppg}$ * 0.052 * $TVD_{ft}$

$HP_{1\ psi}$ = 8 ppg * 0.052 * 2,500 ft = 1,040 psi

$HP_{2\ psi}$ = 10 ppg * 0.052 * 2,500 ft = 1,300 psi

$HP_{3\ psi}$ = 12 ppg * 0.052 * 2,500 ft = 1,560 psi

$HP_{4\ psi}$ = 14 ppg * 0.052 * 2,500 ft = 1,820 psi

Calculating total downhole pressure:

Total $HP_{psi}$ = $HP_1 + HP_2 + HP_3 + HP_4$

At 2,500 $HP_{psi}$ = $HP_1$

At 2,500 $HP_{psi}$ = 1,040 psi

At 5,000 $HP_{psi}$ = $HP_1 + HP_2$

At 5,000 $HP_{psi}$ = 1,040 + 1,300 = 2,340 psi

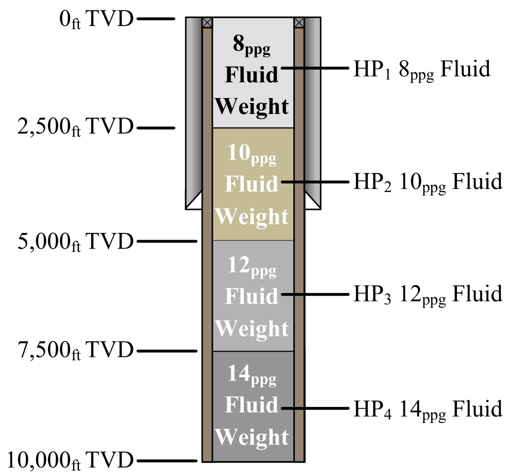
At 7,500 $HP_{psi}$ = $HP_1 + HP_2 + HP_3$

At 7,500 $HP_{psi}$ = 1,040 + 1,300 + 1,560 = 3,900 psi

At 10,000 $HP_{psi}$ = $HP_1 + HP_2 + HP_3 + HP_4$

At 10,000 $HP_{psi}$ = 1,040 + 1,300 + 1,560 + 1,820 = 5,720 psi

Figure 2.5.



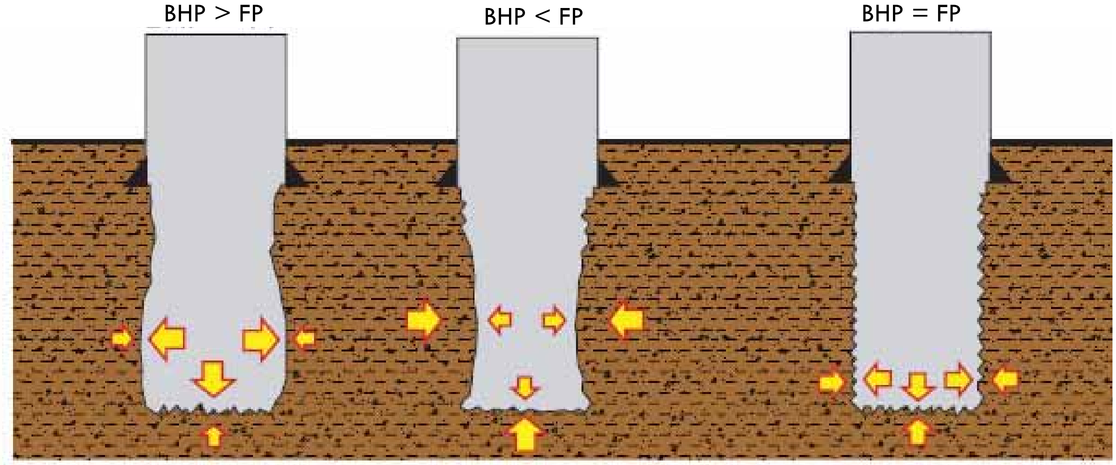

## Differential Pressure

The difference between two pressures is differential pressure. For example, the pressure difference between the inside and outside of a tubing string could be called the *differential pressure*. The term could also be applied to the difference between the wellbore pressure and the reservoir pressure. However, in drilling, workover, completion operations, and well control work, the term differential pressure, when applied to the difference between wellbore BHP and formation pressure, is replaced by three other terms that identify the status or direction of the differential pressure. A well is considered balanced when there is zero differential pressure between the BHP and the formation pressure. A well is considered to be in an overbalanced state when the BHP is greater than the formation pressure, and a well is underbalanced when the formation pressure is greater than the BHP. The three states of differential pressure between the bottom of the well and formation pressure at that depth are illustrated in figure 2.6.

When a well is overbalanced, the formation fluid will not enter the well, but wellbore fluids can seep into the formation or, in the extreme case, fracture the formation. When the well is underbalanced, formation fluids will flow into the well. The influx of formation fluids is called a *kick*.

A well is intentionally underbalanced when production occurs; i.e., an intentional kick is allowed. If the well becomes underbalanced when a static intervention is in progress, an influx of formation fluids enters the well; i.e., an unintentional kick occurs, and the well must be shut in.

Figure 2.6.




## Specific Gravity

Many fluids in the oilfield are also expressed in specific gravity (sp gr or SG) as well as weight, in ppg. Specific gravity is the ratio of the weight of a fluid (liquid) to the weight of fresh water. It is also necessary to be able to convert specific gravity to pressure gradient in order to calculate hydrostatic pressures. Fresh water weighs 8.33 ppg and salt water is nominally 10 ppg. Therefore, the specific gravity of salt water is:

Specific Gravity (SG) of Salt Water = 10 ppg ÷ 8.33 ppg

Specific Gravity of Salt Water = 1.2 sp gr

The SG of fresh water is 1.0. As the gradient of fresh water is known to be 0.433 psi/ft, to obtain the gradient of a fluid, it is simply necessary to multiply its SG by 0.433 psi/ft

$$\boxed{\text{Gradient}_{psi/ft} = \text{Sp gr} * 0.433_{psi/ft}}$$

Example:

What is the hydrostatic pressure (HP) exerted by a true vertical 5,000-foot column of brine with a 1.17 SG.

$$\boxed{HP_{psi} = Gradient_{psi/ft} * TVD_{ft}}$$

$$\boxed{Gradient_{psi/ft} = SG * 0.433\ psi/ft}$$

Or substituting SG * 0.433 for gradient

$$\boxed{HP_{psi} = SG * 0.433_{psi/ft} * TVD_{ft}}$$

HP of brine = 1.17 sp gr * 0.433 psi/ft * 5,000 ft

HP of brine = 2,533 psi

## API Gravity

API gravity is another value used to express relative weight of fluids, and was introduced by the American Petroleum Institute (API) to standardize the weight of oilfield fluids at a base temperature of 60 ° F. The range for API fluids used in the oilfield is usually between 10 ° API and 70 ° API. Water is used as the standard and assigned the value of 10 ° API. If a fluid's API gravity is greater than 10 degrees, it is lighter and floats on water; if less than 10 degrees, it is heavier and sinks.

To convert from API gravity to specific gravity, the following formula is used.

$$\boxed{\text{Specific Gravity} = 141.5 \div (131.5 + \text{API Gravity})}$$

Example:

What is the specific gravity of 30 degrees API oil?

Specific Gravity = 141.5 ÷ (131.5 + API Gravity)

Specific Gravity = 141.5 ÷ (131.5 + 30)

Specific Gravity = 0.876 sp gr

## Gas Correction Factors

Most well servicing operations entail working with live wells, whether using a through-tubing method or rig intervention. Even with a rig operation, the well must be prepared by being killed prior to the intervention. This involves dealing with gas in the well.

Production wells with gas in the fluids will exert a static surface pressure equal to the formation pressure less the hydrostatic pressure in the production bore. The gas entrained in the production fluids will segregate from the liquids as shown in figure 2.7. In a static situation, the closed in tubing head pressure (CITHP) and hydrostatic pressure will balance the formation pressure.

As discussed earlier, gas is also a fluid and exerts a hydrostatic pressure. Being compressible, pressure affects the density of the gas. A set of correction factors are used to calculate hydrostatic pressures at varying TVDs with a range of gas gravities (refer to table 2.1). The correction factor, according to the TVD of the gas column and the gas gravity, is multiplied by the CITHP:

$$\boxed{HP_{psi} = \text{Correction factor} * CITHP_{psi}}$$

Example:

What is the HP of a 5,000-foot TVD column of 0.7 specific gravity gas (correction factor i.e., 1.129, see table 2.1) with a closed-in tubing head pressure of 1,650 psi?

$HP_{psi}$ of gas = Correction Factor * CITHP

HP of gas = 1.129 * 1,650 psi

HP of gas = 1,863 psi

Using the calculations already given in earlier sections and the gas correction factors, hydrostatic pressures in relatively complicated systems can now be determined.

Table 2.1. Gas Correction Table.

| **Well Depth** | **Correction Factors (Gravity)** | | | |
|---|---|---|---|---|
| | **0.6 SG** | **0.7 SG** | **0.8 SG** | **0.9 SG** |
| 3,000 | 1.064 | 1.075 | 1.087 | 1.098 |
| 3,500 | 1.075 | 1.089 | 1.102 | 1.115 |
| 4,000 | 1.087 | 1.102 | 1.117 | 1.133 |
| 4,500 | 1.098 | 1.115 | 1.133 | 1.151 |
| 5,000 | 1.110 | 1.129 | 1.149 | 1.169 |
| 5,500 | 1.121 | 1.143 | 1.165 | 1.187 |
| 6,000 | 1.133 | 1.157 | 1.181 | 1.206 |
| 6,500 | 1.145 | 1.171 | 1.197 | 1.224 |
| 7,000 | 1.157 | 1.185 | 1.214 | 1.244 |
| 7,500 | 1.169 | 1.204 | 1.232 | 1.265 |
| 8,000 | 1.181 | 1.214 | 1.248 | 1.282 |
| 8,500 | 1.193 | 1.214 | 1.266 | 1.304 |
| 9,000 | 1.206 | 1.239 | 1.282 | 1.324 |
| 9,500 | 1.218 | 1.244 | 1.302 | 1.345 |
| 10,000 | 1.232 | 1.259 | 1.320 | 1.366 |
| 10,500 | 1.244 | 1.275 | 1.338 | 1.388 |
| 11,000 | 1.257 | 1.289 | 1.357 | 1.410 |
| 11,500 | 1.270 | 1.306 | 1.376 | 1.433 |
| 12,000 | 1.282 | 1.322 | 1.395 | 1.455 |
| 12,500 | 1.297 | 1.338 | 1.415 | 1.477 |
| 13,000 | 1.311 | 1.354 | 1.434 | 1.500 |
| 13,500 | 1.324 | 1.371 | 1.455 | 1.523 |
| 14,000 | 1.338 | 1.388 | 1.475 | 1.548 |
| 14,500 | 1.352 | 1.405 | 1.495 | 1.573 |
| 15,000 | 1.366 | 1.422 | 1.515 | 1.596 |

Example:

What is the differential pressure between the annulus and tubing at a circulation device installed at a depth of 8,200 feet TVD in the tubing string? See figure 2.7.

The following are the well conditions:

- The tubing/casing annulus is filled with a 10.29 ppg brine.

- The well is shut in at surface with a CITHP of 600 psi.
- There is a gas cap of 0.6 sp gr gas from 4,000 feet to surface.
- There is 32 ° API oil from 4,000 feet to 12,000 feet.

HP of brine in annulus at circulation device:

$HP_{psi}$ = Fluid $Weight_{ppg}$ * 0.052 * $TVD_{ft}$

$HP_{psi}$ = 10.29 ppg * 0.052 * 8,200 ft

HP = 4,388 psi

HP of gas cap:

$HP_{psi}$ = Correction factor * $CITHP_{psi}$

HP of gas cap = 1.087 (from table) * 600 psi

HP of gas cap = 652 psi

HP of 32 ° API oil column:

SG = 141.5 ÷ (131.5 + API Gravity)

SG of 32 ° API oil = 141.5 ÷ (131.5 + 32)

32 ° API oil = 0.865 SG

HP of oil column:

$Gradient_{psi/ft}$ = SG * 0.433

$HP_{psi}$ = $Gradient_{psi/ft}$ * $TVD_{ft}$

$HP_{psi}$ = SG * 0.433 * $TVD_{ft}$

$HP_{psi}$ = 0.865 SG * 0.433 psi/ft * (8,200 - 4,000) ft

HP = 1,573 psi

Total HP in tubing:

Total $HP_{psi}$ = HP of gas + HP of oil

Total HP = 652 psi + 1,573 psi

Total HP = 2,225 psi

Differential pressure across circulation device:

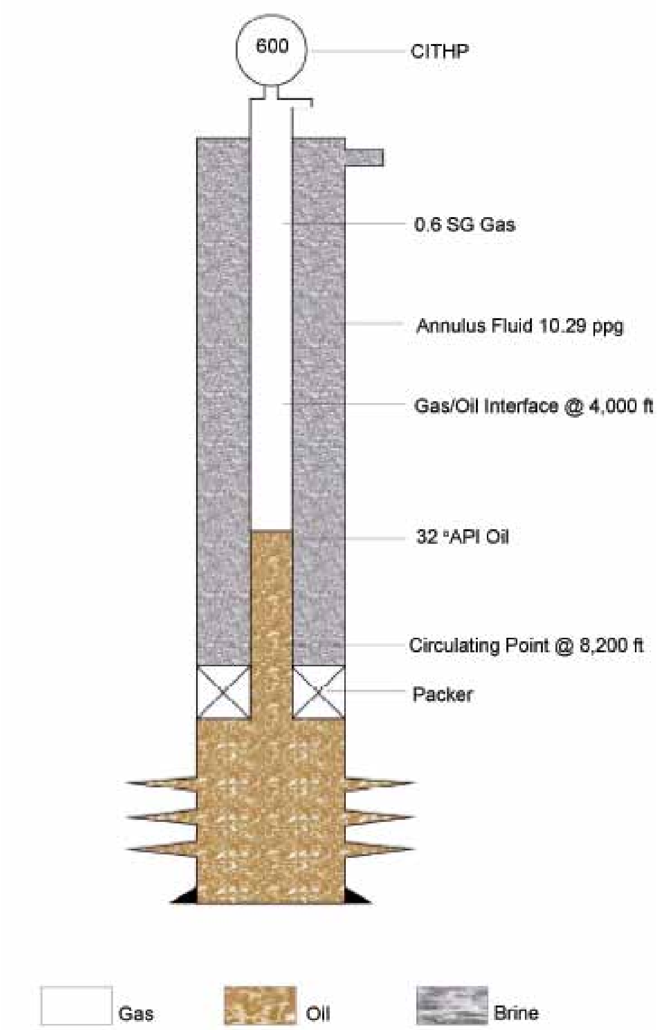
Differential $Pressure_{psi}$ = HP of annulus - HP of tubing

Differential $Pressure_{psi}$ = 4,388 psi - 2,225 psi

Differential $Pressure_{psi}$ = 2,163 psi pressure differential between annulus and tubing

If the circulation device were to be opened, then the opening tool string would be exposed to 2,163 psi differential pressure. If using wireline, this pressure differential will need to be equalized before opening the device; otherwise, there is a high risk of having the tool string "blown up the hole."

Figure 2.7. Example of a production well.




## Commonly Used Formulas

Well control requires calculating capacities, volumes and displacements. Commonly used formulas can be found in the formula sheet in the appendix B of your manual.

## Volume/Capacities/Displacements

It is important, in well-control operations, to understand how wellbore volumes are calculated. These volumes include total string capacity and total annular capacity. The volume inside a tubular is calculated by multiplying the capacity of that tubular component times the length of that component.

$$\boxed{\text{Total Volume} = \text{Capacity}_{bbl/ft} * \text{Length}_{ft} = \text{barrels}}$$

Displacement of the steel making up a piece of tubular equipment in the wellbore is calculated by multiplying the displacement of that component of the tubular times the length of the component.

$$\boxed{\text{Total Displacement of Steel} = \text{Displacement}_{bbl/ft} * \text{Length}_{ft} = \text{barrels}}$$

Most standard tubular goods have their capacity and displacement tabulated along with other physical characteristics of the item. However, very good estimates of these properties can be calculated with simple formulas:

$$\boxed{\text{Capacity}_{bbl/ft} \text{ inside a tubular} = ID^2 \div 1{,}029.4}$$

$$\boxed{\text{Capacity}_{bbl/ft} \text{ of an annular space} = (ID^2\text{annulus} – OD^2\text{tubing}) \div 1{,}029.4}$$

$$\boxed{\text{Displacement}_{bbl/ft} \text{ of a open ended tubular} = (OD^2 – ID^2) \div 1{,}029.4}$$

$$\boxed{\text{Displacement}_{bbl/ft} \text{ of a tubular with closed ends or a solid bar is} = OD^2 \div 1{,}029.4}$$

Note: When using tables, the displacement of a closed end tubular is the sum of the tabulated capacity and displacement.

Example:

What is the volume inside 4,000 feet MD of 5 inch, 24.7 pounds per foot (ppf) DP with an ID of 4.60 inches?

Solution:

$\text{Volume}_{bbl} = \text{Capacity}_{bbl/ft} * \text{Length (MD)}_{ft}$

$\text{Capacity}_{bbl/ft} = ID^2 \div 1{,}029.4$

$\text{Capacity}_{bbl/ft} = 4.6^2 \div 1{,}029.4$

$\text{Capacity}_{bbl/ft} = 21.16 \div 1{,}029.4$

$\text{Capacity}_{bbl/ft} = 0.02056 \text{ bbl/ft}$

$\text{Volume}_{bbl} = 0.02056 \text{ bbl/ft} * 4{,}000 \text{ ft} = 82.24 \text{ bbl}$

Example:

What is the volume in the annular space surrounding 600 ft of 8 inch OD drill collars inside a 12-1/4 inch open hole?

Solution:

$\text{Capacity}_{bbl/ft} \text{ of an annular space} = (ID^2\text{annulus} – OD^2\text{tubular}) \div 1{,}029.4$

$\text{Capacity}_{bbl/ft} = [12.25^2 - 8^2] \div 1{,}029.4 = 86.0625 \div 1{,}029.4 = 0.08360 \text{ bbl/ft}$

$\text{Volume}_{bbl} = 0.08360 * 600 = 50.16 \text{ bbl}$

## Tanks

### Rectangular Capacity

Other important calculations are the capacities and volumes of various tanks or “pits” used in the handling of wellbore fluids, cement, treatment fluids, completion fluids and drilling fluids. These tanks generally have open tops, with either rectangular or cylindrical shapes. The capacity of tanks is usually defined as the maximum volume of fluid the tank or pit can contain. For rectangular tanks or pits,

$$\boxed{\text{Capacity rectangular tank (cubic ft)} = \text{Length}_{ft} * \text{Width}_{ft} * \text{Height}_{ft}}$$

Or

$$\boxed{\text{Capacity rectangular tank (cubic m)} = \text{Length}_{m} * \text{Width}_{m} * \text{Height}_{m}}$$

In English (engineering) units, capacity is generally measured in barrels, so the resulting number of cubic feet are converted to barrels by multiplying by 0.178 bbl/ft$^3$.

$$\boxed{\text{Capacity rectangular tank (bbl)} = \text{Length}_{ft} * \text{Width}_{ft} * \text{Depth}_{ft} * 0.178 \text{ bbl/ft}^3}$$

Example:

Calculate the capacity of a rectangular pit used in coiled tubing operations. The tank is 8 feet in length and 6 feet in width and 4 feet in height. Show the answer in barrels.

Capacity rectangular tank (bbl) = $\text{Length}_{ft} * \text{Width}_{ft} * \text{Depth}_{ft} * 0.178$ bbl/ft$^3$

Capacity rectangular tank (bbl) = 8 ft * 6 ft * 4 ft * 0.178 bbl/ft$^3$

Capacity rectangular tank (bbl) = 192 ft$^3$ * 0.178 bbl/ft$^3$

Capacity rectangular tank (bbl) = 34.18 bbl

Capacity in bbl/in

4 * 12 = 48 inches

48 in ÷ 34.18 bbl = 1.4 bbl/inch

The volume of fluid in a rectangular tank or pit is its *length * width * depth* of fluid in the tank or pit. The units of measure are generally barrels or cubic meters (cubes).

Volume rectangular tank (bbl) = $\text{Length}_{ft} * \text{Width}_{ft} * \text{Depth}_{ft} * 0.178$ bbl/ft$^3$

Volume rectangular tank (m$^3$) = $\text{Length}_{m} * \text{Width}_{m} * \text{Depth}_{m}$

Many of these tanks have markers on their sides that measure the fluid volume in the pit directly in barrels. These tanks use a pre-determined conversion factor applicable to that particular tank or pit only. Volume measurements are simple when there are barrel markers on the inside wall that can be easily read. A modern tank has a "float" that sends an electrical signal to the control console so the operator has a direct measurement of the volume of the fluid inside the tank or pit.

Example:

Calculate the volume of a rectangular tank filled with a mixed treatment fluid ready for pumping into a well. The tank is 10 feet long by 6 feet wide and the fluid level is 41 inches.

There is not a barrel marker or float on the tank, but there is a marker that measures the depth of the tank in inches.

Volume rectangular tank (bbl) = $\text{Length}_{ft} * \text{Width}_{ft} * \text{Depth}_{ft} * 0.178$ bbl/ft$^3$

Volume rectangular tank (bbl) = $\text{Length}_{ft} * \text{Width}_{ft} * \text{Depth}_{in} * 1/12$ (ft/in) * 0.178 bbl/ft$^3$

Volume rectangular tank (bbl) = 10 ft * 6 ft * 41 in * 1/12 (ft/in) * 0.178 bbl/ft$^3$

Volume rectangular tank (bbl) = 36.49 bbl

## Vertical Cylinder Capacity and Volume

The maximum capacity of a vertical cylindrical tank is calculated by multiplying the cross sectional area of the inside of the tank by its height. The ID of the tank is measured in inches or meters.

$$\boxed{\text{Capacity cylindrical tank (bbl/ft)} = \text{Tank Diameter ft}^2 \div 7.148}$$

$$\boxed{\text{Capacity cylindrical tank (bbl/ft)} = \text{Tank Diameter in}^2 \div 1{,}029.4}$$

$$\boxed{\text{Capacity cylindrical tank (bbl/in)} = \text{Tank Diameter ft}^2 \div 85.78}$$

$$\boxed{\text{Capacity cylindrical tank (bbl/in)} = \text{Tank Diameter in}^2 \div 12{,}352.9}$$

Vertical cylinder volume is calculated by:

$$\boxed{\text{Volume cylindrical tank (bbl/ft)} = \text{Capacity}_{bbl/ft} * \text{Height}_{ft}}$$

$$\boxed{\text{Volume cylindrical tank (bbl)} = \text{Capacity}_{bbl/in} * \text{Height}_{in}}$$

As in rectangular tanks, volume measurements are simple when there are barrel markers on the inside walls that can be read easily. Many modern cylindrical tanks have a "float" that sends an electrical signal to the control console so the operator has a direct measurement of the volume of the tank or pit.

## Primary Well Control

Primary well control consists of maintaining drill fluid hydrostatic density greater than formation pressure. During normal drilling operation, the hydrostatic pressure of the drilling fluid creates the primary barrier to avoid any flow of formation fluid into the well bore.

## Barriers[1]

In its most basic form, a barrier is something that blocks the energy of a hydrocarbon formation from reaching other points in a wellbore or the surface. More specifically, a barrier is a tool, material, fluid or operational practice that is used to isolate and manage the energy within the formation from sections of the well or the surface drilling or production system. Barriers are either physical (mechanical tool, material or a hydrostatic column of fluid) or operational (a drilling practice that supplements or activates an inactive physical barrier, such as operating a BOP or valve).

## Hydrostatic or Fluid Barriers

The hydrostatic pressure of a column of fluid of known density and vertical height must be sufficient to overcome the pore pressure of the exposed formation. The fluid cannot be considered a barrier unless it can be monitored for density and vertical height. A drop in vertical height or the density of a fluid will produce a corresponding drop in hydrostatic pressure, and possibly lead to an underbalanced condition. The fluid would then no longer be an effective barrier. There should be a sufficient hydrostatic pressure overbalance above the formation pressure to allow for contingencies.

Most drilling muds can be reliable barriers in open hole if properly monitored. Brines and completion fluids generally do not make effective hydrostatic barriers if exposed to permeable formations because there is no filter cake as with muds. Hence, completion fluids will generally leak off into the formation, losing their hydrostatic pressure. Brine may be regarded as a reliable barrier during a drilling or workover operation as long as its density and fluid level can be monitored. However, brine or any completion fluid left above a packer between tubing and casing or between casing strings may not be a reliable barrier if it cannot be monitored.[2]

### Fluid Column[3]

The following is from NORSOK Standard D-010, 15.1 Table 1:

A. Description

   This is the fluid in the well bore.

B. Function

The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the well bore that will prevent well influx/inflow (kick) of formation fluid.

C. Design construction selection

1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g., riser margin, trip margin).
2. Critical fluid properties and specifications shall be described prior to any operation.
3. The density shall be stable within specified tolerances under downhole conditions for a specified period of time when no circulation is performed.
4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin.
5. Changes in well bore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.

## The Well As A U-Tube

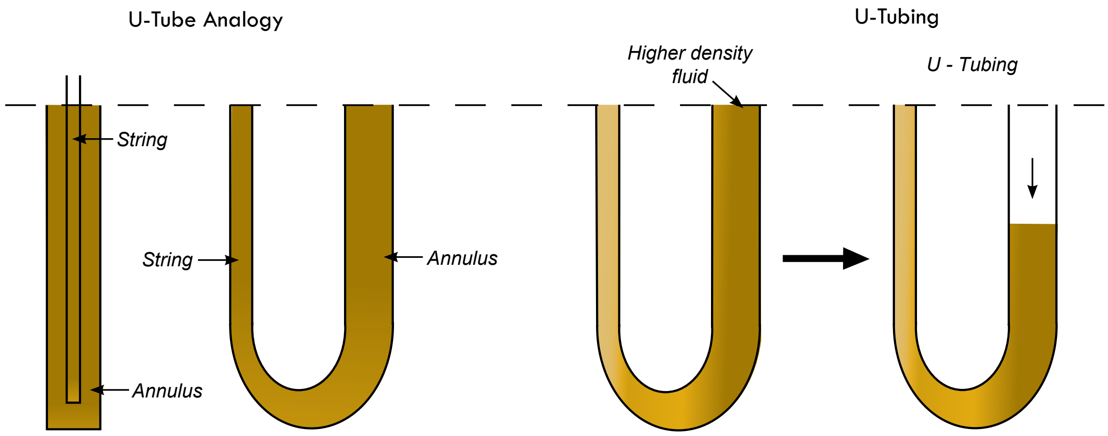
Pressures acting within a well are often explained by thinking of the well as a long tube in the shape of a U. One side of the tube represents the drillpipe or tubing, and the other side, the annulus; two tubes with different diameters are connected at the bottom as illustrated in figure 2.8. If both sides of the tube were filled with fluid of the same density and left open at the ends, there would be no fluid movement within the U-tube because both the height and the density remain constant on each side of the tube. If a different density fluid, were introduced into one side, the columns would shift, or move as the fluid sought a level of balance. When the U-tube was balanced, the fluid movement would stop. The fluid level on one side of the tube, the side containing the denser (heavier) fluid, would be lower than the side with the less dense (lighter) fluid. The hydrostatic pressure on each side of the tube would be equal.

The U-tube effect is often seen in the field. For example, if the annulus is loaded with cuttings due to fast drilling, mud might flow out of the drillpipe when the kelly or top drive is broken off to make a connection. In this case the hydrostatic pressure in the annulus is greater than the hydrostatic pressure inside the drillpipe due to the effective increase in annular fluid density. The opposite U-tube effect is seen when a small amount of heavy mud, a slug, is spotted at the top of the work string before making a “dry” trip out of a well.

## Porosity and Permeability

A rock may look solid to the naked eye; however, a microscope examination would reveal the existence of tiny opening in the rock. The name given to the tiny micro openings found within the rock is called pores. The amount of pore space within a rock is called *porosity*, and is expressed in percentages. It is within these micro openings that oil, gas and/or water can lay embedded in the formation. Another formation characteristic is *permeability.* If the pore spaces in the rock are connected, the rock is said to be permeable. In other words, formation fluids can move from pore to pore. Almost all sedimentary rocks have porosity, but many (shale, for example) have little or no permeability. If there is fluid in these rocks, it remains locked in place and cannot flow into a well. Permeability is measured in Darcys or millidarcys (mD). Reservoir rocks typically have a

Figure 2.8.



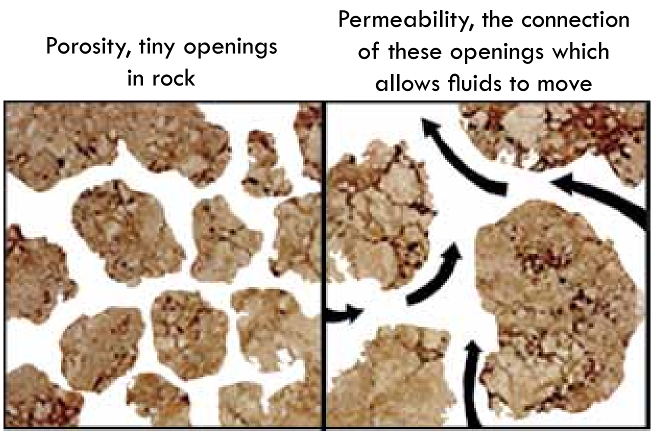

permeability ranging from 5 to 500 mD. Highly permeable sand zones containing water and/or gas may have a permeability of 2 to 5 Darcys.

## Formation Pressure (FP)

Formation pressure is the pressure within the pore space of formation rock. Formation pressure is the result of the weight of the overburden (rock layers and fluid) above the formation, exerting pressure on both the grains and pore fluids. Grains are the solid rock material, and pores are spaces between the grains. If the fluids within the pores are free to move, and can escape, the grains lose some of their support and move closer together. This process is called *compaction*.

Classifications of formation pressure are relative to the pore pressure of the formation rock, and the density of the native fluid contained in the pore spaces. *Normally* pressured formations exert a pressure equal to a column of native fluid from the formation to the surface. The pressure gradient of native

Figure 2.9. Two important characteristics of reservoir rocks are:




fluid usually ranges from 0.433 psi/ft to 0.465 psi/ft, and varies depending on the geologic region, i.e., the Gulf Coast versus the North Sea. Formation pressure gradients in this range are considered to be *normal* but in normally pressured formations, the grains that compose the rock support most of the overburden weight. As the overburden increases, pore fluids are free to move, and the amount of pore space is reduced due to compaction. The formation is said to be *abnormal* if the pressure of the pore fluids exceeds the normal gradient for that area.

Faults, salt domes, uplifting, and differences in elevation of underground formations may also cause abnormal pressure. In many regions, hundreds of feet of pre-existing rock layers (overburden) have been stripped off by erosion. At the shallower depth this loss from erosion can cause the pressure to be reclassified as abnormal pressure.

When a normally pressured formation is faulted, or moved upward to shallower depths while being prevented from losing any pore fluid in the process, it will change from normal pressure (at a greater depth) to abnormal pressure (at a shallower depth). This process accounts for many of the shallow, abnormally pressured zones throughout the world. Mud weights as high as 20.0 ppg may be required to control these shallow formations.

Abnormal pressure may also occur as a result of geologic phenomena other than faulting. Salt layers or domes and excessive geothermal gradients are two examples. Well histories, surface geology, downhole logs, and geophysical surveys are all tools that are used in predicting abnormally pressured formations.

*Subnormally* pressured formations have pressure gradients less than that of fresh water, that is, less than 0.433 psi/ft. Depletion of original pore fluids through evaporation, capillary action, and dilution produces hydrostatic gradients less than 0.433 psi/ft. Subnormal pressures may also be induced through the production of formation fluids.

A well is *balanced* when the hydrostatic pressure in a well equals the formation pressure (HP = FP). If the hydrostatic pressure in a well is greater than the formation pressure, the well is *overbalanced*, as in most conventional drilling operations (HP > FP). Well intervention operations (wireline, coiled tubing, snubbing) are often conducted in *underbalanced* conditions, that is, wells in which the formation pressure is greater than the hydrostatic pressure (FP > HP). The difference between the formation pressure and the hydrostatic pressure is *differential* pressure.

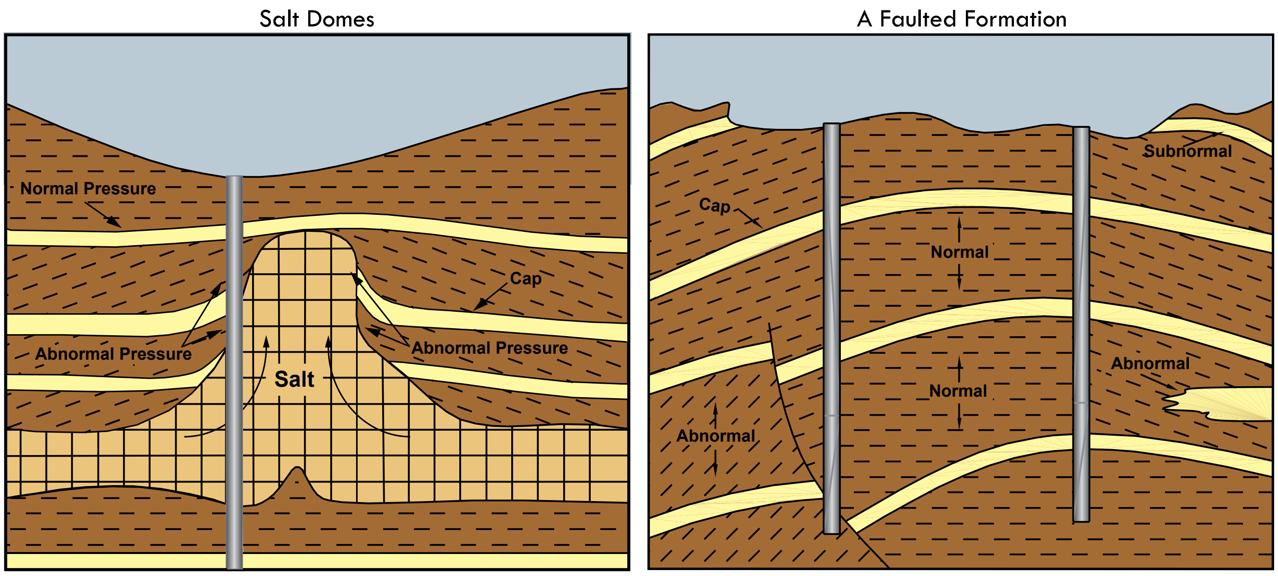
Balanced fluid weight is calculated by:

$$\boxed{\text{Balanced Fluid Weight}_{ppg} = \text{Formation Pressure}_{psi} \div \text{TVD}_{ft} \div 0.052}$$

Or

$$\boxed{\text{Balanced Fluid Weight}_{ppg} = \text{Formation Gradient}_{psi/ft} \div 0.052}$$

Figure 2.10. Salt domes and faulted formation.



Formation pore pressure gradient is the increase of formation pore pressure per unit of depth where the formation pore pressure is the maximum within a series of formations.

Initial formation strength gradient is the increase of initial formation strength per unit of depth, where the initial formation strength is expressed as the pressure at which the weakest formation in a series will break down and allow fluid to enter.

## Fracture Pressure

The amount of pressure a formation can withstand before it splits is termed the fracture pressure. The pressure of fluid in a well must exceed formation pressure before the fluid can enter a formation and cause a fracture. Fracture pressure is expressed in psi, as a gradient in psi/ft, or as a fluid weight equivalent in ppg.

In order to plan a conventional rig well intervention, it is necessary to have some knowledge of the fracture pressures of the formation to be encountered. If wellbore pressures were to equal or exceed this fracture pressure, the formation would break down as the fracture was initiated, followed by loss of workover fluid, loss of hydrostatic pressure, loss of primary well control and irreparable damage to the formation. Most operating companies have strict policies and procedures to ensure the fracture pressure is never exceeded (unless the formation was to be deliberately fractured for reservoir productivity improvement through sand fracking operations, etc.). Unless the service is to conduct remedial operations on or in the casing across the formation, it is preferable to isolate the formation from the kill fluid by installing a barrier or plug.

Fracture pressures are related to the weight of the formation matrix (rock) and the fluids (water/oil) occupying the pore space within the matrix, above the zone of interest. These two factors combine to produce what is known as the overburden pressure.

Since the degree of compaction of sediments is known to vary with depth, the gradient is not constant.

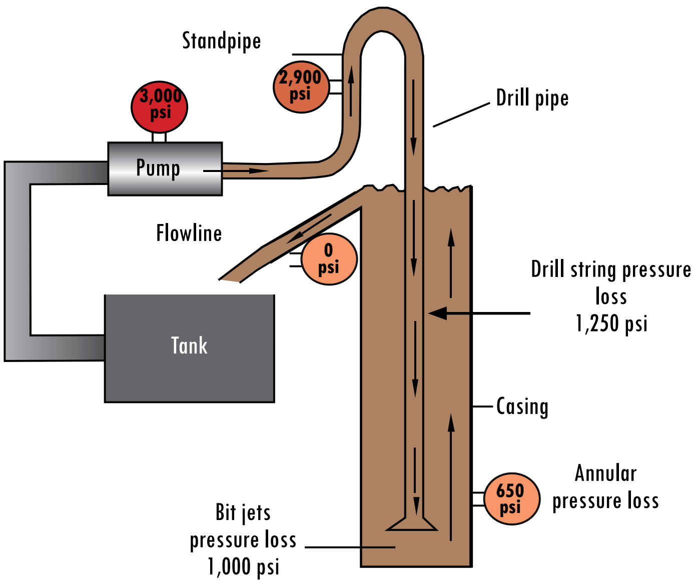
Onshore, since the sediments tend to be more compacted, the overburden gradient can be taken as being close to 1.0 psi/ft. Offshore, however the overburden gradients at shallow depths will be much less than 1.0 psi/ft due to the effect of the depth of seawater and large thickness of unconsolidated sediment.

## Circulating (Friction) Pressure

When a well is being circulated conventionally (down the work string and back up the annulus) the pressure seen at the pump, or on the driller's standpipe gauge, is the result of the friction required to push the fluid throughout the system. Imagine that the pressure gauge on the pump and the gauge on the standpipe were perfectly accurate and calibrated to the same accuracy. Pumping at any given rate, the pressure value on the standpipe gauge would be less than the pressure read on the pump gauge. The difference between the gauge readings is called the *pressure drop or pressure loss* and is the result of the friction that had to be overcome in order to move the fluid from the pump's suction to the rig floor. The pumping rate, the fluid density, the length and diameter of the piping, the interior surface of the piping and even the temperature of the fluid are all components of the total friction loss. It is not necessary for field workers to do complex calculations in order to determine the exact friction pressures that result from pumping. Nowadays friction losses can be predicted using computer programs. Practically, the driller simply reads the system pressure loss at the pump or his standpipe gauge.

It can be seen that if the second gauge (the standpipe gauge in our example) were placed in a different location, the pressure drop would be different. The farther the gauge is from the pump the greater the pressure drop (or lower the pressure) read on the gauge. If the gauge were placed on the open flowline, where the fluid is falling across the shale shakers due to gravity, the gauge would read zero. The pressure seen on the pump gauge would represent the total pressure drop in the entire circulating system.

Figure 2.11. Circulating pressure.




Fluid pumped from the tank, through the standpipe into the drill pipe, through the bit, up the annulus and out the flow line as shown in figure 2.11. Note: The pump pressure of 3,000 psi is reduced to 0 psi at the flow line due to circulating frictional pressure losses.

When engineers design the hydraulics program for a drilling or workover operation they are interested in the pressure drop at several different locations in a system, even though no gauges are placed at those locations. For example, engineers use the calculated pressure drop at the bit when selecting bit nozzles. The pressure drop in the annulus is estimated in order to ensure that cuttings are brought to the surface with the maximum efficiency and minimum hole enlargement due to washouts.

When circulating down a work string and back up the annulus, most of the pressure losses in a circulating system will occur in the work string and the nozzles at the end of the string. If the direction of flow is changed, that is, reverse circulated; the friction pressures will be distributed differently as illustrated in figure 2.12.

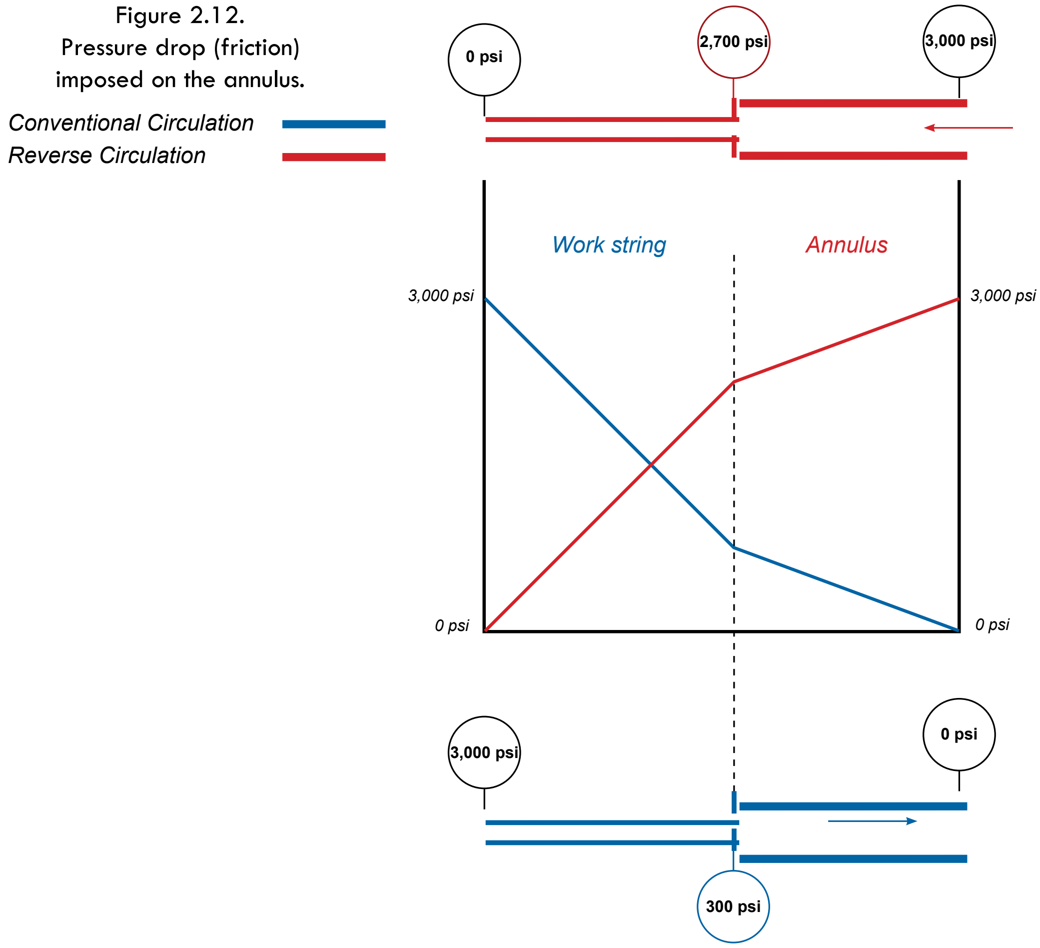
In conventional circulation, fluid is circulated down the work string and back up the annulus. Usually the pressure drop in the annulus is a small portion of the pressure seen on the standpipe gauge. When the old time driller, looking at his standpipe gauge, says, “I’ve got 2,900 psi on the hole”, he is not correct. Most of the 2,900 psi that he sees on his gauge is expended within the work string, not on the wellbore. Only a fraction of that number is actually lost in the annulus or exerted on the wellbore. This pressure drop in the annulus, called the *annular pressure loss* (APL), though low in comparison to the total loss in the system, is an important consideration in all operations that involve circulation. It is not important that rig personnel know the actual value of the APL, but it is important that they understand what it is, and how it may affect operations with regard to well control and lost circulation. Modern sophisticated instruments are sometimes run in the drill string. These instruments, coupled with computers, are capable of measuring and transmitting annular friction pressure to the surface with a great deal of accuracy.

Since the APL is pressure exerted on the walls of a well, the effective mud weight in the annulus is greater when circulating than it is when the well is static. If the APL is known (or accurately estimated) the effective circulating mud weight can be determined by transposing the hydrostatic pressure formula. For example, assume the APL is 200 psi at a certain circulating rate and the density of the working fluid is 10.0 ppg in a well 10,000 feet deep (TVD).

Use the formula for hydrostatic pressure: HP = MW * 0.052 * TVD

Transpose the formula: MW = HP ÷ 0.052 ÷ TVD

Figure 2.12.
Pressure drop (friction) imposed on the annulus.




Substitute in the transposed formula: 200 ÷ 0.052 ÷ 10,000 = 0.38 ppg

Therefore when circulating this well, the effective mud weight is: 10.0 + 0.38 = 10.38 or 10.4 ppg.

This is called the *equivalent circulating density* or the ECD. Equivalent circulating density is the sum of pressure exerted by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus divided by TVD ft and by 0.052, in pounds per gallon.

$$ECD_{ppg} = (\text{Annular Pressure Loss}_{psi} \div 0.052 \div TVD_{ft}) + \text{Current Mud Weight (CMW)}_{ppg}$$

If the standpipe pressure of 2,900 psi were actually exerted on the wellbore as our old time driller thought, the *equivalent mud weight* (EMW) would be (2,900 ÷ 0.052 ÷ 10,000) + 10.0 = 15.6 ppg, a huge overbalance that would almost always result in lost circulation and a stuck drill string.

EMW is the sum of all pressures at a given depth expressed as a fluid density. These pressures include hydrostatic pressure, choke or back pressure, applied pressure, kick pressure, circulating pressure, and any pressure losses.

$$\boxed{EMW_{ppg} = (Pressure_{psi} \div 0.052 \div TVD_{ft}) + \text{Current Mud Weight}_{ppg}}$$

EMW can be converted to pressure.

$$\boxed{Pressure_{psi} = (EMW_{ppg} - CMW_{ppg}) * 0.052 * TVD_{ft})}$$

Pressure gradient can be converted to EMW:

$$\boxed{EMW_{ppg} = \text{Pressure Gradient}_{psi/ft} \div 0.052}$$

If all the factors that affect friction in a circulating system remain constant, pressures throughout the system also remain constant when pumping at a constant rate. Therefore it can be said that for every different pumping rate in a given system, there is a certain friction loss. So long as the rate does not change, the circulating pressure will not change. A small increase in pump rate will result in a relatively large change in pressure. This is the nature of positive displacement pumps (rig pumps). In fact, the pumping rate/friction pressure relationship is exponential. That is, if the pumping rate is doubled, the pressure on the standpipe gauge and throughout the system would increase approximately four times. The change in circulating pressure is estimated by the following formula:

$$\boxed{P_2 = (S_2 \div S_1)^2 * P_1}$$

Let:

$S_1$ = Original pump rate

$S_2$ = Desired pump rate

$P_1$ = Original circulating pressure

$P_2$ = Resulting pump pressure

Assume the standpipe pressure was 1,000 psi at 30 strokes per minute (spm). What would the standpipe pressure be at 40 spm?

$(40 \div 30)^2 * 1{,}000 = 1{,}778$ psi

And at 20 spm?

$(20 \div 30)^2 * 1{,}000 = 444$ psi

Changes in fluid density will also affect the pressure loss in a system. Suppose in the example above (circulating pressure of 444 psi) the mud weight had been 10.0 ppg but that later it was increased to 10.5 ppg while continuing to pump at 20 spm. The pressure change due to the higher mud weight can be estimated.

$$\boxed{P_2 = W_2 \div W_1 * P_1}$$

Let:

$W_1$ = Original density

$W_2$ = New density

$P_1$ = Original pressure

$P_2$ = New pressure

$10.5 \div 10.0 * 444 = 466$ psi

With regard to well control, there are three important points to remember about pumping pressure.

- For every pumping rate in a given system there is a certain circulating pressure.
- A small change in pump rate results in a relatively large change in pressure loss.
- The annular pressure loss (APL), though small in relation to total system pressure loss, increases the effective fluid density.

### Equivalent Static Fluid Density

The equivalent static fluid density is the total hydrostatic pressure in the annulus, converted to equivalent mud weight units, ppg. For a static well, it is calculated by the formula below.

$$\text{Equivalent Static Fluid Density}_{ppg} = HP_{psi} \text{ (or Total Hydrostatic Pressure)/(Depth TVD}_{ft} * 0.052)$$

*EXAMPLE:*

A well has 9.0 ppg brine in the lower 6,000 feet (TVD) and 8.4 ppg water in the upper 5,000 feet (TVD) when the well is static (not flowing) nor shut in. Calculate the equivalent static fluid density, in ppg.

Solution:

The total hydrostatic pressure at the bottom is:

$HP_{psi} = (9.0 * 6{,}000 * 0.052) + (8.4 * 5{,}000 * 0.052)$

$HP_{psi} = 2{,}808 + 2{,}184 = 4{,}992$ psig, then the

$\text{Equivalent Static Fluid Density}_{ppg} = HP_{psi} \div (\text{Depth}_{ft} \text{ TVD} * 0.052)$

$= 4{,}992 \div [(6{,}000+5{,}000) * 0.052)]$

$= 4{,}992 \div [11{,}000 * 0.052]$

$= 8.72727$ ppg or 8.7 ppg (rounded)

The temperature sensitivity of brines is especially important on critical wells. As downhole temperature increases, the effective density of the fluid is reduced. Figure 2.13 represents a quick reference guide to

Figure 2.13.

| BRINE WEIGHT (ppg) AT SURFACE | PERCENTAGE OF WEIGHT LOSS PER DEGREE (FAHRENHEIT) OF TEMPERATURE DIFFERENCE |
|---|---|
| 8.4 – 9.0 | 0.0017 |
| 9.1 – 11.0 | 0.0025 |
| 11.1 – 14.5 | 0.0033 |
| 14.6 – 17.0 | 0.0040 |
| 1701 – 19.2 | 0.0048 |

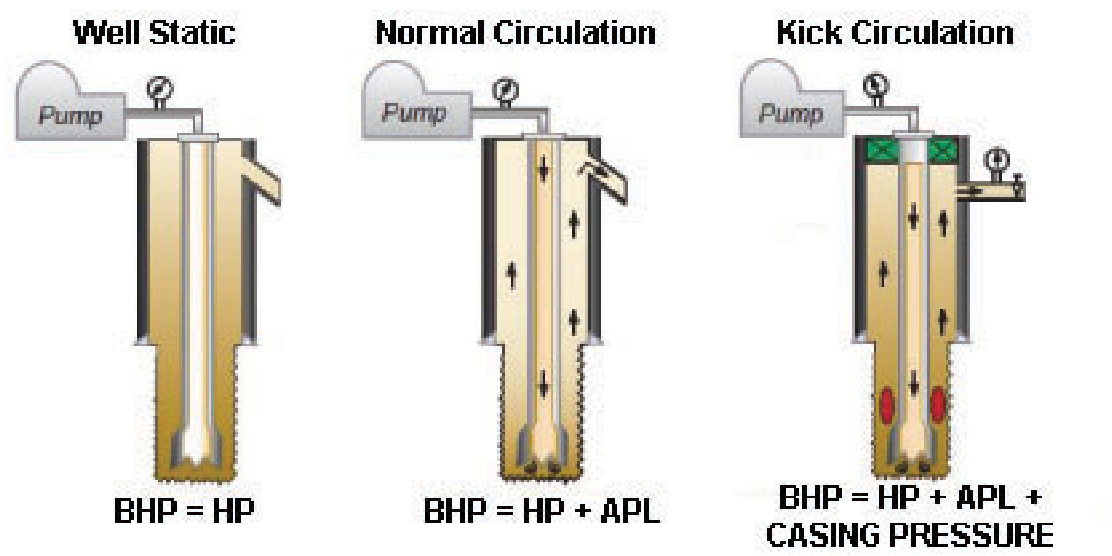
calculating the equivalent static fluid density when brine density is a critical factor.

Using this chart, a brine with a density of 9.2 ppg at surface where the ambient temperature is 700 °F will lose 0.0025 ppg for every degree over 700. If the temperature of the brine at 10,000 feet is 1500, there is an 800 difference between the surface and downhole temperatures. By multiplying the loss percentage of 0.0025 times 80, we can determine that the brine loses 0.20 ppg at a temperature of 1500. The equivalent static fluid density at 10,000 ft. is therefore 9.0 ppg. For the brine to be an effective barrier at 10,000 feet, it should be weighted up to 9.4 ppg.

## Bottomhole Pressure (BHP)

When reservoir engineers and production workers speak of bottomhole pressure, they may be referring to pore pressure, or formation pressure, but to drilling and workover personnel, bottomhole pressure is something quite different. In this text, bottomhole pressure is the sum, that is, the total, of all pressures exerted on the bottom of a well. According to this definition, bottomhole pressure may be made up of various pressures, depending on the operation. For example, when a well is static, with the annulus open, bottomhole pressure equals hydrostatic pressure (BHP = HP). However when a well is circulated, a portion of the total circulating pressure is exerted on the annulus. This is called *applied pressure*. At that time, bottomhole pressure equals the hydrostatic pressure plus the annular pressure loss (BHP = HP + APL). Furthermore, if the well were to be circulated through a choke manifold with the BOPs closed, the gauge on the manifold or the choke panel would reflect the back-pressure on the annulus due to the restricted flow through the choke. This is called *casing* or *wellhead pressure* (CP). At this time bottomhole pressure would equal the hydrostatic pressure, plus the APL, plus the casing pressure (BHP = HP + APL + CP). It is seldom necessary to calculate the exact value of bottomhole pressure, but it is important to know its approximate value relative to

Figure 2.14. Bottomhole pressure varies during different operations.




formation pressure. In this context, applied pressure is any pressure other than hydrostatic pressure that adds to the sum of pressure exerted on the bottom of the well.

## Surge and Swab Pressures

As pipe is moved up or down within a well, the total pressures acting on the well change as the pipe moves.

## Swabbing

*Swabbing* one of the most dangerous situations that a rig crew can face, when pulling the string out of the well. The upward motion of the work string causes some reduction in bottomhole pressure. If the fluid cannot fall below the string as fast as the string moves upward, formation fluids may be drawn into the well.

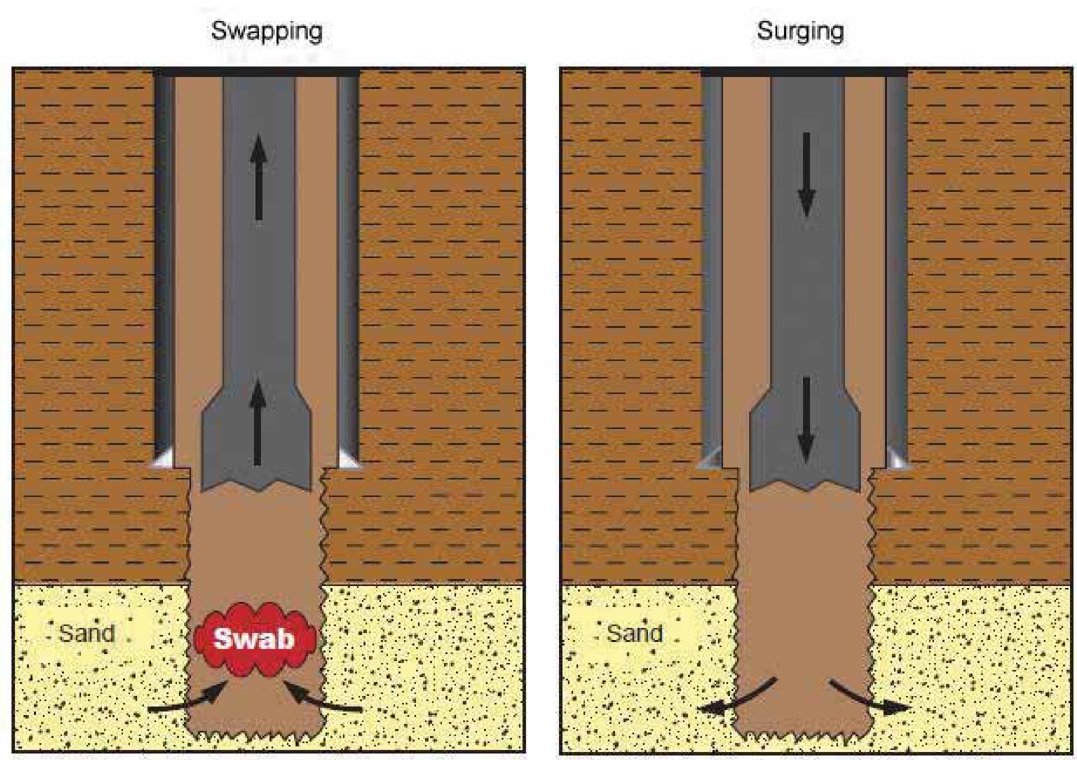
## Surging

*Surging* may occur if the string is lowered faster than the fluid can move out of the way, bottomhole pressure can increase to the point at which the formation might fracture.

The three main factors that determine swab and surge pressures are:

- Rate of pipe movement
- Clearances between pipe and hole
- Fluid properties

Figure 2.15. Swabbing and surging.



### Trip Margin

*Trip margin* is an increase in fluid density prior to making a trip to compensate for loss of circulation pressure (ECD). Additional safety margins are sometimes used to compensate for swab pressures as the pipe is pulled. Some considerations when selecting safety margins are the wellbore diameter, hole condition, pipe pulling speed, fluid, and formation properties.

One method that can be used to determine a safe trip margin, prior to tripping out of a hole, is to use the data from a downhole pressure while drilling tool (PWD). This is particularly effective when an excessive margin might otherwise be used in a well with a narrow margin between pore and fracture pressure. While circulating, carefully increase the pump rate until losses are first initiated, then record the ECD (in ppg) as measured by the PWD tool. From the ECD measure, subtract the mud weight in use (ppg). This result is the maximum trip margin that should be used in the trip.

Procedures to mitigate pressure reduction if a trip margin and safety margin cannot be maintained include:

- Tripping the drill pipe at a slower speed.
- Keeping mud viscosity as low as possible while maintaining enough viscosity to keep the hole clean and lift cuttings while drilling.

### Summary

Considering a well as a vertical cylinder filled with liquid, the total of all the pressures acting on the bottom of the well is termed *bottomhole pressure*. The primary component of bottomhole pressure is *hydrostatic pressure*, which is dependent on the density of the fluid within the well and the true vertical depth.

Hydrostatic pressure in a well is controlled by adjusting the fluid density. Other pressures, for example, friction loss when circulating, or pressure that is imposed on the annulus, also contribute to bottomhole pressure.

Pressure from the formation as a result of depth and formation characteristics is exerted upward from the bottom of a well, opposing bottomhole pressure. When these two opposing pressures are equal, the well is said to be *balanced*.

# Barriers

# 3

## Introduction

The topic of barriers has received a focused attention since the Macondo accident in the Gulf of Mexico in 2010. The concept of barriers has been a part of well design for many decades, but the well construction industry had no single, authoritative set of guidelines. In industry well control classes, the selection, testing, and implementation of blowout preventers (BOP) and other critical pieces of well control equipment have always been topics of discussion. However, industry-wide guidelines on the relationship between the drilling risk and the selection of the appropriate well control equipment, other than the maximum allowable working pressure (MAWP) and bore size required, have been lacking. Maximum Allowable Working Pressure (MAWP) is the maximum pressure for which a pressure-bearing piece of equipment is designed as specified by the manufacturer. A well barrier envelope will have an MAWP rating based on the weakest element of the envelope. Also missing have been guidelines on what makes up an acceptable test for a barrier. Recently, both well operators and drilling contractors have become more receptive to the idea that selection, implementation and testing of barriers to the flow from a hydrocarbon reservoir need become more science than art. The first steps are to establish a common set of definitions, barrier philosophy, well design principles and guidelines for barrier implementation. These definitions, philosophy, principles and guidelines continue to evolve throughout industry. Industry workgroups continue to pursue perfection in commonality.

## Terms, Definition and Abbreviations

The following is from NORSOK Barrier Terminology, D-010,3

- *Primary well barrier*: the first object that prevents flow from a source.
- *Secondary well barrier*: the second object that prevents flow from a source.
- *Well barrier element*: an object that alone cannot prevent flow from one side to the other side of itself.
- *Common well barrier element*: a barrier element that is shared between primary and secondary barriers.
- *Working well barrier stage*: the state which shows the well barrier elements that are used to confine the pressure in a normal working mode.
- *Intermediate well barrier stage*: the stage(s) of a well barrier element activation sequence before the ultimate well barrier state is reached.
- *Ultimate well barrier stage*: the final stage of a well barrier element activation sequence which normally includes closing a shearing device.

## Barrier Definition

Well barriers are envelopes (something that surrounds or encloses something else) of one or more dependent *well barrier elements (WBE)* to prevent fluids or gases from flowing unintentionally from a formation, into another formation or back to surface.

Well barrier(s) shall be defined prior to commencement of an activity or operation by description of the required WBE to be in place and the specific acceptance criteria.

Well Barrier Elements Examples

1. Fluid barriers
2. Casing and cement
3. Drill string
4. Drilling, wireline, coiled tubing, workover BOPS
5. Wellhead
6. Deep set tubing plug
7. Production packer
8. Stab-in safety valves
9. Completion string
10. Tubing hanger

*Barrier elements in red denote other operations in a well.

Figure 3.1. An example of elements that form the barrier envelope.

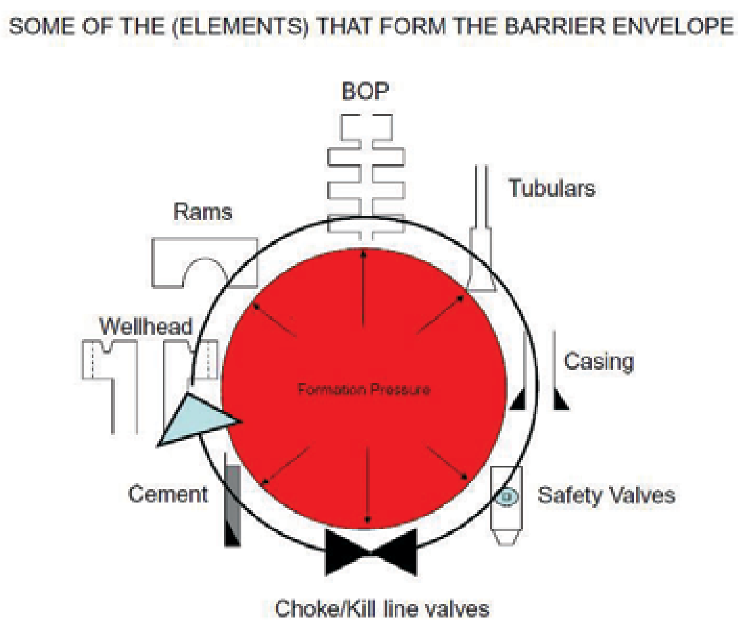
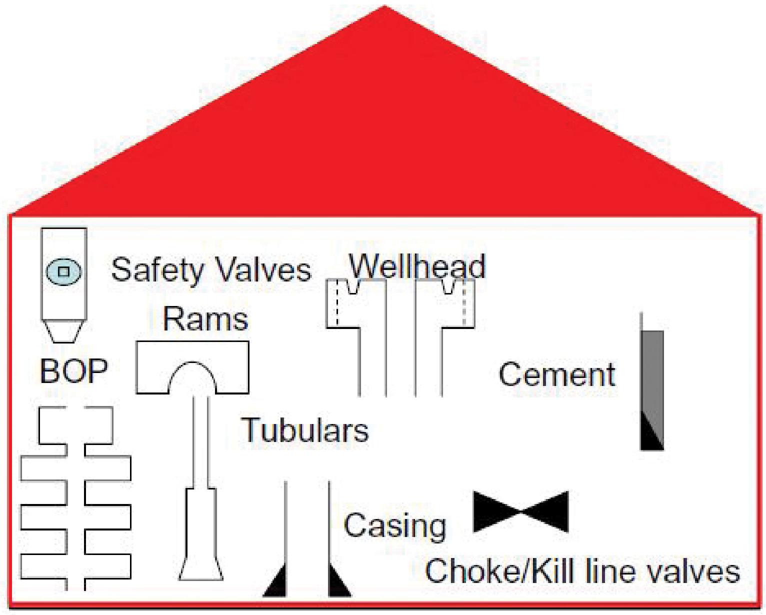


Figure 3.2. An example of elements that form the barrier envelope.




Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or WBE for its intended use.

The function of the well barrier and WBE shall be clearly defined.

- One well barrier shall be in place during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow cross flow in the wellbore between formation zones.
- Two well barriers shall be available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole / well to the external environment.

## Definition of Barriers

In its most basic form, a *barrier* is something that blocks the energy of a hydrocarbon formation from reaching other points in a wellbore or the surface. More specifically, a barrier is a tool, material, fluid or operational practice that is used to isolate and manage the energy within the formation from sections of the well, or the surface drilling or production system. Barriers are either physical (mechanical tool, material or a hydrostatic column of fluid) or operational (a drilling practice that supplements or activates an inactive physical barrier, such as operating a BOP or valve).

### Barrier Definition

The following barrier definition is from NORSOK Barrier Terminology, D-010,3. A barrier is one of several dependent barrier elements, which are designed to prevent unintentional flow of a formation fluid. A barrier is an envelop preventing hydrocarbons from flowing unintentionally from the formation, into another formation or, to surface. Barrier elements that makeup the primary barrier are those elements, which are, or might be, in direct contact with well pressure during normal operation. These elements provide the initial and inner envelope preventing unintentional flow of reservoir fluid to surface, or another zone. Barrier elements that make up the secondary barrier are those, which are, or might be, exposed to contact with well pressure should any of the elements described as a primary barrier fail. These elements provide an envelope outside the primary barrier envelope, providing a second barrier that will prevent unintentional flow of reservoir fluid to surface, or another zone.

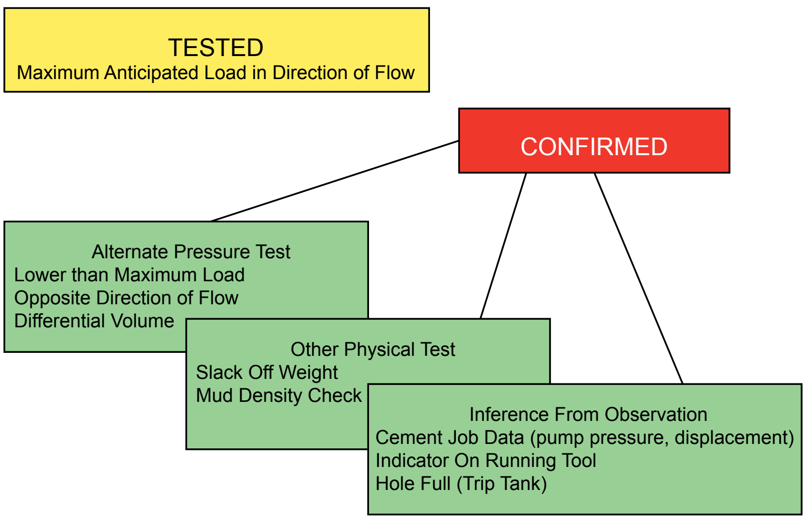
### Mechanical Barriers

Mechanical barriers are also call *physical barriers*. These include packers, valves, bridge plugs, etc. A *blowout preventer (BOP)* is a barrier when activated (closed), but until it has been closed it cannot be considered an active, physical barrier. The reliability of a mechanical barrier is enhanced if its integrity is tested to its design load in the direction of flow, after the barrier has been installed.

Casing and liners are also a class of physical barriers. Their integrity can be verified by testing after having been run and cemented in place. Here a casing is a barrier to prevent flow from inside the well through the walls of the casing string; the casing typically undergoes a *positive test* in the direction that flow might take, were the casing not present. A confirmed column of cement around the casing provides a second barrier to this potential flow path.

Physical barriers are accepted as barriers only when they have been either verified or confirmed. Ideally, verification should be determined by testing the barrier to its maximum anticipated load in the direction of flow. This is not always possible following barrier installation. Hence, the barrier must be confirmed either by a) alternative pressure testing, b) some other type of physical test, or c) inference from observation of the barrier. This representation of barrier verification categories is illustrated in figure 3.3.

Figure 3.3. Barrier verification categories.




APR RP 65 defines a mechanical barrier as a subset of physical barriers that features mechanical equipment, not set cement or a hydrostatic fluid column.

Barrier test criteria reference sources may be found in:

- The well program

- Operational manuals
- API standards
- Equipment manufacturer catalogues

Barrier testing is performed during all phases of a well's life:

- Construction
- Completion
- Production
- Workover or remediation (coiled tubing, wireline, snubbing)
- Abandonment

## Barrier Philosophy and Purpose

The primary purpose of a barrier is to eliminate or at least significantly minimize the potential for uncontrolled flow. The possibility of uncontrolled flow during well construction and operation is inversely proportional to the quantity and quality of the barriers in place. A system of multiple effective barriers, correctly positioned and applied, will increase well integrity and reliability and can essentially eliminate any potential for uncontrolled flow. A system of multiple barriers for each potential flow path is considered to be a *barrier envelope*.

There are four types of barriers – hydrostatic (or fluid) barriers, mechanical barriers, material barriers (cement) and operational barriers. The first three are considered to be physical barriers. It is generally accepted by industry that a physical barrier is a reliable barrier only if it has been verified by testing to its maximum anticipated load, in the direction of that load. Some accept a barrier to be verified by confirming it is securely in place. Hydrostatic barriers are discussed in chapter 2, "Well Control Principles".

Overall barrier system reliability is the probability that the system will prevent loss of well control. While multiple barriers in a series obviously increase system reliability, mathematical calculation of the reliability (probability the system will prevent loss of well control) is left to those skilled in probability analysis.

An oil or gas well can be thought of as a pathway extending from potential hydrocarbon bearing zone(s) to the surface. As the well is deepened, barriers are installed to prevent these hydrocarbons from taking undesired paths to the surface or from flowing uncontrolled to the surface. A system of multiple barriers is used in the well construction to achieve a high level of reliability. Experience has demonstrated that the philosophy of multiple barriers is effective.

Many barriers are designed specifically to prevent the loss of well control. Others are designed specifically to prevent annular pressure build up between casing and liner strings, or prevent the reservoir fluids from finding a pathway to the surface that is outside the well structure.

## Types of Barriers

There are four types of barriers: hydrostatic (or fluid) barriers, mechanical barriers, material barriers (cement), and operational barriers. The first three categories are considered to be *physical barriers*. It is generally accepted by industry that a physical barrier is a reliable barrier only if it has been verified by testing to its maximum anticipated load, in the direction of that load. Some accept a barrier to be verified by confirming it is securely in place.

### Hydrostatic Barriers

The hydrostatic pressure of a column of fluid of known density and vertical height must be sufficient to overcome the pore pressure of the exposed formation. The fluid cannot be considered a barrier unless it can be monitored for density and vertical height. A drop in vertical height or the density of a fluid will produce a corresponding drop in hydrostatic pressure, and possibly lead to an underbalanced condition. The fluid would no longer then be an effective barrier. If there is a test failure of a fluid barrier, possible solutions would be to hold back-pressure to compensate loss of hydrostatic pressure, shut in the well or increase pump speed to generate a higher annular friction pressure.

Most drilling muds can be reliable barriers in open hole if properly monitored. Brines and completion fluids generally do not make effective hydrostatic barriers if exposed to permeable formations because there is no filter cake as with muds. Hence, completion fluids will generally leak off into the formation, losing their hydrostatic pressure. A drilling brine may be regarded as a reliable barrier during a drilling operation as long as its density and fluid level can be monitored. However, a brine or any completion fluid left above a packer between tubing and casing or between casing strings may not be a reliable barrier if it cannot be monitored.

### Mechanical Barriers

Mechanical barriers are also called physical barriers. These include packers, valves, bridge plugs, etc. A blowout preventer (BOP) is a barrier when activated (closed), but until it has been closed it cannot be considered an active, physical barrier. The reliability of a mechanical barrier is enhanced if its integrity is tested to its design load in the direction of flow after the barrier has been installed.

Casing and liners are also a class of physical barriers. Their integrity can be verified by testing after having been run and cemented in place. Here casing is a barrier to prevent flow from inside through the walls of the casing string; the casing typically undergoes a *positive test* in the direction flow might take were the casing not present. A confirmed column of cement around the casing provides a second barrier to this potential flow path.

### Material Barriers

Another common physical barrier is cement. Cement is placed in the annular space outside casing or liner to prevent hydrocarbons or other undesired formation fluids from flowing up that space and possibly into a lower pressure permeable zone above. Cement is also used as plugs (material barriers) in a well during well abandonment, as well as temporary plugs when operations cease temporarily, such as removal of a BOP stack for weather or repair.

### Operational Barriers

In many instances an operational practice is considered a barrier. The most common example of everyday use of an operational barrier is the procedure in place for closing a BOP when a well kicks. The BOP itself is not a barrier unless it has been closed; there must be an operational barrier (procedure) to activate (close) the BOP. Another example of an operational barrier is a well thought out plan and procedure for installing a crossover from screens to drill pipe with a full-opening safety valve (FOSV), and then lowering the screens such that a BOP can be closed around the pipe. This procedure (operational practice) can be viewed as an *operational barrier*. This operational practice allows the inactive mechanical barriers (FOSV and BOP) to become physical barriers, blocking flow up the drill string or up the completion screens by casing annulus.

Operational barriers are used also to assure that failure of any physical barrier is detected early and managed so as to prevent loss of well control. Operational well control barriers include institutional controls such as industry and company well control standards, well control training, organizational well control policy and philosophy and governmental regulations.

The following table provides a few examples of the barrier types defined.

Table 3.1. Examples of barriers (not all-inclusive).

| | |
|---|---|
| Hydrostatic | Water-Based Muds<br>Oil-Based Muds<br>Synthetic Muds<br>Brines |
| Mechanical Tools | Liner Top Packers<br>Expandable Tubulars<br>Multiple Seals in High-Pressure Wellhead<br>Liner Hanger Profiles<br>Inflatable Casing Packers<br>Hydraulic or Mechanical Set Casing Packers<br>Annular Seal Rings<br>BOP Ring Gaskets<br>Subsea BOP Connector Ring Gaskets<br>HCR and Fail-Safe Valves<br>Blowout Preventers (when closed)<br>Cased-Hole Retrievable Tools<br>Drillable Bridge Plugs<br>FOSV, IBOP, SCSSV, BPV |
| Material | Cement in Annulus<br>Cement Plug<br>Gunk Plug (temporary only) |
| Operational Practices | Procedures for Closing BOP<br>Procedures for Installing FOSV (tripping)<br>Plans and Procedures for Handling Kicks<br>Diverter Procedures<br>Procedures for Emergency Disconnect<br>Procedures for LMRP Disconnect |

*Note: It is tempting to consider each BOP in a stack as a barrier, since multiple preventers of the same type are often used for redundancy and increased reliability. However, this thinking is faulty because one must remember that the BOP stack is operated by a single hydraulic control system. The argument that subsea systems have two control pods and therefore should allow a stack to be considered as having more than one mechanical barrier is faulty because the two pods receive their fluid power from a single hydraulic power source at the surface.*

### Barrier Installation/Implementation

Multiple barriers are installed to achieve a high level of reliability that the system of barriers will not fail. The level of reliability desired is dependent on the risk and consequences of a failure. Generally, the higher the reservoir pressure, the greater the risk for uncontrolled flow of hydrocarbons to the surface. The consequences of failure to prevent uncontrolled flow are dependent on the well location. Obviously the consequences are greater for a well located in an urban area or offshore than for a location in a remote unpopulated area. Hence barrier implementation requires thought and planning given to the risk and consequences, if not a full-blown risk assessment.

### Acceptable Minimum Number of Physical Barriers

Industry practice has generally required that the minimum number of barriers is two (2), with at least one of these being a physical barrier; however, for some higher risk operations an operator might require many more to increase overall barrier system reliability. While it is preferred that both barriers be physical, many drilling operations employee a second barrier that has a physical presence, but is not active. It is generally accepted that two physical barriers provides an acceptable degree of reliability. If any operation is conducted with fewer than two physical barriers, operational barriers become critical. An operational barrier can provide a supplement to an inactive physical barrier, such as a BOP. Also, governmental regulators may dictate the number of barriers to be in place for specific well drilling/completion operations.

### Operational Barrier Supplements

In some situations, the second physical barrier requires an effective operational barrier to activate that barrier. A good example of this is the annulus of a drill well, where the hydrostatic mud column serves as the primary barrier, and the secondary barrier is a blowout preventer (BOP); which requires an operational barrier (plan and procedure to close the BOP). The operational barrier should be viewed as a supplement to the physical barrier. As a reminder, the primary barrier (the hydrostatic barrier) also requires an operational barrier (procedures for testing density and monitoring fluid level in the well) as supplements to increase the drilling mud's effectiveness and reliability as a proven barrier.

### Barrier Considerations in Well Design

The implementation of barriers should begin during the planning stage of each well plan, for each hole section to be drilled and for the completion process. Some general considerations that have been recommended by the American Petroleum Institute include:

1. Assume that any single barrier can fail, even those that have been verified by testing. The potential consequences of failure of each well barrier in a given flow path (up casing by open hole annulus, up drill pipe or tubing by casing annulus, up inside drill pipe or tubing) should be considered. The required responses and contingencies should be identified.
2. Determine the operational barriers that should be in place when the rig is working over the well, regardless the number of physical barriers in place or whether the barriers have been verified.
3. If a physical barrier cannot be verified by testing to its fully anticipated loads, one of the following alternative verification methods should be considered:
    a. Test the barrier to a lower load or in the opposite direction of the expected load,
    b. Collect data during the physical barrier installation that confirm effective execution of the installation,
    c. Perform post-installation inspection of the mechanical or material barrier,
    d. If placement of a physical barrier cannot be confirmed, additional operational barriers may be used to enhance the well system reliability. To enhance the effectiveness of supplemental operational barriers, training and drills should be conducted.
4. Review the barrier plan as part of a management of change (MOC) process if well conditions change.
5. Teach personnel that a decision to *not* deploy a planned physical or operational barrier due to the low probability of unexpected conditions (high formation pressure, casing failure, sudden storm, etc.) can increase the probability of well system failure.
6. If a physical barrier is found to be deficient during the course of well operations and it cannot be repaired, reassess the remaining well system reliability. As a part of the MOC process, replacing the physical barrier (if possible), installing additional physical barriers, or using additional operational barriers should be considered.

### Regulatory Requirements

Some of the regulatory requirements adopted worldwide, and in particular the Gulf of Mexico deepwater wells, have been developed in response to the Macando incident in 2010. Many of these regulatory requirements apply to any offshore wells drilled in U.S. waters, not just deepwater wells. For wells drilled with a subsea BOP stack (all floating drilling operations), these regulations enforce, with the power of law, the previously recommended industry practice of having a least two barriers (one of which must be mechanical) in any of the possible paths of flow to the surface.

Governmental regulations vary with time and from country to country; hence these various regulations cannot be included in a single document, nor can they be predicted as time progresses. Hence, the designer of barrier systems should ensure all decisions made are checked against local regulations and ensure the barrier system implemented is in compliance.

### Developing a Barrier Plan

The well operator should develop a plan that identifies flow paths and barriers that prevent flow along any of the possible flow paths to the surface during the drilling and completion of the well. Diagrams illustrating the barriers in place for each operational phase are helpful. The planning process includes determining the operating conditions to which the barriers are subjected during each phase of the well construction and the well's lifetime. These operating conditions are then used to ensure the barrier performance is suitable for that particular well's environment.

Because well construction is a succession of processes (drilling, tripping, running casing, cementing, testing, completing, etc.), the barriers required also change. The number and types of barriers employed vary with time (well construction phase). These processes must we examined in detail, and the associated risks considered before barrier selection can be properly addressed.

Physical barriers are accepted as barriers only when they have been either verified or confirmed. Ideally, verification should be determined by testing the barrier to its maximum anticipated load in the direction of flow. This is not always possible following barrier installation. Hence, the barrier must be confirmed, either by: a) alternative pressure testing, b) some other type of physical test, or c) inference from observations of the barrier. This representation of barrier verification categories is illustrated in figure 3.3.

## Examples of Barriers Implemented During Drilling Operations

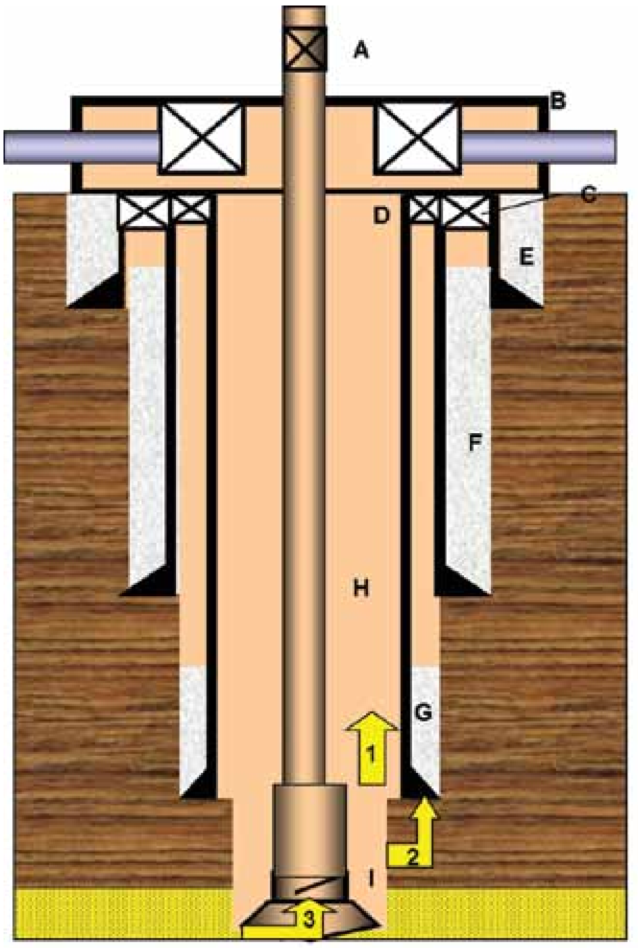
### Example 1 — Drilling Ahead with Surface BOP

While drilling, the hydrostatic pressure of mud is the primary barrier, with the BOP (mechanical) and the well shut-in procedure (operational barrier supplementing the inactive physical BOP) combining to provide the second acceptable mechanical barrier. While tripping, the drilling fluid again is the primary barrier, but only if conducted with the operation of the trip tank (tripping procedure, an operational barrier) and the planned procedure to shut-in the annulus with the BOP (another operational barrier) as the second acceptable barrier or the open ended drill pipe with a full-opening safety valve (FOSV). The potential flow paths from the reservoir to the surface while drilling ahead are illustrated in figure 3.4, along with the barriers required to securely close off those paths described and illustrated. The system of barriers shown in the illustration make up the barrier envelope. Note the drill string float valve is not considered a barrier because it cannot be tested after it has been installed. Also, remember many of these valves are ported so that bottomhole pressure an be determined following a kick shut-in.

It must be emphasized that a drilling or workover fluid can be considered a verified physical barrier only if it is properly monitored. Proper monitoring includes verification that the density of the fluid coming out of the well is at equal to greater than that going in and a full column of fluid exists in the well. Also, the density of the fluid in the well and the length of fluid column must be sufficient to produce a hydrostatic pressure at the exposed formation(s) greater than the formation pressure in the formation(s). Frequent measurements of the drilling fluid's density must be made and continuous observation of the mud level in the well and total pit volumes are operational barriers required to supplement and verify the drilling fluid as a hydrostatic barrier.

The drill string float is not considered a barrier (by most operators and contractors) because it cannot be tested after being implemented (run in the well). However, its presence can be verified before drilling out a casing shoe by closing the BOP and pumping into the annulus. If there is no response on the standpipe gauge, it has been verified but not tested against the maximum potential reservoir pressure. As a point of reference, the U.S. Bureau of Safety and Environmental Enforcement (BSEE) regulations will not even consider dual float valves (float valves in tandem) as an acceptable mechanical barrier.

Figure 3.4. Paths to the surface and barriers toprevent flow from the reservoir.




Example: Barriers While Drilling 2nd Intermediate Casing String

| | | |
|---|---|---|
| Path 1: | Up Pipe by Csg Annulus | |
| | Column of Mud (hydrostatic) | H |
| | BOP (mechanical) | B |
| | Procedure to Close BOP (operational) | |
| Path 2: | Outside Casing | |
| | Cement (material) | G |
| | Csg Seak at Syrface (mechanical) | D |
| | Intemediate Csg Strings (mechanical) | |
| | Cement (material) | F |
| | Casing Seal (mechanical) | C |
| | Surface Casing (mechanical) | |
| | Cement (material) | E |
| Path 3: | Up Drill String | |
| | Column of Mud (hydrostatic) | H |
| | Top Drive or Kelly Valve | A |
| | Drill String Float (mechanical) | I |

Cement outside the casing is another example of a material barrier that cannot be tested. It can however be verified by determining that it is where it was planned to be placed. This can be accomplished by calculation of the theoretical displacement and comparison with observed mud returns and by the use of a cement bond log or other evaluation tools. Also, for set cement in the annulus outside casing to serve as a physical barrier to the influx of formation fluids, the cemented slurry should be designed and laboratory-tested for the anticipated well conditions. Furthermore, to be recognized as a valid physical barrier, the API maintains the slurry be placed in the well using recommended practices and equipment in accordance with API Standard 65-2, *Isolating Flow Zones During Well Construction*.

Data collected during the cement displacement can be used to further confirm cement in the annulus as an acceptable barrier. If the displacement data suggest the top of cement is not where it should be, or the displacement has other problems, a diagnostic log can be run to establish the location of the cement and/or identify bond quality. Finally, a pressure integrity test can be run after drilling out to identify cement channels through the cement that prevent it from qualifying as a barrier in the casing by open-hole annulus.

To provide a second barrier in the annular flow path (annulus external to a casing or liner string), a mechanical barrier is installed. These mechanical barriers are typically set after the cementing operation and include one of the following:

- Liner top packers
- Expandable tubulars
- Multiple seals in a high-pressure wellhead housing
- Subsea wellhead liner hanger profiles
- Inflatable external casing packers
- Hydraulic set external casing packers

### Example 2 — Removing Surface BOP to Set Casing Slips

When drilling on land, a spool wellhead system is traditionally used. The wellhead is considered a build-as-you-go series of casing heads that is assembled as drilling progresses and casing strings are run and set. The starting casing head attaches to the conductor by either welding or treading on to the conductor. A profile on the inside of this casing head is machined to accept a slip and seal assembly to land and support the next string of casing (surface casing). The top of the casing head has a flange to mate with the bottom of the BOP or the next casing spool. The slip and seal assembly transfers the pre-determined casing weight to the conductor while energizing a weight set elastomeric seal. When an intermediate casing string is run, a second *casing spool* is attached to the starting casing head with a flange by flange connection. To make this connection and set the seal assembly for the intermediate casing by surface casing annulus, the BOP must be removed. If the depth for hydrocarbons has not yet been reached, this is a relatively save operation. Ultimately the hydrocarbon zone will be reached and it will become necessary to remove the BOP and install the tubing head spool.

When the BOP is being nippled down to provide for installation of the next casing spool or the tubing head spool, close attention must be paid to ensure sufficient barriers are in place. While the BOP is disconnected and moved over to allow installation of the intermediate casing spool, common industry practice is to do this with only one barrier in place (the hydrostatic column of drilling mud; the cement float collar is not considered a barrier). Unfortunately, experience has shown it is during this operation that some wells have begun to flow.

Some operational barriers that may be implemented to reduce the risk associated with having only one physical barrier during the time the BOP is removed include:

1. Identify any potential zones for well flow
2. Monitoring the well for flow while the BOP is being disconnected
3. Design cement to mitigate the potential for annular gas flow
4. Ensure sufficient weight-on-cement time
5. Contingencies/procedures to quickly “nipple up” the BOP

None of these operational barriers are a substitute for a second physical barrier; in fact, none even supplement the activation of a physical barrier.

Some operators will pursue the option of providing a mechanical barrier in addition to the hydrostatic barrier by setting a wireline plug in the well, and testing this plug from above prior to removal of the BOP to set the slip and seal assembly at the surface.

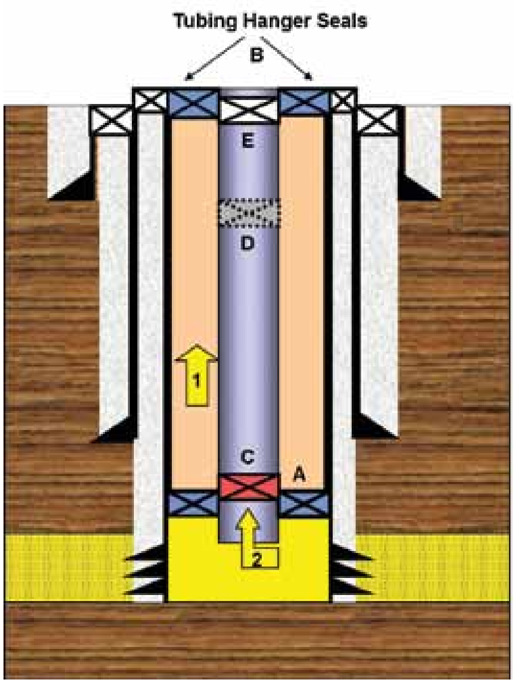
### Example 3 — Removing Surface Tree to Install a BOP

Another similar situation occurs during some well work operations. An example being when it is necessary to remove a production tree and install a BOP prior to conducting  workover activities in a producing well. Even if the well has been killed by bullheading or the volumetric method, the hydrostatic of the fluid in the tubing cannot be considered a barrier unless it can be monitored. Monitoring is not likely while the production tree is being removed. Hence, mechanical barriers must be implemented. If there exists a SCSSV in the tubing, it can be closed and considered to be one barrier, assuming its integrity can be verified by testing. If there is no SCSSV, then a wireline set plug might be set in the well and tested. Many operators seek to achieve the desired second barrier by setting a back-pressure valve (BPV) in the tubing hanger. Unfortunately, this valve has no way to be tested after installation; hence, its integrity as a barrier cannot be verified. Even should the valve have been recently tested in a flow loop, the functioning of the check may have been sufficiently confirmed, but the threading into the tubing hanger and sealing on the outside of the valve cannot be verified.

### Example 4 — Drilling Ahead with Subsea BOP (Floating Drilling)

Drilling ahead from a floating rig using a subsea BOP presents some different considerations in barrier design and implementation, that being due to the location of the BOP and the presence of the marine drilling riser to return the mud/cuttings to the surface. Now the hydrostatic column to overcome formation pressure is measured from the flow line on the floating vessel to the top of the exposed formation pressure. If the mud density pumped in is equivalent to or exceeds the mud density coming out, and the resulting hydrostatic pressure measured from the rig's flowline to the top of the exposed

Figure 3.5. Barrier envelope for tree removal to install surface BOP for workover operations.




Example: Remove Tree to Install BOP - Surface Stack Workover

| | | |
|---|---|---|
| Path 1: | Up Tubing by Casing Annulus | |
| | Column of Mud (hydrostatic) | H |
| | Not a Battier - Cannot be Monitored | |
| | Packer - Set and Tested | A |
| | Tubing Hanger Seals | B |
| | Procedure to Nippled Up BOP (operational) | |
| Path 2: | Inside Tubing | |
| | Wireline Set Plug | C |
| | Subsurface Safety Valve - if tested | D |
| | BPV in Tubing Hanger | E |
| | Not a Barrier - Cannot be Tested | |

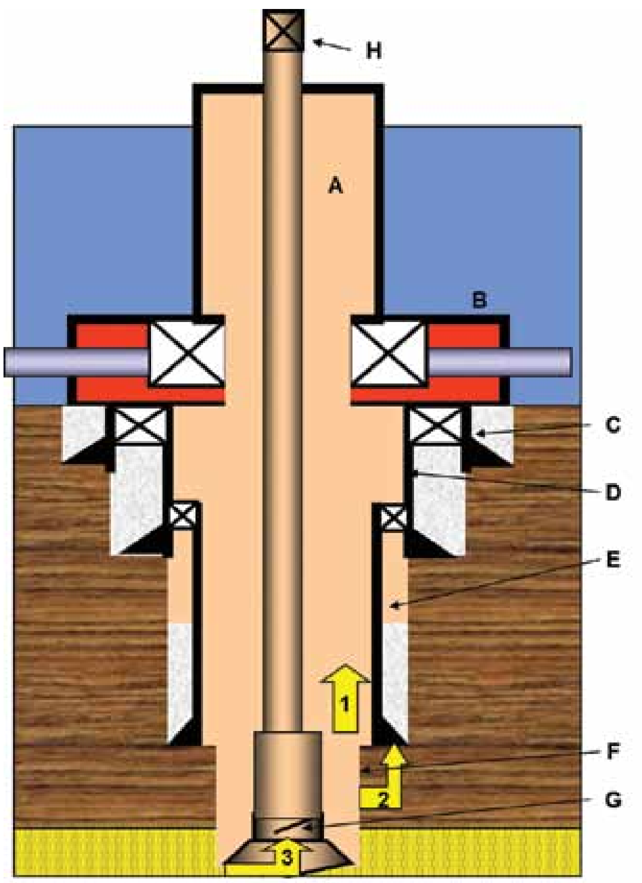
formation exceeds the formation pressure, the mud serves as a hydrostatic barrier and is the primary drilling barrier. The BOP located at the seafloor is a secondary physical barrier but only if there is a satisfactory operational barrier to detect inflow and operational practices to close the BOP.

Consider a subsea well with a surface casing string, an intermediate casing string, a liner and open hole below the liner shoe. This situation is illustrated in figure 3.6, and is a simplification of subsea wells but contains the essential features of subsea wells, the difference being there may be additional casing and or liner strings in other subsea wells.

A sufficient number of barriers exist as long as the column of fluid has enough density and vertical length to overbalance any exposed hydrocarbon zones and the BOP is in place to close in the well when there becomes a need. The vertical length of the fluid column includes the marine drilling riser. Most regulatory entities of countries around the world require displacing the riser with seawater before disconnecting the LMRP and pulling the riser, so that mud will not U-tube into the ocean. Hence, preparations must be made to compensate for the loss of fluid hydrostatic pressure in the wellbore and prevent an inflow of formation fluids.

Generally, a temporary plug, usually mechanical, is set deep in the casing to form a barrier that is tested. The well is left filled with a drilling fluid that when coupled with a seawater hydrostatic gradient above the BOP will not balance or overbalance the potential formation pressure below the temporary plug. After removing any drill string that might be in the well, the blind shearing ram is closed and locked to form the second physical barrier. At this point the riser is displaced with seawater and the riser and LMRP are unlatched from the lower stack.

Figure 3.6. Simplified subsea well with essential features (drilling ahead)




A Marine Drilling Riser
B Subsea BOP
C Surface Casing
D Intermediate Casing
E Liner
F Open Hole
G DP Float
H Top Drive FOSV
I Casing Annulus Seal
J Liner Top Packer

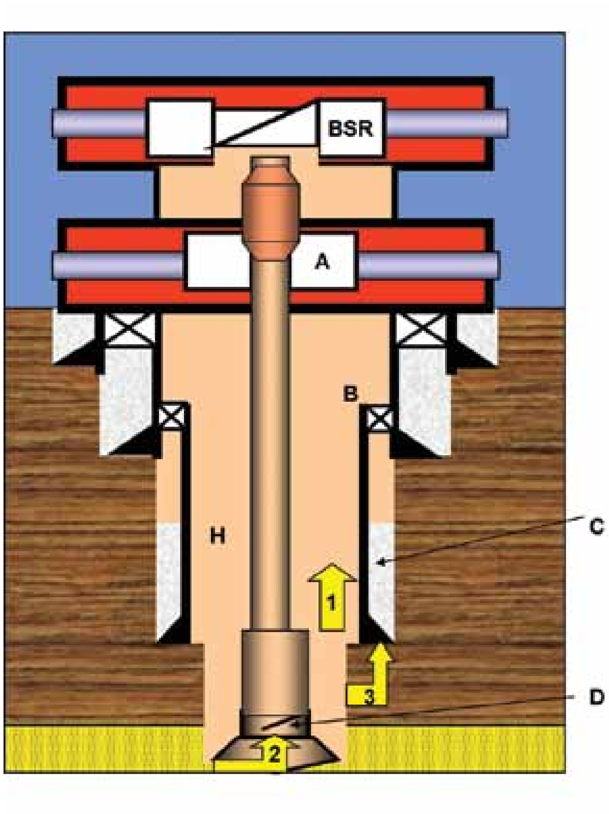
### Example 5 — Emergency Evacuation/Disconnect (DP Vessel)

Fact is, there will be some events during which two mechanical barriers, or even one monitored hydrostatic barrier and one mechanical barrier, are impossible to design for and implement. Consider the example illustrated in figure 3.7. In this case, a dynamically positioned (DP) rig is being used for drilling a deepwater well. The vessel experiences a drive-off or the station-keeping cannot be maintained over the well. An emergency disconnection of the riser from the BOP stack and wellhead must be made or dire consequences will result.

Prior to this situation, drilling has been safely conducted with the hydrostatic overbalance of the mud forming the primary physical barrier. The mud hydrostatic can be considered as a physical barrier because it is being closely monitored (supporting operational barrier) at the surface. The second barrier is the BOP, serving as a passive mechanical barrier, awaiting activation to become a second physical barrier. Activation is achieved through implementation of an operational barrier (the procedure to close the BOP).

During the emergency disconnect, the pipe will be hung-off on closed pipe rams (if there is sufficient time) and the pipe sheared as part of the disconnect sequence. The marine riser and LMRP will be then disconnected at the top of the lower BOP stack, and pulled away with the drilling vessel. Following completion of this activity, the well is left filled with a drilling fluid that does not have sufficient hydrostatic pressure to prevent formation fluids from invading the wellbore. This is because the *riser margin* will have been suddenly lost, when the mud hydrostatic pressure in the riser was replaced with seawater hydrostatic pressure.

Figure 3.7. Barriers in place following emergency disconnect and shearing pipe.




Example: Emergency Disconnect Shear Pipe - DP Rig

| | | |
|---|---|---|
| Path 1: | Up Pipe by Casing Annulus | |
| | Column of Mud (hydraostatic) | H |
| | Not a Barrier - Loss of Riser Margin | |
| | Closed Hang-Off Rams | A |
| | Sheared top of fish will leak pressure from drill string into annulus | |
| | Closed Bling Shearing Ram | BSR |
| Path 2: | Inside Tubing | |
| | Column of Mud (hydrostatic) | H |
| | Not a Barrier - Loss of Riser Margin | |
| | Closed Blind Shearing Ram | BSR |
| | Drill Pipe Float - Not a Barrier | D |
| Path 3: | Outside Casing | |
| | Annular Cement | C |
| | Liner Hanger Seal | B |
| | Closed Bling Shearing Rams | BSR |

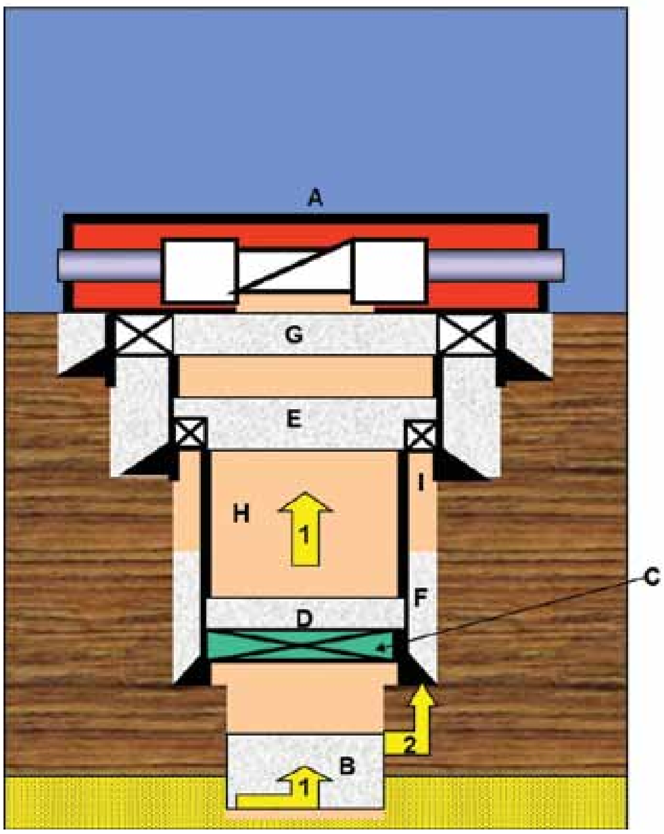
The only mechanical barrier to flow up through the drill string will be the closed blind/shear rams. It might appear on first sight that the primary mechanical barrier to flow up the annulus is the closed hang-off rams. However, after shearing, the top of the drill pipe fish will have pressure communication with the annular space above the hang-off rams, the closed hang-off rams provide no sealing capability to the wellbore above it. Therefore, the closed hang-off rams cannot be counted as a reliable barrier after pipe has been sheared.

The well will remain in this undesired condition until a rig/vessel returns to the site, the marine riser and LMRP reconnected and well killed before opening the closed shear rams and retrieving the fish (disconnected drill string hanging in the *hang-off ram*, or the sheared fish that dropped after shearing if there was not sufficient time to hang off the drill string.) Some emergency disconnect sequences (EDS) include closing the hang-off rams prior to operating the shear rams to catch the drill string if there happened be a tool joint between the hang-off ram and the blind shearing ram. That is not very likely. In most instances the driller will have time to hang-off prior to the execution of the EDS.

### Example 6 — Well Abandonment (Temporary)

Temporary abandonment of a well presents another example of barriers placed in a well when there is sufficient time to prepare, place, and verify the barriers. This might be required if the is ample warning of a storm approaching. In this case there is sufficient time to pull the drill string from the hole and set the appropriate plugs.

Figure 3.8. Typical barriers for deepwater temporary abandonment.




Example: Temporary Abandonment of Deepwater Well

| | | |
|---|---|---|
| Path 1: | Formation into Wellbore | |
| | Column if Mud (hydrostatic) | H |
| | Not a Barrier - Loss of Riser Margin | |
| | Cement Plug | B |
| | Inflow Tested | |
| | Mechanical Bridge Plug | C |
| | Tested from above | |
| | Cement Plug | D |
| | Slurry Test, Displacement Verified | |
| | Tagged after Set | |
| | Cement Plug | E |
| | Slurry Test, Displacement Verified | |
| | Tagged after Set | |
| | Cement Plug | G |
| | Not a Barrier | |
| | Closed Blind Shearing Ram | A |
| Path 2: | Outside Casing (a valid path?) | |
| | Annular Cement | F |
| | Inflow Tested? | |
| | Liner Hanger Seal | I |
| | Previously Tested | |
| | Closed Blind Shearing Rams | A |

Figure 3.8 illustrates typical barriers that are installed in a temporary abandonment of a subsea (deepwater) well. Because the well may be left, possibly unmonitored, for an indefinite period of time, more than two barriers increase the reliability of the system of barriers. In the open hole, a cement plug is placed near the bottom. The plug should be near the bottom and cover and extend above any potential permeable zones that might contain hydrocarbons. This cement becomes an acceptable physical (material) barrier if it can be successfully inflow tested (reducing the hydrostatic pressure in the well to a pressure sufficiently below the formation pressure below the cement plug) after setting. For the inflow test (negative test), the differential test pressure across the barrier should be as large as practical.

A second physical barrier is next installed by the placement of a mechanical barrier. Inside the casing, a mechanical plug (bridge plug) can be set by wireline and tested from above. To further improve the effectiveness of the mechanical plug, a cement plug is placed above the mechanical plug. This plug will generally be verified by testing the slurry before pumping and then tagging its top to estimate its compressive strength after placement.

The example well has a liner. The liner top will have been previously tested. To further ensure the effectiveness of the liner top seal, a cement plug is placed across and above the liner top to further ensure there is no leakage at the liner top hanger. If possible, this cement plug is inflow tested by reducing the hydrostatic pressure above it to a value less than the expected formation pressure that might be leaked through the annular cement column and across the liner top seals. The differential test pressure value is very subjective because one does not know the actual formation pressure up the cemented annulus and to the liner hanger seals.

Many operators do not consider leakage external to cemented casing or liner as a valid flow path; hence any type of inflow test across the cemented liner top seals is not justifiable when this external flow path is not recognized as valid.

Finally, a cement plug is placed in the casing at the surface. This plug cannot be considered a barrier because there is no way to test it. However, its placement can be verified by observation of displacement volumes and the slurry can be tested prior to pumping.

## Barrier Testing

Barrier testing is part of risk management; the consequences of system failures, such as happed with Deepwater Horizon emphasize the importance of barrier testing.

The verification of a barrier's integrity is dependent on the type of barrier. The exact nature of the verification process or test and the associated acceptance criteria should be developed for each physical and operational barrier in the well. The testing and verification process must follow guidelines and procedures in accordance with the well program, manufacturers operations, testing and technical manuals, industry and regulatory agency published standards and procedures. Acceptance criteria define the conditions to be met to satisfactorily verify the integrity of the barrier for its expected application. Barrier verification results must be documented and retained as required by local regulations or company policy.

A physical barrier is best verified by testing, or by confirmation in situations where testing is not practical. Physical barriers are best tested by measurement of a barrier's capability for containing the anticipated pressure load to which it might be subjected. For well control equipment, such as BOPs, valves, drilling chokes, etc., manufacturers submit these kind of physical barriers to extensive in-house design and qualification testing before being released from production. However, because each component has not yet been installed as an integral piece of the complete well system, additional verification of its integrity must be conducted after installation.

The most reliable verification of a physical barrier is to pressure test to the expected differential pressure in the direction of flow after the barrier has been installed in the well. Unfortunately, it is not feasible to pressure test some barriers in the direction of flow. Thus, a lesser assessment of integrity must be made, such as confirmation of the barrier by some other type of test or observation of its presence and performance.

### Pressure (Positive Testing)

For certain kinds of barriers, a pressure load can be applied to evaluate the barrier's proper installation and integrity during a potential operational situation. Such testing, where the applied pressure during the test simulates the applied loading condition is considered *positive testing*. It is practical to verify by pressure testing a newly installed mechanical barrier using the fluid that is in the well at the time of verification. This fluid is typically drilling mud, completion brine or water. Generally local regulations dictate the acceptance criteria for pressure integrity criteria, but in some cases company policy may be used. Acceptance criteria may include:

- A pressure change during a designated hold time
- A visual observation of leak
- A difference between pressure-up volume and bleed-back volume.

An example of positive testing is the testing of blowout preventers. For a BOP test, a *test plug* is placed in the annulus to isolate the well, a selected preventer is closed and test pressure is applied to the bottom side of the preventer. Some subsea stacks are configured with an extra ram BOP as the lowermost ram and designated as a *test ram*. When this ram is closed, test pressure may be applied between it and a ram located higher in the stack to conduct a positive test of the higher ram when closed.

Another example of positive testing is the application of pressure between a previously tested ram BOP and the top of a casing or liner top seal assembly. This test does not verify the integrity of the casing or liner top seal assembly for upward loads applied in the annulus between two casing strings or between a liner and an outer casing. However, it can be used to verify the pressure integrity of seal(s) for downward pressure loads between the two casing strings and or the top of a liner inside as casing string.

OGP 116530 Well Integrity - Part 27 explains inflow testing as using the tuning tubing or casing pressure to perform leak tests. The valve to be tested is closed, the pressure downstream of the valve is reduced to create a pressure differential across the valve and the volume downstream of the valve is monitored for a pressure increase that indicated a leak through the closed valve.

### BOP Test Tools

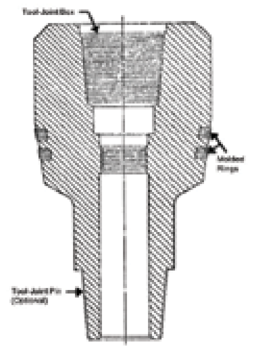
The design of the BOP test tool varies, but it is a device attached to the end of tubing or drill pipe and run to the bottom of the BOP stack or in the casing head, and is held in place initially by the pipe weight. It is typically fitted with elastometric seal rings and may also have several scaling cups to effect a seal. Use case. If the seals fail, the wellbore may be energized. Above the seals is an opening to the ID of the pipe to allow water to be pumped to fill the bore and allow pressure testing of the BOPs. On the upper part of the joint(s) of pipe is another tool with connection fittings or manifold back to the test pump.

The maintenance of the test tool should include component inspection for signs of damage or wear. Follow the manufacturer's instruction for proper cleaning and storage. After each use, inspect and replace sealing elastomers and O-rings as needed.

## Test Plug

A test plug is used to test BOPs and associated well control equipment without exerting pressure on the wellhead and casing. Wellhead side outlet valves should be open to avoid casing and formation damage when pressure testing using a test plug. See figure 3.9.

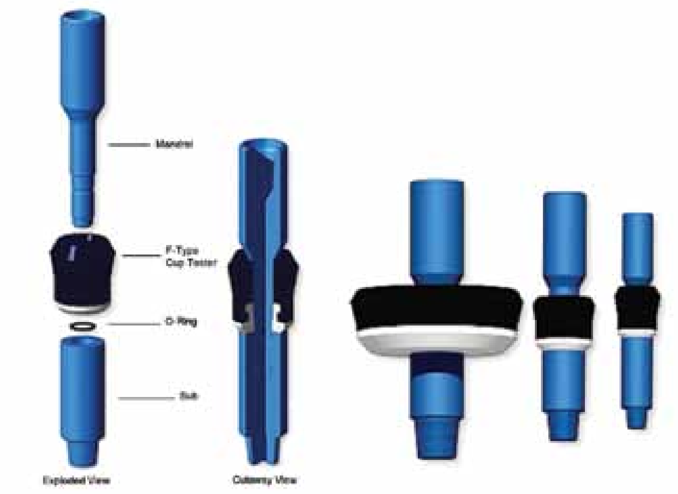
Figure 3.9. A test plug.




## Cup Type Tester

A cup type tester is used to test wellhead and wellhead side outlet valves without exerting pressure on casing and formation. The cup type tester should be run on open-ended drill pipe to release any buildup of pressure below the cup. See figure 3.10.

Figure 3.10. Cup type testers.




## Inflow (Negative Testing)

Inflow tests are usually used to verify the integrity of a well barrier to make sure there is no communication with the formation through the casing, a liner or a cement plug. A failed inflow test indicates that there is communication through a well barrier. Well control depends on barrier integrity. Loss of well barrier integrity was one of the concerns during the blowout of the Deepwater Horizon well in 2010.

In many cases the positive generation of differential fluid pressure (in the direction of flow) is impossible. An *inflow test* is a method to apply a differential pressure in the direction of flow from the formation to the wellbore. The pressure differential across the barrier to be tested is generated by the reduction in hydrostatic pressure on the upper side of the barrier. Another common name for inflow testing is *negative testing*. Because the pressure differential is created by the density of the fluid on the upper side, the maximum applied differential test pressure may be limited and cannot always simulate the maximum possible load during well operations.

To limit the quantity of kill weight fluid displaced from the well and to create a trapped volume for the test, the lower density fluid above the physical barrier to be tested is often displaced down the drill string and trapped by closing an upper temporary barrier such as a BOP or wellhead test plug. This upper temporary barrier serves as a second barrier during the inflow testing of the barrier undergoing verification.

The method by which the original hydrostatic will be re-established at the conclusion of the inflow test (e.g., the negative test) should be considered. Also, the method by which barrier control be re-established should a failure occur of either the barrier subjected to the inflow test or the barrier used to trap the volume of lower density fluid. A contingency plan should be prepared to handle the failure of the barrier being tested and the plan thoroughly reviewed with all personnel prior to implementation of the test.

### Inflow Test Roles and Responsibilities

The execution of the inflow test can become quite complex. Hence various members of the drilling crew and engineering support staff will be required to understand and competently execute their respective roles. There are no exact rules for establishing the roles each individual will play. As a starting point, consider assigning the determination of the maximum potential load across the barrier to the engineers in the office or on-site (if any). The engineers, along with the operator's on-site representative and the contractor's on-site representative (toolpusher) should work together to establish the practical maximum load that can be applied. A test plan and procedure should then be developed, signed and dated by the operator's on-site representative after review with the engineering support staff. All should agree on an "acceptance criteria" for a successful inflow test of the barrier. The toolpusher should be responsible for the assembly of all required test equipment and instrumentation; then assign specific duties to each member of the crew after carefully communicating the test procedure and objectives. The operator's representative should sign-off on the set-up of the equipment. The test should be conducted under the supervision of the operator's representative, with assistance from the toolpusher. The operator's and contractor's on-site representatives should agree the test did or did not meet the acceptance criteria, and then sign and date the test report.

#### *SAMPLE INFLOW TEST PROCEDURE*

1. A test string made up of pressure gauges, a retrievable packer, reversing valve, safety joint and collars, is run into well and seated above the barrier to be tested (usually 50 feet).
2. Pressure test the retrievable packer by increasing annular pressure to make sure it is seated and not leaking.
3. Lighter (underbalanced) fluid is circulated down the tubing until the predetermined drawdown pressure is reached.
4. Perform the inflow test for 15 minutes.
5. Reverse circulate out the lighter fluid with the balanced fluid.
6. The retrievable packer is unseated.
7. The well is circulated.
8. A flow check is performed.
9. The retrievable packer is pulled out of the hole.

### Inflow (Negative Testing) Results

The graph shown in figure 3.11 has the results of an inflow test on a 7-inch liner using diesel. The inflow test passed; note the results (in the table and the graph) show a flow rate that decreases to zero, indicating no inflow. The initial flow might have been due to expansion of the test fluid as it heated after being displaced into the well.

Figure 3.12 shows inflow occurred after a period of time, indicating leakage of gas through the liner top seal. The gas then began to expand as it migrated up the well. Note the flow rate curve trends down and then builds up, indicating an inflow, The inflow test failed.

Example of inflow tests are provided in appendix C of API RP 96 *Deepwater Well Design and Construction*. These examples provide guidance for establishing inflow test procedures, identifying potential leak paths that produce failed tests, and re-establishing an overbalanced hydrostatic pressure above the barrier undergoing the inflow test following completion (for failed or successful test).

Figure 3.11. Negative inflow test showing passing results.

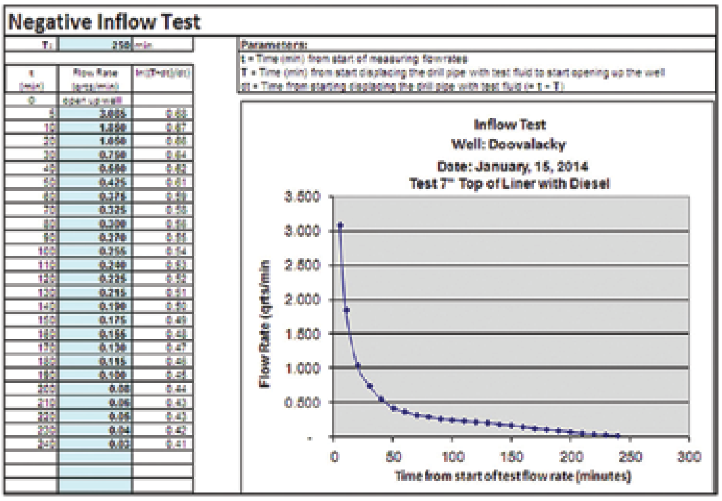
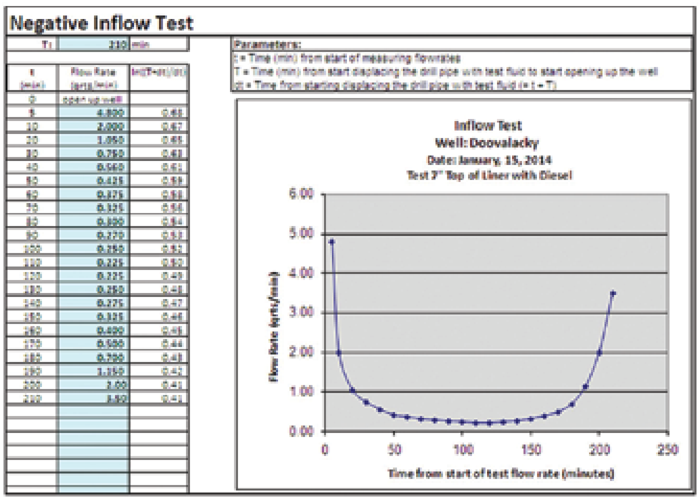



Figure 3.12. Negative inflow test shows failing results.




The conduction of a barrier test at full differential pressure in the direction of flow is not always feasible. The integrity of the barrier must be evaluated using other verification methods. Barriers that are verified by methods other than a positive pressure test or negative pressure test (inflow test) in the direction of flow are categorized as "confirmed". Pressure testing alternatives may include:

- Pressure test in a direction opposite the flow (if appropriate for the barrier).

- A shallow barrier such as a cement plug or bridge plug set above a properly inflow-tested deeper plug cannot be inflow tested. This is because the pressure below the shallower plug is unknown. Pressure must be applied to the upper side of plug, but the differential pressure is unknown due to not knowing the pressure under the plug. Hence a simple pressure test in the direction opposite the flow direction does not verify the integrity to a barrier to known differential pressure, it can only confirm the existence of the plug.
- For a cement plug, slack off string weight to confirm that the plug has set or hardened as designed.
- Perform a drilling test on a cement plug by assessing the cement strength indirectly by measuring the rate of penetration and the weight on bit need to drill the plug.

Experience has shown that the best place to set a cement barrier in a well that is either to be temporarily or permanently abandoned is to locate the plug as deep in the well as possible, through and just above the exposed hydrocarbon zone (see figure 3.7). The formation pressure thus creates the maximum wellbore pressure at the base of the plug. A reduction in hydrostatic pressure above the plug created by displacement of the kill weight mud with the lowest practical drilling fluid weight thus generates the maximum practical pressure differential across the plug for an inflow test in the direction of flow.

### Barrier Failure During Negative Testing

Contingency plans must be made prior to conducting negative pressure testing to mitigate kick size in case of barrier failure. Contingency plans may include procedures for dealing with leaks or failure of a packer, tubing collapsing or parting, surface equipment failure or leaking, cement failure, and circulation device or other downhole failure. If a barrier fails during negative pressure testing, shut in the well, determine which barrier failed and follow contingency plans.

### Verification that Barriers are Installed

Hydrostatic barriers cannot be verified by a pressure test or an inflow test. Verification of a hydrostatic barrier requires several mini-tests or observations of the performance of the barrier. For example, the fluid (mud or brine) must be tested for density, both in the pits and the return. The measured density, when coupled with the depth to the exposed formation, must always be sufficient to generate a hydrostatic pressure greater than the formation pressure. If there is no circulation of the fluid, such as while pulling pipe out of the hole, the returns should be monitored with a trip tank to observe any possible returns, even when the calculated hydrostatic pressure overbalances the formation pressure. A pump style trip tank is the tool of choice because it continually fills the hole while simultaneously measuring the fluid volume displaced into the hole (tripping out) or the fluid volume displaced from the hole (tripping in).

If brines are in use, the operator should diligently monitor the returns when the well is static, even if there is no work activity, because brines do not have the ability to create a *filter cake*, and the fluid will seep into an overbalanced formation, continuously reducing the fluid level and hydrostatic pressure. A brine placed in an annulus above a packer, or open hole above a mechanical plug or cement plug set in open hole cannot be counted as a barrier, because the seepage into the rock will ultimately reduce the hydrostatic pressure in the annulus.

### Verification of Annular Cement

Cement displaced into a casing annulus cannot be verified as a material barrier by positive testing or inflow testing; therefore an annular cement barrier can only be confirmed. For set cement in the annulus to serve as a physical barrier to the influx of formation fluids, the cement slurry must be designed and laboratory tested for the anticipated well conditions. Then the cement should be placed in the well using the recommended practices and equipment in accordance with API Standard 65-2.

Successful placement of the properly designed slurry can create a reliable annular barrier is confirmed using the data collected during the slurry placement operation. If the data indicates the top of cement may not be at the planned depth or that slurry placement has other problems, a diagnostic log may be used to establish the location of the cement top and/or evaluate the bond quality of the cement. Local regulations may specify alternative acceptance criteria or evaluation steps.

Exercise caution when using cement evaluation logs as the primary means of establishing the barrier competency of cement in the annulus. Often, interpretation of cement evaluation logs is subjective. Refer to API 10 TR-1 for an overview of the attenuation physics and limitations of the various types of cement evaluation logs.

### Testing Operational Barriers

By definition an operational barrier is not a physical barrier (mechanical or material). Hence they are often view as soft barriers, with lesser importance than physical barriers. This is a totally incorrect characterization of operational barriers. Operational barriers are an integral part to the application of many physical barriers, such as BOPs, FOSV, hydrostatic and cement barriers. Recall that a BOP is not a barrier unless closed; the same is true for a FOSV. A hydrostatic barrier such as drilling mud is not a barrier unless key operational practices as conducted by the mud engineer to ensure the fluid density is correct, or by the drilling team to ensure the trip tank is monitored at all times when the well is static (not being circulated).

Because these key operations are considered barriers, they too must be tested. Listed in the table below are a few operational barriers along with a method for testing them.

Table 3.2.

| Operational Barrier | Method of Verification |
|---|---|
| Ensure Correct Mud Density | • Weigh mud in and out<br>• Correct for temperature variation in well |
| Ensure Well Stands Full | • Monitor trip tank on trips, connections |
| Procedure for Shut-in | • Conduct pit drills, trip drills, time response |
| Procedure for Kick Circulation | • Conduct choke drills; attend well control schools<br>• Simulate pump start-up, and circulation keeping BHP constant with the choke |
| Procedure for Bullheading Well | • Simulator drills |
| Function Test BOPs | • Observe closure; closing times |
| Pressure Test BOPs | • Observe leakage or pressure loss vs. time |
| Volumetric Well Control Procedures | • Attend frequent well control schools<br>• Conduct practice exercises |
| Stripping Procedures | • Conduct practice exercises |
| Inflow Test Procedures | • Review procedures with drill crews<br>• Follow-up with simulation/discussion |
| Procedure for Cement Placement | • Review procedure with drill team; ensure complete understanding by questioning |
| Assessment of Barrier Plan | • Review of barrier performances; Identify poor performers and/or potential weakness in supporting operational barriers |
| Training in the Topic of Barriers | • Inclusion in well control training course |

### Barrier Test Documentation

The test or verification of barriers within the system of barriers (barrier envelope) must be documented. The required form of documentation is determined by the operator and/or the local regulatory agency. In general the document should include the following elements:

- Description of the barrier tested
- Location in the wellbore
- Potential maximum load on/across the barrier
- Acceptance criteria
- Maximum test load applied
- Direction of flow and direction of test load applied
- Positive test or inflow test
- Leakage observed (if any)
- Test load (pressure) chart, dated and initialed by tester
- Leakage observed or measured
- If positive test, volume to pressure and volume bled after test
- Signed and dated test report by operator's representative

If the barrier was not pressure tested or inflow tested, but rather verified (see section "Verification that Barriers are Installed"), describe the method of verification and results, signed and dated by the operator's representative.

API RP 96 defines tested and confirmed (verified) barriers as:

- "*Tested barrier*: a barrier whose performance has been verified through meeting the acceptance criteria of a pressure test. The test is in the direction of flow and to a pressure differential equal to or greater than the maximum differential pressure anticipated during the life of the barrier."
- "*Confirmed barriers*: a barrier whose performance has been verified through meeting the acceptance criteria of a pose installation evaluation other than that of tested barrier, or through evaluation data collected during installation. A confirmed barrier has a lower level of assurance than a tested barrier." An example of a confirmed (verified) barrier is a barrier that was tested in the direction opposite from formation flow.

Table 3.3. Testing Operational Barriers.

| Operational Barrier | Method of Verification |
|---|---|
| Ensure Correct Mud Density | • Weigh mud in and out<br>• Correct for temperature variation in well |
| Ensure Well Stands Full | • Monitor trip tank on trips, connections |
| Procedure for Shut-in | • Conduct pit drills, trip drills, time response |
| Procedure for Kick Circulation | • Conduct choke drills, attend WC schools<br>• Simulate pump startup and circulation, keeping BHP constant with the choke |
| Procedure for Bullheading Well | • Simulate drills |
| Function Test BOPs | • Observe closure; closing times |
| Pressure test BOPs | • Observe leakage or pressure loss vs. time |
| Volumetric Well Control Procedures | • Attend frequent WC schools<br>• Conduct practice exercises |
| Stripping Procedures | • Review procedures with drill crews<br>• Follow up with simulation / disccussion |
| Inflow Test Procedures | • Review procedures with drill crews<br>• Follow up with simulation / discussion |
| Procedure for Cement Placement | • Review procedure with drill team; ensure complete understanding by questioning |
| Assessment of Barrier Plan | • Review of barrier performance. Identify poor performance and / or potential weaknesses in supporting operational barriers. |
| Training in the Topics of Barriers | • Included in well control training course |

### Barrier Maintenance

Because any physical barrier can fail, the ongoing effectiveness of barriers should be assessed on a periodic basis. The policy of a company or governmental regulatory body to require re-assessment of a physical barrier as well construction progresses is in itself an operational barrier. Detection of physical barrier failure should result in immediate action to correct the failure before continuing work in the well.

A retest of a physical barrier is the highest level of verification of the ongoing reliability of the barrier. Company policy and/or government regulations generally dictate the required re-test frequency of well control equipment. Some examples of re-testing for barrier effectiveness include pressure and function testing of BOPs every fourteen (14) days and running a caliper log as drilling or other well work that requires rotation of the string of pipe. This log is used to measure the thickness of the casing wall; significant loss of wall thickness reduces the burst and collapse pressure capability of the casing.

Should a barrier fail, the integrity of overall well system should be re-evaluated before continuing the drilling, completion or workover operation. Some type of remedial operation will usually be required, local regulators will likely have input. With a barrier failure, some alternatives are suggested:

- Make a diligent effort to repair the barrier
- Install a different barrier (could be the same type or an upgrade)
- Re-evaluate the well control system reliability based on the forward plan
- Develop additional operational barriers and prepare MOC as needed.

Some additional, more specific examples of barrier assurance and barrier re-establishment are found in appendix B of API RP 96. The examples there are applicable to floating drilling operations in deepwater.

## Leak Testing Of Well Barriers

The following is an excerpt from the NORSOK Stand D-010, 4.2.3.5 - 4.2.3.5.3

### *GENERAL*

Leak testing of well barriers of well barrier elements (WBEs) shall be performed:

- before it can be exposed to pressure differentials,
- after replacement of pressure confining components of the well barrier,
- when there is a suspicion of a leak,
- when an element will become exposed to different pressure / load than it originally was designed for, and
- routinely.

#### *Pressure Direction*

The pressure should be applied in the flow direction. If this is impractical, the pressure can be applied against the flow direction, providing that the WBE is constructed to seal in both flow directions or by reducing the pressure on the downstream side of the well barrier to the lowest practical pressure (inflow test).

#### *Leak Test Pressure Values and Duration*

A low-pressure leak test 200 to 300 psi for 5 minutes should be performed prior to high-pressure leak testing.

The high-pressure leak test value shall be equal to, or exceed, the maximum anticipated differential pressure that the WBE will be exposed to. Static leak test pressure shall be observed and recorded for a minimum of 10 minutes.

The above test values shall not exceed the rated work pressure (WP) or any WBE.

#### *Acceptable Leak Rates*

The acceptable leak rate shall be zero, unless specified otherwise.

For situations where the leak rate cannot be monitored or measured, the criteria for maximum allowable pressure fluctuation shall be established.

#### *Function Testing of Well Barriers*

A function test of the WBE(s) shall be performed:

- after installation,
- after having been subjected to abnormal loads,
- after repairs, and
- routinely.

### Documentation Of Leak And Function Testing Of Well Barriers

All well integrity tests shall be documented and accepted by an authorized person. This authorized person can be the driller, toolpusher, drilling and well intervention supervisor or the equipment and service provider's representative.

The chart and the test documentation should contain:

- type of test,
- test pressure,
- test fluid,
- system or components tested,
- estimated volume of system pressurized,
- volume pumped and bled back, and
- time and date.

### Accepted Minimum Number Of Physical Barriers

Industry practice has generally required that the minimum number of barriers is two (2) for any given flow path, with at least one of these being a mechanical (physical) barrier; however, for some higher risk operations, an operator might require many more to increase overall barrier system reliability. While it is preferred that both barriers be physical, many drilling operations employee a second barrier that has a physical presence, but is not active. It is generally accepted that presence of two physical barriers provides an acceptable degree of reliability. If any operation is conducted with fewer than two physical barriers, operational barriers become critical. An operational barrier can provide a "supplement" to an inactive (potential) physical barrier, such as a BOP. Also, governmental regulators may dictate the number of barriers to be in place for specific well drilling/completion operations.

### Operational Barriers

In many instances, an operational practice is considered a barrier. The most common example of everyday use of an operational barrier is the procedure in place for closing a BOP when a well kicks. The BOP itself is not a barrier unless it has been closed; there must be an operational barrier (procedure) to activate (close) the BOP. Another example of an operational barrier is a well thought out plan and procedure for installing a crossover from screens to drill pipe, with a full-opening safety valve (FOSV), and then lowering the screens so that a BOP can be closed around the pipe. This procedure (operational practice) can be viewed as an "operational" barrier. This operational practice allows the inactive mechanical barriers (FOSV and BOP) to become physical barriers, blocking flow.

# INFLUX FUNDAMENTALS

# 4

## UPON COMPLETION OF THIS CHAPTER, THE STUDENT SHOULD BE ABLE TO:

- Explain primary well control.
- Identify and answer questions on the causes of kicks.
- List situations which may cause kicks.
- Explain hydrostatic, circulating and formation pressure relationships.
- List causes that may reduce hydrostatic pressure.
- List potential causes of lost circulation.
- Determine the correct initial action to take during lost circulation for seepage, partial and total losses.
- List the causes of surging and swabbing.
- Describe the consequences of surging and swabbing on bottomhole pressure.
- Interpret the results on a trip sheet and determine the correct action to take.
- Compare and calculate dry trip and wet trip volumes and measurements.
- Describe possible remedial steps if calculated trip volumes do not compare with results on the trip sheet.
- Perform calculations relative to pressure concepts using WCS Formula Sheet (Appendix B):
  - Barrels to fill – dry trip
  - Barrels to fill – wet trip
  - Pressure drop per foot – tripping dry pipe
  - Pressure drop per foot – tripping wet pipe

*Excerpt from "Guide to Blowout Prevention, Second Edition, Revised November 2011" manual by Well Control School*[1]

The term *kick* is a field expression used in the upstream oil and gas industry to denote that formation fluids are flowing into a well. The International Association of Drilling Contractors (IADC) classifies kicks as intentional or unintentional. An intentional kick refers to operations that *deliberately* induce the controlled flow of formation fluids into a well. Obviously, when a well is producing, formation fluids are being brought to the surface under controlled conditions and although producing wells are not usually described as *kicking*, they do fit the definition of an intentional kick. There are other operations that fit the definition as well, for example, drill stem testing, swabbing with wireline, or pumping nitrogen in order to bring a well in.

*An unintentional kick is an unexpected and undesired flow of formation fluids into a well.* Unintentional kicks, if not detected and handled correctly, lead to blowouts. *A blowout is the uncontrolled flow of formation fluids to the surface or into another zone in the same open borehole.* Subsurface or underground blowouts occur when a formation is producing from one formation and entering a weaker or fractured formation before the fluid reaches the surface.

Blowouts are the most tragic accidents in the drilling/workover industry, often resulting in death and injury of personnel, loss of the well and its potential production, and severe damage to the environment. Other potentially negative impacts of a loss of well control include the reputation of the drilling industry, society's view of the oil and gas business, and opportunities for employment as a drilling professional. Kicks can occur during nearly any operation on an oil or gas well, and if improperly handled, kicks can turn into blowouts. The key to blowout prevention is recognition and control of kicks, therefore learning the causes and indications of potential kicks, and taking the correct action to maintain control of the well is the essence of blowout prevention.

Chapter 2 described two opposing forces acting on a well in which the formation is exposed: 1) bottomhole pressure, the sum of all pressures exerted on the bottom of a well, and 2) formation pressure, as a result of local geology, acting upward. It can be seen that a kick can only occur when, for some reason, formation pressure is greater than bottomhole pressure. The following discussions are concerned with unintentional kicks and some of the situations that might cause them.

## A Live Well vs A Kicking Well

*Excerpt from "Well Control for Snubbing Operations" manual by Well Control School*[2]

A well is balanced when the hydrostatic pressure equals the formation pressure. If the hydrostatic pressure in a well is greater than the formation pressure, the well is overbalanced. This is the case in most conventional drilling operations and some workover operations. If something occurs to upset this balance during operations and the hydrostatic pressure is allowed to fall below the formation pressure, the well will "take a kick" or become a kicking well. If the drilling or well intervention activity has been designed to occur in an overbalanced condition, the well must be shut-in and the kick must be removed by circulation or another means.

Well intervention operations (wireline, coiled tubing and snubbing) are often conducted in underbalanced conditions or even while producing; or, in other words, wells in which the formation pressure is greater than the hydrostatic pressure. These underbalanced conditions might also exist when drilling or during the completion of a well, such as in *underbalanced drilling* or *underbalanced completion*. These operations are said to be conducted in a live well and rely on pressure containment through surface well control equipment. Also, once an initially overbalanced well takes a kick and is shut-in, it becomes a live well. The difference between the formation pressure and the hydrostatic pressure is the differential pressure. Generally, a well with a hydrostatic pressure greater than the formation pressure is said to have positive differential pressure.

## The Causes of Kicks

The fundamental cause of any kick is a situation where (1) the local pressure in a well is less than the pore pressure of the adjacent exposed formation, and (2) the formation is either permeable or fractured to permit the flow of formation fluids.

The two conditions above are necessary and sufficient for a kick to occur. If both conditions are present, there will be a kick, but if only one is present there will not be a kick.

The causes of kicks are often thought of as the well situations that lead to the development of the fundamental cause cited above. The following are some of the common causes of kicks:

- Insufficient mud weight or fluid density, such that hydrostatic pressure is less than pore pressure.
- Lost returns while circulating.
- Lost circulation when running or pulling casing.
- Lost circulation when cementing.
- Not keeping the hole full.
- Cutting into abnormal pressure.
- Surging and swabbing when tripping in or out.
- Surging and swabbing when pulling or running casing.
- Lost circulation, surging or swabbing while cementing or after cementing.
- Cutting into an adjacent well.
- Cutting into a charged formation
- Removing wellbore obstructions, packers and plugs with pressure imbalances across them.

## Primary Well Control

Primary well control consists of maintaining fluid hydrostatic pressure greater than formation pressure. During normal drilling operations, the hydrostatic pressure of the drilling fluid creates the primary barrier to avoid any flow of formation fluid into the wellbore.

Well control is the management of the dangerous effects caused by the undesirable flow of formation fluid into the wellbore that happens when formation pressure is more than the hydrostatic pressure in the wellbore. Loss of well control can cause serious injury, or loss of life, equipment damage, and environmental damage.

There should be sufficient hydrostatic pressure overbalance over formation pressure to allow for contingencies.

## Insufficient Fluid Density

The largest component of bottomhole pressure is the hydrostatic pressure created by the density of the fluid in a well. In fact, if the annulus of a well is open on the surface and the pumps are off, bottomhole pressure and hydrostatic pressure are equal. Therefore, *the fluid in a well is the primary barrier against kicks* during conventional drilling and workover operations. Maintaining the fluid at the proper density is crucial to safe operations.

It is possible that the mud weight can be reduced accidentally through human error. Large offshore units have several mud pits in addition to the active system. The manifolds that route the fluid to various pumps and tanks are made up of complex piping with many valves. An inexperienced worker can easily open or close the wrong valve, sending water or light fluid to the rig pumps.

Heavy rain falling into an open pit system can quickly reduce mud weight and alter other fluid properties. Also, a great deal of water is used to clean the screens of shale shakers when drilling soft clay formations. During these intervals, the mud weight in the pits must be checked often. An example of a field test lab with mud balance to weigh the liquid and obtain its density is shown in figure 4.1.

Other causes of incorrect fluid density include mistakes made when changing out the present fluid in the well for fracturing or acid jobs, spotting special pills, or changing to completion or packer fluids.

The density of the working fluid pumped into and returning from a well should be checked frequently with an accurate mud balance.

Sometimes it is necessary to reduce the mud weight because of well conditions. It is always a good idea to consult a mud engineer before starting the job. Reducing the density of the fluid while maintaining other properties in the desired range is often more difficult than increasing the density by simply adding barite or other weight material.

Figure 4.1. Field test lab with mud balance.

## Lost Circulation

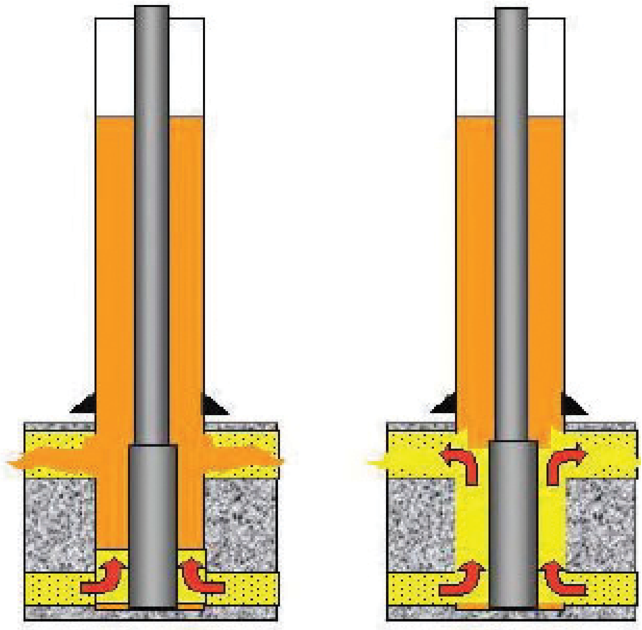
Since the height of the fluid column in a well is a factor in determining total hydrostatic pressure, bottomhole pressure would decrease if the well could not withstand the pressure exerted by a full column of the fluid. The well would not “stand full”. In this case, it is possible that bottomhole pressure would be reduced to a value below that of the formation pressure, thus inducing a kick, usually from a zone higher in the well than the thief zone. See figure 4.2.

The loss of hydrostatic pressure (psi) due to a drop in the fluid level in the well is calculated from the fluid density (mud weight in ppg) multiplied by the vertical distance to the top of mud column (feet), multiplied by the conversion factor 0.052. Following a sudden total loss of returns, a good industry practice is to stop drilling and observe the fluid level in the annulus, then fill the annulus with a light fluid.

$$\boxed{\text{Hydrostatic Pressure Loss}_{psi} = \text{MW}_{ppg} * \text{Fluid Level Drop}_{ft}\ \text{TVD} * 0.052}$$

In figure 4.2, the fluid level has dropped due to lost circulation into the upper sand. As it drops, the BHP is reduced and causes the lower zone to kick. It is also possible for the kick to be above the thief zone.

Figure 4.2. Kick induced by losing circulation.



Lost circulation can be caused by several different situations:

- Some formations are sub-normally pressured; in other words, they will not support a column of water. Other formations are severely fractured, even though the formations above and below them are strong. In that case drilling into the fractured formation would result in lost returns. Well servicing operations in an exposed fractured formation will result in lost returns.
- Some formations take fluid when the well is circulated and yet, when the pump is switched off the annulus will stand full. This is due to the pressure imposed on the annulus by the pump. Often in these cases, the mud weight can be carefully reduced to a point at which full returns can be established.
- Surge pressures created by lowering the work string into a well can also induce lost circulation in fragile formations. In fragile formations, maintain minimium ECD, minimium mud weight and avoid pressure surges.
- Losses can occur in one section of the perforated interval with other areas still producing in a completed well. The perforated interval may be in a multilayed reservoir. These sections or layers may have hydraulic communication with each other or be totally isolated from each other. Each layer may have similar or completely different properties. Hydrostatic head pressure may allow some perforations to flow while perforations in different layer take fluids. If losses are severe, the producing well, will have to be killed or suspended. The thieft section of the well may have to be cemented.

Clear brines are often used as completion fluids. These fluids have little or no solids content and therefore can enter permeable formations easily. Lost circulation can be a tricky well problem at any time. The fact that it can also increase the potential for taking a kick makes it doubly important for a crew to be alert when mud pit volume or return flow from a well changes unexpectedly.

If losses cannot be lessened by reducing mud weight, fluid losses can usually be lessened by adding fluid *loss control materials (LCM)* to the fluid system or changing the mud chemistry.

- Fluid loss control for seepage (one to ten percent losses) is usually controlled with fine to medium fine grade LCM.
- Partial losses (10 percent to less than 100%) can be controlled with fine to medium fine grade LCM.
- Total losses (100 percent) may be controlled with coarse grade LCM, pills or plugs.

Start with finer LCM and use increasingly coarser grades if the finer material does not work.

*NOTE: LCM materials, pills, or plugs, and other loss control material may plug bit nozzles.*

Taking seepage and partial losses during a well kill procedure require good choke control and a slower kill rate speed.

In the event of total fluid losses and circulation cannot be regained, first determine the loss zone location. The lost zone location is generally at the bit, if the formation has been damaged. If the mud weight has been increased recently, it is located at the weakest point in the hole below the last casing shoe. Loss zone location may be determined using radioactive tracers, hot-wire surveys and temperature surveys.

Based on the loss zone depth, decide on:

- If the loss zone is 500 feet or less, first cure the lost circulation using loss control material and gunk squeeze. Then control the kick.

Or

- If the loss zone is more than 500 feet, first isolate the lost circulation zone using barite plugs or cement and then work on the loss zone.

## Well Control with Total Lost Circulation

*Excerpt from "Training Manual for IWCF Rotary Drilling (Surface and Subsea Stacks)" manual by Well Control School*[3]

Standard blowout control procedure cannot be used if the well cannot be circulated. With total lost circulation, gas can rise up to the surface, but there is also the danger of an underground blowout. The only way to solve the problem is first to stop loss of drilling fluid to the formation so the well can be killed with the help of standard procedure.

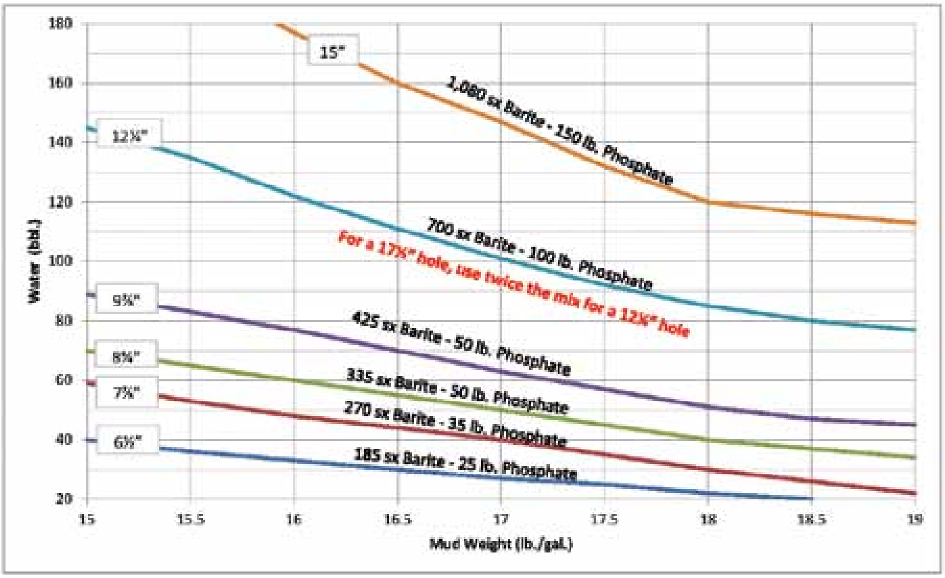
## Barite Plug

The best solution with a gas kick is to try and plug the gas zone with a barite plug and proceed to seal the lost circulation zone. In the meantime it is possible for a high speed underground flow of formation fluid/gas into the weak zone. This flow could wash away the barite plug, so to use a plug as large as 300 feet in height. See figure 4.3.

Mixing procedure for barite plug:

- Add water, the phosphate and finally barite. Adjust the pH to 9.0 using caustic soda.
- Use fresh clean water only.

Figure 4.3. Barite plug mixtures for 300 feet.




## Gunk Plug

A gunk plug is a plug consisting of bentonite mixed with diesel fuel and is a very fast solidifying plug that is especially effective for water flows. The plug will not start to become stiff until it comes into contact with water, so there is no danger of premature setting. When the plug is pumped down to the bottom of the well, the diesel is washed away from the solids, which begin to set as they come into contact with the water. A large plug should be used, about 300 feet in height. An oil plug is pumped before and after the gunk plug to prevent contaminating the plug with drilling fluid, to avoid premature swelling of the bentonite. For gunk plugs in oil-based drilling fluid, Geltone II (MI product name) or similar product is used. See table 4.1.

- Prior to pumping gunk plugs all lines must be flush and cleaned.

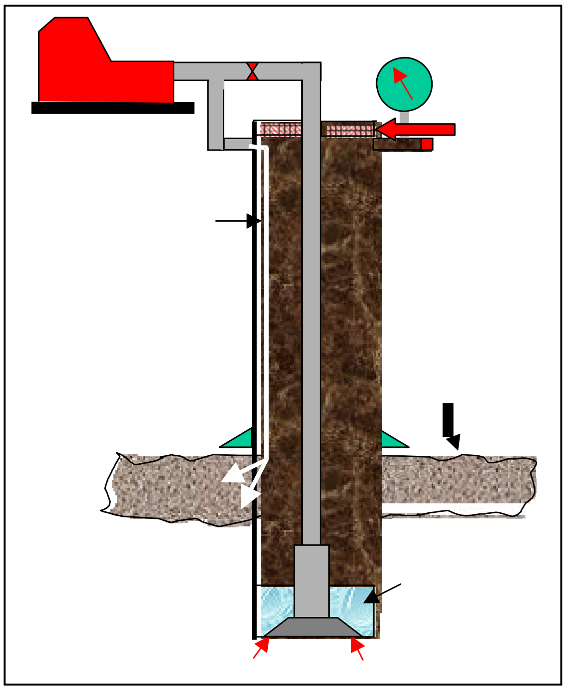
A thick mixture of coarse lost circulation material can sometimes be pumped down the annulus via the kill line, to seal off the thief zone.

Table 4.1. Gunk mixtures.

| Hole Size (in) | Diesel Oil (bbl) | Bentonite (sacks) | Total Volume (bb) |
|---|---|---|---|
| 6½ | 9 | 27 | 12 |
| 7⅞ | 13 | 40 | 18 |
| 8¾ | 14 | 49 | 22 |
| 9⅞ | 20 | 62 | 28 |
| 12¼ | 33 | 98 | 44 |
| 15 | 50 | 150 | 66 |
| 17½ | 66 | 200 | 89 |

Figure 4.4 illustrates the conditions in the well when pumping of a plug to contain the kick zone, and also illustrates the manner in which lost-circulation material is pumped down into the weak zone.

Figure 4.4.



### Lost Circulation when Running or Pulling Casing

Lost circulation can occur while running or pulling casing, due to induced surge or swab pressures or because bottomhole pressures are exceeded when breaking circulation after a trip. Periodically circulate and rotate while running casing to minimize surge. Lost circulation may be minimized by lowering the drilling fluid gel strength, weight, and viscosity prior to running casing. Seepage to partial losses, when running casing, are best treated by adjusting fluid rheology, reducing solid content and fluid yield point rather than using LCM. LCM may adversely affect fluid properties and may increase the fluid ECD. Major or total losses can usually be controlled using LCM materials, pills, or plugs.

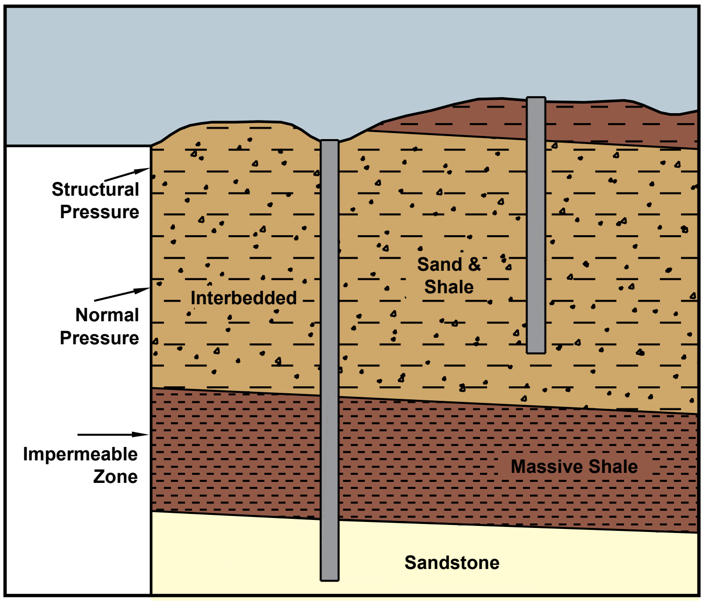
### Lost Circulation when Cementing

Lost circulation may also occur during a cementing operation, due to the narrow margins between fluid weight, formation fracture gradient and increased ECD caused by cementing. Cement filtrate losses in permeable sections dehydrate the cement and impede cement flow. A cement plug may be set across a loss zone when conventional loss control methods fail. The plug is drilled out before continuing operations, the remaining cement sheath covering the formation and the cement that invaded the fractures in the formation usually can stop the fluid loss.

### Abnormal Pressure

As discussed in chapter 2 "Well Control Principles", abnormal pressure is any formation pressure higher than the pressure considered normal in a given geologic area. A formation gradient of 0.465 psi/ft. is considered normal in many areas and is equivalent to 9.0 ppg fluid density (0.465 ÷ 0.052 = 8.94 or 9.0 ppg). In other words, a mud weight of approximately 9.0 ppg would balance a “normally pressured” formation.

Figure 4.5. Massive shale as a transition zone.




Although well programs project the depths at which abnormal pressure is expected, it is impossible to determine the exact formation pressure until the bit actually enters the abnormal zone. Recent advances in technology have made pressure predictions far more accurate than in previous times, but a driller still cannot see ahead of the bit. Drilling crews are trained to recognize the signs of abnormal pressure and to take the appropriate action when those signs are recognized.

It is not uncommon in certain areas to find that a permeable formation is trapped in some way by a long (massive) impermeable shale formation. As drilling progresses and the bit approaches the abnormal zone, changes may occur in various drilling conditions, that is, pump pressure, drilling rate, etc. These changes occur because the differential pressure, the difference between the bottomhole pressure and the formation pressure, changes as the depth increases. The bit is entering a transition zone. *A transition zone is the area where underground pressures begin to change from normal to abnormal as the well is being deepened.*

## Failure to Keep the Hole Full

Failure to keep the hole full during a trip is a common cause of kicks, due to reduction in hydrostatic pressure. The fluid level in the wellbore falls when pipe is being tripped out. When pulling dry pipe, a kick will result if the volume of pipe removed (metal) is not replaced with an equal volume of fluid and the fluid level drops enough for the formation pressure to exceed the fluid hydrostatic pressure. If pipe is pulled wet, both the capacity and the volume of pipe removed (metal) will reduce the well fluid level.

## Tripping Practices

*More kicks have been taken on trips than during any other single operation performed by drilling and workover rigs.* This statement is true for several reasons. Consider a routine trip. Once the trip begins, bottomhole pressure is affected in three distinct ways:

- The pump is off; there is no annular pressure due to pumping.
- There are changes in bottomhole pressure due to the swabbing and surging effects caused by moving the work string within the well.

- As the work string is moved into or out of a well, the level of fluid in the well changes, thereby changing hydrostatic pressure.

The crew can control two of these three factors; swab/surge pressures and the changing fluid level in the well. If a well is stable when the pump is switched off before starting a trip out, it is reasonable to assume that the hydrostatic pressure is sufficient to balance the well. Therefore, if a kick is taken during the trip, it is induced, that is, *the tripping practices of the crew caused the kick.*

Figure 4.6.

When circulating or drilling ahead, a driller and his/her crew have various means of monitoring the well. When tripping, there are no returns at the flowline, no pump pressure, any rotary torque, etc. There is only one way that a crew can monitor well behavior during trips and that is by accurately measuring and documenting the rise and fall of the fluid level in the well. Theoretically, the well should take a barrel of fluid for every barrel of steel pipe removed from the well. The opposite is true for trips into the well.

There are human factors that affect kick detection when tripping. When tripping, the priorities of the crew change from steadily monitoring returns from the well, to making the trip as quickly and safely as possible. Tripping is heavy work. It is a difficult, often dirty job that may have to be done at all hours of the day or night. It is not surprising that many of the worst well control incidents have developed on trips during the early morning hours or on crew change day.

Charts are developed listing the displacement and capacity for all components used in the drill string. The theoretical displacement and capacity values depend on many variables for any given well. A well will seldom take the exact calculated volume; therefore comparisons with recent trips must be made to ensure that the well is acting "normally".

There is a significant difference between pulling a string "dry" that is, pumping a small volume (slug) of heavier mud into the string so that the fluid in the pipe falls as the pipe is lifted, and pulling "wet", when no slug is pumped. When pulling the string dry, only the tubular steel is removed from the casing annulus because the fluid inside the string is falling below the rotary table as the pipe is pulled. On a wet trip both the displacement and the capacity (the closed-in displacement) of the string are removed and that makes a difference in fill-up requirements.

For example, five-inch OD drill pipe (grade G, 19.5 lb/ft) with tool joints, displaces 0.00827 bbl/ft. If a stand of this pipe were 93 feet long, the total displacement on a dry trip out would be 93 * 0.00827 = 0.769 bbl/stand. Many rigs pause to fill the annulus every five stands therefore the theoretical fill-up would be 0.769 * 5 = 3.845 barrels. Suppose the rig did not use a trip tank and therefore counted pump strokes to monitor fill-up. If the pump output were 0.105 bbl/stroke, it should take 3.845 ÷ 0.105 = 36.6 or 37 strokes for each five stand fill-up.

$$\text{Barrels To fill}_{\text{dry pipe}} = \text{Pipe Displacement}_{\text{bbl/ft}} * \text{Length Pulled}_{\text{ft}}$$
$$\text{Pump Strokes for Fill-up} = \text{Barrels to Fill} \div \text{Pump Output}_{\text{bbl/stk}}$$

A wet trip out of the same well changes fill-up requirements significantly. The capacity of the five-inch drillpipe with tool joints is 0.01719 bbl/ft. Since the trip is wet, both the capacity and the displacement would be removed from the casing annulus. Therefore 0.00827 + 0.01719 = 0.0255 barrels would be removed for every foot of pipe pulled: 93 * 0.0255 = 2.37 bbl./stand and 5 * 2.37 = 11.85 barrels for every 5 stands. Computing pump strokes: 11. 85 ÷ 0.105 = 112.85 or 113 strokes. It can be seen that fill-up requirements for a wet trip in this well (11.9 barrels) are much greater than for a dry trip (3.8 barrels).

$$\text{Barrels To fill}_{\text{wet pipe}} = (\text{Pipe Displacement}_{\text{bbl/ft}} + \text{Pipe Capacity}_{\text{bbl/ft}}) * \text{Length Pulled}_{\text{ft}}$$
$$\text{Pump Strokes for Fill-up} = \text{Barrels to fill} \div \text{Pump Output}_{\text{bbl/stroke}}$$

All rig crews have a wet trip. The floormen get drenched with a caustic solution, the floor becomes slippery which creates a safety hazard, morale sags, and some fluid is always lost, even when a mud bucket is used to catch most of the fluid and direct it back into the well. Fill-up is much more difficult to monitor than when tripping dry. Add to these things the increased fill-up requirements and it is not difficult to understand why wet trips can be hazardous, especially in the early hours of the morning or on crew change day.

Local regulatory agencies sometimes have specific requirements regarding trips. For example, in the US Gulf of Mexico, trip tanks must be used. Also, the Bureau of Safety and Environmental Enforcement (BSEE) regulations require that the well be filled before the hydrostatic pressure decreases by 75 psi or every 5 stands of drillpipe, whichever is the safer.

Suppose a crew is tripping the drillpipe in the examples above out of 8⅝-inch casing that has a capacity of 0.05648 barrels per feet and that the fluid density was 13.8 ppg. For a dry trip we would use the drill pipe steel displacement only.

The formulas below can be used to determine how much the hydrostatic pressure in a well will decrease for each foot of pipe pulled from the well. Using the well data from the examples above:

Pulling dry pipe:

$$\text{psi/ft} = \frac{MW_{ppg} * 0.052 * \text{Displacement}_{bbl/ft}}{\text{Casing Capacity}_{bbl/ft} - \text{Pipe Displacement}_{bbl/ft}}$$

$$\text{psi/ft} = \frac{(13.8 * 0.052 * 0.00827)}{(0.05648 - 0.00827)} = 0.123 \text{ psi/ft}$$

$$= 0.123 * 93 * 5 = 57 \text{ psi for each 5 stands pulled}$$

Pulling wet pipe:

$$\text{psi/ft} = \frac{[MW_{ppg} * 0.052 * (\text{Pipe Displacement}_{bbl/ft} + \text{Pipe Capacity}_{bbl/ft})]}{[\text{Casing Capacity}_{bbl/ft} - \text{Pipe Displacement}_{bbl/ft} - \text{Pipe Capacity}_{bbl/ft}]}$$

$$\text{psi/ft} = \frac{[13.8 * 0.052 * (0.00827 + 0.01719)]}{[0.05648 - (0.00827 + 0.01719)]} = 0.589 \text{ psi/ft}$$

$$= 0.589 * 93 * 5 = 274 \text{ psi}$$

It can be seen that with regard to kick detection, wet trips are more difficult to monitor than dry trips, and therefore they can be more dangerous.

The examples above deal only with drillpipe and assume trips out of a well. Obviously, the numbers change dramatically when considering the larger OD of the bottomhole assembly. Most rigs fill the annulus for every one stand of drill collars removed. It must be remembered that these examples illustrate the *theoretical* fill-up required. In wells with open hole sections, the actual volume displacement will differ from the calculated values. Comparisons with previous trips are essential for accuracy and safety. Trip book records (trip logs) should be kept on site and used to confirm that the hole is taking at least as much mud as on previous trips.

## Trip Logs

Trip logs are records of the actual amounts of fluid used (the difference between the starting tank trip reading and the finish tank trip reading) to keep the hole full while pulling drill pipe, compared to the theoretical or calculated amount required to replace the volume of drill pipe being removed. Amounts of the starting trip tank reading and the finish trip tank reading and the theoretical (calculated) amount are recorded for each stand tripped. The difference between actual and theoretical (calculated) amount is recorded in the trend (difference) column. The accumulated trend column is used to record the accumulated amounts for the stands tripped.

Comparisons with previous trips are essential for accuracy and safety. Trip book records should be kept onsite and used to confirm that the hole is taking at least as much mud as on previous trips.

Table 4.2
Trip log while tripping out of the hole; accurate trip records are a must on every job.

| Stand No. | Starting Trip Tank Reading | Finish Trip Tank Reading | Difference | Theoretical (Calculated) | Trend (Difference) | Accumulated Trend | Remarks (Comment when change of pipe, problems, etc.) |
|---|---|---|---|---|---|---|---|
| 5 | 50 | 48.5 | 1.5 | 3.56 | -2.06 | -2.06 | Pull DP off bottom - may be balled |
| 10 | 48.5 | 42.9 | 5.6 | 3.56 | +2.04 | -.02 | Seems ok |
| 15 | 42.9 | 39.2 | 3.7 | 3.56 | +.14 | .12 | |
| 20 | 39.2 | 35.9 | 3.3 | 3.56 | 0.26 | -.14 | |
| 25 | 35.9 | 33.2 | 2.7 | 3.56 | -.86 | -1.0 | possible swab |
| 30 | 33.2 | 32.3 | .9 | 3.56 | -2.66 | -3.66 | Hole not taking proper fluid, stop |
| | | | | | | | Trip and check for flow |

If the fill up accumulated trend indicates that the hole is taking less fluid than calculated, check for flow. If flow is present, treat it as a kick and follow shut-in procedures. See chapter 8, “Procedures” for shut-in procedures.

If the fill up accumulated trend indicates that the hole is taking more fluid than calculated, determine if there is lost circulation. If there is lost circulation follow lost circulation guidelines.

## Surging and Swabbing

Most kicks that occur on trips are the result of swabbing; however excessive surge pressures can lead to formation fracture which in turn, may induce a kick due to a reduction of hydrostatic pressure. The degree to which swabbing and surging pressures develop is dependent upon the rate at which the pipe is moved, the flow properties of the fluid, and the downhole clearance between the string and the casing or open hole.

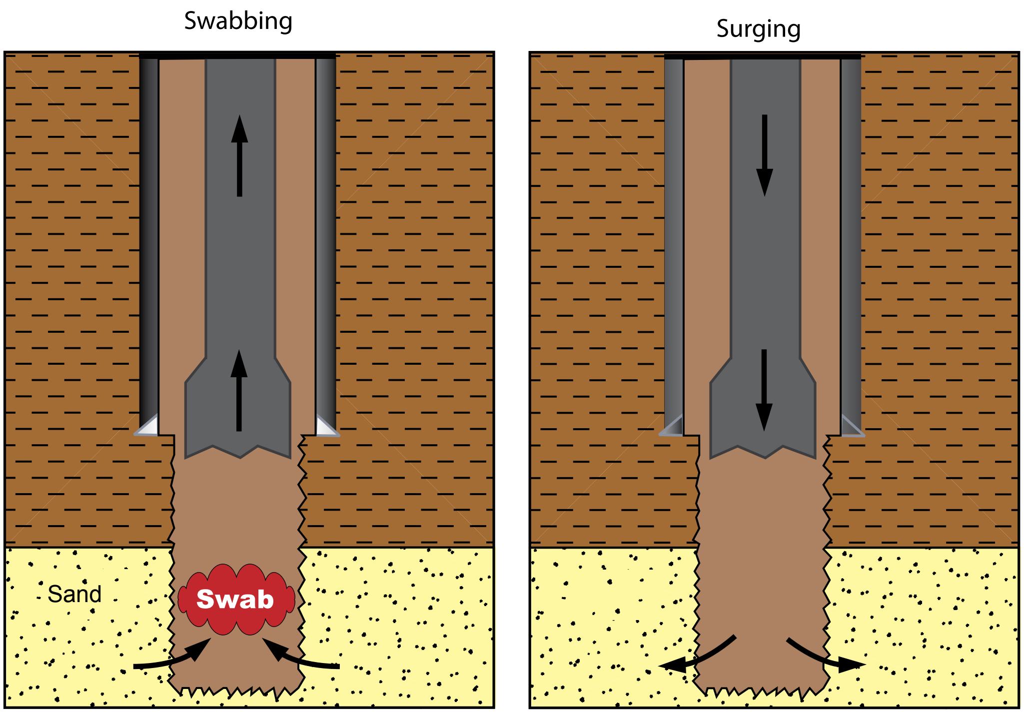
It is common for drillers to start a trip out of a well by pulling the first few stands slowly. It is assumed that the “new” hole is nearly gauge; the potential for swabbing is great. Once the bottomhole assembly (BHA) is pulled into the older, larger diameter open hole, the drag (overpull) is reduced due to the larger annular space. At that time most drillers begin to pick up the pace, pulling the string as fast as practical. This may be a reasonable practice, but it may also ignore other factors that affect swab and surge pressures.

Surging and swabbing pressure effects on bottomhole pressure (BHP) are influenced by:

- Well and string/tool geometry (annular clearance between tools and casing, tubing open)
- Well depth
- Fluid characteristics
- Hole conditions and formation properties
- Tool pulling and running speeds
- Length of horizontal reservoir sections
- Perforations

Modern day drilling fluids can be highly complex solutions. The two fluid characteristics that most affect swab and surge pressures are the viscosity (overall resistance to flow) and gel strength of the fluid. These characteristics are related to one another. Gel strength is a measurement of the fluid’s tendency to form a gel, or solid-like structure, when it is not moving. The flow properties of a fluid are influenced by many things, among them, density, type and amount of solids in the fluid, and the chemical attraction between the solids. The study of fluids is called *rheology* and that is the business of scientists and mud engineers, not the average rig worker. It can be said that the more a fluid is like fresh water, the less likely it is to cause excessive swab or surge pressures. Conversely, the more viscous (thick) it is, the more likely swabbing and surging will be a problem. Drillers seldom have control over the properties of the fluids they use but they can pay attention to the mud reports and talk frequently with mud engineers. Many operators condition the fluid by adding chemicals and circulating the well clean before starting a trip out of the well. As well depth increases, fluid properties such as viscosity and gel strength change as well temperatures increase.

Figure 4.7. Illustrations of swabbing and surging.




The longer the bottomhole assembly and the more stabilizers it contains, the greater the chances of swabbing or surging on trips. The smaller the annular space around the BHA, the greater the effects of swabbing or surging will be. Wells with tight areas, swelling or sticky formations, or sloughing (caving) shale, will decrease clearances and increase the chances of swabbing in a kick.

Salt formations, which are often described as "plastic", have been known to close in around the string giving it just enough clearance for circulation. In addition, many types of clays are water-sensitive and will hydrate or "swell" when exposed to water-based drilling mud. The narrowed annular clearance increases the swabbing/surging effects on trips. During a trip out, balled up stabilizers and drill collars may severely reduce the annular space. Formation properties such as permeability and pore pressure can also affect the rate that formation fluid can enter the wellbore.

When tripping in soft, sticky formations a well can be swabbed in as the BHA is pulled up into the casing, even though the bit is far off bottom. Consider a well in which the open hole is severely washed out so that during the first part of a trip drag presents no problem. The pipe can be pulled as fast as the crew can break the connections and stand it back in the derrick. If the BHA were severely balled with soft clay and pulled into the casing rapidly, excess clay that was stuck to it would shear off and the BHA would then have an OD that was roughly the same as the ID of the casing. Swabbing would be likely. It is considered good practice for drillers to use caution as they pull the BHA into the casing and to pay particular attention to the fill-up volume at that point in the trip since the large diameter drill collars displace much more fluid than the smaller drillpipe or tubing.

Figure 4.8. Plastic Formation.

Perforated zones have reduced permeability, which may lead to swabbing. Special care must be taken when pulling or running pipe in highly deviated wells because the BHA is dragged against the top portion of the wellbore in the angle-building section, reducing the effective clearance between the string and the open hole. In this case it may be difficult for the fluid to fall back down around the assembly. Also cuttings will tend to fall or stay on the low side of deviated wells, further reducing the annulus ID.

To mitigate the risk of swabbing during a trip out of a horizontal well, some operators consider it a "best practice" to "pump out of the hole" until the bit is inside casing or out of the horizontal leg.

### Minimizing surging and swabbing

- Surge and swab pressures may be minimized by:
- Reaming the hole when necessary
- Reducing running and tool pulling speeds
- Checking and conditioning fluid prior to running in or pulling tools
- Circulating while pulling the pipe out of the hole

### Surge and Swab Pressures while Running or Pulling Casing

Casing is generally set when the fluid weight approaches the fracture gradient of an exposed formation. Well control problems may occur when running a casing string or a liner.

Surge pressures, while running casing or liners, may cause lost returns or loss of well control if the surge pressure exceeds formation fracture gradient.

When running or pulling casing from a well, the same practices applied to tripping pipe should be used to mitigate surge and swab pressures. In addition, centralizers should be used when running into the hole, to help mitigate surging the hole.

Surge and swab pressures are proportional to casing running speed and can be reduced by decreasing the running speed. Maximum casing running speed should be calculated so that there is limited surge in the open hole. Casing should be run and reciprocated smoothly; avoiding high acceleration and deceleration that could cause high surge or swab pressures that can fracture the formation. A circulating sub should be installed and used to wash the casing down when running in a tight hole. Consider using an auto-filling float system to reduce the probability of surging in holes with very small annular gaps between the borehole and the casing.

Surge and swab pressures are also reduced by:

- Using an auto-fill float allows the casing to fill from the hole as the casing is run. Using conventional float equipment when running casing causes more surge pressure (refer to "Auto-Fill Float" topic).
- Lowering the drilling fluid gel strength, weight and viscosity prior to running casing
- Staging in hole
- Breaking circulation several times on the way into the hole while running casing

There is a tendency to lose mud to the formations when running or pulling casing. Fluid returns should be monitored constantly, using a trip tank, while running casing. Returns should be taken in the same tank that is used for filling. Increased or decreased fluid return rates could be indicators of a potential kick or loss zone. Casing displacement can be determined by multiplying the length of casing run times the displacement factor, in barrels per foot. When a float is used the displacement is both the capacity and displacement of the casing, if an auto-fill float is used, only the displacement of the casing is used.

If minor losses occur while running casing into the well (no auto-fill installed on the BHA), decrease the running speed or rig up a circulating head to the top of the casing string and displace the mud with a treated mud that has adjusted physical properties designed to minimize losses. If the losses are more serious, consider spotting a calcium carbonate ($CaCO_3$) pill in sand or carbonate formations, or a conventional LCM in shale or other impermeable formations. If there is a total loss of returns, attempt to keep the hole full with a light fluid (seawater or base oil), while a plan is developed to mitigate this very serious situation.

*Auto-Fill Float*

Advantages of auto-fill floats are:

- They eliminate the need to periodically stop the operation to fill the casing from top to bottom. When using conventional floats, the casing should be filled at every joint and topped top off every 10 joints.
- They reduce surge pressures
- They allow increased casing running speeds.
- They reduce mud losses to the formation or damage by displacing mud through both the casing and the annular space.
- They help identify fluid influxes or fluid losses.
- They reduce risk of tubulars collapsing.

Disadvantages of auto-fill floats are:

- The primary disadvantage is the possibility of the float's not opening, resulting in the inability to circulate.
- Auto-fill floats cannot be converted to stop fluid flow into the casing quickly; a ball has to be dropped and it takes time for the ball to drop. This delay may be a problem during a kick situation.
- Auto-fill floats should not be used when there are high concentrations of loss control material.

If an auto-fill float fails when running in casing, the casing may collapse when the external pressure exceeds the casing collapse rating. If the valve fails in the closed position, the casing may be filled with the rig pump or cement pump. Pump rates will tend to be slower and filling up the casing will take much longer. Cementing heads also allow control of cement U-tubing, should the float equipment fail in the open position when cementing.

## Cementing

Cementing is the process of filling the annular space between the outside of the casing and the formation. It is one of the most critical steps in the drilling and completion of oil or gas wells.

Cementing:

- Reinforces and supports the casing string.
- Supports the wellbore walls to prevent formation collapse.
- Protects the casing against corrosion.
- Prevents gases or liquids from flowing up or down the annular space.
- Restricts fluid movement between permeable zones.
- Seals off lost circulation or thief zones.
- Isolates the casing seat for further drilling.

Good cementing results depend on:

- Good fluid properties: mud is conditioned and circulated until it has the required fluid properties before running in casing and cementing. Casing is worked up and down or rotated during mud circulation to help removes cuttings, gelled mud, and filter cake. Higher mud flow rates improve wellbore conditioning.
- Optimal borehole pipe. Clearance should be verified with a caliper log to check the size, shape and uniformity of the wellbore.
- Centralizing the casing: keeping the casing centered in the wellbore prevents mud from remaining behind in the narrower annular spaces
- Casing movement while cementing: the casing is reciprocated and rotated during cementing. Cement must be pumped at higher pump rates to remove gelled and caked mud from the side of the wellbore.*

**NOTE: Increased pump pressure causes increased bottomhole pressure which increases the risk of lost circulation. The cement slurry density should be the same as mud density to minimize the risk of blowouts or lost circulation.*

## Cementing Procedure

After a well interval has been drilled and the mud has been circulated and conditioned, a caliper log is run and casing is run into the well with centralizers, float collar and guide shoe. A cementing head is attached to the top of the wellhead to receive the cement slurry from the pumps. Spacers and mud flushes are pumped down the inside the casing, displacing the drilling mud. A bottom plug (wiper plug) is inserted and cement slurry is pumped, displacing the drilling fluids still located within the well and replacing the fluid with cement. The volume of cement slurry that is pumped has been calculated to be sufficient to fill the space between the wellbore and the casing. The bottom plug lands on the float collar and is caught. The float collar functions as a one-way valve, allowing the cement slurry to enter the well. Continued pump pressure breaks a diaphragm in the bottom plug, allowing the cement slurry to flow through the bottom plug and up the outside of the casing. A top plug (wiper plug) is then inserted after the cement slurry. Then displacement fluid is pumped, forcing the top plug downward until it reaches the bottom plug. The pumps are stopped and the cement is allowed to harden. See figure 4.9.

## Flow Check after Cementing

*Excerpt from "Well Control for Snubbing Operations" manual by Well Control School[2]*

It is also important, after a drilling operation or remedial cementing, to flow check the well. Often, when a cementing operation is performed, a slug of light fluid is pumped ahead of the cement to flush old mud or debris ahead of the cement slurry. As the slug is pumped ahead of the heavier cement and into the annulus, the well may become temporarily underbalanced until enough of the cement fills the annulus to overbalance the formation pressure. During this period, an influx may enter the well. As the cement sets, it loses its hydrostatic capability so that gas below the cement percolates up through the setting cement. This is known as “annular gas flow.” So, after the cement has set, a flow check should be conducted to ensure that no gas has migrated above the top of the cement.

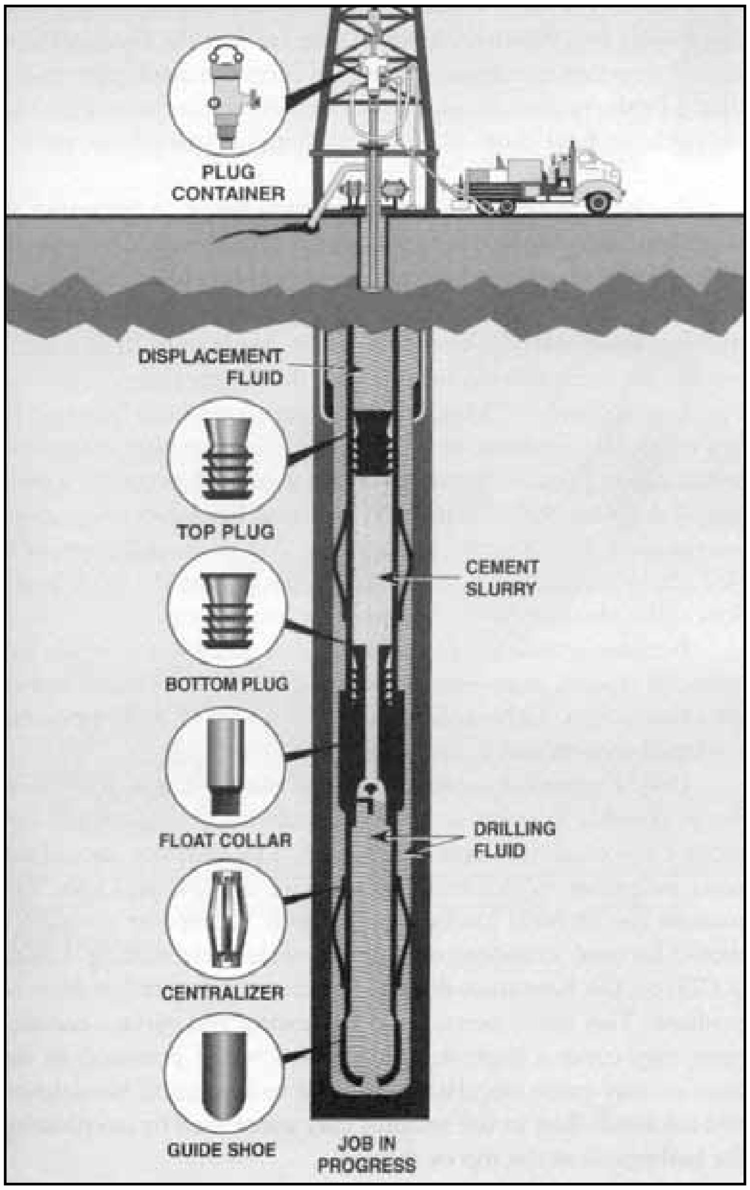
## Casing Integrity Test

*Pressure Testing Of Casing - 30 CFR 250.1609[4]*

Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested. The conductor casing shall be tested to at least 200 psi. All casing strings below the conductor casing shall be tested to 500 psi or 0.22 psi/ft, whichever is greater. (When oil or gas is not present in the cap rock, the production liner need not be cemented in place; thus, it would not be subject to pressure testing.) If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be re-cemented, repaired, or an additional casing string run and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained. The time, conditions of testing, and results of all casing pressure tests shall be recorded in the driller's report.

After cementing any string of casing other than structural, drilling shall not be resumed until there has been a time-lapse of at least 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other casing strings. Cement is considered to be under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

Figure 4.9. Illustration of cementing operation.




*Pressure Integrity Test - 30 CFR 250.427* [4]

You must conduct a pressure integrity test below the surface casing or liner and all intermediate casings or liners. The District Manager may require you to run a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. You must conduct each pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight, if identified in an approved APD.

## Kicks During Cementing Operations

Most kicks that have occurred during cementing operations have been the result of reducing the hydrostatic pressure during the operation. There are several possible causes:

- A spacer or flush is usually pumped ahead of the cement. The density of the flush and perhaps more importantly, the height, must be taken into consideration when planning the job.

- If the density of the cement is too great it can cause lost circulation that can lead to a kick.
- If light weight cement is used, pressure across the choke should be held to compensate for the decrease in annular hydrostatic pressure. A pressure/volume schedule can be used to maintain a safe bottomhole pressure.
- Cement dehydrates as it sets up. The dehydration may reduce the effective hydrostatic pressure to a point at which the well will flow.
- The heat created by the curing process of cement will cause the casing to expand. As the casing cools, a micro-annulus between the casing and the walls of the well may create a channel that would allow fluid movement.
- There have been instances where the casing float equipment has failed.
- Wells should be closely monitored during all phases of cementing operations. The BOPs should not be rigged down until it is determined positively that the well will not flow.

The change in hydrostatic pressure due to the spacer fluid in the annulus must be calculated at the point where all of the spacer fluid has left the string. This requires an accurate measurement of the space volume and the capacity of the annulus. In a vertical well, dividing the spacer volume by the annulus capacity yields the height of the spacer. From this height, the hydrostatic pressure of the spacer is then calculated. The hydrostatic pressure of the mud being displaced is determined by subtracting the spacer height from the well TVD and multiplying the mud column by 0.052 times the mud density. The resulting hydrostatic pressure of the spacer, plus and the hydrostatic pressure of the mud column, are then added to determine the total hydrostatic pressure in the well. A useful formula for calculating the loss of hydrostatic pressure due to the light spacer is:

$$\text{Loss of HP}_{psi} = 0.052 * (\text{MW}_{ppg} - \text{MW}_{ppg}\ \text{Spacer}) * \text{VOL}_{Spacer} \div \text{Annulus Capacity}_{bbl/ft}$$

Other causes of reduced hydrostatic pressure include density decrease due to thermal expansion of a heated fluid and the settling of weighting materials in the mud.

Figure 4.10. Cementing Operations.

Wells should be closely monitored during all phases of cementing operations. The BOPs should not be rigged down until it is positively determined that the well will not flow. Obtaining a high-quality cement job is critical to the prevention of gas flow behind the casing or liner string. Indicators of a successful cement job include:

- Pressure profile that demonstrates a rapid setup of the cement column after it has been displaced into the annulus. Signs of a good pressure profile include:
  - The pumping pressure steadily decreases as the cement is pumped inside the casing.
  - There is a slight increase and then a drop in pressure as the bottom plug reaches the float collar.
  - Circulating pressure increases steadily as the cement slurry height increases outside the casing.
- There is a sharp increase in pressure when the top plug reaches the bottom plug.
- Volume of mud returns that match the volume of mud displaced into the annulus. Mud tank volumes are carefully monitored to make sure mud or cement is not being lost to the formation.
- Volume of spacers and cement pumped match the volume of returns.
- Determination that the plugs bump at the calculated volume pumped (e.g., pump strokes).
- No back flow of cement. Back flow or flow back up through the annulus is reverse flow or u-tubing. Back flow may cause the cement in the shoe track or annular space to be contaminated and leave mud channels in the cement.
- Density of the slurry matches the amount planned and the quantity pumped is sufficient to reach the required height in the annulus. If the cement is to be qualified as a barrier (internal flow path), it must complete a successful inflow test.

## Obstructions in the Wellbore

Many routine operations require removing wellbore obstructions by releasing packers, drilling cement plugs, and fishing. Experienced crews always assume the worst case situation because it is always possible that pressure may be trapped below any annular obstruction. Pressure trapped below a packer or plug can cause a well control problem if the packer is pulled. Be sure there is adequate hydrostatic pressure above the packer to ensure primary well control, prior to unseating the packer, and open the packer's bypass ports to equalize pressure above and below the packer. One good practice in preparing for anticipated trapped pressure is to route returns from the well through the choke manifold.

Consider a gas well that was previously plugged and abandoned, but is now being re-drilled. If the formation pressure were 2,694 psi at 7,000 feet TVD a fluid density of 7.4 ppg should balance the well. (2,694 ÷ 0.052 ÷ 7,000 = 7.4 ppg). If a cement plug had been set at 2,000 feet and the plug was drilled with an oil base fluid with a density of 7.4 ppg, the hydrostatic pressure at 2,000 feet would be about 770 psi. (7.4 * 0.052 * 2,000 = 770 psi) When the bit breaks through the cement, the formation pressure of 2,694 opposes a hydrostatic pressure of only 770 psi. In reality, the density of the formation fluid would reduce the upward force somewhat, but it will surely be much greater than the fluid hydrostatic pressure, in other words, the well would kick.

## Drilling into an Adjacent Well

Advances in directional drilling technology make drilling into a producing well unlikely nowadays, however the potential does exist, especially offshore where many wells are drilled from a single platform. The gas and oil drilling industry is now more than 100 years old and there are tens of thousands of wells, many inadequately documented, all around the world. If one well penetrated another, we could expect that the U-tube effect caused by the different fluid densities would drastically affect bottomhole pressure in each well.

## Man-Made Charged Formations

There are several ways in which the pressure in a well can be inadvertently charged or over-charged. Below are a few examples:

- Inadequate cement bonding allows pressure from one zone to migrate or feed into another zone.
- Formations charged through underground blowouts, that is, uncontrolled flow from one permeable zone to another.
- Zones charged from injection projects such as steam or water injection.
- Casing fails.
- Formation fractured from one zone to another, natural or man-made by frac jobs.

## Gas Cut Fluid

Fluid contaminated by gas from bit cuttings infrequently causes a kick. Gas is released into the fluid as the bit cuts the formation; when the gas is circulated to the surface, it expands and reduces the hydrostatic pressure. Since gas is compressible, it usually does not cause a large reduction in hydrostatic pressure and the BHP reduction is small if the volume of gas is small. Gas cutting may be an issue in large diameter holes drilled at a high rate of penetration, since gas expansion usually occurs near the surface and a kick may occur if the hydrostatic pressure is reduced below the formation pressure. Gas cut fluid density can be measured accurately, using a pressurized mud balance. Defoamer chemicals can be added to the fluid to release the trapped gas. Fluid can also be degassed using a mechanical vacuum pump degasser.

## Subsea Concerns

Floating units have several concerns that do not apply to surface rigs. Since the BOP stack is installed on the sea floor, the drilling fluid is transported back to the surface through a marine riser. If for some reason the marine riser is lost or disconnected bottomhole pressure is reduced by the difference between the hydrostatic pressure in the riser full of mud and the hydrostatic pressure of the sea water.

If gas has been circulated out through the choke line on a floating rig it is almost certain that a small amount of gas will remain under the closed preventer in the stack. Care must be taken to remove the trapped gas safely before the BOPs are opened. The deeper the water, the greater problem this trapped gas becomes. If the gas is allowed to come to the surface uncontrolled it will expand to many times its original volume, unloading the working fluid as it rises and expands.

## Drill Stem Tests (DST)

A drillstem test is essentially a temporary completion in a producing zone. Formation fluids are allowed into the well and into the drill stem test (DST) string. Once the test is completed care must be taken when restoring the drill string and the annulus back to an overbalanced condition. The possibility of gas migration and/or equipment malfunction always exists and either situation can cause an intentional kick to quickly become an unintentional kick. Drill stem testing is "high alert time" and should always be conducted during daylight hours.

## Underbalanced Drilling

When underbalanced or near balanced (managed pressure) drilling is done, a rotating head or stripper is used to hold backpressure on the annulus. Returns from the well are taken through a blooey (vent) line rigged under the preventer to a choke manifold. The well program contains a backpressure range or "design window" which is considered safe for optimum conditions. An unintentional kick occurs when the backpressure exceeds the design window. The three primary causes of exceeding the maximum recommended backpressure are as follows:

- Drilling too fast
- Reducing the hydrostatic more than desired with the working fluid (often gas or a mixture of gas and water)
- Malfunction of surface equipment

Well "kicks" were defined in chapter 2, "Well Control Principles", and some of the situations that could cause a well to kick were discussed. This chapter discusses the primary warning signs that could indicate to the crew that a kick might be in progress. Primary warning signs can indicate to the crew that a kick is about to occur. Kick indicators show that a kick is in progress. Failure to recognize a developing well control incident and take prompt action can lead to excessive surface pressure and eventually to a blowout and fire. The danger to human life and the environment are unacceptable.

A kick can enter a well during almost any well-site operation. Drillers are taught that when the warning signs of a kick are detected they should immediately suspend the present operation, and observe the well to see if it will flow after the pumps have been stopped. *If a well flows, even though nothing is being pumped into the well, it is a sure indication that a kick is in progress*. Detailed procedures for performing flow checks are discussed later in this chapter.

Kick warning signs can be divided into two main groups:

- Warning signs observed when drilling
- Warning signs observed when tripping

## Kick Detection When Circulating

Kick warning signs observed when circulating include:

- Sudden or unexpected deviations in ROP
- Change in appearance (the amount, size and shape) of cuttings
- Increasing trend in drilled gas, gas-cut mud and connection gas
- Increase in flow line fluid temperature
- Decreasing trend in shale density

- Change in mud flow properties
- Increased chloride content in the fluid
- Change in pressure and/or speed
- Changes in string weight
- Gas/oil shows while circulating

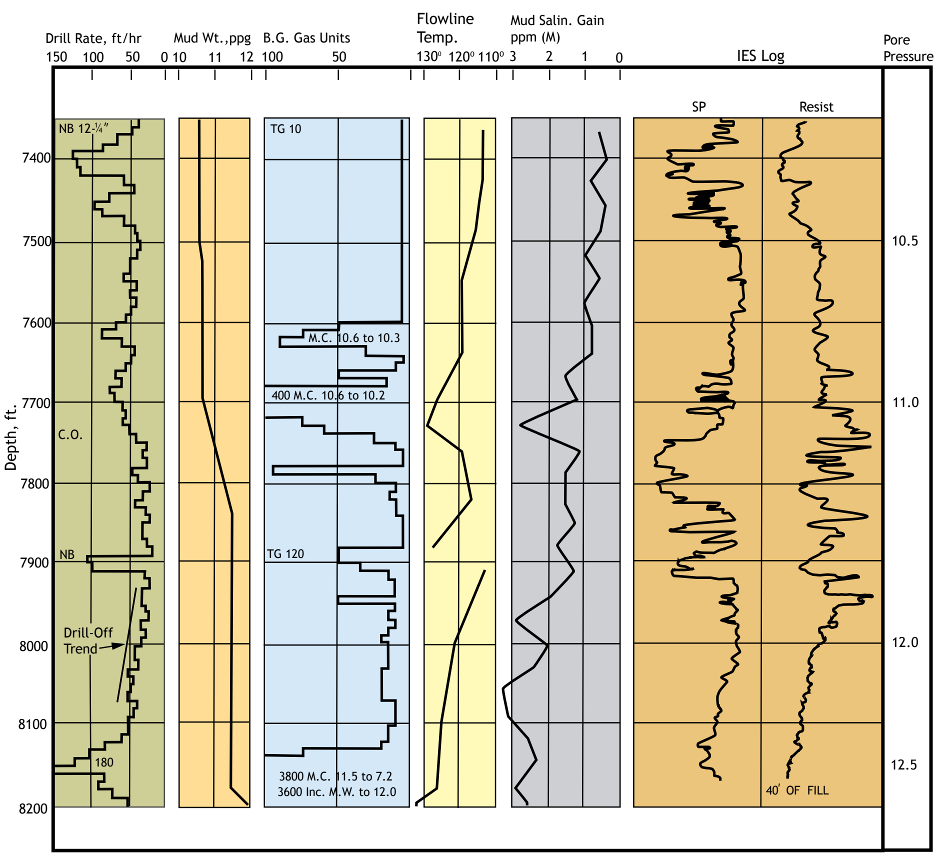
### Abnormal Pressure

On most wells, drillers are instructed to drill with a specific weight on the bit (WOB), rotary speed, and pump pressure. When downhole motors are used the speed that the bit turns is controlled by hydraulic concerns, that is, the recommended pump rate and pressure. Once the parameters are set, a somewhat reasonable constant drilling trend is established. In this way sudden or unexpected deviations in the established rate of penetration (ROP) indicate that the bit may be entering a different formation.

When rock bits are used, a definite bit wear or "dulling trend" is established. This is reasonable because as the bit drills, the teeth will wear and become duller. Also, as drilling continues, the deeper formations are more compacted. A steady, slight decrease in ROP would be considered normal. An increase in ROP may be an indication that a transition zone is being drilled. This is because as the differential pressure between bottomhole pressure and the formation pressure decreases; there is less resistance for the bit to overcome. A sudden, rapid increase in ROP is called a *drilling break.*

Polycrystalline diamond compact (PDC) and thermally stable polycrystalline (TSP) bits react differently from roller cone bits when they enter a transition zone. These bits may actually drill slower

Figure 4.11.
Abnormally pressured formations can be identified by electric logs.

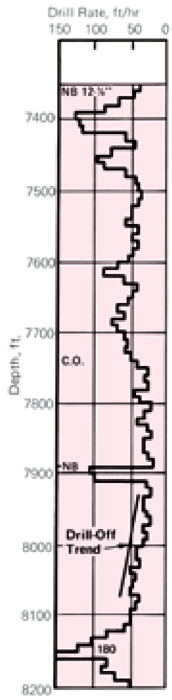


than the established trend, or even stop drilling altogether as the formation characteristics change. In either case, a definite change in ROP is one of the first signs that indicate that the bit may be approaching an abnormally pressured formation.

Figure 4.12.

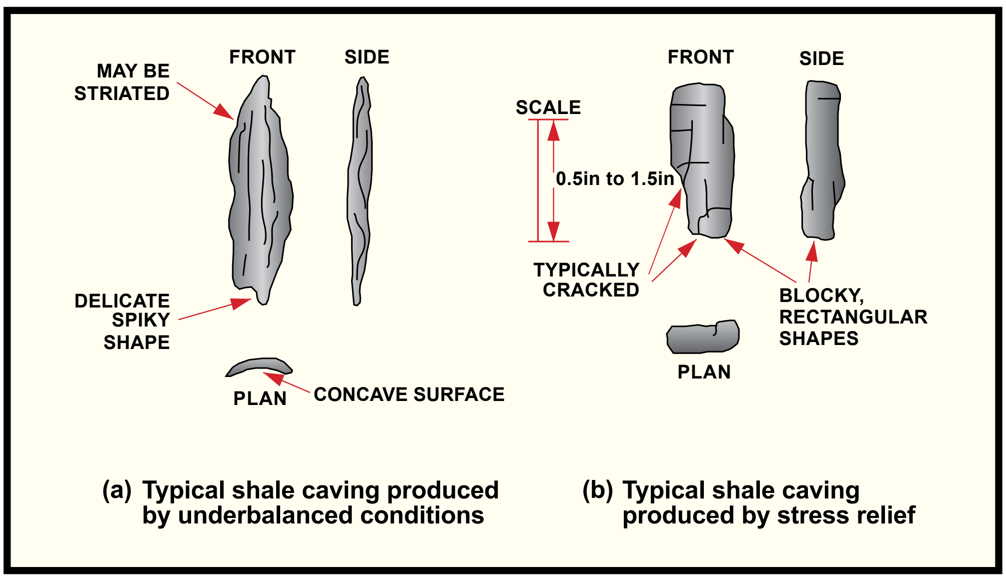
*Left*, a geolograph records ROP and depth while drilling

*Right,* a change in rate of penetration note the drilling break approximately 7,400 and 815 feet




It stands to reason that if the drilling rate changes, the amount of bit cuttings coming to the surface will also change. In shale formations, many of the cuttings may be larger than normal and are often curved, or oddly shaped. These misshapen cuttings are not true bit cuttings at all, but pieces of shale that have sloughed, or "popped off" the walls of the hole due to pressure. A change in the appearance (the amount, size and shape) of cuttings, tied in with other indications, can be a predictor of abnormal pressure.

Figure 4.13. Different sizes and shapes of cuttings.

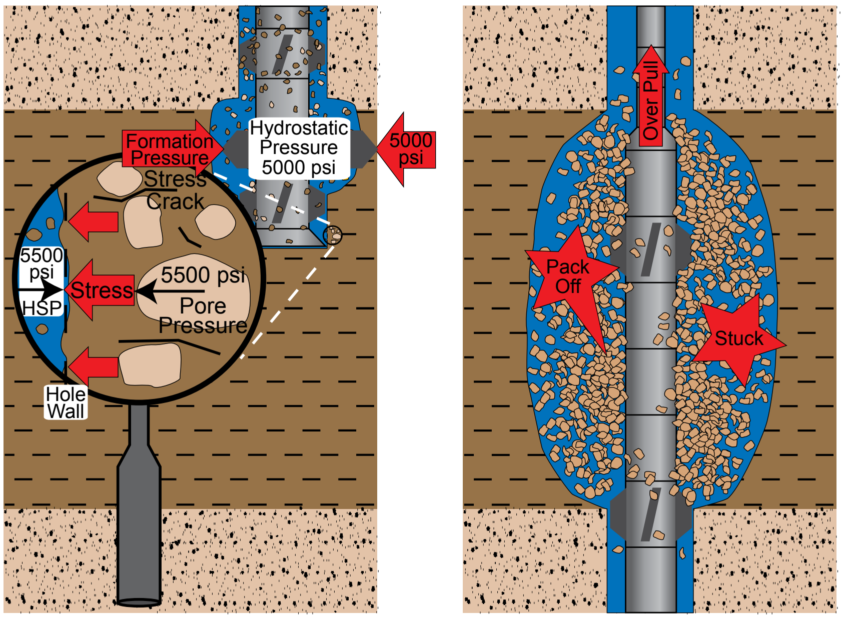


A buildup of cuttings around the bottomhole assembly will likely cause increased rotary torque and an increase in drag, (over-pull) when the work string is picked up, as when making a connection. These too, can indicate a formation change. In short, many of the rig floor indicators grouped together as "hole trouble" can indicate that the bit is approaching, or has entered an abnormally pressured formation.

Increases in the gas content of the fluid returns may be an indication of abnormal pressure. If the pumping rate is steady, the gas content should remain at approximately the same level. It is not the gas content itself that is the warning sign; it is the increase that should be noted. The gas that returns steadily as drilling progresses is called background gas. The amount that is considered "normal" depends entirely on the penetration rate and the characteristics of the formation being drilled.

It is common to see increases in gas at bottoms up from a connection or after trips. These "spikes" in gas content in the working fluid occur because bottomhole pressure decreases when the pump is stopped and because there may be some swabbing and surging effect when the work string is moved. Like background gas, connection gas and trip gas in itself is not necessarily a matter of concern. It is the increase in the trends that may indicate formation change.

Figure 4.14.




Many wells have a "mud logging" unit on location to analyze and document formation data as the well is drilled. The mud logger, often a geologist, uses instruments to generate graphs and records of various drilling data including flowline gas. Below is a short list of data collected and correlated by the mud logger:

- Flowline fluid temperature: there is almost always an increase in bottomhole temperature in a transition zone.
- Qualitative and quantitative flowline gas content
- Shale density: a decreasing trend in shale density may be an indicator of abnormal pressure.
- The "d" exponent is a computer-generated graphic presentation of drilling trends developed from drilling conditions (ROP, torque, drag, bit size, etc.)

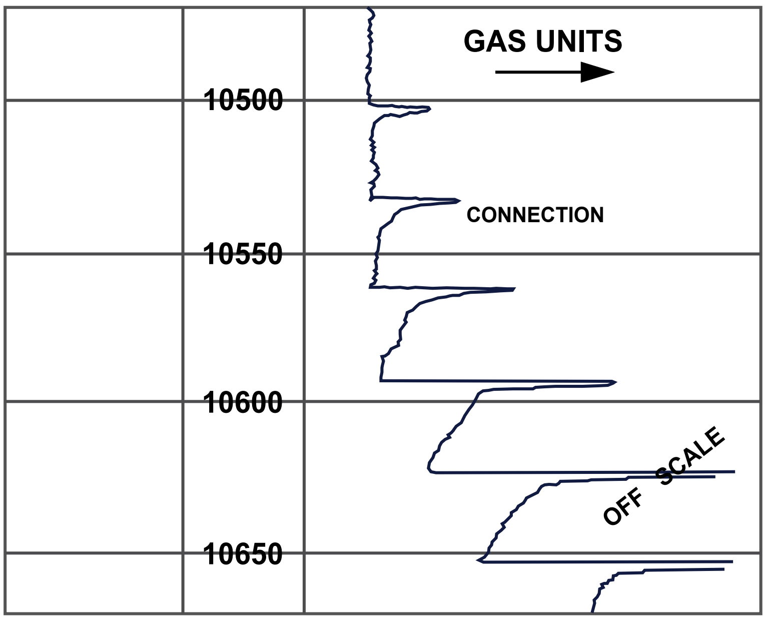
- Chloride content of the fluid: there is often an increase in chlorides (salts) in the mud as the bit approaches an abnormally pressured zone. Mud engineers test the fluid for chlorides as part of their routine testing. There is usually a copy of the last mud report posted in the "dog house" near the rig floor and in the tool pusher's and operator representative's office.

Today, many drilling and workover rigs run measurement while drilling (MWD) or logging while drilling (LWD) tools in the work string. These tools collect a host of data and send it back to computer monitors mounted in various locations around the site so that formation pressure, bottomhole pressure, temperature and drilling data are instantly presented to drillers and supervisors. These high-tech tools are revolutionizing the drilling industry and have proven invaluable in identifying abnormally pressured formations.

## Change in Pressure and/or Speed

Conventional drilling requires keeping a well slightly overbalanced. Any formation fluid that enters a well will nearly always be lighter (less dense) than the working fluid. If an influx of formation fluid enters a well the hydrostatic pressure in the annulus would decrease. It would require less pressure to move the annular column of fluid upward at the same pumping rate.

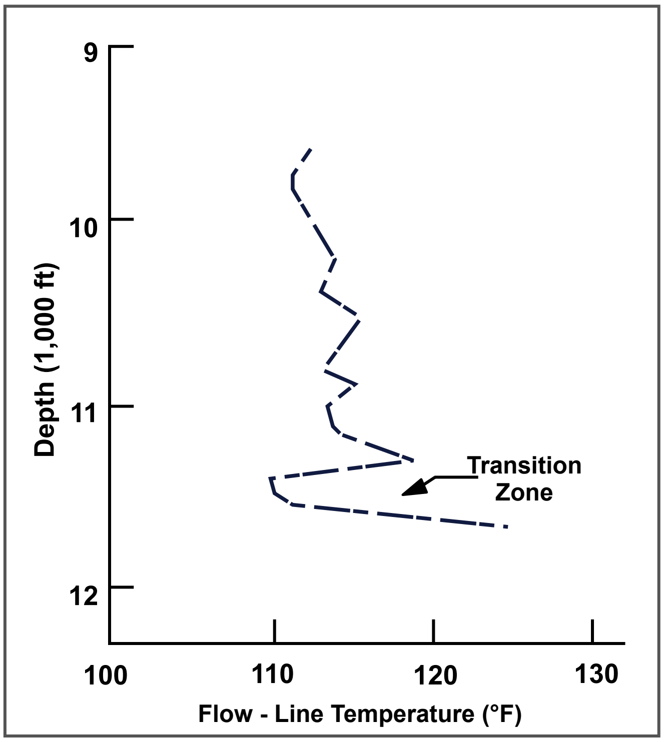
Figure 4.15.




An increase in pump rate may also accompany the reduction in circulating pressure. If the kicking fluid is mostly gas, the pressure change may be more noticeable as the expanding gas moves up in the annulus. In some cases, a momentary increase in pump pressure has been noticed, followed by a gradual decrease in pump pressure accompanied by the increase in pump speed. This kind of detail is difficult for a driller to recognize from his standpipe gauge. However it can be easily seen on plots generated by fluid-monitoring instruments.

Usually when a driller notices a loss of pressure and an increase in pump rate, he thinks that he probably has a washout in the work string or perhaps a leaky swab in the pump. As a matter of fact, he would be correct in many instances; washouts and pump problems are more common than kicks. A washout is a serious problem but it pales in comparison to the seriousness of a blowout. Deviations in pressure can be noticed at other times, for example, when a heavier fluid is pumped down the work string. An experienced driller will make sure that the well is not kicking before assuming another, less dangerous problem.

Figure 4.16.



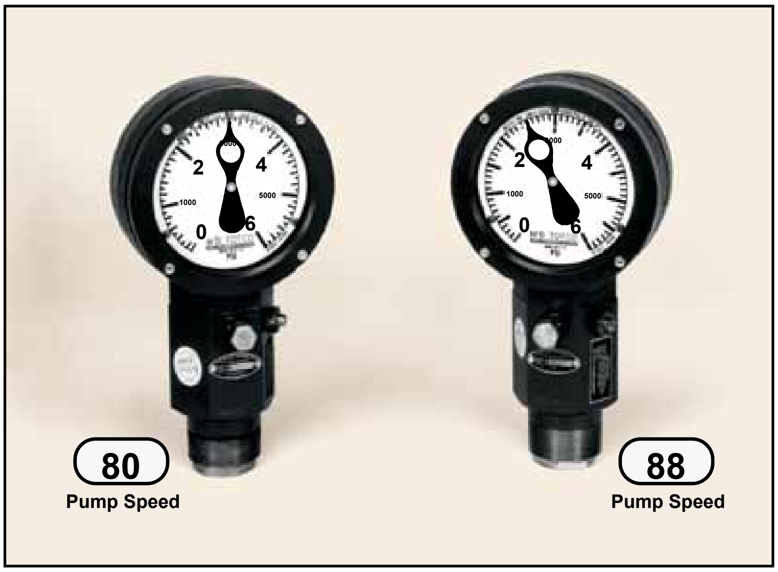

## Excessive Drilling Rate through Gas Sands

The density of formation gas (2.0 ppg) is usually much less than the density of any liquid (9.0 ppg) that is used for a drilling fluid. It stands to reason that if the penetration rate in a gas sand is great enough, the annulus would become charged with gas, thus lowering bottomhole pressure. In many areas, especially offshore locations, drilling rates of more than 100 feet per hour can be achieved easily. Shallow gas kicks are arguably the most dangerous of all kicks. In order to guard against shallow kicks, drilling rates are controlled so that the annulus does not become charged with gas. Often drillers are instructed to pause from time to time and circulate gas (i.e., connection gas) out of a well before proceeding to drill ahead.

## Changes in String Weight

Buoyancy is the tendency of a liquid to support anything that is suspended in the liquid. The buoyancy provided by the working fluid in a well is a function of the fluid's density. The heavier, or more dense, the fluid, the more buoyancy it will provide. Another way to say this is that the string weight of the pipe in fluid decreases by an amount equal to the weight of the fluid displaced by the pipe.

Figure 4.17.




Here is how to calculate buoyancy effects to string weight:

$\text{Buoyant force}_{lb} = MW_{lb/gal} * \text{Volume of fluid displaced}_{gal}$

$\text{Buoyant force}_{lb} = MW_{lb/gal} * \text{Tubular displacement}_{bbl/ft} * MD_{ft} * 42\ gal/bbl$

$\text{Buoyant force}_{lb} = (OD^2 \div 1{,}029.4\ bbl/ft) * MW_{lb/gal} \times MD_{ft} * 42\ gal/bbl$

The buoyed weight of the string would be:

$$\boxed{\text{Buoyed Weight}_{lb} = (\text{Tube Weight}_{lb/ft} * MD_{ft}) - (\text{Buoyant Force}_{lb})}$$

For a close-ended tubular such as would be present during snubbing, this simplifies to:

$$\boxed{\text{Buoyant force on close-ended tubularlb} = (OD^2 * 0.0408 * MW * MD)}$$

The buoyed weight of a close-ended tube in the well is:

$$\boxed{\text{Buoyed weight of close-ended tubular}_{lb} = (\text{Tube weight}_{lb/ft} * MD_{ft}) - (\text{Buoyant force on close- ended tube}_{lb})}$$

There is a point where the weight of the string is great enough to equal the buoyant force. This is called the balance point. This is the transition between pipe light and pipe heavy. Calculating this point is dependent on pressure, area, pipe weight and the fluid in the well and in the pipe. When snubbing, it is common to run dry pipe into the hole past the balance point. The pipe is then filled with fluid, and stripped to the desired depth.

From the discussions on Pressure/force/area, and buoyancy calculations (again, ignoring friction, upsets and couplings), we can calculate this point by:

$$\boxed{BP = (D^2 * P * 0.7854) \div [(65.4 - \text{Fluid Weight}_{ppg}) \div 65.4] \div \text{Pipe Weight}_{lb/ft}}$$

Where:

BP = Balance point (ft)

P = Well pressure (psi)

D = Diameter of the pipe (inches)

65.4 = Weight of one gallon of steel

*EXAMPLE*

The fluid weight in the well is estimated to be 7.3 ppg. How many feet of dry 2⅞-in, 6.5 lb/ft tubing would have to be snubbed into a well with a shut in surface pressure of 650 psi to reach the balance point?

$$BP = (D^2 * P * 0.7854) \div [(65.4 - \text{Fluid Weight}_{ppg}) \div 65.4] \div \text{Pipe Weight}_{lb/ft}$$

$$BP = [2.875^2 * 650 * 0.7854] \div [(65.4 - 7.3) \div 65.4] \div 6.5$$

$$BP = [8.26 * 650 * 0.7854] \div [(58.1) \div 65.4] \div 6.5$$

$$BP = 4219 \div 0.888 \div 6.5$$

$$BP = 730.9 \text{ ft}$$

Various other forces can affect the apparent string weight. When snubbing, mechanical force is created when the pipe or tubing is pushed into a well that has pressure. The upward force of an underbalanced well is pressure force. The buoyant force may affect the mechanical force necessary to lower the string. There is also a frictional force created by the stripper mechanism. This force is created when the sealing force of the stripper is overcome in order to push the tubular into the well.

When an influx of formation fluid enters a well, the density of the fluid surrounding the work string decreases, therefore the buoyant effect is reduced. In effect, the string weighs more, and the increased weight will be reflected on the driller's weight indicator. In a large wellbore this might not be pronounced, but in a slimhole, a long, light influx can cause a significant change in string weight.

It is also true that small diameter tubing or coiled tubing with check valves in the bottomhole assembly, might actually be forced upwards by a powerful kick, thus causing a decrease in effective string weight.

## Gas/Oil Shows While Circulating

Often the returning fluid will be *gas-cut*. The apparent density is reduced due to tiny bubbles of gas that are entrained in the fluid. Gas-cut mud normally has little effect on bottomhole pressure so long as the gas is removed before the fluid is pumped back into the well. However some formations have a very high pore pressure but practically no permeability.

When drilling these formations, there may be a slow feed-in of formation fluid. Although these formations rarely cause a well to blow out, a kick is defined as the unwanted feed-in of formation fluid into a well. Gas and oil shows on the surface could be indicators of a kick, and should be treated as such until proven otherwise.

## Positive Kick Indicators When Drilling

Positive kick indicators observed when drilling include:

- Increase in return flow rate
- Gain in pit volume
- Flow from well with rig pumps off

## Increase in Return Flow

When the pump is running at a constant rate, it is displacing a fixed amount of fluid into the well every minute. Since the injection rate of fluid into the well is constant, the rate of fluid returns should also be constant. If more fluid is returning at the flowline than is being pumped down the work string it is likely that formation fluids are entering the well and displacing the working fluid. Most rigs today

Figure 4.18.
Gas-cut mud usually does not cause a reduction in BHP.

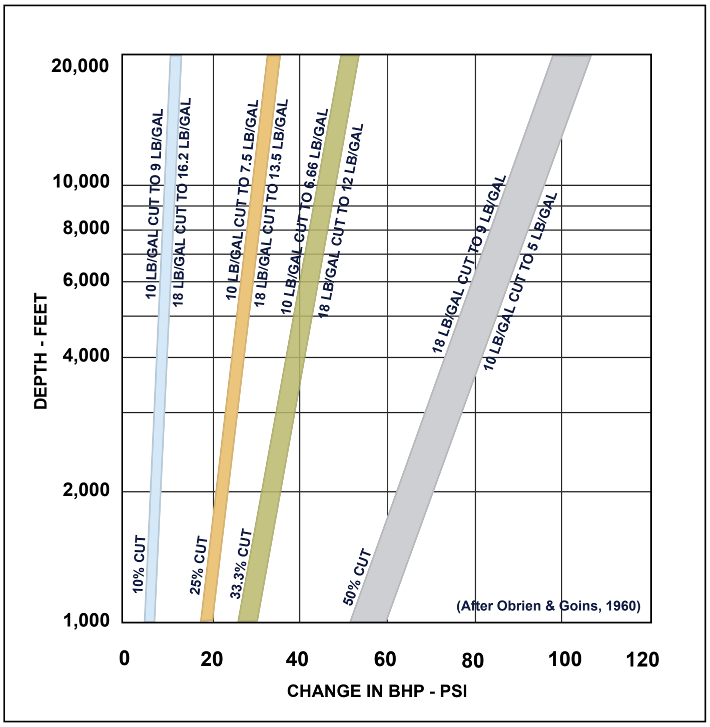
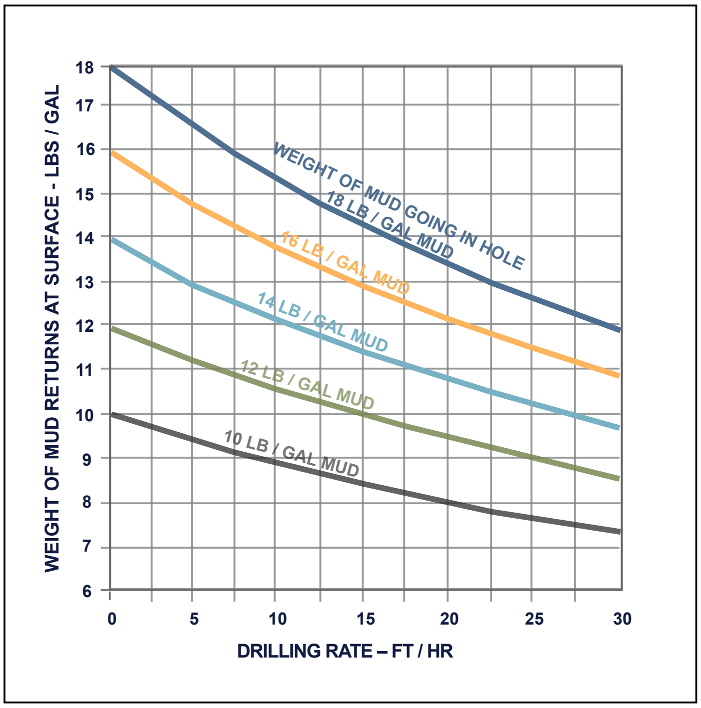
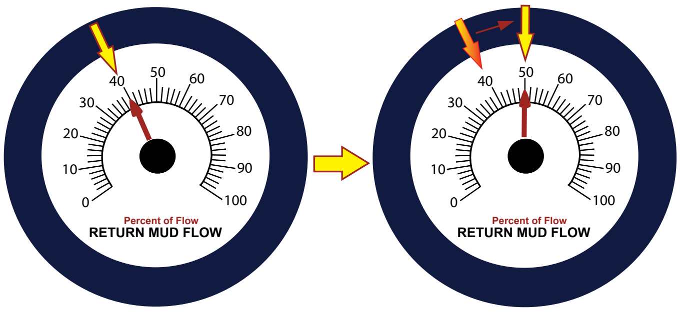



Figure 4.19.
Gas cutting caused by drillling gas sands.



have a flow sensor installed on the flowline. The flow sensor is not a flow meter. It is not necessarily an instrument of exact measure. It is a simple mechanical paddle inside the flowline that is pushed upward by the fluid as it passes by.

Figure 4.20.
*Left*, a flow rate sensor.
*Right*, an influx of formation fluid will cause an increase in flow from the well.

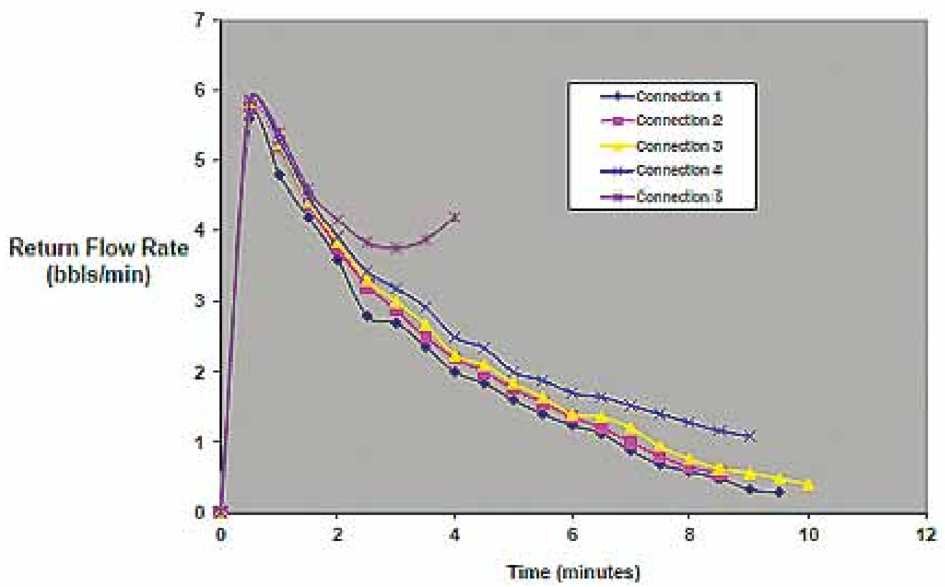



Flow sensors measure relative changes in returns. It makes little difference whether the readout is in barrels per minute or percentage. The unit of measurement is not important. What is important is that a driller can see increases and decreases in returns instantly. If the pump rate does not change, the return flow should not change. The readout unit of the flow sensors on the rig floor is equipped with audio and visual alarms that can be set once a constant pumping rate is established.

“Finger printing” the return flow rate during connections can be used to detect both a kick warning signs and kick indicators. This is best accomplished by catching the returns in the trip tank during connections, and recording accurate measurements of the return volume with time.

*NOTE: A chart can be produced similar to the chart shown in figure 4.21. In this example, the return flow rate generally decreases with time during the connections, but for each successive connection, the return rate is increasing. This is an indication that a kick might be imminent. During connection #5, the return rate begins to increase about four minutes into the connection, indicating that the well is flowing.*

Figure 4.21. "Finger printing" return rate during connections.



## Gain in Pit Volume

Since formation fluids entering a well displace liquid out of the well, a flowing well will cause a gain in total volume in the active pits. When a kick is taken, the volume of the influx can be estimated by noting the total pit gain. The increase in total pit volume warns the crew that a kick may be occurring. It is common for the workers who are responsible for maintaining the mud system to monitor the changing level in the pits with a weight dangling at the end of a small rope (soft line). This is a good, common sense practice, but it does not provide much information to the driller or other supervisors.

Most rigs today have pit volume totalizer (PVT) systems. The PVT is an instrument that displays to the rig floor and other locations, the total changes in the volume of the active mud system regardless of the present operation. Although their manner of operation varies depending upon the manufacturer, PVTs all share the same purpose. A series of floats are distributed throughout the mud system. As the level of the fluid in the pits changes, the floats move up or down, sending a signal to the display unit. Also, PVTs generate a graphic printout, so that pit level activity can be documented on a twenty-four hour basis. Like flow sensors, PVTs have audible and visual alarms that are set to alert the driller to changes in pit volume.

Figure. 4.22.
A float-type pit level sensor.

Changes in pit volume can be especially difficult to monitor on floating units due to rig motion. Laser detection systems have been developed and are in use on many rigs. These systems are accurate and do away with the common float apparatus.

Many rig activities cause changes in the active pit volume, such as adding liquid and material for general maintenance, deepening the well, etc. For this reason it is not always as easy to recognize the beginnings of a kick in the pit area as it is in other places, for example, at the flowline. One thing is sure, the liquid forced out of the well will show up as a net gain in liquid on the surface. An unexpected gain in pit volume is a definite indication that a kick is in progress.

## Checking a Well for Flow When Circulating

The only way to positively identify a kick is to turn off the pump, wait for the well to stabilize, and then observe the annulus. If a well flows, even when no liquid is being pumped into the annulus, it is a sure indication that a kick is in progress. Flow checks are performed by stopping rotation, picking up the pipe to connection height, shutting down the mud pumps and observing the well. If the flow persists after the usual time it takes for the fluid to drain down the flowline, then it must be assumed that the formation is kicking. Any of the warning signs mentioned in the previous discussions should prompt a driller to do a flow check. Every connection, or whenever the pump is shut off for any reason, provides an opportunity to check a well for flow.

It is not always easy to determine if a well is actually flowing because the flow can be masked by the current operation, as well as by formation characteristics. Each well acts differently, so experience is the only way to know how long it will take for a well to stabilize. Listed below are some circumstances that can affect a flow check.

- Charging pumps that did not shut down when rig pumps were turned off.
- U-tubing of heavier fluid in the string than in the annulus. An indication of U-tubing is that the rate of annular flow usually decreases significantly after only a few barrels.
- Certain formations take some fluid when the pump is brought up to the operating rate. Once the circulating pressure has been established, the return flow eventually stabilizes. Later, when the pump is turned off, for example when making a connection, the fluid continues to flow back until the original loss is nearly all regained. This phenomenon is called *ballooning*. Ballooning has been attributed to mud being lost into fractures, or elasticity of the formation that seems to "balloon" the wellbore due to the annular friction pressure. Whatever the cause, checking a ballooning formation for flow can be a maddening experience because a great deal of fluid may flow back before the well stabilizes. Generally, careful observation will reveal that the flow will decrease in a ballooning situation. If a kick has entered a well, the flow will likely increase because the lighter formation fluid causes bottomhole pressure to continue to decrease. Maintaining a mud gain/loss log may be helpful in getting a handle on what is "normal" for a particular well. Some operators have policies that require a ballooning well to be shut in. After the flow stops and well pressure stabilizes, they bleed off mud intermittently, observing the pressure changes in order to make a positive determination about the annulus flow. However ballooning situations are handled, they should be treated with extreme caution.

*PROCEDURE FOR A FLOW CHECK WHEN CIRCULATING*

1. Alert the crew.
2. Stop rotating.
3. Pick up kelly or top drive to clear uppermost tool joint above rig floor.
4. Shut off the pump(s).
5. Observe the well for flow.

## Kick Detection When Tripping

Warning signs when tripping:

- Trip or connection gas increases
- Takes less fluid to fill than was recorded
- Requires more than the calculated volume to fill the annulus

### Trip Gas

Trip gas enters the fluid while tripping the pipe when not pumping. Trip gas is detected in the fluid when circulating bottoms up occurs after a round trip. Trip gas is caused by swabbing if the well is balanced when not pumping. An increasing trend in trip gas may indicate a near balance or underbalanced condition. If the static mud column is sufficient to balance the formation pressure, the trip gas is caused by swabbing and gas diffusion. Consider weighting up the fluid if there is an increasing trip gas trend.

#### Connection Gas

Connection gas is due to the temporary effective total pressure reduction in the fluid column during a connection due to pump shut down and swabbing. Connection gas indicates a near balance or underbalanced condition. Consider weighting up the fluid if there is an increasing connection gas trend.

### Kick Indicators During a Trip

Kick indicators observed when tripping include:

- No volume change when tripping out
- Trip log deviation and/or excessive pit gain when tripping in
- Flowing well when pumps are off

Chapter 2 stated that the majority of kicks have occurred during trips, specifically on trips out of the hole. Bottomhole pressure is affected in three distinct ways during trips.

- When the pumps shut down, there is no annular pressure loss.
- As the work string is moved, swab and surge pressures develop.
- Running pipe into or pulling pipe out of a well affects the height of the column of fluid in the annulus.

These three factors constantly change as the pipe is moved through different sections of the well. The primary means of detecting kicks when making a trip is by carefully monitoring the changing level of fluid in the annulus.

A well should be monitored to ensure that it is not flowing before beginning a trip out. Since the pumps are not running during trips, bottomhole pressure is reduced by the value of the annular pressure loss when circulating (ECD). Therefore the well should be observed before pulling off bottom.

The only way to monitor a well for flow when tripping is to accurately measure the fluid displaced on a trip into a well and the annular fill-up volume on a trip out.

- The indicator of a kick, while tripping out, is that the annulus takes less fluid to fill than was recorded at that depth on a previous trip. In this case, it can be assumed that the formation fluid is invading the well.
- The indicator of a kick, while tripping in, is the hole keeps flowing between stands, while running in. In this case, it assumes that formation is taking fluids if it requires more than the calculated volume to fill the annulus.

It can be seen that monitoring the fluid level in the annulus is a critical job because the only means of detecting a kick on trips is constantly measuring and comparing volumes with previous trips. This may be done in several ways, depending on the equipment available and the policies of the operator and contractor. The best way to monitor a well is by using a trip tank. A trip tank is a small tank graduated in such a way that accurate measurements are possible as the trip proceeds. Some trip tanks are rigged above the floor so that the well is filled by gravity. Others use centrifugal pumps to pump continuously across the annulus. Another, method is to use the rig pumps to fill the well at various intervals. The pump strokes are counted as a means of monitoring the fill-up. On the trip in, the displaced fluid is measured as it returns to the pits. Whatever method is used, it is imperative that accurate measurements are made and recorded.

On trips into a well, the pipe should displace a volume of fluid equal to the pipe displacement if no float (check valve) is run. As on the trip out, the fluid being displaced out of the hole should always be carefully measured. If the pipe is lowered too fast, fluid may be forced into the formation ahead of the pipe due to surge pressures. This can result in lowering the fluid column and reduction of the hydrostatic pressure to a value below the formation pressure. If formation fluid invades the well, more volume will be displaced than the calculated displacement. This may be due to gas expansion and/or a flowing well. If the fluid displaced out does not match the displacement of pipe going in, the trip should be suspended and the well checked for flow. Pipe should be run (or stripped) to bottom and "bottoms up" circulated through a choke.

It is possible for formation fluids to enter the well on trips at a rate great enough to prevent the fluid inside the pipe from falling. If a well begins to flow, it may be easier for the flow to enter the string when pulling large diameter tools. If the string should pull "dry" at first, but begins to pull "wet" later, the trip should be suspended, a safety valve installed on the pipe, and the well evaluated.

It can be seen that monitoring a well during trips is not as easy as when drilling or circulating near bottom, but the basic technique for identifying a kick is the same. The trip must be interrupted and the well checked for flow. Checking for flow during trips is more complicated and time-consuming than when drilling, especially when no check valve is used in the string. If the work string is open there is a possibility of the kick entering the string. Special well control equipment used in the event of a kick during trips is kept on the drill floor at all times. They are:

- *Full-opening safety valve (FOSV)* sometimes called a *TIW valve*. The FOSV is made up on the pipe in the rotary table when checking for flow. The FOSV is heavy and is often counter-balanced to facilitate easier handling by the crew. The valve is closed with a large Allen-type wrench that is kept nearby the valve.
- *Inside BOP (IBOP),* for installation in the event stripping is necessary. The IBOP is sometimes called a Gray valve and is actually a check (non-return) valve. If a well is closed in with the BOPs and pipe is to be run back into the well through the closed preventer, the IBOP can be made up on top of the FOSV, at which time the FOSV can be re-opened and the pipe run back into the well. Since the IBOP is a one-way valve, it is possible to pump down the string conventionally.
- *Crossover (XO)* subs with thread profiles that match whatever component of the work string that may be in the rotary table.

*PROCEDURE FOR A FLOW CHECK WHEN TRIPPING*

1. Alert the crew.
2. Set slips so last tool joint is at normal working level above rig floor.
3. Install full-opening safety valve in the open position.
4. Observe the well for flow.

Table 4.3. Trip log while tripping in the hole; accurate trip records are a must on every job.

| Stand No. | Starting Trip Tank Reading | Finished Trip Tank Reading | Difference | Theoretical (Calculated) | Trend (Difference) | Accumulated Trend | Remarks (Comment when change of pipe, problems, etc.) |
|---|---|---|---|---|---|---|---|
| 67 | 5 | 8.7 | 3.7 | 3.7 | - | - | Starting in with collars |
| 66 | 8.7 | 12.3 | 3.6 | 3.7 | -0.1 | | |
| 65 | 12.3 | 14.2 | 1.9 | 3.7 | -1.8 | -1.9 | |
| 64 | 14.2 | 16.9 | 2.7 | 3.7 | -1 | -2.9 | Slowing speed down, possible surge |
| 63 | 16.9 | 20.6 | 3.7 | 3.7 | - | -2.9 | Fill collars and monitored hole - ok |
| 62 | 20.6 | 22.1 | 1.5 | 2.43 | -.093 | -3.83 | Running collars in |
| 61 | 22.1 | 25.3 | 3.2 | 2.43 | +0.77 | -3.06 | |
| 60 | 25.3 | 27.6 | 2.3 | 2.43 | -0.13 | -3.19 | Filled up hevi-wate |
| | | | | | | | Running in with pipe |
| 55 | 27.6 | 36.9 | 9.3 | 11.5 | -2.2 | -5.39 | Slowing down run speed |
| 50 | 36.9 | 44.2 | 7.3 | 11.5 | -4.2 | -9.59 | Still losing, emptied trip tank |
| 45 | 0 | 12.7 | 12.7 | 11.5 | +1.2 | -8.39 | |
| 44 | 12.7 | 27 | 14.3 | 11.5 | +2.8 | -5.59 | Stop trip and check for flow |

## Kick Detection When out of the Hole

Kicks that occur when out of the hole often began during the trip out, but were not noticed. The kick may have started during the early part of the trip, but it is more likely that the kick started when the hole was not filled frequently enough toward the end of the trip while handling the BHA.

Lengthy wireline operations like logging and fishing operations require almost continual movement of tools in and out of a well. Kicks that occur while logging and wirelining are the result of

- the swabbing action of the tools being pulled through a tight section of hole;
- the swabbing effect of tools being pulled too fast; and
- failure to monitor the fluid level in the annulus throughout the operation.

Small volumes of formation fluid can be swabbed into a well during these operations when the tools are run and pulled repeatedly. Eventually, the accumulated fluid can cause bottomhole pressure to decrease to a point at which the well will flow. Consideration should always be given to the use of a wireline lubricator. A lubricator long enough to encompass the tools will allow them to be pulled from the well without having to cut the wireline in the event that the BOPs have to be closed.

The indication of a kick when out of the hole is flow from the well or pressure buildup, if the well is closed with the blind rams. It is good practice to close the blind rams and monitor pressure at the choke. Closing the blind rams will prevent objects from falling into the wellbore as well as prevent flow if the choke is in the closed position. If the choke is closed, it is also a good idea to have a pressure sensitive alarm to monitor pressure buildup on the shut-in system. If the choke is left open, a watch must be set to check for flow from the choke manifold. The pit alarm should be set to its lowest alarm setting. Some rigs pump continuously across the BOP stack when out of the hole. The mud pits are lined up in such a way as to permit pumping from and returning to the same tank. This technique ensures that the well is full at all times. If possible, alarms for gain and loss should be set on the one active tank.

### Kick Detection While Running Casing

Kicks that occur while running casing are identified in the same way as kicks while tripping. It is a matter of measuring changes in fluid volume. However, an important point to remember about kicks while running casing is that rig operations are oriented to the job at hand, not to detecting a kick; therefore, crew awareness is a concern.

When running casing, a kick can be detected by observing that the flow of displaced mud does not stop between joints of casing. The flow sensor and pit volume totalizer (PVT) should be monitored closely. Good practices require that calculations be made for the displacement of the casing and couplings. A log comparing theoretical and actual displaced volumes will help to determine that proper volumes are being displaced. A circulating swage that fits the casing being run should be available on the rig floor. A high-pressure/low-torque valve should be made up on the swage. It should be checked for proper operation and noted on the drilling report prior to starting the casing job.

### Kick Detection While Cementing

When pumping cement, the flow sensor can be monitored for flow increases. Pit volume increases and cement displaced should be monitored to make sure the volume of mud displaced is essentially equal to the cement volume pumped. Once the top plug has bumped, nipple-down procedures normally begin. If flow is noticed, it is sometimes attributed to temperature expansion. This may be so, but the BOP stack should not be nippled down until the possibility of a kick is eliminated.

Figure 4.23. Casing operations.

### The Importance of Timely Response

It is extremely important to make a rapid response when a kick indicator is observed or a kick is detected. The purpose of the rapid response is to minimize the volume of the influx. A large volume of influx generally translates into a long vertical column of influx (except for horizontal wells), which produces higher values of shut-in casing pressures (SICP). The higher SICP is needed to balance the loss of hydrostatic pressure of the working fluid column. In some cases, the SICP will be high enough to cause loss of wellbore integrity at the casing shoe and the subsequent development of an underground blowout. It should be noted that, in theory, the weak point is near or at the shoe.

It is possible for weak formations to exist below the shoe area.

For gas kicks, the gas must be allowed to expand as it is circulated up the well, producing still higher values of surface casing pressure during the kick circulation. This further increases the likelihood of the loss of formation integrity at the casing shoe, as well as the generation of surface casing pressures that might surpass the integrity of the casing, casing hanger seals or even the blowout preventer. However, it must be understood that this is dependent on the position of the gas kick. Consequences of not responding quickly or correctly include:

- Larger kick and higher shut-in surface casing or wellhead pressures
- Larger casing shoe pressures
- Kick becomes a blowout
- Potential release of poisonous gases
- Potential pollution of ground or water
- Potential for fire
- Destoyed equipment and wasted or poluuted natural resources
- The potential loss of life, which is unacceptable

# Gas Behavior

# 5

## Upon completion of this chapter, the student should be able to:

- Identify and discuss shut-in pressures - SIDPP, SICP, and their relationship to bottomhole pressure (BHP).
- Identify the different types of influx fluids and the related hazards: gas (hydrocarbon, hydrogen sulfide, carbon dioxide)
- Identify and discuss BHP and the parts of the sum of all pressures.
- Identify the types, characteristics and behavior of formation gas.
- Discuss the solubility of gas as it relates to oil-based mud.
- Explain gas migration in open and closed wells.
- Describe the purpose and function of a variable choke.
- Discuss the relationship of gas kick's position and maximum pressure.
- Describe the differences likely to occur in different kick situations where gas does not normally behave according to "ideal" gas law predictions.
- Perform calculations using the WCS Formula Sheet (Appendix B):
    - Boyle's law
    - Bottomhole pressure (BHP)
    - Height of influx in a vertical well
    - Density of influx

When a well is shut in on a kick and the pressures stabilize, the well is balanced. It is *mechanically* balanced with the blowout preventers. In other words, all the forces exerted downward toward the bottom of the well are equal to all the forces exerted upward from the formation. This is true provided that there are no leaks on the surface and no fluid is being lost to the formation. It can be seen that if this balanced condition is maintained throughout subsequent operations, no further influx can enter the well. Since the well is holding the stabilized pressures at the time of shut in, there is a good chance that the kick can be safely circulated out of the well as long as the pressure on the annulus is not approaching the pressure at which the formation would fracture. All conventional methods of well control are based on this constant bottomhole pressure idea.

Imagine that a kick has been taken while drilling a vertical well and that the driller recognized the kick and closed the blowout preventers. After a few minutes, the pressures within the well stabilize. There is no float (back pressure valve) in the string and the influx is near bottom. The circulating pressure gauge now indicates a stabilized pressure of 200 psi. Pressure on the annulus can also be determined because the blowout preventers have been closed. Assume the annular pressure is 400 psi. On most rigs these pressures are actually read from gauges on a remote choke panel located on the rig floor. The 200 psi is called the *shut-in drill pipe pressure* (SIDPP) or the *shut-in tubing pressure* (SITP). The pressure on the annulus, 400 psi, is called the *shut-in casing pressure* (SICP).

When the influx entered the well the annulus was open at the surface, therefore the formation fluids forced a certain volume of the working fluid out of the well and into the mud pits. Looking at the well as a U-tube (chapter 2, "Well Control Principles"), the drill string side of the tube is filled with a fluid of known density. It is unlikely that the influx could enter the drill string through the small nozzles in the bit and the drill string is connected back to the pumps. The influx would have taken the path of least resistance, into the open annulus. The column of fluid on one side of the shut-in well, the drill pipe, has a consistent density from the surface to the bit. The column on the other side, the annulus, consists of drilling fluid and formation fluid, each having different densities. The stabilized shut-in pressures reflect this condition.

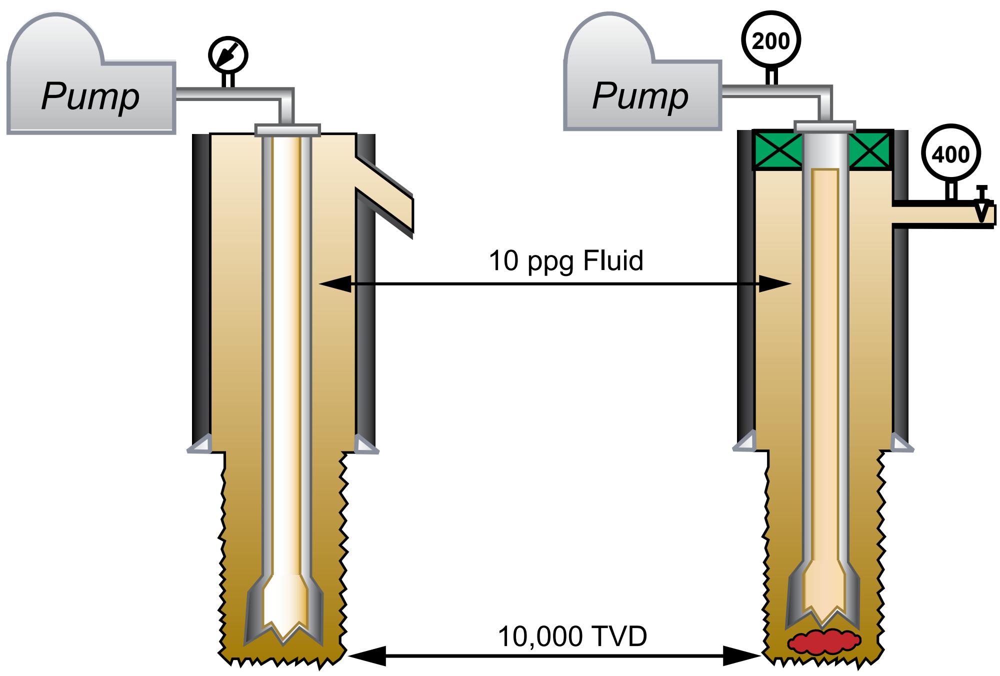
The shut-in well is balanced; therefore, bottomhole pressure equals formation pressure (BHP = FP). On the drill string side of the U-tube, bottomhole pressure is made up of the hydrostatic pressure *inside* the string plus the value of the SIDPP; $BHP_{psi} = HP_{psi(dp)} + SIDPP_{psi}$. Since the density of the drilling fluid and the TVD of the well are both known, the bottomhole pressure can be determined. Suppose the density (MW) is 10.0 ppg and the TVD is 10,000 ft. Bottomhole pressure, which is also formation pressure is:

$$\boxed{\text{Formation Pressure}_{psi} = \text{Hydrostatic Pressure in Drill String}_{psi} + \text{SIDPP}_{psi}}$$

$(10.0 * 0.052 * 10{,}000) + 200 = 5{,}400$ psi

If the hydrostatic pressure in the drill string is known and the string is near bottom, formation pressure can be determined.

Figure 5.1.



Things are different on the side of the U-tube that represents the annulus. The exact height or the density of the invading fluid cannot be accurately determined. The annular hydrostatic pressure is unknown; consequently, the SICP cannot be used to determine the formation pressure. However, the same expression can be used to describe bottomhole pressure on the annulus side:

$$\boxed{\text{Formation Pressure}_{\text{psi (Annulus)}} = \text{Hydrostatic Pressure in Annulus}_{\text{psi}} + \text{SICP}_{\text{psi}}}$$

Both gauges indicate the hydrostatic pressure that is required to balance the well on their respective sides of the U-tube. The SICP is greater than the SIDPP because the hydrostatic pressure in the annulus is less than the hydrostatic pressure inside the drill pipe. The SICP is exerted on the annulus in excess of the hydrostatic pressure. Therefore, the earlier a kick is identified and shut in, the lower the casing pressure, and the less likelihood of fracturing the formation.

## Gas Kicks

Of the three types of formation fluids, gas, oil and water, gas is by far the most dangerous because of its physical nature.

- Gas is highly compressible; therefore, its volume, pressure and density are subject to change when exposed to changing external forces.
- Gas is less dense, or lighter than liquids. The low density of gas creates a tendency for the gas to rise in a well (gravity segregation/migration).
- Most formation gases are flammable, creating a potential fire hazard when the gas is released at the surface.
- Some formation gases are highly toxic and present a life-threatening danger to personnel.
- Under certain conditions gas is soluble. It can dissolve into the liquid working fluid, becoming "invisible" at the time the gas enters the well. Later, as it nears the surface, the gas in solution can suddenly break out of the liquid and assume a pure gaseous state.
- Some formation gases are highly corrosive to steel and can severely damage tubular goods, casing, rig pumps and other equipment.

The compressive nature of gas can be explained by the *general gas law*, which is written:

Where:

$$\boxed{\frac{P_1V_1}{T_1Z_1} = \frac{P_2V_2}{T_2Z_2}}$$

$P_1$ = Pressure at position 1

$P_2$ = Pressure at position 2

$V_1$ = Volume at position 1

$V_2$ = Volume at position 2

$T_1$ = Absolute temperature (Rankine scale) at position 1

$T_2$ = Absolute temperature (Rankine scale) at position 2

$Z_1$ = Compressibility factor of a single gas at position 1

$Z_2$ = Compressibility factor of a single gas at position 2

The general gas law is actually a combination of two laws of physics. The top portion of the expression is Boyle's law. Robert Boyle was a British physicist who lived about 350 years ago. *Boyle's law* explains the inverse relationship between a volume of gas and the pressure within the gas. That is, if the pressure increases the volume is reduced; if the pressure is reduced the volume increases, and if the pressure does not change the volume will not change. $P_1$ in Boyle's law is some original gas pressure and $V_1$ is some original gas volume. $P_2$ and $V_2$ represent the pressure and the volume respectively at any different value. If any of the three values are known, the fourth value can be determined.

Boyle's law:

$$\boxed{P_1V_1 = P_2V_2}$$

Where:

$P_1$ = Pressure at position 1

$P_2$ = Pressure at position 2

$V_1$ = Volume at position 1

$V_2$ = Volume at position 2

About 100 years after Boyle's work, a French scientist, Jacques Charles, investigated the effects of temperature on the pressure/volume relationship of gas. The bottom portion of the general gas law is known as Charles's law. The "T" symbolizes temperature, but not temperature Fahrenheit or Centigrade. The temperature in Charles's law is absolute temperature (Rankine), which is used in scientific studies and computer modeling, but not in every day life. The "Z" in Charles's law represents a compressibility factor for a single known gas. Just as water and honey are both liquids but they flow differently, so different gases have different compression characteristics.

It can be seen that the general gas law has little direct application in the field because the changing temperature of gas as it moves up in a well is never known. Furthermore, formation gas is always a mixture of gasses; assigning a true compressibility value is virtually impossible. However, Boyle's law can be used to demonstrate the approximate behavior of gas in a well and illustrate its dangers. Since the temperature and compressibility factors of Charles's law are divided into the pressure/volume relationship of Boyle's law, thereby reducing their values, applying Boyle's law represents the worse possible case.

Assume the same well data that was used in the figure 5.1, that is, a well 10,000 feet deep (TVD) and a working fluid of 10.0 ppg. Assume further that a single barrel of gas is swabbed into the well, displacing one barrel of liquid.

On bottom, the gas is contained by the hydrostatic pressure, 5,200 psi, exerted by the column of 10.0 ppg fluid above it. There is a large difference between the density of the liquid in the well and the density of the gas. Therefore, the gas will begin to rise, or migrate, toward the surface. Gas migration is the movement of low-density fluids rising up the annulus. Actually, it is not likely that the influx would remain as a single coherent bubble. Some of the gas might dissolve into the liquid and the remainder would probably percolate through the liquid, stringing out in length. However, for illustration purposes imagine that the influx remains as a single bubble of gas and that the well has a consistent ID from top to bottom (see figure 5.2).

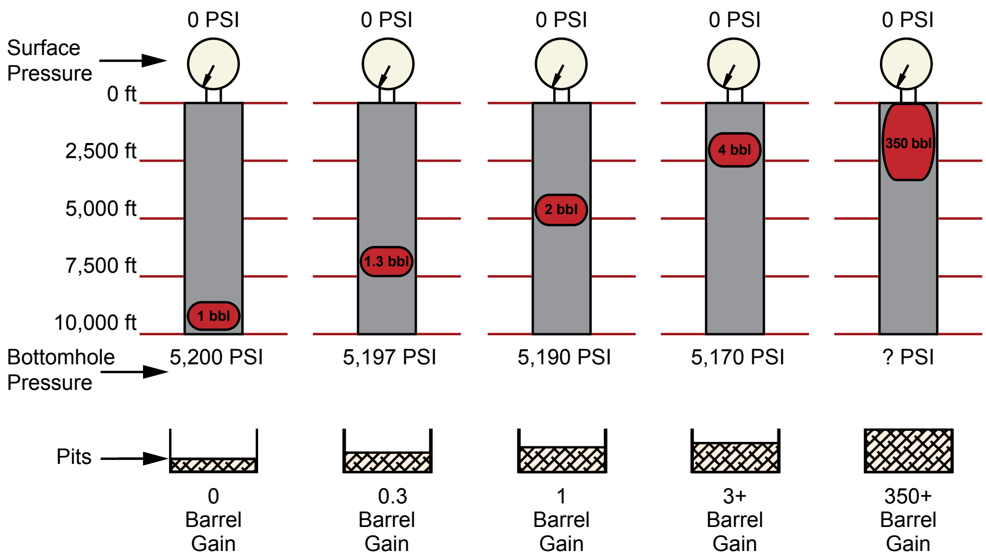
## Gas Migration in an Open Well

When the rising bubble reaches 5,000 feet, the hydrostatic pressure of the liquid above it is 2,600 psi (10.0 * 0.052 * 5,000 = 2,600 psi). According to Boyle's law, if the pressure is reduced by one half, the volume will double. Therefore the volume of the gas is two barrels when the bubble reaches 5,000 feet. The mud pits contain one more barrel of fluid.

As the gas continues to migrate, its volume will double at each halfway point. For example, at 2,500 feet, the volume would be four barrels and at 1,250 feet it would be eight barrels. As the gas rises, the halfway points come more frequently and the volume continues to double. At atmospheric pressure on the surface (about 15 psi at sea level) that same one-barrel influx would have increased to about 350 barrels.

In reality, at some point during the migration, bottomhole pressure would have been reduced to a value below the formation pressure and gas would continue to enter the well at an ever-increasing rate. The working fluid in the well would unload and the well would blow out. If there were drill pipe in this well and the gas was circulated out, the same thing would have happened, only faster. The two important points to be made by this example are: *gas cannot be allowed to rise uncontrolled in an open well and almost all the gas expansion occurs near the surface.*

Figure 5.2. Uncontrolled gas expansion.




## Gas Migration in a Closed Well

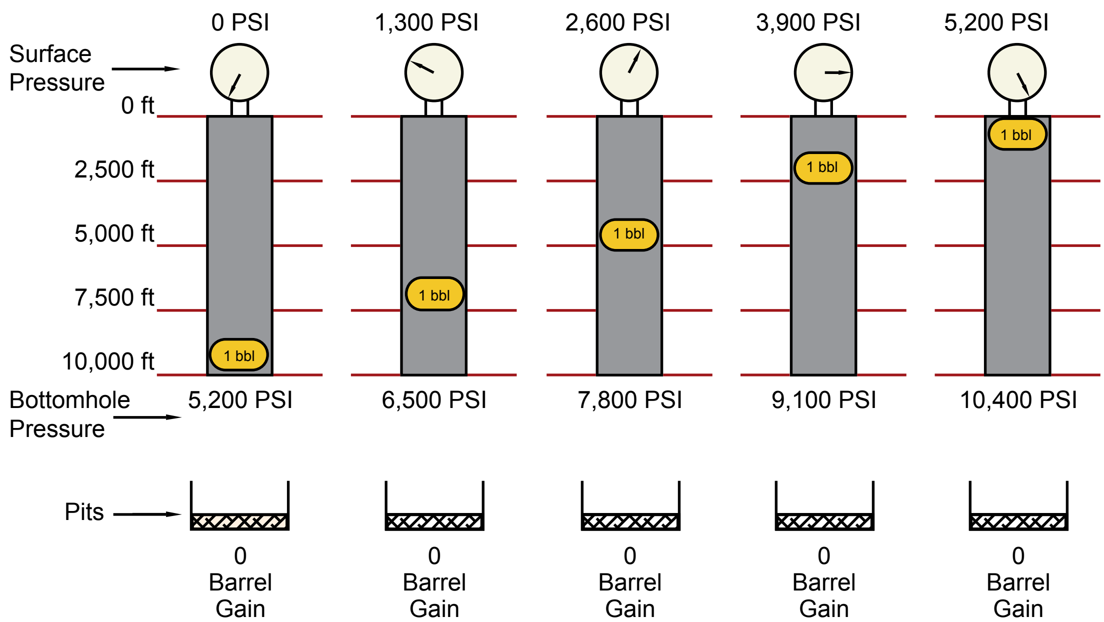
Suppose that the one-barrel gas influx in the example well was recognized as it entered the well and that the blowout preventers had been closed. The difference in density between the gas and the working fluid is the same as in the previous example so the bubble would still have a tendency to rise in the closed well, although at a somewhat slower rate. When the influx reached 5,000 feet, the hydrostatic pressure above and below the gas would be approximately 2,600 psi. According to Boyle's law, if the volume of gas does not change, the pressure within the gas will not change. The pressure within the influx was at 5,200 psi when it entered the well and since the gas cannot force liquid out of the closed well, the gas cannot expand and the pressure within the bubble of gas remains the same as the gas rises.

Pressure is exerted equally in all directions in a closed vessel. This statement applies to the rising gas in the example well. The hydrostatic pressure of the liquid above the gas is about 2,600 psi exerted downward, opposing the 5,200 psi within the gas, exerted upward. The difference between the two pressures appears on the surface gauge (SICP): 5,200 – 2,600 = 2,600 psi. The increasing casing pressure indicates that the gas is rising toward the surface (see figure 5.3).

The hydrostatic pressure below the influx is also about 2,600 psi, so bottomhole pressure at this point would be 2,600 psi plus the pressure within the gas, 5,200 psi; 2,600 + 5,200 = 7,800 psi. The migrating gas is bringing formation pressure to the surface. When the one barrel of gas reaches the top of the well, the SICP would be 5,200 psi because there is no hydrostatic pressure exerted against it, and the bottomhole pressure would have increased to the sum of the influx pressure 5,200 psi, *plus* the hydrostatic pressure below the gas; 5,200 + 5,200 = 10,400 psi. The chances are that the formation, or the casing, or even the wellhead equipment would fail due to these tremendous pressures. The effect would be the same if the well were circulated barrel for barrel, pumping one barrel into the well for every barrel removed. *Gas cannot be allowed to migrate uncontrolled in a closed well because the pressures exerted throughout the well will reach unacceptable levels.* In the case of migrating gas, the surface pressure will increase, indicating that the gas is moving up in the well.

Another condition that leads to pressure build up during shut-in is that oil-based fluids (and water-base fluids to a lesser degree) heat up and expand during static well conditions, leading to higher annular pressure.

Figure 5.3. No gas expansion.



## Controlling Gas Expansion with an Adjustable Choke

Suppose that it was decided to hold the original casing pressure constant by bleeding off liquid through an adjustable choke as the casing pressure increased, due to the gas migration (or circulation). This technique might be successful for a short time because there is little effect on well pressures at first, but eventually bottomhole pressure would decrease, allowing more influx into the well. When the choke is opened, in order to keep the increasing casing pressure constant, the hydrostatic pressure in the well would be reduced. Since bottomhole pressure is the sum of the casing pressure plus the hydrostatic pressure, the decrease in hydrostatic pressure would cause a decrease in bottomhole pressure allowing further influx into the well.

$$\boxed{\underset{\downarrow}{HP_{annulus}} + \underline{CsgP} = \underset{\downarrow}{BHP}}$$

*Gas cannot be allowed to rise in a closed well while bleeding off fluid to maintain a constant casing pressure because the loss in hydrostatic pressure in the annulus would reduce bottomhole pressure.*

The only safe way to handle gas kicks is to allow the rising gas to expand just enough to keep bottomhole pressure constant at the original shut-in value. That can be accomplished using an adjustable choke to control the back pressure exerted on the well. In practice, bottomhole pressure is maintained at a value slightly higher than the formation pressure. Specific techniques for controlling gas kicks under various conditions are discussed at length in chapter 9, "Well Kill Methods".

## Types of Formation Gas

### Methane

Although most kicks contain a mixture of gasses, the most common component of formation "natural gas" is methane. Methane is highly flammable and less dense than air. Although not usually considered toxic, high concentrations of methane in an enclosed area not only present a serious explosion hazard but can also lead to asphyxiation. Methane and the other associated hydrocarbon gasses may come into a deep well in liquid form, due to pressure and temperature. At some point, higher in the well, they will revert to a gaseous state as the pressure and temperature is reduced. This is the effect of the bottom portion of the general gas law, that is, *Charles's law.* This characteristic of gas (changing state of matter) can lead to a misjudgment with regard to the volume of the kick. The original volume gain in the mud pits would not reflect the actual volume of the gas influx.

### Hydrogen Sulfide

The most dangerous drilled formation gas is hydrogen sulfide ($H_2S$), which is contained in many carbonate formations, e.g., limestone formations around the world. Hydrogen sulfide is extremely toxic at relatively low concentrations. Hydrogen sulfide is flammable, corrosive, and is slightly denser than air. Hydrogen sulfide is soluble in crude oil and oil-based fluids (depending on pressure, oil density and temperature). It is slightly soluble in water-based fluids. Although hydrogen sulfide has a sulfur-like smell (like rotten eggs) at low concentrations, the olfactory nerves are quickly deadened and the gas can no longer be detected. Convulsions, unconsciousness and even death follow quickly. Since hydrogen sulfide is heavier than air, when it reaches the surface it has a tendency to lie in low areas around the location.

The only defense against hydrogen sulfide is thorough preparation. Special respiratory equipment and hydrogen sulfide detectors must be placed in strategic locations on the site. Crew members must be made aware of the dangers and practice drills, constantly in anticipation of a release of gas on the surface. If hydrogen sulfide is anticipated, drilling fluid programs are designed to scavenge or otherwise handle the gas and limit the corrosive effects on equipment. Hydrogen sulfide is so dangerous that a very small mistake can lead to a great tragedy.

### Sulfur Dioxide

If hydrogen sulfide is burned, the by-product is sulfur dioxide ($SO_2$). Sulfure dioxide, like hydrogen sulfide, has the sulfurous odor of rotten eggs and is extremely toxic. It is approximately twice as dense as air, so if hydrogen sulfide is to be burned, consideration must be given to prevailing winds.

### Carbon Dioxide

Carbon dioxide ($CO_2$) may also be present in carbonate formations. Carbon dioxide, like hydrogen sulfide, is heavier than air and corrosive. Carbon dioxide is soluble in water, and forms a corrosive acid, carbonic acid ($H_2CO$). It is extremely soluble in crude oil and oi-based fluids a relatively low pressures. If trapped in a confined area, carbon dioxide can displace oxygen and persons in the area risk suffocation. Cardbon dioxide will not burn and therefore does not present an explosion hazard.

## Solubility of Gas

The behavior and solubility of formation gasses into the liquid working fluids used in a well is a complex issue. It is not possible to accurately predict solubility because there are simply too many unknown factors to consider. The type of mud in use, the pressure, temperature, pH and the types and ratios of gases encountered, all affect solubility. The time that the gas has been exposed to the liquid would have to be known if specifics of solubility and influx behavior were to be accurately determined. However, some general statements about solubility can be made.

Hydrocarbon gases are much more soluble in oil-based liquids than in water-based liquids. This is reasonable since they are chemically similar. Just as salty water mixes easily with fresh water, hydrocarbon gases mix easily with hydrocarbon liquids. It has been estimated that as much as 60 to 70 percent of the gas will go into solution if the working fluid is oil-based mud. The degree of gas solubility in oil-based fluids is affected by the base oil type, oil / water ratio and the emulsifier type and concentration.

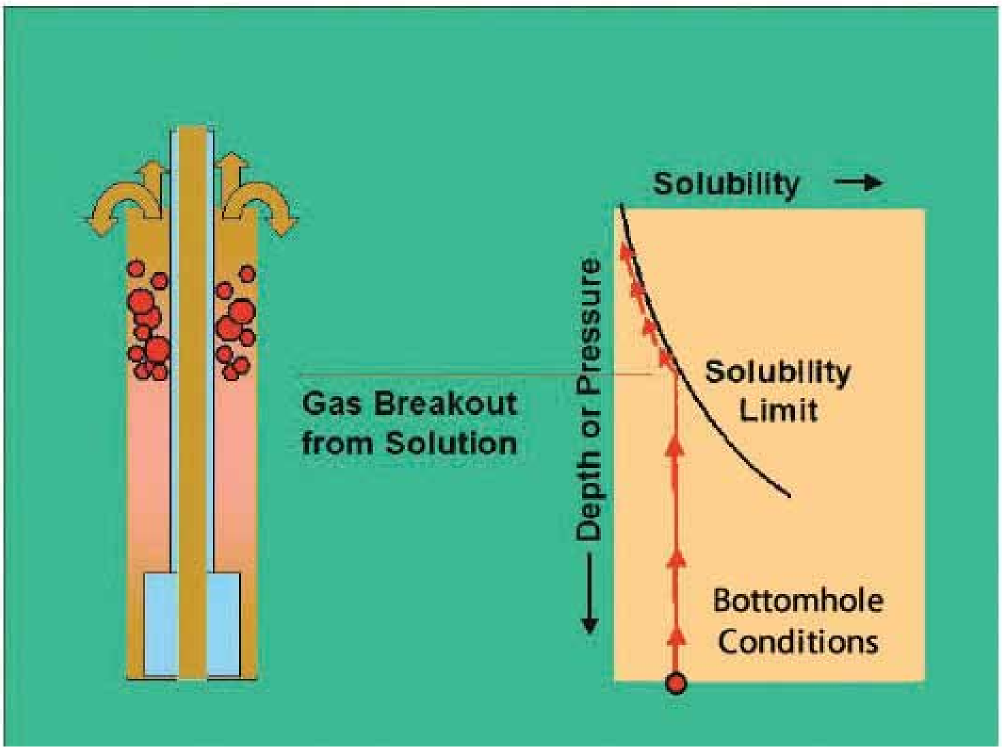
With water-based fluid, the gain in the pit would reflect the size of a gas influx. For example, if a well were shut in with a ten-barrel pit gain, this would be the result of a ten-barrel influx of gas. With oil-based fluid, the same ten-barrel gas kick might cause a pit gain of only two or three barrels. The severity of the kick would be disguised. Synthetic oil-based mud, which is a man-made hydrocarbon used for environmental reasons, will exhibit the same gas absorption characteristics as other oil-based mud, but to a lesser extent depending on its composition.

Once shut in, gas in solution will not migrate to any appreciable extent, thereby giving the appearance of a liquid kick. The assumption that the kick is oil or saltwater should not be made if oil-based fluid is being used. The influx will not expand as it is circulated until the kick nears the surface. When the gas comes out of solution, it will expand rapidly. If the well is being circulated, this will result in a sudden unloading of the liquid above the gas as it expands. If the kick is being circulated through the choke, this rapid expansion will require choke adjustments to maintain a constant bottomhole pressure. The choke operator must anticipate the change from a liquid to a gas as the kick nears the surface and be prepared to make necessary adjustments.

### To Summarize:

- If enough pressure is exerted, gas may be compressed to a liquid state. If a gas kick enters a well in a liquid state, the kicking fluid is not likely to migrate or expand until it moves up the well to a point at which the gas can no longer stay in liquid form. At that point, (called the *bubble point*), the gas will break out of the liquid and its volume will expand rapidly (figure 5.4).
- Solubility of gas cannot be accurately predicted. It is dependent on many variables such as temperature, pH, pressure and type of working fluid in the well.
- Methane and hydrogen sulfide are more soluble in oil-based muds than in water-based muds. Gas solubility will usually increase as the pressure increases and decrease as the temperature decreases.
- Some gas is usually present in all kicks. All kicks should be treated as gas kicks unless there is reason to believe otherwise.

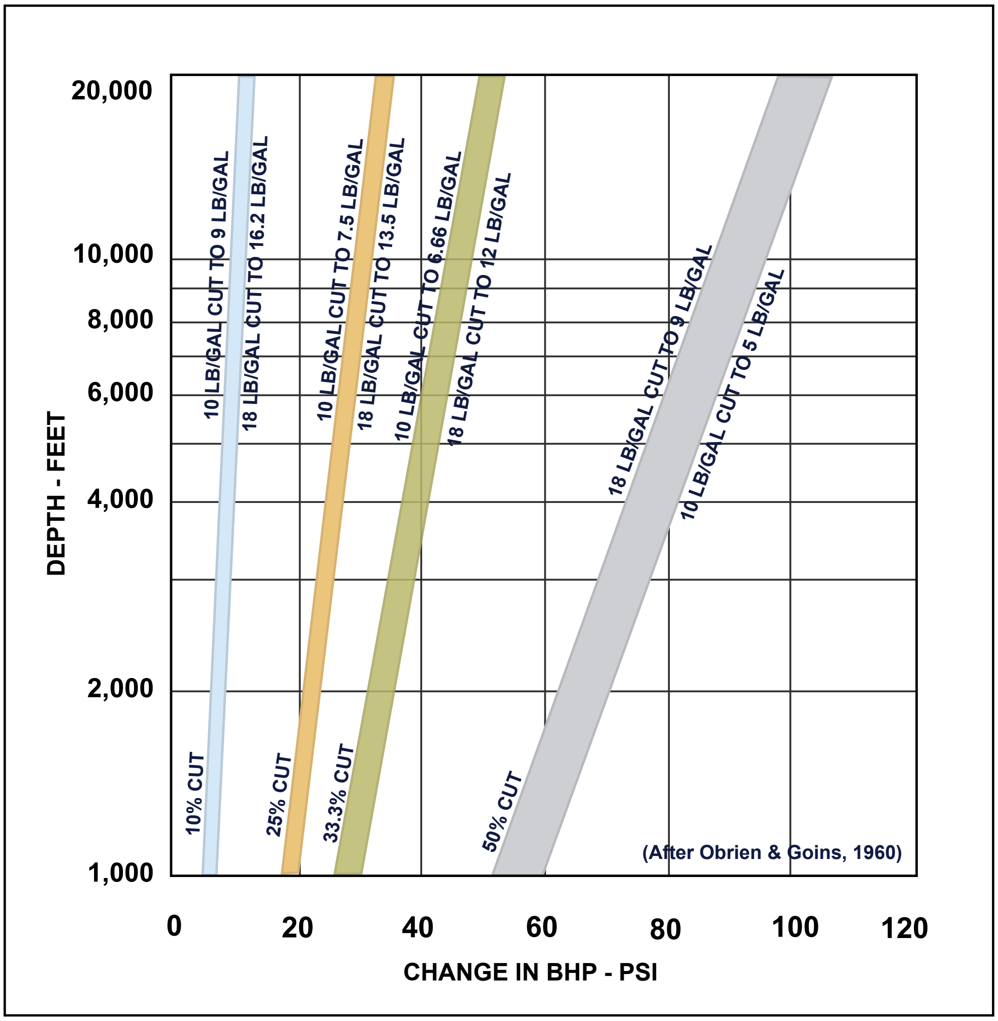
Figure 5.4. Dissolved gas breakout near surface and rapid expansion.




## Gas-Cut Fluid

When the density of the mud returning at the flowline is reduced due to tiny bubbles that are entrained in the fluid, the mud is said to be *gas-cut*. Gas-cut mud, even if apparently severe, usually does not cause a major reduction in bottomhole pressure. A small volume of gas at the bottom of a well can cause a large reduction in the apparent density at the surface. Almost all of the gas expansion occurs as the liquid reaches the atmosphere. The chart in figure 5.5 illustrates the affect on bottomhole pressure from gas cut fluid. Note that in a well 20,000 feet deep, with the density cut by 50% on the surface, bottomhole pressure is only reduced by about 100 psi.

Figure 5.5.




Increases in gas cut mud are important warning signs, but so long as the gas is removed from the fluid before it is pumped back into the well, it usually presents no problem. Gas cutting can be significant when drilling fast, especially at shallow depths. It is possible to load the annulus with gas if the drilling rate is so fast that the mud cannot be circulated and conditioned before returning to the pump suction. Generally, once surface casing is set, the problem is minimized.

## Liquid Kicks

Liquid kicks do not present the same level of danger as pure gas kicks. They are however troublesome, and can be dangerous if handled incorrectly. Since they do not expand to any appreciable extent as the pressure imposed on them is reduced, the input and return flow rates will be essentially equal. The casing pressure will not increase greatly, provided no further influx enters the well. If bottomhole pressure is held constant as the kick is circulated, changes in hydrostatic pressure in the annulus will be due to variations in well geometry and choke adjustments. These changes are not nearly as pronounced as changes that occur when handling a gas kick.

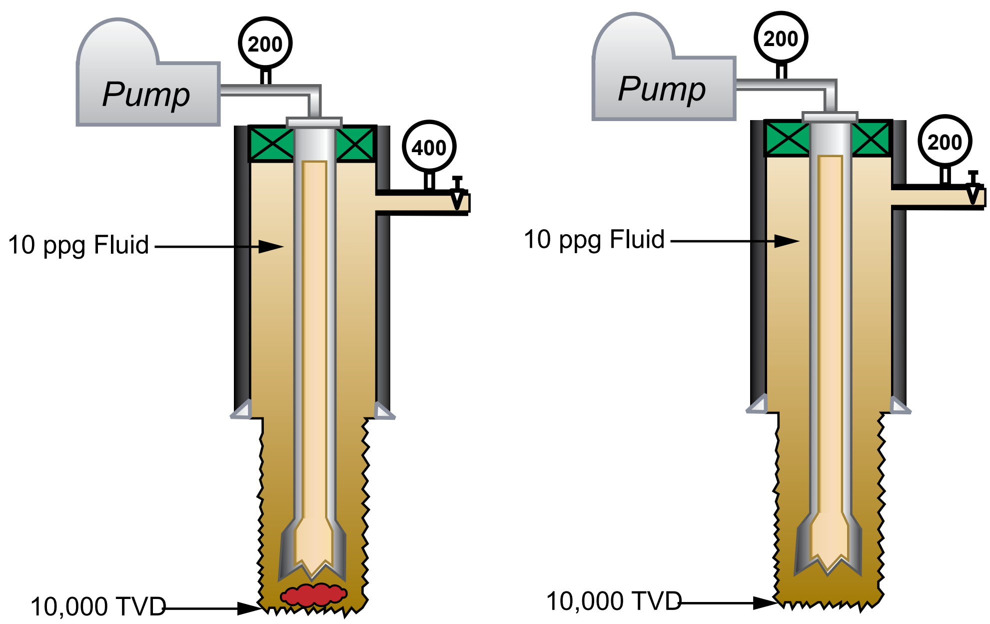
If a well is shut in on a liquid kick, there is not as great a difference between the SIDPP and SICP as there is with a gas kick. Liquid kicks are not likely to migrate. If the liquid kick does not migrate, shut-in pressures will not increase from migration to the same extent as seen with a gas kick. The risk of fire and explosion is not nearly as great as with gas kicks.

One of the major problems associated with liquid kicks is the effect on the working fluid in the well. The flow properties of water-based fluids can be radically altered and hydrostatic pressure may be reduced due to dilution. In the case of oil-based fluids, the kick may break, or "flip" the emulsion, permitting weight material and other desirable solids to separate and fall out of the fluid. As stated previously, nearly all water influxes contain some solution gas that will cause the surface pressures to react like a gas kick, but to a lesser degree. Safe practice requires that every kick be treated as if it were a gas kick.

## Determining the Kick Material

When a well is shut in on a kick, the difference between the SIDPP and SICP is a reflection of the height and the density of the influx. If the influx were circulated completely out of the well, both sides of the U-tube would contain a fluid of 10.0 ppg at a true vertical depth of 10,000 feet and therefore both gauges would read 200 psi (see figure 5.6). An estimate of the influx density could be formed if the height of the influx were known.

Figure 5.6.



Well data:

15 bbl pit gain

SIDPP 200 psi

SICP 400 psi

CMW 10.0 ppg

Annular capacity at BHA is 0.029 bbl/ft

Assume that the influx in the illustrated well is near the bottom of the well.

1. Estimate the height of the influx.

   (8.52 – 6.52) ÷ 1,029.4 = 0.029 bbl/ft annular capacity around the BHA

   15 bbl ÷ 0.029 bbl/ft = 517 ft estimated height of the influx

| |
|---|
| Height of Influx (Vertical Well)$_{ft}$ = Kick Size Volume$_{bbl}$ ÷ Annular Capacity$_{bbl/ft}$ |

The height of the kick is about 517 feet. Using the transposed hydrostatic pressure formula, the approximate density lost across the kick can be determined. The loss is represented by the difference between the SIDPP and the SICP.

2. Determine the hydrostatic pressure in the annulus lost due to the lighter fluid.

   (400 – 200) ÷ 0.052 ÷ 517 = 7.4 ppg density lost across the kick.

3. The original fluid in the annulus was 10.0 ppg, therefore

   10.0 – 7.4 = 2.6 ppg is the approximate density of the influx.

| |
|---|
| Density of Influx$_{ppg}$ = CMW$_{ppg}$ - [(SICP$_{psi}$ – SIDPP$_{psi}$) ÷ 0.052 ÷ Kick Height$_{ft}$] |

The density of fresh water is about 8.34 ppg at room temperature. The density of diesel oil is between 6.8 and 7.0 ppg, and the density of pure gas is usually less than 2.0 ppg. Therefore, the kick in the example well is mostly, if not all, gas.

It should be understood that the explanation above has several limitations in the field and the calculations can only be used as estimates, not as hard data. Some things that affect the accuracy are:

- The example assumes that the open hole is in gauge. In reality, it may be under or over gauge.
- The example assumes a vertical well. If the well were highly deviated, the inclination would have to be taken into account in order to determine the vertical height of the influx. There will not be much annular hydrostatic pressure reduction when it occurs in a horizontal section. Gas will not migrate or expand in a high angle (>90°) section but will expand and migrate when circulated into the vertical section.
- If the influx were liquid, it would displace well fluid barrel for barrel because liquids are essentially incompressible. Gas, however, is highly compressible and soluble to some degree; therefore, the pit gain will not always reflect the kick volume accurately.

## Maximum Pressures

It is impossible to estimate accurately the maximum surface pressure that can be expected from a poorly handled kick. The circulating pressure is regulated by adjusting the choke. If the influx is mostly gas, and it is allowed to migrate to the surface without expanding, then pressure on the surface could be between one half and two-thirds of the formation pressure that produced the gas. Solubility of the kicking fluid, as well as temperature, will likely reduce the volume of the influx and therefore reduce pressure. Kick composition, solubility, and exact kick size are never perfectly known. In some cases, the method used to control the kick will reduce the pressure exerted on a well.

There are a few general statements that apply to maximum pressures:

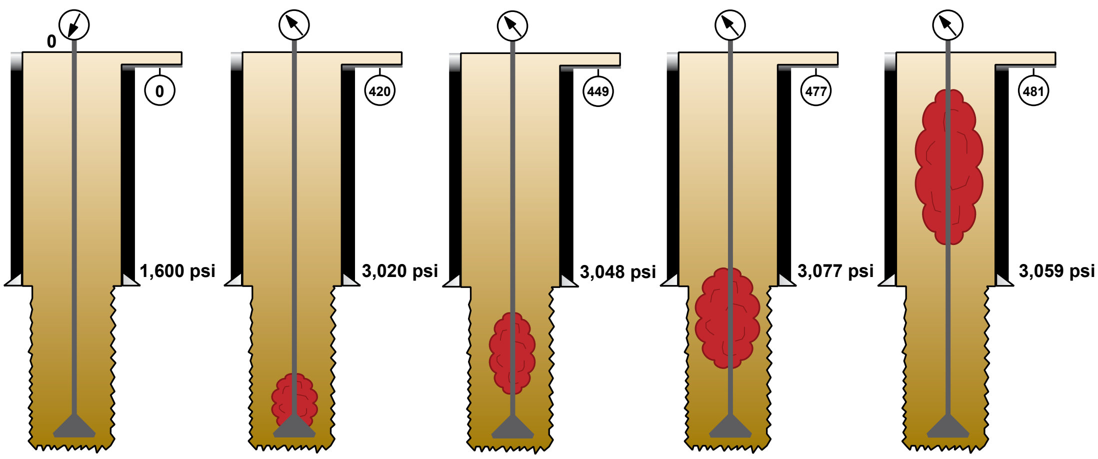
- Casing pressure increases with the magnitude and size of the kick.
- Formation and circulating pressures increase with well depth.
- Increases in fluid density cause increased circulating pressure.
- Shut-in casing pressure is lowest with saltwater and highest with gas kicks.
- The method of killing the well affects the surface pressure. Increasing the fluid density before circulating may help minimize surface pressure.
- Gas migration, while a well is shut in, can result in surface pressures increasing to near formation pressure.

## Effects of Kick Position

A major concern in all well control operations is the possibility of lost circulation. As pointed out earlier, the pressure at any weak point in the wellbore is equal to the hydrostatic pressure above that point plus the casing pressure at surface. Usually, the formation directly below the casing seat is assumed to be the weakest point. If bottomhole pressure remains constant as the kick rises in the well, pressures at the weak point will increase only until the gas reaches the weak point.

Once the kick enters the casing, the hydrostatic pressure at the weak point decreases, provided that the influx is less dense than the working fluid in the well. The pressure at the weak point will not increase any more as the gas is circulated to the surface and out of the well.

Figure 5.7. Effects of kick position.



These statements are generally true even though casing pressure may continue to rise until gas reaches the surface. It is the total pressures against the weak point, not just the pressure seen on surface, which causes formation failure. Pumping the kick up into the casing reduces the chances of lost circulation because the pressure at the casing shoe stabilizes or is reduced. It can be said that *if bottomhole pressure remains constant, pressure at the weak point will not increase any more after the kick reaches the weak point, even though surface pressure may continue to increase.*

## Multiple Kicks

It would be nice to be able to circulate a kick completely out of a well in one circulation, but in many cases that is not possible. Several circulations are often required because of inefficient displacement and because the influx may be strung out through the annulus.

In theory, if constant bottomhole pressure is maintained during the circulation, no further influx can enter the well. In reality, taking a second or even a third kick is not unusual. The main causes of secondary kicks are:

- improper pump start up procedures after initial shut in;
- difficulty in mixing kill fluid throughout the system in one circulation;
- improper circulating pressure;
- not maintaining the pump rate;
- difficulty controlling the circulating pressure as the kick evacuates the well; and
- incorrectly responding to problems such as washouts, nozzle plugging, etc.

After circulating a kick out, the pump should be shut down and the well shut in. If pressure registered on the casing gauge, it is an indication that there is still formation fluid in the annulus and the well should be circulated until all of the influx has been pumped from the well.

# Completion and Workover Fluids

6

### Upon completion of this chapter, the student should be able to:

- Describe types of fluids.
- Describe properties of fluids.
- Describe differences in densities.
- Describe the effects of gas-cut mud on hydrostatic pressure.
- Describe the effects of temperature on density and viscosity.
- Demonstrate fluid testing procedures.
- Define and describe crystallization and hydrates.
- Name and discuss the two common types of workover fluids.
- List the three primary functions of workover fluids related to blowout prevention.
- Identify and discuss the two main properties of workover fluids.
- Name and discuss some common workover fluid additives.
- Define rheology as it relates to well control.

The term *remedial fluid* refers to any working fluid used in a well after the drilling has been completed. Although both gas and liquids are fluids, and some remedial work does involve using gas, for the purpose of this discussion the words "fluid" and "liquid" are considered interchangeable. Just as drilling fluid (mud) is an integral part of drilling operations, so too, are the fluids that are used for remedial operations.

Remedial fluids may be separated into three main groups; workover fluids, completion fluids and packer fluids. Many times the fluid used in a completed well satisfies both functions. The primary difference is nominal, and refers to the specific use in a given well. Completion fluids are used opposite producing formations in order to prevent damage to the reservoir. Packer fluids are left in a well between the tubing and casing, above the production packer. Remedial fluids share the common desirable characteristics listed below.

- *Density stability*. The fluid should be sufficiently dense to control well pressures without being too dense. Usually the density is maintained close to formation balance in order to reduce losses and/or damage to the producing formation.
- *Solids-free*. Solids can plug perforations and reduce production or otherwise damage the production zone. This is especially true after a fracture or gravel pack operation. Sand can be especially abrasive and damaging to surface equipment, as well as downhole equipment.
- *Noncorrosive*. Corrosive fluids will damage the tubing, the casing and all metal components in a well.
- *Temperature stable*. Remedial fluids are often left in a well for extended periods of time. During that time, there may be wireline work or perhaps the need to circulate the fluid.

Good remedial fluids do not develop high viscosities and gel strengths, even though they remain static for long periods of time at relatively high well temperatures.

- *Environmentally acceptable*. Some remedial fluids can damage the environment if spilled. Spill and waste control must be considered when selecting the best fluid for the well.
- *Cost-effectiveness*. Although the initial cost of the remedial fluid in some wells may seem excessive, like all well costs, higher initial costs may be offset by the long-term gains. Each well is different and the most cost-effective fluid is the one that is no more expensive than is required to do the job.

Other fluid characteristics such as cuttings transport, solids suspension, etc., are much less important for completion fluids and packer fluids because the open hole is cased off in most completed wells.

*Excerpt from "Well Control for Snubbing Operations" manual by Well Control School*[1]

## Primary Purpose of a Drilling or Well Servicing (Remedial) Fluid

The primary purpose of drilling (and most well servicing) fluids is to maintain pressure control over the well during the operation. If the activity is conducted in a presumably "dead" well, the primary purpose is to produce a hydrostatic pressure that is greater than the exposed formation's pore pressure. Today, in many operations (including some drilling operations) the work is conducted in "live" wells, where the hydrostatic pressure of fluid alone is not sufficient to control the well. For these operations in live wells, a choke or rotating BOP must be used to supplement the hydrostatic pressure of the working fluid in the well, so that the pressure control of the well can be maintained.

This chapter discusses the fluids most often used today. Although a properly designed circulating fluid or mud may provide eight to ten beneficial functions to the overall operation, only three of those functions pertain directly to blowout prevention. They are:

- Control formation pressure (fluid density) and maintain the stability of the well wall
- Hole cleaning efficiency, pumping pressures and surge/swab resistance (viscosity)
- Suspension of solids when not circulating (gel strength)

## Completion and Well Servicing Fluids

Completion and well servicing fluids include freshwater and oil-based muds, brines, emulsions, gases and foams. Selection of the right fluid depends on the application or specific well servicing to be performed. Within these broad fields of applications, there is a wide range of uses.

### Applications

The majority of completion and well servicing applications is dependent on the circulation, placement or injection of a fluid. Usually, when solid materials are pumped into a well or debris is to be removed from it, gelled fluid is selected. Gelled fluids require a mixing capability at the surface, and generally, the use of a polymer to make the fluid viscous. Typically, this requires the selection of the right polymer to match the fluid to be pumped.

Stimulation fluids are used to convey proppants into a well and then farther out into the formation, in well fracturing operations. Proppants are solid materials used to hold the fractures open once the stimulation operation is completed. Sand is the most commonly used proppant.

Fluids are also used to convey liquid materials, such as acids, solvents, alcohols or other chemicals, into a well and to spot these treatment liquids adjacent to specific points in the wellbore.

It is necessary, in drilling applications, to collect thoroughly and remove drilled cuttings from the fluid stream. Gelled fluids, which are required for drilling applications, are referred to as *drilling mud* or just *mud*.

### Delivery of Hydraulic Energy

Fluids are also used to deliver hydraulic energy to downhole tools in the BHA of the work string. The hydraulic energy delivered can be in the form of pressure to operate tools in the BHA, or it can be in the form of increased velocity and turbulence, to aid in cleaning out the scale or paraffin that has adhered to the inner walls of the production string. In some instances, the energy is delivered to wash over a failed section of tubing or work string, so that the lower stub can be retrieved by fishing. Hydraulic energy (in the form of pressure) is also used to stimulate production from wells by fracturing the producing reservoir.

In drilling applications, the hydraulic energy delivered to the drill bit is used to lubricate, cool, and clean the bit. As the fluid passes through the nozzles in the drill bit, a high-velocity jet is created to clean the rock/bit interface. The hydraulic energy also assists in removing the drilled cuttings from the well by lifting the cuttings from it. The velocity of the fluid stream in the annulus, coupled with the gel properties of the drilling mud, makes cutting removal more efficient.

### *PROVIDE A MEDIUM FOR WELL SERVICING OPERATIONS*

Workover fluids provide a medium for wireline and electric logging. Wireline is used for well servicing operations, such as electrical logging, perforating and setting plugs or packers.

### Stimulation

Fluid pumped through tubing is used to assist in the stimulation of a well. One technique requires the use of highly pressurized fluids to fracture producing zones, creating additional wellbore exposure to the formation hydrocarbons located far from the wellbore. Hydraulic energy is applied in the form of pressure, which ultimately overcomes the formation integrity of the reservoir zone(s) and creates large, vertical fractures that extend several wellbore diameters into the formation. As the formation is first broken apart by the applied pressure, fluid is rapidly pumped into the well/formation, propagating the fracture deeper into the reservoir. As the fluid creates fractures, it carries with it proppants that are used to keep the fractures open after the hydraulic energy ceases. The proppants are carried in a “temporary gel” slurry to assist in the effective delivery of the proppants into the fracture. The slug of gelled fluid is designed to “break” at a specific time or temperature and release the proppants. Thus it allows the excess fluid to back out of the fracture(s) when the pressure is relieved and the fracture(s) begins to close. The delivered proppant holds the fracture(s) open for enhanced productivity.

The selection of a good stimulation fluid requires us to consider the fluid’s interaction with the formation, so that clay swelling in shale does not plug the pore spaces in the formation and defeat the purpose of the fracturing operation. The desirable characteristics of a hydraulic fracturing fluid are:

- Controllable characteristics of the gel slurry and gel-break time/temperature
- Clean, non-damaging fluid before and after formation fracture

- Efficient transport of selected proppant and release of proppant from the fluid
- Efficient cleanup following the operation

Stimulation fluids formulated with acids, solvents and alcohols are intended for specific applications. These fluids should be checked for compatibility with the target reservoir and operational conditions. The benefit of a stimulation treatment can be compromised or even completely eradicated if the spent stimulation fluids react with the reservoir or wellbore fluids to create secondary chemical compounds that effectively plug the treated formation.

### Pressure Control

A very important use of fluids in well servicing applications is to assist in controlling pressure. In the case of static or dead wells, formation fluids, alone, control the pressure in the well. The pressure control results from the hydrostatic pressure in the well. For a well that is underbalanced, pressure control is achieved by the hydrostatic pressure in the annulus plus the back-pressure generated by the choke. The fundamentals of well-control operations involve the use of the density of completion, workover or drilling fluid to maintain pressure control of the well.

Pressure control is, to a lesser degree, maintained by the fluid's frictional pressure losses during circulation. However, when there are small margins between the wellbore pressure and the formation pressure, fluid friction in the form of equivalent circulating density (ECD) can provide the difference needed to maintain the control of a well.

### Environmental Concerns

When using any drilling, completion or workover fluid, concerns about how the specific fluid selected interacts with the environment must be considered. There are concerns about human health issues as well as the potential damage that might be caused to the local wildlife, waterfowl, fish and vegetation. The environment is one of our most precious resources, but it can be damaged by most of the fluids used in (or produced from) an oil or gas well. Regulatory agencies mandate actions to prevent and report spills.

Many of the fluids used in well intervention work can be hazardous to personnel. Acids, caustics, bromides, some chlorides and other chemicals can cause serious burns. They can also be toxic and cause vision and respiratory problems. Extreme care and proper safety clothing, gloves and eyewear should be used when handling and mixing these fluids. Personnel who handle and mix the fluids should have safety training for the specific types of fluids to be used.

### Fluid Loss Control

An appropriate fluid for use in well-work operations must be selected with consideration for the fluid loss into an exposed formation. In this context, the fluid loss is not due to the fracturing of the exposed formation, but is, instead, due to seepage of the fluid into the formation. Often called filtration loss, it is a measure of the relative amount of base liquid in the working fluid lost to the formation, due to overbalance pressure. Historically, the control of fluid loss was most important in drilling operations, where drilling muds with high solid content have been used. In a permeable formation, the overbalance pressure squeezes whole mud against the wellbore wall, where the solids cannot pass but, instead, form a filter cake. The filter cake is a layer of mud solids that provides resistance to the flow of mud into the permeable rock. The drilling mud can be formulated to provide well designed, thin layers of filter cake that will minimize fluid losses. Thick layers of filter cake might be effective for preventing losses from the liquid phase of the working fluid, but they can cause sticking of the drill string, work string or coiled tubing string that is used in the well.

Mud engineers use the API filter press to measure base fluid (water) loss and determine the characteristics of the filter cake that will form. A typical API filter press is shown in figure 6.1a. First, a sheet of standard API filter paper is loaded into the bottom of the test chamber. Then, a sample of whole mud is poured into the chamber and gas pressure of 100 psig is applied. After 30 minutes, the fluid losses are measured in milliliters after the filtrate is caught in a graduated cylinder. The excess liquid is drained, the cap is opened, and the thickness of the filter cake on the filter paper is carefully measured. The results are reported as fluid loss per 30 minutes, and the thickness of the filter cake is measured to the nearest 1/32 inch.

For fluid applications in a well with a high bottomhole temperature, the API also recommends the use of the standard API high-temperature, high-pressure filter press. Not all personnel involved in well servicing or snubbing operations need to be familiar with this piece of equipment. However, the individual designated as the “mud engineer” should be familiar with its operation, if the bottomhole temperatures are abnormally high.

Clear brines are often used as completion fluids. These fluids have little or no solid content and can easily enter permeable formations. Lost circulation can be a tricky and costly well problem at any time. The fact that it can also increase the potential for a kick means it is doubly important for the crew to be alert when the pit volume or return flow from a well changes unexpectedly.

Figure 6.1a. A typical API filter.

Figure 6.1b. An API high-temperature/high-pressure filter press.

### Minimize Formation Damage and Corrosion

In completion operations, the goal is to complete, without damaging the formation, before it is evaluated and produced. In a workover operation, the goal is to conduct the well intervention without damaging the formation. Therefore, water, oils, gases or brine fluids are typically used and selected for the specific well conditions. With these fluids, there are no solids in the fluid to plug up pore spaces in the producing zone. However, there is no way to minimize fluid losses with water, and there is very little opportunity to limit fluid losses with brines. So, these fluids must be carefully selected so that they are compatible with the producing formation. It is important that the selected fluid will not cause permanent damage to the productive zone by leaving silts, fines, sludge, gum or resins in the formation. Formation erosion can also occur if a high pump rate is used. Freshwater can create flow-blocking emulsions in some gas/oil formations. Fluids with high water loss may swell sensitive formations, reducing permeability within the wellbore (skin) as a result of fluid invasion into the wellbore reservoir rock. This damage is called *skin damage*.

Give consideration to the fluids that are left in the hole, such as packer fluids. They should be non-settling and non-corrosive. The expected life of the well often dictates which type of packer fluid is selected. During remedial activities, the packer fluid is sometimes diluted, altered or replaced. If the fluid is not properly treated, it might become corrosive. This can jeopardize the expected life of the seals and other equipment in the well. Corrosive fluids can also lead to the failure of sealing elements on many types of surface equipment. Sand-laden fluids can be abrasive too. They can erode and cut valves and other equipment within even a short circulating period.

There are three major classifications of liquids used as the basis for working fluids in workover operations: (1) water-based fluids, (2) oil and synthetic oil-based fluids, and (3) emulsions and suspensions. A common fluid for well intervention operations is water. Water is selected when a fluid density of 8.33 ppg is ideal for the operation, since there is little or no chance that the formation will be negatively impacted by swelling clays or other interactions that water might have with the formation. Water might be used as an inexpensive kill fluid when these favorable conditions exist.

In well servicing operations, muds are generally reserved for drilling, (well deepening, drilling horizontal drain holes or milling operations) where good cutting transport is needed. Muds are primarily water-based or seawater-based, but often diesel oil or synthetic oil is required to make up the base fluid in the formulation of a mud. Muds contain solids that are used to enhance the viscous properties and increase the density of the fluid mixture. The solids primarily found in mud are (1) bentonite or a polymer that increases the viscosity and solid suspension capabilities of the fluid, and (2) barite, which increases the density of the fluid.

To mix a water-based mud, it is important that the mixture is developed with continuous mixing and agitation, as the materials are added. Prehydrated bentonite formulated from seawater, and a mixture of bentonite and freshwater, should be created prior to adding the seawater and barite. However, it is essential to hydrate and disperse the clay platelets that make up bentonite. (Saltwater will not allow the effective hydration of the clay particles.) The dispersed clay platelets later attach themselves, edge to edge, in a process called flocculation. This provides the fluid with the suspension capability to add barite and increase the fluid density. A high degree of flocculation produces a gelled fluid with high viscosity. The addition of certain chemicals (deflocculants) to the highly flocculated mixture will cause the fluids to thin or deflocculate. With these basic materials and mixing principles, the density and viscosity of a fluid can be tuned to provide the characteristics that are needed. The density and viscous properties of the mud should be monitored continuously, both during mixing and field application.

## Characteristics of Water-Based Fluids

Most drilling fluids are shear-thinning. So, the faster they move, the thinner they become. There is no one true viscosity for shear-thinning fluids. For example, the fluid moving upward around the bottomhole assembly will have a lower viscosity than the fluid moving more slowly up the larger annulus around the drill string. When bentonite fluids move, they flow freely, but when the movement stops, the fluid thickens and forms a gel-like structure. This tendency to thicken as the movement slows is called *thixotropy*. When drilling, circulation has to stop now and then, as when making a connection. The thixotropic nature of the mud prevents bit cuttings from falling back around the bottomhole assembly.

Field personnel usually think of viscosity in terms of Marsh funnel viscosity. The Marsh funnel is found on nearly all rigs along with a mud balance (mud scale) and a sand content kit. These items are the primary rig site tools used to test the mud.

Calcium bentonite, called a sub-bentonite, is also used as a viscosifier. Sub-bentonites do not yield or disperse in freshwater to the same degree that high-quality sodium bentonite does.

Although the Marsh funnel is useful, mud engineers use an instrument called a rotational viscometer or VG meter, which is portable and rugged enough for field use. The VG meter applies force to a sample of the fluid at any of various speeds. Two flow properties are determined: the plastic viscosity (PV) and yield point (YP). The gel strength can also be determined using a VG meter. The relative viscosity of the mud at these two points is the result of the percentage of solids in the mixture and the chemical attraction between the particles in the solids. The mud engineer makes some of his treatment recommendations, based on these tests.

Plastic viscosity is a reflection of the solids content (both desirable and undesirable) in the mud.

The greater the solids content is, the higher the PV will be. The yield point represents a force (lb/100 $ft^2$) and is a reflection of the electrochemical attraction between the solids particles in the mud. It can be seen that the YP and gel strength are closely related, and the more perfectly that mud solids are dispersed in the fluid, the lower the YP and gel strength.

As the fluid is circulated down the drill string or work string and back up the annulus, it is subject to various conditions that affect its properties. It must tolerate the increased downhole pressures and temperatures, while carrying the drilled cuttings back to the surface. In fact, the mud returning at the flow line is not the same as the mud in the suction pit. Mud engineers perform a variety of tests on the fluid that guide them in making recommendations for mechanical and chemical treatments aimed at reconditioning the mud before it is pumped back into the well. The goal is to build volume as the well is deepened, while maintaining the stability and performance of the fluid.

Water-based muds are very sensitive to sudden changes in downhole conditions. If formation fluids enter a well unintentionally, the properties of the whole mud can change dramatically. In the case of water flows, especially saltwater, major changes to the flow properties are likely.

The water will dilute the mud, causing it to lose density, and the salt content of the invading fluid will cause a chemical base exchange in the bentonite particles. The solids will flocculate, meaning they will gather together in "flocks." When this happens, the mud becomes very thick in the area of the influx and perhaps loses its ability to support barite. The PV is likely to decrease, but the YP will increase dramatically. When circulation is stopped and the blowout preventers are closed, the fluid will form a thick, progressive gel. When saltwater first enters the well, the circulating pressure will likely decrease, as a result of the relatively low density of a saltwater influx. However, more pressure might be needed to resume circulation, in order to overcome the high gel strengths caused by flocculation.

In the case of a gas kick, the extreme low density of the gas is likely to cause a greater decrease in circulation pressure than a water kick. There is usually an increase in the salinity associated with formation fluids, but a highly dispersed, chemically treated mud can minimize the bentonite's tendency to flocculate.

### Brines

For most operations other than drilling or milling, the solids carrying demands on the fluid are less. However, the need for cleaner fluids with little potential for damaging the exposed formation is increased. *Brines* are ideal for these operations, because they are essentially mixtures of water and salt. The salt will be chosen according to the density requirement and the potential for corrosion of the downhole equipment. Brines are readily available and easily mixed, and they are generally low in cost. Brines are different from muds, in that adding salts to water does not increase the solids content of the fluid because the salts are dissolved (up to their saturation limit). So, brines are very effective for increasing density and hydrostatic pressure, without adding solids. Unfortunately, brine fluids can pose environmental hazards in some areas.

Brines can be developed from simple, inexpensive sodium chloride (NaCl). Unfortunately, in most reservoir formations, sodium chloride is only slightly more effective than freshwater as an inhibitor to clay swelling. Brines can be designed to minimize the damage to an exposed formation by using calcium chloride ($CaCl_2$) or potassium chloride (KCl), either by using these salts as the weighting agent or as additives to other salts used to form the brine water fluid. When very heavy kill fluids are required for well intervention, the use of calcium bromide ($CaBr_2$) salt or zinc bromide ($ZnBr_2$) salt can be used to create kill weight fluids greater than 15 ppg. Table 6.1 illustrates the range of densities that can be achieved with various brine intervention fluids.

Table 6.1 Fluid Densities Achievable in Multiple Brines.

| Fluid Densities | | | |
|---|---|---|---|
| Fluid Density | Approximate Minimum Density | Approximate Maximum Density | Practical Maximum Density |
| | ppg | ppg | ppg |
| Oil | 6.0 | 8.5 | 8.0* |
| Diesel Oil | 7.0 | 7.0 | -- |
| Fresh Water | -- | 8.3 | -- |
| Sea Water | 8.4 | 8.6 | 8.5 |
| Brine Sodium Chloride (NaCl) | 8.4 | 10.0 | 9.8 |
| Brine Potassium Chloride (KCl) | 8.3 | 9.8 | 9.7 |
| Brine Calcium Chloride ($CaCl_2$) | 11.0 | 11.6 | 11.5 |
| Brine Calcium Bromide ($CaBr_2$) | 11.7 | 15.1 | 14.6 |
| Brine Zinc Bromide ($ZBr_2$) | 15.2 | 21.0 | 19.2 |
| * Some oils will sink to the bottom | | | |

Once the brines have been mixed and stored in surface tanks for application downhole, the density of the fluid should be constantly monitored. This is not because the salts settle out but instead because certain salts are hygroscopic. This is a term used to describe a brine fluid's ability to absorb moisture from the atmosphere, which reduces its effective density. Heavier brines are more affected by this process. Sacks of weighting salts should be kept on site, and the mixture density should be continually monitored and corrected when needed.

Brines are a good choice for packer fluids because there is no settling of solids over time. However, brines can be corrosive to certain materials such as compounds and metals. The compatibility of the brine and the completion equipment exposed to the brine should be checked during the planning of the application.

### Gels

*Gels* are fluids that behave quite differently from most of the fluids used in workover operations. As the name implies, a gel becomes thick and very viscous when static, but after circulation begins, the gel type of structure breaks down and flows more easily. The purpose of a gel is to provide a fluid in the well that will support solids and prevent their settling when circulation stops.

A fluid is considered to be a gel when it has high "gel strength." Technically, this means the fluid has a high value of yield point (YP), which is measured in pounds per 100 square feet (lb/100 $ft^2$). It is an indication of the electrochemical attraction among particles in a fluid. The greater this attraction is, the "thicker" the fluid becomes and the better the solids in the liquid can be suspended.

Gels are often designed to be temporary in nature. They are thick and viscous, so they can transport solids in the form of slug or slurry to a specific point in the well, after which they break down and allow the solids to settle. One use of this type of gel is to transport proppants (usually sand grains) into a fracture created during well stimulation. Gels also allow the liquids to move out of the fractures into the wellbore, when the surface pressures are decreased.

### Stimulation Fluids: Acids and Carbon Dioxide

Acids and solids, together with solvents, make up another class of fluids used in stimulation operations. These fluids are mainly used to improve productivity. The scale or paraffin in a producing well is often removed by pumping acid or solvents down the tubing string to the area that needs treatment.

The dissolved scale and spent treatment fluid are then circulated from the well. The chemical treatment used depends on the type of scale or paraffin that clings to the inner wall of the production tubing. It may be hard to ensure thorough treatment if the scale thickness or composition varies along the axis of the production tubing.

The disadvantage of chemical treatments for scale is that large pieces of scale are often freed from the wall. These large pieces are hard to circulate out of the well unless high velocities are achieved.

Workover units are often used for cleaning areas of the wellbore/reservoir interface that have become clogged and are limiting production. Acid or a chemical wash is pumped down the tubing and applied across selected intervals such as perforations, sand screens or open-hole completions. Often, a high-pressure rotary jetting tool is run on the BHA of the coiled tubing string to ensure complete coverage of the wellbore/reservoir interface. Hydrochloric acid (HCL) is the most commonly pumped acid. Surfactants and chemical solvents are pumped in some cleanup operations.

It should be noted that acids shorten the life of a work string or a coiled tubing string. Carbon dioxide ($CO_2$), which occurs in formation fluids, forms carbonic acid in the presence of water. This acid is corrosive to tubing. Any brine in the fluid streams exposed to $CO_2$ creates an acid that is more corrosive to tubing.

It is important that a corrosion inhibitor is run with acids so that damage is minimized. Pumping acid can ultimately lead to pinholes in the tubing and become a hazard to personnel. Handling acids is hazardous, and all personnel involved must be aware of the issues regarding the specific acid or chemical solvent that is used. When acids are pumped into a work string, the string should be flushed with a corrosion-inhibiting fluid as soon as it is practical to do so.

Carbon dioxide ($CO_2$) is often used in stimulation operations. Historically, these applications generally involved injection of liquid ($CO_2$) from dedicated field injection wells to displace crude oil from reservoir rock and to gather the displaced oil in nearby producing wells. For many years, carbon dioxide has been used to successfully enhance productivity in an oil field. More recently, carbon dioxide gas has been found to be effective in the matrix acidizing of individual wells. Experience has shown that, in sandstone formations, oil wells respond to matrix acidizing differently than gas wells do. For oil wells, the improvement in permeability resulting from the acid stimulation peaks as the volume of acid is injected and then drops as the volume of acid injected increases. For gas wells, however, the resulting improvement in permeability is roughly proportional to the volume of acid injected, and it is normally much better than what is achieved in oil wells. It has been found that displacing the oil in the near wellbore area to be stimulated, with carbon dioxide gas prior to acidizing the zone, can enhance the overall results. Nitrogen gas can also be used to accomplish this "preconditioning," but carbon dioxide is considered to be a more effective gas for this application.

Liquid carbon dioxide is often used to convey proppants in fracturing operations. Liquid carbon dioxide is a cleaner conveying fluid for proppants than gels. The liquid carbon dioxide is handled at the surface, as a liquid at approximately 200 psi and -30 °F, which is not considered cryogenic. Blending equipment, designed specifically to inject sand grains (proppant) into the liquid carbon dioxide, is employed, and the mixture is pumped into the well at these pressure/temperature conditions. After the fracture of the formation and upon heating to the reservoir temperature, the liquid carbon dioxide will vaporize. The carbon dioxide gas will then flow back into the well, creating a low-pressure gradient to initiate well production and leave a much cleaner, more permeable, flow path for oil than a gel-type proppant fluid can.

### Oil-Based and Synthetic Oil-Based Fluids

Oil (crude oil) can be used as a wellbore fluid for many applications. In most producing areas, oil is plentiful and economical to use. It is usually non-corrosive and will not cause clay swelling in a producing zone. Oil is also light, at less than about 7.0 ppg, so it is excellent for working in low pressure oil wells. Some precautions to observe when using oil are:

- Oil can contain wax, fine sand particles or asphalt.
- Oil may be corrosive if hydrogen sulfide or carbon dioxide are present.
- It may be too light to maintain a static well in some wells but too heavy in others.
- Oil is a fire hazard, and it is an environmental pollutant, if spilled.
- It may not always be compatible with reservoir oil, if from another well.
- Oil should never be used in a gas well.

Diesel oil and kerosene are sometimes used. Both are more expensive and potentially hazardous, but they are cleaner and less corrosive than crude oil. Proper fire-extinguishing equipment should be readily accessible, and the entire workover crew should be trained in the use of that equipment. Synthetic oils have been developed and made available for application. Generally, these synthetic oils are less harmful to the environment. Synthetic oil is a lubricant that has been chemically synthesized from compounds other than crude oil. Synthetic oils are much cleaner, being free of waxes, sand particles and asphalts. Generally, though, synthetic oils are too expensive for most applications.

### Characteristics of Oil-Based Fluids

Oil muds usually have lower viscosity than water muds of the same density. The PV values are approximately the same as for water-based fluid, but the YP and gel strengths are lower. Water additions to oil muds increase the viscosity, while additions of oil cause it to decrease. Mud engineers are especially concerned with the stability of the emulsion, so volume is usually built by gradually adding pre-mixed whole mud to the system.

Gas kicks in oil-based muds can be dangerous because of the solubility of gas into the continuous oil phase. The volume of the influx can be deceptively low when the kick enters the well at bottomhole pressure. Circulation pressure may not be seriously affected at that time. However, when the kick is circulated up the annulus where hydrostatic pressure is less, the gas will expand rapidly to many times its original volume, making control difficult.

Liquid kicks taken in oil-based fluids can break or "flip" the emulsion. The water may break completely out of the oil. In this case, the fluid can separate into three layers : the barite and drill solids on bottom, the water above the solids, and the oil at the top. Such a separation will complicate the well control situation dramatically, making it hard to regain control of the well.

### Emulsions and Suspensions

The most common emulsion fluid is oil in water. With oil in water, oil is the dispersed phase and exists as small droplets. The continuous phase can be either freshwater or saltwater. Stability of the emulsion depends on the presence of one or more emulsifying agents (starch, soap or organic colloids). Diesel oil is normally used as the dispersed phase. The advantage of using diesel in a workover application is that it is less damaging to the formation than crude oil.

The reverse of the oil-in-water emulsion is the water-in-oil emulsion. In a water-in-oil emulsion, water is the dispersed phase, and oil is the continuous phase. Fluids of this type have very low filtrates (fluid loss rates) and any filtrated fluid is oil. This mixture is generally unstable above 200 °F. If these fluids are laden with solids (e.g., suspended solids), when they become unstable, the solids can fall out of suspension and cause the plugging of the exposed producing zone.

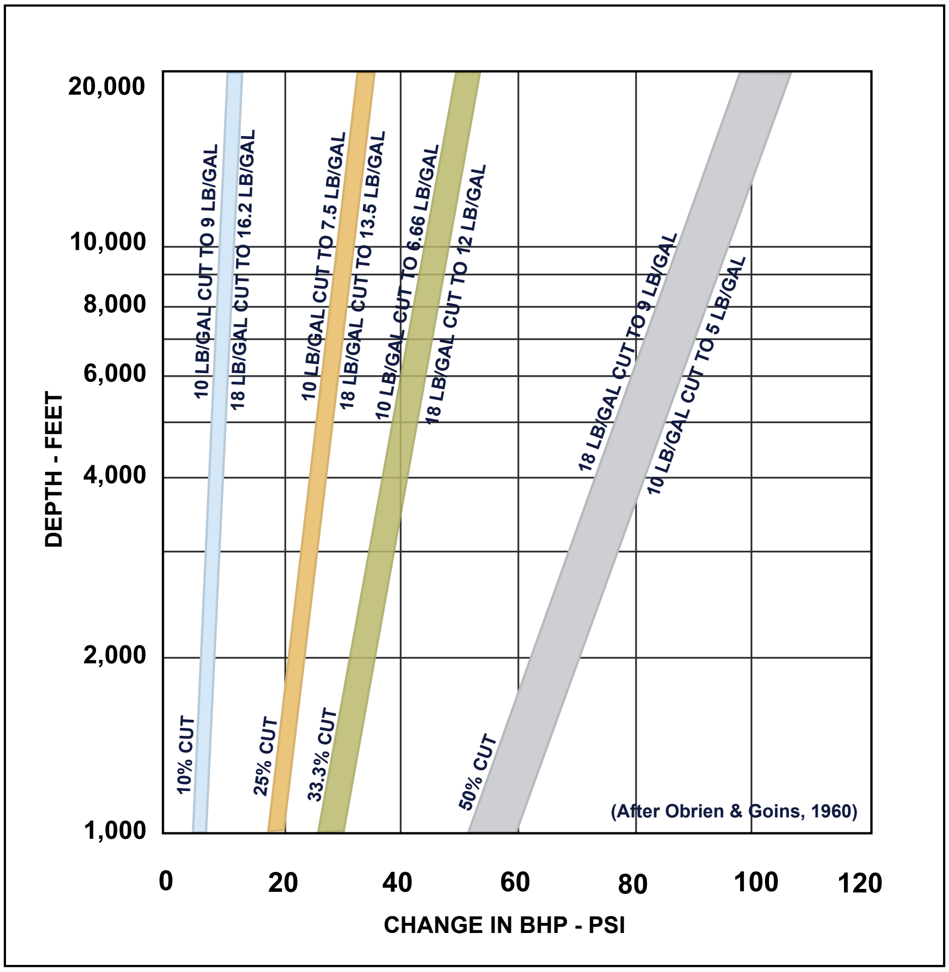
Water-in-oil emulsions are frequently used in workover drilling operations. The water phase is often modified with the use of polymers, such as potassium chloride (KCl), in order to minimize any tendency of the water phase to cause clay swelling when exposed to a producing formation or a shale zone. By adding additional chemicals to the water phase, and adding solids to the oil phase, drilling muds that are fine-tuned to the requirements of a specific application can be created. In recent years, synthetic oils have been used as the oil phase, producing more environmentally acceptable drilling muds. These muds can remain stable up to 400 °F.

## Gas-Cut Fluid

When the density of circulating fluid returning at the flow line is reduced due to tiny bubbles that are entrained in the fluid, the fluid is said to be gas-cut. The gas-cutting of a fluid or mud, even if it seems to be severe, usually will not cause a major reduction in bottomhole pressure. However, a small volume of gas at the bottom of a well can cause a large reduction in the apparent density at the surface. Nearly all of the gas expansion occurs as the liquid reaches the atmosphere. The chart in figure 6.2 illustrates the effect on bottomhole pressure from gas-cut fluid. Note that in a well 20,000 feet deep, with the density cut by 50 percent on the surface, bottomhole pressure is only reduced by about 100 psi.

Increases in gas-cut mud are important warning signs, but usually there is no problem as long as the gas is removed from the fluid before its pumped back into the well. Gas cutting can be significant when drilling is rapid, especially at shallow depths. It is possible to load the annulus with gas if the drilling rate is so fast that the mud cannot be circulated and conditioned before it returns to the pump suction. Generally, once the surface casing is set, the problem is minimized.

Figure 6.2. Change in bottomhole pressure due to gas-cut fluid.



## Nitrogen Gas

Nitrogen is used extensively in coiled-tubing operations, in virtually all regions of the world. For convenience and reliable delivery at the well site, liquid nitrogen is most commonly used. In regions of the world where liquid nitrogen is impractical or unavailable, air compressors and nitrogen-gas separation units are used. Such systems are maintenance-intensive and deliver relatively low rates.

Nitrogen has many applications in well completions and servicing operations. Some of them are listed below:

- Unloading wells
- Fracture proppant transport
- Washing sand
- Dry perforating
- Setting hydraulically set packers

Nitrogen handling equipment consists of:

- A storage vessel (cryogenic tank)
- Pumping system
- Gasifier (generally a heat exchanger)
- Necessary controls for equipment operation

## Safety Issues and Nitrogen Pumping Equipment

Nitrogen is a chemically inert gas, but liquid nitrogen and its conversion to gas are extremely hazardous. Liquid nitrogen is a cryogenic material, with a boiling point of -320 °F at atmospheric pressure. The liquid nitrogen is stored and transported in specially constructed stainless-steel tanks, which can withstand the extreme cold. Generally, such a tank is constructed in the form of an inner tank with an outer tank (shell). A vacuum between the two serves as an insulator. There are venting devices in the tank, with gauges and rupture discs to prevent pressure buildup inside the tank or the shell (outer tank). Extreme care must be exercised when transporting a tank of liquid nitrogen. Sudden jolts, shocks or vibration can cause the inner tank to break its support with the outer shell.

Any significant spillage of liquid nitrogen within the outer shell can cause it to vaporize more rapidly than it can be vented, and a cryogenic vessel will burst with an explosive force.

The process of working with liquid nitrogen presents a significant hazard to body tissue. So, it requires special *personal protective equipment (PPE)* and safety procedures. The PPE must not allow any liquid nitrogen to contact and freeze or burn the skin. Handling and containment of a fluid that quickly converts to a large volume of gas must be done with caution. For example, should a hose or a short section of line pipe containing liquid nitrogen be trapped by the closure of valves at each end, the ambient heat and absence of insulation will cause the line pressure to build rapidly. So, the transfer hoses and equipment used to link the nitrogen tanks for liquid transfer and pumping must be managed and operated with great care. Also, the sudden spillage of liquid nitrogen onto the ground can create a low-oxygen environment in a low-lying area. The sudden venting and bleed-down of gaseous nitrogen creates hazards associated with extreme noise and a high-velocity gas stream.

Liquid nitrogen must be gasified before it is injected into tubing or a work string for downhole circulation. A high-pressure pump, built for cryogenic operations, pumps the liquid into a gasifier unit, where the expansion occurs in a controlled manner, and gaseous nitrogen is routed to a manifold, for injection down the tubing string.

### Injecting Single-Phase Gas

Many operations involve the injection of gas only. This is called *single-phase gas injection*. The primary application of nitrogen gas is to bring a well on line to production by "unloading" the well.

The process of using nitrogen to unload a well is also a quick, cost-effective method to regain sustained production. A wellbore that has a fluid column with sufficient hydrostatic pressure to prevent reservoir hydrocarbons from flowing into the well can have its fluid column lightened by the displacement of some of the fluid with nitrogen gas. This reduction in bottomhole pressure makes it possible for the reservoir fluid to flow naturally into the wellbore. This process is sometimes called "well kickoff," or "kicking off a well." In many situations, the well will continue to flow even after nitrogen injection ceases.

There are many benefits associated with the use of nitrogen gas injection in a well unloading operation. This is because the rate and depth of the nitrogen injection can be adjusted to fit a wide range of field conditions. Nitrogen injection also provides a way to deliver an uncontaminated sample of formation fluids.

### Multi-Phase Nitrogen Services

Nitrogen gas can be mixed with a liquid stream to provide other nitrogen services. Well cleanout operations can be executed using foams or nitrogen/gelled-fluid stages. Acids can be nitrified for improved treatment and cleanup efficiency. Treatment fluids can be atomized at the surface to enhance the mixing of nitrogen gas with the liquid phase. An atomizing tee is installed where the gas stream and the liquid stream meet. The gas is used to agitate the liquid acid or treatment fluid as it mixes with the gas.

Nitrogen gas can be commingled with various fluids, to create a range of mixtures or staged treatments that are very effective in treating hard wellbore conditions. For example, pumping alternating stages of gelled fluid and nitrogen gas can create a downhole condition where sand and debris are entrained in the gelled fluid, while the nitrogen stages help maintain a low annulus pressure. This makes cleanup more efficient.

It is better, in some cases, to create a foamed fluid to carry debris from the wellbore. Foams are extremely effective at carrying solids and will carry a higher load of solids per volume than any other fluid mixture. However, the efficiency of the foam is limited to a relatively narrow band of foam quality. Foam quality is defined as the ratio of the total gas volume per total volume of the mixture. The foam quality must be maintained throughout the wellbore to ensure the stability of the foam and the effective transport of solids to the surface. Because the gas volume of the foam changes with the wellbore pressure, the foam quality changes (gas volume ratio increases) as the foam moves up the wellbore. When foam approaches 100% quality, it becomes unstable and breaks down, losing its ability to transport solids. There will be a significant risk of sticking a work string or coiled tubing in the well if the foam system only transports the solids to another section of the wellbore before it breaks down.

## Fluid Properties: Concerns and Measurement Methods

### Density

For the purpose of well control, density is a measure of how heavy a fluid is per unit volume. In oil field applications, density is stated in pounds per gallon (ppg) or, in international units, kilograms per cubic meter ($kg/m^3$). Fluid density, along with the vertical depth into a well, determines the hydrostatic pressure.

The worksite instrument used to measure the density of a working fluid in workover applications is called the *mud balance*. However, most field workers refer to this instrument as a "mud scale" because they use it to "weigh the fluid." Generally, the mud balance is used by the "mud engineer" or "mud man" in drilling operations, but in workover applications, nearly all crew members use the instrument from time to time. It should be noted that there are some good practices to follow when checking the working fluid density, and of course there are bad practices to avoid.

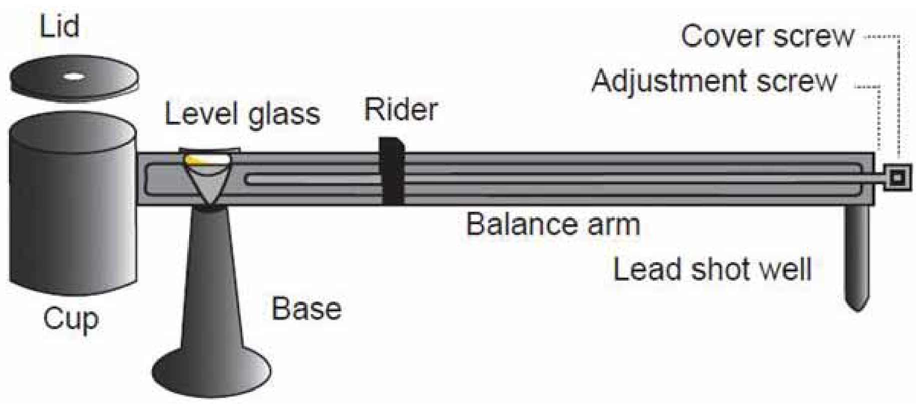
An illustration of a mud balance is provided in figure 6.3. A typical mud balance has four density scales scribed into the metal. Density can be directly measured in pounds per gallon, pounds per cubic foot, psi per 1,000 ft, and specific gravity (SG or sp gr)). Specific gravity is the ratio of the density of the fluid to the density of freshwater. On the lower end of the scale, near the cup, there is a long, deep mark. If the balance is correctly calibrated, this mark represents the density of freshwater at 70 °F. The balance should be frequently checked for accuracy by weighing a sample of clean freshwater. This calibration check should also be made after the instrument has been dropped or handled roughly.

The person responsible for the upkeep of the balance should note any slight inaccuracies and then adjust (calibrate) with the adjustment screw at the far end, so that correct weights are reported.

If the instrument is so far out of calibration that the adjustment screw cannot make it read the sample of freshwater correctly, it may be tempting to force the calibration by adding or removing the "shot" inside the cover screw. (On the far right end of the balance, there is a chamber inside a cap screw. The chamber is filled with various sizes of shot for fine calibration.) It is not a good idea to try to add or remove shot at the well site. If the mud balance carries an error that cannot be zeroed out with the adjustment screw, it should be replaced and recalibrated by the manufacturer.

The hole in the cap (the lid of the cup) is bored out to a precise diameter. It must be kept clean for accurate weighing. It should never be reamed or bored out to a larger diameter. The balance is usually made of aluminum and will oxidize when exposed to air. This oxidation forms a thin layer of aluminum oxide film, which protects the aluminum from corrosion. The formation of the layer is

Figure 6.3. Details of a mud balance.



self-renewing when exposed to air, so that scrapes or small gouges will be protected from corrosion by the reformation of that layer of aluminum oxide. The only real maintenance required to keep a mud balance in good condition is to make sure it is clean and dry when not in use.

To weigh the working fluid, catch a sample and pour it into the dry, clean balance cup until the cap overflows freely. This is to ensure that the cup is full to the brim and to expel any trapped air. Wet the cup lid with some of the working fluid, and then slide it slowly and gently over the cup. The only expulsion of fluid should be through the hole in the lid. Once the lid is firmly in place, block the hole with a thumb and thoroughly wash and dry the entire cup and balance arm. Slide the counter-weight to the far right end of the balance arm, and place the knife edges of the arm on the pedestal (base).

Looking only at the sight glass (level), slide the counterweight slowly toward the cup until the bubble in the sight glass is centered. Read the fluid density from the appropriate scale.

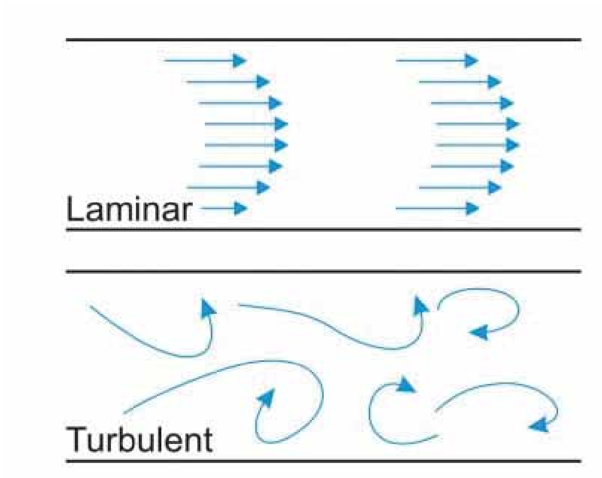
A pressurized mud balance is very useful in applications where there is likely to be entrained air or nitrogen in the working fluid sample. For workover applications, this is an excellent instrument for measuring the liquid-phase fluid densities, when nitrified fluids or foams are used. The volume of space occupied by entrapped or entrained gas or air bubbles in a working fluid may distort the accuracy of fluid density measurement. So, pressurizing the fluid in the "mud cup" can significantly reduce this distortion. Pressure is created with The injection of a small additional amount of the fluid mixture into a sealed cup volume creates pressure. The pressurized fluid density balance is similar in operation to a conventional mud balance. The only difference is that the fluid sample in the fixed volume cup is pressurized. Screw the lid onto the sample in the cup, and place the sample under pressure with a simple plunger attached to the lid. After application of pressure by injecting additional fluid sample with the plunger, a check valve holds the sample under pressure and the plunger is removed.

The sample is then weighed exactly the same as the conventional balance does.

## Viscosity

The viscosities of many working fluids can be very complex. Viscosity is a measure of a fluid's resistance to flow or shearing, which is the function of one layer of fluid moving at a velocity different from the layer immediately adjacent to it. As a fluid moves along a solid surface, such as the inside wall of tubing or a work string, the fluid immediately touching the wall does not move. The fluid farther from the wall moves faster, approaching its maximum at the centerline of the tubing. The distribution

Figure 6.4. Laminar and turbulent flow.



of velocity within the tubing is called the velocity profile. The viscosity of a fluid influences the shape of the velocity profile. The shape of the velocity profile also depends on whether the flow is laminar or turbulent. Laminar flow generally occurs at low average velocities and high viscosities, where one layer of fluid slides smoothly and parallel to the adjacent layer. Turbulent flow usually occurs at higher average velocities and lower viscosity, where the fluid layers tend to mix. In engineering terms, viscosity is the property of a fluid that describes the internal resistance of fluid particle motion relative to adjacent fluid particles.

Very high gel strength and/or viscosity are undesirable properties of a fluid. Gel strength and viscosity are important factors in the running or pulling of a work string or a string of tubing. Sudden movements of the tubing string, in a gelled fluid, lead to changes in bottomhole pressure, which can produce surge or swab effects. Fluids with high viscosities also cause surge and swab pressures on the bottom of the well. The operator should know the gel strength and viscosity of a fluid prior to running a work string or tubing into a well. Similarly, very low gel strength is an undesirable fluid property because solids will settle when circulation ceases.

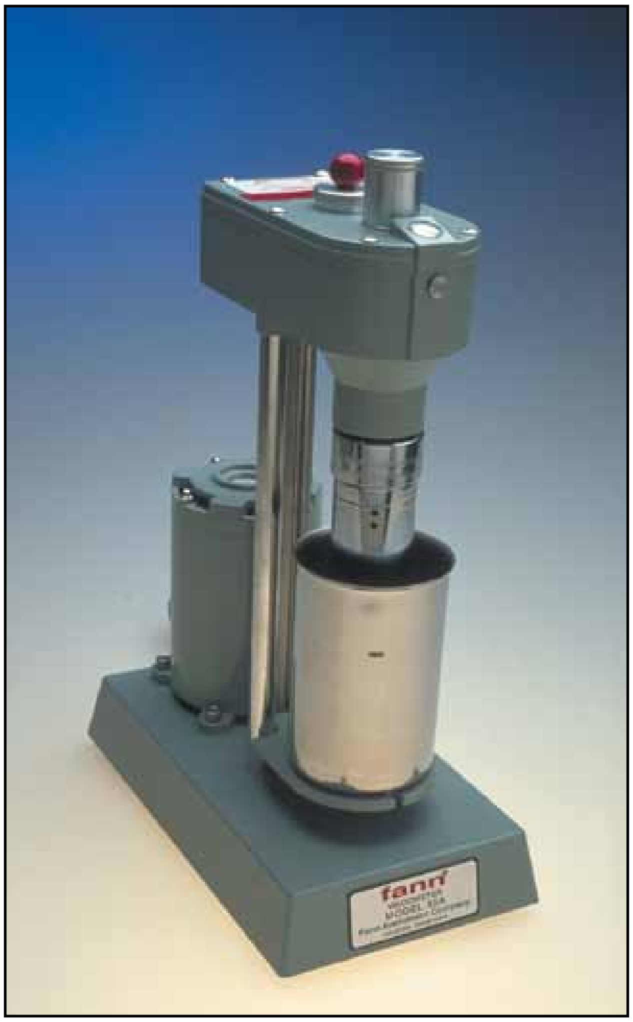
When field personnel think of viscosity, they often think in terms of marsh funnel viscosity. The Marsh funnel is an instrument used to obtain a representative value of fluid viscosity. The Marsh funnel, like the mud balance, is a standard portable oil field instrument. It is very simple, as we can see in figure 6.5. The funnel is filled with the working fluid. The time required for a volume of fluid to drain through the funnel into a graduated cup is measured and defined as the viscosity, which is reported in seconds. Normally, it takes a quart of clear water 26 seconds to flow through the Marsh funnel. However, the Marsh funnel is useless in treating fluids for excessive viscosity.

Figure 6.5. A Marsh funnel.


A rotational viscometer (Fann V-G viscometer, or “rheometer”) is also portable and rugged enough for field use. A typical rotational viscometer is illustrated in figure 6.6. It measures the rheology of the fluid, meaning that it determines the viscosity at multiple levels of shearing stress. The rotational viscometer applies a shearing force to the test sample at various rotational speeds. Two flow properties are measured: the plastic viscosity (PV) and the yield point (YP). The PV, which is measured in centipoises (cp), is an indication of the viscosity of the fluid during circulation. The YP is measured in lb/100 $ft^2$, and is an indicator of the gel strength of the fluid. With these values, the mud engineer knows, for example, that gel strength might need to be improved so that it can prevent solids from settling, or that the viscosity during circulation is too high. These are much more useful pieces of information about the rheology of the fluid. An increase in solids in an oil field fluid will increase the PV, while an increase in bentonite in a water-based fluid increases the yield point (YP). The plastic viscosity (PV) of a typical working fluid measured with a rheometer (rotational viscometer) is similar to the viscosity of a Newtonian fluid of equivalent density. A Newtonian fluid is a fluid (such as water) that has a constant viscosity, regardless of any external stress, such as mixing or a sudden application of force, such as pumping.

Viscosifiers are chemicals that can be used to increase the viscosity of a fluid. Commonly used viscosifiers include bentonite, attapulgite clays, polymers such as hydroxyethyl cellulose (HEC), capillary electro chromatography (CEC) and polysaccharide. Viscosity reducers are lubricants that can be added to a fluid to decrease the circulating friction and pressure loss. These lubricants are often polymers that adhere to the surface of the tubing and reduce the attraction of solids to the wall of

Figure 6.6. Rotational viscometer for measuring viscosity and gel strength.



the tubing. Often the removal of unnecessary solids and the addition of water (or oil) can effectively reduce viscosity. Thinners are chemicals that reduce the yield point of a fluid. Among them are lignosulfonates, lignins and tannins. Other inorganic thinners include sodium acid pyrophosphate (SAPP) and tetrasodium pyrophosphate.

## Alkalinity and Acidity (pH)

The acidity of a fluid is a measure of the hydrogen ion (H+) concentration relative to that of clean, pure water. Fluids with a lower hydrogen ion concentration than freshwater are acidic, fluids with a higher hydrogen ion concentration than freshwater are alkaline. The alkalinity of a fluid is a measure of how well the fluid can neutralize the acidity of a fluid. Acidity is measured in terms of pH. The pH scale is 1 to 14. The pH of pure clean water is 7.0. An acid fluid will have a pH less than 7.0. The higher the acidity (or lower pH+ concentration) is, the lower the pH level will be. High acidity (low pH) increases the corrosion of metals in contact with the fluid. Therefore, a pH of 1.0 is extremely acidic and a pH of 14 is very alkaline. Each integer unit of pH represents a value of acidity that is 10 times that of the next higher integer. In other words, a pH of 5.0 is 10 times more acidic than a pH of 6.0. Conversely, a pH of 9.0 is 10 times more alkaline than a pH of 8.0.

In working fluids, the pH is generally maintained greater than 8.0. This is necessary to provide a reserve of H+ ions, in the event that hydrogen sulfide or carbon dioxide gases are encountered during the well intervention process. Typically, if these gases are expected, the pH of the working fluid is generally maintained at approximately 10.5. In other words, the working fluid is sufficiently alkaline to manage an influx of gases that create acidity in the fluid. Caustic soda (NaOH) and potassium hydroxide (KOH) are two chemicals that can be added to increase the alkalinity of a working fluid and increase its pH. The pH of a fluid is often measured with color-coded paper, but a pH meter is more accurate.

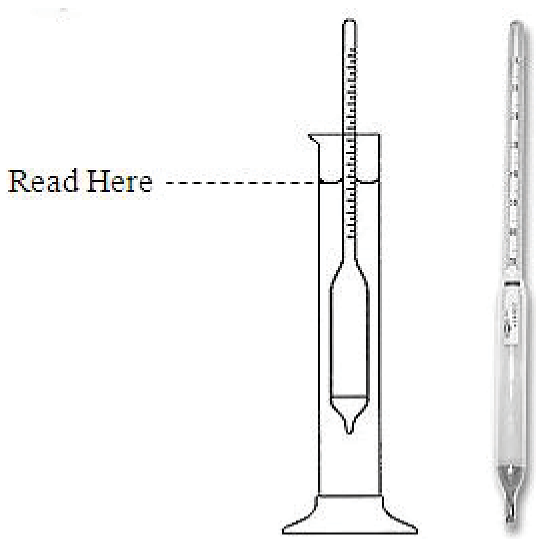
A pH meter, an electronic instrument, is used to measure the acidity of a liquid with a glass probe (electrode) connected to an electronic meter, which measures the activity of hydrogen ions surrounding the glass bulb. The activity produces a small voltage, generally 0.06 volts per unit of pH.

The instrument is designed and calibrated so that 0 volts yields a pH reading of 7.0. Negative voltages represent pH readings below 7.0 (acids), while positive voltages correspond to pH readings above 7 (alkaline fluids).

## Hydrometer

Specific gravities of brine fluids are measured with a hydrometer, in degrees. A hydrometer measures specific gravity, not pounds per gallon. A hydrometer has an attached thermometer and a temperature correction chart on the back to correct the measured density to the standard 60 °F. A hydrometer reading is taken by looking at a scale (contained in the stem) where the top of the liquid is being measured.

Figure 6.7. Hydrometer.



## Other Rheological Concerns

### Effects of Temperature on Density and Viscosity

The density of a fluid is affected by both pressure and temperature. Base liquids, such as water and oil, are considered incompressible in most oil field applications. However, under the application of extreme pressure, the volume occupied decreases and there is a very slight increase in density. Oil, water, and brines are more greatly influenced by temperatures, over the range of typical well operations. For example, the density of freshwater at 68 °F is 8.33 ppg, decreasing linearly with temperature to a value of 8.05 ppg at 240 °F. The density of a 10 ppg $CaCl_2$ brine at 68 °F is only 9.7 ppg at 240 °F.

The viscosity of liquids is greatly affected by temperature, but is essentially independent of pressure (except for very high pressures). For example, the viscosity of freshwater at 68 °F and atmospheric pressure is 1.0 cP. (This is the definition of centipoises (cP).) The viscosity of the same sample of freshwater at 240 °F and atmospheric pressure is only 0.2 cP. A sample of 10 ppg $CaCl_2$ brine water at 68 °F has a viscosity of 1.80 cP. This sample of brine at 240 °F is has a viscosity of 0.33 cP. Hence, it is obvious that temperature cannot be neglected when estimating the viscosity of a fluid. Fluid densities should be measured within 10 °F of the same temperature (because temperature affects density) to make the density reading more accurate. Completion brine density changes with temperature; the density must be adjusted so that the brine will have hydrostatic pressure to balance the formation pressure, at a specific depth.

### Settling of Solids

The viscous properties of a fluid must be correctly tuned to the mission of the operation. If solids are to be transported in any significant quantity, provisions must be made for maintaining a yield point, YP, high enough to ensure there is sufficient gel strength to prevent solids settling when circulation ceases, but yet have a low PV to provide a low friction pressure loss while circulating. In addition, the fluids must be able to maintain the gel properties when heated, if circulation is suspended when the fluid is solids-laden near the bottom. Solids settling can lead to stuck tubing, high friction, inability to run to bottom in a high-angle well, and formation damage due to plugging.

Settling barite or other fluid weighting agents may cause density changes.

Fluid solid settling occurs when:

- The fluid is not circulated or is circulated slowly.
- Fluid gel strength is not sufficient.
- Logging
- Casing is run.
- Using oil-based or synthetic-based drilling fluids

### Crystallization

Often a brine fluid mixture contains all the salt material that water can hold at given temperature. This is called the saturation point. No additional fluid weight can be obtained and yet keep the liquid free of solid salt particles. Should more salt be added, with the temperature held constant, one of two things will happen:

1. The excess salt minerals will fall to the bottom of the tank, or
2. Crystallization will occur.

Crystallization has the appearance of ice forming. Field personnel often call it *freezing*. Should the temperature of fluid in the tanks be reduced by change in weather or other effects, crystallization can occur. Crystallization can become a real hazard. Crystallization reduces not only the fluid density, but also its ability to be pumped. Temperature affects each brine in its own way. The chart in table 6.2 compares the crystallization points for three brine solutions.

Variations in the ratio of brines in the mixture and ratio of total brine to water in solution may affect the crystallization point drastically. Do not rely on charts in training manuals, but obtain actual charts from the fluid supplier, for a specific brine mixture.

When these types of working fluids are used in cold climates, steam coils or other heating source should be applied to the surface holding tanks. Long line sections should be insulated. Winter blends can be obtained, but they also increase the cost per barrel of the brine.

Table 6.2.

| Crystallization Point | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Sodium Chloride Brine | | | | Calcium Chloride Brine | | | | Calcium Chloride/Calcium Bromide Brine | | | |
| Weight | | Crystallization Point | | Weight | | Crystallization Point | | Weight | | Crystallization Point | |
| ppg | kg/m³ | °F | °C | ppg | kg/m³ | °F | °C | ppg | kg/m³ | °F | °C |
| 8.5 | 1,018 | 29 | -1.6 | 8.5 | 1,018 | 30 | -1.1 | 12.0 | 1,438 | 54 | 12.0 |
| 9.0 | 1,078 | 19 | -7.2 | 9.0 | 1,078 | 21 | -6.1 | 12.5 | 1,498 | 57 | 13.8 |
| 9.5 | 1,138 | 6 | -14.4 | 9.5 | 1,138 | 9 | -12.7 | 13.0 | 1,558 | 59 | 15.0 |
| 10.0 | 1,198 | 25 | -3.8 | 10.0 | 1,198 | -8 | -22.2 | 13.5 | 1,618 | 61 | 16.1 |
| -- | -- | -- | -- | 10.5 | 1,258 | -36 | -37.7 | 14.0 | 1,678 | 64 | 17.7 |
| -- | -- | -- | -- | 11.0 | 1,318 | -22 | -30 | 14.5 | 1,737 | 65 | 18.3 |
| -- | -- | -- | -- | 11.5 | 1,378 | 1.6 | 35 | 15.0 | 1,797 | 67 | 19.4 |

### Hydrate Inhibition with Fluid Design

The potential for hydrate formation can be decreased and perhaps eliminated by the use of an inhibitive fluid. An inhibitive fluid is a specially designed working fluid that contains materials that eliminate or at least reduce hydrate formation when conditions for hydrate formation are known to exist. Inhibitive fluids contain salts and glycerol that increase the "freezing point" (temperature) at which gas/water hydrates form in the fluid. Typical salt concentrations needed are 20 to 26 percent by weight. If greater inhibiting properties are required, up to 10 percent glycerol may be added.

# EQUIPMENT

# 7

## UPON COMPLETION OF THIS CHAPTER, THE STUDENT SHOULD BE ABLE TO:

- Discuss and answer questions about the operating principles of BOP ram type equipment.
- Discuss and answer questions about the operating principles of BOP blind/shear equipment.
- List the precautions to be taken when opening a valve under pressure.
- Describe how Christmas trees are pressure tested.
- Describe how Christmas trees are shut in.
- Explain why a bell guide would be used in preference to mule shoe guide.
- Describe the types of production packers.
- Describe how packers are set.
- Describe the primary function and positioning of landing nipples.
- List the reasons why tubing moves and the ways to mitigate.
- Explain how circulation devices are used and their placement in the production string.
- Describe the primary function, applications, and positioning of subsurface safety valves.
- Describe the procedure for equalizing and opening subsurface safety valves.

## COMPLETION EQUIPMENT

In general, a well completion should provide a production conduit which:

- Maximizes the safe recovery of hydrocarbons from a gas or oil well throughout its producing life.
- Gives an effective means of pressurizing selected zones in water or gas injection wells.
- Provides for routine downhole operations.
- Protects the casing from flowing well fluids.
- Contains reservoir pressure in well control situations.
- Allows the well to be killed prior to removing completion equipment.

Downhole accessories used should be designed to provide the safe installation and completion equipment retrieval, and flexibility for subsurface maintenance of the well using wireline, coiled tubing or other methods.

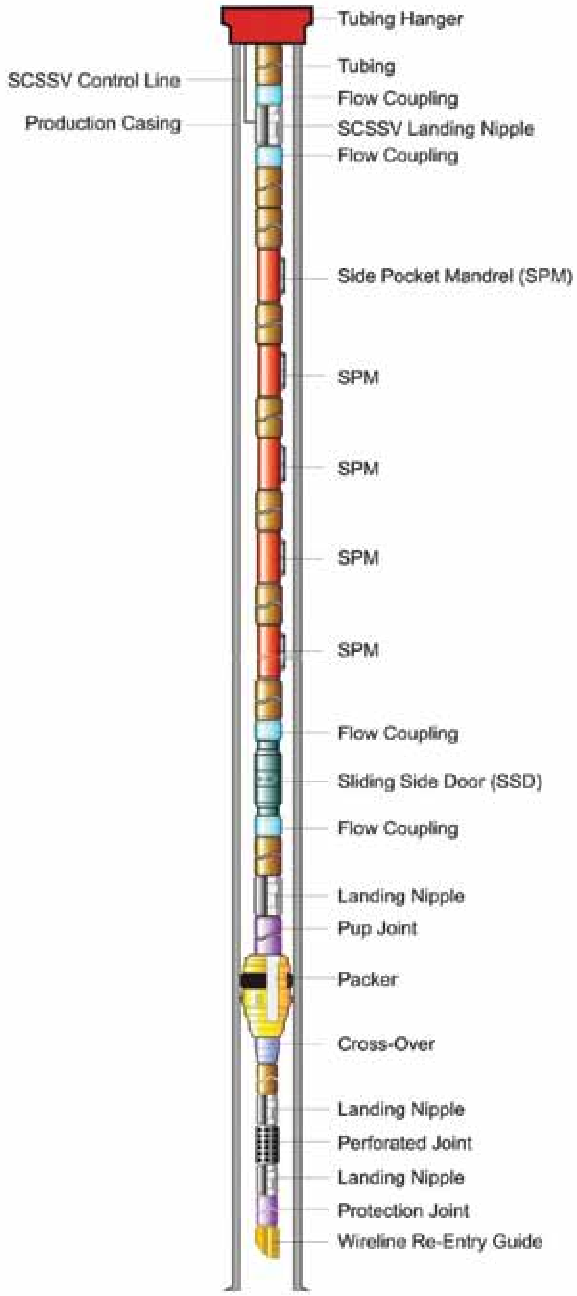
Different types of wells present distinct design and installation problems for engineers. Most completions are just variations on a few basic design types and, therefore, in the majority of cases, the equipment used is fairly standard. However, there is a move to more versatile and complex equipment as used, for example in smart wells, but that is beyond the scope of this manual. An overview of the equipment commonly used in single and dual string completions is given in the following sections.

The detailed operation of some the items such as *sliding side doors (SSDs)*, *side pocket mandrels (SPMs)* and packers will not be covered in this manual. However, the relative location of these tools in a completion and their functions in intervention work or workovers will be addressed.

Figure 7.1 shows a schematic drawing illustrating the location of equipment in a generic oil well completion.

In order to ensure compatibility between the manual and course lecture, the completion description will start from the bottom of the completion and work up the hole.

Figure 7.1. A generic well oil well completion.



## Wireline Reentry Guide

A *wireline entry guide* is used for the safe reentry of wireline tools from the casing or liner back into the tubing string. It attaches to the end of the production string or packer tailpipe assembly and, where possible, has a chamfered lead in with a full inside diameter.

Wireline reentry guides are generally available in two forms:

- Mule-shoe
- Bell guide

## Mule-Shoe

This type of guide would be second choice on any completion design. Essentially it has the same function as the bell guide but incorporates a large 45-degree angle cut on one side of the guide, (refer to figure 7.2a). It would only be used when the completion tailpipe has to be run into another packer, or past a liner hanger. Should the guide hang up on a casing item such as a liner or packer top while being run, rotation of the tubing will cause the 45-degree shoulder to "kick" into, and enter the liner or packer. This item has a very limited reentry chamfer, and has been known to cause severe reentry difficulties for tool strings in deviated wells.

## Bell Guide

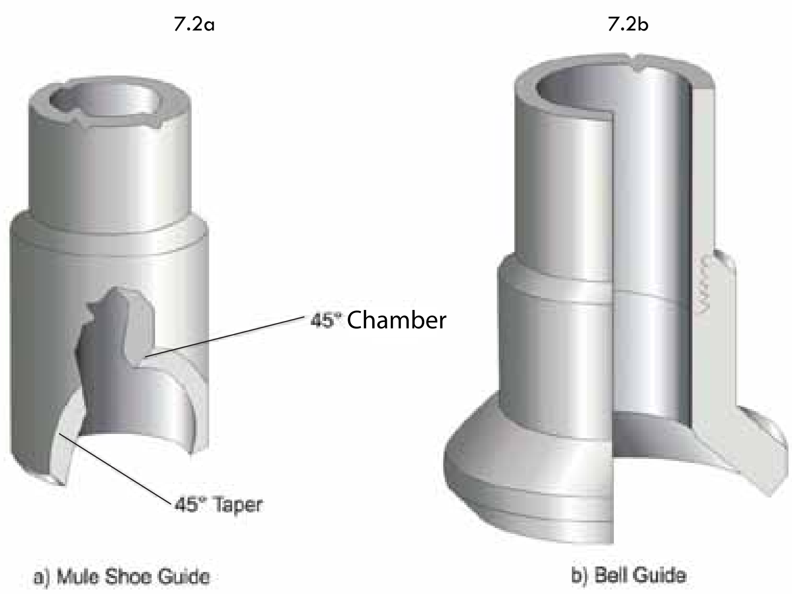
This guide has a 45-degree lead in taper to allow reentry into the tubing of wireline and coiled tubing tools, and would always be the "first choice" option. This type of guide, (refer to figure 7.2b), is used in completions where the end of the tubing does not need to pass through any casing obstacles such as liner laps.

*Excerpt from "Well Control for Snubbing Operations" manual by Well Control School*[1]

## Completion and Workover Tubulars

The primary tubulars of concern in completion operations are production tubing, casing and liners, and the work string (typically drill pipe but sometimes coiled tubing). These tubulars are typically

Figure 7.2. A wireline reentry guide.



subjected to axial loads (tension and compression), internal pressure loads, and external pressure loads that tend to collapse the tubular. Fortunately, a great deal of science and engineering has gone into the development of tubular goods for oil and gas operations.

### Burst Rating

The *burst rating* is the theoretical internal differential pressure at which a joint of tubing or casing will fail. Burst pressure rating is a key factor in well control contingency planning. The predetermined internal pressure differential is calculated in the absence of other loads on the tubing (axial, torsional, bending, etc.). Burst ratings for casing, tubing, drill pipe and coiled tubing have been calculated and tabulated in tables of the mechanical properties of the tubulars. API accepted formulas for the burst pressure of standard sizes, weights and grades (basic material and alloys) of casing and tubing are provided in API Spec 5CT[2]. The values of the burst pressure are also provided in handbooks distributed by the major well intervention service companies. Many of these service companies offer interactive websites so that the burst pressure rating for a specific type of tubing or casing can be determined over the Internet.

### Collapse Rating

The *collapse rating* equates to the burst rating. The collapse pressure rating is a predetermined "external-to-internal pressure differential" that will collapse the tubing or casing in the absence of other loads. Collapse ratings for all standard sizes, weights and grades of tubing and casing are provided in handbooks distributed by the major service companies. Many offer interactive websites to provide the collapse rating of a type of tubing or casing.

### Tubing Protection Joint

This is normally a single tubing joint, short joint or pup joint and is used to prevent downhole gauges from buffeting in the flow stream. The protection joint is installed directly below the gauge hanger landing nipple in the tailpipe and must be long enough to accommodate the longest BHP tool string that may be run.

### Torsion, Tension and Buckling

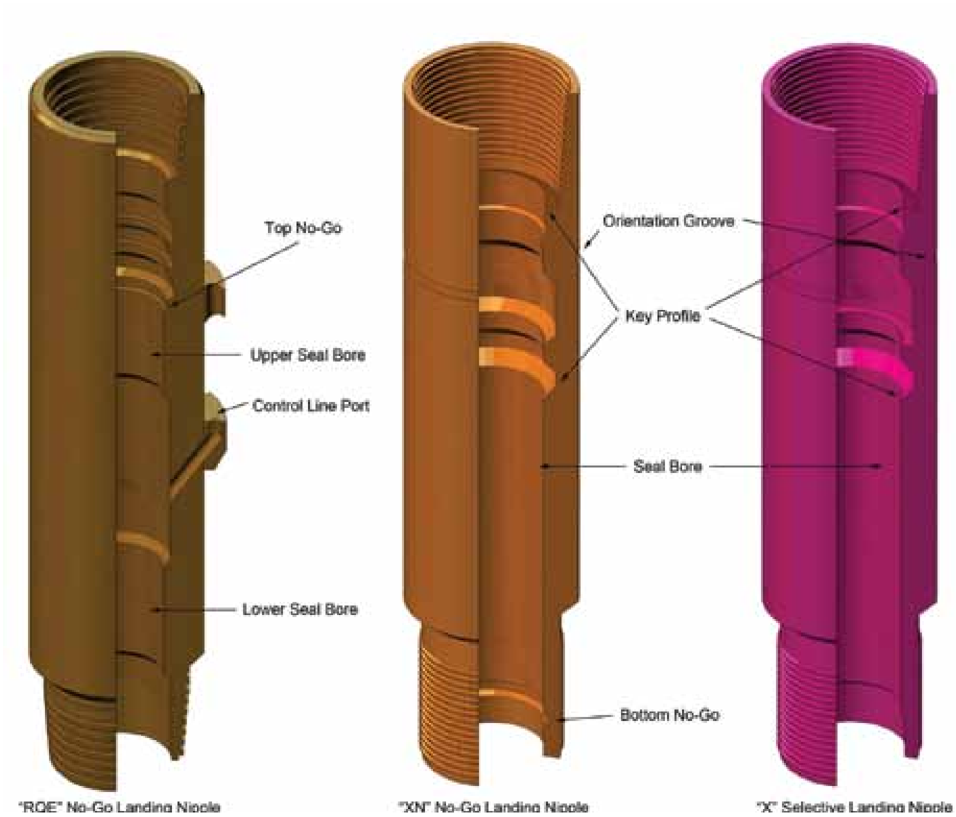
In addition to stresses generated by the application of pressure, tubing is subject to combined loadings due to pulling, pushing, twisting and bending forces. These loads induce axial, torsional and bending stresses in the tubing wall that should be combined with the hoop stresses induced by the applied pressures to determine the resultant stress. It is possible to calculate the resultant stress due to the combined loads (or stresses).

The API recommends that, for well control purposes, the combined stresses due to pressure and tension (axial) loads not exceed the working limits (80 percent of the yield strength) of the tubing, based on the measured material properties. The resultant stress due to pressure (hoop stress and radial stress) and axial stress is generally calculated using a *von Mises equivalent stress method (VME)*. The axial (tensile) stress at any point includes the stress due to (1) the simple axial force (push or pull) applied, plus (2) the axial stress due to bending, plus (3) the axial stress due to buckling. It is possible to include the stress due to twisting (torsional stress) in the VME, but not required by paragraph 5.2.1. of API RP 16ST.[2]

The von Mises equivalent stress calculation has many shortcomings. Among these are:

- Ovality is not considered
- Residual stresses are ignored (stresses in the tube with no loading)
- Cold working the material over time is ignored
- Diametrical growth is ignored
- Wall thinning

Figure 7.3. Typical wireless landing nipples.




## Wireline Landing Nipples

*Landing nipples*, (refer to figure 7.3), are short profiled tubulars installed in the tubing string to accommodate wireline retrievable flow control devices. These can seal within the nipple bore if required, dependent upon the tool's function. The most common tools run are plugs, chokes, and pressure and temperature gauges. The main features of a landing nipple are:

- Locking groove or profile
- Polished seal bore
- No-go shoulder (only on nipples that rely on a shoulder for device location).
- Landing nipples are supplied in ranges to suit most tubing sizes and weights with API or premium connections and are available in two basic types:
  - No-go or non-selective (or selective by a top or bottom shoulder)
  - Selective

### No-Go or Non-Selective

The *non-selective nipple* receives a locking device that uses a no-go for location purposes. This requires that the OD of the locking device is slightly larger than the no-go diameter of the nipple. The no-go diameter is usually a small shoulder located below the packing bore (bottom no-go) but in some designs, the top of the packing bore itself is used as the no-go. Only one no-go landing nipple of a particular minimum ID size should be used in a completion string.

The no-go nipple provides a positive location and is widely used in high angle wells where wireline tool manipulation is difficult and weight indicator sensitivity is reduced.

### Selective

In the *selective system*, the locking devices are designed with the same key profile as the nipples and selection of the nipple is determined by the operation of the running tool and the setting procedure. The selective design is full bore and allows the installation of several nipples of the same size and type. Selective landing nipples with similar profiles should be placed at least 30 feet from each other. Selective landing nipples with different diameters should be placed at least 10 feet from each other.

Uses of landing nipples are to:

- plug tubing from above, below or from both directions for pressure testing.
- detect leaks.
- install safety valves, chokes and other flow control devices.
- install bottomhole pressure and temperature gauges.

### Perforated Joints

In wells, where flowing velocities are high, a restriction in the tubing, such as a gauge hanger, can cause false pressure and temperature readings. Vibrations in the tool can cause extensive damage to delicate instruments. To provide an alternative flow path, a perforated joint is installed above the gauge hanger nipple to allow unrestricted flow around the gauge. The perforated joint is normally a full tubing joint that is drilled with sufficient holes to provide a flow area greater than in the tubing above.

### Packers

A *packer* is a primary safety device used to provide a seal between the tubing and the casing which allows well control. With a suitable completion string, this seal allows the flow of reservoir fluids from the producing formation to be contained within the tubing up to the surface. This isolates the production casing from being exposed to well pressure and corrosion from well effluents or injection fluids.

A packer is tubular in construction and consists basically of:

- Case hardened slips to bite into the casing wall and hold the packer in position against pressure and tubing forces.
- Packing elements that seal against the casing.

Figure 7.4 gives examples of typical packer installations and shows common types of packers. In general, packers are classified in two groups:

- Retrievable (refer to figure 7.5)
- Permanent (refer to figure 7.6)

Packers may be further classified according to the number of bores required for production, i.e.:

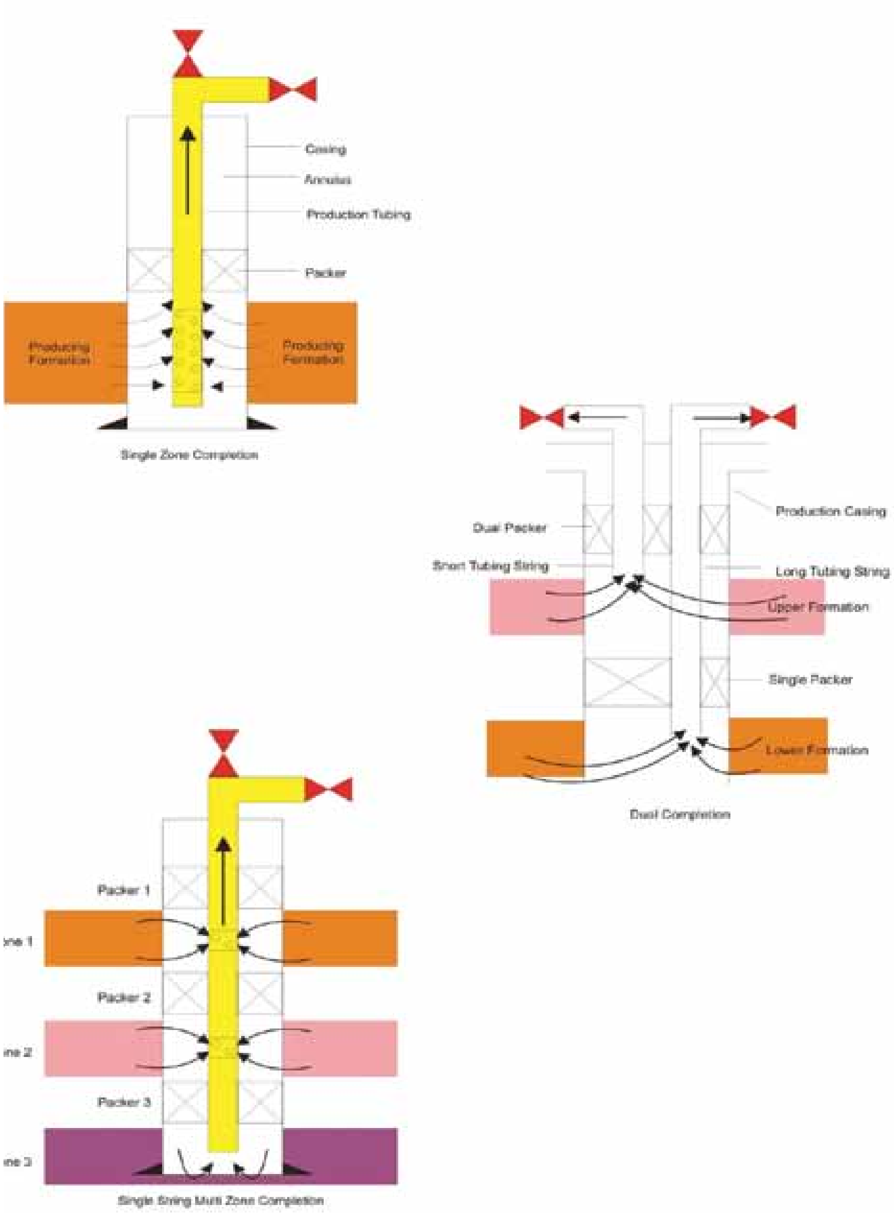
Table 7.1

| | |
|---|---|
| Single | One concentric bore through the packer for use wth a single tubing string |
| Dual | Two parallel bores through the packer for use with two tubing strings |
| Triple | Three parallel bores through the packer for use with three tubing strings |

### Retrievable Packers

These are often run into the wellbore on the production tubing string, but can also be set individually on wireline. As the name implies, retrievable packers can be recovered from the well after setting, by a straight overpull, usually around 40,000 pounds, with the tubing. Overpull is additional tension applied when pulling the tubing without breaking the tubing tensile load limit.

Figure 7.4. Examples of packer installations completion variations.



## Permanent Packers

These are installed in the wellbore either by wireline or coiled tubing, or as an integral part of the production tubing string. A permanent packer may also be considered as an integral part of the casing. Older type permanent packers can only be removed from the well by milling operations. However, more modern permanent packers can be retrieved by cutting the center mandrel with a chemical cutter, but these packers are not covered in this manual.

Figure 7.5. Examples of common types of retrievable packers.


## Setting Methods

### Mechanical

A mechanical packer is run on a work string, it is set by manipulation of the tubing, i.e., by applying compression or tension in combination with rotation, depending on the particular setting mechanism for that packer.

*NOTE: Packers having rotation set/release mechanisms should not be used in highly deviated wells since the application of tubing torque may not be transferred downhole.*

### Hydraulic

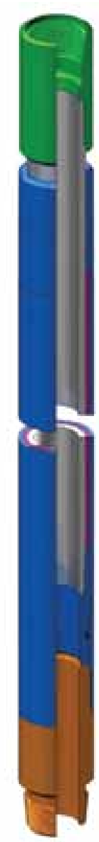
Hydraulic packers can be run on a work string or on the tubing string. When the desired setting depth is reached, the tubing is plugged below the packer with a check valve, standing valve or a wireline plug. Hydraulic pressure is applied to the tubing to set the packer.

Figure 7.6. Examples of common types of hydraulic packers.

### Electrically on Wireline

This is more commonly used with permanent packers, but retrievable packers, i.e., Perma-Trieve™, are also set with this method. The packer is attached to a wireline setting adapter, connected to a setting gun on the end of the wireline and run in the wellbore. On reaching the desired depth, an electrical signal transmitted to the gun activates an explosive charge and, through a hydraulic chamber, provides the mechanical forces to set the packer.

Figure 7.7.
Travel joint.



## Retrievable Packer Accessories

### Travel Joints (Telescoping or Expansion joints)

A *travel joint* is used to compensate for tubing movement due to temperature and/or pressure changes, which can cause a change in tubing length (shortening or lengthening), during testing, treating or production. Changes of tubing length can lead to increases in tubing compression or tension and may cause the tubing to fail or unseat the packer. Traveling joints are used with retrievable packer systems.

Figure 7.7 shows a travel joint commonly used on the short string in dual string completions. Some expansion joints may be locked in the open position to compensate for pipe movement when producing or treating, or in the closed position, when running in the packer before it has been set.

### Permanent Packer Accessories

An important part in a completion with a permanent packer is the tubing/packer seal. The packer, in effect, becomes part of the casing after it is set. The tubing must connect to the packer by a method that allows it to be released. This connection, whether it is a straight stab in, latched or otherwise, must have a seal to isolate the annulus from well fluids and pressures. This seal usually consists of a number of seal elements to allow for some wear and tear.

These seal elements are classified into two groups, "premium" and "non-premium". The premium group is used in high temperature and/or severe or sour well conditions, i.e., hydrogen sulfide, carbon dioxide, etc. These are normally "V" type packing stacks containing various packing materials resistant to the particular environment. The non-premium seals are for low to medium temperature and/or sweet service and can be either "V" type packing stacks or molded rubber elements.

#### Locator Tubing Seal Assemblies

Locator tubing seal assemblies and tubing seal extensions, (refer to figures 7.8a and 7.8b), are fitted with a series of external seals providing an effective seal between the tubing and packer bore. They also have a no-go type locator for position determination within the packer. Locator seal assemblies are normally spaced out so that they can accommodate both upward and downward tubing movement induced by changes in temperature, pressure and ballooning.

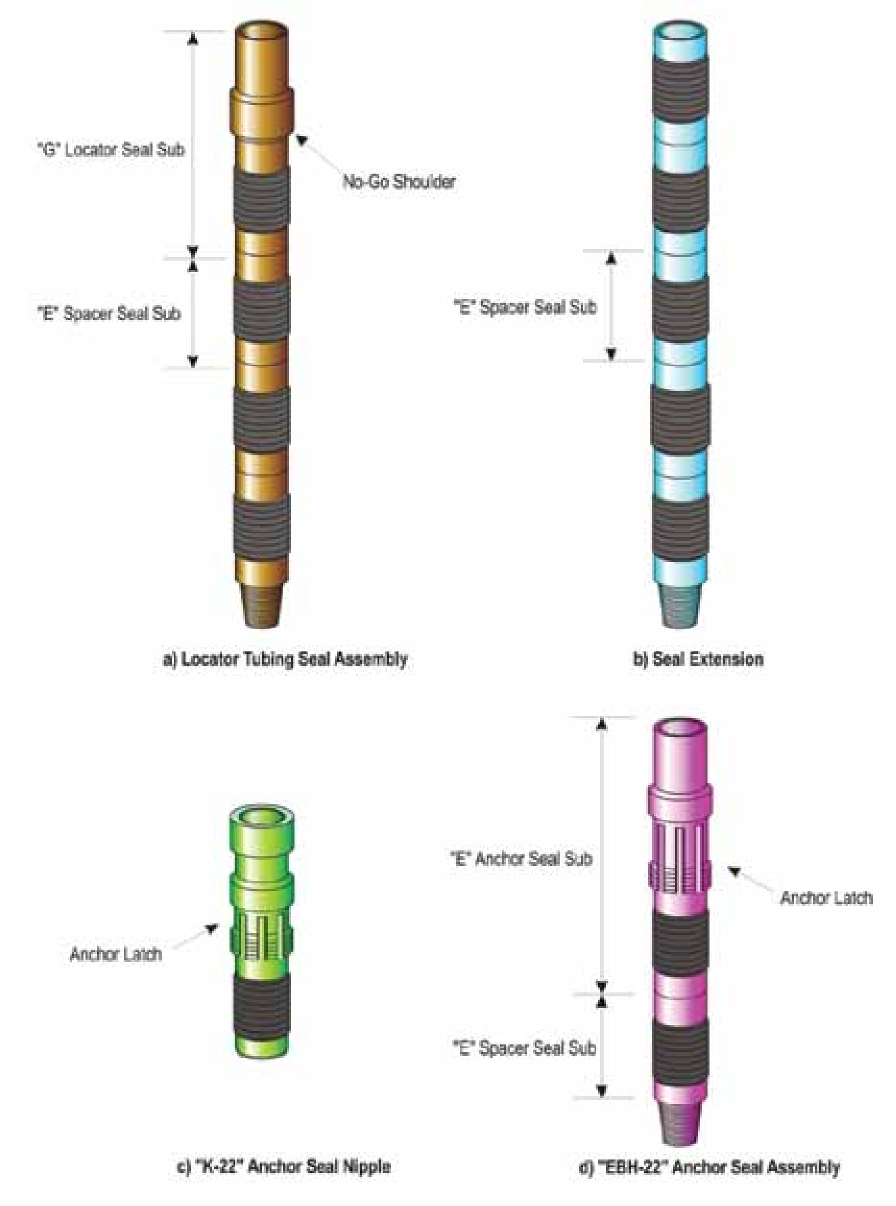
#### Seal Bore Extensions

A seal bore extension is used to provide additional sealing bore length when a longer seal assembly is run, to accommodate greater tubing movement. The seal bore extension is run below the packer and has the same ID as the packer.

#### Anchor Tubing Seal Assemblies

Anchor tubing seal assemblies, (refer to figures 7.8c and 7.8d), are used where it is necessary to anchor the tubing to a permanent packer while retaining the option to unlatch when required. Anchor latches are normally used where well conditions require the tubing to be landed in tension or where sufficient weight is not available to prevent seal movement.

Figure 7.8. Permanent packer seal accessories.



### Polished Bore Receptacles (PBRs)

A *polished bore recetable (PBR)* is simply a seal receptacle attached to the top of a permanent packer or liner hanger packer in which the seal assembly lands, to allow tubing movement compensation. As the PBR bore can be made larger than the packer, this provides a larger flow area through the seal assembly (refer to figure 7.9). A PBR is used in the closed position when setting a packer or line hanger. It is opened to allow tubing movement or to establish a circulating path from the production tubing to the annular area between the production tubing and casing.

Figure 7.9. Polished bore receptacle.

## Tubing Seal Receptacles (TSRs)

A *tubing seal receptacle (TSR)* is an inverted version of a PBR, whereby a polished OD male member is attached to the top of the packer and the female (or overshot) is attached to the tubing. The seals are contained in the female member so that they are recovered when pulling the tubing (refer to figure 7.10).

Figure 7.10.
Tubing seal receptacle.

## Sliding Side Doors

*Sliding side doors (SSDs)* or *sliding sleeves* are installed in the tubing during well completion to provide a means of communication between the tubing and the annulus, or across zones that may be selectively produced when the sleeve is moved to the open position (refer to figure 7.11).

SSDs are used to:

- bring a well into production after drilling or workover, by circulating the completion fluid out of the tubing, and replacing it with a lighter underbalanced fluid.
- kill a well prior to pulling the tubing in a workover operation.
- provide selective zone production in a multiple-zone well completion.

Sliding sleeves are usually positioned either above the uppermost packer, as a circulation device, or between two packers in multilevel reservoirs for selective production. The application of SSDs as a circulation device means they must be positioned as close as possible to the packer, normally within 100 feet. They are usually run in closed to allow for tubing tests and hydraulic packer setting.

Used for selective zonal production, a number of SSDs can be installed in a single completion string between isolation packers and selectively opened or closed by wireline or coiled tubing methods. Coiled tubing is generally used in high angle or horizontal wells where wireline tools cannot be jarred effectively.

SSDs are available in versions that open by shifting an inner sleeve, either, upwards or downwards, by the use of an appropriate shifting tool. Sliding sleeves can be jar-up to open or jar-down to open. When there are more than one SSDs in a well, the sleeves may be opened and/or closed with selective shifting tools without disturbing sleeves higher up in the string.

*CAUTION: Sliding sleeve valves have an equalizing position between the open and closed positions. A common problem with sliding sleeves is that they may be accidentally over shifted from the fully closed position to the fully open position without first equalizing the pressure between the annulus and the interior of the tubing. Tubing and annulus pressures must be equalized before an SSD is opened, to prevent wireline tools from being blown up or down the tubing.*

A common fault with SSDs is that seal failure usually leads to a workover, although a pack-off can be installed as a temporary solution. The top sub of the SSD incorporates a nipple profile, and the bottom sub has a polished bore. This enables the installation of the pack-off, sometimes also termed a *straddle*.

To test a sliding sleeve:

1. Rig up wireline or coiled tubing to set a plug in a landing nipple below the sliding sleeve.
2. Rig down wireline or coiled tubing unit.
3. Pressure tubing string up to 3,000 psi and hold for five minutes.
4. Slowly increase the tubing pressure to 4,500 psi and hold for 10 minutes.
5. Release the pressure.
6. Rig up wireline or coiled tubing to open the sliding sleeve using wireline or coiled tubing.
7. Unset the plug using wireline or coiled tubing.
8. Rig down wireline or coiled tubing unit.

Figure 7.11.
Sliding side door (SSD).

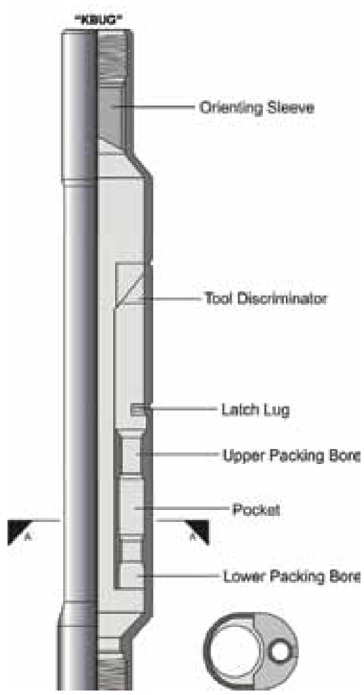
## Flow Couplings

*Flow couplings* are heavy-walled tubulars, which are installed above, and sometimes below, any completion component which may cause turbulent flow such as wireline nipples, SSDs, subsurface safety valves, etc., and delay the effects of internal erosion, thus prolonging the life of the completion.

They may be manufactured from harder materials and have a thicker external wall thickness so that, if erosion is experienced, the flow coupling will still maintain pressure integrity over the projected life of the well.

In higher velocity wells, such as high-pressure gas wells, injection wells, or in wells that produce sand or other fine particles, it is common practice to have flow couplings placed above and below restrictions.

Figure 7.12. A side pocket mandrel.




## Blast Joints

*Blast joints* are installed opposite perforations (non-gravel packed) where external cutting or abrasive action occurs, due to produced well fluids or sand. They are heavy-walled tubulars available usually in ten-, fifteen-, and twenty-foot lengths.

They should be long enough to extend at least four feet on either side of a perforated interval for a safety margin.

## Side Pocket Mandrels (SPM)

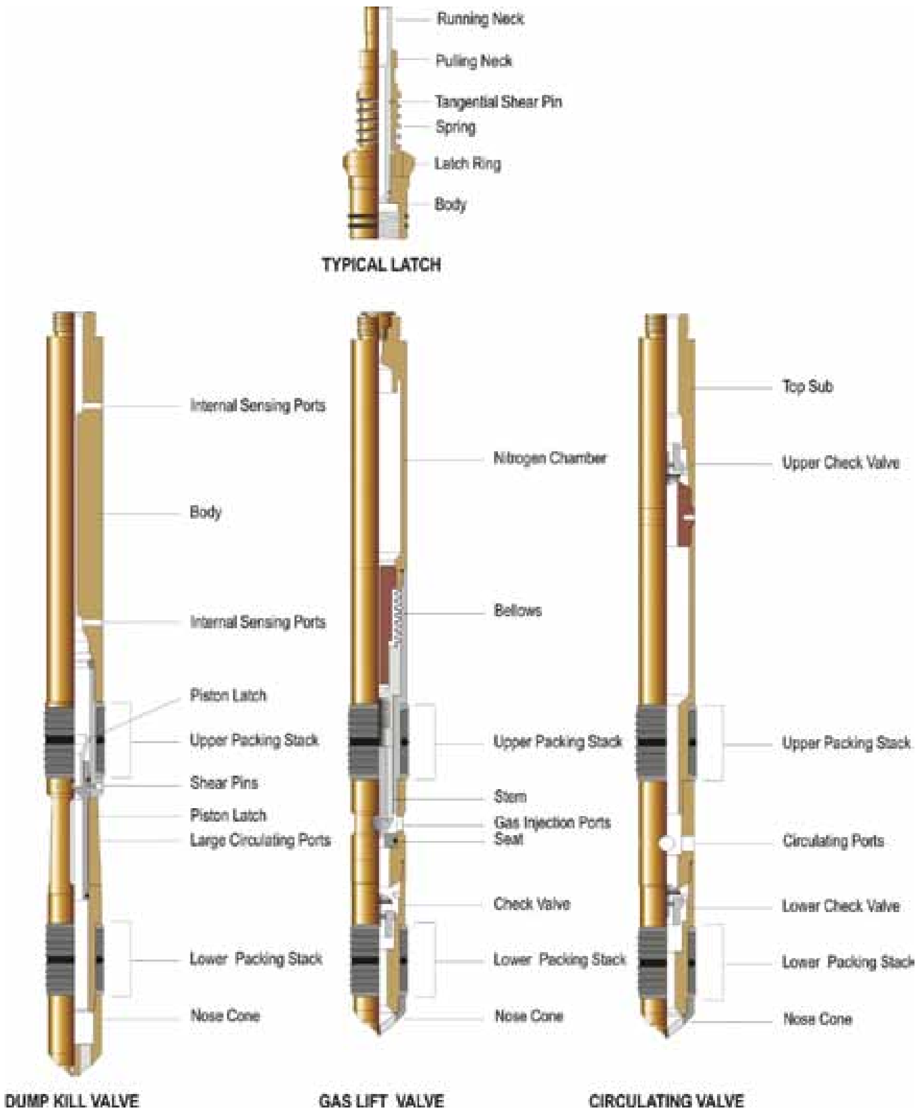
The *side pocket mandrel system* was originally designed for gas lift completions. They provide a means of injecting gas from the casing/tubing annulus to the tubing via a gas lift valve. However, in recent times, side pocket mandrels with dummy valves have been commonly used in place of an SSD as a circulating device because seal failure can be rectified by pulling the dummy gas lift valve (or kill valve) with wireline and replacing the seals.

SPMs are installed in the completion string to act as receptacles for the following range of devices:

- Gas lift valves
- Dummy valves
- Chemical injection valves
- Circulation valves
- Differential dump kill valves
- Equalizing valves

It is essential to understand the operation of the device installed in a SPM before conducting any well intervention, as it may affect well control. Refer to figure 7.12 for a typical SPM and figure 7.13 for types of valves.

Figure 7.13. Types of SPM valves.



### Gas Lift Valves

There are many different designs of *gas lift valves* for various applications. They range from simple orifice valves to pressure-operated, bellow-type valves. However, they all contain check valves to prevent tubing to annulus flow. These check valves may leak after a period of use and they should never be relied on as barriers in a well control situation. These should be replaced with dummy valves and the tubing pressure tested to confirm integrity.

### Dummy Valves

These are tubing/annulus isolation valves. They are installed in place of the valves so that the completion tubing string can be pressure tested from both sides, during installation or when well service operations are required.

### Chemical Injection Valves

The injection valve is designed to control the flow of chemicals injected into the production fluid at the depth of the valve. A spring provides the force necessary to maintain the valve in the fail-safe closed position. Reverse flow check valves, which prevent backflow and circulation from the tubing to the casing, are included as an integral part of the valve assembly.

Injection chemicals enter the valve from the annulus in an open injection system. (This requires the annulus to be full of the desired chemical. An alternate method is to run an injection line from surface to the SPM.) The valve opens when the hydraulic pressure of injected chemicals overcomes the preset tension in the valve spring, plus the pressure in the tubing. Chemicals then flow through the crossover seat in the valve and into the tubing.

### Circulating Valves

A *circulating valve* is recommended to be installed in any SPM whenever a circulating operation is to be carried out. The circulating valve is designed to enable circulation of fluid through the SPM without damaging the pocket. The valve allows fluid to be dispersed from both ends, allowing circulation of fluid at a minimal pressure drop. Some valves permit circulation from the casing into the tubing only and others to circulate fluid from the tubing into the casing only.

If a valve is not used when circulating, the pocket could be cut by the flow and a workover would be required to replace the SPM.

### Differential Dump/Kill Valves

*Differential dump/kill valves* are designed to provide a means of communication between the casing annulus and the tubing when an appropriate differential pressure occurs. Below a preset differential pressure, the valve acts as a dummy valve since it uses a moveable piston to block off the circulating ports in the valve and the side pocket mandrel.

The differential pressure necessary to open the valve will depend on the type and number of shear screws installed. The valve will only open when the casing annulus pressure is increased by the differential (of the shear screw rating) greater than the tubing pressure. An increase in tubing pressure greater than the casing annulus pressure will not open the valve. After opening, the piston is locked in the up position and fluids can flow freely in either direction. The hydrostatic pressure from the column of annulus fluid will kill the well and remedial operations can be planned.

## Equalizing Dummy Valves

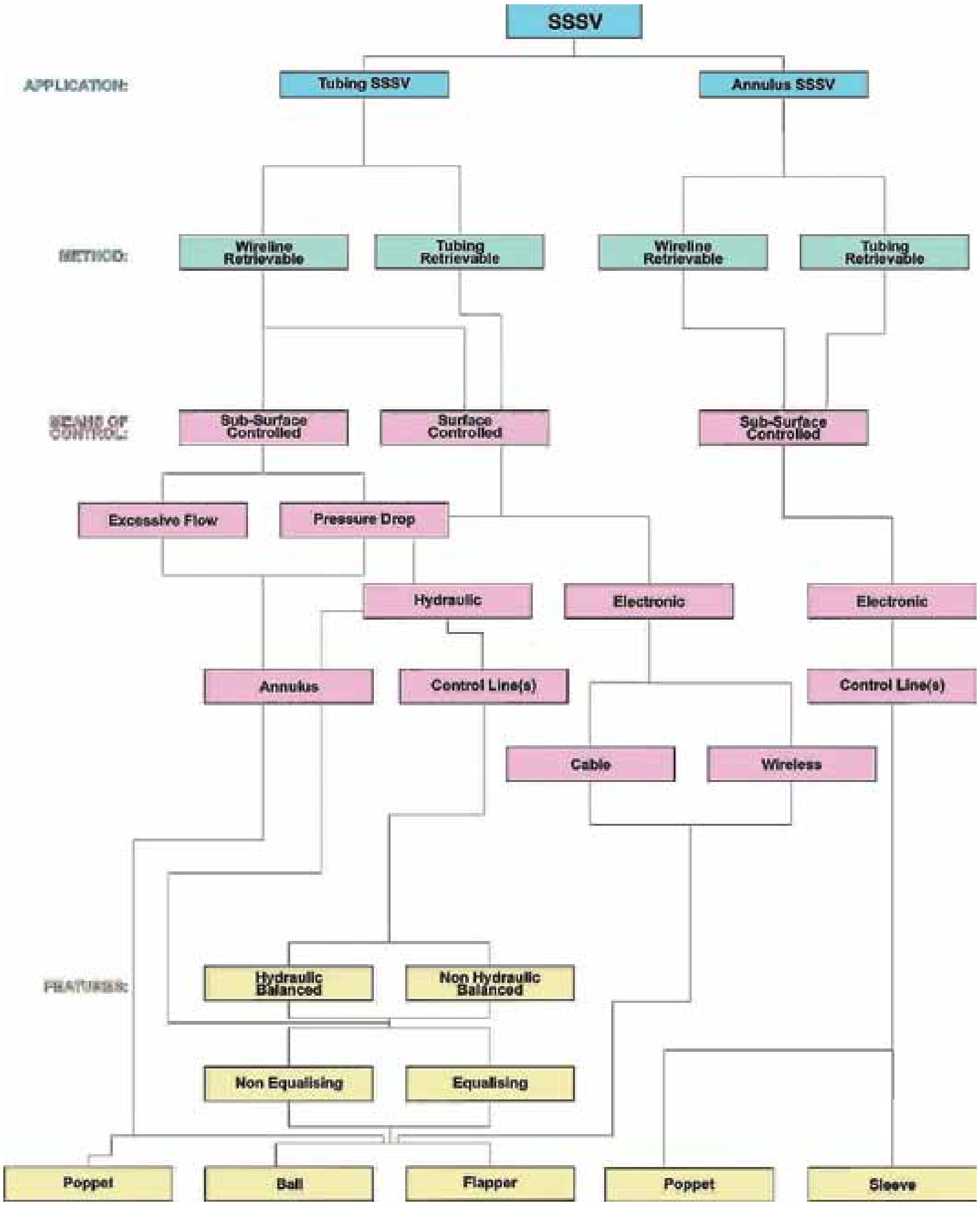
The equalization valve is designed to equalize pressure between tubing and casing and/or to circulate fluid before pulling the valve from the SPM.

The valve has two sets of packing that straddle and pack off the casing ports in the SPM. The tubing and annulus are isolated from each other until a pulling tool operates the equalizing device. Pressures equalize through a port before the valve and latch are retrieved.

## Subsurface Safety Valves (SSSV)

The applications of various subsurface safety valve systems are shown in figure 7.14.

Figure 7.14. A diagram of subsurface safety valve applications.



The modern subsurface safety valve has been developed from the earliest low technology versions produced in the 1930s. The initial demand was for a downhole valve that would permit flow during normal conditions, but would isolate formation pressure from the wellhead to prevent damage or destruction. This valve would be installed downhole in the production string for use in an emergency.

The valve that was developed was a subsurface controlled safety valve (SSCSV) which was a poppet type valve with a mushroom shaped valve/seat system. Compared with today's valves, this simple poppet type valve had several disadvantages: restricted flow area, tortuous flow paths, low differential pressure rating and calibration difficulties. Despite these limitations, the valve operated successfully and other versions were developed with less tortuous flow paths such as the ball and flapper valve. These valves have a long service record, and are commonly used today in such areas as the Gulf of Mexico USA and Nigerian Niger Delta. They are also used in the UK North Sea as an emergency valve on wells where control line integrity has failed. CFR 250.801, part D allows subsurface controlled valves to be installed in wells with a surface controlled safety valve that has become inoperable and cannot be repaired without removal and reinstallation of the tubing.

From this beginning, the surface controlled subsurface safety valve (SCSSV) was developed in the late 1950s. This moved the point of control from downhole to surface (refer to figure 7.15). This design provided large flow areas, remote control of opening and closing, and responsiveness to a wide variety of abnormal surface conditions (fire, line rupture, etc.). Initial demand for this valve was slow due to its higher cost and the problems associated in successfully installing the hydraulic control line; hence, its usage was low until the late 1960s.

The SCSSV is controlled by hydraulic pressure supplied from a surface control system, which is ideally suited to manual or automatic operation, the latter of which pioneered the sophisticated emergency shut-down systems required today. The versatility of the valve allows it to be used in specialized applications as well as in conventional systems.

SCSSVs are available in two variants - tubing retrievable safety valves (TRSV) and wireline retrievable safety valves (WRSV). SCSSVs are available with ball or flapper type closure mechanisms.

*NOTE: SCSSVs are set below any depth where damage could possibly occur to the valve from surface impact or explosion.*

## Types of Subsurface Safety Valves

Fail-safe subsurface safety valves, whether directly or remotely controlled, are installed to protect personnel, property and the environment in the event of an uncontrolled well flow (or blowout) caused by collision, equipment failure, human error, fire, leakage or sabotage. Whether safety valves are required in a particular operating area depends on the location of the wells and in some cases, on company operating policy and/or government legislation.

In general, each application must be considered separately due to varied well conditions, locations, regulations, depth requirements etc.

Table 7.2 shows the various applications of WRSVs and TRSVs.

Figure 7.15. An example of downhole safety valve system.

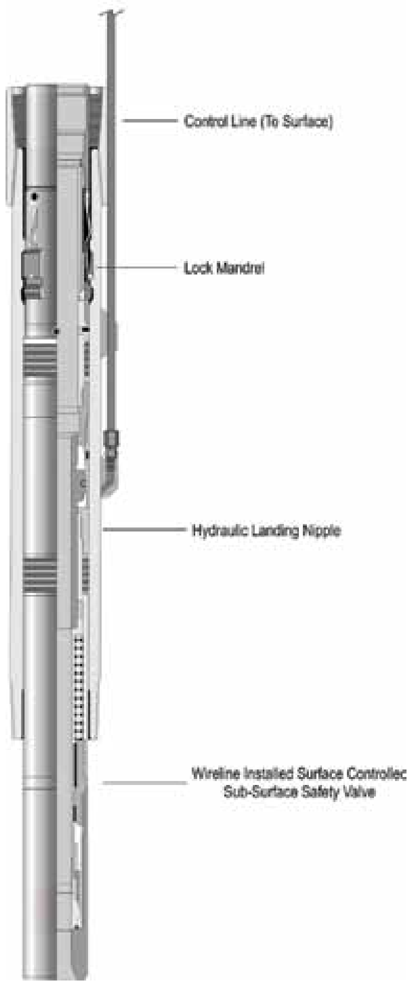



Table 7.2. Subsurface safety valve applications

| WRSV Applications | TRSV Applications |
|---|---|
| General application: where intervention by wireline is available | General application: where larger flow area is desired for the tubing size |
| High-pressure gas wells | High-volume oil and gas wells |
| Extreme hostile environments where well fluids or temperatures tend to shorten the life of component materials | Subsea completions |
| High-velocity wells with abrasive production | Multiple zone completions where several flow control devices are set beneath the TRSV |
| | Greater depth setting capabilities |

## Subsurface Controlled Subsurface Safety Valves

These valves are installed in regular wireline type nipples on a lock mandrel.

### Pressure-Differential Safety Valves

This type of direct-controlled safety valve is a "normally open" valve that utilizes a pressure-differential to provide the method of valve closure. Normally, a spring holds a valve off-seat until the well flow reaches a predetermined rate.

This rate can be related to the pressure differential generated across an orifice or flow bean. When this differential is reached or exceeded, a piston moves upwards against a preset spring force closing the valve. Valves of this type are sometimes termed *storm chokes*.

There are three closing mechanisms available with these valves, i.e.:

- Poppet
- Ball
- Flapper

The valve is held open by a spring force that may be increased by adding spacers or changing the spring. The relationship between flow rate and differential may be adjusted by changing the bean size. The valve, when closed, will remain in this position until pressure is applied at surface to equalize across it, then the spring will return to the open position.

*NOTE: pulling should not be attempted unless pressures have been equalized and the valve is open.*

These valves are still in use today but also a derivative, the injection valve, which is normally closed, is widely used in injection wells. This injection valve opens when fluid or gas is injected and travels to the fully open position when the predetermined minimum injection rate is reached, (refer to the subsection on injection valves, below).

### Ambient Safety Valves

This type of direct-controlled safety valve is a fail-safe closed valve which is precharged with a calibrated dome (chamber) pressure prior to running. Ambient controlled valves will open when the well pressure reaches the set point of the dome calibration. The valve will close when the flowing pressure of the well, at the point of installation, drops below the predetermined dome pressure. Ambient type safety valves are also generally referred to as *storm chokes*.

This type of valve is not limited by a flow bean, which gives it a large internal diameter and, hence, a large flow area, making it suitable for high-volume installations possibly producing abrasive fluids.

Ambient type safety valves are run with an equalizing assembly to allow equalization across the valve if it closes, and a lock mandrel to locate and lock the valve in the landing nipple.

*NOTE: Both pressure differential and ambient controlled subsurface safety valves close on predetermined conditions. They do not offer control until these conditions exist. In addition, valve settings may change if flow beans become cut. Surface-controlled safety valves should be considered in such cases.*

### Injection Valves

Injection valves are normally closed valves installed in injection wells. They act like check valves, allowing the passage of the injected fluid or gas but close when injection ceases.

The closure mechanism is usually either a ball or flapper type that opens when the differential pressure from the injected medium equalizes the pressure below the valve. As the injection rate is increased to the precalculated rate, the differential acts on a choke bean and overcomes a spring to move the mechanism to the fully open mode. If the injection rate is insufficient or fluctuating, the mechanism will be damaged and possibly cut by flow.

The flapper-type valve is more commonly used because its operation is less complicated and is less prone to damage if the injection rate is not high enough.

### Bottomhole Regulators

*Bottomhole regulators* are essentially throttling valves installed downhole to enhance the overall safety in wells where high surface pressures or hydrate formation are problems. Bottomhole regulators are designed to reduce surface flow line pressures to safe, workable levels and to keep surface controls from freezing.

In gas wells, the pressure drop across a regulator will be downhole where the gas and surrounding well temperature is higher than at surface. The higher gas temperature and surrounding well temperature tend to prevent hydrate formation when a pressure drop occurs across the regulator.

In oil wells, a bottomhole valve may be installed to release gas from the solution downhole and lighten the oil columns to increase flow velocity.

The regulator has a stem and seat that are held closed by a spring and open at a preset differential pressure.

If high reductions in pressure are necessary, more than one regulator can be installed, providing stepped reductions that reduce the risk of hydrate formation and flow cutting.

*NOTE: An equalizing sub should be installed between the lock mandrel and the regulator to facilitate pressure equalization.*

### Surface-Controlled Subsurface Safety Valves

The *surface-controlled subsurface safety valve (SCSSV)* is a downhole safety device that can shut-in a well in an emergency or provide a barrier between the reservoir and the surface. As the name suggests, the valve can be controlled from the surface by hydraulic pressure transmitted from a control panel through stainless steel tubing to the safety valve.

The remote operation of this type of valve from the surface can also be integrated with pilots, emergency shut down (ESD) systems, and surface safety control manifolds. The greatest advantage of the surface controlled safety valve is its flexibility of design.

In the simplest system, an SCSSV is held open by hydraulic pressure supplied by a manifold at the surface. The pressure is maintained by hydraulic pumps controlled by a pressure pilot installed at some strategic point at the wellhead. Damage to the wellhead or flow lines causes a pressure monitor pilot to exhaust pneumatic pressure. A low-pressure line, in turn, causes a relay to block control pressure to a three-way hydraulic controller, resulting in hydraulic pressure loss in the SCSSV control line. When this pressure is lost, the safety valve automatically closes, shutting off all flow from the tubing.

To prevent valve damage, equalize differential pressure must be equalized on both sides of the valve before attempting to open the SCSSV. Self equalizing valves have internal baffles in the body of the valve to allow fluid or gas to flow above and below the valve. After the differential pressure, has been equalized, the valve may be opened.

There are two SCSSV types: flapper and ball valves. The flapper type can be equalized by pumping down the tubing. Ball valves generally are opened using the surface hydraulic control unit via the low pressure control line.

There are two main categories of SCSSVs:

- Wireline Retrievable SCSSV
- Tubing Retrievable SCSSV

Additional information about the design, operation, installation and repair of SCSSVs is available in *API 14B Design, Installation, Repair and Operation of Subsurface Safety Valve Systems ANSI/API Recommended Practice 14B Fifth Edition, October 2005.*[3]

Statistics have proven that the TRSV valve is more reliable than the WRSV and that the flapper is more reliable than the ball mechanism. Therefore, the TRSV flapper valve is considered to be the most reliable of all.

SCSSVs use only the ball or flapper type closure mechanisms.

Both categories are supplied with or without internal equalizing features. The equalizing feature allows the pressure to equalize across the valve so it can be reopened. Valves without this feature need to be equalized by pressure applied at surface.

The equalizing valve, with more operating parts, is less reliable than a non-equalizing valve; however, equalizing non-equalizing valves is more difficult and usually takes more time.

### Wireline Retrievable SCSSV

*Wireline retrievable subsurface safety valves* are located and locked, using standard wireline methods, in a dedicated safety valve landing nipple (SVLN). The SVLN is connected to a hydraulic control line pressure source at the surface, normally by a ¼-inch OD stainless steel tubing.

When the safety valve is set in the nipple, the packing section seals against the bore of the nipple below the port. The packing section of the lock mandrel forms a seal above the port in the nipple. Control pressure, introduced through the control line, enters the valve through the port in the housing and allows pressure to be applied to open the valve. Figure 7.16 shows a typical surface-controlled, wireline retrievable safety valve.

Because a wireline retrievable SCSSV seats in a landing nipple installed in the production string, it offers a much smaller bore than a tubing retrievable SCSSV for the same size of tubing. Frequently, WRSVs have to be pulled prior to carrying out wireline operations below them, which have strong implications on well safety.

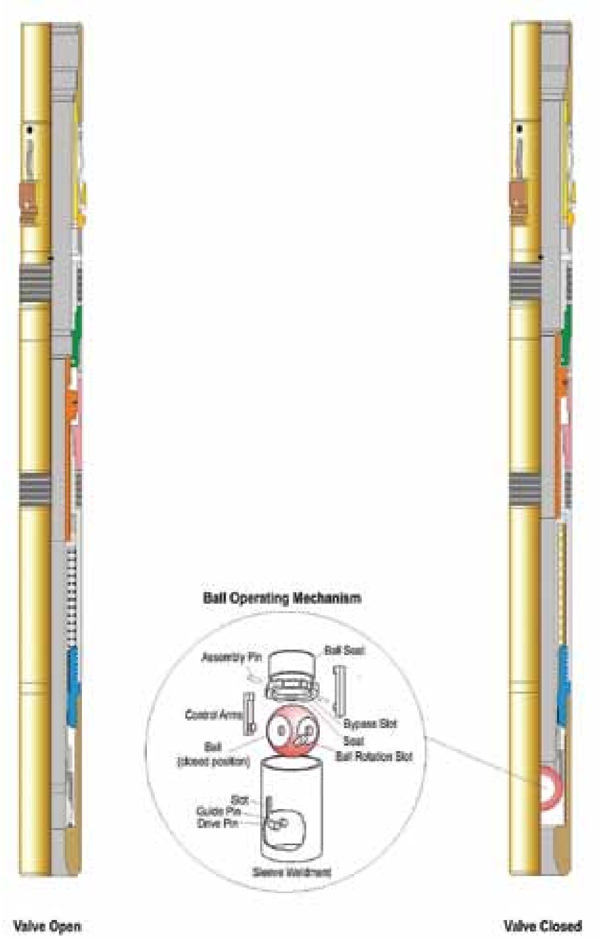
Compared to a tubing retrievable SCSSV, the wireline retrievable SCSSV is easy to replace in the case of failure. Introducing a planned maintenance schedule in which valves are regularly pulled and serviced can prevent most failures. However, during wireline entry operations, there is also a safety risk and care must be maintained at all times.

The components that are required for the installation of a wireline retrievable SCSSV are:

- Hydraulic control line
- Control line protectors
- Hydraulic control manifold
- Wireline retrievable safety valve

- Safety valve landing nipple
- Locking mandrel
- Wireline installation and retrieval tools for the locking mandrel

Figure 7.16. A typical wireline retrievable SCSSV (ball type)




### Tubing Retrievable SCSSV (TRSV)

*Tubing retrievable safety valves* operate by the same principle as wireline SCSSVs. The main difference is that all components are incorporated into one assembly, which is installed in the completion string (refer to figure 7.17). Some later models have rod pistons instead of concentric piston designs.

They also have both equalizing and non-equalizing versions, and versions that enable the insertion of a wireline valve inside the TRSV when the operating mechanism has failed. If the failure is due to a leaking control line, then this contingency measure is ineffective. In this case, it may be possible to run a "storm choke" to continue production until it is possible to conduct a workover.

To enable the installation of the insert valve, the tubing retrievable valve needs to be "locked open" or "locked out". However, the reduced internal bore may adversely affect production rates.

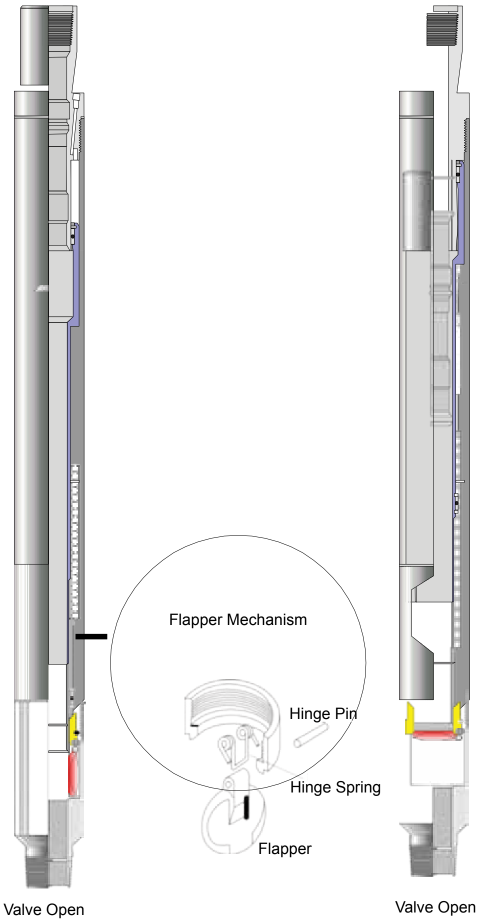
The components required for a TRSV safety system are:

- Hydraulic control line
- Control line protectors
- Hydraulic control manifold
- Tubing retrievable safety valve

Additionally, for insert capability:

- Wireline safety valve
- Locking mandrel
- Wireline installation and retrieval tools for the locking mandrel
- Lockout tool for the tubing retrievable valve

Figure 7.17. A typical tubing retrievable SCSSV (TRSV) flapper type.




## Safety Valve Leak Testing

Leak tests are performed immediately after subsurface safety valves are installed. A typical leak test involves closing the production, kill and swab valves on the Christmas tree and bleeding off the control line pressure to the subsurface safety valve. Tubing pressure is bled off slowly above the valve, to zero, for a tubing retrievable valve and in 100 psi stages, for a wireline retrievable valve.

The system is closed in again and tubing pressure monitored. If there is a rapid buildup, a major leak is indicated or improper functioning of the valve; in this case, the valve should be cycled and the test repeated. After a specified shut-in period, the tubing head pressure should be below a maximum allowable pressure, as specified by the operator's leak off criteria. Many operators apply an API standard.

*NOTE: The API standard allows some leakage through downhole safety valve, which is why some companies do not consider them to be barriers.*

Permitted Leakage:

- Fluid leakage allowed - up to 6.3 gal/hr
- Gas leakage allowed - up to 900 scf/hr

After initial installation, leak tests should be carried out periodically; this accomplishes three functions:

- To test the integrity of the seal in the safety valve.
- To test that the lock mandrel in a wireline retrievable valve is still properly locked.
- To cycle the valve to prevent "freezing" in wells where they have been sitting in either fully open or fully closed position for extended periods of time.

*NOTE: Authorized personnel should conduct all the above tests on all subsurface safety valves.*

### Annulus Safety Valves

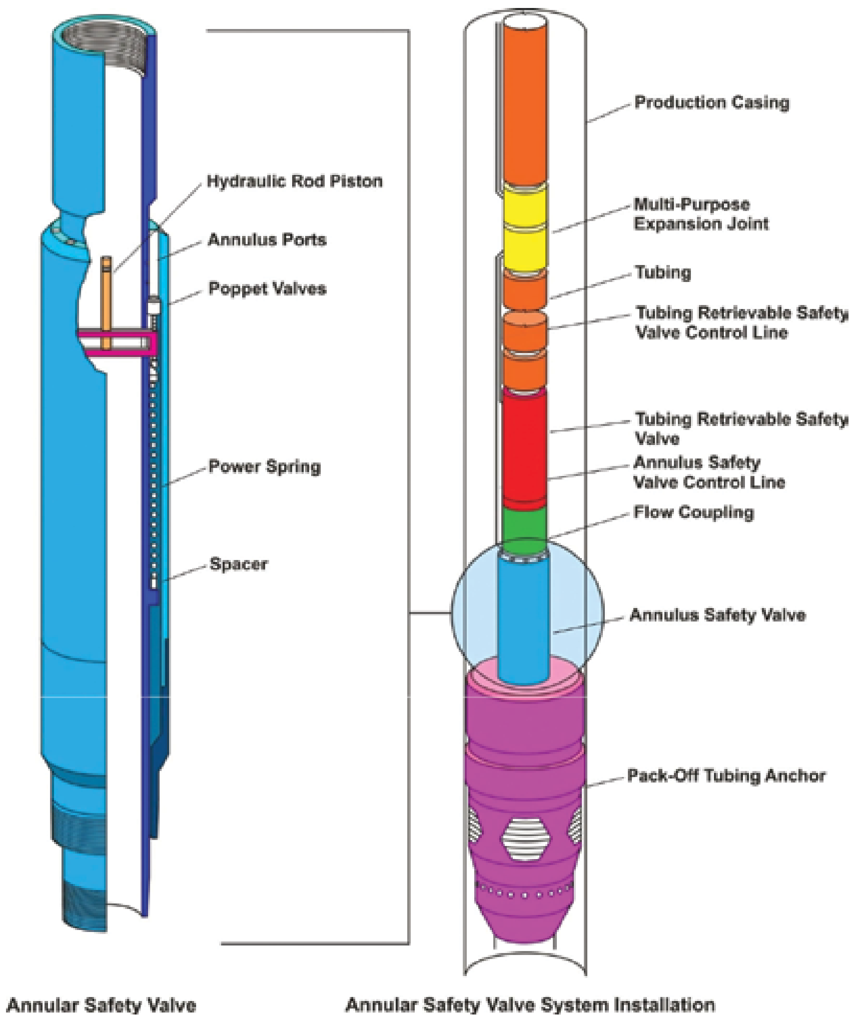
The subsurface safety valves discussed so far, i.e., tubing retrievable and wireline retrievable, only provide control on the tubing. In these systems, no annular flow control exists.

*Annulus safety valve systems* are usually associated with completions where artificial lift or secondary recovery methods are employed, e.g., gas venting in electric submersible pump (ESP), hydraulic pump, and gas lift installations. Their application is to remove the potential hazard of a large gas escape, in the event there is an incident where the tubing hanger seal is breached.

There are numerous designs on the market and the variety of modes of operation is too wide to be covered in this document. However, the basic concepts are the same. With any annulus system, there must be a sealing device between the tubing and the casing, through which the flow of gas can be closed off. This is generally a packer type installation, but may also be a casing polished bore nipple into which a packing mandrel will seal. In the sealing device, there is a valve mechanism operated by hydraulic pressure, similar to an SCSSV. The valve mechanism opens the communication path from the annulus below the valve to the annulus above the valve and is fail-safe closed.

The closure mechanism may be a sliding sleeve, poppet or flapper device. Figure 7.18 shows a typical annulus safety valve.

Figure 7.18. A typical annular safety valve system.



## SCSSVs Opening Procedures

These procedures are found in API method *API 14B, E.1.10. Opening Procedures for Equalizing and Self-Equalizing SCSSVs*[3]*:*

1. SCSSVs with equalizing features

   a. *External pressure source*: Pressurize the tubing above the valve until the pump-through feature of the SCSSV functions to indicate the pressures are equalized. When equalized, slowly increase control-line pressure to the value recorded in step 1 or to the pressure established for normal operations.

   b. *Without external pressure source*: With the well shut in, increase control pressure slowly until the tubing pressure begins to increase. Close the manifold control valve and record the opening pressure. When the tubing pressure stabilizes, pressurize the control system to open the SCSSV. Increase the hydraulic control-line pressure to the value recorded in step 1, or to at least 3.45 MPa (500 psi) greater than the opening pressure.

2. *SCSSVs without equalizing features*: An external pressure source should be used to equalize the pressure across the SCSSV before opening. When equalized, slowly increase control-line pressure to the value recorded in step 1 or to the pressure established for normal operations.

## Surface Control Manifolds

*Surface control manifolds* are designed to provide and control the hydraulic pressure required to hold an SCSSV open. The manifold has one or more air powered hydraulic pumps to maintain the hydraulic operating pressure for the safety valve.

The hydraulic pressure is provided through a three-way control valve, which is controlled by remote pressure pilots and fire sensors. Pilot, sensor or manual activation removes the hydraulic pressure, closing the safety valve.

*NOTE: Activation can occur from the operation of remote control pressure sensing pilots, fusible plugs, plastic line, sand probes, level controllers or emergency shutdown (ESD) systems.*

Surface control manifolds are generally supplied as complete systems containing a reservoir, pressure control regulators, relief valves, gauges, and a pump with manual override.

Manifolds, in combination with the various pilot monitors, have many different applications, e.g., controlling multiple wells using individual control, multiple wells using individual pressures and any combination of these.

Other additional features have been incorporated into surface control manifolds when the system is integrated with other pressure-operated devices. A control panel, designed to supply hydraulic pressure to a surface safety valve (SSV) and hydraulic pressure to an SCSSV, contains circuit logic for proper sequential opening and closing of the safety valves, i.e.:

Sequential closing:

- SSV first
- SCSSV second

Sequential reopening:

- SCSSV first
- SSV second

Sequential logic is incorporated to increase the service life of hydraulic master valves and SCSSVs to prevent SCSSVs becoming flow cut by high velocity wells.

Improvements have also been made in the monitoring systems, e.g.:

- Sand erosion probes installed on a flow line to monitor sand flow production.
- Quick exhaust valves, which allow rapid exhausting of control line pressure, to speed up valve closures.

### Control Lines

The conduit, which supplies the hydraulic fluid to the SCSSV, is termed the *control line*. The control line is normally ¼-inch OD tubing attached between the subsurface valve (TRSV) or nipple (WRSV) and the tubing hanger. It is attached with compression fittings, and clamped to the outside of the tubing.

The method of porting through the hanger to the control manifold is dependent on the type of wellhead and hanger system being used. Some systems on land wellheads are simply fed out through a port with a packing element (often a tie-down bolt hole) that is tightened to seal around the outside of the tubing. Other systems have drilled ports through the hanger, into which the control line is fitted again by a compression fitting, and the spool sealed off from the annulus and the Christmas tree bore by concentric weight set or pressure energized seals.

Subsea wellheads have different methods of termination so the tree can be installed without diver assistance.

The control line material is selected to meet the environment where it will be installed and must be compatible with the safety valve and the hanger materials to avoid corrosion caused by electrolysis (dissimilar materials). There is a large choice of control line materials from 316 stainless steel for sweet service to Inconel and Elgiloy alloys for more demanding service. They are also supplied in hard durable plastic coatings for added protection from corrosion and against crushing damage during installation, which at one time, were major problems during completing. Two lines can be encased for operation of dual-control line safety valves.

Control lines are held flat to the tubing by control line protectors, usually placed across a coupling or connection, and sometimes also in the middle of a joint. The protector has a slot into which the control line plastic outer coating fits. Simple banding can be used but it is not strong and is easily ripped off. Protectors are now metal clamp types, as earlier rubber versions were easily detached and caused major problems while retrieving the completion string.

The purpose of using tubing in a well is to convey the produced fluids from the producing zone to the surface, or in some cases to convey fluids from the surface to the producing zone. It should continue to do this effectively, safely and economically for the life of the well, so care must be taken in its selection, protection and installation.

The tubing must retain the well fluids and keep them out of the annulus to protect the casing from corrosion and well pressure, which may be detrimental to future well operations such as workovers.

Tubing connections play a vital part in the function of the tubing. There are two types of connection available today; API and premium connections. API connections are tapered thread connections and rely on thread compound to effect a seal, whereas the premium thread has at least one metal-to-metal seal. Premium connections are generally used in high pressure wells.

Tubulars up to and including 4½-inch OD are classified as tubing. Tubulars over 4½-inch OD are casing. In large capacity wells, casing size tubulars are often installed as the production conduit.

Tubing selection is governed by several factors. Anticipated well peak production rate, depth of well, casing sizes, well product, use of wireline tools and equipment, pressures, temperatures, and tubing/annulus differential pressures are among those which must be considered.

To meet various completion designs, there is a wide range of tubing sizes, wall thickness (weights) and materials to provide resistance to tubing forces and differing well environments. The best tubing selection is the cheapest tubing which will meet the external, internal and longitudinal forces it will be subjected to, and resist all corrosive fluids in the well product.

Tubing is supplied in accordance to API specifications. There is a wide range of materials to that resist most of the potential corrosive well conditions, but today, where deeper high-pressure sour reservoirs are being developed, the API range may not be suitable. To fill this gap in the market, steel suppliers provide proprietary grades. These grades are usually high chrome steels (up to 24 percent chrome) designed for various high temperature and sour well conditions.

For ease of identification, tubing is color-coded to API specification. Some specialist suppliers' steels are not covered by the code and provide their own specific codes. Refer to these codes to ensure the tubing is according to requirements.

## Tubing Hangers

### Bowl-Type Tubing Head/Mandrel Type Tubing Hanger

A tubing head/tubing hanger combination unit is attached to the uppermost casing head on the wellhead. The main functions of this unit are to:

- suspend the tubing and support tubing weight
- seal the annular space between the tubing and the casing
- lock the tubing hanger in place and provide a threaded profile for tubing
- provide a base for the wellhead top assembly (Christmas tree)
- provide access to the annular space ('A' annulus).

Suspension of the tubing is accomplished usually by threads, slips or any other suitable device, i.e., rams.

The tubing head consists of a spool piece type housing where the internal profile of the top section is a straight or tapered cylinder receptacle (bowl) into which the tubing hanger is landed, suspending the tubing and sealing off the volume between the tubing and the casing. A tapered mandrel type tubing hanger system is shown in figure 7.19.

Important features of tubing hanger spools are outlined below.

### Top and Bottom

*Connections* size and pressure ratings of these connections (usually flanged) must be compatible with the size and pressure rating of the joining connections.

*Upper bowl* provides the seal area for various tubing hangers and a load shoulder to support the production tubing.

*Lower bowl* is provided to house some type of isolation seal.

*Set screws* or *hold-down screws* are found in most tubing heads and have two important functions:

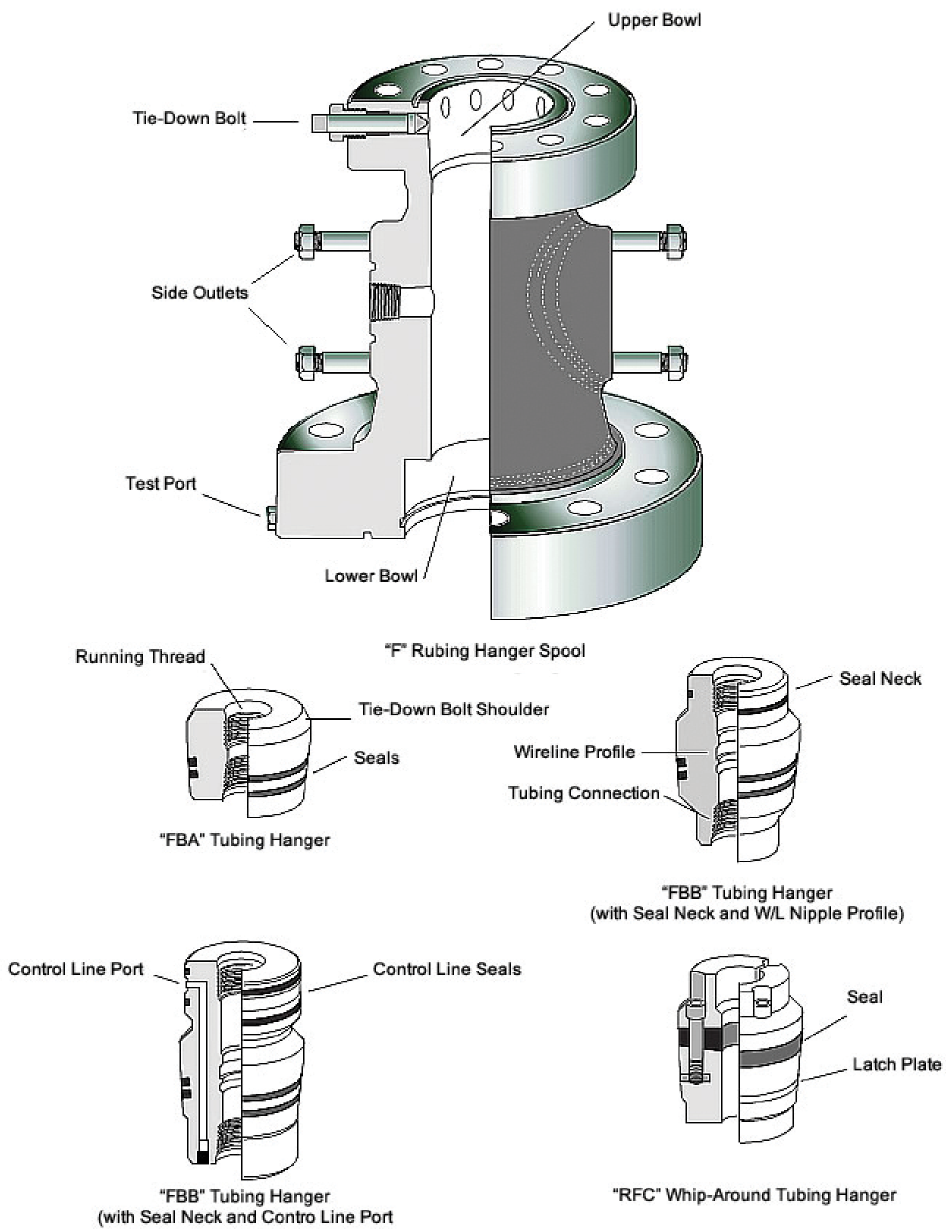
- Retain the tubing hanger and prevent any upward tubing movement due to pressure surges.
- Activate (energize) the body seals on the tubing hanger.

*Outlets* provide access to the annulus (e.g., for pressure monitoring or gas lift) during production.

*Test port* permits pressure testing of the hanger seal assembly, lock down screw packing connection between flanges, and the secondary (isolation) seal.

Important features of tubing hangers are:

Figure 7.19. Cameron 'F' tubing head and hangers.



*Landing threads* are the uppermost threads on the hanger and they must support the entire weight of the tubing string during landing operations.

*Bottom threads* must support the entire weight of the tubing string and seal the producing conduit from the tubing/casing annulus.

*Sealing areas* provide compression type sealing between the outside diameter of the hanger body and the inside diameter of the hanger bowl. Sealing is accomplished by energizing elastomer seals or metal-to-metal seals by the action of tubing weight on various load-bearing surfaces.

*Tubing hangers* are sized according to the upper bowl of the tubing head and the tubing size the hanger will be supporting. Thus, a 7-inch multiplied by a 2⅞-inch tubing hanger means a 2⅞-inch production string will be suspended from a tubing head seven-inch top bowl.

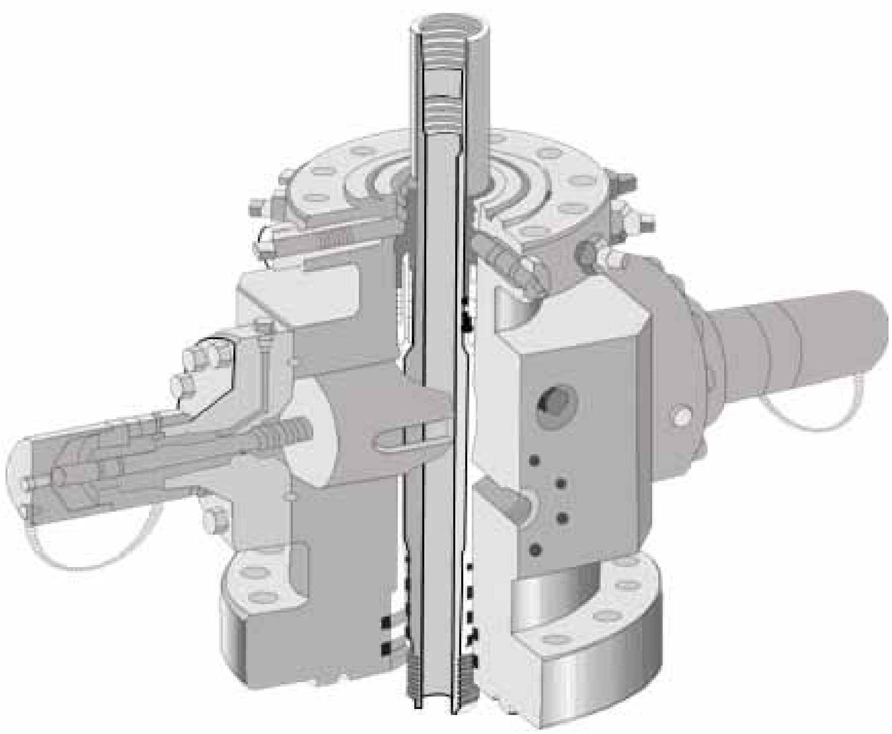
### Ram-Type Tubing Head

*Ram-type tubing heads* find their application in completions where manipulation of the tubing is necessary to locate and latch into a packer and to maintain tension in the tubing when landed.

Figure 7.20 shows a ram type tubing head that is comprised of a housing with two side outlets in which are located retractable rams. These rams, when closed, support the hanger nipple, which is screwed onto the top of the tubing string. A seal assembly provides the seal between the annulus and the tubing, which is located around the hanger nipple, above the rams.

With the ram type tubing hanger installed on the wellhead and the packer set, production tubing is run and spaced out so that the final position of the hanger nipple is that distance below the tubing head corresponding to the amount of stretch required to give the appropriate tension. The tubing is latched into the packer and tensions applied to the tubing so that the hanger nipple is just above its final hang off position. The rams are closed, the tubing weight is set on the rams and the handling string removed. The seal assembly is then installed, bolted down, and the seal system energized by the injection of plastic packing. Finally, the BOPs are removed and the Christmas tree installed.

Figure 7.20. A Cameron single ram tubing head (SRT)



*NOTE: Like mandrel type hangers, landing nipple hangers are provided with a top thread for the landing joint, an internal left hand thread or wireline profile for the installation of a back pressure valve, and can be supplied with extended necks to facilitate secondary sealing. Also, ram type tubing heads are available with control line outlets to allow an SCSSV to be incorporated in the tubing string.*

The disadvantages of ram type tubing hangers are:

- After long service periods, it may be difficult to re-open the rams.
- The tubing pick-up weight must be overcome prior to opening the rams, otherwise, the rams will be difficult to open.
- They are bulky, heavy and expensive.

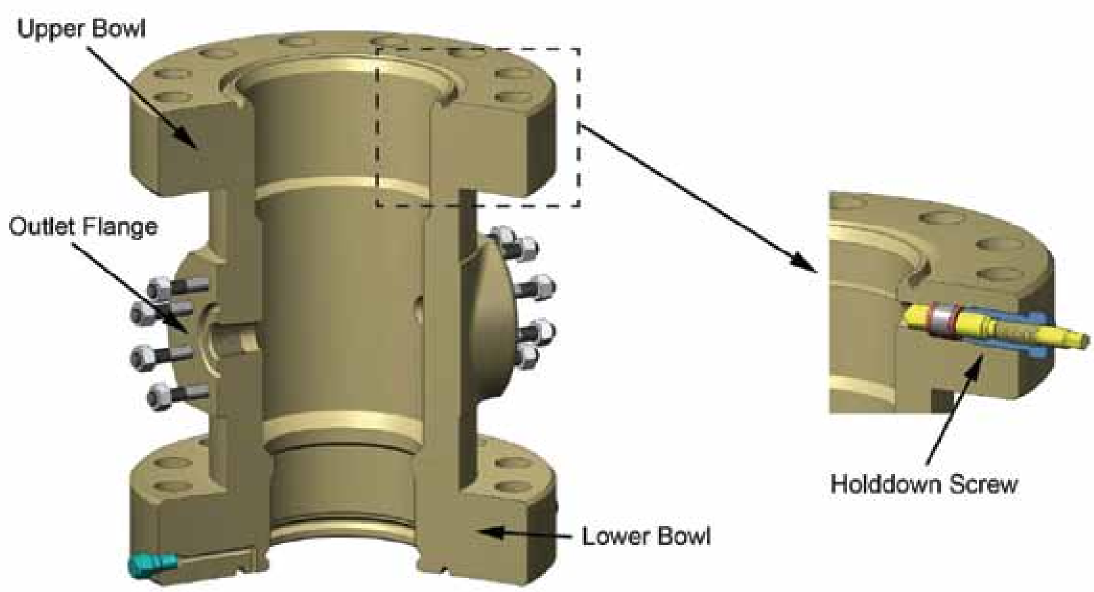
### Multiple Tubing Heads/Hangers

A multiple completion produces multiple reservoirs simultaneously without any pressure or reservoir fluid combining during the transfer of fluid from the production zones to the production facilities.

For multiple string completions, two or three segments, one for each production string, are used to form a hanger assembly that is installed in the appropriate tubing head, and resembles a mandrel type tubing hanger. Figure 7.21 shows a tubing hanger spool arrangement for use in a dual completion. An important characteristic of this tubing hanger is that it has support wedges (or in other heads, support pins) that are used to guide and align the two segmented hangers in their proper positions in the upper bowl. The segmented hangers are locked in place with the tie-down screws. A disadvantage of this type of hanger is that seals are often damaged while installing the second segment.

*NOTE: Segmented hangers are available to accommodate back-pressure valves and are also manufactured with control line outlets to allow a SCSSV to be installed in the production tubing.*

Figure 7.21. A tubing hanger spool.



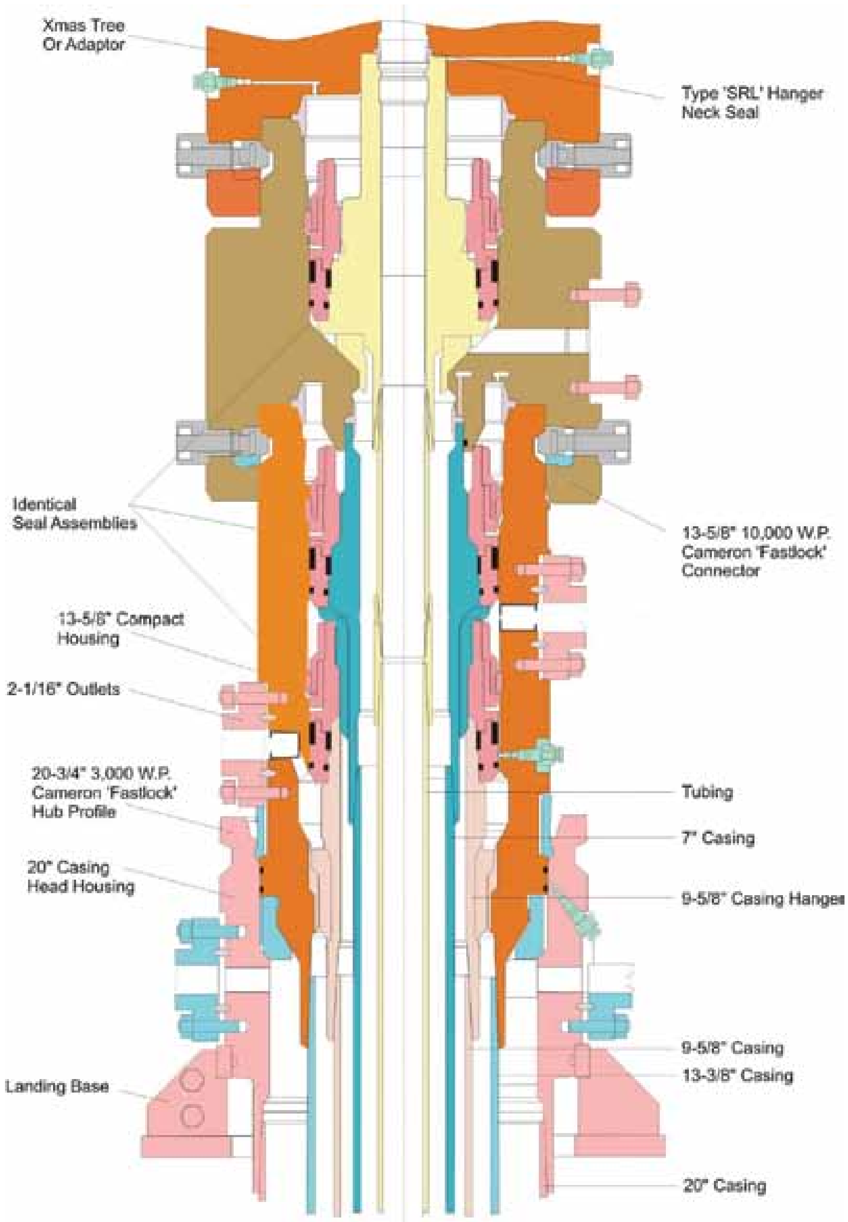
## Wellheads

### Tubing Heads

At the drilling stage, casing is run and cemented in a well to line the well to protect against collapse of the borehole, to prevent unwanted leakage into or from formations and to provide a concentric bore for future operations. Various strings of casing, i.e., conductor, surface string are run (providing a base for the wellhead) followed by one or more intermediate strings, depending on the target depth and expected conditions in the well. At the completion stage, production tubing is run to act as a flow line between the formation and surface. Unlike casing, production tubing is not cemented in the hole, so the entire tubing weight must be supported by a suspension system suitably installed in a tubing head. The tubing head is positioned on top of the uppermost casing head of a well and is used to suspend the production tubing and to produce an effective seal between tubing and casing.

A wellhead is composed of a body, a hanger-sealing device (tubing hanger), and a mechanism that retains the hanger. Figure 7.22 shows a typical modern compact wellhead.

Figure 7.22 An illustration of a typical compact wellhead.



The wellhead equipment installed on top of the tubing head serves to control and direct the flow of well fluids from the production tubing string. Surface equipment may range from a simple flow cross with stuffing box, to an elaborate Christmas tree. Choice of surface tree depends on well fluid production method (natural flow or artificial) and the wellhead pressure encountered. In general, most surface trees are comprised of at least one master valve, at least two wing or flow valves (one of which may be hydraulically operated), and one swab valve utilized in wireline operations (refer to figure 7.23).

Wellhead equipment (spools, valves, chokes) are either screwed, flanged or a combination of both. Wellheads with screwed connections are used for pressures not exceeding 1,000 psi; those with screwed valves and chokes not exceeding 5,000 psi. However, most operators specify flanged connections, even for low pressure wellheads, since they are less susceptible to leakage, more easily orientated and, especially in the larger sizes, more easily manipulated.

*NOTE: API test pressures for all wellhead, including pressure control equipment and downhole equipment, is twice the rated working pressure for equipment up to 5,000 psi and 1½ times working pressure for 5,000 psi and above.*

API 170 provides a standard for subsea wellheads, and manufacturers all have their own specific designs that includes some means of orientation and aligning the subsea tree inlets and outlets to the flow lines, or to a subsea manifold system[4].

## CHRISTMAS (PRODUCTION) TREE

A *Christmas tree* is an assembly of valves and fittings used to control the flow of tubing fluids at surface and to provide access to the production tubing. It is essentially a manifold of valves installed as a unit on top of a tubing head or wellhead.

The range of trees available is wide, and are not all addressed in this manual. However the valve layout of surface Christmas trees is similar throughout and typically contains the following valves and features.

The basic components making up the Christmas tree are:

- *Pressure gauge*. Pressure gauges allow well pressures to be monitored. Tubing pressure and casing or annular pressures are monitored with these gauges.
- *Tree cap*. The Christmas tree cap provides the appropriate connection for well control equipment when conducting well interventions and is installed directly above the swab valve.
- *Crown valve (swab valve)*. The crown valve permits vertical entry into the well for wireline (e.g., running BHP/BHT gauges, tubing conditioning) or for well interventions such as coiled tubing operations and logging. This valve is operated manually.
- *Flow tee (cross, tee)*. The flow tee is used so that tools may be run into the tubing without disconnecting the flow line.
- *FlowWing valve*. The flow wing valve (FWV) permits the passage of well fluids to the choke valve. This valve can be operated manually or automatically (pneumatic or hydraulic), depending on whether a surface safety system is to be included in the production wing design.
- *Choke*. The choke is used to restrict, control or regulate the flow of hydrocarbons to the production facilities. This valve is operated manually or automatically and may be of the fixed (positive) or adjustable type. It is the only valve on the Christmas tree that is used to control flow. It is sometimes located downstream at the production manifold.

*NOTE: All other valves used on Christmas trees are invariably gate valves that provide fullbore access to the well. These valves must be operated in the fully open or fully closed position.*

- *Upper Master valves*. The upper master valve (UMV) is used on moderate to high-pressure wells as a emergency shut-in system where the valve should be capable of cutting at least 7/32-inch braided wireline. This valve can be actuated pneumatically or hydraulically. The UMV valve is a surface safety valve and is normally connected to an emergency shut-down (ESD) system.
- *Lower Master valves*. The lower master valve (LMV) is utilized on all Christmas tress to shut-in a well. THis valve is usually opereated manually. When closed, this valve should keep the well pressure under full control and therefore should be in optimum condition -— it should never be used as a working valve.
- In moderate to high-pressure wells, Christmas trees are often furnished with a valve actuator systems for automatic or remote controlled operation (i.e., surface safety valve system). This is often a regulatory requirement in sour gas or high-pressure wells.

## Opening Valves

Before opening or closing any valve that may be under pressure:

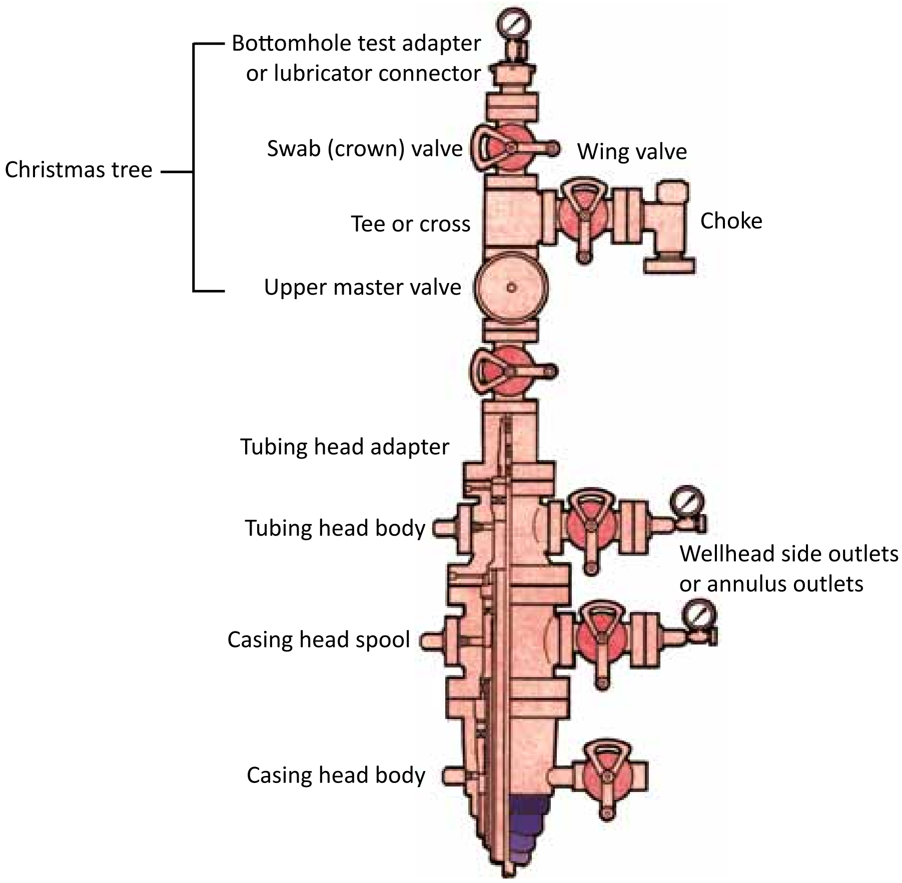
- know the function of the valve.
- know what the valve is controlling.
- know what fluids it is controlling.
- know what pressure may be on the valve.
- be sure there is nothing interfering with valve closure.
- know the type of valve (ball, gate, needle, etc.). The type of valve will determine if it can be partially opened or must be fully opened.
- know the position of the valve, normally open or normally closed.
- know the number of turns when fully open, and the number of turns to close it.

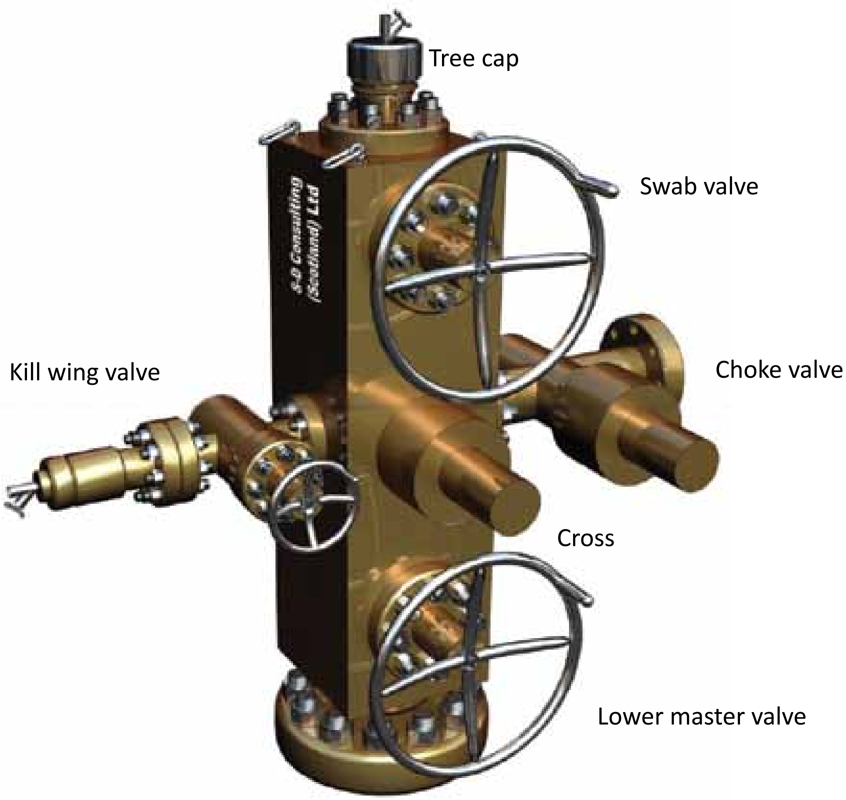
It is a good idea to function the casing valve prior to intervention in order to check for functionality, pressure and possible barrier failures such as a casing string or cement. Wing valve should be function tested to check for functionality and to ensure the well can be isolated from downstream equipment. The term wing valve is typically used when referring to the flowing wing.

## Leak Testing The Christmas Tree

Bleed the wellhead pressure to the lowest practical pressure and shut-in the well at the wing or flow line valves. Bleed the flow line header pressure down to, or below, wellhead pressure, if possible. Observe the flow line and wellhead for a pressure change that indicates a surface valve leak. Any leaks must be repaired before proceeding with the test. Surface valves may be equipped with valve removal (VR) plugs. These plugs are installed to enable valve removal under pressure. Because of the possibility of extreme pressure, a lubricator should always be used when removing a VR plug. Downstream valves should always be tested before removing the plug.

Figure 7.23 Examples of Christmas trees.



### Manual Shut-In Using The Christmas Tree

The Christmas tree lower master valve is used to shut-in a well for well control, or if a valve or fitting in the upper part of the tree needs replacing when no tools are in the hole. In most cases, it takes 12½ turns to close the master valve. It should always be closed slowly and the turns it takes to close should be counted. The upper master valve is used on moderate to high pressure wells as an emergency shut-in system. To determine if the well is shut-in and not leaking, bleed down pressure downstream of the master valve and monitor for pressure buildup.

### Christmas Tree Removal

When planning to remove a Christmas tree and rig BOPs up on a well, several questions will be considered, for example:

- Will the tree be sent to a shop or serviced at the location, if necessary?
- Is the tree manufacturer service representative present and are there all the parts that mayrequire replacement on site?
- Is the rig BOP equipment ready for immediate installation?
- Will the well be killed, or worked on under pressure?

If the well is to be killed by bullheading, several checks should by carried out before beginning the operation. The casing should be full of liquid and there should be no communication between the tubing and the casing. Kill fluid will be pumped until the produced fluid in the tubing has been displaced into the formation. Overdisplacement can be major concern to avoid formation damage. After killing the well, a wireline plug is set in tubing, the wing valve is closed, and a back-pressure valve (BPV) is set in the tubing hanger. If there is no pressure buildup in the tubing or the annulus, the tree can be removed and the BOPs installed. Lockouts must be activated to ensure remotely activated valves are disabled.

*Excerpt from "Guide to Blowout Prevention, Second Edition, Revised 2011" manual by Well Control School*[5]

### Pressure Control Equipment

The primary source for the material found in this chapter is *API 53, Recommended Practices for Blowout Prevention Equipment for Drilling Wells*[6]. The blowout preventers and associated wellhead equipment are considered to be the secondary barrier against blowouts. The discussions which follow briefly describe a variety of blowout prevention equipment and their applications. Manufacturer manuals and industry publications should be consulted for specific information.

### The Blowout Preventer (BOP) Stack

The *blowout preventer stack* is the assembly of well control equipment that includes preventers, spools, valves, and nipples connected to the top of the wellhead. Its purpose is to stop the flow from a well when a kick occurs and to allow the greatest flexibility for subsequent operations. The stack should have a working pressure that is at least equal to the maximum anticipated surface pressure (MASP) for the well upon which it is installed. Maximum anticipated surface pressure is normally defined as the highest pressure that could be encountered at the surface. When estimating the MASP, remember to take future activities into consideration. Perforating, fracturing and the introduction of energized fluids into the wellbore can affect these estimates. Nearby operations being performed simultaneously (SIMOPS) can also have unforeseen consequences.

Example arrangements for BOP equipment are based on rated working pressures.

Example stack arrangements shown in figure 7.24 should prove adequate in normal environments, for rated working pressures of 2k, 3k, 5k, 10k, 15k, and 20k. M stands for 1,000 psi.[2]

Table 7.3 Design Test Pressure.

| Rated Working Pressure | Test Pressure |
|---|---|
| 2k 2,000 psi | 4M |
| 3k 3,000 psi | 6M |
| 5k 5,000 psi | 10M |
| l0k 10,000 psi | 20M |
| 15k 15,000 psi | 22.5M |
| 20k 20,000 psi | 25M |

The design test pressure for production and completion is two times the working pressure for equipment up to 10M, 1.5 times the working pressure for 15M, and 1.25 times the working pressure for 20M equipment. API requirements state that the test pressure should not result in permanent damage and must include a safety factor of at least 1.2.

Leak testing is performed to the given working pressure after the equipment is installed.

Well control equipment is usually tested to working pressure even if the annulus and adjacent equipment is rated at a lower pressure. It is only pressure tested up to the highest anticipated pressure the equipment is expected to withstand if the test pressure is considered unreasonably high for the application.

API has established the following codes to designate stack components.

A = annular type blowout preventer

G = rotating head

R = single ram type preventer with one set of rams, either blind, or pipe, as the operator prefers

Rd = double ram type preventer with two sets of rams, positioned as the operator prefers

Rt = triple ram type preventer with three sets of rams, positioned as the operator prefers

S = spool with side outlet connections for choke and kill lines. Spools and their locations in the BOP stack are optional

M(K) = 1,000 psi rated working pressure

Using the code and describing the stack from the bottom up, a 10,000 psi rated stack with a 13⅝-inch bore, a drilling spool, two single rams, and an annular preventer would be coded:

10M – 13⅝ - SRRA

It can be seen that many possible stack configurations are possible. Although the working pressure is the primary element to consider when designing an individual stack, there are other considerations as well. For instance, how high will the stack be? Obviously, the stack must fit in the space available under the rig substructure. Other considerations are the maximum anticipated surface pressure (MASP), temperature, fluid/elastomer compatibility, BOP pressure rating, flange connection type, anticipated formation fluids and the effective cost.

The best stack arrangement for a job is one that is adequate for the particular job at hand. However, most rigs have BOP equipment that is suited for use over a wide geographic area with a minimum of stack alteration required.

### Pressure Control Equipment Certification and Compatibility for Intended Service

BOP certification and verification is not currently required by US drilling regulations, however both certification and verification are required when using a subsea BOP in US waters.

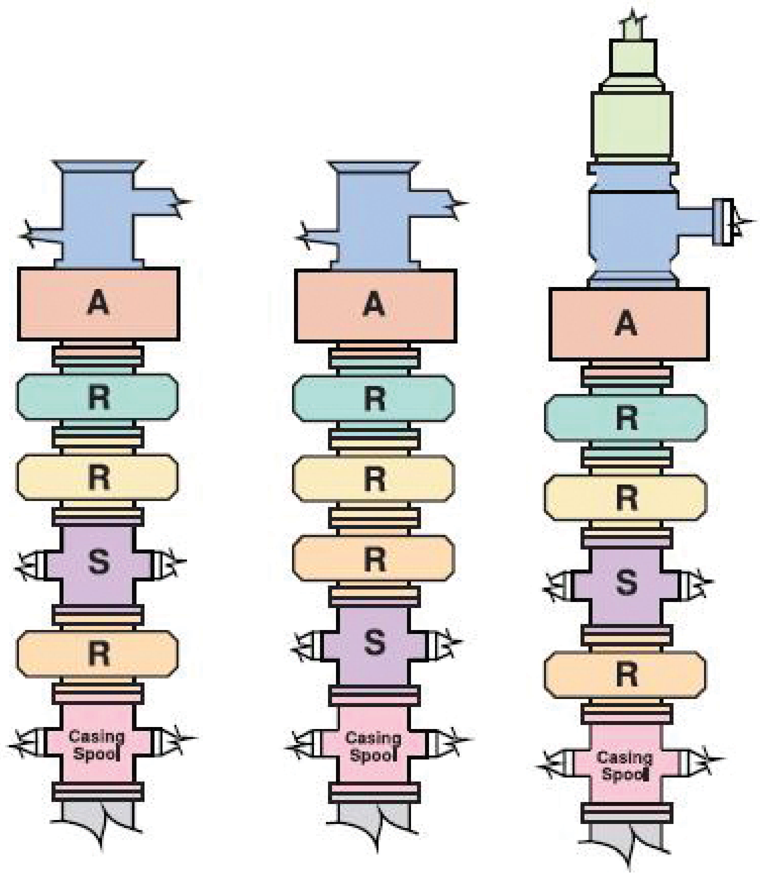
### Workover BOP Verification

From *30 CFR 250*[7]: For well workover operations, your *Application for Permit to Modify* must include the following BOP descriptions:

(a) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(b) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

Figure 7.24. Typical BOP stack arrangement.



(c) Independent third party verification and supporting documentation that show the blind/shear rams installed in the BOP stack are capable of shearing any drill pipe (including work string and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for under maximum anticipated surface pressure;

(d) When you use a subsea BOP stack, independent third party verification that shows:

  (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design;

  (2) The BOP stack has not been compromised or damaged from previous service;

  (3) The BOP stack will operate in the conditions in which it will be used; and

(e) The qualifications of the independent third party referenced in paragraphs (c) and (d) of this section:

  (1) The independent third party in this section must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

  (2) You must:

    (i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using, or its employees, hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm, has the expertise and experience necessary to perform the required verifications.

    (ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the BSEE district manager at least 72 hours in advance.

### Workover Stack Requirements

*Title 30 - Mineral Resources. BSEE, Subpart F - Oil and Gas Well-Workover Operations*[7] states:

(a) The BOP system, system components and related well control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form BSEE-0124, requesting approvals of the well workover operation, a well control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) Minimum BOP system for well workover operations, with the tree removed, must meet the appropriate standards from the following table:

c) The BOP systems for well workover operations, with the tree removed, must be equipped with the following:

Table 7.4. BOP stack requirements.

| **When...** | **The minimum BOP stack must include . . .** |
|---|---|
| (1) The expected pressure is less than 5,000 psi | Three BOPs consisting of an annular, one set of pipe rams, and one set of blind/shear rams. |
| (2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings | Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind/shear rams. |
| (3) You handle multiple tubing strings simultaneously | Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind/shear rams. |
| (4) You use a tapered drill string, | At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. You may substitute one set of variable bore rams for two sets of pipe rams. |

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units, with a minimum pressure of 200 psi above the precharge pressure, without assistance from a charging system. Accumulator regulators supplied by rig air, without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations, if rig air is lost;

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed;

(3) Locking devices for the pipe ram preventers;

(4) At least one remote BOP control station and one BOP control station on the rig floor; and

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

## BOP Pressure Ratings and Operations to be Performed

*Title 30 - Mineral Resources. BSEE, Subpart F - Oil and Gas Well-Workover Operations*[7] states:

### FOR WELL SURFACE PRESSURE < 5,000 PSI

Use three BOPs consisting of an annular, one set of pipe rams, and one set of blind/shear rams for:

- Workovers and completions, single and dual string
- Non-staging tubing couplings or tool joints

### FOR WELL SURFACE PRESSURE > 5,000 PSI

Use four BOPs consisting of an annular, two sets of pipe rams, and one set of blind/shear rams for:

- Multiple string completions
- Staging tubing couplings or tool joints
- Stripping in or out dual string completions
- Asphaltene, paraffin, and scale removal
- Sand cleanouts
- Installing sand screens
- Deploying and retrieving acidizing tools
- Deploying and retrieving tubing conveyed perforating guns
- Lubricating
- Fishing

Use four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind/shear rams when:

- Handling multiple tubing strings simultaneously
- Underbalanced drilling
- Milling

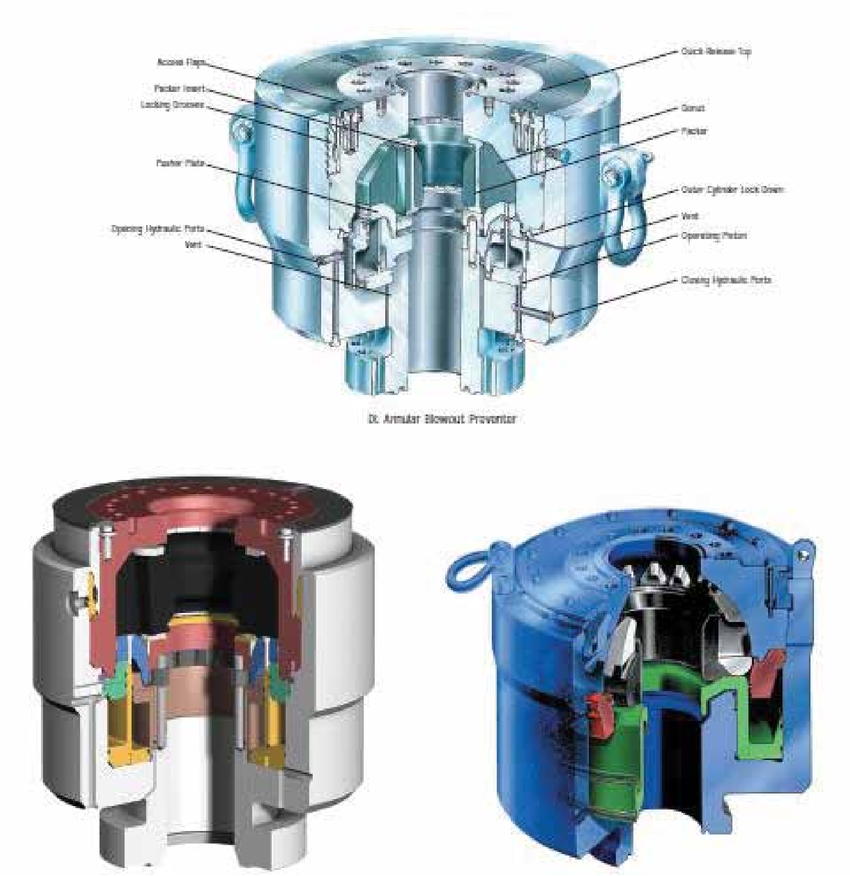
### TAPERED WORK STRING

At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, have at least two sets of pipe rams that are capable of sealing around the larger size drill string. One set of variable bore rams may be substituted for two sets of pipe rams.

## BOP Stack Maximum Rated Wellbore Pressure

API 16D 3.61[8], Note: In the event that the rams are rated at different pressures, the BOP stack maximum rated wellbore pressure is considered equal to the lowest rated ram BOP pressure. In stacks that do not contain any ram BOP, the BOP stack maximum rated wellbore pressure is considered equal to the lowest rated BOP pressure. Keep in mind that some equipment may have been derated due to general wear and tear or exposure to extreme temperatures, erosion or corrosion. The de-rated status has an effect on the overall rating of the stack.

Figure 7.25. Three types of annular preventers




## Annular Preventers

An *annular blowout preventer* is a large valve that is usually installed above the ram preventers in a BOP stack. When closed, it forms a seal in the annular space between the pipe and the wellbore. An annular preventer is also designed to seal off the open well if there is no pipe in the hole.

The preventer consists of a circular rubber packing element, a piston, a body, and a head or cap. When hydraulic fluid is pumped into the closing chamber, it moves the piston upward against the packer, forcing the packer element to constrict inward closing off the annular space. The packer will mold itself around nearly any shape: (drill pipe, tool joints, kellys, or wireline) and effectively seal off the annulus. This versatility is the primary reason that annular preventers are often the preventer of choice when initially shutting in a well.

Most annular preventers are designed for a maximum recommended closing pressure of 1,500 psi, though some annular BOPs have a maximum operating chamber working pressure as high as 3,000 psi. When moving the pipe through the closed packer, as during stripping operations, the regulated pressure may be reduced to less than 1,000 psi. The regulator valve that supplies closing pressure to surface BOPs allows flow in both directions. This is an important feature for moving or stripping pipe and tool joints through the preventer, while holding a constant closing pressure, thus maintaining the seal against the pipe. Stripping operations using the annular preventer cause excessive packer wear.

The rubber packing element is the critical part of the preventer and its life is reduced when operating against high pressure. Some models are highly energized by wellbore pressure, that is, well pressure pushes upwards and provides additional sealing force. The use of high operating pressure on the annular preventer is a major source of wear and packer failure. If the well pressure exceeds working pressure of the preventer and a seal fails, well pressure could unload through the closing line regulator, back to the accumulator reservoir. Manufacturers provide specific recommended closing pressures according to pipe size and well pressure to be contained. Enough pressure should be exerted on the packer to ensure a good seal, but pressure should not be so high as to cause excessive wear. Annular packer life is extended when the closing pressure is adjusted just low enough to allow a slight amount of drill fluid leakage when the tool joint passes through the preventer packing seal. A slight leakage around the tool joint indicates the lowest usable closing pressure and minimizes wear by lubricating the drill pipe.

Annular preventer members can effect a more secure seal on the drill pipe than a kelly. It may be necessary to increase annular closing pressure in order to have effective seal on wireline when running wireline through an open BOP with or without a lubricator. Annular preventers can close on an open hole, but are not as effective maintaining a seal on an open hole as ram preventers.

There are situations in which a positive tight seal is necessary, as when closing around wireline or the kelly, or when hydrogen sulfide gas is present. These operations will result in reduced packer life. In most situations, every effort should be made to use as low an operating pressure as is safely possible. If the annular preventer cannot seal around the wireline effectively, the wireline can be cut and dropped through the BOP.

Figure 7.26. Examples of BOP sealing elements.

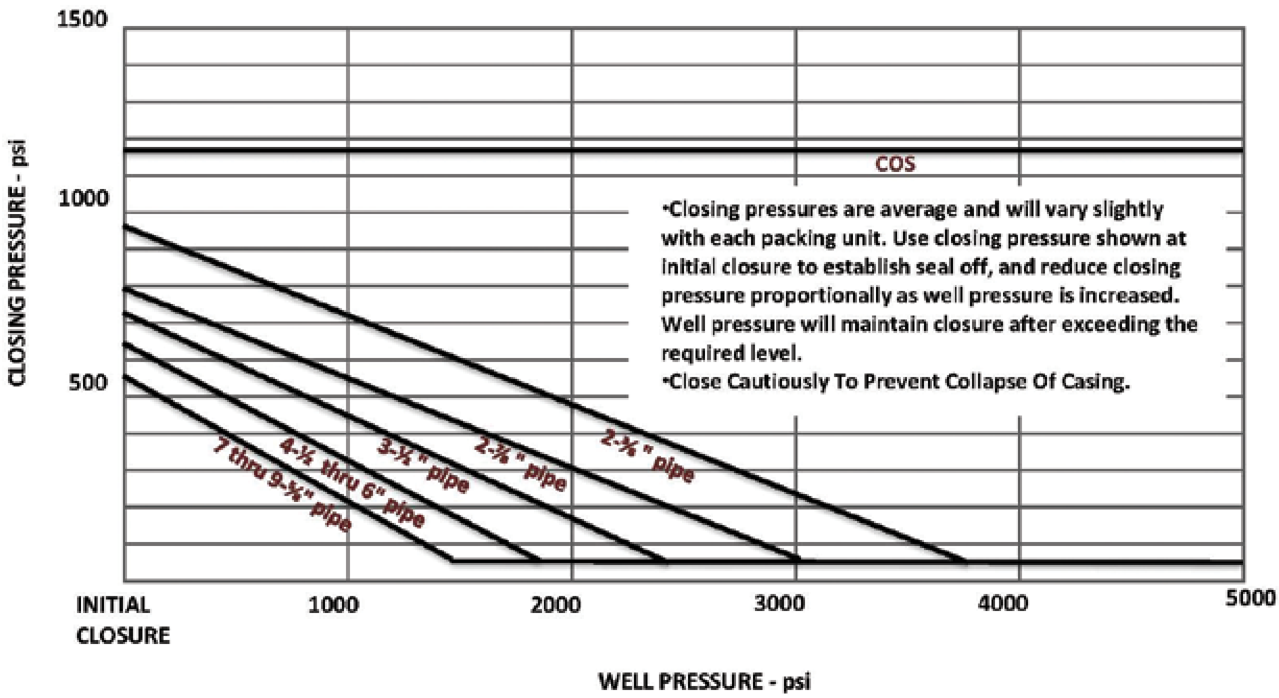
If it becomes necessary to change a worn or damaged packer when the string cannot be removed from the well, the packer can be split and removed. Split packing elements are also available from manufacturers.

It takes more hydraulic fluid to close an annular preventer than it does for pipe rams. Therefore, it takes longer to effect shut-in. Higher closing pressure will not improve the closing time as much as larger diameter operating lines, larger fittings, and regulators.

Although the annular preventer will close and seal on a various tools, it should be tested using the body of the work string. Recommended practices call for annular preventers to be tested at low and the high pressures. The high-pressure test should be a minimum of 70 percent of the rated working pressure of the preventer.

Annular preventers are subject to failure, primarily the annular sealing elements. Just because the preventer successfully passed its most recent low- and high-pressure test, there is no guarantee it will seal on the next closure. Most failures are in the form of leaks around the pipe. When observed, increasing the closing pressure might effect a seal long enough to get through a crisis. However, a better practice is to close a ram BOP lower in the stack. In floating drilling operations, keeping gas out of the riser is critical; a leaking annular can result in evacuation of the mud in the riser as the gas expands as it migrates. It is a good practice to put the well on the trip tank to monitor a closed annular BOP to detect leaks very early. Mitigation is generally accomplished by closing the surface diverter and closing an alternate annular (many subsea stacks have two annulars) or a pipe ram lower in the stack.

Figure 7.27. The graph illustrates a manufacturer's recommended closing pressure according to well pressure.




Some general guidelines are listed below:

1. Store packers in cool, dry, dark areas away from the electric motors.
2. Never use more pressure on the closing unit than necessary, especially when moving pipe.

3. Test the packer when it is installed in the preventer to the pressure required by operations, and according to state or federal regulations.
4. Check the manufacturer's manual for operating data of various models. There can be considerable differences between the various annular preventers.

#### *Visual Inspection*[2]

1. *Annular preventer packer*: Visually inspect condition of packer. Check for gouges in seal area. Verify and record age of packer. Ensure that the age is within shelf life of manufacturer. Record drilling fluid and inquire about compatibility.
2. *Throughbore*: Ensure no key seat damage in annular cap wear band. Record if any.
3. *Drift*: Ensure that the packer is fully open and not protruding into the wellbore.
4. *Surge bottle*: Check for proper nitrogen precharge in accumulator bottle. Consider water depth for subsea application.
5. *Milling*: Check for metal shavings if milling operations have been performed.
6. *Operating pressures*: Ensure that a operating range pressure chart in relation to pipe size and wellbore pressure is posted.
7. *Drift test*: Drift test the annular preventer to ensure that it returns to full open bore within thirty minutes.

## Testing

### *FUNCTION TEST*

All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

Function tests should be conducted alternatively from the driller's panel and from mini remote panels, if on location.

### *PRESSURE TEST*

All blowout prevention components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi and then to a high pressure.

When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may continue to seal after the pressure is lowered and therefore misrepresenting a low pressure condition.

A stable low test pressure should be maintained for at least *five minutes*.

Then conduct the high pressure test of components that could be exposed to well pressure, to the rated working pressure of the ram BOPs, or the rated working pressure of the wellhead on which the stack is installed, whichever is lower. Components to be tested include the BOP stack, choke manifold and choke/kill lines. Initial pressure tests are defined as those tests that should be performed on location before the well is spudded or before the equipment is put into operational service.

Annular BOPs, with a joint of drill pipe installed, may be tested to the test pressure applied to the ram BOPs or to a minimum of *seventy percent* of the annular preventer working pressure, whichever is the lesser.

Subsequent high pressure tests on annular BOPs, with a joint of drill pipe installed, should be tested to a minimum of seventy percent of their working pressure or to the test pressure of the ram BOPs, whichever is less. Subsequent pressure tests are tests that should be performed at identified periods during drilling and completion activities on a well.

A stable high test pressure should be maintained for at least *five minutes*. With larger size annular BOPs some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This *packer creep* movement should be considered when monitoring the pressure test of the annular.

Pressure test operations should be alternately controlled from the various control stations.

The pressure test performed on *hydraulic chambers* of annular BOPs should be to at least 1,500 psi.

The tests should be run on both the opening and the closing chambers.

Pressure should be stabilized for at least five minutes.

Subsequent pressure tests are typically performed on hydraulic chambers only between wells or when the equipment is reassembled.

## Sealing Elastometric Components

The packer or sealing elements of annular and ram preventers come in many sizes and pressure ratings. They are constructed of a high tensile rubber or rubber like material that has been molded or shaped. An annular preventer packer is molded around a series of steel fingers. The steel fingers add strength and control the extrusion of packer material. The packer element may be made from a multitude of different compounds for a variety of uses. The most common compounds used for packer elements are natural rubbers, nitrile and neoprene. Specific compounds have been formulated for oil tolerance, extreme cold and heat, sour gas, and corrosive environments. Elastomeric components should be changed out as soon as possible after exposure to hydrogen sulfide under pressure.

Packer elements are identified by a coding system that includes information on the hardness, generic compound, date of manufacture, lot/serial number, manufacturer's part number and operating temperature range of the component. Spare BOP seals and packing units should be kept on location and stored according to the manufacturer's recommendations.

### Annular Preventer Packing Unit

Packing units for the annular BOPs are available in *nitrile, neoprene* or *natural* rubber. See figure 7.25.

Nitrile rubber is used with oil-based or oil additive drilling fluids, provides the best overall service life when operated at temperatures between +20 °F to +190 °F.

*Neoprene* rubber is for low temperature operating service and oil-based drilling fluids. It can be used at operating temperatures between -30 °F to +170 °F.

*Natural* rubber is for use in non-oil-based drilling fluids and can be used at operating temperatures between -30 °F to + 225 °F.

In extreme emergencies and when no other alternatives are available sealing elements can be replaced while drill pipe is in the hole. However, this potentially hazardous procedure involves a high degree of risk that is unacceptable in any circumstances other than emergency. The packing units consist of two components: steel segments and rubber compound.

The steel segments are molded into the rubber and will partially close over the rubber to prevent excessive extrusion when sealing under high pressure. The segment will ensure that the element maintains it shape. When the element is closed the steel segment will compress the rubber out against the wellbore and create a seal. When the element is opened up, the compressed rubber will expand and bring the element to full open position again within thirty minutes.

### Pressure Test Frequency

Pressure tests on the well control equipment should be conducted, at least:

a. Prior to spud or upon installation.

b. After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, or choke manifold, but limited to the affected component.

c. At least every 21 days.

### Response Time

Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. Closing time should not exceed *30 seconds* for annular preventers smaller than 18¾ inches nominal bore and *45 seconds* for annular preventers 18¾ inches and larger. Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function, and ends when the BOP or valve is closed, affecting a seal. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting.

## Diverter Systems

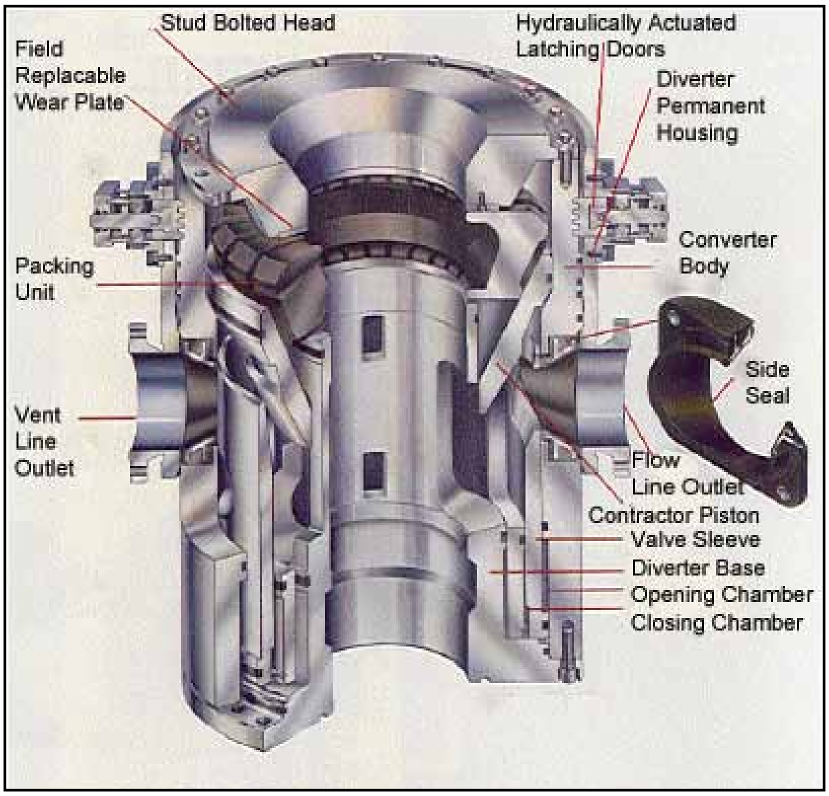
*Diverter systems* are used when a well cannot be shut-in for fear of lost circulation or formation breakdown. Diverter systems consist of a blowout preventer (usually an annular type) coupled with large diameter vent lines rigged below the preventer. The system is designed to protect personnel and equipment from shallow gas flows that can occur before casing is set and the blowout preventers are installed. Diverter systems are not used to stop the flow from a well. When the system is hydraulically activated, full-opening valves open the vent lines before the diverter packer closes, thus diverting the flow away from the rig. The system is designed to packoff around the kelly, drill string, or casing and divert flow in a safe direction. Diverters having annular packing units can also close on wireline and open hole.

Diverter controls on the floor are usually arranged as a single separate control to avoid confusion since diverter operations have to be undertaken quickly. The hydraulic supply pressure to the diverter control panel is routed directly from the hydraulic control unit with 3,000 psi. The control lever on the accumulator is coupled with the controls for the diverter line so that the annular preventer cannot be closed before the diverter lines opens. Two (or more) diverter vent lines are used and the valve arrangement allows the driller to preselect downwind lines, according to wind direction.

State and government regulations require diverters during top-hole drilling on all offshore rigs; on floating units, they are a permanent component of the marine riser package.

Diverter systems are designed for brief periods of high flow rates. Therefore, erosion is a concern. The vent lines should be as large and simple as possible, with a minimum of bends or turns. API recommends lines with a minimum inside diameter of 10 inches for offshore installations and six inches for land rigs. Some operations use both an annular and ram preventer above the diverter lines, due to anticipated high flow rates. Tests for diverter systems include a function test, pumping water at a maximum rate to ensure that the system is not blocked, and a low-pressure test in accordance with state or government regulations and company policies. API recommendations for testing diverters can be found in chapter 11. For more information on diverter systems, refer to API RP 64[10].

Figure 7.28. An illustration of a diverter.




Guidelines for diverting with string on bottom:

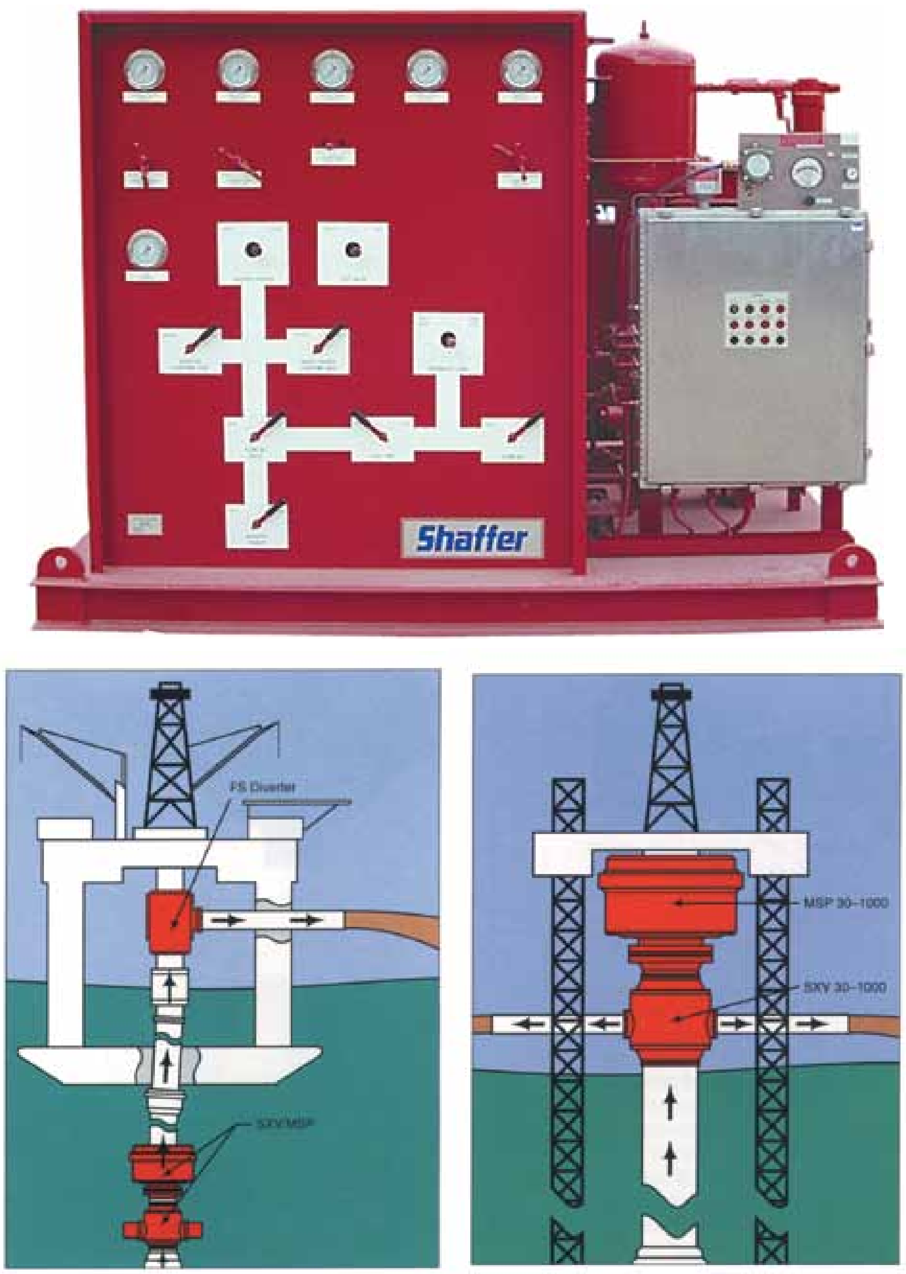
1. Route returns to downwind vent line and close diverter.
2. Pump at maximum rate and switch to kill fluid without shutting down pumps. If no kill fluid, use seawater. (Do not shut down the pumps)
3. If diverter system fails before control of the well is regained or broaching to surface occurs, evacuate all personnel, leaving the mud pumps running on sea water at maximum rate.

Guidelines for diverting with string off bottom:

If it becomes necessary to divert gas, water and/or sand debris, route returns to downwind vent line and close diverter.

1. Do not stop pumping and if mud reserves run out, keep pumping seawater at maximum rate. Do not shut down the pumps.
2. Conduct emergency evacuation of all non-essential personnel and prepare evacuation of remaining personnel.
3. If diverter system fails before control of the well is regained or broaching to surface occurs, evacuate all personnel, leaving the mud pumps running on seawater at *maximum* rate.

Figure 7.29. Diverter systems.




## Special Purpose Annular Preventers

Most manufacturers of BOP equipment offer a variety of special purpose annular type preventers. The specific function of each is indicated by its name, e.g., rotating heads, tubing strippers, wireline strippers, rod strippers, stuffing boxes and circulating heads.

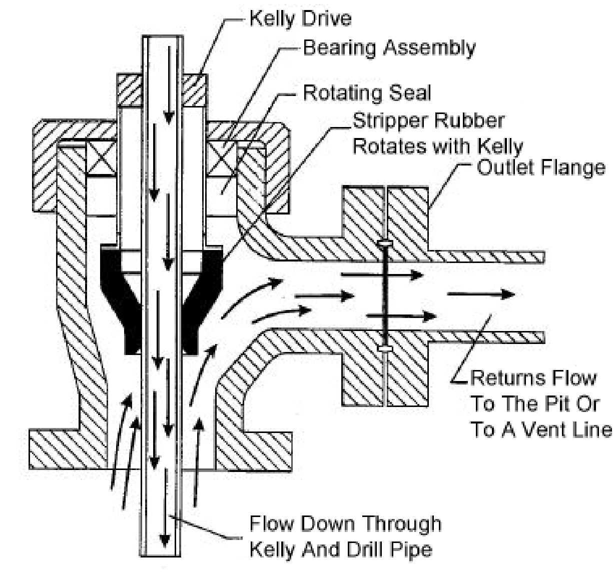
This group of equipment allows stripping and/or rotation of pipe, wireline, or pumping rods, while the well is under pressure. The packing elements are designed to be flexible enough to expand and contract while maintaining a pressure seal. Tool joints, collars, and other large string components are stripped slowly in order to prevent premature packer element failure.

These preventers are sometimes used in place of standard annular preventers. Depending on the type and model, they may be actuated manually, hydraulically or have a permanently seated packing element that is always closed.

Figure 7.30. Three components for a rotating head system.
*Top*, chiller
*Bottom left*, control panel
*Bottom right*, rotating head


Rotating control heads or rotating blowout preventers are not a new concept. The rotating head maintains a constant seal around all of the rotating elements in the drill string except such large diameter pieces as the bit and reamer. This seal is maintained when going in, coming out or holding in static position. The original equipment was designed for air drilling, and later used for mud, gas and geothermal applications. Later generation equipment was applied by industry to the flow drilling applications that cause high pressures at the wellhead. The original design and engineering principles for its use have held and still apply today. Within the BOP system the API recognizes the rotating head as a diverter. See figure 7.31. The rotating BOP is always used on top of a regular BOP stack, consisting of ram and annular BOPs.

Figure 7.31. A rotating head.




The rotating head seals off around almost any shape of kelly and will also seal on any type of drill pipe whether flush joint, upset or coupled. No special operations are required for handling the pipe. As the various elements of the drill string are raised or lowered, the stripper rubber changes shape to conform to the OD of these elements. In this way, the hole is closed at all times. A flanged outlet below the stripper rubber allows pressure to be directed out through the flow line.

The rotating blowout preventer is ideal for use wherever there is:

- Drilling where hydrogen sulfide is encountered
- Circulating with air or gas
- Underbalanced drilling
- Drilling with reverse circulation
- Drilling in areas susceptible to blowouts
- Geothermal drilling

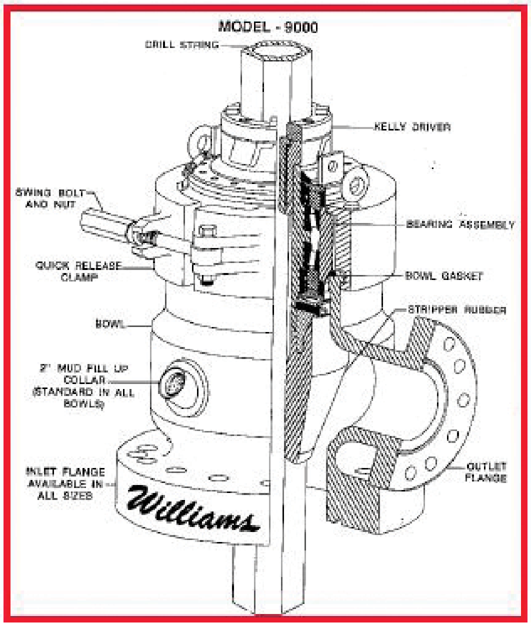
The rotating blowout preventer consists of three major assemblies:

- Rotating assembly
- Body
- Kelly drive unit

The body is flanged to the top of the blowout preventer and the rotating assembly is locked in with a quick release mechanism. The kelly drive unit is installed on the kelly and turns the rotating sleeve that has the stripper rubber attached to the lower end. The stripper rubber seals off the well pressure between the annulus of the hole and the outside of the drill pipe. The rotating sleeve packing effectively seals between the outside of the rotating sleeve and rotating assembly housing. The stripper rubber is constructed in such manner, that as the well pressure increases, the stripper forms a tighter seal. Some rotating heads are built with hydraulic pressurized stripping rubbers.

Underbalanced drilling is now being more widely used in the oil and gas industry. The major advantages of underbalanced drilling are that it lowers costs, reduces drilling days, reduces differential sticking and hole drag caused by mud cake, and reduces trouble time during drilling. Because underbalanced drilling creates the condition for fluid to flow from the formation into the wellbore, successful underbalanced drilling must include the selection of proper control equipment to handle the drilling fluids and formations fluids. The rotating control head is one of the major elements of the system.

Figure 7.32. A kelly drive.




## Ram Preventers

Rams are the primary closing and sealing components in a blowout preventer. One of several types of rams can be installed in a preventer body; pipe, blind, shear, blind/shear and variable bore. A set, consisting of two ram blocks (which contain the sealing elements) are mounted on opposing shafts in the preventer on either side of the wellbore. When the preventer is activated, the shafts carry the rams together, forming a seal to close the well.

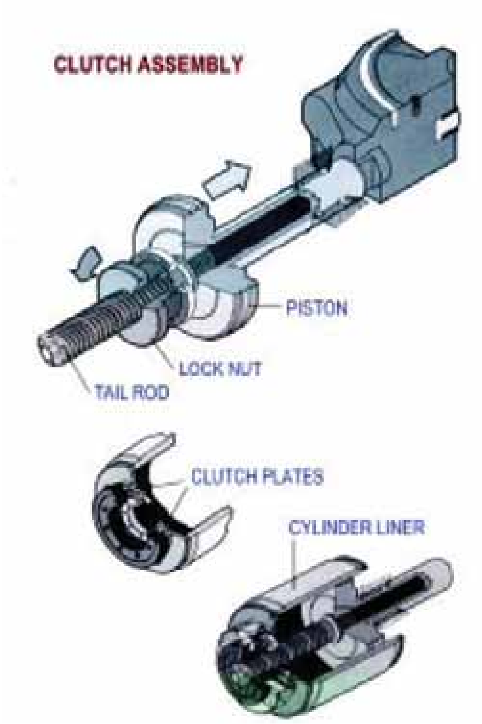
Rams are manufactured in various sizes and pressure ratings. Some are custom built or specially designed for particular applications. They may range from simple manual single ram sets to multiple ram set bodies. The simplest ram consists of a polished rod that closes by turning handles on either side in order to screw the ram inward to close. Complex multiple sets of rams may be housed in a single preventer body and remotely operated by hydraulic pressure.

Although some ram BOP closing systems use a screw jack to close the preventer, the rams of most BOP systems are closed by hydraulic pistons. The piston rod is sealed against the well by a primary lip seal, which is installed in the bonnet and through which the operating rod passes. If well pressure bypasses the primary seal and enters the operating cylinder, it may force the ram open. To prevent this, a series of secondary seals and detection methods are provided, including back up "O" rings, plastic packing injection seals and a vent to the atmosphere. If fluid is noticed venting out of the BOP, the secondary or auxiliary plastic seal should be energized against the piston shaft. In case of hydraulic system failure, most rams can be closed manually.

## Hydraulic Ram Locking System

Every ram BOP must be equipped with a ram lock system that can either be operated manually or operated hydraulically to assure that the ram does not open if the hydraulic closing pressure is lost. If it is a manual system, it should be equipped with extension hand wells.

Figure 7.33. A clutch assembly.




There are many types of hydraulic ram locking systems. The following are descriptions of several manufacturers' types.

The Hydril Multiple-Position Lock (MPL) is a hydraulically operated mechanical lock which automatically maintains the ram closed and locked with the optimum rubber pressure required for sealing off of the front packer and upper seal.

Hydraulic closing pressure closes the ram and leaves the ram closed and locked. The engaged clutch assembly allows unrestrained closing motion but prevents opening motion. Hydraulic opening pressure unlocks and opens the ram. Unlocking and opening motion are achieved by applying opening pressure in the opening cylinder, which disengages the clutch assembly.

A provision for testing the locking mechanism is incorporated in the MPL. Manually operated lockout devices prevent opening pressure from disengaging the clutch assembly. Application of opening pressure then simulates opening forces applied to the ram thus testing proper functioning of the lock. The lockout device position is visually indicated.

Cameron wedge locks lock the ram hydraulically and hold the rams mechanically closed even when actuating pressure is released. The operating system can be interlocked using sequence caps to ensure that the wedge lock is retracted before pressure is applied to the open BOP. For subsea applications, a pressure balance chamber is used with the wedge locks to eliminate the possibility of the wedge lock's unlocking due to hydrostatic pressure.

The Shaffer UltraLock system incorporates a mechanical locking mechanism within the piston assembly. This locking system is not dependent on closing pressure to maintain a positive lock. It uses flat tapered locking segments, carried by the operating piston, which engages another stationary tapered shaft located within the operating cylinder. Only one hydraulic actuation is required to operate the cylinder's open/close function and the locking system. The system automatically locks in the closed position each time the piston assembly is closed. Once the operating piston is closed on the pipe, the locks are engaged until opening pressure is applied. Only hydraulic pressure can unlock and reopen the preventer.

Figure 7.34 A wedge lock.

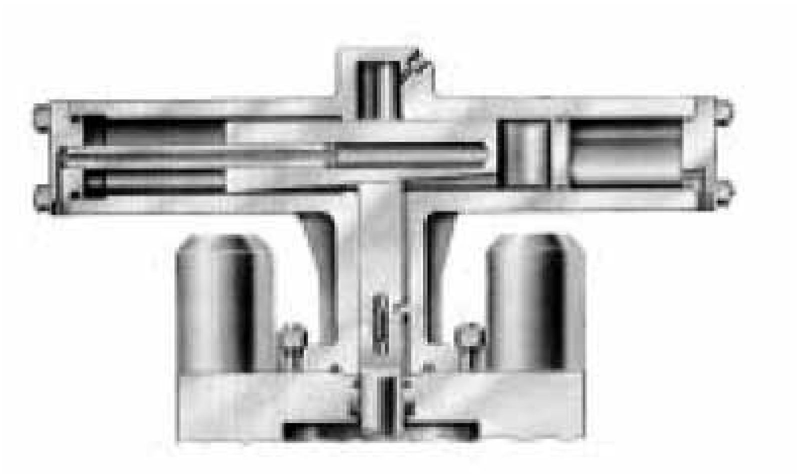
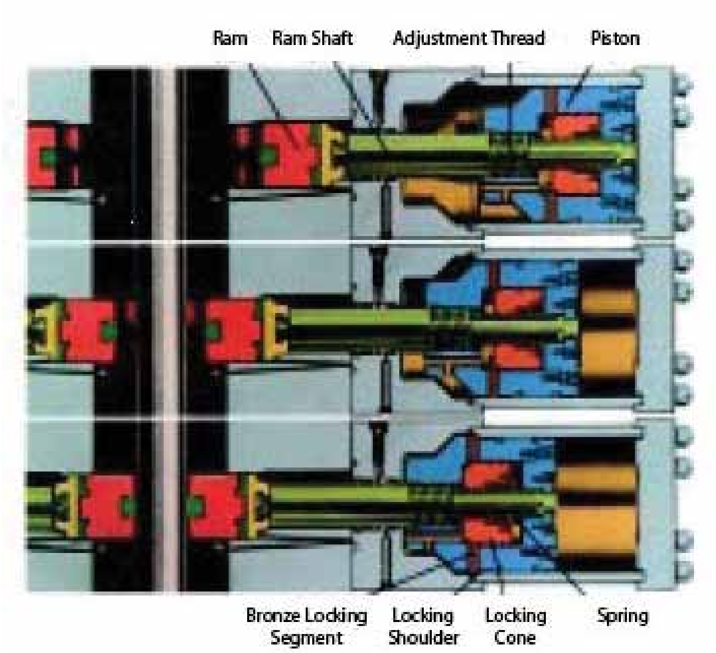


Figure 7.35. A poslock piston assembly.

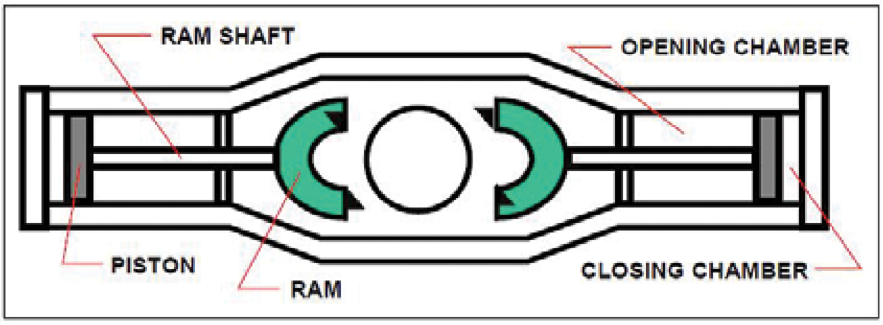



A ram block has a rubber or elastomeric seal that fits on the top side of the block. When the rams are closed wellbore pressure energizes the top seal upwards against the preventer body. The ram is not designed to seal if pressure is exerted from the top. There have been cases where a preventer was installed upside down and consequently failed to seal off a flowing well. The manufacturer's name on the preventer should be right side up, and the circulating ports or outlets should be located below the ram. When changing packers on the rams it is good practice to inspect and replace the bonnet or door seals each time the rams are changed or the doors are opened. Most ram preventers are normally closed with 1,500 psi operating pressure but may be functioned at lower pressures.

Each type and size of ram preventer has a specified closing and opening ratios, which is a function of that ram's particular geometry. Ram preventer closing or opening ratios and BOP-rated working pressure (RWP) determine the minimum required pressure to close or open the ram against the wellbore pressure, at the surface.

Figure 7.36 shows a simplified sketch of a hydraulic operated ram preventer.

Figure 7.36.

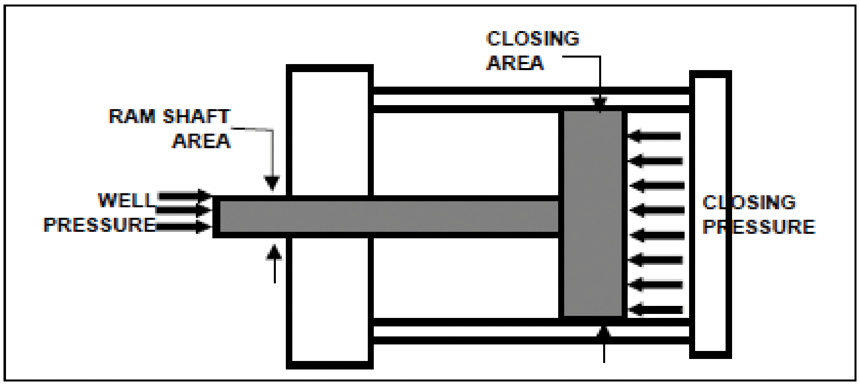



## Closing Ratios

*Closing ratio* is a dimensionless factor equal to the wellbore pressure divided by the operating pressure necessary to close the ram BOP against wellbore pressure.

When closing the rams, hydraulic closing pressure, acting on the ram operating piston area must overcome the wellbore pressure, acting on the ram shaft area, which is attempting to force the ram into open position. This ratio exists because of difference in areas that the closing hydraulic pressure acts upon, compared to the ram rod area exposed to wellbore pressure. See figure 7.37.

Figure 7.37.



Ram closing ratio = wellbore pressure ÷ minimum pressure required to close the ram

Or,

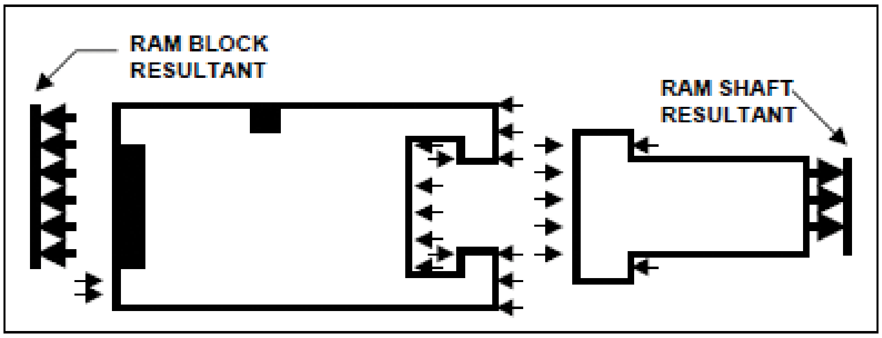
Minimum pressure required to close ram = BOP rated working pressure ÷ ram closing ratio

Closing ratios are generally in the range from 6:1 to 9:1. This means that it takes 1.0 psi of closing hydraulic pressure per 6 to 9 psi wellbore pressure, to close the preventer. Stated in another way, on a preventer with closing ratio of 6:1, if the wellbore pressure is 3,000 psi it should take 500 psi hydraulic pressure to close the preventer. The extreme case is closing the ram preventer while it is exposed to maximum rated pressure in the wellbore.

*WARNING: Opening rams under pressure is not recommended. The following are for information and understanding purposes only!*

When closing the rams, hydraulic closing pressure, acting on the ram operating piston area must overcome the wellbore pressure acting on the ram shaft area, which is attempting to force the ram in to open position. This ratio exists because of difference in areas that the closing hydraulic pressure acts upon, compared to the ram rod area exposed to wellbore pressure. See figure 7.38.

Figure 7.38.




## Opening Ratios

*Opening ratio* is a dimensionless factor equal to the wellbore pressure divided by operating pressure necessary to open a ram BOP containing wellbore pressure.

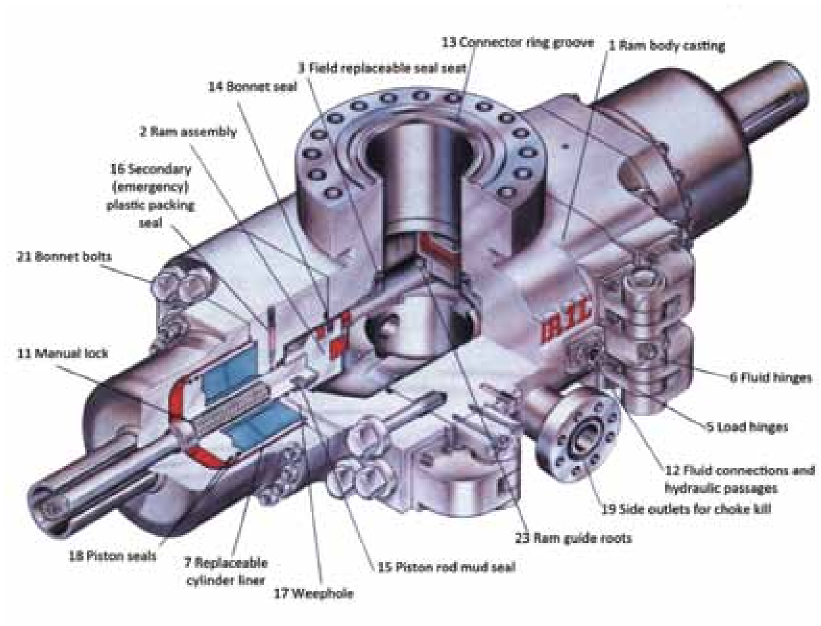
Figure 7.38 is an exposed view showing forces on a ram block and ram shaft while containing pressure below the ram cavity. The packer is sealed on pipe and opening force is being applied to the operating piston.

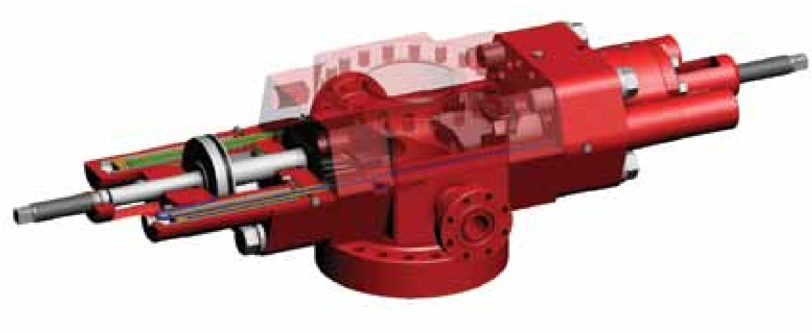
Ram opening ratio = wellbore pressure ÷ minimum pressure required to open the ram

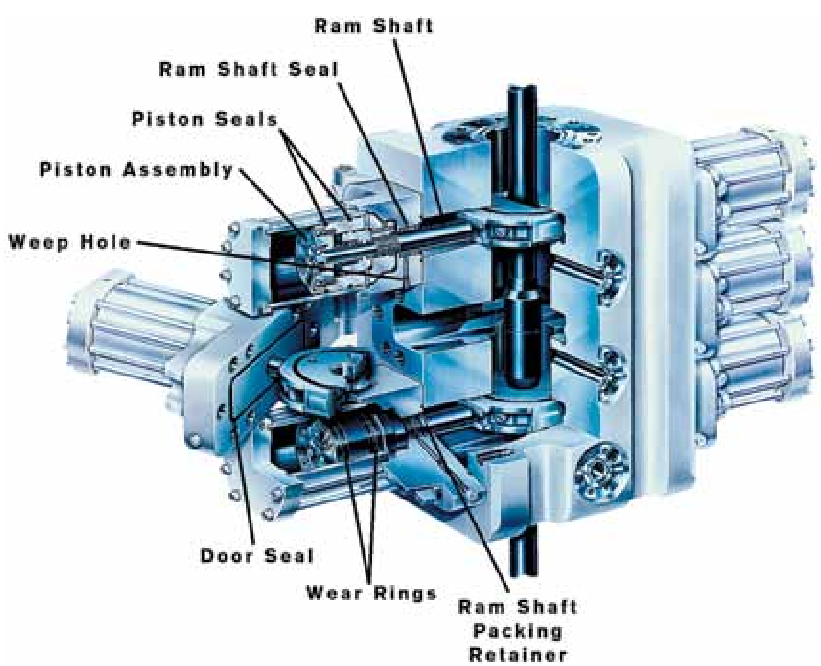
Or

Minimum pressure required to open ram = BOP rated working pressure ÷ ram opening ratio

Figure 7.39. Three ram preventer models.



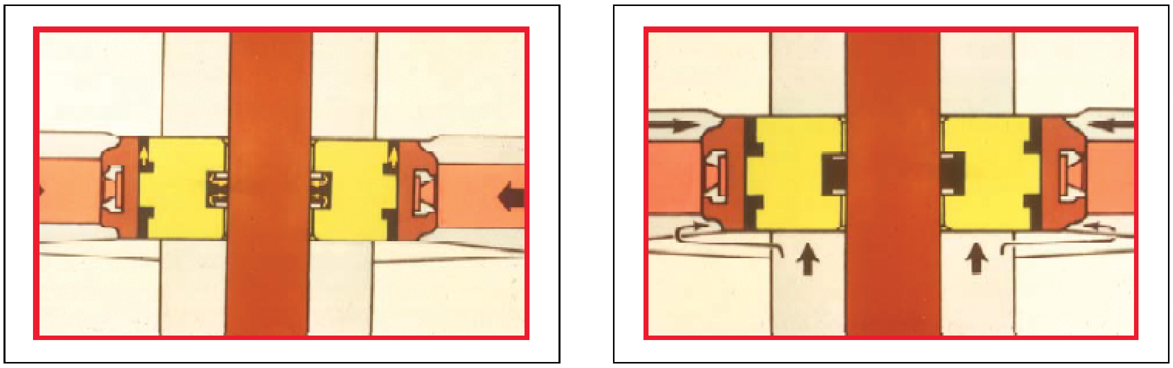


## Pipe Rams

*Pipe ram preventer blocks* are cut out to fit around a specific pipe size. Guides center the pipe as the rams close and a self-feeding packer rubber in the face of the ram block forms a seal around the pipe.

Most rams are hydraulically operated and energized by wellbore pressure. Hydraulic pressure is applied from opposing hydraulic cylinders, causing the rams to operate in unison. Conventional rams are designed to hold pressure coming up from beneath them. Wellbore pressure is allowed behind the rams and the wellbore pressure assists the sealing mechanism by pushing the rams together. When the rams close, the annular space around the pipe is effectively sealed off and wellbore pressure energizes the top seal upward against the body of the preventer. As the wellbore pressure rises, the packer pressure also rises due to the closing effect that the wellbore pressure has upon the ram blocks. See figure 7.40. With this mechanism, packer pressure is maintained above wellbore pressure.

Figure 7.40.



Although pipe rams might form a seal around a slight taper, if they are closed on larger diameters, for example, a tool joint, the joint will be crushed and the packing at the face of the ram will be damaged. Special care must be taken when closing pipe rams near a tool joint, especially with aluminum pipe that has a larger taper than steel pipe.

Some operations call for the pipe to be "hung off" on the rams by slacking off the string weight until a tool joint is resting on the closed ram blocks. Pipe and tubing can be stripped through pipe rams, however rotating or reciprocating the string may cause excessive packer wear and is not generally recommended. Pipe movement through closed rams should be minimized, as much as possible. Accumulator closing pressure is sometimes reduced (considering safety) when operations call for continuous pipe movement, as in stripping operations.

Pipe rams should not be function tested unless the appropriate size pipe is in the well. Likewise, they should not be closed on the open hole because the packing will be extruded and damaged.

## Blind Rams

Blind rams as the name implies, have no pipe cutout on the face of the ram blocks. The rams seal against each other to completely close an open well.

### Changing Ram Elements

Ram actuator assemblies are usually secured to the BOP housing by removable bonnets. Bonnets are unbolted from the BOP housing for maintenance, visual inspection, lubrication and changing ram blocks.

Visual inspection includes disassembling and inspecting ram blocks, ram seals, ram connecting rods and ram cavities for wear, scoring or local damage.

Follow the manufacturer's guidelines when performing maintenance, inspections or changing ram blocks and ram block elements. Maintenance guidelines include disassembly instructions, guidelines for cleaning parts, inspecting parts, replacing rubber elements, gaskets, and damaged parts, lubrication, reassembly and testing.

Maintenance records should be kept at the rig site. Records should indicate the preventers' manufacturer, model, nominal size, pressure rating and overhaul history. Maintenance dates, work description, and parts repaired or replaced should be recorded. Always use original OEM parts when replacing equipment parts.

## Pipe and Blind Ram Block Assemblies

The ram assembly consists of the ram body, front packer and top seal. To dress the ram body the front packer must be installed first. Then install the top seal and lock the front packer in place. See figures 7.41 and 7.42. Fixed ram assemblies are sized from 2⅜ to 6⅝ inches.

Figure 7.41. An illustration of a pipe ram block.

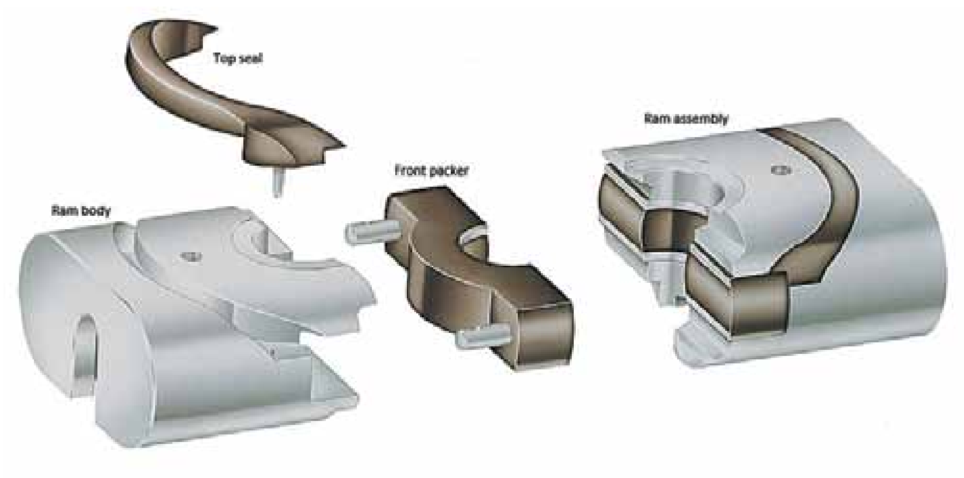
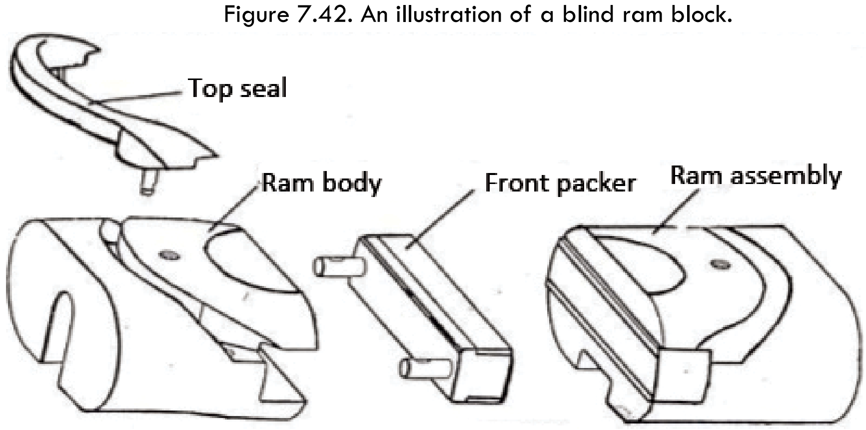



Figure 7.42. An illustration of a blind ram block.



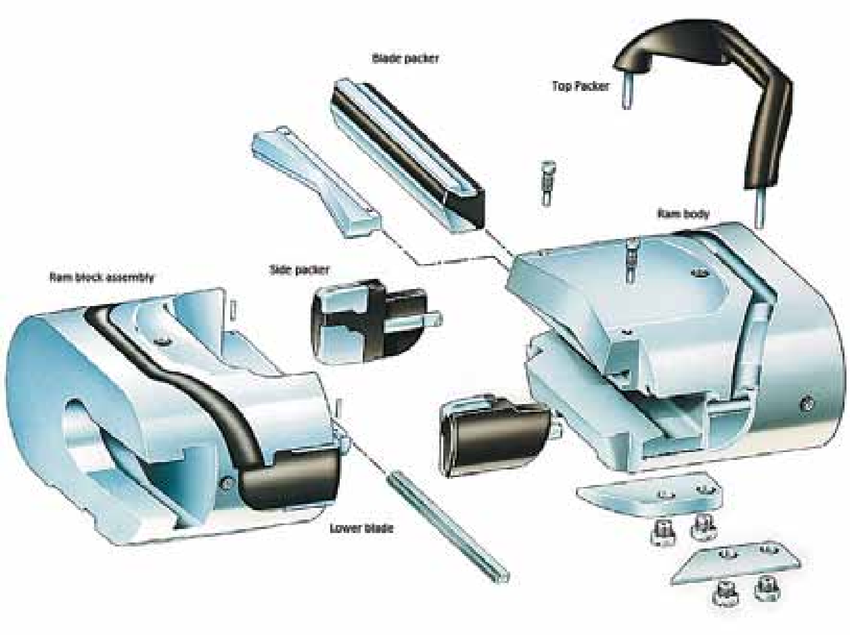
Ram packers and top seals should be in good condition. Rubber should not be missing from the pipe contact area on the front packer or sheared off on the top seal. As a general rule, ram packers should be considered acceptable when eighty percent of the rubber in the pipe contact area is still in place.

### Shear and Blind/Shear Rams

Shear rams are special rams with blades that are used in an emergency to cut (or shear) the work string in a well. Depending on the ram and the tubular to be cut, higher than normal regulated pressures or hydraulic boosters may have to be used to accomplish the shear. Ordinarily, a shear ram can shear larger tubular sizes than a blind/shear ram. Although shear rams are not always used in surface BOP stacks, they are always components of subsea stacks.

Rams specifically designed to shear large diameter casing have been developed and used primarily in subsea applications. These "casing shear rams" typically do not seal after shearing. A typical application is to place a set of blind/shear rams above the casing shear rams when in a BOP stack. Casing is sheared and the blind/shear rams are closed to provide a seal.

Figure 7.43. A diagram of a blind/shear block.




### Blind/Shear Rams

*Blind/shear rams* combine the functions of cutting the pipe and providing a strong wellbore seal after the cut. The obvious advantage of blind/shears is that one ram set does the job of two separate rams. Blind/shear rams have a built-in cutting edge that will shear tubulars that may be in the hole, allowing the blind rams to seal the hole. The upper portion of the severed drill string is freed from the ram, while the lower portion (fish) may be crimped and captured to hang the drill string off the BOP. The drill string must be hung off in the pipe rams before it is sheared to prevent it from falling into the bottom of the well or moving upward to damage the draw works or derrick.

When blind/shear rams are pressure tested, the packer is extruded and since the packer element in a shear ram is small, only a few pressure tests can be performed while retaining a usable packer element.

Federal regulations require that blind/shear rams installed in the BOP stack (both surface and subsea stacks) must be capable of shearing the drill pipe in the hole, under maximum anticipated surface pressures. There must be sufficient closing force to shear the work string.

The shear/blind rams consist of upper and lower ram bodies. The blade or front packer is installed first when dressing a shear/blind ram body. The side packers are then installed to keep the blade packer in place and finally, the top packer is inserted to lock the side packers. See figure 7.43.

## Feedable Rubber

All of the major ram type BOP manufacturers use the feedable rubber design concept in their ram packers. This includes Cameron, Hydril, Shaffer and MH Koomey. Extrusion plates molded into the front packer serves several purposes:

- To support the rubber, in order to prevent unwanted extrusion, due to wellbore forces in the vertical direction.
- Act as pistons to extrude feedable rubber to the point of pipe contact.

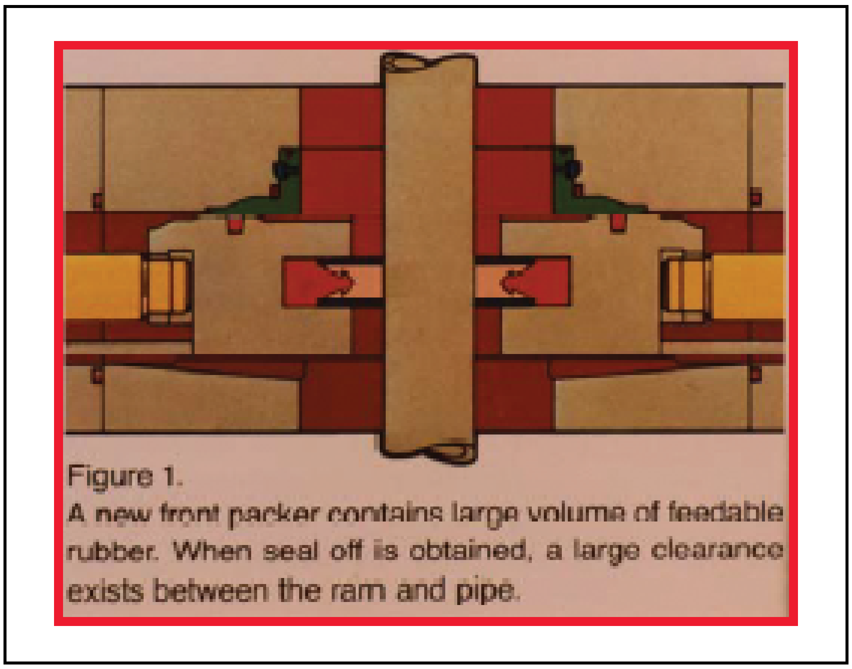
A new front packer contains large volume of feedable rubber. When seal off is obtained, a large clearance exists between the ram and pipe.

A moderately worn packer still retains a large but reduced volume of feedable rubber. The clearance between the ram and pipe is reduced at the seal off position.

The extensively worn front packer has used almost all of the feedable rubber volume, but is still able to effect a full rated seal off. The clearance between the ram and pipe is now approaching zero, indicating completion of the useful life of the front packer.

All ram type BOPs are only designed to contain and seal rated working pressure from below the ram.

Figure 7.44. A feedable rubber.



### Non-Shearable tubulars

Blind/shear rams may not be able to come together to shear and seal even with sufficient closing force if the work string diameter or wall thickness is too great. Typical shear rams cannot cut through some drill string components, such as drill pipe connections, sand screens, cables, control lines, some types of tools and wireline/braided cable that is not under tension in the wellbore. BOP manufacturers have shearing force data for a growing number of pipe, casing and screen sizes and materials. If no data are available, consider conducting a shearing test on the tubular in question. Specialty shear rams are available that are capable of cutting casing, drill collars, tooljoints, multiple tubing strings, solid sinker bars and shearing wireline or braided cable with zero tension. A line cutter can be used to cut the wireline and let it drop back into the hole, if blind or shear rams are used to shut-in a well during a wireline operation. Shear rams are not pressure tested except when operators accept new or rebuilt BOP stacks. Shear rams should not be slammed shut with high pressure when they are function tested. They should be functioned with a reduced operating pressure.

Bottoms up circulation followed by a flow check should be performed before pulling or running non-shearable tubulars.

Contingency plans should be made for not being able to shear all tubulars in higher risk wells, where blind shearing rams are a part of the BOP stack and non-shearable tubulars are pulled from or tripped into a well.

Contigency planning should include handling positioning equipment problems and when to stop pulling out of the hole, so that non-shearable drill string is below the ram shears or blind ram shears, if equipment problems occur. A diagram with all tool joint measurement positions and BOP spacing should be available to the driller at the BOP control panel.

Plans must be made for circulating kill fluid through a BOP, if the pipe is hung off. The well can be killed by circulating through the drill stem in the conventional manner, if the fish is hung off in the shear ram. The bottoms up circulation is followed with a flow check. Detailed plans should be made for fishing the drill string if it is intentionally or unintentionally sheared and dropped, allowing the fish to fall down the hole or if the drill string is released without closing the shear rams.

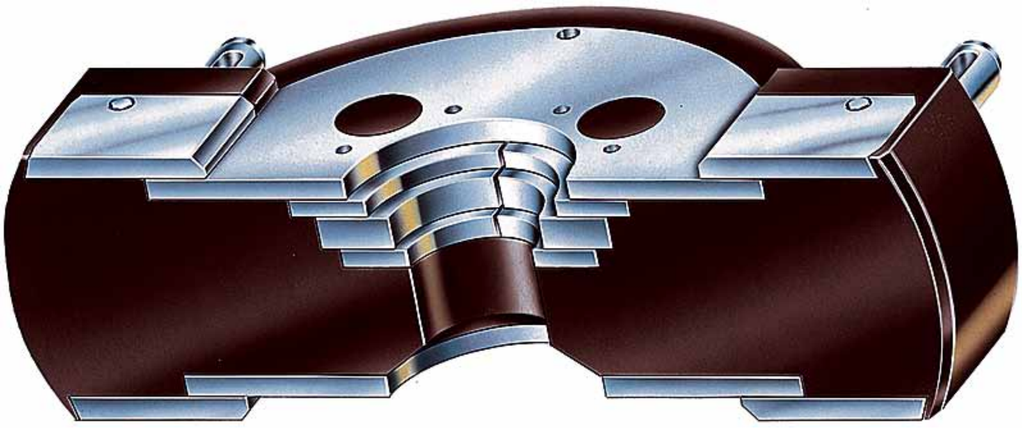
Good communications are required when non-shearable components are about to be run in or pulled out through the BOP. Good communications may allow for problems to be recognized and the non-shearable components can be stopped above the BOP, when running into the hole, or stopped below the BOP, if being pulled out. In higher risk wells, where blind shearing rams are a part of the BOP stack and nonshearable tubulars are pulled from, or tripped into a well, contingencies for the inability to shear (as the last resort) these tubular sections should be made. The contingencies might include: bottoms up circulation followed by a flow check prior to beginning the trip, and detailed plans for dropping the string. Depending on operations, the drill string can be dropped and allowed to fall down the hole or dropped and the BOP released, without closing the shear rams. Procedures should be in place to minimize the time that the non-shearable material is across the BOP stack.

## Variable Bore Rams (VBR)

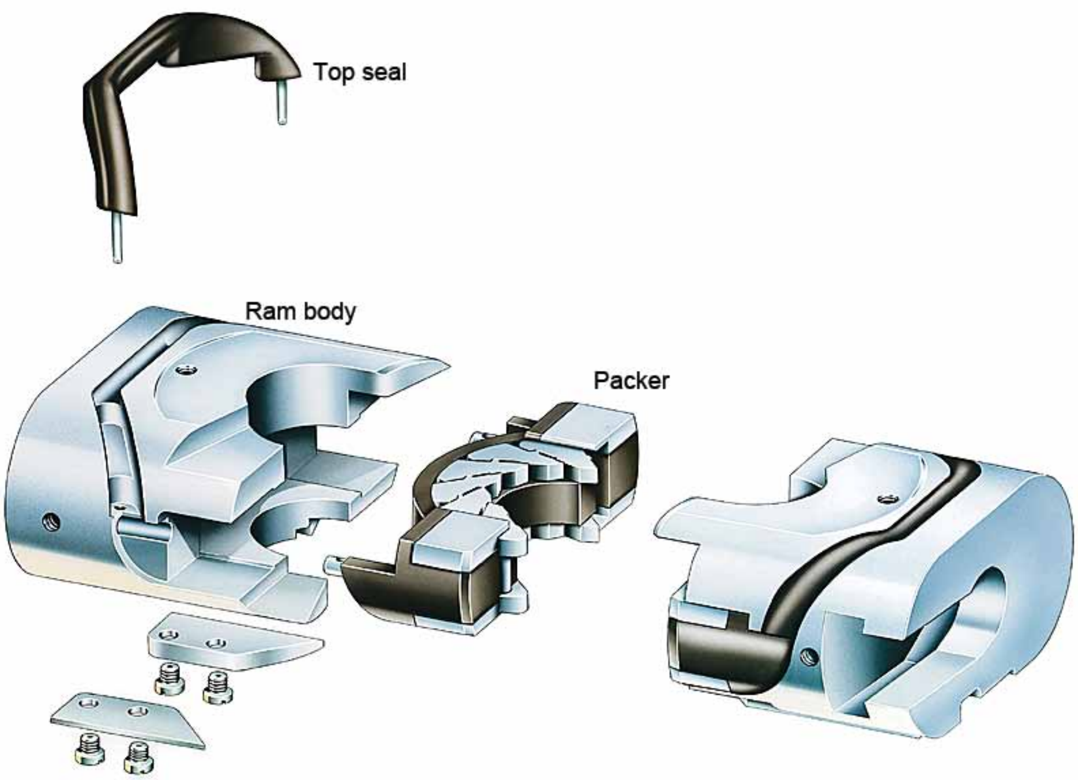
*Variable bore rams* seal on several sizes of pipe, and depending on the type of VBR, on a hexagonal kelly. They may also serve as the primary ram for one size pipe and a backup for another. On wells with tapered strings where space (height) is a concern, variable bore rams may be used. A set of variable bore rams in a preventer may save a round trip of the subsea blowout preventer stack because the rams do not have to be changed out when different diameter pipe strings are used or casing is set.

Figure 7.45. Variable bore ram (*top*) and flex bore ram (*bottom*)

Variable bore ram



Flex bore ram




On one type of VBR, the packer contains steel reinforcing inserts similar to those in an annular BOP packer. The inserts rotate inward when the rams are closed; the steel provides support for the rubber that seals against the pipe. In standard fatigue tests, variable bore ram packers performed comparably to pipe ram packers and VBRs are suited for hydrogen sulfide service.

Another type of VBR consists of several small pipe cutout plates that slide back out of the way of larger sized pipe until the correct cutout closes around the pipe. Sealing elements are placed between each plate to create the seal.

Table 7.5.

| Sample Range of Variable Bore Rams | |
|---|---|
| Preventer Bore (in inches) | Pipe Size Range (in inches) |
| 7¹⁄₁₆ | 2⅞ — 2⅜ |
| 7¹⁄₁₆ | 3½ — 2⅜ |
| 7¹⁄₁₆ | 4 — 2⅞ |
| 11 | 2⅜ — 3½ |
| 11 | 5 — 2⅜ |
| 11 | 5 — 2⅜ |
| 13⅝ | 5 — 2⅞ |
| 13⅝ | 5½ — 3½ |
| 13⅝ | 6 — 3½ |
| 13⅝ | 6⅝— 5 |
| 16¾ | 5 — 2⅞ |
| 16¾ | 7 — 3½ |
| 18¾ | 5 — 2⅞ |
| 18¾ | 5 — 3½ |
| 18¾ | 7⅝ — 3½ |

### Inspection and Maintenance

Equipment should be inspected regularly for signs of damage, wear, corrosion, deterioration, loose or missing parts and proper lubrication. Inspection may involve disassembly to inspect critical components for wear. Damaged or non-functional equipment must be properly repaired or replaced. Using damaged equipment may cause serious harm to personnel, damage to equipment, and business loss.

It is very important to maintain well control equipment, if well control equipment is not properly maintained, it may not function properly. Any failure of well control equipment can lead to disaster. Follow manufacture's maintenance recommendations and company maintenance guidelines and perform periodic planned maintenance on all well control equipment.

### Ram Visual Inspection:

After each well open the ram bonnets (doors). The ram cavity and ram block should be cleaned prior to the following visual inspection. This visual examination is generic and valid for all ram preventers. A few additional areas are required when inspecting the Cameron or Koomey "J" line ram preventer.

### RAM PACKERS, TOP SEALS AND BONNET SEALS RAM PACKERS

Ram packers and top seals should be in good condition. Rubber should not be missing from the pipe contact area on the front packer or sheared off on the top seal.

### BONNET SEALS

Bonnet seals are generally replaced each time the bonnets are opened.

### TOP SEALS

When top seals do not stand above ram block, in order of 0.075 to 0.140 inches for manufactures in general, the low pressure integrity of the preventer is jeopardized.

### RAM CAVITY

Visually inspect cavity upper seal seat for damage. The surface finish at the top of the cavity is the most critical aspect of this inspection. Sharp scratches make it difficult for top seal rubber to flow into these grooves for pressure integrity.

### RAM BLOCKS

If rams are used for hang off, record the part numbers of the ram blocks and verify their capabilities. Tagging rams is the usual cause of damage to the top of a ram block.

### HANG-OFF TEST

According to API 16A[2] the following minimum value is given before leaks develop for fixed pipe rams:

5-inch fixed rams 600,000 lb

3½-inch fixed rams 425,000 lb

For variable rams always check with manufacturer for correct value.

### CONNECTING RODS/RAM SHAFT PACKING

To visually examine the connecting rod, the operating piston must be stroked to the closed position when the bonnets or doors are open.

### POWER RAM CHANGE (PRC) PISTON

Cameron and Koomey rams use PRC pistons to open and close the bonnets. The surface finish of these chrome rods should also be checked to assure that the operating system has good pressure integrity.

### PACKING INJECTION

Check to ensure that secondary packing has not been energized. Check weephole to ensure it is free of sealant. Sealant could prevent a primary wellbore seal from leaking during a stump test which is performed to find such leaks.

### *THROUGH BORE*

Visually inspect through bore for key seating record. Repairs should be initiated when this bore wear exceeds 3/16 inches.

## Testing

### *FUNCTION TEST*

All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

Function tests should be alternated from the driller's panel and from mini remote panels, if present on location.

## Pressure test

All blowout prevention components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi and then to a high pressure. When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may continue to seal after the pressure is lowered, and therefore, may misrepresent a low-pressure condition. A stable low test pressure should be maintained for at least five minutes.

The initial high-pressure test on components that could be exposed to well pressure (BOP stack, choke manifold, and choke/kill lines) should be to the *rated working pressure of the ram BOPs or to the rated working pressure of the wellhead* that the stack is installed on, whichever is lower. Initial pressure tests are defined as those tests that should be performed on location before the well is spudded or before the equipment is put into operational service.

There may be instances when the available BOP stack, and/or the wellhead, have higher working pressures than are required for the specific wellbore conditions, due to equipment availability. Special conditions such as these should be covered in the site specific well control pressure test program.

Subsequent high pressure tests on the well control components should be to a *pressure greater than the maximum anticipated surface pressure*, but not to exceed the working pressure of the ram BOPs. The maximum anticipated surface pressure should be determined by the operator, based on specific anticipated well conditions. Subsequent pressure tests are tests that should be performed at identified periods, during drilling and completion activity on a well.

A stable high test pressure should be maintained for at least *five minutes*. Pressure test operations should be alternately controlled from the various control stations. Initial pressure tests on hydraulic chambers of ram BOPs and hydraulically operated valves should be to the maximum operating pressure recommended by the manufacturer. The tests should be run on both the opening and the closing chambers. Pressure should be stabilized for at least *five minutes*. Subsequent pressure tests are typically performed on hydraulic chambers only between wells or when the equipment is reassembled.

### *PRESSURE TEST FREQUENCY*

Pressure tests on well control equipment should be conducted at least:

a. Prior to spud or upon installation.

b. After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, or choke manifold, but limited to the affected component.

c. At least every 21 days.

*RESPONSE TIME*

Response time, between activation and complete operation of a function, is based on BOP or valve closure and seal off. For surface installations, the BOP control system should be capable of closing each ram BOP within 30 seconds. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time. Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed, effecting a seal. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

### Drilling Spools

Drilling spools are used to connect the BOP and wellhead and are used between preventers. A drilling spool must have an internal diameter that is at least equal to the bore of the BOP and have a rated working pressure equal to the rated working pressure of the installed ram BOP. It has smaller side outlets for choke and kill lines. The spool must be sufficiently tall to provide additional space between preventers to space out to facilitate stripping, hang off, and/or shear operations where no BOP rams (annular and pipe rams) close against a tool joint.

It is also used to provide stack outlets (to localize possible erosion in the less expensive spool). Drilling spools also increase the overall height of the stack, which may or may not be an advantage.

Figure 7.46. An example of drilling spools.

Drilling spools for BOP stacks should meet the following minimum qualifications:

a. Three thousand and 5k arrangements should have two side outlets no smaller than a two-inch nominal diameter and be flanged, studded, or hubbed. Ten thousand, 15k, and 20k arrangements should have two side outlets, one 3-inch and one 2-inch nominal diameter as a minimum, and be flanged, studded or hubbed.

b. Have a vertical bore diameter the same internal diameter as the mating BOPs and at least equal to the maximum bore of the uppermost casing/tubing head.

c. Have a rated working pressure equal to the rated working pressure of the installed ram BOP.

For drilling operations, wellhead outlets should not be employed for choke or kill lines.

### Stack Installation

Rigging the BOP stack up and down becomes a routine operation for crews, as their rig moves from one location to another. It is difficult dirty work that must be done, no matter the hour of the day or the most unpleasant conditions. It must be done efficiently and as quickly as possible. The contractor is constantly under pressure to save time. It is all too easy to make mistakes under such circumstances. But if a component of the BOP stack fails during a well control incident the result can be tragic.

Connections are the weakest points in any piping or valve system and the BOP stack is no exception. The flanges and sealing ring gaskets are subject to accumulative abuse in the rigging up/rigging down process, which can lead to failure. BOP flange rating must be equal to or greater than the Christmas tree's rating.

### BOP End and Side Outlet Connections

On all type of BOPs Three different types of connections are used both as end connections and side outlet connections on all type of BOPs. This includes ram preventer, annular preventer, drilling spools, casing spools and hydraulic connectors. The three types are studded, clamp hub and flanged connection. See figures 7.47, 7.48 and 7.49.

Figure 7.47. Studded connection.

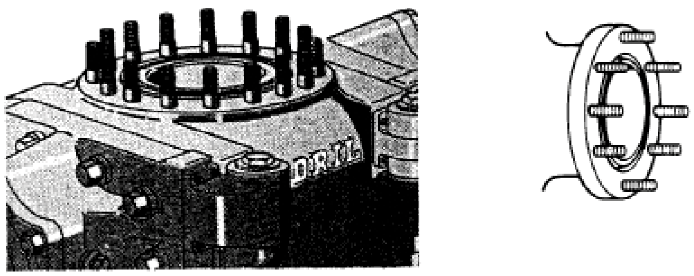


Figure 7.48. Clamp hub connection.

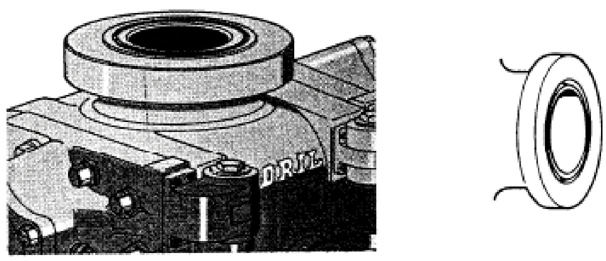
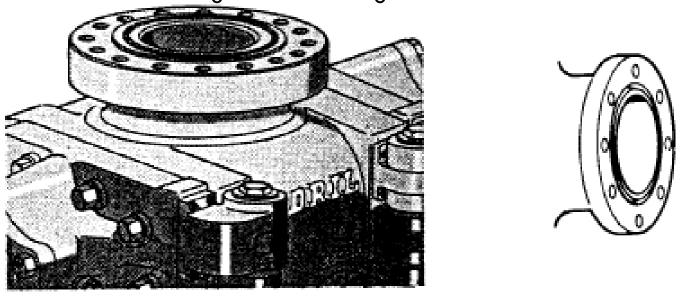


Figure 7.49. Flanged connection.



## Flanges

### API Type Flanges

Two types of flanges are used in well control equipment, according to API.

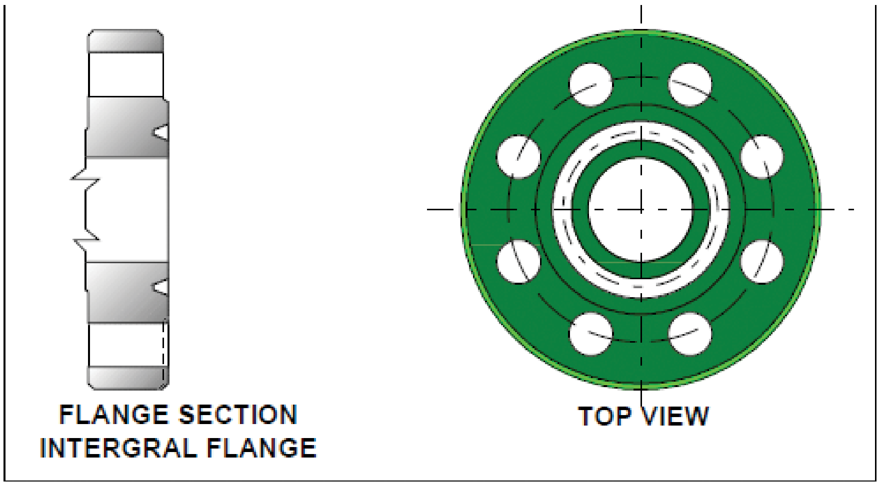
- API Type 6B flange
- API Type 6 BX flange

### API Type 6B Flange

API Type 6B flange is a "low" pressured flange with maximum pressure rating of 5,000 psi.

API Type R or RX ring gaskets are used for this type flange. They do not allow face to face contact between hubs or flanges, so external loads are transmitted through the sealing surfaces of the ring. The flange face might be flat or raised. See figure 7.50.

Figure 7.50. An illustration of API Type 6B Flange.




### API Type 6 BX Flange

API Type 6 BX flange is a "high" pressure flange with maximum pressure rating of 20,000 psi.

API Type BX ring gaskets are used for this type of flange, allowing face to face contact of the flanges. The flange face shall be raised, except for studded flanges, which may have flat faces. See figure 7.51.

### Marking

According to API, the following marking should be visible on the flanges OD:

- Manufacturer's name and mark
- API monogram
- Size
- Thread size
- End and outlet connection size
- Rated working pressure

- Ring gasket type and number
- Ring gasket material

Figure 7.51. An illustration of API Type 6BX Flange.

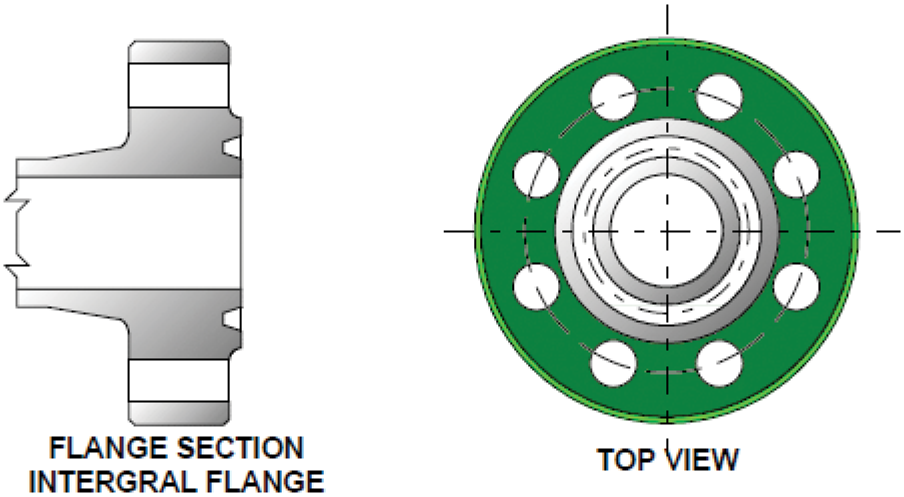



Table 7.6. Flange sizes and ratings.

| Rated Working Pressure (psi) | Flange Size Range | |
|---|---|---|
| | Type 6 B (inch) | Type 6 BX (inch) |
| 2,000 | 2¹⁄₁₆ – 21¼ | 26¾ – 30 |
| 3,000 | 2¹⁄₁₆ – 20¾ | 26¾ – 30 |
| 5,000 | 2¹⁄₁₆ – 11 | 13⅝ – 21¼ |
| 10,000 | N/A | 1¹³⁄₁₆ – 21¼ |
| 15,000 | N/A | 1¹³⁄₁₆ – 18¾ |
| 20,000 | N/A | 1¹³⁄₁₆ – 13⅝ |

## Ring Gaskets

### Ring Joint Gaskets and Grooves

*Introduction*

Ring joint gaskets and grooves are described within API RP 16A[2] and API RP 53[6].

"Ring gaskets have a limited amount of positive interference which assures the gaskets will be joined into sealing relationship within the flanges grooves. These gaskets shall not be re-used".

### Material

Purchasers can specify one of the four different materials when they purchase API gaskets:

Table 7.7. Materials.

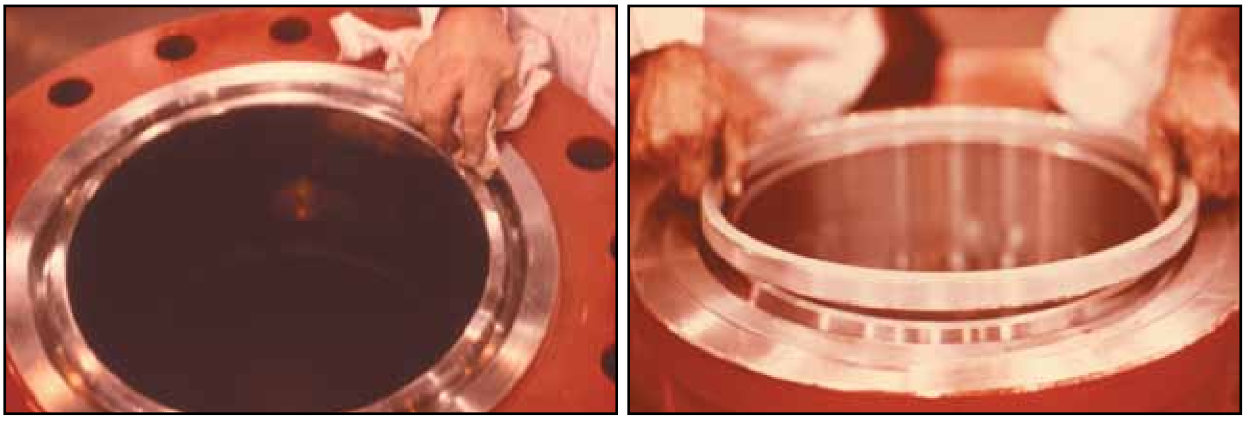
| Material | Hardness Brinell | Identification Marking |
|---|---|---|
| Soft Iron | 90 | D |
| Low-Carbon Steel | 120 | S |
| Type 304 Stainless Steel | 160 | S 304 |
| Type 316 Stainless Steel | 140 to 169 | S 316 |
| Inconel 625 | 481 to 560 | N/A |

Scratching the ring gaskets, ring grooves, and mating surfaces when rigging up is a major source of failure. It is not the purpose of this text to describe stack installation in detail, however there are some basic good practices that apply and since safety is always a key point, they are worth mentioning.

- Ring grooves and mating surfaces should be cleaned with soap and water and inspected carefully before installation. In some cases of close ring-to-groove tolerance, it may be necessary to apply a mist of light oil to assist the ring in seating properly.
- Wire brushes and scrapers should never be used on mating surfaces and ring grooves.
- Identify the closing and opening hydraulic ports and keep them clean. Trash and dirt in the hydraulic operating system will eventually cause failure of the system.
- When making up the stack one component at a time, all bolts should be hand tightened as the entire stack is made up before torquing them tight. Flange studs and nuts must be of the correct size and grade and made-up, to the proper torque in a crisscross manner (see API Spec 6A).

The X type rings, that are pressure energized, help in keeping the flanges tight but still, they should be checked and retightened as necessary. Type RX and BX ring joint gaskets are used in self-energized type gaskets or grooves. Type R ring gaskets are not self-energized. Therefore, they are not recommended for use on well control equipment. The RX ring gaskets are used with Type 6BX flanges and 16B hubs. Type BX ring gaskets are used with type 6BX and type 16BX hubs.

Figure 7.52



API hub and clamp connections consist of two hubs pulled together against a metal seal ring by a two or three piece clamp. This connection requires fewer bolts to make up and is lighter, but is not as strong as the equivalent bore API flange connection in tension, bending or combined loading. However, proprietary clamp or hub connections may be equal or superior to the API flanged connection, for combined loading.

## Common Ring Joint Gaskets

*API R* ring joint gaskets are not energized by internal pressure. Sealing takes place along small bands of contact between the grooves and the gasket on both the OD and ID of the gasket. The gasket may be either octagonal or oval in cross section. The type R design does not allow face-to-face contact between the hubs or flanges. External loads are transmitted through the sealing surfaces of the ring. Vibration and external loads may cause the ring grooves to deform plastically, so that the joint may develop a leak unless the flange bolting is tightened on a weekly basis.

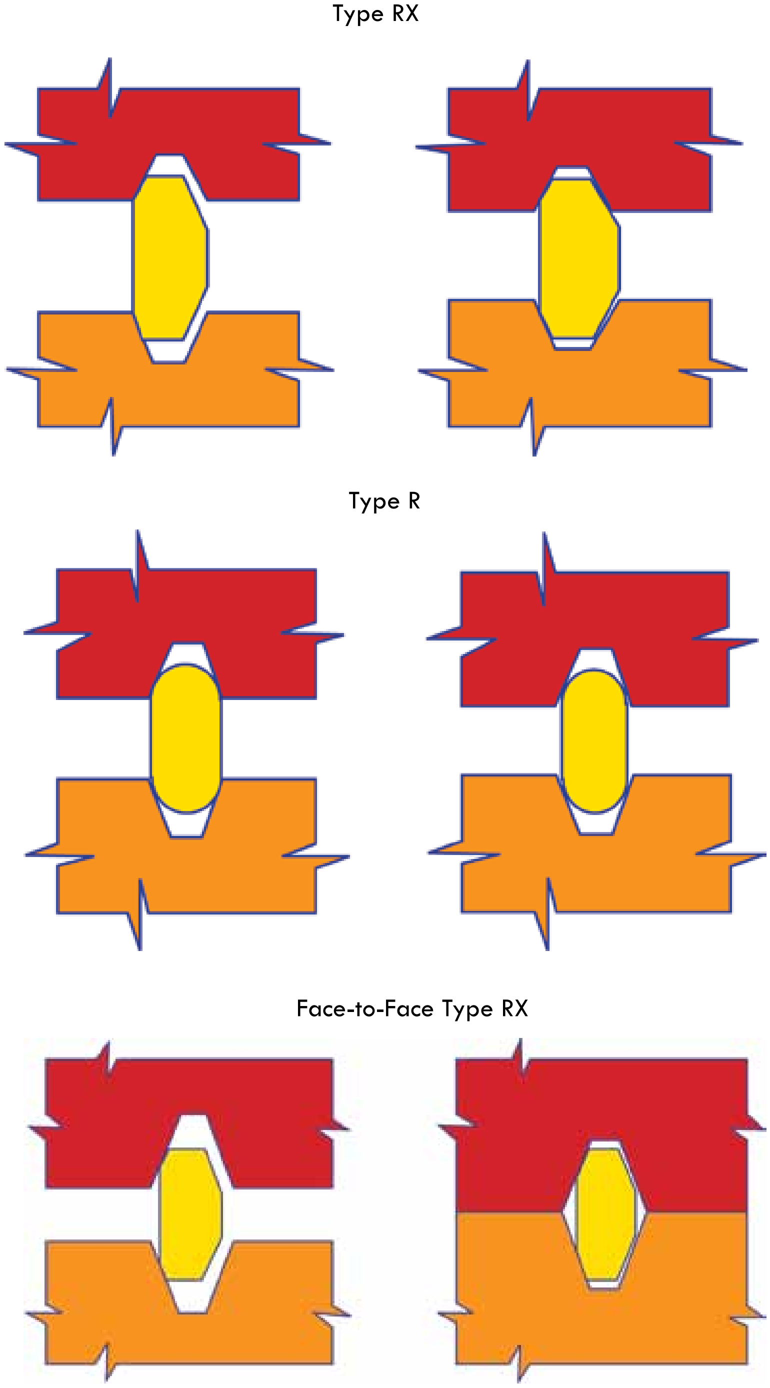
In the *API RX* pressure energized ring joint gasket, the seal takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing as the joint is tightened. The RX design does not allow face-to-face contact between the hubs of flanges because the gasket has large load bearing surfaces on its inside diameter to transmit external loads without plastic deformation of the sealing surfaces of the gasket. A new gasket should be used each time the joint is made up. API RX (and BX) ring gaskets each have a hole bored through the height of the gasket to provide a pressure passage through the gasket.

The *API face-to-face RX* pressure energized ring joint gasket was adopted by API as the standard joint for clamp hubs. Sealing takes place along small bands of contact between ring grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the grooves and is compressed to some degree to achieve initial sealing as the joint is tightened. The increased groove width ensures face-to-face contact between the hubs, but this leaves the gasket unsupported on its ID. Without support from the ID of the ring grooves, the gasket may not remain perfectly round as the joint is tightened. If the gasket buckles or develops flats, the joint may leak.

Cameron Iron Works (CIW) modified the API face-to-face type RX pressure energized ring joint grooves to prevent leaking caused by the gasket buckling in the API groove. The same API face-to-face type RX pressure energized ring joint gaskets are used with these modified grooves. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is slightly larger in diameter than the grooves, and is compressed to achieve initial sealing as the joint is tightened. The gasket ID will also contact the grooves when it is made up. This constraint of the gasket prevents any leaking caused by buckling of the gasket. Hub face-to-face contact tolerances of the gasket and the groove is maintained within a tolerance of 0.022 inches.

The *API BX* pressure-energized ring joint gasket was designed for face-to-face contact of the hubs or flanges. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. The gasket is made slightly larger in diameter than the ring grooves. It is compressed to achieve initial sealing, as the joint is tightened. The intent of the BX design was to provide face-to-face contact between the hubs or flanges. However, the groove and gasket tolerances, which are adopted, are such that if the ring dimension is on the high side of the tolerance range and the groove dimension is on the low side of the tolerance range, face-to-face contact may be very difficult to achieve. Without face-to-face contact, vibration and external loads can cause plastic deformation of the ring and may eventually result in leaks. Both flanged and clamp hub BX joints are equally prone to this difficulty. The BX gasket is frequently manufactured with axial holes to ensure pressure balance, since both ID and OD of the gasket may contact the grooves.

Figure 7.53. Ring joint gaskets.

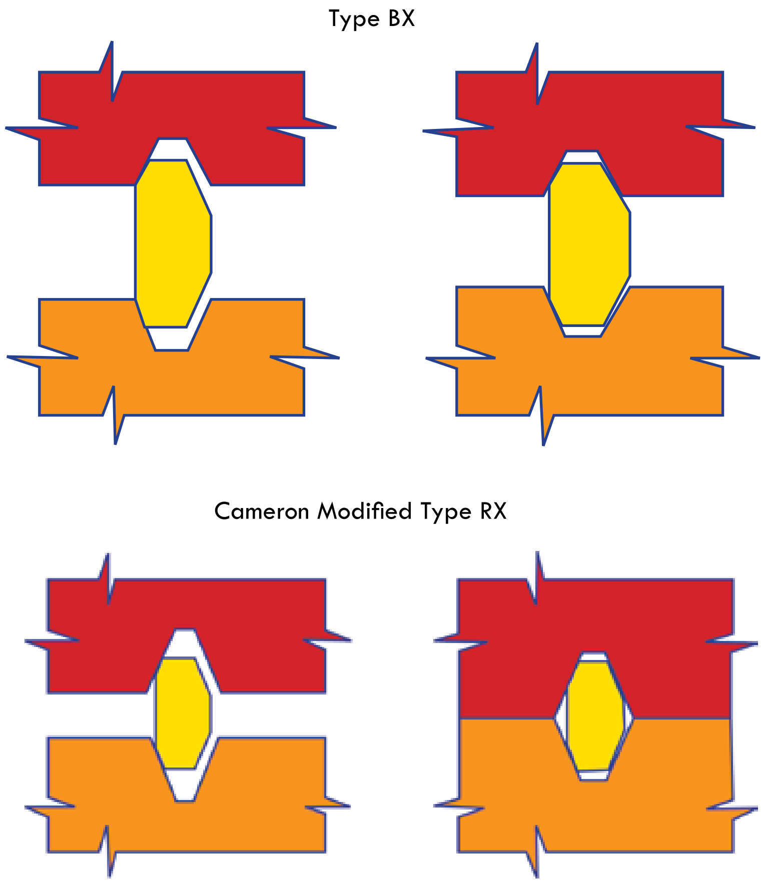



With *Cameron AX and Vetco VX* pressure energized ring gaskets, the sealing takes place along small bands of contact between the grooves and the ID of the gasket. The gasket is made slightly larger in diameter than the grooves and is compressed to achieve initial sealing as the joint is tightened. The ID of the gasket is smooth and is almost flush with the hub bore. Sealing occurs at the diameter, which is only slightly greater than the diameter of the hub bore, so the axial pressure load on the collet connector is held to an absolute minimum. The belt at the center of the gasket keeps it from buckling or cocking as the joint is being made up. The OD of the gasket is grooved to allow the use of retractable pins or dogs to positively retain the gasket in the base of the collet connector when the hubs are separated.

The AX and VX gasket design allows face-to-face contact between the hubs to be achieved with minimal clamping force. It is used at the base of the collet connector, because the lower gasket must be positively retained in the connector when the hubs are separated. Its design ensures that axial pressure loading on the collet connector is held to an absolute minimum. External loads are transmitted entirely through the hub faces and cannot damage the gasket. The AX or VX gasket is also suitable for side outlets on the BOP stack, since these outlets are not subject to keyseating.

*Cameron CX* pressure-energized ring gaskets allow face-to-face contact between the hubs to be achieved with minimal clamping force. Sealing takes place along small bands of contact between the grooves and the OD of the gasket. External loads are transmitted entirely through the hub faces and cannot damage the gasket. The gasket is made slightly larger in diameter than the grooves, and is compressed slightly to achieve initial sealing, as the joint is tightened. The gasket is patterned after the AX gasket, but is recessed instead of being flush with the hub bore for protection against keyseating. The gasket seals approximately the same diameter as the RX and BX gaskets. The belt at the center of the gasket keeps it from buckling or cocking as the BOP or riser joint is made up.

Figure 7.54. Ring joint gaskets.




Wellhead flange bolts are particularly critical on stacks in deep water jackups. This is because the movement of the long conductor pipe to the sea bottom is restrained at the upper end by tying off the stack to the rig. On any rig, if only the stack is tied off to the rig, tremendous forces can act against the wellhead flange where all the bending is concentrated. It is good practice to tie off the conductor against the rig whenever possible.

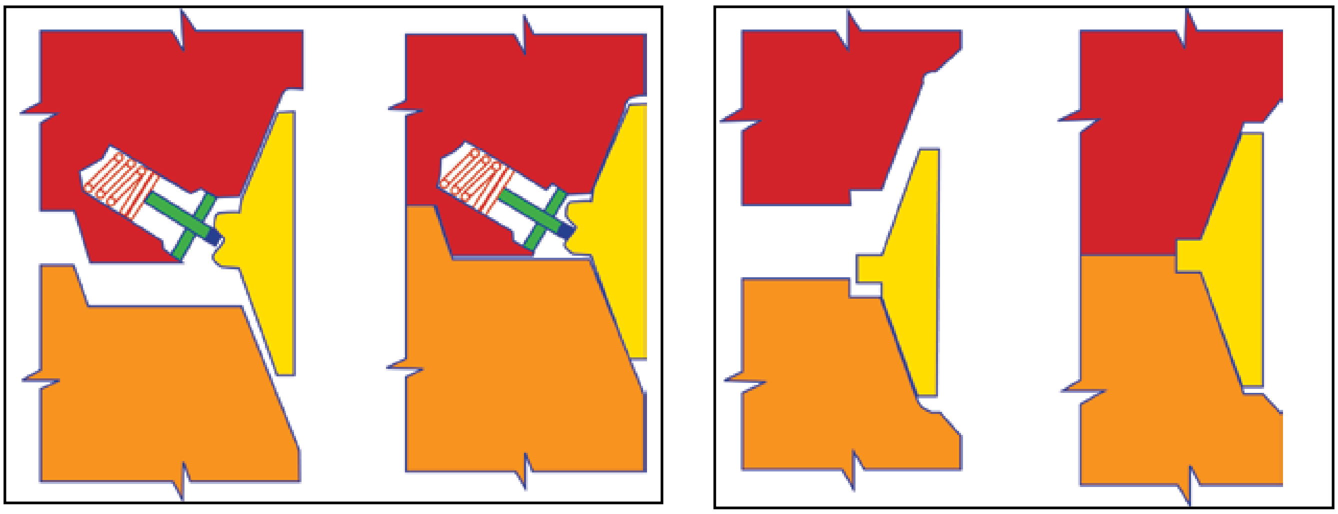
Every effort should be made to keep the derrick centered over the well in order to minimize contact between the work string and the stack. The string should drop through the center of the BOP without contact. Rigs can move; settling can cause the derrick to move off-center. If the derrick is not perpendicular from the base, the top of it may be several feet off the center of the well.

The wear effect is not immediate, because the rams and annular preventer will close and test. However, the long-term damage is severe. It can result in off-center wear in the stack and bit or tool gouges in the stack bore, ram or annular faces. Wear and damage also may occur to the casing and wellhead. Minor damage may seal on a test, but there is always the chance that further damage will occur and the stack will not seal during a kick. Beyond that, repair to the bore of the stack is a manufacturing plant job that is long and costly. Generally, wear rings, or wear bushings, will minimize inside wear and damage. In addition, the stack should be stable. Procedures for testing the BOPs and auxiliary equipment can be found in chapter 11.

Figure 7.55. Ring joint gaskets.

Type AX or VX

Cameron Type CX



## Other Connections

Hydraulic pipes and fittings are commonly joined together using National Pipe Tapered threads. When made up, these threads will pull tight and make an effective seal if first coated with a sealing compound or wrapped with polytetrafluoroethylene (PTFE) tape. Pipe threads in general are not recommended for high-pressure applications, as they tend to leak more than any other style of connection.

Swivel joints are adjustable and provide safe and reliable shortcuts to complicated piping configurations. They are used in the construction of pipelines and other oilfield operations. High pressure swivel joints are often used in fracturing, cementing, acidizing, and well testing. Designed for the critical service conditions, a high pressure swivel joint is made of heat treated high-strength alloy steel to maximize the service life and ensure working pressure standards are met.

### Fill-Up Lines

A fill-up line above the uppermost preventer (usually incorporated in the bell nipple) is recommended. The fill-up line is used to fill the hole during trips and when the well is not being circulated. There is little maintenance required other than assuring that the line does not become plugged or seriously corroded.

### Accumulators (BOP Control Units)

In the early days of drilling, blowout preventers were closed and locked manually. Although some small rigs still operate the BOPs by hand, most rigs function the stack hydraulically by means of an accumulator (control) unit. An accumulator is a device that stores hydraulic fluid under pressure in special containers (bottles) and provides a method to close and open the blowout preventers quickly and reliably. A typical accumulator unit and its main components are depicted in figure 7.57.

Accumulator units used with surface BOP systems consist of pumps, special valves, a liquid reservoir, and several banks of bottles. The bottles are precharged with nitrogen, an inert or non-flammable gas, to a specified pressure and then liquid is pumped into the bottle, compressing the nitrogen until the pressure on the bottle is at system operating pressure. When the unit is operated, valves on the bottles open and the nitrogen expands, acting like a spring, and forcing liquid out of the bottle to do the mechanical work of functioning the preventer. The most common nitrogen precharge for a 3,000 psi system is 1,000 psi (±10percent). The control fluid is usually hydraulic fluid or in some cases water-based soluble oil. Bactericides or fungicides are sometimes added to water-based fluids to prevent the growth of organic matter. The use of improper oils or corrosive waters will harm the accumulator unit and the closing elements of the BOP stack. Some important components of an accumulator system are described below.

- *Primary pump*. The primary pump is an electrically driven positive displacement pump that maintains the system pressure. A pressure switch (usually set for about 2,700 psi) senses system pressure and turns the pump on or off as necessary.
- *Air pumps*. Air driven pumps are provided as a backup in the event of electrical power loss.
- *Pressure reducing/regulating valves*. One regulating valve is used to provide and reduce pressure on the manifold (usually 1,500 psi) to operate the rams and valves. A separate regulating valve provides pressure for the annular preventer. The operating pressure for the annular varies depending on the type of annular preventer in use, company policy, and present operations.
- *Four-way valves*. The four-way valves are used to function the BOPs and valves. The valves have three positions; open, close, and neutral or blocked. When the valve is in the neutral position it is blocked; the associated equipment cannot be functioned.
- *Gauges*. Three gauges are mounted on the unit to display system pressure, manifold pressure, and annular preventer pressure.
- *Remote control panels*. BOPs can be functioned on the rig floor by means of a remote control panel. There may be other remote panels located on site, for instance, in the operator or toolpushers offices.

The driller's remote control panel display should be laid out as a graphic representation of the BOP stack. See figure 7.56.

Figure 7.56. A remote control panel.

Its capability should include the following:

1. Control all the hydraulic functions which operate the BOPs and choke and kill valves.
2. Display the position of the control valves and indicate when the electric pump is running (offshore units only).
3. Provide control of the annular BOP regulator pressure setting.
4. Provide control of the manifold regulator bypass valve or provide direct control of the manifold regulator pressure setting.
5. The driller's panel should be equipped with displays for readout of:
   - Accumulator pressure
   - Manifold regulated pressure
   - Annular BOP regulated pressure
   - Rig air pressure
6. Offshore rig driller's panels should have an audible and visible alarm to indicate the following:
   - Low accumulator pressure
   - Low rig air pressure
   - Low hydraulic fluid reservoir level
   - Panel on standby power (if applicable)
7. All panel control functions should require two handed operation. Regulator control may be excluded from this requirement.

BOP stack functions should also be operable from the main hydraulic control manifold. This unit should be installed in a location that is remote from the drill floor and easily accessible to rig personnel in an emergency.

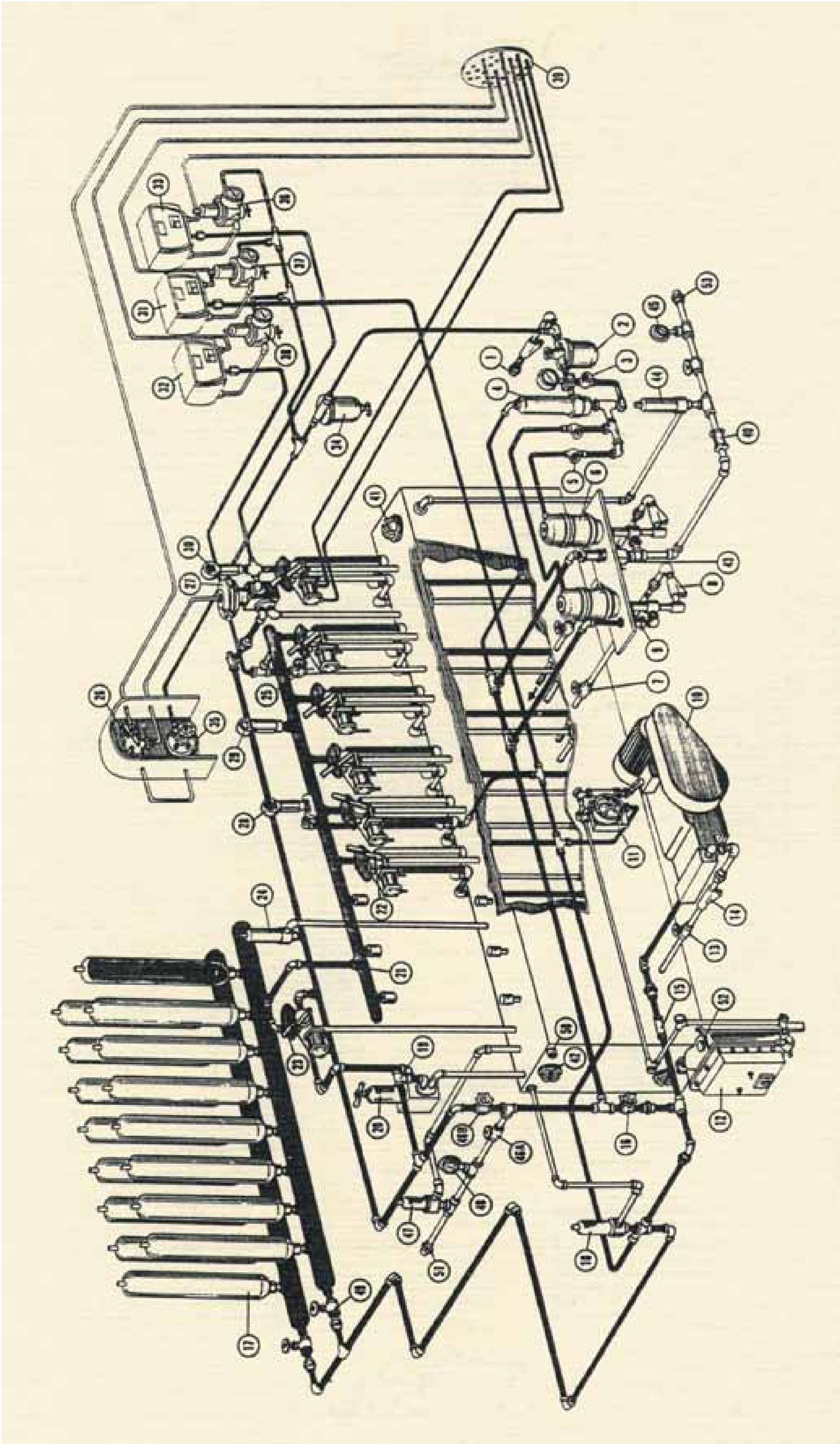


Figure 7.57. Typical Koomey BOP Control Schematic.

Figure 7.57. Typical Koomey BOP Control Schematic.

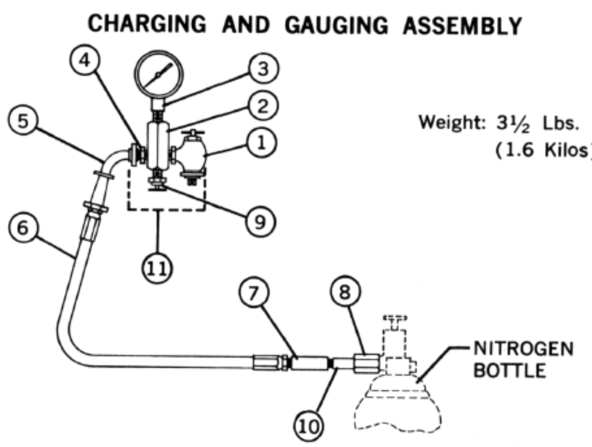
1. Customer air supply: normal supply is 124 psi. (Higher may require air regulator.)
2. Air lubricator: on air inlet line to air pumps. Use SAE 10 lubricating oil.
3. Bypass valve: to automatic hydro-pneumatic pressure switch. If pressures higher than normal 3,000 psi are required, open. Close at all other times.
4. Automatic hydro-pneumatic pressure switch: 2,900 psi cut-out with air and electric pumps. 3,000 psi for air pumps alone. Adjustable spring tension control.
5. Air shut-off valves: manual – open/close supply to air hydraulic pumps.
6. Air operated hydraulic pumps: normal operating air pressure is 125 psi.
7. Suction shut-off valve: manual. Normally open. One for each suction line.
8. Suction strainer: one for each suction line. Removable screens.
9. Check valve: one for each air operated hydraulic pump delivery line.
10. Electric motor driven triplex or duplex pump assembly.
11. Automatic hydroelectric pressure switch: pressure switch is set at 3,000 psi cut-out and 250 psi cut-in differential. Adjustable.
12. Electric motor starter (automatic): for motor driving triplex/duplex pump. Works with auto. hydroelectric pressure switch. Manual override on-off switch.
13. Suction shut-off valve: manual, normal open. In suction line of pump.
14. Suction strainer: located in the suction line of the triplex or duplex pump.
15. Check valve: located in the delivery line of the triplex or duplex pump.
16. Accumulator shut-off valve: manual. Normally open when the unit is in operation. Close when testing or skidding rig or applying pressure over 3,000 psi to open side of ram preventers. Open when test is completed.
17. Accumulators: check nitrogen precharge in accumulator system every 30 days. Precharge should be 1,000 psi +/–10 percent. Caution: use nitrogen when adding to precharge. Other gases and air may cause fire and/or explosion.
18. Accumulator relief valve: valve set to relieve at 3,500 psi.
19. Fluid strainer: located on the inlet side of the pressure reducing and regulating valves. Clean strainer every 30 days.
20. Koomey pressure reducing ad regulating valve: manually operated. Adjust to the required continuous operating pressure of ram type BOPs.
21. Main valve header: 5,000 psi W.P., 2” all welded.
22. Four-way valves: with air cylinder operators for remote operation from control panel. Keep in standard operating mode (open/close), never in center position.
23. Bypass valve: with cylinder operator for remote operation from control panels. Close position puts pressure on main valve header (21). Open position puts full pressure on header. Keep closed unless 3,000 psi+ required on ram type BOPs.
24. Manifold relief valve: valve set to relieve at 5,500 psi.
25. Hydraulic bleeder valve: manually operated – normally closed. Note: this valve should be kept open when precharging the accumulator bottles.
26. Panel-unit selector: manual 3-way valve for applying pilot air pressure to air operated Koomey pressure reducing/regulating valve, either from air regulator on unit or from air regulator on remote control panel.
27. Koomey pressure reducing and regulating valve – air operated: reduces accumulator pressure to required annular BOP operating pressure. Pressure can be varied for stripping operations. Maximum recommended operating pressure of annular preventer should not be exceeded.
28. Accumulator pressure gauge.
29. Manifold pressure gauge.
30. Annular preventer pressure gauge.
31. Pneumatic pressure transmitter for accumulator pressure.
32. Pneumatic pressure transmitter for manifold pressure.
33. Pneumatic pressure transmitter for annular preventer pressure.
34. Air filter: located on the supply line to the air regulators.
35. Air regulator, Koomey pressure reducing/regulating valve – air operated.
36. Air regulator for pneumatic transmitter (33) for annular pressure.
37. Air regulator for pneumatic pressure transmitter (31), accumulator pressure.
38. Air regulator for pneumatic pressure transmitter (32), manifold pressure. Controls for transmitters normally set at 15 psi. Increase or decrease air pressure to calibrate the panel gauge to match the hydraulic pressure gauge on unit.
39. Air junction box: connect unit lines to panel lines through air cable.
40. Rig test check valve.
41. Hydraulic fluid fill port.
42. Inspection plug port.
43. Rig test outlet isolator valve: high pressure, manually operated. Close when rig testing – open when test is complete.
44. Rig test relief valve: valve set to relieve at 6,500 psi.
45. Rig test pressure gauge.
46. A. Rig skid outlet and 46B. Valve header isolator valves: manually operated. Close valve header isolator and open rig skid isolator when rig skidding. Open valve header isolator and close rig skid isolator during normal drilling.
47. Rig skid relief valve; valve set to relieve at 2,500 psi.
48. Rig skid pressure gauge.
49. Accumulator bank isolator valves: manually operated, normally open.
50. Rig skid return: customer’s connection.
51. Rig skid outlet: customer’s connection.
52. Electric power: customer’s connection.
53. Rig test outlet: customer’s connection.

Remote control from the remote panels of the hydraulic control manifold valves may be actuated by pneumatic (air), hydraulic, electro-pneumatic, or electro-hydraulic remote control systems. The remote control system should be designed so that manual operation of the control valves, at the hydraulic control unit, will override the position previously set by the remote controls.

The accumulator system must have enough capacity to supply the volume necessary to meet or exceed the minimum requirements for closing systems. *Usable fluid* is defined as "the hydraulic fluid recoverable from the accumulator system between the maximum accumulator operating pressure and 200 psi above the precharge pressure."[11] The system should have enough usable hydraulic fluid volume (without the pumps) to close one annular preventer, the rams, and one HCR (hydraulically operated choke line) valve and still maintain 200 psi above the precharge. Therefore a 3,000 psi system with bottles properly precharged to 1,000 psi should have a remaining minimum pressure of 1,200 psi after the BOPs are functioned. It can be seen that the nitrogen precharge is the most critical element in maintaining usable fluid. *If the nitrogen precharge is depleted, usable fluid is lost.* Good practice, as well as regulations in certain areas dictate that the precharge on each bottle be checked and recorded at least every 30 days, or every well, whichever comes first.

API RP 53[6] states that a drawdown test shall be performed after the initial nipple-up of BOPs, after any repairs that required isolation/partial isolation of the system, or every 6 months from previous test and details the mathematics involved to calculate the API recommended minimum volume. The Bureau of Safety and Environmental Enforcement (BSEE) requires 1.5 times the volume (a fifty -percent safety factor) necessary to close and hold closed all BOP units with minimum pressure of 200 psi above precharge pressure.

Figure 7.58.




| ITEM NUMBER | PART DESCRIPTION |
|---|---|
| Ass'y. | Charging and Gauging Assembly, Complete |
| 1 | Air Chuck |
| 2 | Adapter |
| 3 | Gauge |
| 4 | Tank Valve |
| 5 | Swivel Connector |
| 6 | Hose |
| 7 | Coupler |
| 8 | Nut |
| 9 | Bleeder Valve |
| 10 | Gland |
| 11 | Gauging Head Assy. |

Government or state agencies or company policies may have different volume requirements. Since it is better to have more than a minimum volume, most operators and contractors prefer to use a factor of three times the volume required to close everything on the stack. The goal is to have enough reserve power for the accumulator system to operate the stack and still have more than the nitrogen precharge remaining.

A quick estimation of usable volume on a typical 3,000 psi system with 1,000 psi precharge is half the volume of the accumulator bottle. Calculations demonstrate that approximately one-half of the total bottle volume may be used before the pressure drops to 200 psi above the precharge. For example, a twenty-gallon accumulator bottle, properly precharged, has a usable volume of approximately 10 gallons. The larger spheres normally have a volume of 80 gallons and a usable volume of 40 gallons.

### *ESTIMATED ACCUMULATOR VOLUME REQUIREMENTS USING 1.5 SAFETY FACTOR*

Using manufacturer's manuals to collect closing data, assume a stack comprised of:

One Hydril GK annular preventer :

13⅝ inches to close = 17.98 gallons

Three Cameron type U Rams:

13⅝ inches to close 5.80 gallons * 3 = 17.40 gallons

Total volume required to close:

17.98 + 17.4 = 35.38 gallons

BSEE requires a fifty-percent safety factor, therefore:

35.38 * 1.5 = 53.07 usable gallons

53.07 gallons is rounded up to the next increment of 10 for a total of 60 gallons of usable fluid. In this example, it would be necessary to have six 20-gallon bottles, or spheres, or some combination that would give a minimum total of 60 gallons of usable fluid.

If exact requirements must be met, or if a system other than the 3,000 psi system, for example 2,000 psi, the following formula can be used.

$$\boxed{V_3 = V_R \div ([P_3 \div P_2] - [P_3 \div P_1])}$$

Where:

$P_1$ = Maximum pressure when fully charged

$P_2$ = Minimum operating pressure

$P_3$ = Nitrogen precharge pressure

$V_3$ = Total accumulator volume

$V_R$ = Total usable fluid (including safety factor)

Using the required volume from the example above, 53.07 gallons, what is the total accumulator volume required for a 2,000 psi system with a 1,000 psi recharge and 1,200 psi minimum operating pressure?

$V_3 = V_R \div ([P_3 \div P_2] - [P_3 \div P_1])$

$V_3 = 53.07 \div ([1{,}000 \div 1{,}200] - [1{,}000 \div 2{,}000])$

$V_3 = 53.07 \div (.8333 - .5)$

$V_3 = 53.07 \div 0.3333$

$V_3$ = 159.22 gallons rounded up to 160 gallons

In extremely cold environments, take care to prevent the core temperature of the accumulator system from dropping below freezing. The rubber goods inside, such as the bladders, will become brittle and can burst.

The accumulator system should have maintenance at least every 30 days or every well, whichever comes first. The following thirty-day schedule is a guide, but may not be sufficient for some operations.

- Clean and wash the air strainer.
- Fill the air lubricator with 10 weight oil (or other specified weight).
- Check the air pump packing. The packing should be loose enough so that the rod is lubricated, but not loose enough to drip.
- Check the electric pump packing.
- Remove and clean the suction strainers. They are located on the suctions intakes of both air and electric pumps.
- Check the oil bath for the chain drive on the electric pump. It should be kept full of chain oil. Check the bottom of the oil reservoir for water.
- The fluid volume in the hydraulic reservoir should be at operating level (generally two thirds to three quarters full).
- Remove and clean the high-pressure hydraulic strainers.
- Lubricate the four-way valves. There are grease fittings on the mounting bracket, and generally, a grease cup for the piston rod.
- Clean the air filter on the regulator line.
- Check the precharge of individual accumulator bottles (should read 900 to 1,100 psi).

To check the accumulator precharge:

- Shut off the air to the air pumps and power to the electric pump.
- Close the accumulator shut-off valve.
- Open the bleeder valve and bleed the fluid back into the main reservoir.
- The bleeder valve should remain open until the precharged pressure is checked.
- Replace the guard from the accumulator bottle precharge valve. Screw on the gauge assembly.
- Open accumulator precharge valve by screwing down on the T-bar handle. Check the precharge pressure. The gauge should read 1,000 psi ±10 percent. If too high, bleed excess pressure off; if low, recharge to the proper pressure with nitrogen. Close the precharge valve by unscrewing the T-bar handle, then remove gauge assembly. Replace the guard.
- Open the accumulator shut-off valve.
- Turn on air and power. The unit should recharge automatically.

The procedure given here is for a typical closing unit. Variations will occur with specialized equipment and operations. For example, subsea BOP stacks have accumulator bottles on the stack. The precharge on these bottles in deep water is the calculated hydrostatic pressure of the seawater plus 1,000 psi, plus a safety margin for seepage or temperature. Special high-pressure bottles are used to prevent burst when precharging on the surface. Recommended procedures for testing accumulator units appear in appendix D.

### Response Time

Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For surface installations, the BOP control system should be capable of closing each ram BOP within 30 seconds. Closing time should not exceed 30 seconds for annular preventers smaller than 18¾-inch nominal bore and 45 seconds for annular preventers of 18¾ inches and larger. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time.

Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed, effecting a seal. A BOP may be considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

### Choke and Kill Line Connections

*Choke and kill line connections*, although sometimes ignored in the rush of rigging up and down on rig moves, are an important component of the surface BOP system. Common problems may include using nipples that are too light, dirty seal rings, damaged mating surfaces, loose nuts and long unsupported nipples or lengths of pipe. Avoid the temptation to use low pressure hoses where there is little room available for steel piping. Likewise, excessive bends in pipe, or the use of bent lines, can lead to unexpected failures at the worst possible time.

### Choke Manifolds

The purpose of the manifold is to provide a method of circulating from the BOP stack under a controlled pressure. The manifold provides alternate routes so that chokes and valves can be changed out or repaired.

API bulletin RP 53[6] provides a description of the choke manifold and recommended practices for planning and installation. The recommendations include:

- Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) should have a working pressure at least equal to the rated working pressure of the blowout preventers (rams) in use. This equipment should be tested when installed to pressures equal to the rated working pressure of the blowout preventer stack in use.
- Components should comply with applicable API specifications to accommodate anticipated pressure, temperature, abrasiveness and corrosivity of the formation fluids and drilling fluids.
- For working pressures of 3M and above, only flanged, welded or clamped connections should be used with components subjected to well pressure.
- The choke manifold should be placed in an accessible location, preferably outside of the rig substructure.

- The choke line (which connects the blowout preventer stack to the choke manifold) and lines downstream of the choke should:
  - Be as straight as practical; turns, if required, should be targeted.
  - Be firmly anchored to prevent excessive whip or vibration.
  - Have a bore of sufficient size to prevent excessive erosion or fluid friction.
  - Minimum recommended size for choke lines are three-inch nominal diameter (2-inch nominal diameters are acceptable for Class 2M installations).
  - Minimum recommended size for vent lines downstream of the chokes are 2-inch nominal diameters.
  - For high volumes and air or gas drilling operations, four-inch nominal diameter lines (or larger) are recommended.
- Alternate flow and flare routes (blooey lines), downstream of the choke line, should be provided so that eroded, plugged or malfunctioning parts can be isolated for repair without interrupting flow control. Low-temperature properties of the materials used in installations that will be exposed to unusually low temperatures should be considered carefully.
- The bleed line (the vent line that bypasses the chokes) should be at least equal in diameter to the choke line. This line allows circulation of the well with preventers closed while maintaining a minimum of back-pressure. Also, it permits high-volume bleed off of well fluids to relieve casing pressure with the preventers closed.
- Although not shown in typical equipment illustrations, buffer tanks (watermelons) are sometimes installed downstream of the choke assemblies for manifolding the bleed lines together. When buffer tanks are employed, provision should be made to isolate a failure or malfunction without interrupting flow control.
- Pressure gauges suitable for abrasive fluid service should be installed so that tubing or drill pipe and annulus pressures may be accurately monitored and readily observed at the station where well control operations are to be conducted.
- All choke manifold valves subject to erosion from well control should be full-opening and designed to operate in high-pressure gas and abrasive fluid service. Double, full-opening valves between the blowout preventer stack and the choke line are recommended for installations with rated working pressures of 3M and above.
- For installations with rated working pressures of 5M and above ,the following are recommended:
  - One of the choke line valves should be remotely actuated.
  - Double valves should be installed immediately upstream of each choke.
- At least one remotely operated choke should be installed. If prolonged use of this choke is anticipated, a second remotely operated choke should be used.
- All chokes, valves and piping should be hydrogen sulfide service rated.

Figure 7.59. A single manual adjustable choke.

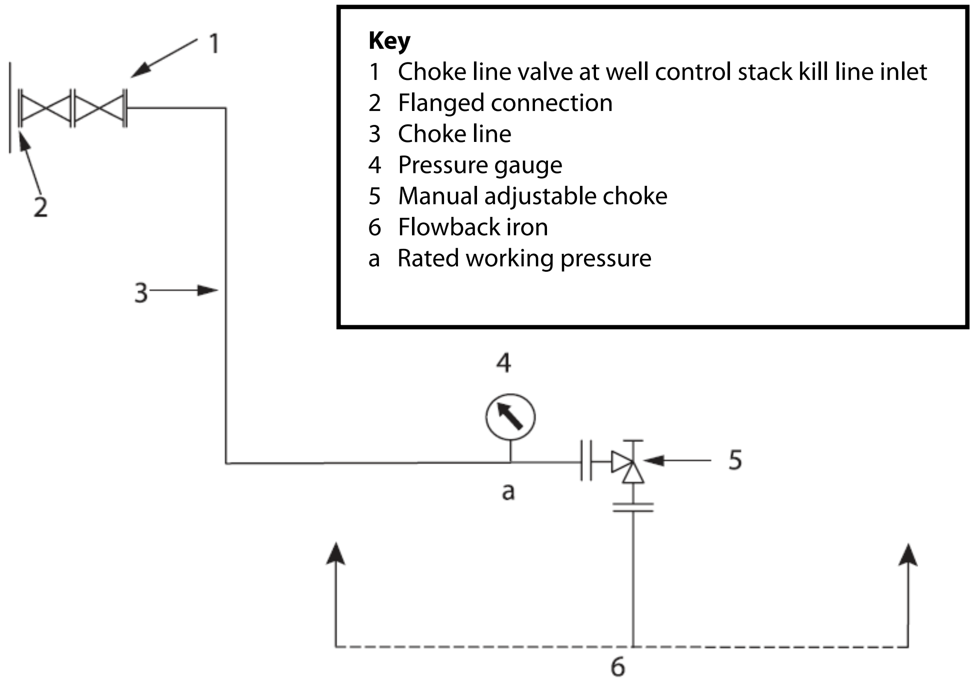



Figure 7.60. A dual remotely adjustable choke.

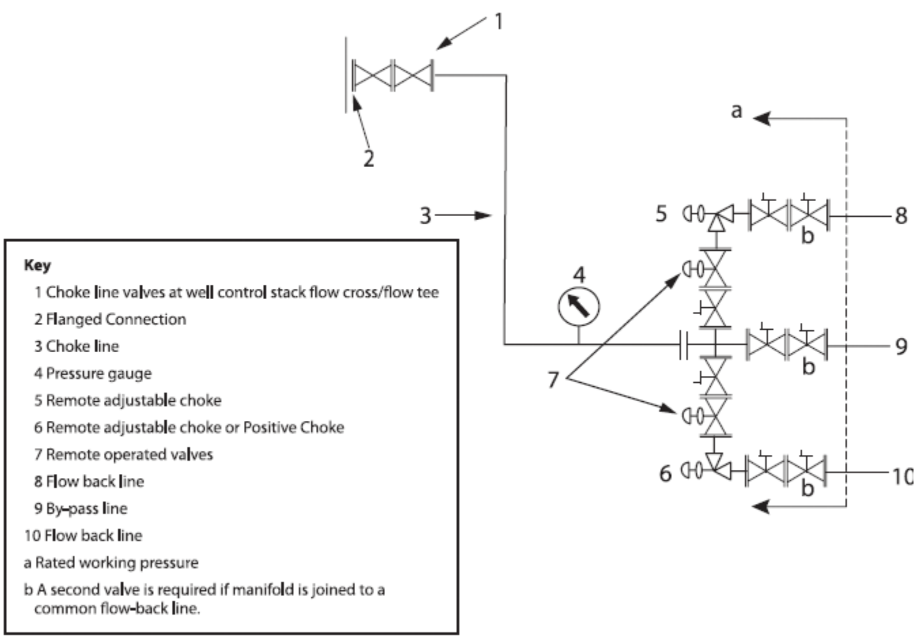
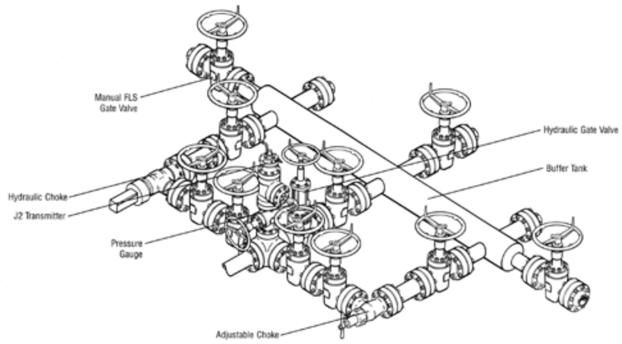
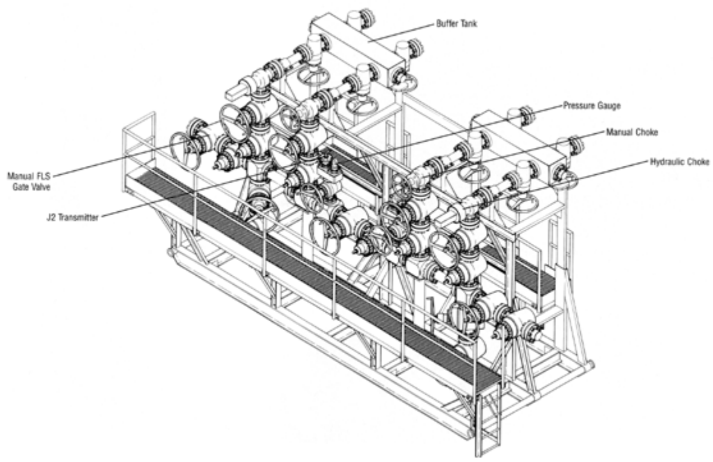


Figure. 7.61. Several examples of choke manifolds.

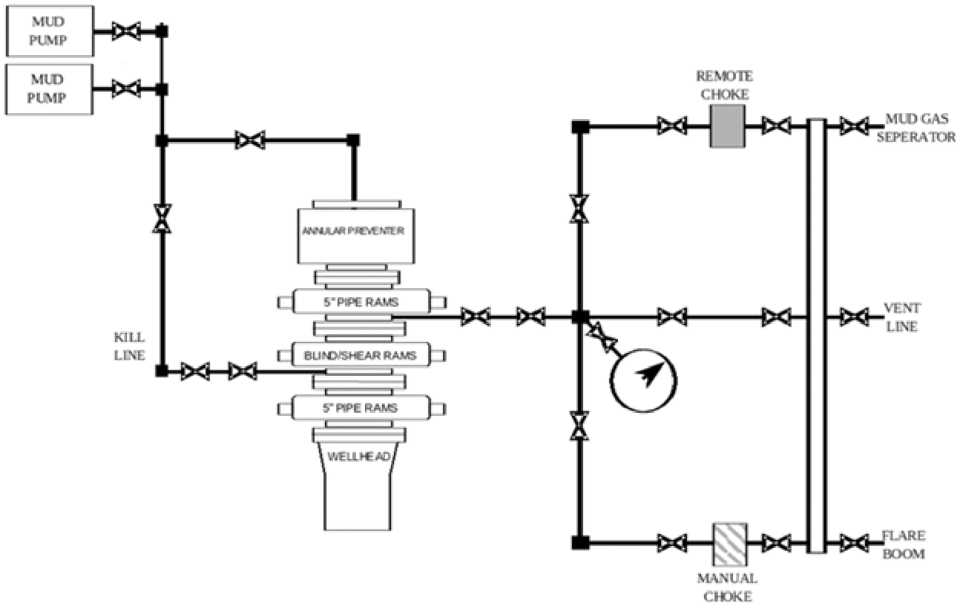



**Typical Choke Manifold Designed for Land Drilling Applications**




**Typical Choke Manifold Designed for Subsea Drilling Applications**

Figure 7.62. A diagram of circulating path.




## Kill Lines

*Kill lines* are an integral part of the surface equipment required for drilling well control. The kill line system provides a means of pumping into the wellbore, when the normal method of circulating down through the kelly or drill pipe cannot be used. The kill line connects the drilling fluid pumps to a side outlet on the BOP stack. The location of the kill line connection to the stack depends on the particular configuration of BOPs and spools employed.

The connection should be below the ram type BOP most likely to be closed.

On selective high pressure, critical wells, a remote kill line is commonly used to permit use of an auxiliary high-pressure pump, if the rig pumps become inoperative or inaccessible. This line normally is tied into the kill line near the blowout preventer stack and extended to a site suitable for location of a pump. This site should be selected to afford maximum safety and accessibility.

The same guidelines which govern the installation of choke manifolds and choke lines apply to kill line installations.

## HCR – Side Outlet Valves

Good practices require that two valves are located between the BOP stack and the choke manifold for installations with rated working pressures of 5,000 psi and above. One of these two valves should be remotely controlled. During operations, all valves should be fully opened or fully closed.

Of the two valves installed on the BOP side outlet the manual valves should be installed as the first coming from the BOP and is always left in open position during normal drilling operation. See figure 7.63.

The outside valve is a hydraulically operated valve that can be operated from the control unit or from remote operation panels, using 1,500 psi operating pressure. The maximum operating pressure of the valves is normally 3,000 psi. See figure 7.64.

Figure 7.63. A manual operated HCR.

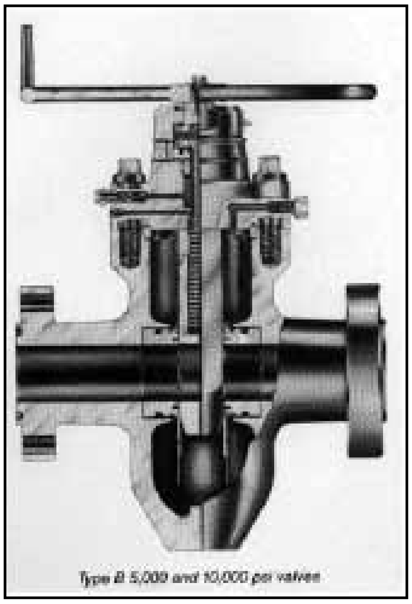
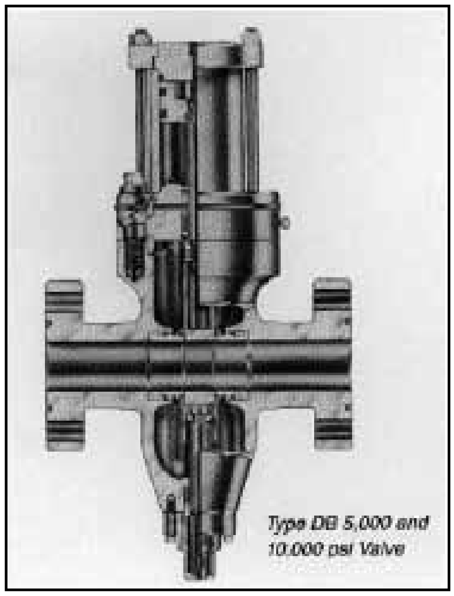



Figure 7.64. A hydraulic operated HCR.

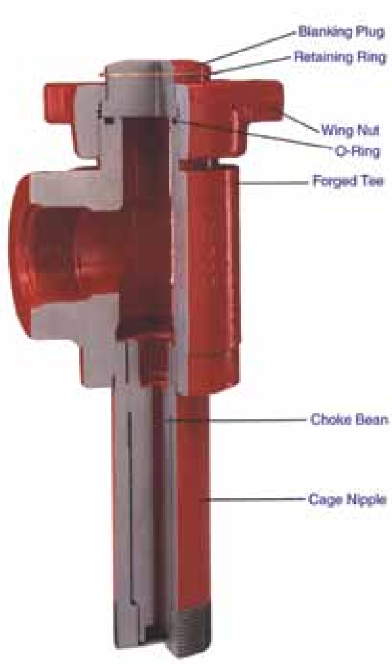



## Chokes

A *choke* is a device with an orifice installed in line to restrict the flow of fluids. By restricting the flow, extra friction or back-pressure is placed on the system, thus providing a means of controlling flow rate and wellbore pressure.

Figure 7.65. Examples of chokes.

Production Choke




Manual Adjustable Choke

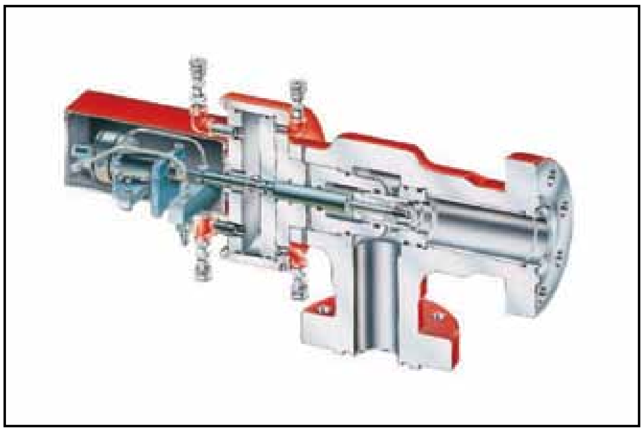
Chokes used for well control are designed differently from production chokes. Production chokes are not suitable for well control operations because the choke orifice cannot be varied. Adjustable chokes, both manual and hydraulic, are used for well control operations because the back-pressure on the well can be controlled within the limits of the choke rating.

*Fixed chokes* are part of the Christmas tree on a well and contain a choke nipple, or bean, with a small diameter bore that serves to restrict the flow from the well.

A *manual adjustable choke* has a tapered bar and seat. As the bar gets closer to the seating area, there is less clearance for the fluid going through it, thus producing more back-pressure on the well. All drilling choke manifolds are fitted with one or more manual adjustable chokes. On rigs that use a remote adjustable choke as the primary choke, the manual adjustable serves as a back up. It should be functioned frequently to ensure it is in good working order and tested during BOP tests.

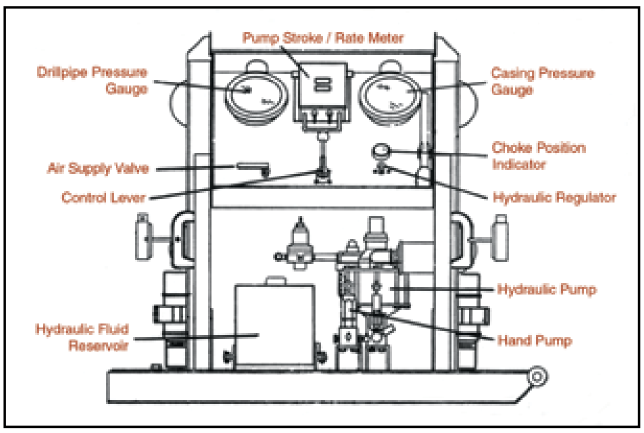
Figure 7.66.

Remote Hydraulic Choke



Remote Choke Panels

Remote Choke Panels




Remote Choke Panels

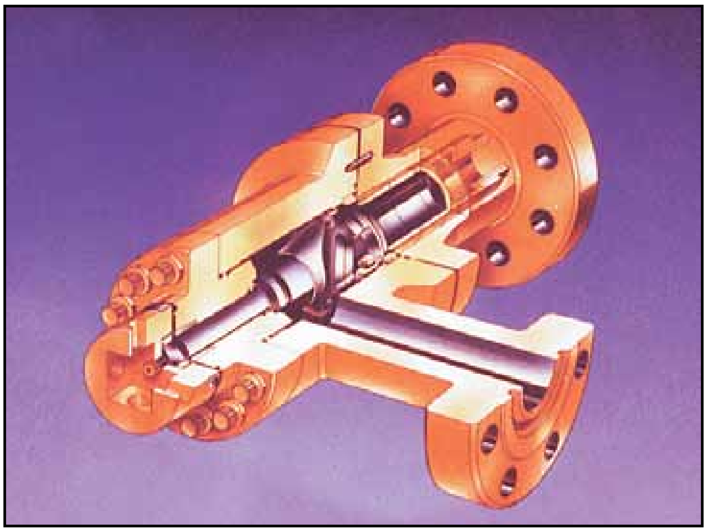
*Remote adjustable chokes* are the chokes of preference for drilling operations and for pressure-related work. They provide the ability to monitor pressures and volume pumped, and to adjust the choke orifice from a console, usually located on the rig floor.

There are two basic types of remote adjustable chokes. One type uses a bar that moves in and out of a tapered choke gate. When the choke is fully open, the bar is all the way out of the gate and provides a two-inch opening. The operating mechanism is a double-acting cylinder operated by hydraulic pressure from the choke console. Several manufacturers provide this type of choke.

The SWACO Super Choke uses two lapped tungsten carbide plates, each with a half-moon opening, one fixed and the other rotating when the choke is operated. When the two half-moons are in line the choke is fully open to slightly less than the area of a full two-inch choke bean. The SWACO choke will close and seal tight to act as a valve. The operating mechanism is a set of double-acting cylinders operating a rack and pinion, which turns the upper choke plate. Hydraulic pressure is supplied by the choke panel.

Both types of remote adjustable chokes are commonly rated for 10,000 psi operating pressure. However, 15,000 and even 20,000 psi rated adjustable chokes can be built to order. All remote chokes are available in hydrogen sulfide trim and all have operating panels that include choke position, pumped volume, circulating (drill pipe) and casing pressure gauges, a pump for hydraulic operation, and an on-off switch. It is a good idea to briefly operate remote hydraulic chokes briefly at each shift change to ensure they are functioning properly. Some operators conduct remote choke drills in which mud is pumped through the choke manifold. The object of the drill is to familiarize personnel with the technique of controlling drill pipe pressure by adjusting the choke while pumping at a consistent rate.

Figure 7.67. An adjustable choke.



## Mud-Gas Separators

A *mud-gas separator (gas buster, poor boy degasser)* is a device designed to separate free gas from the mud returning from a well as a kick is being circulated out. It is usually connected to the end of the manifold or choke line at a point just before fluid enters the back of the shale shaker or return line. The greatest amount of gas coming up with a kick will separate from the liquid below the choke. The separator directs the free gas to a flare line or to a point safely away from the rig. Mud-gas separator design varies from a simple, open cylinder used with some manifolds, to more complex float-operated separators. Separation is more efficient in light, low viscosity fluids than in viscous fluids.

Two types of atmospheric designs of mud-gas separators are available, the vertical type and the horizontal type. The horizontal type is gaining recognition within the industry because of its design advances and they are:

a. Larger exposed liquid surface area
b. Longer retention time of the fluid
c. The gas flows perpendicular to the direction of the fluid flow.

Due to space problems the vertical mud-gas separator is still the most common type used in the industry.

Gas blow-by or blow-through is a term used to describe overloading mud-gas separators, thus allowing gas to overtake the liquid and escape into the pit area. On some separators, retention time in the vessel is controlled solely by the hydrostatic pressure in the U-tube that leads to the pits. Pressure within the gas separator should be monitored and pumping should be controlled at a rate that avoids a blow-by situation. Care should be taken to ensure the gas vent line does not plug. A restriction in the vent line may result in rapid pressure build up, which could cause the vessel to rupture.

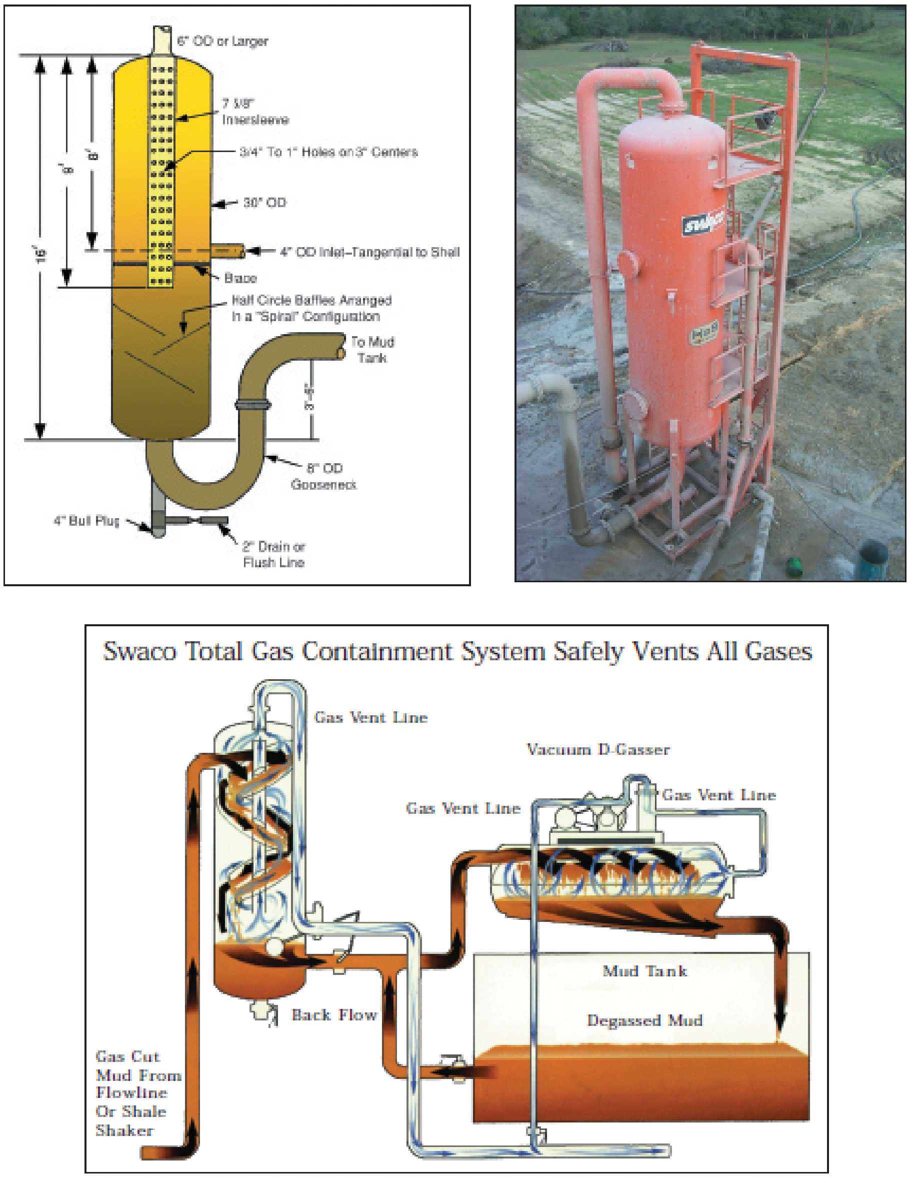
Mud-gas separators have a maximum allowable pressure rating that is determined by the height of mud in the separator. Fluid density and mud leg height determine hydrostatic pressure in the separator. Blow-through occurs when the back-pressure from the vent line overcomes the hydrostatic pressure of the mud leg. This can be calculated from the equation:

$$\boxed{\text{Blow-Through Pressure}_{psi} = \text{Mud Leg}_{ft} * \text{MW}_{ppg} * 0.052}$$

Blow-through will also occur if the mud-gas separator vessel ID is too small to give enough retention time for the gas to separate from the liquid.

Flow may have to be redirected to the flare line, if the mud-gas separator operating limits are being reached, the return flow line becomes plugged, or there is blow-by in the mud-gas separator.

Figure 7.68. Illustrations of mud-gas separators.




## Degassers

*Degassers* are used to remove *entrained gas* from the mud after it has passed through a mud-gas separator. Like the solids separation equipment in a mud system, degassers use centrifugal pumps for fluid throughput. The centrifugal pumps and associated lines and tanks are sized to pass the mud 1½ times before it is moved into the active mud system. As is true of all mud system separation equipment, degasser efficiency is reduced when handling high viscosity fluids.

There are several different degasser designs. Some use a pressurized vacuum chamber, others a centrifugal spray or a combination of these designs. Degassers require little maintenance beyond routine lubrication of moving parts and ensuring that the vessel and lines are clean and free of obstructions.

Figure 7.69. Two common degassers.

## Solids Separation

Settling, dilution, and mechanical separation equipment are used to separate solids from fluid. All methods of solids separation may lessen fluid density by removing weighting material from the mud. Fluid density and other fluid properties should be carefully monitored.

Sufficient fluid retention (settling) time allows heavier solids to separate from the lighter fluid base. Barite, or other weighting material, can settle from the active mud system, causing fluid density to decrease.

Dilution decreases solids concentration by adding more base fluid to the system. Concentration of the weighting agents is diluted as mud volume is increased.

Mechanical separation equipment such as shale shakers, centrifuges, desilters, desanders and hydrocyclones, are used to separate solids from the drilling fluids. All separation equipment is intended to remove low density solids (drilled solids) from the active fluid system. Centrifuges and hydrocyclones are designed to remove low density drilled solids and return heavier material (weighting materials) back to the active system.

## Upper Kelly Cocks

The purpose of an *upper kelly cock* is to protect the kelly hose, swivel and surface equipment from high well pressure. The OMSCO upper kelly cock (figure 7.70*)* has an integral one-way valve. Other upper kelly cocks may be ball, flapper or plug type valves. Normal BOP test procedures include a pressure test of the upper kelly cock.

## Lower Kelly Cocks

A *lower kelly cock* is a full-opening valve used as a backup to the upper kelly cock. It allows removal of the kelly when pressure on the string is greater than the surface equipment rating. On many rigs it is common practice to use the lower kelly cock as a mud saver valve. Continual use of the lower kelly cock has mixed consequences. The valve is operated at every connection therefore it is unlikely that the valve will "freeze" up. Also, the crew learns how to operate the valve and the wrench is available at all times. On the other hand, repeatedly using the valve will reduce its operating life. The threads can be damaged by continual makeup and breakout. Using a saver sub will minimize the chances of damaged threads. The threads should be inspected and gauged frequently for signs of galling and stretching.

## Stabbing or Full-Opening Safety Valves (FOSV)

The *FOSV, or stabbing valve*, commonly referred to as a *TIW* valve, is a full-opening ball valve. If a kick occurs during a trip, this valve is installed on the top of the drill string immediately. The valve is kept on the floor in the open position and the wrench to close it is placed in a location readily accessible to the crew. Remember that a FOSV is not a barrier unless it is closed. Crossover subs are also kept on the drill floor in order to fit the FOSV, no matter what size tubular is being handled at the rotary table.

Figure 7.70. An upper kelly cock.

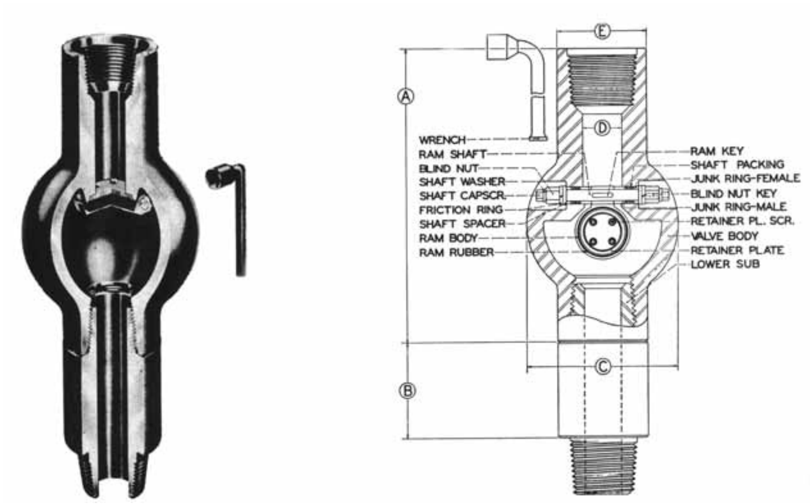



Figure 7.71. Kelly FOSV.


Cutaway view of standard Hydril Kellyguard in open position.

Large stabbing valves are heavy and can be difficult to handle. Some rigs use an air hoist or a counter balance system to assist the crew when handling the valve. Sometimes a removable handle is rigged at a good balance point so that the valve can be made up on the string more easily. Stabbing valves require little maintenance but they should be operated frequently to keep them from "freezing up".

Full opening does not mean that the valve ID is the same as the drill pipe ID; it means the valve has a smooth inside diameter when the ball is opened.

FOSV advantages:

- Is larger bore than an IBOP
- Is easy to stab onto flowing pipe when the valve is open
- Allows wireline to be rigged up on top of valve

FOSV disadvantages:

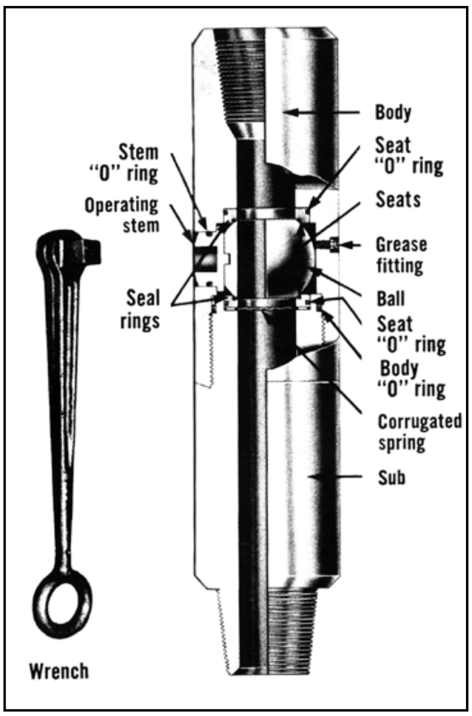
- Heavy and difficult to handle
- Requires an additional crossover on the top connection for pumping

## Inside Blowout Preventers (IBOP)

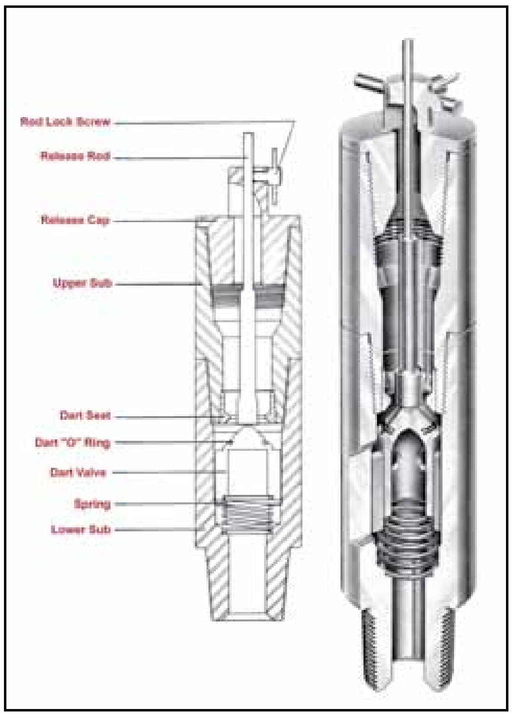
An inside BOP, sometimes referred to as the *Gray valve*, is a nonreturn, or check valve. It is a spring-operated, one-way valve that can be locked in the open position with a removable rod lock screw. Its primary use is for stripping back into a well against pressure. The inside BOP allows conventional circulation down through the valve, but prevents flow reversing back into the string. IBOPs are not full opening, the inside diameter is restricted, therefore wireline tools cannot be run through the tool. The inside BOP should not be used to stab onto the drill string if there is flow back up the work string. If needed, it can be attached after the flow has been stopped with a safety valve. An IBOP is

Figure 7.72.

Full-Opening Safety Valve




Inside BOP



kept on the rig floor (in the open position) at all times.

IBOP advantages:

- Can be run into the hole

IBOP disadvantages:

- Heavy
- Difficult to stab onto a flowing pipe
- Wireline cannot be used with it
- Requires additional an crossover on the top connection for pumping

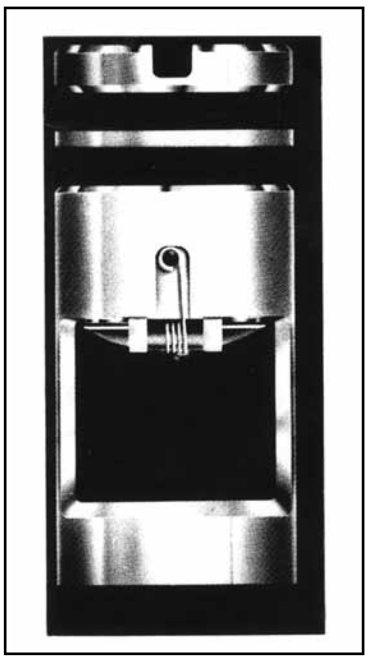
## Back-Pressure Valves

*Nonreturn valves* (*NRV*), back-pressure valves (BPV), check valves, and "floats" all perform the same function. They allow flow in one direction only and are used to prevent flow back up through the work string in an underbalanced well. The nomenclature changes according to the specific way the valve is designed and used as well as local field expressions. It is common to run a float valve just above the bit while drilling at shallow depths and some operators choose to run them throughout the entire drilling operation. A two-way check valve fits the same profile as a back-pressure valve. It holds pressure from both directions but can be equalized to enable testing.

The two most common types of floats are spring operated piston (plunger) types, and those with a flapper valve. Plunger type floats are reliable, but are not full opening. Both types are available in latch-open models for running into a well with the valve in the open position. Pumping down the string releases the latch and returns the valve to its one-way mode. On wells in which survey tools are run, a tool to receive the survey instrument is installed above the float to prevent the survey instrument from becoming jammed in the valve.

Some operators run ported floats. A ported float is a flapper type valve with a small opening in the bottom so that if the well is shut in on a kick, shut in drill pipe pressure can be read, but the port is small enough to restrict potential flow from the formation to a negligible volume.

Figure 7.73. Examples of back-pressure valves (BPV)

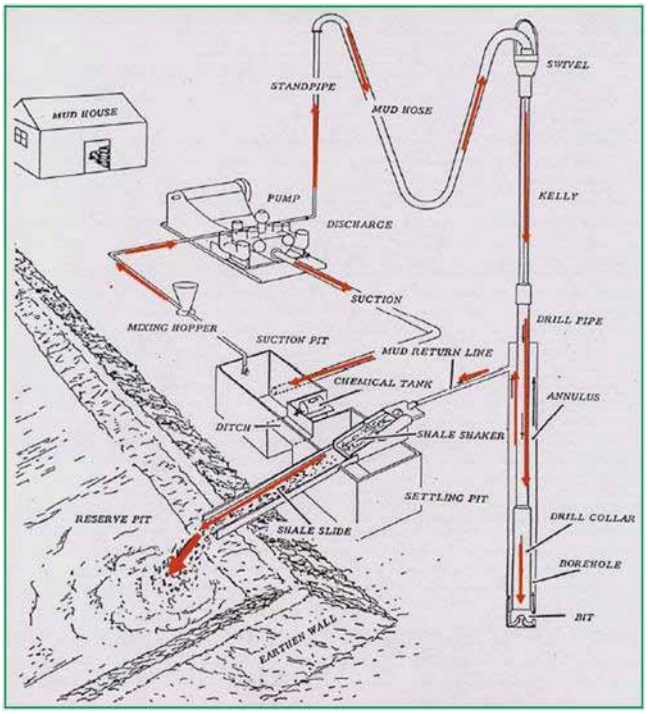


## Circulating Systems

A typical circulating system for a drilling rig is composed of pumps, surface lines, standpipe, kelly hose, swivel, kelly or top drive, work string, well annulus, shale shakers, fluid tanks (pits) and associated manifolds.

Positive displacement pumps are used to move fluid through the circulating system. Duplex pumps have two cylinders and triplex pumps have three. The pumps have liners that can be changed, due to wear, in order to prevent damage to the pump body itself. Due to the smooth displacement when moving high volume, triplex pumps are commonly used on most rigs nowadays. Triplex pumps are supercharged with centrifugal pumps, and when in good condition, a supercharged triplex rig pump will discharge at nearly 100 percent efficiency. It is a good practice to estimate pump efficiency often by pumping a known volume of fluid and comparing the actual displacement with the theoretical displacement.

Figure 7.74. A circulating system.




Rig pumps are outfitted with one or more stroke counters that are essential for measuring volume displacement. There are several types of stroke counters available, ranging from a simple mechanical whisker type to more complex electronic devices. Take care to remount and set the counters correctly if they have been removed for some reason. If stroke counters are not available, measuring time at a constant pump rate is the only way to track the volume pumped.

Circulating manifolds are used to select various mud flow paths within the surface mud system. The standpipe manifold directs the fluid from the pumps to the rig floor and up the derrick to connect with the rotary hose. The rotary hose makes a flexible connection between the standpipe and swivel, and allows the work string to travel up or down while continuing to pump. The swivel is the device that allows the kelly to turn while pumping. Returns from the well may be routed to the pits from the bell nipple on surface BOP stacks or through a kill manifold connected to the BOPs. The circulating manifold systems on some of the larger rigs may be extremely complex. For example, cementing pumps and/or chicksan lines may have specific lineups different from standard pump and return paths.

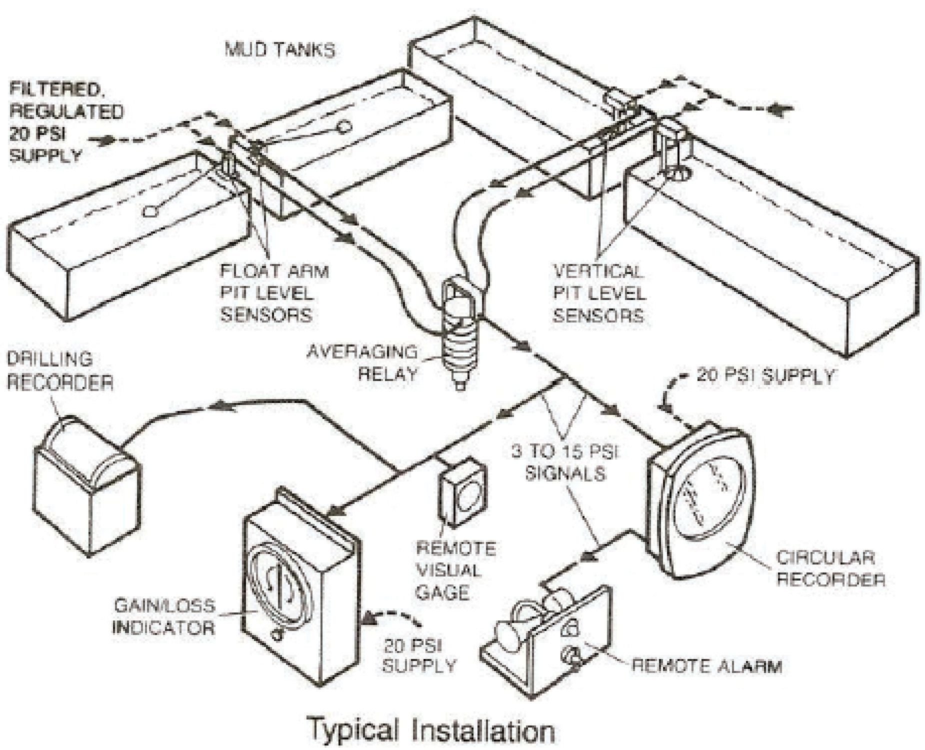
## Mud Pits (Tanks)

The function of the interconnected mud pits is to hold the drilling fluid on the surface and to provide the time and means to separate solids and mix any required additives. Most rigs have three pits used as the active system. Mud is routed via ditches interconnecting the pit system, by equalizing lines from tank to tank, or using circulating/mixing manifolds. As the mud returns from the well, spilling down the flowline, it falls across one or more vibrating screens (shale shakers). Below the shakers is a small pit called the *sand trap*. The sand trap is a settling pit which catches some of the undesirable solid particles and prevents them from entering the pits of the active system. From the sand trap the mud enters the separation, or testing pit. Entrained air, gas, and drill solids are removed before the mud moves to the next active pit. Samples of the fluid are taken from the separation pit and tested to determine any treatment that might be required before pumping the mud back downhole.

The second pit in the active system is used for adding any liquids and/or solid additives, to "condition the mud". Most mud additives are mixed through a mixing "hopper". The material is drawn into and mixed with the mud by means of a venturi-like effect, created by pumping mud through one or more jets at the lower end of the hopper.

The third pit in the active mud system is called variously the "suction" or the "check" pit. The fluid in this pit is directed to the pumps and moved into the well via the drill string. The mud properties in this pit, especially the mud weight and funnel viscosity, should be checked frequently to make sure that the fluid is being properly controlled within the bounds of the mud program.

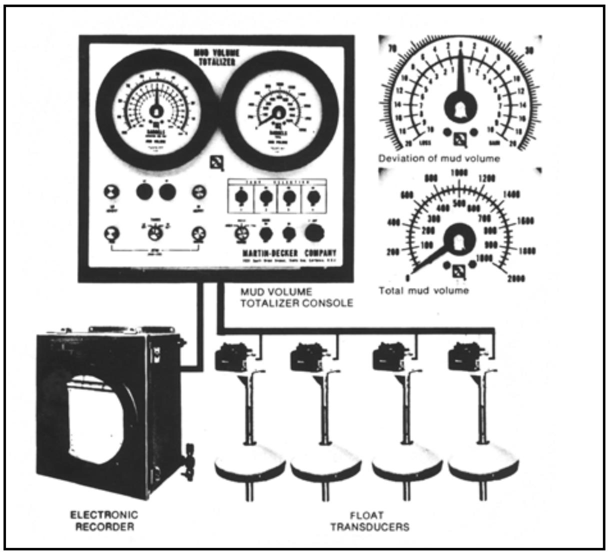
Figure 7.75. A typical fluid pit (tank) measurement system.

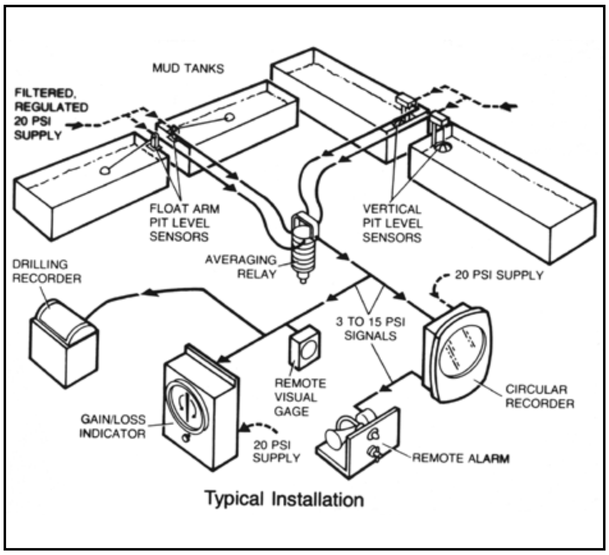



## Pit Level Indicators

Pit level indicator devices continuously monitor the volume of fluid in the mud pits and transmit the data to charts and readout instruments near the driller's station. There may be remote indicators at other locations on the rig site. Pit level indicators measure and record the volume in each pit, as well as the total surface volume. The systems use mechanical floats, electrical (sonic) sensors, or lasers to measure the height of the fluid in each pit. The fluid height in each pit is then multiplied by the pit volume in barrels per inch (or local measuring units). The volume of the individual pits is totaled and transmitted to the charts and indicators. The systems are fitted with audio and visual alarms that can be set in order to call attention to changes in pit level.

Figure 7.76. A pit volume totalizer system.




## Mud Return Indicators (Flow Line Sensors)

The *mud return indicator* consists of a paddle placed in the flow line which is connected to a microswitch so that as the flowing mud lifts the paddle, a signal is sent to an indicator at the driller's console where it may be registered as a percentage of return flow or as gallons per minute. When the pumping rate is constant a change in return flow from the annulus almost always indicates that something has changed downhole. A sharp increase may be the first signal that formation fluids are entering the well.

Like pit level indicators, flow line sensors have audio and visual alarms that can be set to alert the crew to flow rate changes. Flowline sensors are simple and require little maintenance beyond checking for full paddle movement and keeping the flowline free of solids buildup. Some rigs today have extremely accurate mud measuring systems that use modern laser beam technology.

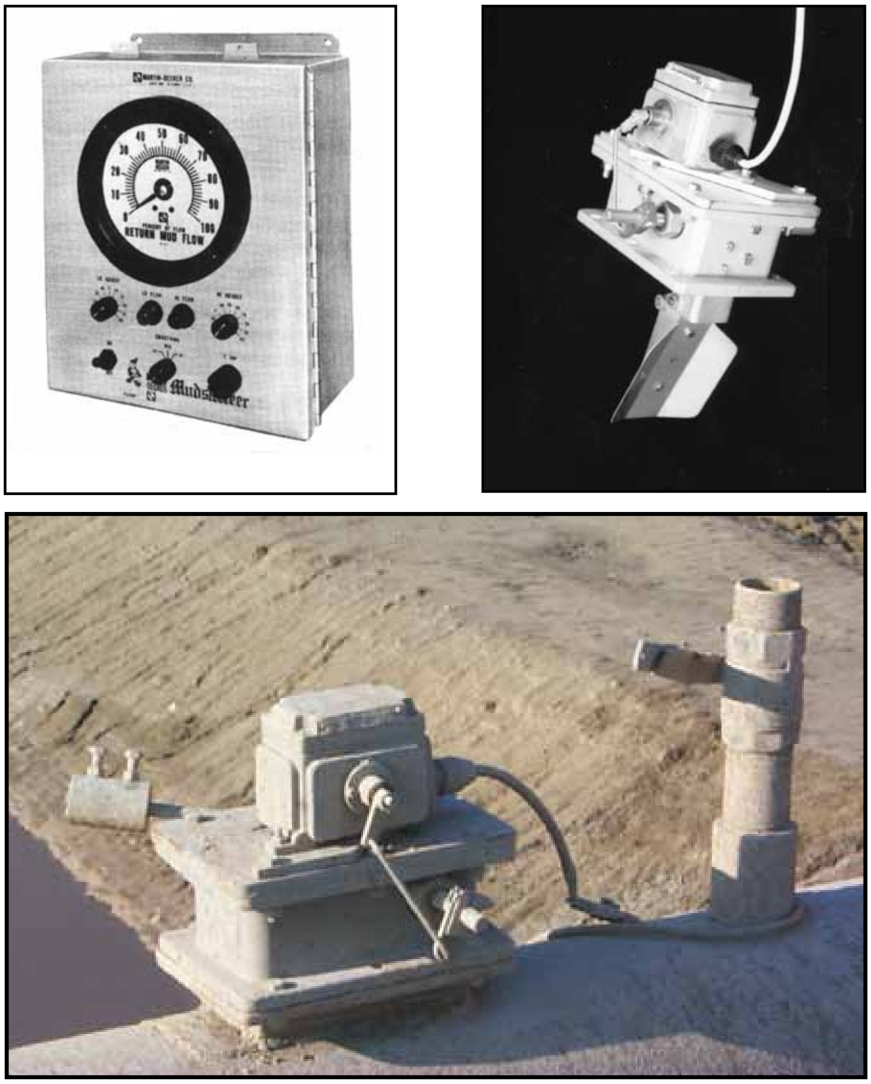
## Pressure Gauges

There are many pressure gauges located around the rig floor, each offering a potential for failure at a critical time. Signs of malfunction include gauges that read "0" pressure, gauges that show the maximum reading at all times, gauges that do not vary when an obvious change in pressure occurs, and pairs of gauges, such as those on the remote choke control panel that show the same value when the well is shut-in. To avoid problems, gauges should be checked and calibrated periodically. When a gauge is suspected of malfunctioning, it should be replaced with a recently calibrated gauge with the same pressure range. If an accurate low pressure measurement is required on a gauge with a large pressure range, replace it with a gauge with a lower pressure such that the reading is more towards the mid-range of the gauge.

## Gas Detectors

*Gas detector* have sensors that are mounted in the small tank (the possum belly) at the back of the shale shakers into which the mud is spilling out from the flowline. The sensors detect and measure gas that is carried to the surface by the returning mud. Certain special gas detectors may be placed in areas where toxic gases, such as hydrogen sulfide, can accumulate. If the site does not have a mud logger on location, crews should take pains to perform the required maintenance and calibration according to the manufacturer's specifications.

Figure 7.77. Flowline sensors.




## Trip Fill-up Systems

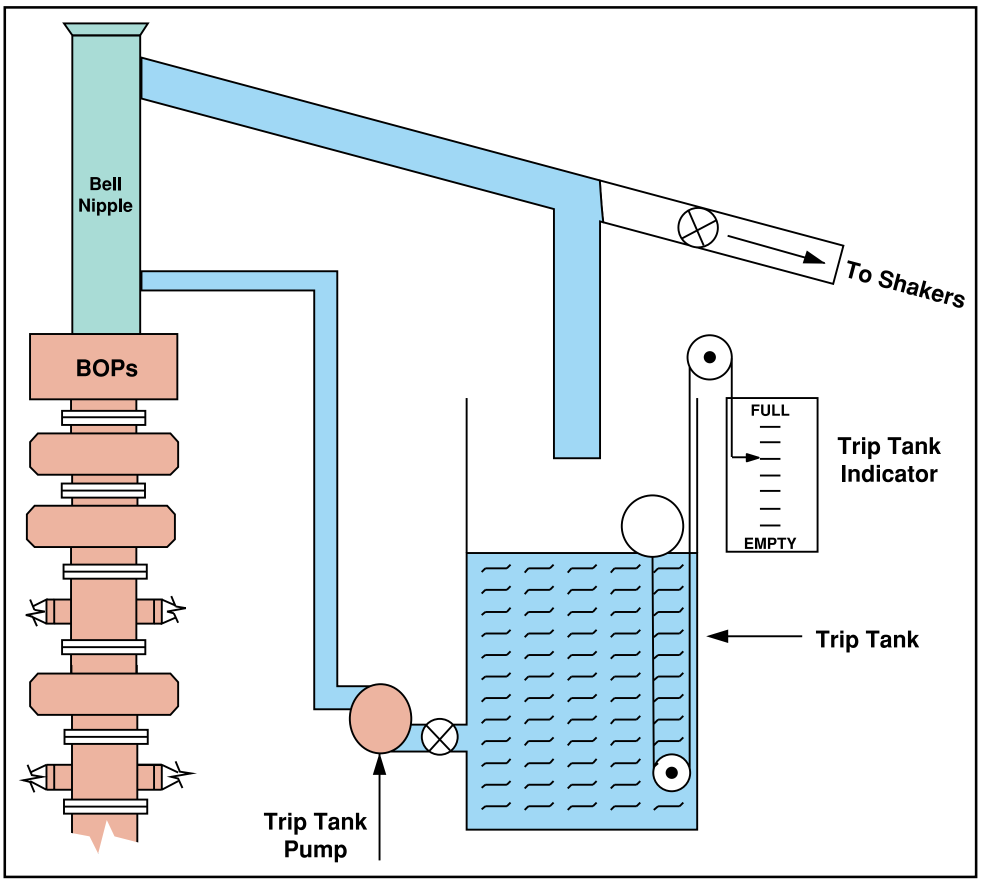
A *fill-up system* is used to measure the mud pumped into the annulus on trips out of the hole. It consists of a combination of flowline sensor and pump stroke counter. The flow sensor console at the driller's station has a "mode" switch. In order to operate the device, the switch on the driller's console on the flow sensor is turned to "trip" and one of the pumps is lined up to the fill-up line. After pulling one or more stands, the driller turns on the pump. The pump automatically turns off when the flowline sensor indicates returns from the well. The calculated pump strokes required to fill the well per stand of pipe are compared to the strokes actually pumped. The pump strokes are usually recorded on both the total strokes to fill the hole, and the strokes required for the last fill-up. It is important to check the hole during the first fill-up to be sure that the pump stroke counter shuts off when flow starts.

## Trip Tanks

*Trip tanks* are small tanks that permit accurate measurement of the fluid that is pumped into or displaced from a well on trips. As each stand of pipe is run into, or pulled from the well, the level of fluid in the well changes and is measured in the calibrated trip tank.

There are several types of trip tanks. A simple gravity-fed trip tank includes a small tank on the rig floor or at a point above the flow line. A valve is used to release the fluid which drains into the bell nipple above the flowline. The valve is manually opened, and then closed when the hole is full. The fill-up volume recorded and compared to theoretical fill calculations. Automated versions of gravity-fed trip tanks have a pump actuated by the driller which automatically turns off the pump when the flow line sensor indicates that the hole is full. This type of setup does not permit volume to be measured while tripping in.

Figure 7.78. Trip tank arrangement.



Continuous-fill trip tanks automatically circulate from the tank across the hole throughout the trip. Fluid volume is measured and transmitted to a recorder on the rig floor for comparison against the calculated theoretical volume required for fill-up. If the tank is used to measure the displaced fluid on the trip into the well, it is usually positioned below the flow line level. The displaced fluid is then routed from the flow line to the trip tank where it is measured and compared to the theoretical pipe displacement.

## Information Systems

Like society itself, the drilling/workover industry is moving rapidly ahead in this age of computers and satellite communications. Downhole measurement tools (MWD) that transmit a host of real-time data have been developed and are now used on drilling locations throughout the world. Computers link information to locations far from the actual rig site. A driller on a modern rig may find that the familiar brake handle has been replaced by a joystick operated from a console. The console displays and records all the various operational data that was once gathered on a drilling recorder plus downhole information such as pore pressure, temperature and even geological information. The entire operation can be simultaneously monitored in several locations around the site by means of computer display monitors

Figure 7.79.

In many cases, analog gauges have been replaced by more dependable and more accurate digital gauges. It is true that many rigs still use standard drilling recorders and analog gauges, but service companies have developed instrumentation that can be rented and installed to supplement the rig's permanent equipment. Analog gauges are more subject to damage and calibration errors caused by vibration and the general harshness of work on the rig floor. The accuracy of an analog gauge is suspect at the lower range. Usually the high-pressure gauges (standpipe, casing, etc.) are calibrated so that the mid-range of the gauge is most nearly accurate. Extreme low and high ranges are somewhat less accurate. Digital gauges have no moving parts, therefore their calibration is not seriously affected by pulsation, vibration and routine rig floor activity.

Figure 7.80. Modern rigs provide the driller with a wealth of information.


## Top Drive Systems

*Top drive systems* replace the conventional rotary table used for turning the drill string. Modern top drives combine the elevators, the tongs, the swivel, and the hook. The rotary table is retained however, in order to provide a place to set the slips and suspend the string.

Figure 7.81. A top drive system.

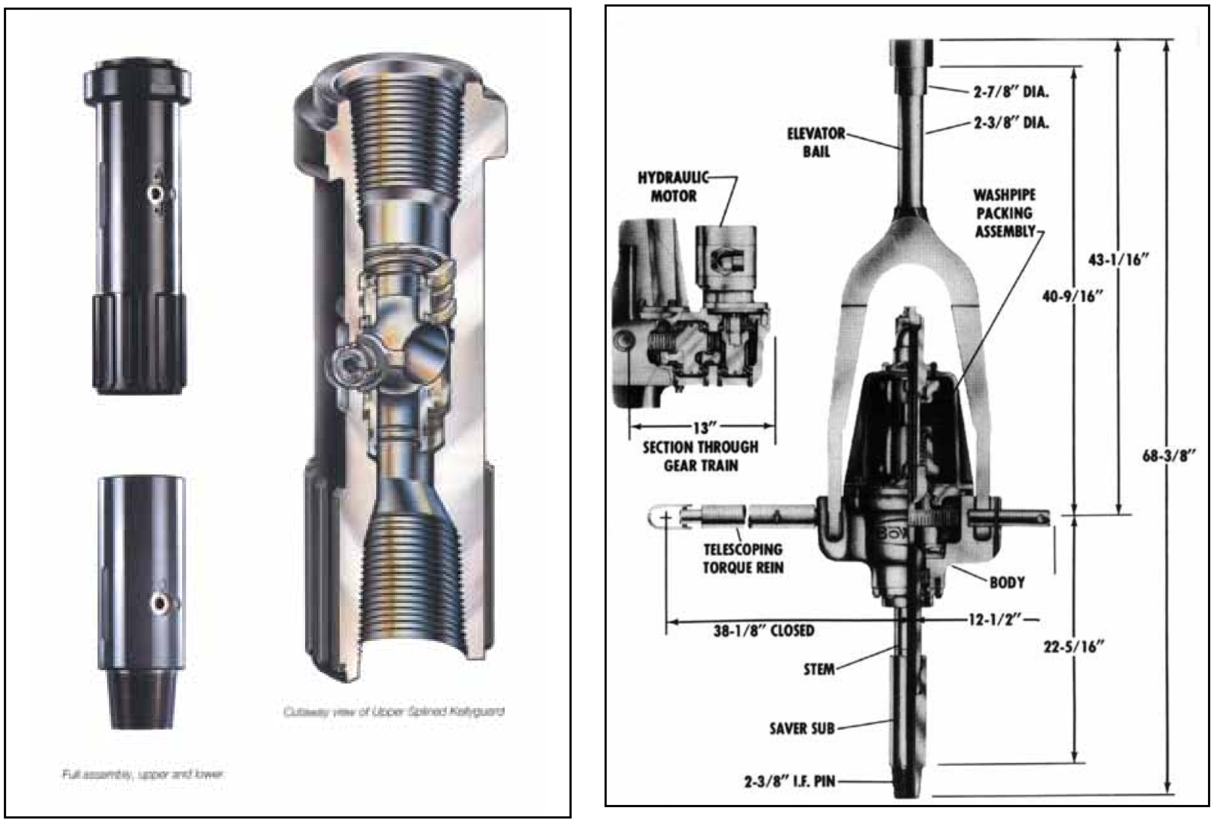
Top drive systems offer a significant improvement in rotating technology because multiple joints of pipe may be used at one time. Since the system handles a complete stand of pipe (two to three joints of drill pipe screwed together, 60 to 90 feet), it is possible to circulate and to back-ream when necessary. Safety is enhanced during routine, non-emergency operations since the number of connections is reduced. If a well control incident develops, the driller can quickly set the pipe in the slips, stab the top drive onto the string, rotate and torque up the connection with minimum assistance from the rig floor crew. Top drive systems employ two full-opening safety valves; one hydraulically operated valve at the top, and another manual valve at the lower end, replacing the kelly valves.

A well can be shut-in during a trip by making up the top drive at any point in the derrick, but in some cases leads to unnecessary difficulties. Before stripping on the elevators can begin, it will be necessary to break off the closed manual DPSV (typically a DPSV with pin-up configuration). This must be opened after a pin by box crossover has been made up above it and IBOP installed. Advanced thought must be given to this operation, for it is possible the manual DPSV will not pass through the casing or liner in the well. Also, a second manual DPSV for the top drive must be available to replace the one that went down the hole in order to circulate the well after reaching bottom or the desired depth.

## Power Swivel

*Power swivels* are hydraulically operated rotating equipment designed for light drilling and workover operations. On workover rigs, the hydraulic system pumps are usually used. Skid or trailer-mounted portable hydraulic power units are also available. A telescoping torque rein, or arm, must extend to a guide, or rigid part of the rig, due to the effects of the torque developed by rotation.

Figure 7.82.
*Left*, kellyguard
*Right*, power swivel



## Surface Equipment Failure During a Kick

Most operators and contractors prepare contingency plans for equipment failure. Crew members should follow those plans.

### *BOPS FAIL TO CLOSE*

When a BOP fails to close it is usually due to accumulator malfunction. In this case the hydraulic closing system should be checked. Check for air supply and hydraulic leaks at the control panel. If hydraulic pressure fails, rams can be closed and locked manually, by turning large wheels. Manual closure takes longer than with a hydraulic operating unit and the extra closing time will allow additional influx to enter the well. If a ram cannot be closed manually, a cement pump or high pressure test pump may be manifolded to the stack's closing lines to provide closing pressure.

### *ANNULAR PREVENTER PACKING ELEMENT FAILURE*

If the annular preventer packing element is not properly sealing around the pipe or on an open hole, with maximium closing pressure applied, immediate steps should be taken to close in the well. Pipe rams are used as a backup, if the annular preventer fails. The pipe rams should be closed, after making sure the drill string is spaced out, so the rams will not close on a tool joint. The failed packing element in the annular preventer can be changed after the well kill.

Other indications of annular preventer failures are:

- Failure to fully open or close: the hydraulic closing system should be checked. Check for air supply at the control panel and for hydraulic leaks.
- Internal hydraulic leakage (control fluid part)
- Internal leakage (leakage through a closed annular)

### *BOP FLANGE FAILURE*

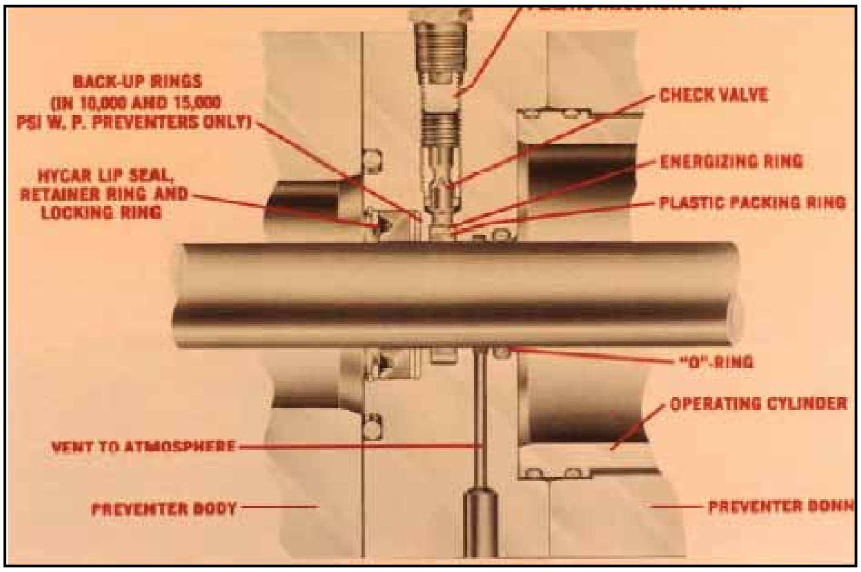
Flange seals are located at the bottom of the annular preventer and between ram preventers. A flange seal failure can result in a high-pressure fluid leak at the failure point. If a large leak occurs, the annular pressure may be reduced enough to allow additional influx. If the annular preventer flange seal fails, the uppermost pipe rams should be closed, after making sure the drill string is spaced out. Another possible procedure is to pump sealant into the wellhead and then bullhead down the annulus. Repairs can be made and the well kill continued.

If a flange fails above the chokeline, close the ram between them. If a flange fails below the chokeline, close the ram below the flange. If failure is at the chokeline or choke manifold, stop pumping and close the ram below the chokeline. If the uppermost pipe ram's flange gasket fails, the bottom master pipe rams can be closed. Repairs can be made and well kill continued. If the lowermost BOP flange fails when the BOP is shut-in, the pipe may be dropped into the hole and the blind rams closed. If the blind rams fail, then as a last resort, cement can be pumped in to plug the well.

### *WEEPHOLE LEAKAGE*

A failed shaft seal can lead to ram closure failure. Most BOP rams have a weephole between wellbore ram shaft packing and the hydraulic seal. Hydraulic fluid will leak out the weephole, which alerts crew members when the shaft hydraulic seal leaks. There is a hex screw on the BOP next to the weephole that can be tightened to prevent leakage until the seal can be replaced. During pressure testing of the ram, BOP leakage through the weephole indicates worn seals against the wellbore and require changing out immediately prior to commencing operation. In the event of leakage during a well control situation, the seal can be engaged by injecting plastic packing through a packing ring that will seal against the wellbore. The seal should be changed when routine operations resume. See figure 7.83.

Figure 7.83.



# Procedures

# 8

## Upon completion of this chapter, the student will be able to:

- Identify the possible impact of a well control event on personal well-being, life and limb, employment, environment, reputation and society.
- List the effects of a well control incident.
- Discuss and explain the limitations and exposure after the rig has left the well site.
- Discuss and explain how a compromised integrity envelope might impede ongoing production capability and compromise well intervention requirements.
- List the reasons why you are taking well control training.
- List parameter changes that will necessitate a new annular pressure loss calculation.
- Discuss and explain the importance of well control preparation and readiness processes.
- Identify the steps in shutting in the well when tripping utilizing soft and hard shut-in methods.
- Identify the steps in shutting in the well when drilling utilizing soft and hard shut-in methods.
- Identify the steps in shutting in a well when out of the well.
- Discuss the process and importance of checking for leaks after the well is shut in.
- Discuss and explain the purpose of a diverter system.
- Explain well control drills and the recommended frequency.
- Identify and explain the use of shut-in recorded data requirements including:
    - Shut-in drill pipe pressure (SIDPP)
    - Shut-in casing pressure (SICP)
    - True vertical depth (TVD) at the time of the kick
    - Current mud weight (CMW)
- Perform calculations using the WCS Formula Sheet for the following calculations:
    - Maximum allowable mud weight (MAMW)
    - Maximum allowable annular surface pressure (MAASP)
    - Test pressures
- Determine slow circulating rate for 2 pumps - 3 strokes per minute (spm) speeds each.
- Identify and set alarms for return flow and pit gain indicators.
- Drill ahead maintaining identified RPM, pump speed, and WOB.
- Detect and recognize a kick.
- Shut in the well using the hard shut-in procedures.
- Determine SIDPP with a float in the string.
- Record shut-in information - SIDPP, SICP, pit gain, CMW.

- Describe the importance of preplanning.
- List reasons for gathering prerecorded information.
- List reasons for conducting pre-job meetings.
- List reasons for pre-job safety meetings and daily toolbox talks.
- List reasons for exercising the stop work authority (SWA).
- List the benefits of holding a pre-kill meeting prior to any well control operation.

## Well Control

Well control is the management of dangerous effects caused by the undesirable flow of formation fluid into the wellbore that happens when formation pressure is greater than the hydrostatic pressure in a wellbore. A well is considered out of control when there is a continuous flow of oil, gas or water above or below the ground surface or water bottom.

## Importance of Well Control

Not maintaining well control can impact:

- Personal well-being
- Life and limb
- Employment
- Environment
- Reputation
- Society

Improperly managed well control situations can cause blowouts, the unexpected release of formation fluid, such as natural gas and/or crude oil, to the surface with oil or gas escaping into the atmosphere, leading to environmental pollution and potentially resulting in a fire.

In April 2010, a blowout in the Gulf of Mexico at the Deepwater Horizon drilling rig resulted in an explosion and fire that claimed the lives of nine crew members on the platform floor and two engineers (presumed killed in the initial explosion), and injured sixteen others. The oil drilling rig that was insured for more than $500 million burned and sank. The blowout left the well gushing oil for 87 days resulting in a massive offshore oil spill in the Gulf of Mexico. It was the largest accidental marine oil spill in the history of the petroleum industry and the largest environmental disaster in U.S. history.

The reputations of some of the companies involved in the disaster may never recover.

Some of the other effects of the Deepwater Horizon well control incident include:

- Capital loss
- Over-regulation
- Moratorium on drilling
- Limiting areas of operations

The drilling contract cost for the rig was $544 million, or $496,800 a day, with the crew, gear and support vessels estimated to cost the same. Litigation, damage, and the scope of final insurance recovery will take years to resolve. Fines for violations of the U.S. Clean Water Act are in the billions.

The oil spill affected more than 1,000 miles of Gulf of Mexico coastline and caused economic harm to the vast fishing and tourism industries of the region.

In response to the Deepwater Horizon explosion and resulting oil spill in the Gulf of Mexico, inspections of all deep-water operations in the Gulf of Mexico were initiated. On May 30, 2010, a six-month moratorium on all deepwater offshore drilling on the Outer Continental Shelf was declared by U.S. Secretary of the Interior Ken Salazar, in response to the Deepwater Horizon oil spill which occurred in the Gulf of Mexico. The moratorium imposed in response to the spill caused further harm to the economies of coastal communities, as the oil industry accounts for about seventten percent of all Louisiana jobs.

Mistrust and resistance to oil companies has caused new regulation and limited operations in the Gulf Coast and in the Arctic.

The Obama administration also launched the most aggressive and comprehensive regulatory reform of the offshore oil and gas regulation and oversight in U.S. history. These regulations include heightened drilling safety standards to reduce the chances that a loss of well control might occur in the first place, as well as a new focus on containment capabilities in the event of an oil spill. These new regulations will result in increased operational costs and cause significant regulatory and operational risks for individual companies, their investors and the oil industry as a whole.

## Well Integrity Throughout the Well's Lifecycle

Well control detection and prevention depends on established well control policies and procedures, well preparation, and well control prevention procedures that extend throughout a well's life cycle from planning to abandonment.

It is important to maintain well integrity requirements throughout a well's life cycle, from planning, drilling, and completion to abandonment. Maintaining sound operational procedures, safe work practices, sufficient safety systems and properly rated, properly installed and maintained equipment will help prevent well control events. Mistakes or ill-advised, cost-cutting decisions made during any of the steps, from construction to completion, may compromise the well integrity envelope and impede production capability, and compromise well intervention requirements.

If the well integrity envelope has been compromised due to negligence, there may be consequences such as legal proceedings, criminal prosecution and punitive fines after the rig has left the well site.

Personnel with assigned well control responsibilities and all personnel involved in well planning, drilling, completion and well servicing operations must take responsibility for choices they make in preventing and managing well control incidents. Prevention and management of well control incidents must be carried out by competent, well control certified personnel.

## Well Control Training, Assessment and Accreditation

One of the goals of WCS well control training, assessment and accreditation is to deliver effective training techniques and provide learning events to ensure the competence of our students in all well operations, to prevent future major oil spill incidents.

Proper well control training:

- Increases the trust of stakeholders/investors. Stakeholders include the federal agencies, local governments, stockholders and the public. The trust of the stakeholders is increased with confidence in the abilities of well trained personnel that are able to get tasks done safely by being able to identify risks and reduce potential well control events.

- Helps avoid over-regulation. Overregulation can be avoided by not giving regulatory authorities a reason for tightening existing regulations or creating new regulations.
- Aids in recruiting new personnel. Recruiting new personnel becomes easier when they are provided a safer work environment and know that their colleagues are well trained and knowledgeable.
- Makes personnel more responsible to their colleagues. Work teams are made stronger and more effective when they know they can trust the abilities and judgment of their team members and colleagues.
- Ensures personnel competence. Personnel feel more confident in knowing they have the ability to proactively identify possible risks and are able to take corrective actions to mitigate them.

A previous chapter discussed the procedures for observing a well with the pumps shut off in order to determine whether or not a well is flowing. There are times when a flow check is routinely performed as part of standard company policy. Examples include, prior to beginning a trip out of a well, when the BHA is pulled into the casing and prior to pulling collars through the BOPs. Flow checks are also performed at the driller's discretion based on changes in drilling performance, or at the request of supervisors, the mud logger, or others who have noticed kick indicators. It is not always easy to determine if a well is actually flowing. Depth, fluid type, formation permeability, the degree of underbalance and other factors are all borehole characteristics. The duration of the flow check should be long enough to make positively sure whether or not the well is flowing. Flow checks may be performed by direct observation at the rig floor by flow sensor equipment or at other locations, depending upon the particular equipment in use.

As soon as it is determined that a well is flowing, the annulus must be closed with the BOPs. Closing the BOPs shut in the well. The flow of formation fluids into the well must be stopped as quickly and safely as possible. This chapter discusses shut-in procedures that are generally accepted throughout the industry. The specifics of any particular procedure are developed according to the equipment in use, the operation at the time of the incident, and the policies of the operators and contractors involved.

Four important things are accomplished simultaneously when a well is properly shut in:

- The flow from the well is stopped.
- Personnel and equipment are protected.
- Data can be collected.
- Well pressures stabilize, providing time to analyze the situation.

By definition, if a well is flowing from the annulus, bottomhole pressure is lower than formation pressure. Bottomhole pressure continues to decrease as more and more formation fluids enter the well. Therefore, the rate of flow will constantly increase. The longer it takes to stop the flow, the greater the influx volume and the higher the resulting casing (annulus) pressure. The greater the volume of the influx, the more dangerous the situation will be and the more difficult it will be to regain control of the well.

The personnel, the rig and the environment are all in jeopardy when formation fluids are allowed to flow into a well uncontrolled. There is no time to discuss the developing problem as the well flows. Once the well is shut in and the flow is effectively stopped, things will begin to stabilize and there will be time to discuss and analyze the situation.

So long as a kick is flowing into a well, the crew is not in complete control. Once the well is safely shut in, control is regained. When a well is shut-in the stabilized pressures on the annulus and the drill pipe can be determined. The approximate size of the influx can be estimated by measuring the gain in the mud pits. Using this information and other data that may be available, a plan of action can be formed.

Specific shut-in procedures vary throughout the industry depending on company policy, rig type, present operations and anticipated formation pressures. All wells are different and procedures are agreed upon, posted and practiced on an individual well basis.

Usually, the operating company and the contractor's representatives will have one or more pre-spud meetings before the operation begins. When discussing anticipated well control incidents, they establish procedures and preparation for identifying kicks and shutting the well in. Good practices require equipment to be properly tested and lined up in such a way that the crew can shut the well in with maximum efficiency and safety. Depending on the ongoing operation, the actual shut-in procedures require several distinct actions to be taken by the supervisor and his crew. Preparation is all-important.

Some of the questions that arise are:

- Which preventer will be closed on initial shut-in?
- Which choke will be used?
- Will the choke be in an open or closed position during routine operations?
- How will information be passed around the location?
- What are the assignments of various members of the crew?
- What are the individual steps required for the shut-in procedure and who will perform them?

Once these general questions have been answered and passed to the crew, safety meetings are held before each shift at which the specific on-going operation can be discussed.

Routine checks at each crew change might include:

- a visual inspection of the BOP stack and BOP closing unit (accumulator)
- a visual inspection of the choke manifold to ensure proper line-up
- setting flow sensor, PVT, gas detector and other alarms that may be available;
- being aware of space-out distances, that is, the distance from the rotary table to the BOP stack components and the location of tool joints in the stack at the time of shut-in.

Well control drills are held on a regular basis in order that each crew becomes proficient at kick recognition and shut-in procedures. It is generally recommended that drills be held at least once every seven days for each crew. Specific standards for the frequency of drills are dictated by company policy as well as local regulations. Examples of typical well control drills can be found later in this chapter.

It can be seen that early kick detection and safe, efficient shut-in action is a matter of preparation, communication, and practice. Good communication must extend from the supervisors down to each individual crew member. Shut-in procedures begin with the flow check and end when the flow into the well has stopped and accurate pressures can be determined.

The American Petroleum Institute publication API RP 59[1] classifies shut-in procedures as *soft* or *hard* according to the prealigned choke system and the order of the steps required to stop the flow from a well.

### Soft Shut-In

The line-up for a soft shut-in requires that, with the exception of a valve located near the BOP stack, there be an open path through the choke manifold to the open choke.

- *Advantage*: Casing pressure buildup can be monitored with regards to formation fracture and the maximum allowable annular surface pressure. This also allows the operator to consider various alternative procedures before maximum pressures are reached.
- *Disadvantage*: It may allow for a greater influx volume into the well resulting in high shut-in pressure. Assuming that the equipment has been prealigned correctly, a soft shut-in is accomplished in three steps:

1. Open the choke line valve (HCR) near the BOP stack.
2. Close the BOP.
3. Close the choke.

The following procedures assume that a kick has been identified.

| *SOFT SHUT-IN WHEN DRILLING* | *SOFT SHUT-IN WHEN TRIPPING* |
|---|---|
| 1. Open the choke line valve (HCR)near the BOP stack.<br>2. Close the designated BOP.<br>3. Close the choke while watching casing pressure to ensure pressure limitations are not exceeded or trapped pressure.<br>4. Read and record the pit gain and the SIDPP and SICP each minute until pressures stabilize.<br>5. Notify company personnel. | 1. Close the full-opening safety valve (FOSV).<br>2. Open the choke line valve (HCR) near the BOP stack.<br>3. Close the designated BOP.<br>4. Close the choke while watching casing pressure to ensure pressure limitations are not exceeded or pressure trapped.<br>5. Make up kelly or top drive and open FOSV.<br>6. Read and record the pit gain and the SIDPP and SICP each minute until pressures stabilize.<br>7. Notify company personnel. |

### Hard Shut-In

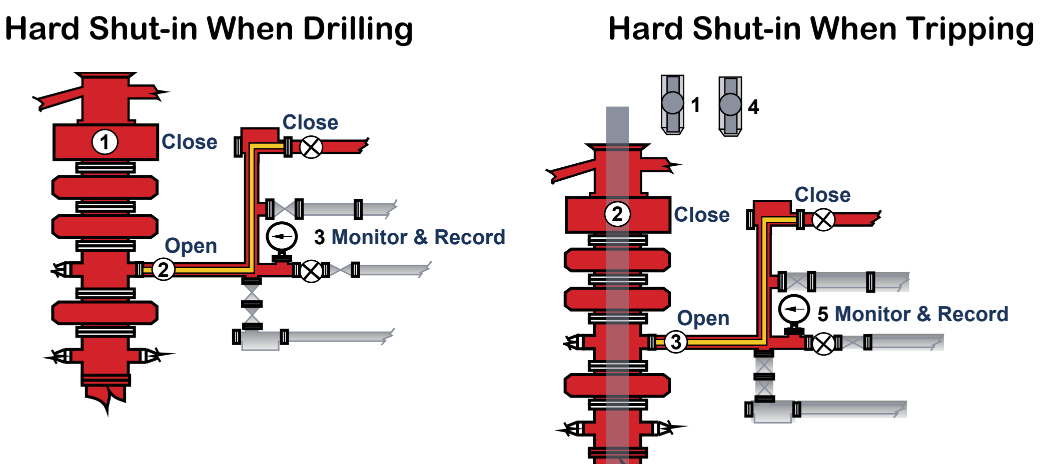
Although there is a clear flow path through the choke manifold itself, the valve on the BOP stack and the primary choke remain closed during normal operations. Once it is determined that a well is flowing, the BOP is closed, thus stopping flow from the well. If the casing pressure cannot be read at the wellhead, the choke line (HCR) valve near the stack is opened. *The choke remains closed.*

- *Advantage*: Faster than a soft shut-in because one step has been eliminated.
- *Disadvantage*: Limited to well conditions where the maximum allowable annular surface pressure (MAASP) is greater than the anticipated initial shut-in pressure and formation fracture.

If the well is flowing, the FOSV is closed and a short joint of pipe (pup joint) is made up on top of the safety valve before lowering and spinning up the top drive. Then the safety valve is reopened so that the SIDPP can be read. At shallow depths, where time is especially critical, the top drive can be connected without using a pup joint.

| *HARD SHUT-IN WHEN DRILLING* | *HARD SHUT-IN WHEN TRIPPING* |
|---|---|
| 1. Close the designated BOP.<br>2. Open the choke line valve (HCR)near the BOP stack.<br>3. Read and record the pit gain and the SIDPP and SICP each minute until the pressures stabilize.<br>4. Notify company personnel. | 1. Close full-opening safety valve (FOSV).<br>2. Close the designated BOP.<br>3. Open choke line valve (HCR) near the BOP stack.<br>4. Make up kelly or top drive and open FOSV.<br>5. Read and record the pit gain and the SIDPP and SICP each minute until pressures stabilize.<br>6. Notify company personnel. |

Figure 8.1 Hard shut-in.



## Well Monitoring During Shut in[2]

Anytime the well is shut in, it should be monitored for flow. The objective is to determine if the closed BOP is leaking. The correct action is to line the return flow line up to the trip tank so that any leakage can be observed and recorded. The correct procedure is described below:

*PROCEDURE FOR MONITORING A SHUT-IN WELL*

1. Close the valve in the flow line to shut off returns to the mud-gas separator.
2. Open the valve thath directs flow into the trip tank.
3. Observe the trip tank for an increasse in volume (due to leaking BOP).
4. If there is leakage, close another BOP.
5. If the leakage persists, prepare to periodically bullhead fluid into the annulus and push any migrating gas back downward.
6. Monitor shut-in pressures to ensure that pressure limitations are not exceeded.
7. Expidite a plan to circulate or bullhead the migrating influx.

## Shutting-in a Producing (Live) Well

The shut-in procedure for a live and flowing well is different because, at first, there is no circulatory flow. Instead, all flow is up the tubing string. The initial shut-in is not done with a BOP, but instead, with valves on the flow line and wellhead, generally with the wing valve and master valve on the wellhead and/or the SCSSV, if applicable. To enter a live well, the BOP stack must be installed above the Christmas tree and tested before the well is opened. For well entry, it is important to know the shut-in tubing pressure, since that is the pressure used to calculate the initial snubbing forces required in order to enter the well.

In other operations, the well must be dead in order to perform well servicing operations. In that case, the well is first killed by bullheading, reverse circulation, circulation with coiled tubing or one of the volumetric techniques described in this manual.

## Trapped Pressure

Trapped pressure is any pressure recorded on the tubing or annulus that is more than the amount needed to balance the bottomhole pressure. Using pressure readings containing trapped pressure results in kill calculation errors.

Pressure can be trapped in the system by:

- Gas migrating and expanding up the annulus
- Closing the well in before the mud pumps have stopped running.

Procedure for checking and relieving trapped pressure is: *

1. Bleed only from the casing side through the choke, to avoid contaminating the fluid in the tubing and possibly plugging the bit jets.
2. Use the SIDPP for a guide. The tubing side is not contaminated with kick fluid and will give the bottomhole pressure.
3. Bleed ¼ to ½ barrel of fluid at a time, comparing it to the tubing pressure.

4. Continue to alternate between bleeding pressure and comparing it to the tubing pressure, as long as the tubing pressure continues to fall.
5. Record the true SIDPP and SICP when the tubing pressure creases to fall.
6. If the tubing pressure decreases to zero, continue to bleed the casing pressure, checking the SICP as long as the SICP continues to decrease. (This step is not normally necessary)

*Do not bleed off more pressure than is necessary to balance the bottomhole pressure. More influx will flow into the well and the surface pressures will increase if too much pressure is bled off.

The tubing should be checked again for trapped pressure when the tubing has been displaced with clean kill fluid.

## Top Drives

Today many units are fitted with top drive systems, replacing the traditional kelly. Top drives offer several advantages over kellys. They have a remotely operated full-opening safety valve (FOSV) that is always made up on the top drive and sometimes another manual FOSV at the lower end. If a kick is suspected while making a trip the shut-in procedure can be slightly different from kelly rigged units but the principles are the same. The pipe is set in the slips and a flow check is conducted in the conventional manner by making up an FOSV on the string.

Figure 8.2.

## Verifying Shut In

Once a well has been shut-in, the wellhead, the BOPs, the choke and kill manifolds, pump pressure relief valves, standpipe connections and other lines should all be checked for possible leaks. If equipment is leaking, it is not possible to monitor shut-in pressures precisely. Leaks may also erode well control equipment.

Offshore rigs should post a watch for signs of gas around the rig. On land rigs, check the surface area around casing for broaching. After shutting in the well and reading and recording pit gain, SIDPP and SICP, verify that the well is shut-in and holding pressure. Precisely recording and monitoring SIDPP and SICP, once the well is shut-in, is very important. Well control calculations are based on shut-in pressures. Monitor fluid volumes, and check the flow line for flow.

Until the nature of the kick has been determined, the entire rig should be alerted to the possibility of toxic and/or explosive gases at the surface. Depending on the specific situation, the well and all well control equipment may be operating under pressure for hours. During this time, and until normal operations are resumed, the equipment should be monitored on a continual basis. A partial equipment checklist might consist of the following:

- Frequently monitor gas detectors, breathing and warning devices for proper operation.
- Ensure that flow from the choke is lined up through a mud-gas separator and degasser

before annulus fluids enter the main mud system.

- When circulating, monitor the separator for pressure buildup and overloading (gas blow-by).
- Check the degasser operation frequently.
- Ensure downwind vent/flare lines are open and the igniter is operational.
- If a derrick flare line is to be used, caution must be exercised to ensure that any liquids or heavy gases, which could be toxic or explosive, do not settle around the rig.
- Ensure that all unnecessary potential sources of ignition are extinguished.
- Direct all unnecessary personnel to a safe standby area.

### Shut-in Pressures

If there is a check valve (float) in the work string, the shut-in drill pipe pressure will read zero or some other unreliable value. The correct shut-in drill pipe pressure can be determined by applying pump pressure to open the valve. There are several ways in which this can be done, depending on rig equipment. Four methods of opening a downhole valve are listed below.

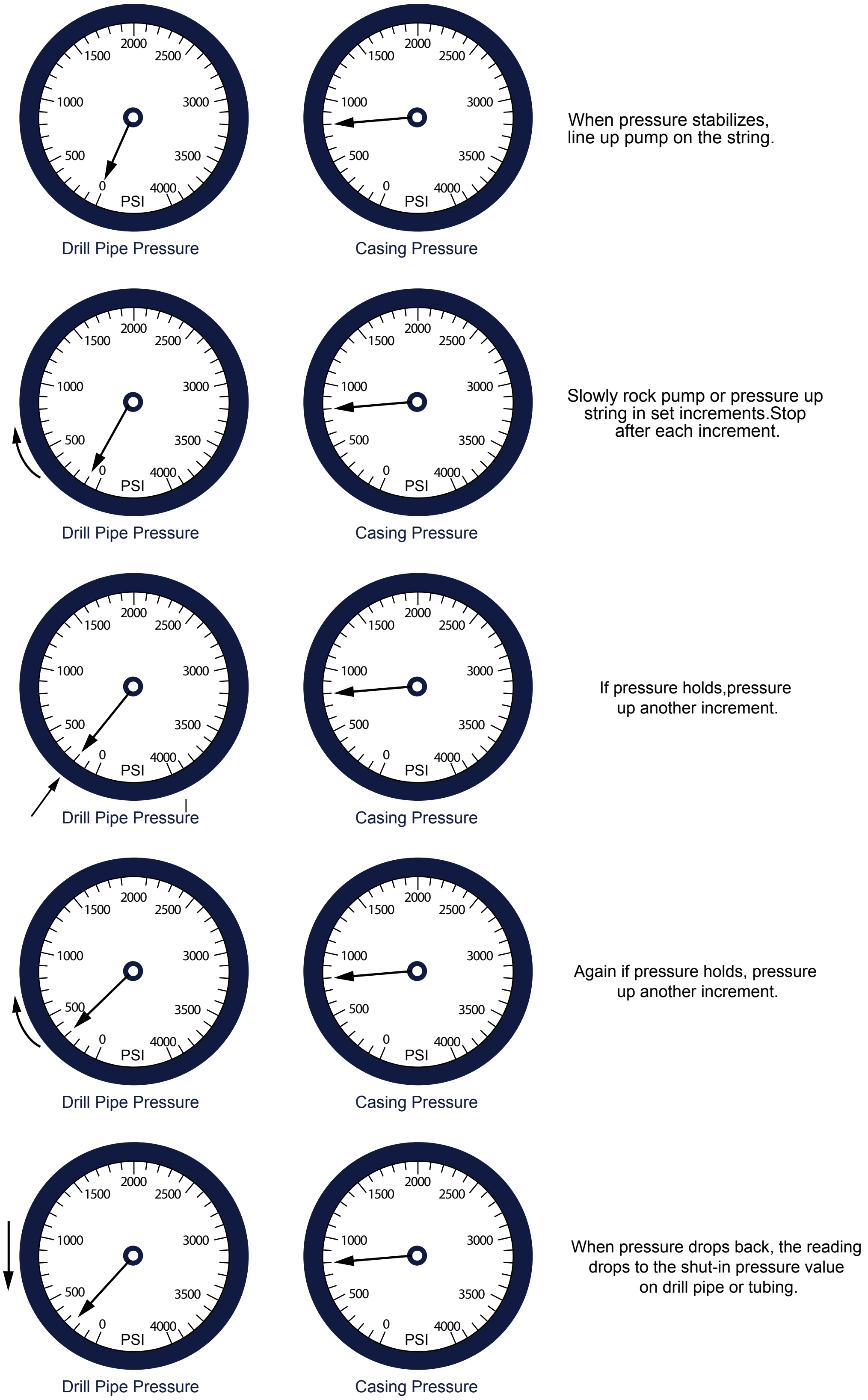
1. Pump into the string in small increments, kicking or rocking the pump in and out, pausing to note the pressure at the end of each cycle. When the downhole valve opens, the pressure will fall or "break back". The value to which the pressure drops is the SIDPP.
2. Using a high-pressure/low-volume pump (like a cement pump), slowly apply pressure to the string while monitoring the pressure gauge. When the pressure inside the string equalizes with well pressure a small dip or "break back" may be noticed when the valve opens. This is the SIDPP value.
3. If slow circulating rate (SCR) pressures were taken recently and are considered accurate, open the choke and bring the pump up to the slowest recorded SCR. Adjust the casing pressure to the shut-in value. When the circulating pressure stabilizes, subtract the recorded SCR pressure from the circulating pressure. The SIDPP is the difference between the two pressures. When using this technique, it is important to use the slowest prerecorded rate in order to avoid additional circulating friction.

$$\boxed{\text{SIDPP}_{psi} = \text{Circulating Pressure}_{psi} - \text{SCR Pressure}_{psi}}$$

4. If the pump can be carefully controlled, or cementing pumps are used, pump the equivalent of one half barrel and stop. Check the casing pressure. Repeat until an increase in casing pressure is noted. Subtract the increase in casing pressure from the pressure reading on the string. These steps should be repeated after bleeding casing pressure back to its original value. The pressures should agree within 100 psi.

When measuring shut-in pressures, it is best to work with the gauges on the choke control panel. Before drilling, ensure the pressure gauges have a range best suited for the potential shut-in pressures. Pressure gauges are most accurate in the middle portion of the range; accuracy decreases at the low and high ends of the range. If a well is shut-in at the extreme low or high end of a gauge's range, replace the gauge with one that will read SIDPP or SICP values closer to the middle section of its range.

Figure 8.3. Determining shut-in pressure.



## Differences in SIDPP and SICP Readings

The shut-in drill pipe pressure (SIDPP) reflects the difference between the formation pressure and the hydrostatic pressure of the liquid inside the drill pipe. While the light influx fluid in the annulus normally accounts for the SICP being greater than the SIDPP, there are instances where the reverse situation might be true upon shut-in. If low density fluids such as aerated fluid are used and the kick is saltwater, the SICP may be lower than the SIDPP. Kick fluid density varies from 1.5 ppg for gas up to 10.0 ppg for saltwater, the lighter the kick density the lower the SICP reading. If a saltwater kick is taken in a well being drilled, with a light oil serving as the drilling fluid, the hydrostatic pressure of the fluid in the annulus can be greater than that in the drill string. Position of bit and/or pipe, plugged drill pipe or bit, or if there is communication between the pipe and annulus, influence the SIDPP and SICP readings.

In some cases where rapid drilling has occurred, cuttings in the annulus may cause the hydrostatic pressure in the annulus to be greater, even if there is a small gas kick in the well. If some back flow occurs up the drill string, there may be sufficient gas influx to cause both gauges to read approximately the same. If there is a blockage in the annulus or gelled mud in the annulus, the SICP might register a very low value while there is a significant SIDPP reading. SIDPP cannot be read if the drill pipe or bit is completely plugged. It is also very possible that an inaccurate gauge can cause an incorrect reading of either or both SICP and SIDPP. In horizontal wells, if the influx is captured prior to any gas influx getting into the vertical leg of the well, both gauges could read the same value.

If the drill pipe/bit is off the bottom or if there is communication between the drill pipe and annulus, SIDPP will reflect the hydrostatic pressure at the depth of the communication point or drill pipe/bit depth and not the formation pressure.

It is possible that an incorrect shut-in procedure may produce a misleading interpretation of the shut-in data and actually be a "non-kick" event. For example, if the driller does not stop the pumps completely prior to fully closing in the well, "trapped pressure" might be misinterpreted as shut-in kick pressure. If this is suspected, it can be eliminated by slowly opening the choke. If both SICP and SIDPP (ported float) are brought back to zero, then it was "trapped pressure" and not a kick. If the pressures are reduced and begin to increase again, then at least a part of the shut-in values was indicative of trapped pressure. This is often referred to as *ballooning* when there were mud losses prior to shut in.

SIDPP and SICP are about the same in a horizontal well, as long as the kick remains in the horizontal section. When the kick is out of the horizontal section, the SICP is usually higher than the SIDPP.

## Pressure Gauge Limitations

Gauges should be tested on a regular basis; they are subjected to rough use and may be damaged during rig-up and rig-down operations. Inaccurate gauges should be recalibrated. Gauges may read inaccurately. Minor inaccuracies are not a problem as long as the inaccuracies are consistent across the gauges' range. A gauge's lack of a stop at maximum pressure can lead to false pressure readings, as the indicator hand can sweep around the face of the gauge and indicate an incorrectly lower pressure. Over pressuring a gauge can ruin its accuracy and may make it read very high or very low. Some gauges receive readings from remote sending devices that may be damaged, fail or provide erroneous readings.

A backup gauge may be used when a gauge is determined to be inaccurate. Be aware that the difference in the way a backup gauge reads (different range/scale) may lead to problems.

### Annular Pressure

There are three limits to consider with regard to annular pressure: 1) BOP and wellhead equipment, 2) internal yield (burst) limit of casing, 3) formation strength/cement integrity.

Blowout preventers, choke manifolds, stab-in valves, and other connecting surface equipment are regularly tested according to operator policies and regulatory requirements. Test limits are determined according to the weakest rated components in the system. A system with 10,000 psi BOPs, but a 5,000 psi choke manifold, would be rated at 5,000 psi.

The internal yield for various casing strings is determined from manufacturer's data and downgraded for a safety margin. A safety margin for new casing is commonly 70%. As drilling continues, it may be downgraded further if caliper logs indicate excessive wear. Particular attention is paid to casing wear in directional wells.

The weakest link in the blowout prevention system is the formation. Lost circulation is one of the most expensive and time-consuming problems encountered in the drilling industry. Lost circulation during a well control operation poses an even greater problem. A well with formation fluids flowing from one zone and entering another zone (an underground blowout) jeopardizes the well itself, future production from the well, and the environment.

After setting a new string of casing, good drilling practices, as well as regulations in many areas, dictate that the strength of open formations should be estimated before drilling operations continue. In the shallow sections of a well, before blowout preventers are rigged up on surface casing, the formation strength is estimated using available data from nearby wells. In the case of wildcat wells, geologic and seismic information may be the only data available. Once surface casing is set, rig equipment is used to determine the formation strength immediately under the casing seat (shoe).

Fracture pressure may be defined as the pressure required to permanently deform the rock structure of a formation. Once casing is set, the formation strength can be estimated by means of leak-off tests (LOT) or formation integrity tests (FIT), depending on the requirements of the well program. Both tests are conducted in the same manner. They differ only in the rig equipment available and the preferences of the operator.

- Leak-off tests apply pressure to the formation, as near to fracture pressure as safely possible.
- Formation integrity tests apply pressure to a predetermined limit based on previous experience in a particular area.

It is generally assumed that the zone immediately below the last string of casing is the weakest section of open hole. This is reasonable since formations tend to get stronger with depth, due to compaction. Assume that casing has been set at a certain depth and that a small amount (less than 50 ft) of formation has been drilled and circulated clean. Total pressure at the casing shoe is equal to the hydrostatic pressure at the shoe when the annulus is open at the surface. Now suppose the BOPs are closed and fluid is pumped into the closed well until some pressure is trapped on the annulus. Total pressure at the shoe would then be made up of the hydrostatic pressure at the shoe plus the applied surface (casing) pressure (P(shoe) = HP(shoe) + P(applied)). The quality of the cement job at the shoe and the formation strength are estimated in this way. The well is closed and a pump is used to carefully apply pressure on the annulus until the test is concluded. If possible, high-pressure/low-volume pumps, like cementing pumps, are used when testing formation strength. In addition to gauges, a pressure chart is used on the pumping unit in order to provide documentation. Gauges should be checked for accuracy before starting testing procedures. The upper pressure limit should be determined. Test results are recorded and become part of the overall well record.

Leak-off tests are performed to estimate the maximum pressure that the test point can withstand before formation breakdown occurs. A limited formation integrity test (FIT), also known as a jug test, is performed when it is not necessary or desirable to cause the formation to actually take fluid.

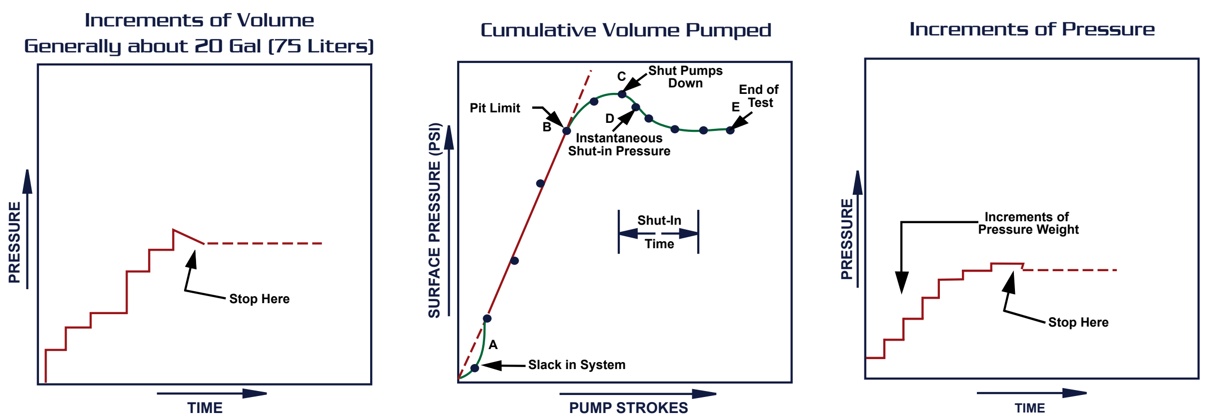
Three test techniques are described in the following sections.

## Leak-Off Technique #1

A well is pressured in increments of 100 psi, or fluid is pumped into the well in approximately one half barrel stages. After each increase in pressure, the pump is stopped and the pressure is observed for about five minutes. As long as the pressure continues to rise, the operation continues. If the pressure does not hold, the well is carefully pressured up again and the situation analyzed. The test is considered complete when the pressure will not hold (leaks off) after several attempts, or if the well will not pressure up any further.

Figure 8.4.

Pressure ~vs~ Time or Volume for Leak-off Tests




## Leak-Off Technique #2

The choke is opened on the manifold and the pump is started at an idle. The choke is then closed to increase the pressure in increments of 100 psi. At each interval of pressure increase, the fluid volume in the pits is noted to determine whether or not fluid is being lost to the formation. The test is considered complete at the pressure that causes fluid to be continuously lost to the formation. Some fluid will be lost at each pressure increase. If this technique is to be employed, a small tank should be used to ensure that large amounts of fluid are not forced into the formation. The small circulating friction pressure losses that are present when this technique is used will add more pressure on the formation, resulting in a slightly lower fracture pressure than when using technique #1 above.

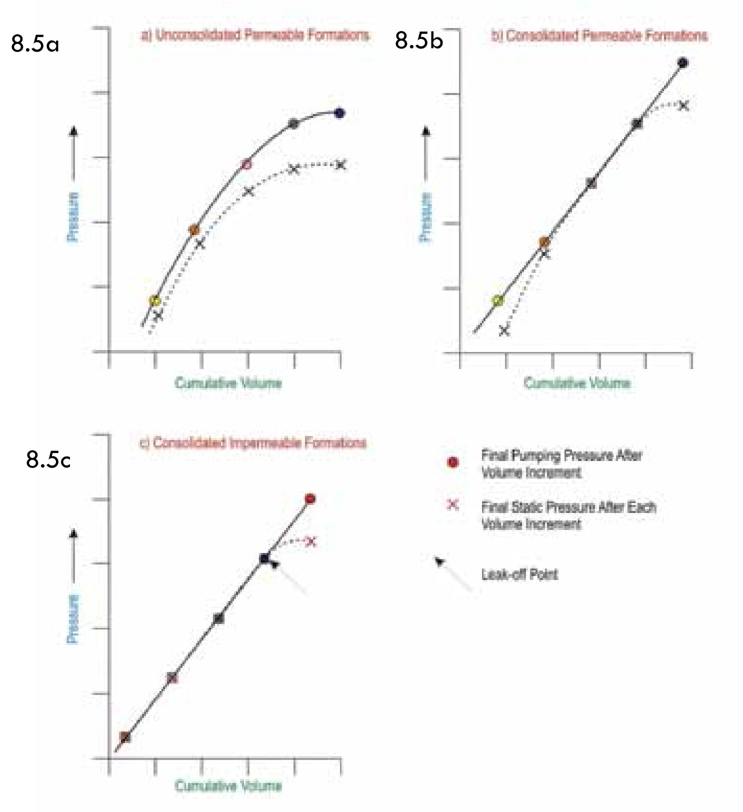
Examples of leak-off test plot interpretation:

In nonconsolidated or highly permeable formations, fluid can be lost at very low pressures. In this case, the pressure will fall once the pump has been stopped and a plot such as that shown in figure 8.5a will be obtained. Figures 8.5b and 8.5c show typical plots for consolidated permeable and consolidated impermeable formations respectively.

## Formation Integrity Test

In this test, pressure on the annulus is applied carefully to a predetermined pressure or equivalent fluid density. If the pressure holds, the test is considered successful. Both FIT and LOT techniques have advantages and disadvantages. In the FIT, the formation is not fractured, however, the maximum pressure before the formation starts to accept fluid is not accurately determined. In the LOT, the pressure at which the formation starts accepting fluid is determined, but there is always a possibility of fracturing the formation.

Figure 8.5. Idealized Leak-Off Test Curves




Once the estimated formation strength has been determined, the final pressure is converted to an equivalent density, usually called the *maximum allowable mud weight* (MAMW).

For example: Assume casing is set, cemented, and drilled out to a depth of 2,500 feet with 8.6 ppg fluid. Pressure was applied to the annulus and it was determined that the formation leaked off when a surface pressure of 1,050 psi was applied.

1. Determine the total pressure that caused the leak-off.

   Total pressure at the shoe is made up of:

$$\boxed{P_{psi\ (shoe)} = HP_{psi\ (shoe)} + \text{Applied Pressure}_{psi}\ (CP)}$$

$$P_{psi\ (shoe)} = (8.6 * 0.052 * 2{,}500) + 1{,}050 = 2{,}168 \text{ psi}$$

*NOTE: If the calculated pressure included a decimal, i.e., 2,168.6, this value is not rounded up because safety from fracture lies in the lower value.*

2. Convert the pressure to an equivalent density or maximum allowable mud weight. Transpose the hydrostatic pressure formula:

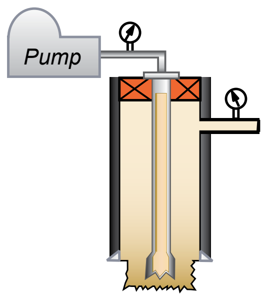
$$\boxed{MAMW_{ppg} = P_{psi\ (shoe)} \div 0.052 \div \text{TVD of the test}}$$

MAMW = 2,168 ÷ 0.052 ÷ 2,500 = 16.67 or 16.6 ppg

*NOTE: The MAMW is never rounded up.*

It can now be assumed that any time the open formation near the casing seat of this well is exposed to 2,168 psi, the equivalent of 16.6 ppg fluid, the formation would take fluid. The pressure that caused the formation to accept fluid and the MAMW are recorded on the driller's report and incorporated in the operator's documentation for the well. These values will likely be used from time to time as the well is drilled from 2,500 feet until the next casing point is reached. Formation strength tests will be conducted below all subsequent casing strings.

Figure 8.6




$P_{psi\ (shoe)} = HP_{psi\ (shoe)}$ + Applied $Pressure_{psi}$ (CP)

The mud weight will likely be increased as the well is drilled deeper. Once the formation test is completed the total pressure that caused the leak-off is considered unchangeable. When the density of the working fluid is changed, the hydrostatic pressure at the shoe also changes. Therefore when the density of the mud is increased, the theoretical surface pressure that would cause fracture decreases.

In the example, the MAMW was calculated using a test fluid density of 8.6 ppg. With 1,050 psi applied pressure, the formation could withstand about 2,168 psi before failing. Suppose, as drilling progressed, the fluid density was increased to 9.0 ppg. The hydrostatic pressure at the casing shoe would be increased and since the test pressure cannot change, it can be seen that the applied pressure (casing pressure), that would likely cause formation fracture, would be a lower value. To calculate the lower surface pressure the difference between the MAMW and the new fluid density is determined and expressed as pressure at the casing seat.

3. $$\boxed{MAASP_{psi} = (MAMW_{ppg} - CMW_{ppg}) * 0.052 * \text{Shoe } TVD_{ft}}$$

(16.6 – 9.0) * 0.052 * 2,500 = 988 psi

MAASP is also calculated as:

$$MAASP_{psi} = \text{Formation breakdown } pressure_{psi} - \text{HP of } fluid_{ppg} \text{ in use at the formation}$$

Or

$$\boxed{MAASP_{psi} = (\text{Fracture } gradient_{psi} - \text{Fluid } gradient_{psi/ft}) * TVD_{ft} \text{ of formation}}$$

Or

$$MAASP_{psi} = (\text{Max. equivalent fluid } weight_{ppg} - \text{Fluid weight in } well_{ppg}) * (0.052 * TVD_{ft} \text{ of formation})$$

This pressure, 988 psi in the example, is the *maximum allowable annular surface pressure* (MAASP). Some operators prefer to call it *maximum allowable surface pressure* and others call it the *estimated formation integrity pressure.* Whatever terminology is used, it is the best estimate of the surface pressure that a formation can withstand before fracturing. In this text, MAASP will be used.

Suppose that instead of performing a leak-off test, the operator had field knowledge and chose to test the formation to the preselected equivalent mud weight of 15.0 ppg. From the well data above, 8.6 ppg fluid is current mud weight (CMW) in the well at the time of the test. Pressure is applied equivalent to the difference between 8.6 ppg and 15.0 ppg. Once again, the hydrostatic pressure formula is used.

4. $\boxed{\text{Test Pressure}_{psi} = (\text{Equivalent Mud Weight}_{ppg} - \text{CMW}_{ppg}) * 0.052 * \text{Shoe TVD}_{ft}}$

Substituting: (15.0 – 8.6) * 0.052 * 2,500 = 832 psi

In this case the MAASP is 832 psi. The *equivalent mud weight*, or EMW, is 15.0 ppg, so that is the mud weight used to re-calculate the MAASP if the mud weight is changed.

A well is under constant pressure during a well control incident. The MAASP is part of the crucial information that is considered when making a safe plan to regain control of the well. Whenever the mud weight is changed during drilling operations the MAASP is recalculated and posted on the choke panel and other appropriate locations.

The drill team must constantly think ahead as formation pressure is likely to increase as the well is drilled deeper. For any estimated formation pressure and/or mud weight change as drilling progresses, the maximum volume of gas influx that can be shut in without fracturing the casing shoe should be determined. First this requires that the estimate of the maximum formation pressure (converted to mud weight equivalent), less the planned mud weight be calculated. This difference is defined as the kick intensity. The kick intensity is the amount of mud weight increase required to balance the formation pressure. For a given kick intensity, the maximum volume of gas influx that will not fracture the shoe upon shut-in is determined. This is defined as the *kick tolerance*. Determination of the maximum influx volume for a given kick intensity requires calculation of the influx height based on the MAASP, kick intensity, TVD of the well, projected mud weight, and estimated gradient of the influx.

It is important to remember that kick tolerance has no fixed value; it is continuously changing as a well is drilled. Kick tolerance is a key parameter when determining depths for which to set a given casing string. In general, the volume of influx that can be safely shut-in decreases with depth. Typically, a drill team will define an acceptable maximum volume for a given kick intensity. For example, an acceptable maximum limit (kick tolerance) for an onshore well might be 30 barrels for a 0.5 ppg kick intensity, while offshore in deep water, an acceptable kick tolerance might be 10 barrels for a 0.5 ppg kick intensity.

MAASP must be recalculated when there are:

- Changes in well barrier elements
- Annular fluid density changes
- Reservoir pressure changes
- Casing or tubular rating changes

### *SETTING OPERATING LIMITS BASED ON MAASP*[1]

The well operator should determine an operating range for each annulus that lies between upper and lower thresholds.

The upper threshold is set below the MAASP value to enable sufficient time for taking corrective actions to maintain the pressure below the MAASP.

The upper threshold should not be so high that the pressure in the annulus could exceed the MAASP due to heating after shut-in.

The lower threshold may be considered for the following reasons:

- Observation pressure for the annulus
- Providing hydraulic support to well barrier elements
- Avoiding casing collapse of the next annulus
- Avoiding hydrate formation
- Accounting for response time
- Potential small leaks
- Variability of fluid properties
- Temperature fluctuations

### *MAINTAINING ANNULUS PRESSURE WITHIN THE THRESHOLDS*

When the annulus pressure reaches the upper threshold value, it should bleed off to a pressure within the operating range. The annulus should be topped up when the lower threshold is reached.

The type and total volume of the fluid recovered or added, and the time to bleed down should be documented for each bleed-down or top-up.

The frequency of bleed-downs and the total volume of fluids recovered from the bleed-downs should be monitored and recorded. These should be compared to limits established by the well operator within the operating limits, and investigation should be taken when limits are exceeded.

The well operator shall define upper thresholds these shall not exceed 80 percent of MAASP of annulus  is applied on or exceed 100 percent of the MAASP of the adjacent outer annulus. Deviation from this standard should be risk assessed, mitigated and recorded through management of change (MOC) with formal technical authority approval.

The annulus may be over pressured by:

- Fracturing the formation at the shoe, by exceeding the MAASP
- The outer casing burst pressure rating*
- The inner casing collapsing*
- Exceeding the:
    - Formation leak-off test value
    - Wellhead pressure rating
    - Packer pressure rating

**Casing pressure burst and collapse ratings must rated lower because of corrosion and wear.*

Maximum allowable annular surface pressure:

- Is constant while gas is moving up in the open-hole section.
- Increases rapidly while gas enters the casing.
- Increases until gas reaches the choke.

#### *EXCEEDING THE MAASP DURING A WELL CONTROL SITUATION*

The MAASP at the casing shoe is normally considered to be the critical factor during well control operations. The formation at the casing shoe is considered to be the weakest part of the well. When the MAASP is exceeded and the top of the influx has reached the shoe, there is a danger of breaking the formation, causing lost circulation or a blowout. Exceeding the MAASP will not always cause lost circulation because the influx in the open hole may not reach the shoe as one bubble. If the influx is not one bubble, it may already be inside the casing shoe.

If MAASP is exceeded and minor losses occur, the following procedures will help to mitigate losses:

- Stop and monitor pressures and, if necessary, use a slower kill rate to reduce circulating pressure.
- Keep the casing pressure equal to the MAASP using the volumetric method until the influx is above the shoe.
- When the gas bubble is above the casing shoe, it can be allowed to rise unless it exceeds the safe operating pressure of the casing or surface equipment.

If the major or total losses occur, hold the casing pressure constant at least 150 psi above the bottomhole pressure until the influx is above the casing shoe. After the influx is inside the casing, the casing pressure can be allowed to rise, depending on returns.

If major or total losses continue, then pump LCM down the annulus to reduce fluid loss. Pumping down the annulus gets the LCM to the casing shoe faster and avoids bit plugging. Other lost control methods are covered in chapter 4, "Influx Fundamentals".

To summarize this discussion:

- The strength of a formation and the quality of primary cement jobs are tested after drilling a small distance below the casing seat, and before drilling ahead.
- The formation test provides an estimated maximum allowable mud weight and the maximum allowable annular surface pressure that the formation can withstand at the casing seat.
- Do not exceed the MAASP if the top of the influx is at the casing shoe.

### Monitoring Annular Pressure

NORSOK Standard D-010 Well Integrity in Drilling and Well Operations 3.1.51 defines well integrity as the "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well.*"[3]

Annular pressure should be monitored over the lifetime of the well. Shut-in pressure tests are used to measure annulus pressure. All annular spaces should be tested in multiple completions. Results should be graphed for analysis. Abnormal or anomalous annulus pressure can indicate tubing-to-annulus communication. There is a risk of tubing burst or tubing collapse if the pressure differential between the tubing and the annulus exceeds the rated pressure of the tubing. There is also a risk of exceeding the casing burst pressure or integrity of the wellhead or Christmas tree.

Annular pressure buildup in a well can be caused by:

- Heat from produced fluids, expanding fluids or gases in the inner annulus or outer annulus, causes the trapped fluids to expand.
  - Fluids that are heated in a confined volume expand to fit the maximum space and then increase the pressure rapidly.
  - Gases, when heated, compress when in a confined space, increasing pressure slowly.
- Weather and external conditions can cause abnormal annulus pressure.
- Poor cementing job or bad cement slurry, allowing leaks into casing.
- Gas and/or fluids leaking from tubing or inner annulus into outer annulus.
- Leaks from the tubular threads, holes in tubulars caused by corrosion, packer seal leaks, wellhead seal leaks
- Operator imposed pressure such as gas lift
- Mechanical damage to tubulars or casing, allowing leaks
- Leaks into the annulus from a shallow or "non-producing" formation

Abnormal annulus pressure can:

- Be bled off.*
  - Fluid annulus pressures up quickly and bleeds off quickly.
  - Gas annulus pressure builds up slowly and bleeds off slowly.
  - Annulus fluid should be analyzed to determine the fluid entering the annular space.
- Vented through an opening made at the shoe.*

**Both bleeding off and venting annulus pressure may cause larger leaks. Venting may pressurize another zone and cause other problems.*

When the tubing is suspected of leaking, the leak can be located (depending on the leak rate):

- If the leak rate is high, it will create enough friction to be located with a high resolution temperature tool.

Or

- If the leak rate is low, inject trace elements and read with a water flow logging tool.
- Run and set a plug and pressure test above it. Keep setting the plug at increasing depths and testing above it until the leak is located.

Cross flow from a formation can be detected by:

- Noise logs
- Temperature surveys
- Cement bond logs

## Space-Out Considerations

Drillers must bear in mind the distance from the rig floor to all components in the BOP stack in order to avoid closing the BOPs on a tool joint. The driller and crew should be aware of the approximate length of pipe above the rotary table at all times. Exact lengths must be determined if the pipe is to be hung off on a set of ram preventers.

Spacing out on floating units can present a more complex problem because water depth, tidal changes and sea conditions complicate spacing-out/hang-off procedures. This is especially true when the subsea BOP system is taller than the average length of a joint of the pipe being used. Accurate measurement of each joint and stand is a must.

## Shut-In on Collars

One of the more critical shut-in situations develops when flow is detected as drill collars are pulled through the rotary table. The annular preventer may be used, but situations complicating the shut-in process must be considered. These include the use of spiral collars and stabilizers and the lack of a float (back-pressure valve). In addition, there is a possibility the influx may be close to surface. If the force acting upwards on the large diameter drill collars is greater than the weight of the collars acting downward, the collars may actually be blown out of the well.

Figure 8.7

Often drill collars have different sizes and types of threads. Therefore, the proper crossover subs must be available on the rig floor, made up with a safety valve, and ready for installation. Procedures for making and picking up this assembly should be understood and practiced by the crew. Other operational questions arise, for example:

- Is it safer to pull the remaining collars once flow is detected, or to install the crossover/safety valve assembly?
- If the collars begin to be ejected from the well, will a choke be used to relieve pressure below the annular, possibly allowing more influx to enter the well?
- If drill collars are to be dropped, how will this be accomplished?

The following procedure is outlined in API RP 59[1] when the BHA or tool joints may be in the BOPs.

1. Alert the crew.
2. Position the upper drill collar or tool joint and set the slips.
3. Stab a FOSV made up on one joint of pipe with the appropriate crossover sub onto the drill collars or tool joint.
4. Lower the collars with the joint of pipe into the well.
5. Close the FOSV.
6. Close the pipe rams above the pipe tool joint.

An important consideration on any trip is the location of collars in the derrick. They should be racked in such a way so as not to block the drill pipe in the event pipe must be run back into the well.

## Shut-In When out of the Well

If flow is detected after the work string has been removed, the well should be shut in with the blind rams. This stops the influx, allows pressures to be determined, and provides time to develop a course of action. Under no circumstances should pipe be run into an open well if a significant flow is present or if there is gas at the surface. The only safe way to get pipe back into the well is by using stripping procedures. Stripping operations are discussed in detail in chapter 10, "Special Situations".

## Shut-In While Running Casing

The philosophy of all shut-in procedures calls for first stopping the potential flow through the smallest and most vulnerable flow path. During routine drilling and tripping operations this is the inner diameter of the work string. The opposite situation exists when running casing.

Figure 8.8. Casing operations.

Prior to running casing, the BOP stack is equipped with casing rams (or variable bore rams) that are tested before the casing is run. A circulating swage with high-pressure/low-torque valve should be made up and positioned near the rotary table to be installed immediately after the BOPs have closed, in case the casing float equipment fails.

The collapse pressure rating of the casing should be checked and the accumulator closing pressure on the annular preventer adjusted accordingly. An alternate to this is to lower a joint of casing into the annular preventer, bleed the annular closing pressure off and then gradually increase the pressure in increments of 100 psi at a time until closure around the casing is obtained. From this point, an additional 100-200 psi should be sufficient to form a seal. Floating units have crossover subs on the floor that are used to connect the casing to drill pipe in order that the string can be hung off on rams, if necessary.

Shutting in a well while running casing is similar to shutting in a well when tripping drill pipe. The main differences involve whether to close a BOP or a diverter. When running surface casing, the BOP stack is not usually nippled up, since there is no casing head to nipple onto. In such cases, crew members will have to use a diverter or other procedures to close in the well. Because casing is normally run with a float shoe, once the diverter or BOPs are closed, the shoe prevents back flow through the casing. Also, the common cement circulating head can be closed to prevent flow up the casing. It is important to remember to plan for having to close in around casing. Ram BOPs will need to be properly sized to close around the casing. Further, annular closing pressure may need to be reduced to prevent collapsing the casing.

## Shut-In While Cementing Casing

If a kick occurs while cementing, the driller should first ensure that the casing has been properly spaced out and there is no casing coupling in the BOP. BOPs may not be able to close properly on a casing connection. Spacing should have been checked before initiating the cementing operation. Next, the cement pump should be shut down, the annular BOP closed and the supervisor notified. Depending on the annular BOP type and size of casing, the closing pressure on the annular BOP should be reduced. A conventional float will prevent backflow through the casing.

## Diverter Procedures

Arguably, the most dangerous interval during drilling operations is the time from initial spud-in until surface casing is successfully run and cemented. Before that time. there is no effective way to stop the flow from a well. Shallow gas flows reach the surface with tremendous force and little warning. Even if a well could be shut in, the formation may not be strong enough to contain the flow. The uncontrolled gas can easily break out around the substructure of a rig and floating units may lose buoyancy as the flowing gas aerates the water.

Diverter systems consist of blowout preventers (usually annular type), which are designed to protect the rig from shallow blowouts by closing off the annulus, while allowing the influx to evacuate safely through vent (blooey) lines below the preventer. The system is rigged so that the blooey lines open before the diverter packer closes around the pipe. Diverter procedures must be implemented quickly because the time from kick detection until gas reaches surface may be minimal. The warning signs of a shallow gas kick are:

- an increase in flow (usually quite dramatic)
- a loss of standpipe pressure and increase in pump strokes
- mud coming over the bell nipple and/or the rig floor

Diverter procedures should be thoroughly discussed at pre-spud meetings and understood by the drillers and crews in order to insure that everyone understands the procedure and is familiar with their individual duties and responsibilities.

*DIVERTER PROCEDURE WHILE DRILLING*

- Stop drilling but do not shut down the pumps.
- Activate the diverter system. Most rigs have coupled the diverter line and diverter packer together to ensure that the blooey line(s) open before the packer closes.
- Pump at maximum rate with drilling fluid, seawater or heavy mud if available.
- Set a watch observing the diverter system for signs of failure.
- Set a watch for signs of broaching around the location.

*DIVERTER PROCEDURE WHILE TRIPPING*

- Install full-opening safety valve in open position. Close valve.
- Open downwind diverter line.
- Close diverter
- Install kelly, chicksan or top drive.
- Open the safety valve.
- Pump at maximum rate with mud, or switch to seawater or heavy mud.

*NOTE: The first three steps above should be done as quickly as possible. As soon as the crew sets the slips and the driller chains the brake, the FOSV should be stabbed and closed by the crew as the driller activates the diverter system.*

## Preplanning

The well intervention preplanning phase includes gathering and prerecording well information on site from the operator and/or contractor and entering it into forms.

The preplanning phase also includes:

- Pre-job meeting
- Pre-job safety meeting
- Well control contingency plans
- Well control pre-kill meeting

### Prerecorded Information

Prerecording information is essential in providing information used for preplanning operations and to improve well control planning. Pre-planning improves well intervention operation performance and increases safety. It also decreases lost operational time by providing well-specific information used to manage and control all aspects of the operation. All available well data information should be maintained by the supervisor in a designated central location and should be accessible to everyone.

Prerecorded information includes:

- Well configuration information
- Maximum allowable surface pressures
- Fluid densities in the well
- Reservoir data

### Well Configuration

The well-specific information that should be available to the workover supervisor includes the following:

- Top and bottom of the existing completion interval(s)
- Packer and other installed tool locations
- Tubular dimensions, lengths, and properties
- Deviation survey (MD, TVD)

- Casing and liner dimensions, lengths, properties
- Formation integrity and formation injectivity index (if known)

The well configuration data that should be available to prerecord on a kill sheet include:

- Tubular dimensions, lengths, burst and collapse pressures
- Top and bottom of existing completion interval, TVD and MD
- MD and TVD of all tubing strings, including production tubing
- Formation integrity (LOT data)
- BOP and tree pressure ratings
- Pump(s) output in bbl/minute

### Maximum Allowable Surface Pressures

Critical values of the maximum allowable surface pressures for the surface equipment include:

- Wellhead and BOP working pressure (WP) rating
- Casing burst and collapse ratings
- Tubing burst and collapse ratings
- Production zones and perforation intervals
- Other, such as pumping lines, return lines, and manifolds

### Fluid Densities in the Well

It is crucial that the fluid densities in the well be known prior to intervention into a well. The densities should be known to the nearest 0.1 ppg. When there is more than one fluid in the well, the lengths of the fluid columns should be known for each fluid density.

### Reservoir Data

As much information as possible should be known about the fluid reservoir(s). For each reservoir, it will be critical to have a very good estimate of:

- Formation pore pressure
- Formation fracture pressure
- Formation temperature
- Sour and/or corrosive gas content

Well information is kept by the supervisor in the truck on location.

### Pre-Job Meeting

Pre-job meetings are conducted before each new job and at the beginning of each work day or in the event of a significant operational change. The pre-job meetings are used to enhance communication, to reduce unscheduled events, to review the well intervention operation plans and to coordinate the responsibilities between the contractors, service companies and operators. The rig crew and contractors must understand the equipment, operational procedures and their assignments, individual roles and responsibilities and how to communicate and coordinate with all other rig site personnel. The operational procedure is discussed with the well intervention crew and contractor personnel. Simultaneous operation documents are also reviewed. Well control training of the contractor and well intervention personnel should be verified.

### Pre-Job Safety Meeting

A pre-job safety meeting with all involved personnel is part of the planning stage. Safety is the first priority in any procedure and is an essential part of any operation. Toolbox or safety meetings, usually conducted by the well intervention supervisor, should be held daily. The daily operations to be completed should be discussed with emphasis on how to do the work safely.

A pre-job safety meeting should address:

- Personal protection equipment (PPE: fire-resistant clothing, hard hat, safety shoes, hearing protection, eye protection, and respiratory protection if hazardous gases are present)
- First aid and medical provisions
- Weather conditions
- Heat and cold stress
- Emergency evacuation procedures (for rig site and injured worker)
- Shut-in procedures and contingency plans
- ESD system functions and locations
- Communication (communication systems and line of site hand signals)
- Equipment handling procedures, transport, offloading and rigging up and down
- Equipment testing procedures
- Hazardous materials exposure
- Chemical handling and spill contingency plans
- Known well-site hazards
- Escape routes
- Fluid circulating requirements
- Recommended circulation paths
- Determining corrosion effects of the string and casing
- Checking fluid chemical compatibility
- Reviewing safety system settings
- Reviewing BOP tests and shut-in procedures
- Complying with hydrogen sulfide standard

### Crew Instructions

Prior to engaging in well completion or well workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for BSEE review.[2]

## Stop Work Authority

All personnel performing work are granted stop work authority (SWA) to stop any unsafe activities or practices to prevent an accident or an environmental incident and are expected to use it when warranted. All personnel are also expected to support the stop work intervention of others.

Supervisors are responsible to create a culture where SWA requests are honored and any issues are resolved before operations are resumed and that all stop work requests are properly reported.

## Well Control Contingency Plans

Most well control situations are due to either equipment malfunction/failure or personnel errors.

Contingency planning is a process that prepares personnel to respond safely to an unplanned event. The contingency plan should emphasize personnel safety at the well site.

All contingency procedures should be reviewed, assessed for risk and approved. Planned responses to well control situations and individual responsibilities should be discussed and agreed on by all parties concerned prior to any well intervention operation. To prevent further complications and worsening of a given situation, constantly assessing well data is key to determining when the plan is not successful and when it is time to decide on the corrective action to take.

Well control situations include:

- Hydrocarbons at surface
- Blowouts at the surface or underground
- Fire at the surface or underground
- Well pressure buildup
- Potential trapped pressure
- Inadvertently drilling into another wellbore
- Problems with existing well tubulars
- Problems with equipment previously used in the well
- Surface equipment issues
- Well control systems issues
- Inside blowout
- Subsurface equipment failure
- Work string failure
- Personnel error
- Incorrect mud pumped
- Insufficient weighting material
- Weather problems
- Ram or annular failure
- Plugged string
- Rig power failure
- Plugging
- Washouts

It is the responsibility of management to define the point at which the well and perimeter will be secured and the well site abandoned.

## Risk Management

Risk management is the process of gathering data and synthesizing information used to identify, assess and prioritize risks. It is used to minimize, monitor, manage and control the probability and/or impact of damage, injury, liability, loss or any other negative occurrence caused by these risks. Risk is composed of two elements, likelihood (frequency) and consequence.

Potential risks at a well site include personnel injuries and/or fatalities, environmental damage including oil spills and pollution, financial loss of facility and equipment, production losses and impact on the corporation's reputation.

### Principles of Risk Management

Risk management should:

- Create value - resources expended to mitigate risks should be less than the consequence of inaction.
- Be an integral part of an organization.
- Be part of the decision-making process.
- Explicitly address uncertainties and assumptions.
- Be systematic and structured.
- Be based on the best available information.
- Be customizable.
- Take human factors into account.
- Be transparent and inclusive.
- Be dynamic, interactive, and responsive to change.
- Be capable of continued improvements and enhancements.
- Be continually or periodically reassessed.

The methods used in risk management consist of the following elements:

- Identifying and characterizing threats.
- Assessing the vulnerability of critical assets to specific threats.
- Determination of the risks (e.g., the expected likelihood and consequences of specific types of attacks on specific assets).
- Identification of ways to reduce the identified risks.
- Prioritization of risk reduction measures based on a strategy and risk probability.

The risk management plan should include appropriate controls or counter measures to measure each risk.

## Management of Change

Change may represent risk. Management of change (MOC) is a best practice of introducing controls to ensure that safety, health and environmental risks are controlled when there are changes in facilities, documentation, personnel or operations. MOC procedures for managing changes should be written and regularly reviewed to reduce the risk associated with any changes. New hazards may be encountered when an operation deviates from a pre-approved procedure. The MOC process ensures that risk assessment and approval of changes take place before deviating from a pre-approved procedure. The MOC program must specify what types of changes are to be managed and how they are managed. The approval process may be made by company management or by management at the well site, according to the MOC procedure. The MOC process is not generally applied to well control contingency procedures which have been reviewed, assessed for risk and approved.

Employees should be trained on any changes before they are allowed to perform the operation the changes are related to. The training on operational changes should emphasize any safety and health hazards and what to do in the case of an emergency.

Unexpected events or circumstances may require a change in the well design throughout execution of the well construction process. In some cases, these changes can affect the integrity of the well and/or barriers. Each operating company shall develop its own practices and policies regarding management of change. Each MOC should follow these steps:

- Assess risks.
- Receive approval at the appropriate level.
- Document procedures.
- Log results.
- Communicate changes to affected parties.
- Monitor while in progress.
- Close procedure when no longer in effect.

In some cases, changes to well equipment, conditions, and barriers may require additional regulatory approval to continue in operation.

### Critical Isolation Requirements

When workovers are performed near facilities such as onshore or offshore oil and gas refineries, chemical processing plants or pipelines there are additional concerns. Hazardous materials at the workover site, nearby refineries, plants and pipelines pose loss of containment risks. Loss of containment of hazardous materials can cause personnel injuries and/or fatalities, damage the environment and equipment. The release may also cause wide spread damage or destruction to nearby facilities. Long-term effects to people or environment may be as serious as the initial release.

Planning must take place to keep risks as low as reasonably practicable (ALARP) prior to conducting a workover operation.

Hazard assessment should be conducted emphasizing:

- Impact of work on the surrounding environment
- Process equipment, mechanical and electrical
- Worksite access and egress
- Process isolation of any interconnecting piping, electrical conductors or drains

Policies and procedures should be put in place for:

- Personnel training

- Personnel roles and responsibilities
- Emergencies
- Installing, testing and removing isolations to reduce risks to ALARP
- Containment of hazardous material
- Clean up and disposal of hazardous material
- Monitoring and auditing requirements
- Draining, venting, flushing and flaring hazardous material

The same hazard assessment, policies and procedures should be used on every workover.

## Well Control Drills

Recommended practices and some regulatory agencies dictate that well control drills must be held at least once a week for each crew. Pit drills are conducted to simulate kick detection and shut-in while drilling and trip drills simulate kick recognition during tripping operations. Drills may be announced or unannounced. They take place at times that will not interfere with current rig activity. Trip drills are not usually held until the BHA has been pulled into the casing to reduce the possibility of stuck pipe. The time it takes for the crew to complete the drill may be documented and used as a measure of crew proficiency.

API Recommended Practice 59, Section 11 addresses crew drills and well control rig practices.[1]

Four types of well control drills in API RP 59 are the:

- Pit drill
- Blowout preventer kick drills
- Stripping drill
- Choke drill

API RP 59 states:

"The proficiency with which drilling crews react to well control situations and follow correct control procedures can be enhanced by repetitive drills. When the desired proficiency is attained, periodic drills should be continued to maintain performance."[1]

## General Well Control Drill Guidelines

Well control drills:

- Are initiated by the contractor or the rig supervisor and performed under the supervision of the drilling supervisor.
- Are conducted before drilling out to any shoe, and at the discretion of the drilling supervisor, but not less than once every week per crew, while normal drilling operations are in progress.
- Only conducted when they do not complicate ongoing operations.
- Include recording the names of crew members who are present on the drill floor at the time of a BOP drill or well control situation. All crew members must be able to react correctly to the drill or real well control situation.

- Must be recorded, including the type of drill and time of drill. The reaction time is recorded in seconds, starting from the moment the kick is simulated or announced until the designated crew member is ready to start the closing procedure. Also record total time taken for the drill. The time taken should be less than the API specified time, or the drill must be repeated.

## Pit Drill

API RP 59 states:

"Without prior warning and during a routine operation, the rig supervisor should simulate a gain in pit drilling fluid volume by raising a float sufficiently to cause an alarm to be activated. If automatic equipment is not available, the drills may be signaled by word of mouth.

When the drill is announced, the drilling crew should immediately initiate one of the blowout preventer kick drills, if not alerted that it is a pit drill.

A pit drill is terminated when steps are taken up to, but not including, closing the blowout preventers."[1]

### *PIT DRILL PROCEDURES*

The steps of a pit drill when drilling on bottom are:

1. A kick is signaled verbally, announcing that a kick has been detected, or by raising a float sufficiently (by adjusting the PVT) to raise an alarm (normally by the rig supervisor or driller).
2. The response time it takes the driller to detect pit gain is recorded. Response time should be one minute or less.
3. The driller or rig supervisor alerts the crew and stops the rotary.
4. Crew assumes the pre-planned positions.
5. The driller pulls the kelly/top drive above the rotary table until the lower kelly cock is above the drilling floor. Slow down the pumps and sound the alarm at the same time.
6. The driller stops the rig pump and performs a flow check.
7. The driller reports no flow; the drill is concluded.
8. The rig supervisor and toolpusher are notified.
9. Log drill and reaction time on the IADC and daily drilling reports.
10. Assess and review proficiency of drill with crew members.

*NOTE: A diagram with all tool joint measurement positions should be available to the driller at the BOP control panel.*

## Blowout Preventer Drills

The blowout preventer drills are:

- Drilling on bottom with the kelly on the string
- Tripping drill pipe drill
- Drilling with drill collars in the preventer
- Out of the hole drill

### *BLOWOUT PREVENTER DRILL WHEN DRILLING WITH THE BIT ON THE BOTTOM*

First perform all the steps of the pit drill, then the blowout preventer drill steps.

This drill should be signaled by raising the kelly/top drive and shutting down the rig pump to help avoid stuck pipe.

The on-bottom drill should be carried only to the point when the driller recognizes the kick.

1. The rig supervisor or driller signals the kick.
2. Stop all operations.
3. Position the drill pipe in the BOP while sounding alarm.

Note: A diagram with all tool joint measurement positions should be available to the driller at the BOP control panel.

4. Stop the rig pump.
5. Measure the fluid gain in the active fluid tank.
6. Notify the rig supervisor and toolpusher.
7. End the drill and return all settings to normal operating mode. Reaction time should be less than two minutes.
8. Log drill and reaction time on the IADC and daily drilling reports.
9. Assess and review proficiency of drill with crew members.

This drill should be repeated on a daily basis until each crew can close in the well within two minutes. The drill should be repeated weekly to maintain proficiency.

## Tripping Drill Pipe Drill

Tripping drill pipe drills should only be performed after the bit is up in the casing. A full-opening safety valve for each size and type connection in the string must be open and on the rig floor and ready for use. Safety valves must be clearly identified as to size and connection to avoid confusion and lost time when stabbing.

The following steps should be performed:

1. The rig supervisor or driller signals the kick.
2. Position the upper tool joint above the rotary table and set the slips.

*NOTE: A diagram with all tool joint measurement positions should be available to the driller at the BOP control panel.*

3. Crew stabs a full-opening safety valve (FOSV) on drill pipe (hand tight) and closes safety valve.
4. Torque-up the safety valve.
5. Shut down the trip tank pump and check for flowback into the trip tank.
6. Take and record gain in trip tank.
7. Record the time to detect trip tank gain.
8. Notify the rig supervisor and toolpusher.
9. Install the circulating head, make it up to the correct torque, open the stabbing valve, then read and record the SICP and SIDPP.

10. End the drill and return all settings to normal operating mode.
11. Log drill and reaction time on the IADC and daily drilling reports.
12. Assess and review proficiency of drill with crew members.

### Drill Collars In The Preventer Drill

Note: Preparation for this procedure must be made in advance. Make up a drill collar change-over sub on a single joint of drill pipe before reaching the drill collars when pulling out of the hole. Make up a full-opening safety valve in open position on the top of the joint of drill pipe.

Flows that occur in drill collars are usually rapid due to gas expansion near the surface. The joint of drill pipe with a change-over sub and safety valve should be easier to stab and make up than a safety valve alone.

The following steps should be performed:

1. The driller or rig supervisor signals the kick.
2. Position the upper drill collar in the rotary table and set the slips.
3. Using the elevators, stab and make up the joint of drill pipe, with a change-over sub and full-opening safety valve onto the collars.
4. Lower the collars with a joint of drill pipe into the hole.
5. Close the drill pipe safety valve.
6. Close the pipe rams above drill pipe tool joint.
7. End the drill and return all settings to normal operating mode.
8. Log drill and reaction time on the IADC and daily drilling reports.
9. Assess and review proficiency of drill with crew members.

### Out Of The Hole Drill

The following steps should be performed:

1. The driller or rig supervisor signals the kick.
2. Close the blind rams.
3. End the drill, and return all settings to normal operating mode.
4. Log drill and reaction time on the IADC and daily drilling reports.
5. Assess and review proficiency of drill with crew members.

### Stripping Drill

API RP 59 states:

"A stripping drill should be performed by at least one crew on each well. This drill can be conveniently performed after casing is set, pressure tested, before drilling out cement, and with the drill pipe in the hole. A blowout preventer should be closed and the desired pressure trapped.

Each crew member should be assigned a specific position. Following an acceptable procedure, the crew should strip sufficient pipe into the hole to establish the workability of the equipment and to allow each crew member to learn to perform assignments.

In addition to establishing equipment reliability, this will permit the training of at least one crew on each well. Over a period of time, all crews should become proficient in stripping operations."[1]

### Choke Drills

API RP 59 states:

"Choke drills should be performed before drilling out surface casing and each subsequent casing string. With pressure trapped below a closed preventer, the choke should be used to control casing pressure while pumping down the drill pipe at a prescribed rate. This drill will establish equipment performance and allow the crew to gain proficiency in choke operation. It is desirable to discharge into a trip tank to accurately monitor flow rates for correlation with choke opening, pump rates and pressure drops in the circulating system and across the choke."[1]

### Choke Drill Procedures

1. Driller ensures casing shoe is not drilled out.
2. Driller or rig supervisor alerts rig crew.
3. Crew lines up for circulation through choke manifold.
4. Crew closes annular BOP.
5. Crew opens HCR on choke line.
6. Crew circulates through choke at various pump speeds, noting circulation pressures.

### Combined Volumetric/Stripping Drill

The following steps should be performed:

Conduct a stripping drill in the casing before drilling out the shoe track, with the drill pipe in the hole, 1,000 feet above the top cement. Check to make sure the trip tank is calibrated, is half full and drains into the stripping tank.

1. Driller or rig supervisor signals a kick.
2. Establish a reference point above the BOP to assist in tool joint location.

*NOTE: A diagram with all tool joint measurement positions should be available to the driller at the BOP control panel.*

3. Close the annular preventer.
4. First, stab a full-opening safety valve on drill pipe (hand tight) and then install an IBOP. Close the full-opening safety valve.
5. Reduce the annular preventer closing pressure (usually when the fluid slightly leaks from between the annular preventer sealing element and drill string when stripping, but does not leak in the static state) to minimize excessive wear in the annular preventer sealing element. (Make sure the bushings are locked).
6. Open the surge bottle valve in the annular closing line.
7. Connect the line from choke manifold to discharge into the trip tank to accurately monitor flow rates. Make sure that any fluid leaking from the annular preventer goes into trip tank.

8. Make up the next stand.
9. Lubricate the work string and run the stand into the hole slowly to avoid pressure surges. Maintain constant annular pressure with choke manipulation. Calculate the closed in volume of the stand and make sure the fluid volume bleed off is equal to the volume of the stand run into the hole.
10. Close the choke manifold after the stand is run in.
11. Drain fluid volume of one stand that was run in from the trip tank into the stripping tank.
12. Make up and run in the next stand.
13. The stripping/volumetric should be repeated until crew is familiar with operation.

## Diverter Drills

A diverter drill might require the driller to go to the diverter console where he would not activate the system. The procedure of opening the downwind diverter line, closing the diverter packer, and pumping is explained to the crew in detail.

## Well Control Personnel Responsibilities

It can be seen that planning is a major element of successful well control procedures. So far as possible, crew assignments should be posted and stressed so that the crew reacts efficiently when a potential emergency exists. Since rig operations and equipment vary widely throughout the industry, it is impossible to specify universal personnel assignments in this text. The following manpower distribution is an example only, and does not in any way recommend or represent any regulatory policy.

All crew members should know their roles and responsibilities during a well control situation and should have practiced those individual roles during well control drills.

Only one person should be in charge during well control procedure. Everyone should be aware of who is in charge (the team leader) of the well kill procedure.

### *COMPANY REPRESENTATIVE*

- Has overall responsibility unless rig has offshore installation manager (OIM).
- Briefs crew, oversees operations and makes sure crew knows their responsibilities.
- Notifies and keeps communications open with operations office.

### *TOOLPUSHER/RIG MANAGER*

- Responsible for rig and personnel.
- Ensures kick drills are carried out routinely.
- Ensures all preparations, personnel certification and drills meet company requirements.
- Verifies on and off shift crew deployment, notifies barge engineer or vessel captain (offshore) of well control operations.
- Coordinates activities of third-party contractor personnel with the Operator throughout the well kill operation.
- Ensures well control equipment is tested and fully functional.

- Holds a pre-kill meeting with key personnel.
- May be responsible for operating the choke or to designate choke operator.

*DRILLER*

- Primary responsibility is kick detection and verification.
- Shuts in the well.
- Ensures well is secure, kill data collected and kill calculations are properly performed.
- Notifies supervisor.
- Organizes crew for kill operation, ensuring all persons know their assigned tasks in the well control operations.
- Performs calculations and plans kill procedure with the toolpusher/rig manager.
- Remains at drilling console to run rig and rig pump during kill operation.

*DERRICKHAND/ASSISTANT DRILLER*

- Goes to mud pit area, aligns gas separator, degasser and pits.
- Liaisons with mud engineer to supervise mixing mud material if necessary.
- Confirms rig pumps and mixing pumps are functioning and aligned properly.

*FLOORHANDS*

- Reports to assigned well control station (rig floor, pump room, choke console, etc.).
- Follows instructions of driller.

*ELECTRICIAN/MECHANIC*

- Assists mechanic/motorman if required.
- Stands by for orders.

*BARGE ENGINEER (OFFSHORE)*

- Notifies support vessels of operations.
- Stands by in control room for instructions.

*ROUSTABOUTS*

- Goes to mud or pump room and follow instructions of supervisor.

*MOTORMAN*

- Shuts off all non-essential equipment.
- Maintains rig power throughout operations.
- Goes to assigned station for well control operations.
- Stands by for orders.

*CEMENTER*

- Reports to cement unit.
- Lines up to pump cement.
- Stands by for orders.

*MUD ENGINEER*

- Ensures emergency barite stocks are on site.
- Goes to mud pits.
- Supervises weight-up operations.
- Recommends mud material and techniques as required.

*SUBSEA ENGINEER (FLOATING OPERATIONS)*

- Reports to rig floor to inspect subsea panel.
- Checks for possible problems.
- Stands by for orders from rig manager.

*SERVICE PERSONNEL*

- Go to assigned stations for well control operations.
- Stands by for orders.

## Pre-Kill Well Control Meeting

One of the toolpusher/rig manager's responsibilities is to organize a pre-kill meeting after the well has been shut-in. In the pre-kill meeting, a well kill strategy/method is chosen. Everyone involved in the well control operation is determined to be familiar with the well kill procedures. Lines of communication are established and personnel responsibilities are assigned. Nonessential personnel are evacuated from the rig site and company representatives and local authorities are informed of the situation.

## Communication

Good communication before and during the well kill operation is essential, especially during simultaneous operations. Everyone in the well kill operation should be aware of the lines of communication and the communication method used.

Intrinsically safe handheld radios, cell phones and hand signals can be used for communication. Everyone should be able to understand hand signals, if they are used.

## Bridging Documents

Bridging documents are agreements drawn up between companies (most often between drilling contractors and operating companies) in order to define a policy interface between the companies before the actual work is begun. They address health, safety and environment (HSE) policies as well as other issues such as communications, work organization, equipment policies, and paper flow. Bridging documents are used to form a more or less seamless interface between two separate systems already in place.

# Well Kill Methods

# 9

### Upon completion of this chapter, the student should be able to:

- List and describe well kill methods.
- Explain the difference between kill, control and suspend.
- Explain advantages and disadvantages of the different well kill methods.
- Describe normal and reverse circulating well kill operation.
- Identify and discuss the characteristics and applications of the driller's method.
- Identify and discuss the characteristics and applications of the wait-and-weight method.
- Compare the driller's and wait-and-weight methods.
- Explain the circulating start-up procedures.
- Explain choke adjustments and lag time.
- Discuss the characteristics and application of the volumetric method.
- Discuss the characteristics and application of the lubricate-and-bleed method.
- Perform calculations using the WCS Formula Sheet:
    - Initial circulating pressure (ICP)
    - Final circulating pressure (FCP)
    - Kill mud weight
    - Completion of WCS kill sheet using the wait-and-weight method
- Complete the Wait-and-Weight Method Kill Sheet.
- Apply the kill mud weight formula.
- Perform the proper start-up procedure.
- Maintain bottomhole pressure using the pressure chart from the ICP to FCP.
- Maintain FCP from bit to surface.
- Identify well control methods used in remedial operations.
- Complete the WCS Bullhead Worksheet.
    - Record shut-in pressures.
    - Construct a pumping schedule.
    - Construct and/or apply the kill mud weight.
- Perform calculations using the WCS Formula Sheet for:
    - Rectangular tank capacity
    - Water cushion
    - Hydrostatic pressure
- Calculations on the well completion and workover operations handout.
- Discuss and answer questions on remedial operations well control methods

*Excerpt from "Guide to Blowout Prevention, Second Edition, Revised November 2011" manual by Well Control School*[1]

Kick detection and well control procedures were discussed in previous chapters. This chapter covers methods used to kill a well. Well control procedures and well kill methods are also used to suspend a well. A well is suspended when it has failed to produce or is no longer being used for its licensed purpose. Suspending a well for long term usually consists of killing a well and placing a tubing plug or bridge plug, or with sour wells, a bridge plug is placed with a cement cap above it.

Blowout prevention consists of three basic steps: detection, shut in, and the actions taken in order to regain and maintain control of the well. Once a well is successfully shut in and the flow of formation fluids into the well has been stopped, the situation is analyzed and a course of action for regaining control of the well is developed.

- How reliable are the gauge readings? It is possible that some pressure was trapped during the shut-in procedure. If the tubing has a float (check valve) installed, was pressure trapped with the pump when the float was forced open? If trapped pressure is suspected, some fluid will have to be bled off at the choke, risking additional flow into the well.
- Are the shut-in drill pipe and shut-in casing pressures remaining constant? Many operators will record the shut-in pressures every minute as the well comes into balance in order to establish a stabilization trend as the pressures increase. If the casing pressure stabilizes after a reasonable time, then the pressures are assumed to be correct. If the casing pressure continues to increase slowly it may be an indication that gas is migrating up toward the surface.
- Is there a potential for lost returns? As soon as accurate shut-in pressures have been determined the shut-in casing pressure should be compared to the predetermined MAASP. Plans for regaining control of the well will not only consider removing the influx and killing the well if necessary, but also preventing an underground blowout. Once the safety of the crew and the rig is assured, every effort is made to avoid a blowout beneath the surface.

## Circulating Methods

When a well is shut in on a kick, it is balanced by the closed blowout preventers. The total force exerted on the bottom of the well, bottomhole pressure (BHP), is equal to the formation pressure (FP). Since a shut-in well is balanced, the *shut-in tubing pressure* (SITP) and the *shut-in casing pressure* (SICP) each represent bottomhole pressure on their respective sides of the U-tube. Conventional methods of well control are based on this idea.

There are two circulating methods commonly used in well control operations. The goals of both methods are the same: to remove the kicking fluid from the well safely without allowing further influx, and to increase the density of the fluid in the well, if desirable, so that normal operations can be resumed. These methods are:

- Driller's method
- Wait-and-weight method (engineer's method)

The decision as to which of these methods should be used depends upon the specific situation. The methods have several aspects in common. Techniques common to both methods are discussed in the following section.

## Start Up

The driller's method and wait-and-weight method are constant bottomhole pressure methods. Constant bottomhole pressure methods use the hydrostatic head of the kill fluid (kill mud) to overcome the formation fluid pressure while holding shut-in tubing pressure at a constant value.

In the driller's method and the wait-and-weight method, circulation is conventional, i.e., pumping down the work string and taking returns up the annulus. If it is assumed that the work string is full of a fluid of known density, then the *shut-in tubing pressure* (*SITP*) plus the fluid hydrostatic pressure inside the work string would equal the formation pressure.

$$\boxed{\text{Formation Pressure}_{psi} = \text{Fluid HP}_{psi} + \text{SITP}_{psi}}$$

Therefore, if the well could be circulated while holding the SITP at a constant value, bottomhole pressure would also remain constant. When the pump starts up, the circulating pressure will increase as the pump rate increases, so that maintaining the SITP at its shut-in value is impossible so long as the pump rate is changing. If the friction at a certain pump rate is known, that friction *plus* the SITP would equal the circulating pressure required to maintain constant bottomhole pressure *at that pump rate*. Once the selected pump rate is achieved, the resulting circulating pressure is called the *initial circulating pressure* (*ICP*).

The circulating pressure should be checked and recorded at several reduced pump rates at the beginning of each shift.

- After 500 feet of new formation
- Before drilling out casing shoe
- After tripping in to bottom
- Any time there is a mud weight change
- A change in BHA
- Anytime the pumps are changed or repaired

Slow circulating rates should not be taken

- when the fluid is contaminated;
- when there is a hydrostatic imbalance between work string and annulus;
- when there is lost circulation; and
- when the work string is parted or washed out.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

### Circulating Pressure (CP)

As an example of the importance of the pump operator's maintaining a constant pump rate, the change in circulating pressure, CP, is proportional to the ratio of the pump speeds, measured in strokes per minute, squared. That is:

$$\boxed{CP_{2\ (psi)} = CP_{1\ (psi)} * (SPM_2 \div SPM_1)^2}$$

### Circulating Pressure Learning Example Problem:

During the circulation of an influx from the well, the pump operator inadvertently lets the pump speed increase from 30 spm to 35 spm. The circulating pressure (CP), that is to be maintained by the choke operator is 850 psi.

(a) What is the new CP if the choke operator does nothing to respond to the increase in pump stroke rate?

Solution to (a):

$CP_{2\ (psi)} = CP_{1\ (psi)} * (SPM_2 \div SPM_1)^2$

$CP_2 = 850 * (35 \div 30)^2$

$CP_2 = 850 * 1.361$

$CP_2 = 1{,}157$ psi

(b ) What would happen to the pressure at the bottom of the well?

Solution to (b):

Nothing, the circulating pressure, CP, is consumed by the time it reaches the end of the work string.

(c ) The choke operator's job is to maintain 850 psi CP. If he did not know there was an increase in the circulating rate, he would open the choke to keep the CP constant. What would this do to the pressure at the bottom?

Solution to (c):

The pressure would decrease because the increase in friction pressure was over compensated for. The pressure would drop by:

Drop in $BHP_{psi} = 1{,}157 - 850$

Drop in BHP = 307 psi

A pressure drop this large would almost certainly cause a second influx into the well, while circulating the original influx out. The second influx would continue until the choke operator noticed that 850 psi was no longer controlling the well.

Stated again, the pump operator must maintain a constant pump rate. If, for any reason, the pump rate changes, the well control operation should be shut down, the situation re-assessed, and the operation restarted.

## Slow Circulating Rate (SCR)

A *slow circulating rate (SCR)* is any circulating rate (when the well is not shut in) that is slower than the normal circulating rate used to do work. The SCR is the circulation rate used in the well kill operation.

Slow circulation rates are used in well kill operations:

- To make sure SCR pressure plus shut-in tubing pressure does not exceed surface equipment pressure ratings;
- To allow the mud-gas separator to separate gas from the mud;
- To allow time for kill fluid to be weighted up and recirculated;
- To allow more time for choke adjustments;
- To give personnel more time to think and prepare if something goes wrong;
- To reduce annular pressure losses;
- Limit the circulating pressure imposed on the formation.

There is no fixed rule about choosing this *slow circulating rate* (SCR). Several slow circulating flow rates for each pump should be taken when the bit is on bottom while not rotating or drilling. Arbitrary slow rates are chosen according to the pumps in use and the means of controlling pump speed, for example, silicon rectifier controller systems and hydraulic control systems as opposed to mechanical devices.

Slow circulation rates are chosen for several reasons. Consideration is given to well pressures, pump condition, choke reaction time, mud mixing capability of the rig, and the volume throughput limit of the mud-gas separator (gas buster).

Kill rate pressure is the amount of circulating pressure, measured at the pressure gauge, used to kill the well when pumps are operating at the chosen slow circulating rate. Kill pump rates are the SCR chosen to kill the well. Slower pump rates create less annular friction, less bottomhole pressure, risk of fracturing a fragile formation and less flow through the surface disposal system.

Since the SCR pressure is simply the circulating pressure at a selected pump rate, anything that changes the friction, for instance, a change in fluid density, should prompt a check for updated SCR pressures for each pump. These new SCR pressures should be recorded.

It is unlikely that any two pressure gauges on a rig will read the same value. If the rig has a remote hydraulic choke, the SCR pressure should be recorded from the gauge on the choke panel, since that choke will be used to control the well during a well control operation. It is a good idea to also note the pressure on the standpipe gauge as a reference and as a backup in case of gauge failure. If a recent SCR pressure is available the ICP can be determined by adding the selected SCR pressure to the SITP ($ICP_{psi} = SCR_{psi} + SITP_{psi}$). Both the driller's method and the wait-and-weight methods follow these procedures for estimating the ICP.

$$\boxed{\text{Initial Circulating Pressure (ICP)}_{psi} = \text{Slow Circulating Rate (SCR)}_{psi} + \text{SITP}_{psi}}$$

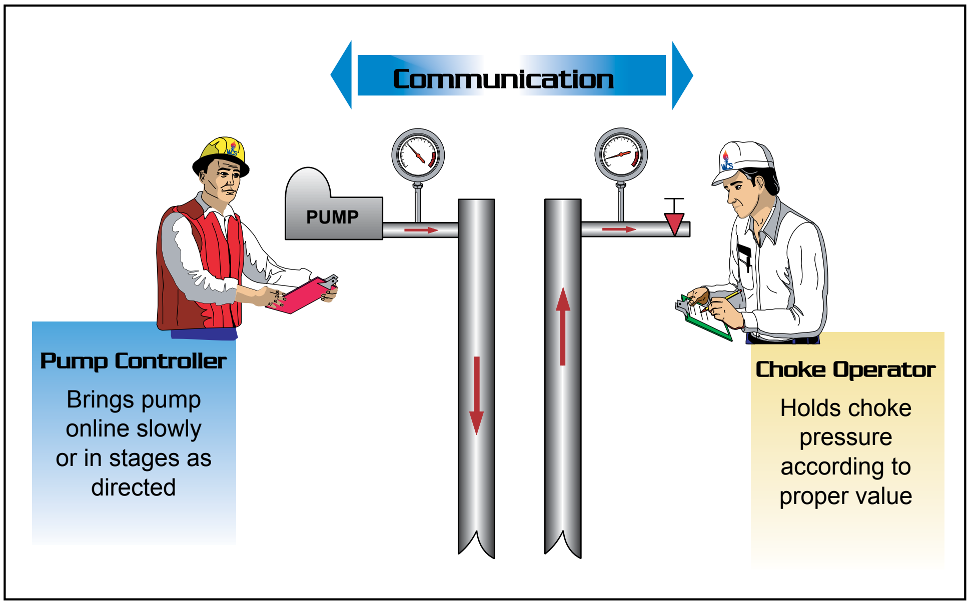
The casing pressure can be used as a guide while the pump is started and the rate (and consequently the circulating pressure) is increasing to the SCR pressure. In other words, the casing pressure is held constant with the choke while the pump is brought up to the SCR. This is possible because very little of the observed circulating pressure is exerted on the annulus and there will be little or no gas expansion until the influx moves higher up the wellbore.

It is virtually impossible for the choke operator to perfectly control the casing pressure during start-up. If the pump starts before the choke is open, excessive pressure may be exerted on the well, causing formation damage or even lost circulation. On the other hand, if the choke is opened before starting to pump, more formation fluid may flow into the well. In most cases it would be better to take a small secondary kick than to risk losing returns. The steps of a typical pump start-up technique are listed below.

1. The choke operator opens the choke slightly while observing the casing pressure.
2. The pump operator is instructed to start pumping slowly.
3. As the pump rate increases, the choke operator adjusts the choke to keep the casing pressure close to the original shut-in value.
4. Once the pump is at the kill rate (SCR) and the casing pressure is adjusted to the original shut-in pressure, the choke operator notes the circulating pressure, which should be at, or near, the calculated ICP.

From this time forward, the choke operator controls the well by controlling the circulating pressure and the pump operator makes certain that the pump rate never changes.

Figure 9.1.




If the rig equipment allows careful control of the pumps, the pump rate can be increased to the SCR in stages during the start-up. At each stage the pump operator pauses and waits for the choke operator to advise him when to go to the next stage. On some rigs however, the pump may actually idle at or near the SCR. In this case, the choke operator will have to make his adjustments after the pump is at the correct rate. However it is done, communication and coordination between the pump operator and the choke operator are essential for a smooth, safe start-up.

Pump startup and gradually increasing pump speed to kill rate speed is extremely important when circulating where there is a weak or depleted zone, to prevent lost circulation. Remember that a small increase in pump rate will result in a relatively large change in pressure. The pump operator and choke operator must be careful when starting up, bringing pumps up to speed and holding the casing pressure constant with the appropriate margin.

That is no cause for alarm if the circulating pressure is slightly different than the calculated ICP even though the pump rate and casing pressure are correct, once the SCR is achieved. If the pressure were slightly higher than expected, the best choice would be to accept the higher value. If, however, the actual pressure were slightly lower than the calculated pressure, the safest choice would be to maintain the calculated ICP.

Accurate measured SCR may not be available due to:

- The current work string depth
- Changes in fluid properties
- Downhole conditions such as washouts, parted work strings or plugged bit jets.

When no SCR pressure has been taken, or conditions have changed and the pre-recorded SCR may be no longer valid, circulation is started in the same way. The casing pressure is maintained until the pump is at the selected rate. The SCR pressure equals the ICP minus the SITP ($SCR_{psi} = ICP_{psi} - SITP_{psi}$). If there is a large, unexplained difference between the calculated ICP and the actual circulating pressure, the best course of action would be to stop pumping, close the choke, and analyze the situation.

$$\boxed{SCR_{psi} = ICP - SITP}$$

### Choke Adjustments

Once the ICP has been established, bottomhole pressure is maintained by manipulating the adjustable choke, holding the circulating pressure at the planned value. As circulation continues, the casing pressure will vary, as it reacts to the changing hydrostatic pressure in the annulus. In the case of gas kicks, the expansion of the gas will cause a reduction in the hydrostatic pressure that in turn, results in increases in the casing pressure as the gas nears the surface. Changes in casing pressure will be less dramatic when handling liquid kicks. As the influx rises in the well, annular hydrostatic pressure will change due to changes in the various annular diameters and will result in a change in the casing pressure.

Since the shut-in well is a closed system, the changes in casing pressure will also affect the circulating pressure to the same degree, but only after a time delay. The casing gauge is located near the choke, therefore any change in the choke orifice will be reflected on the casing gauge immediately. The circulating pressure will also change, but only after the pressure wave has traveled down the annulus and back up the work string. This delay in gauge reaction time must be accounted for when making choke adjustments. The proper technique is to determine the required change on the circulating gauge and then adjust the choke so that the casing pressure changes by the required value. After some delay, the circulating pressure will reflect the change. For example, if it were determined that the circulating pressure was 50 psi too high, the choke would be opened to reduce the casing pressure by 50 psi. After the transit time delay, the circulating pressure would be reduced by the desired 50 psi. There is no way to accurately determine the lag time, but a rule of thumb is to assume two (2) seconds for each 1,000 feet of measured depth until the actual delay time is established. The important thing to remember is that bottomhole pressure is controlled by controlling the circulating pressure with an adjustable choke while pumping at a constant rate.

As the influx nears the surface and begins to evacuate through the choke, the casing pressure will usually become erratic, due to the mixture of fluids coming through the choke and the rapidly changing hydrostatic pressure in the well. In this case, the circulating pressure would also be affected after the normal lag time, possibly resulting in a decrease in bottomhole pressure. It is a good idea to keep a written record of the casing pressure as a reference. After the casing pressure is adjusted to the proper value and time is allowed for pressure to stabilize throughout the system, control is returned to the circulating pressure gauge. When the liquid following the kick goes through the choke, casing pressure may increase. Once again, casing pressure is adjusted to its last recorded value until pressures stabilize and the correct circulating pressure can be reestablished.

Figure 9.2

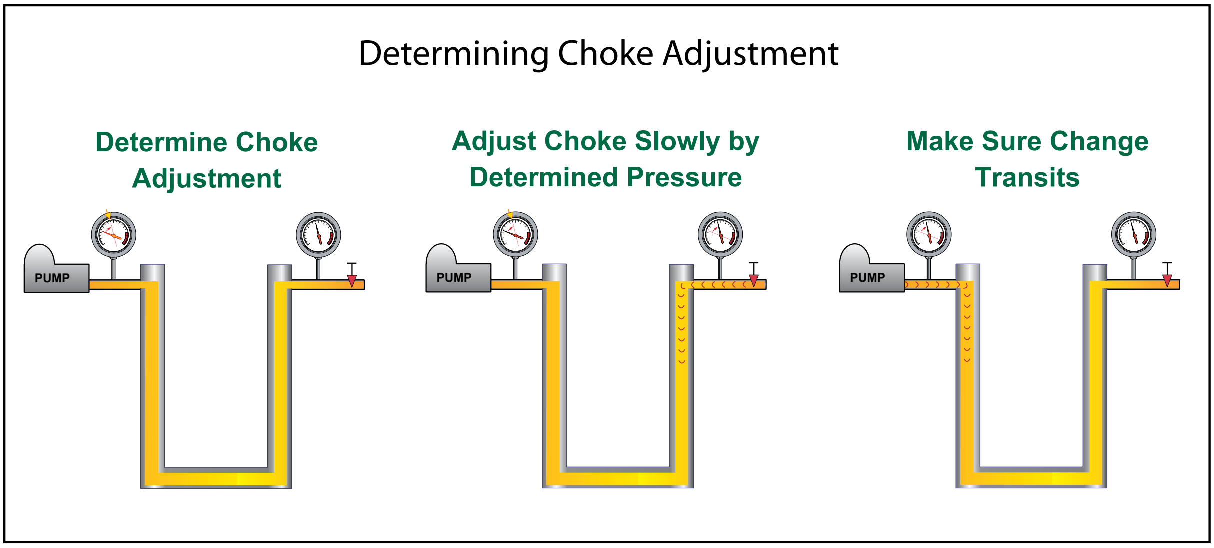
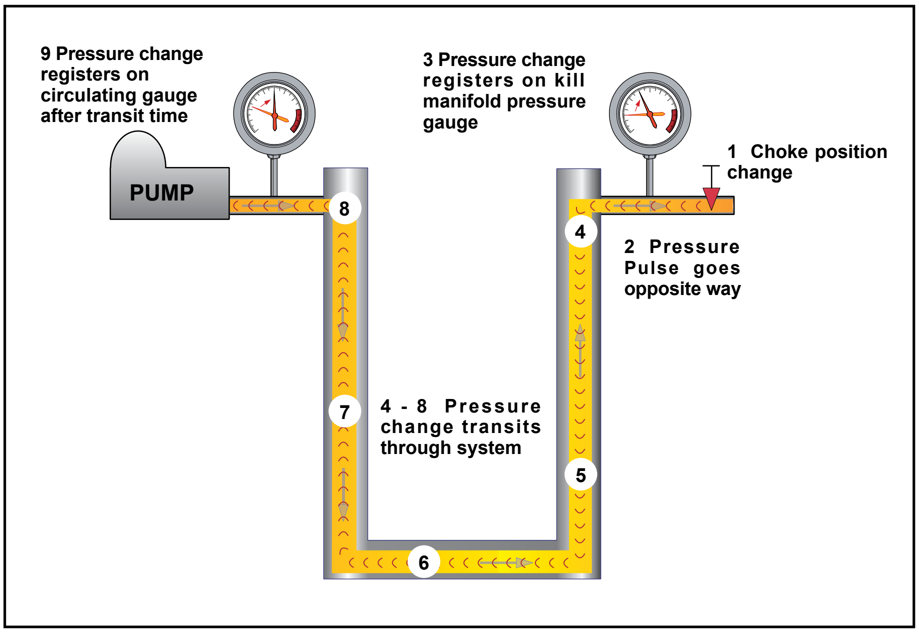



Figure 9.3. Choke adjustment.



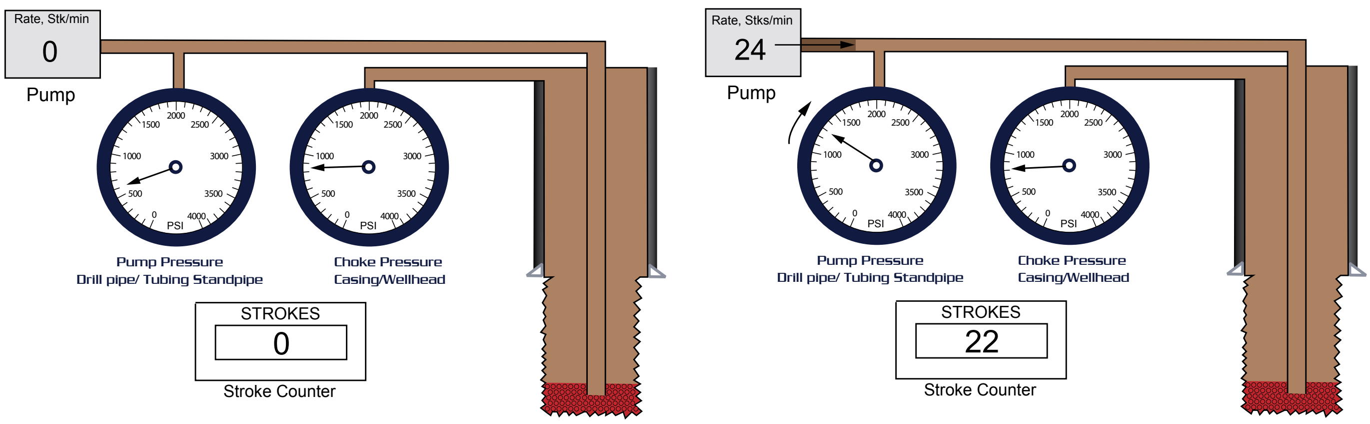
### The Driller's Method

The driller's method requires a minimum of two complete circulations to kill an underbalanced well. On the first circulation, the influx is pumped out of the well, and on the second circulation, the density of the working fluid is increased to kill the well. After the well has been checked to ensure that it has been killed (or is under control) regular rig operations can resume.

### The First Circulation

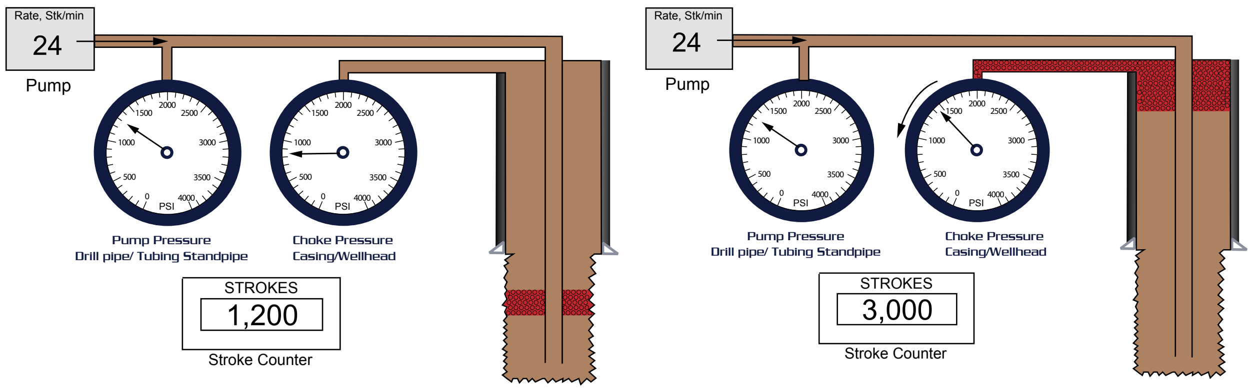
The pump is brought up to the kill rate speed while maintaining casing pressure constant at its shut-in value by adjusting the choke. When the pump is running at the correct rate and the casing pressure has been adjusted with the choke to its correct value, control is shifted to the circulating pressure gauge. The circulating pressure at this time is the initial circulating pressure (ICP). The ICP is the sum of the SITP, and the friction pressure at this pump speed.

Figure 9.4.



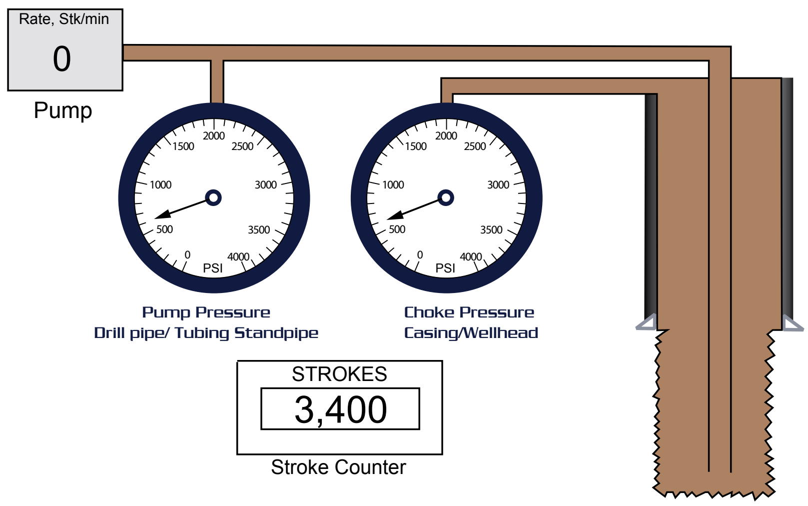

The circulating pressure is held constant by choke adjustments, and the pump rate is held constant until the kick is circulated out of the well. If the kick is gas, frequent pressure adjustments may be necessary to maintain the proper circulating pressure. As the gas expands, it displaces fluid which causes the annular hydrostatic pressure to decrease. An increase in casing pressure compensates for the reduction of hydrostatic pressure. If the influx is mostly liquid fewer adjustments will be required.

Figure 9.5.



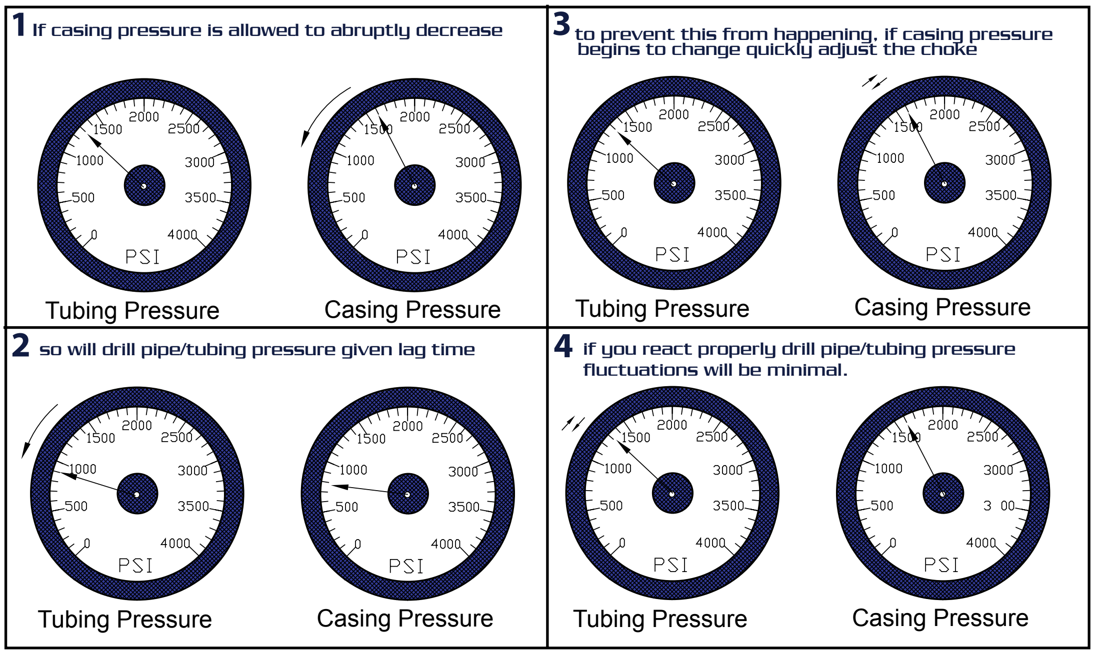

If it becomes necessary to pause or stop the operation for any reason, the start-up procedure is reversed. The choke operator maintains the casing pressure at the present value while the pump operator slowly reduces the pump rate. Once the pump has been switched off, the choke operator closes the choke, taking care not to trap excess pump pressure in the system. Providing no excess pump pressure has been trapped, the resulting shut-in pressures will reflect the well conditions.

Figure 9.6.




Care must be taken when shutting in after the first circulation because an underbalanced well would not be dead even though the influx has been circulated out of the well. If the casing pressure is allowed to fall below the original SITP another influx could enter the well. If all the influx has been removed, the hydrostatic pressure in the annulus should equal the hydrostatic pressure in the tubing; consequently, both shut-in pressures should have approximately the same values, that is, close to the original SITP value. If the pressures are not nearly equal, another influx may have entered the well. If shut-in pressures begin to increase, it is an indication that another influx has entered the well and is migrating toward the surface.

Figure 9.7.

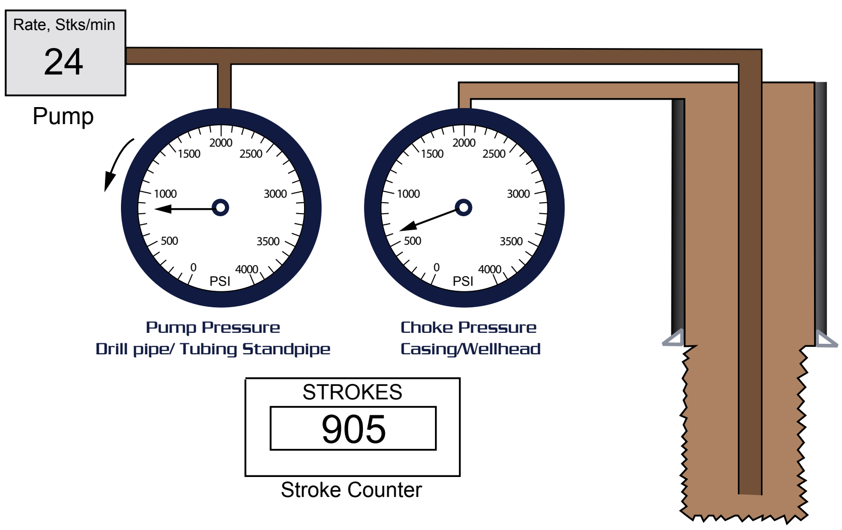



## The Second Circulation

The fluid density in the active pits must be increased before the second circulation is started. The density of the kill fluid is determined by calculating the equivalent density of the SITP at TVD. That value is then added to the original fluid density.

Once the fluid density in the pits has been increased, the second circulation can begin. The start-up procedures for the first and second circulations are identical. The pump is brought up to the selected rate while holding the casing pressure constant at its shut-in value by means of choke adjustments. If no additional influx has entered the well, the casing pressure represents the original degree of underbalance, the SITP.

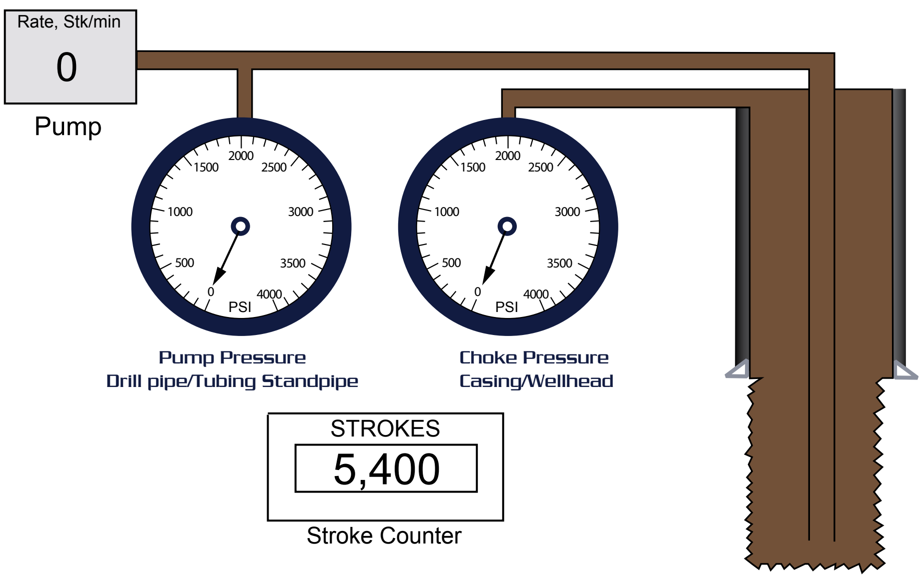
Figure 9.8.



In theory, bottomhole pressure could be kept constant by maintaining a constant casing pressure until the kill fluid reaches the bit or the bottom of the string. This is possible because there is a column of fluid with a consistent density in the annulus. The influx has been circulated out during the first circulation. If bottomhole pressure is held constant, the circulating pressure will decrease as the kill fluid is pumped, because the hydrostatic pressure in the tubing is increasing due to the kill weight fluid. (The heavier fluid is killing the well on the tubing side of the U-tube.) Once the kill fluid reaches the end of the string and starts up the annulus, the circulating pressure will be at the *final circulating pressure (FCP)* value. From this point on, the FCP is maintained on the circulating gauge until kill fluid returns to the surface. As the kill fluid is pumped up the annulus, the casing pressure will decrease, reflecting the increasing hydrostatic pressure in the annulus.

Another way to maintain a constant bottomhole pressure as the kill fluid fills the tubing is to prepare and follow a circulating pressure schedule. It is sometimes difficult to accurately determine whether or not all the influx has been circulated out of the annulus on the first circulation. A circulating pressure schedule can be used to predict the correct circulating pressures at various points as the kill fluid is pumped down the string, compensating for any gas remaining in the annulus. The schedule eliminates guesswork and provides a simple means of documentation. This is especially true in wells with long open hole sections. The schedule plots circulating pressures against the volume of fluid pumped. The choke operator makes adjustments according to the schedule until the kill fluid is at the bottom of the string and FCP is reached. A circulating pressure schedule is discussed in detail later in this chapter (wait-and-weight method).

Figure 9.9.




## Kill Fluid at the Surface

Once the kill fluid returns at the surface, the well can be shut in and the pressures checked. SITP and SICP should be zero if the well is dead. If, after an appropriate time the pressures remain at zero, the choke may be opened carefully in order to check for flow from the annulus. If the pressures are not zero, or if flow is detected, the problem may be that the kill weight fluid is not consistent throughout the well, another kick may be in the well, or an incorrect kill fluid was used. In any case, the best action would be to pump another complete circulation while holding the pump rate and the circulating pressure constant. The mud weight should be checked frequently and adjusted as necessary. If the well is dead, and the BOPs are to be opened, be aware that pressure may be trapped in the BOP stack.

### Driller's Method Summary

1. The kicking well is shut in. SITP, SICP and the gain in mud pits (kick volume) are recorded.
2. Begin circulating by maintaining a constant casing pressure by means of choke adjustment while bringing the pump up to the kill rate (SCR).
3. When the pump speed is at the kill rate, the circulating pressure is recorded and kept constant by adjusting the choke until the influx is circulated out of the well.
4. After the influx has been circulated out, the well is shut in. The density of the fluid is increased (if necessary) and a circulating pressure schedule is prepared.
5. Circulation is started again, following the same start-up procedures in step 2 above. The choke is adjusted as necessary to follow the circulating pressure schedule until the kill fluid reaches the bit.
6. When the tubing is full of kill fluid, the FCP is maintained on the circulating gauge until the annulus is displaced with kill fluid.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

### Characteristics of the Driller's Method

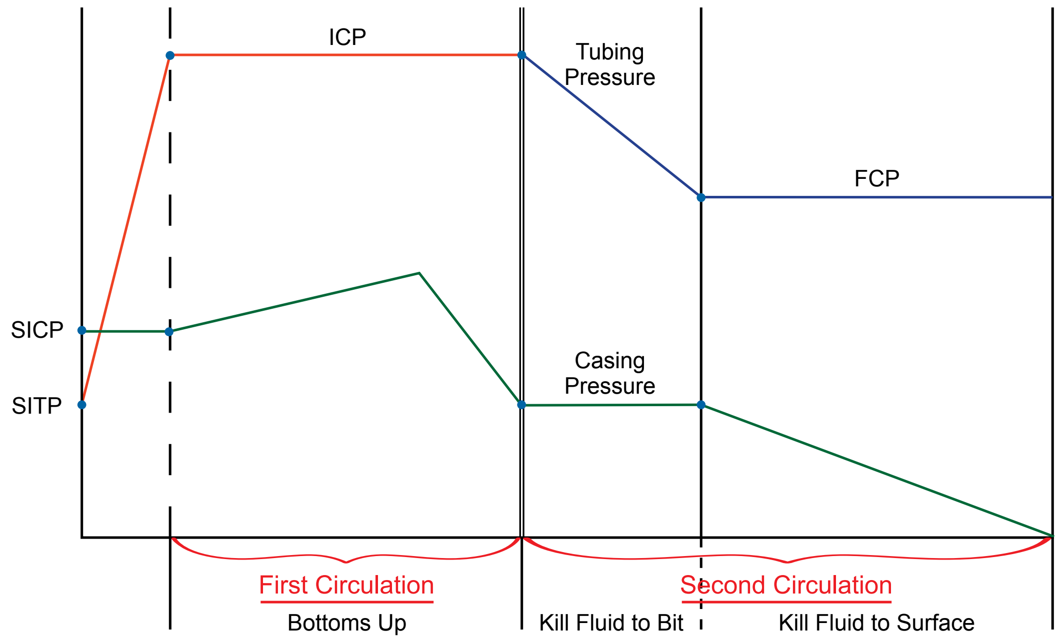
- Requires at least two circulations to kill underbalanced wells.
- There is no waiting time. Circulation may begin once the shut-in pressures have stabilized.
- No weight material is required on location for the first circulation.
- Few calculations are required to begin the operation.
- May result in greater surface pressure imposed on a well than other circulating methods.

### Driller's Method Applications

- Removing formation fluids that have been swabbed into a well on trips
- In areas where stuck pipe is a major concern
- Wells where it is not possible or desirable to increase the fluid density
- Remote locations with poor logistics
- Underbalanced drilling operations
- Horizontal or highly deviated wells
- Limited mud mixing equipment or limited manpower

The driller's method of well control is ideally suited for controlling kicks that occur during remedial operations. The fluid that is in place when the well is perforated is generally heavy enough to hold back the formation fluids. Using the first circulation of the driller's method, an unwanted influx can be safely circulated to the surface, using the original fluid in the well, thus bringing the well back under control. Since most remedial operations are conducted in casing, formation fracture is not always a concern but lost circulation problems are common.

Figure 9.10. The driller's method.




## The Wait-and-Weight Method

The driller's method requires at least two complete circulations of the well fluid in order to kill an underbalanced well. The first circulation removes the influx and the second circulation replaces the original well fluid with a higher density, kill fluid (KMW). The wait-and-weight method was developed to accomplish both of these goals in one circulation. The method has the additional advantage in that wellbore and surface pressures are sometimes lower than in other methods if kill mud can be pumped into the annulus before the gas reaches a specific weak point in the well. As the name implies, an up-front waiting period is required because circulation does not begin until the kill mud weight is mixed and ready for pumping into the well.

Few calculations are absolutely required to kill a well using the driller's method because during each circulation, one side of the U-tube always contains a full column of fluid of a known density. In the wait-and-weight method, the plan is to kill the well in one circulation therefore the tubing will contain a mixture of original working fluid and kill density fluid as soon as circulation begins. At the same time, the annulus will contain a mixture of formation fluids and original working fluid. In order to maintain constant bottomhole pressure while the kill fluid is being pumped down the string, some calculations are required in order that a circulating pressure schedule can be prepared. The minimum calculations required to construct the pumping schedule are:

- *Kill fluid density* (KMW): the fluid density that will exert sufficient hydrostatic pressure to balance the kicking formation. Always round kill mud weight up.

$$\boxed{\text{Kill Mud Weight}_{ppg} = \text{SITP}_{psi} \div 0.052 \div \text{TVD}_{ft} + \text{Current Mud Weight (CMW)}_{ppg}}$$

- *Initial circulating pressure* (ICP): the circulating pressure that is required to keep bottomhole pressure constant before the kill fluid enters the tubing. This is the sum of the circulating pressure at a pre-determined slow pump rate (SCR) and the SITP.

$$\boxed{\text{Initial Circulating Pressure (ICP)}_{psi} = \text{Slow Circulating Rate (SCR)}_{psi} + \text{SITP}_{psi}}$$

- *Final circulating pressure* (FCP): the circulating pressure that is required to keep bottomhole pressure constant once the string is filled with kill fluid.

$$\boxed{\text{Final Circulating Pressure (FCP)}_{psi} = \text{SCR} * \text{Kill Mud Weight}_{ppg} \div \text{CMW}_{ppg}}$$

- *Volume in the work string*: the pump strokes or barrels required to displace the string

These are the same calculations that are recommended for the second circulation of the driller's method. Often, a job aid, called a *kill sheet*, is used to organize the calculations and the preparation of a circulating pressure schedule. Once the kill fluid is mixed and the circulating pressure schedule is constructed, the kill operation can begin. Techniques for pump start-up, choke adjustments, etc., are the same as the second circulation of the driller's method. The figures on the following page illustrate killing a well using the wait-and-weight method.

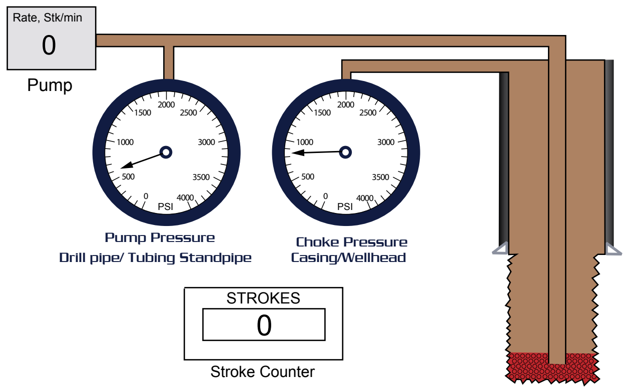
### Characteristics of the Wait-and-Weight Method

- In theory, kills a well in one circulation.
- The operation cannot begin until the mud weight in the surface system has been increased.
- There must be weight material, adequate mixing facilities, and manpower available to increase the mud weight.
- A circulating pressure schedule (completed kill sheet) is required before the operation begins.
- When well geometry permits, the method can result in lower pressures exerted on a well than other circulating methods if kill fluid is filling the annulus before the influx enters the casing.

### Wait-and-Weight Method Applications

- In fragile formations where lost circulation is a major concern
- On locations with good mud mixing facilities and manpower

Figure 9.11. Killing a well using the wait-and-weight method.




Hold casing pressure constant when bringing pump online.

1. The kicking well is shut in. Stabilized SITP, SICP and kick volume information is recorded.

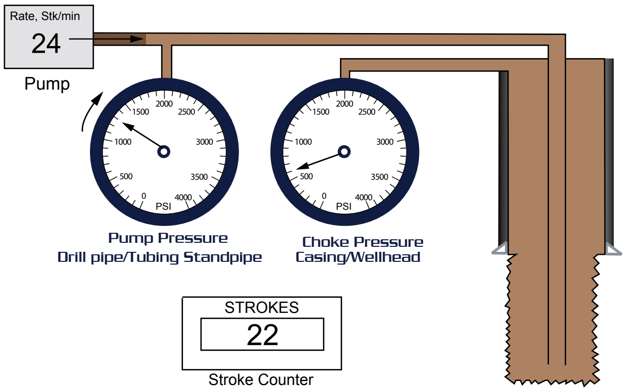
## Pressure Chart

| Strokes or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Casing Pressure | Pit Volume Deviation |
|---|---|---|---|---|
| 0 | ICP 1,290 | | | |
| 90 | 1,244 | | | |
| 181 | 1,198 | | | |
| 271 | 1,152 | | | |
| 362 | 1,106 | | | |
| 452 | 1,061 | | | |
| 543 | 1,015 | | | |
| 633 | 969 | | | |
| 724 | 923 | | | |
| 814 | 877 | | | |
| BIT 905 | FCP 832 | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

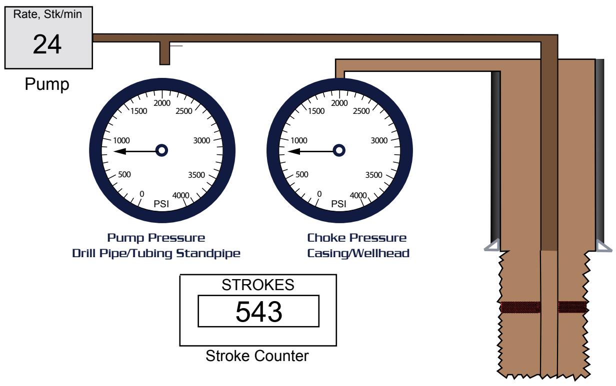
905 (Stks Surf to Bit) ÷ 10 = 90.5 (Strokes per Step)

1,290 (Initial Circ Pressure) – 832 (Final Circ Pressure) ÷ 10 = 45.8 (PSI per Step)

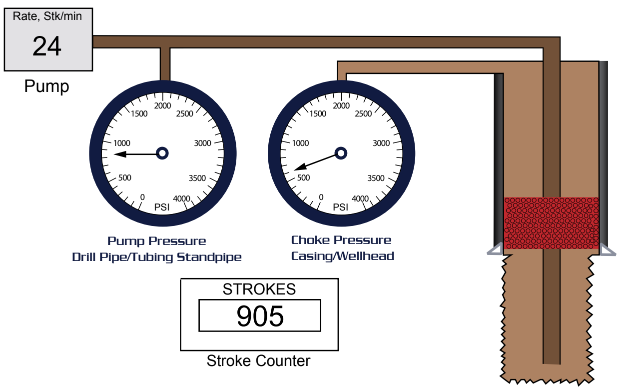
2. Pumping Schedule. The kill fluid density is determined and the fluid density in the pits is increased to the calculated kill fluid value and a circulating pressure schedule is prepared.



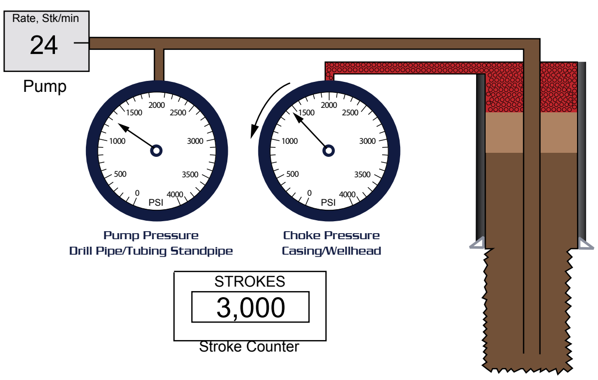

3. The pump is brought to the kill rate while maintaining casing pressure at its shut-in value by means of choke adjustments.



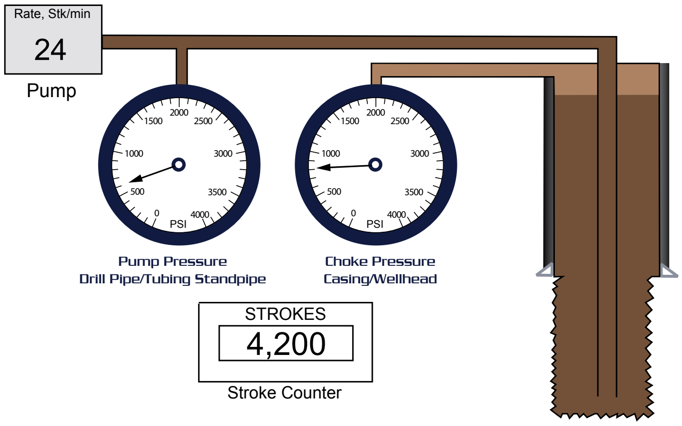

4. Once the pump is at the kill rate, circulating pressure is controlled by choke adjustments according to the prepared schedule.



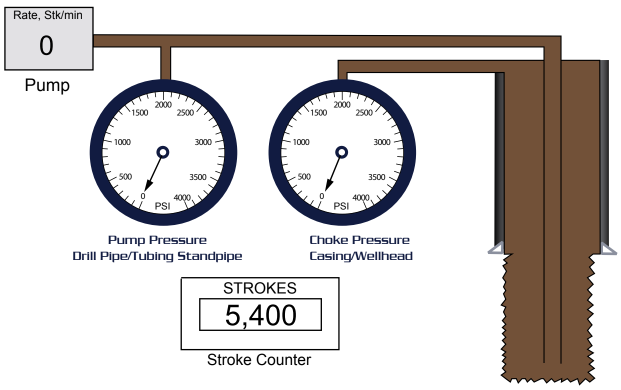

5. When the kill fluid reaches the end of the tubing, the circulating pressure is maintained at the final circulating pressure until kill fluid returns at surface.




6. When the gas/liquid mixture evacuates the choke, the casing pressure may become erratic and require rapid choke manipulation to maintain a constant circulating pressure. If the casing pressure decreases rapidly, the circulating pressure will decrease after the established lag time. In this case, the choke operator should try to hold the casing pressure constant until the circulating pressure is re-established.




7. Even though the calculated surface-to-surface volume has been pumped, the returning kill mud weight may not be consistent for some time, due to gas cutting and light spots in the mud.




8. When kill mud is consistent throughout the well, the pumps are shut off and the well pressures monitored. If there is no pressure buildup after a reasonable time, the well can be considered dead. BOPs should be opened cautiously in case pressure is trapped beneath the preventer.

Figure 9.12. Comparison between the driller's method and wait-and-weight method.

| Comparison: Driller's Method and Wait-And-Weight Method | |
|---|---|
| **Driller's Method** | **Wait-and-Weight Method** |
| • At least two circulations required<br>• Little or no waiting time required<br>• No weight material required to begin<br>• Few calculation necessary<br>• May result in higher pressure exerted on a well than other circulating methods | • In theory, one circulation<br>• Cannot begin immediately<br>• Must have weight material available<br>• Some calculations required<br>• May result in lower pressures on a well than other circulating methods |

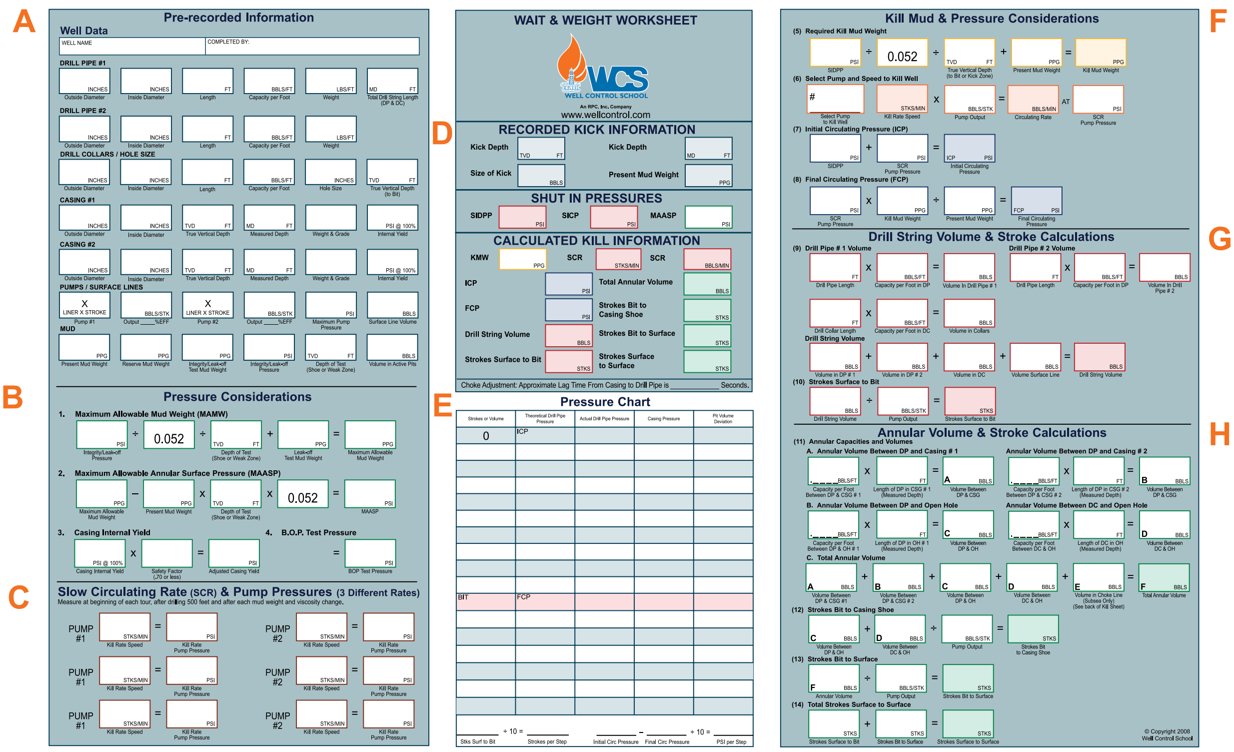
## The WCS Kill Sheet

The WCS kill sheet[3] is a job aid designed to assist field personnel plan and execute a well killing operation. It provides a structured approach to calculating well volumes and circulating pressure changes in order to maintain a constant bottomhole pressure as dissimilar fluids are pumped down the work string.

The kill sheet includes these main areas:

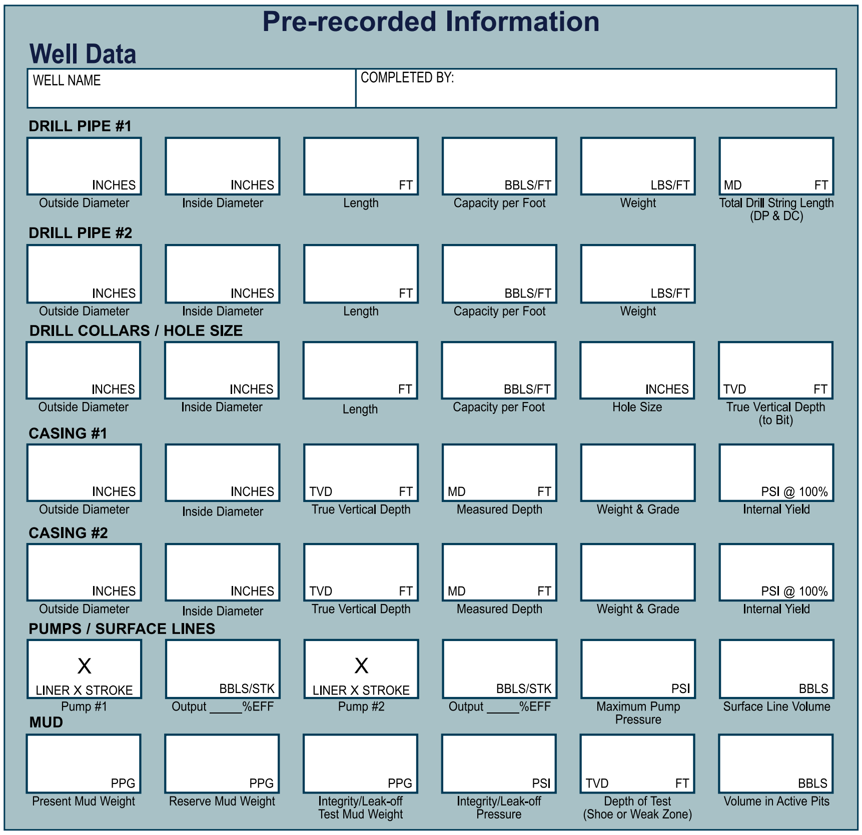
1. Prerecorded Information
2. Pressure Considerations
3. Kill Rates and Pressures
4. Kill Fluid and Pressure Considerations
5. Volume and Stroke Considerations
6. Pressure Chart

Figure 9.13. WCS Kill Sheet.



The prerecorded information section (label *A*) located on the upper left of the kill sheet consists of various well data. Some of the data varies as the operation continues, i.e., depth, fluid density. Other data such as tubing diameters may remain constant throughout the course of the well. This section is intended to have the various data gathered in a convenient place for use in completing the entire kill sheet if it becomes necessary to do so.

Figure 9.14. A, the prerecorded information section of the kill sheet.


Pre-recorded Information

Well Data

| WELL NAME | COMPLETED BY: |
|---|---|

DRILL PIPE #1

| INCHES | INCHES | FT | BBLS/FT | LBS/FT | MD FT |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Weight | Total Drill String Length (DP & DC) |

DRILL PIPE #2

| INCHES | INCHES | FT | BBLS/FT | LBS/FT |
|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Weight |

DRILL COLLARS / HOLE SIZE

| INCHES | INCHES | FT | BBLS/FT | INCHES | TVD FT |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Hole Size | True Vertical Depth (to Bit) |

CASING #1

| INCHES | INCHES | TVD FT | MD FT | | PSI @ 100% |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | True Vertical Depth | Measured Depth | Weight & Grade | Internal Yield |

CASING #2

| INCHES | INCHES | TVD FT | MD FT | | PSI @ 100% |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | True Vertical Depth | Measured Depth | Weight & Grade | Internal Yield |

PUMPS / SURFACE LINES

| X LINER X STROKE | BBLS/STK | X LINER X STROKE | BBLS/STK | PSI | BBLS |
|---|---|---|---|---|---|
| Pump #1 | Output _____%EFF | Pump #2 | Output _____%EFF | Maximum Pump Pressure | Surface Line Volume |

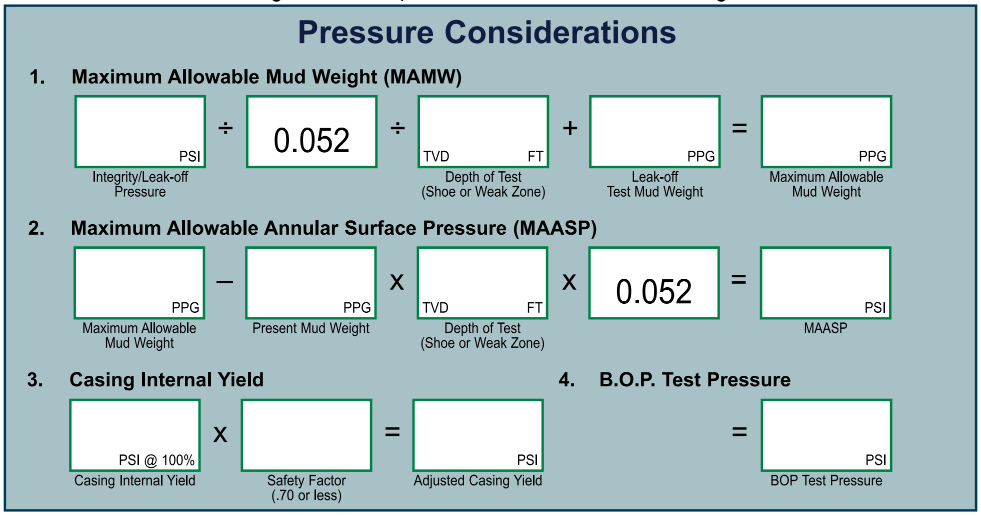
MUD

| PPG | PPG | PPG | PSI | TVD FT | BBLS |
|---|---|---|---|---|---|
| Present Mud Weight | Reserve Mud Weight | Integrity/Leak-off Test Mud Weight | Integrity/Leak-off Pressure | Depth of Test (Shoe or Weak Zone) | Volume in Active Pits |

The kill sheet considers three pressure limitations (calculations 1 through 4): the formation, the casing, and the wellhead equipment.

The formation strength is estimated by *leak-off tests* (LOT) or *formation integrity tests* (FIT). These tests are conducted after drilling a small amount of hole below a new string of casing. The formation at the casing setting depth is usually considered the weakest area in the open hole. The maximum allowable annular casing, or surface pressure (MAASP), which is reduced as the fluid density is increased, is constantly updated.

Figure 9.15. B, kill sheet calculations 1 through 4.

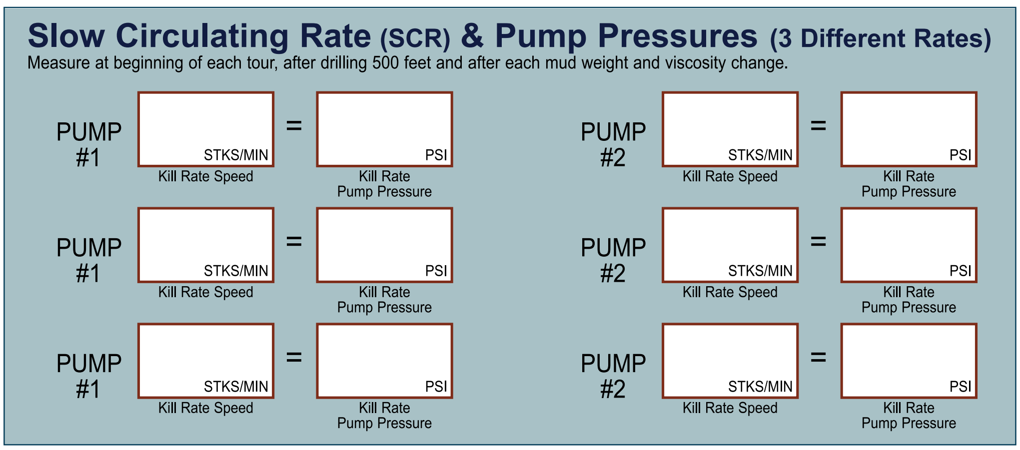



The internal yield, or burst limit of casing, is found in tables, and downgraded by a selected safety factor (often 70 percent for new casing).

The wellhead equipment is rated and tested to the minimum rated value in the pressure control system. In drilling, the rams and valves and choke manifold are usually tested to their rated value. In workover or well intervention operations, this may not be the case. The weakest component in the system sets the limit for the tests.

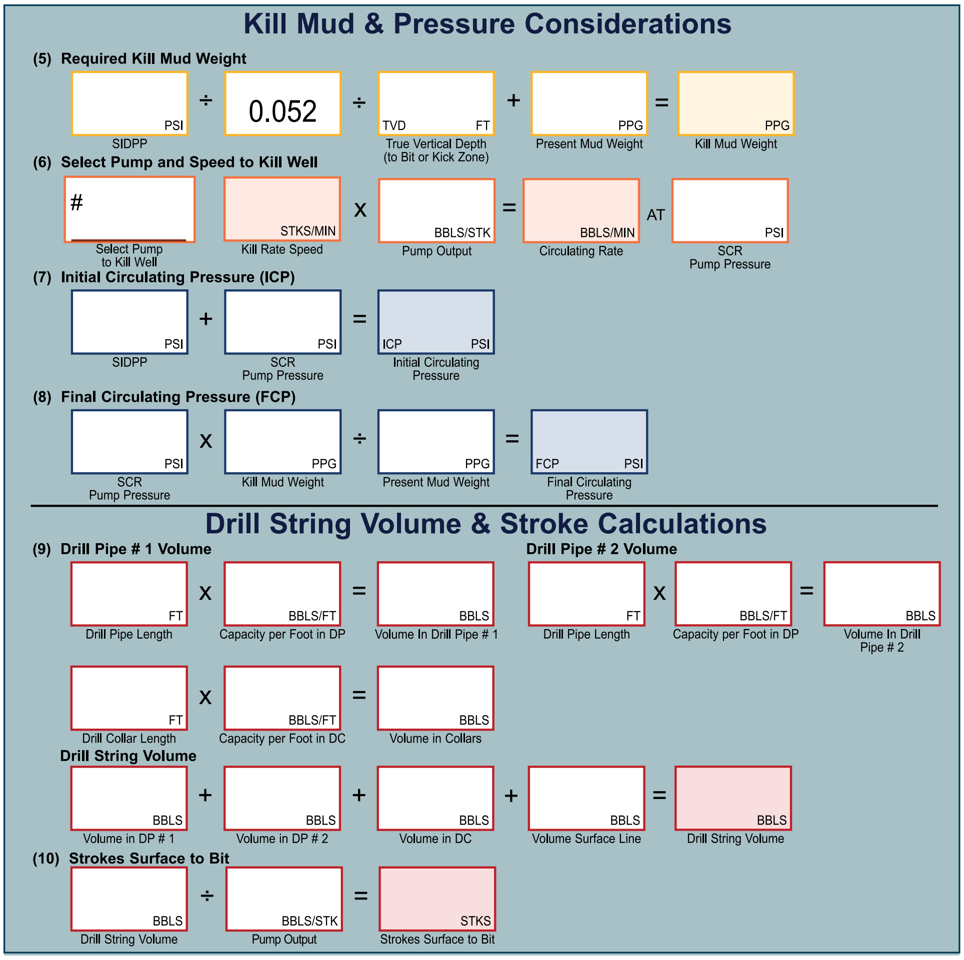
The bottom of the left side of the kill sheet is used to record the slow circulating rate pressures ($SCR_{psi}$). The $SCR_{psi}$ is simply the friction pressure at some arbitrary slow pumping rate. If the rig is equipped with a remote hydraulic choke, the $SCR_{psi}$ is observed and recorded off of the choke panel since the choke panel gauges would be used to control the well in the event of a kick. Several friction pressures are recorded at the beginning of each shift. The $SCR_{psi}$ is recorded for each pump and it is revised from time to time whenever friction is likely to change, i.e., a change in fluid density and changes to BHA, each tour.

Figure 9.16. C, slow circulating pressure calculations in the kill sheet.



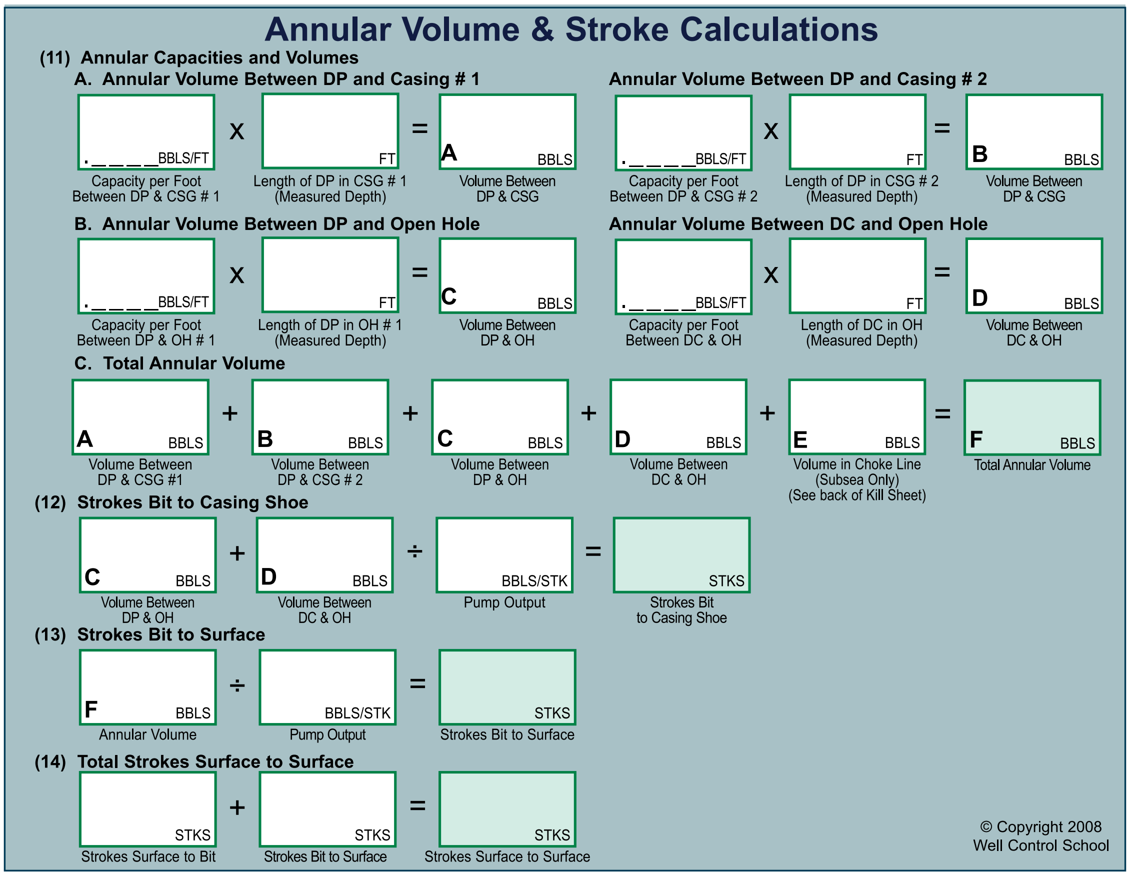
The upper section of the right side of the kill sheet (calculation 5 through 10) contains all the data and calculations used to develop a work string pressure schedule including selection of pump and pumping rate.

Figure 9.17. F and G, kill sheet calculations 5 through 10.



The lower portion of the right side of the kill sheet (calculations 11 through 14) is useful in tracking progress during the kill operation. For example, block F is the total annular volume, calculation 12 estimates the time (pump strokes) that an influx would reach the casing seat. Calculation 13 is an estimate of "bottoms up", and finally, calculation 14 predicts the time at which the kill fluid returns to the surface (complete circulation).

Figure 918. H, kill sheet calculations 11 through 14.



The pressure chart is divided into 10 steps, or check points, used to guide the choke operator as kill fluid is pumped down the workstring. As the pumped volume increases, the circulating pressure is allowed to decrease from the initial circulating pressure (ICP) to the final circulating pressure (FCP) in order to maintain a constant bottomhole pressure. A simple method that can be used to assist in constructing the chart is placed below the chart, at the very bottom of the sheet. The pressure chart represents the theoretical minimum pressures required to safely control a well, therefore space is provided for documentation of actual pressures during the operation.

Figure 9.19. E, the pressure chart section of the kill sheet.

**Pressure Chart**

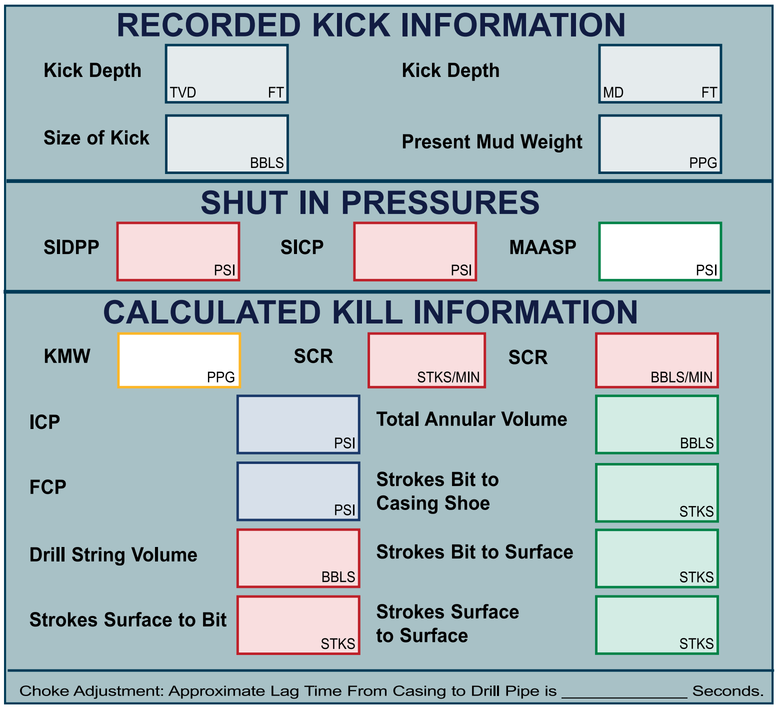
| Strokes or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Casing Pressure | Pit Volume Deviation |
|---|---|---|---|---|
| 0 | ICP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| BIT | FCP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

________ ÷ 10 = ________    ________ – ________ ÷ 10 = ________

Stks Surf to Bit   Strokes per Step   Initial Circ Pressure   Final Circ Pressure   PSI per Step

All the necessary information for the operational plan is transferred to the upper portion of the center section. The kill sheet is designed to be double folded in order that supervisors have a convenient reference to planned choke adjustments as well as easy reference to the complete operation.

Figure 9.20. D, the pre-recorded section of the kill sheet.




## Production Well Kill Procedures

Well intervention personnel may be involved in preparing a production well for workover. This entails killing the well by displacing well fluids with workover fluids. During workover operations it is common to have gas in the tubing and annulus due to tubing or casing leaks, bad cementing jobs or packer failure.

The choice of kill procedure will depend on a number of factors, including tubing and casing integrity, ability to circulate the fluid in the annulus, formation pressure, characteristics of the completion methods, and formation parameters that may inhibit techniques such as pumping into the formation. Each well must be assessed individually to determine the most effective kill procedure to be implemented.

The kill methods available are:

- Forward circulation
- Reverse circulation
- Bullheading
- Lubricate-and-bleed
- Deploying coiled tubing (or a work string by snubbing) and displacing the tubing.

As the completion tubing is normally full of well fluids, and the tubing/casing annulus full of completion or packer fluid, it is easier to conduct a reverse circulation as the gravities of the fluids will tend to keep them segregated as they are pumped up the tubing. The preferred method is to install a wireline set plug as low as possible in the well below the packer, (e.g., packer tailpipe), if possible, to isolate the formation from the kill fluid, and then reverse circulate to kill the well.

Forward circulation is not recommended as it involves higher circulating pressures and disposal of formation fluids through the tubing spool side outlets is very troublesome to handle effectively.

Bullheading is only recommended where it causes no damage to the formation. Some operators have strict policies stating under which conditions this method may be used.

Lubricate-and-bleed is the least preferred and is only used when there is some obstacle to conducting the other methods. For instance, it may be a combination of an obstruction in the tubing that prevents the running of wireline to open a circulating path (e.g., a partially closed valve) and a blockage or tight formation preventing bullheading.

## Well Preparation

Prior to initiating well killing operations, several safety precautions must be exercised. The well must be shut-in in advance of operations to stabilize bottomhole pressure and allow time to inspect and service the Christmas tree. The tree valves and sub-surface safety valves should be tested to ensure they comply with API criteria. Where practicable, each annulus should be checked for $H_2S$.

## Forward circulation

In forward circulation, the kill fluid is pumped down the work string and returns are taken up the annulus. Forward circulation is not as commonly used in workover operations as is reverse circulation. Work string pressure is expended by the time the fluid reaches the end of the tubing and does not overpressure the formation perforations.

## Calculating Forward Circulation Strokes

Surface Line Strokes

$$\boxed{\text{Surface Line ID}^2 \div 1{,}029.4 * \text{Surface Line Length}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Surface Line Strokes}}$$

Tubing Strokes

$$\boxed{\text{Tubing ID}^2 \div 1{,}029.4 * \text{End of Tubing (EOT) MD}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Tubing Strokes}}$$

Annular Stokes

$$\boxed{(\text{Casing ID}^2 - \text{Tubing OD}^2) \div 1{,}029.4 * \text{EOT to Bottom Perfs. MD}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Annular Strokes}}$$

Forward Circulation Total Strokes

$$\boxed{\text{Surface Line Strokes} + \text{Tubing Stokes} + \text{Annular Strokes} = \text{Total Strokes}}$$

Some advantages of forward circulation are:

- The annulus and bottom of the well are exposed to less friction pressure than reverse circulation at the same pump speed.
- It does not expose the formation to bad packer fluid. Packer fluids in an older well may have corrosion products, crystallized salts and scales.

Disadvantages of forward circulation include:

- It takes more circulating time than reverse circulation.
- It creates more upper casing pressure, if gas is circulated up the wellbore.

### Reverse Circulation

Most preplanned well kill procedures occur during well workovers. Reverse circulation is a commonly used method for well workovers where the well must be killed. Kill fluid is pumped down the annulus, through a circulating port in the tubing between the annulus and the production tubing above the production packer. The procedure is even more effective if a plug can be installed to isolate the completion/packer and kill fluid from the formation, but this is dependent upon whether or not operations are to be carried out below this point. If there is no plug, the old completion/packer fluid may contaminate the formation if losses occur before the clean kill fluid can enter the tubing.

One of the main reasons for using the reverse circulation method is that it is easier to pump, maintaining oil and/or gas on top of the kill fluid, than it is to force the oil and gas down below the kill fluid. There is far less contamination of the kill fluid with well fluids, and there is less of a problem in establishing a clean kill fluid for circulation.

Lighter wellbore fluids are displaced up the tubing by heavier kill fluids and up the tubing. Often, when a circulating port is opened in the tubing, the fluids in the annulus will U-tube. The circulation point is usually a sliding sleeve, built into the production tubing that is normally closed during normal operations.

It is also common to punch a hole in the tubing using wireline for circulation kills fluids if the sliding sleeve cannot be opened or a plug has been placed when there is no packer. Punching a hole in the tubing causes permanently damage, but the tubing will be pulled out and replaced anyway.

Oftentimes the tubing may be filled with gas, so the choke manifold is lined up so that returns from the tubing are routed through an adjustable choke.

With regard to well control, the basics for reverse circulation are essentially the same as for any constant bottomhole pressure method. It differs in that no circulating rate or pressures are established beforehand. The pump must be brought up to speed, bottomhole pressure stabilized, and then circulating pressure established.

It also differs that instead of using tubing pressure to control bottomhole pressure, the casing gauge is used. Back-pressure is exerted with the choke (on the tubing). It should be noted that gas will reach the surface much sooner than in conventional circulation.

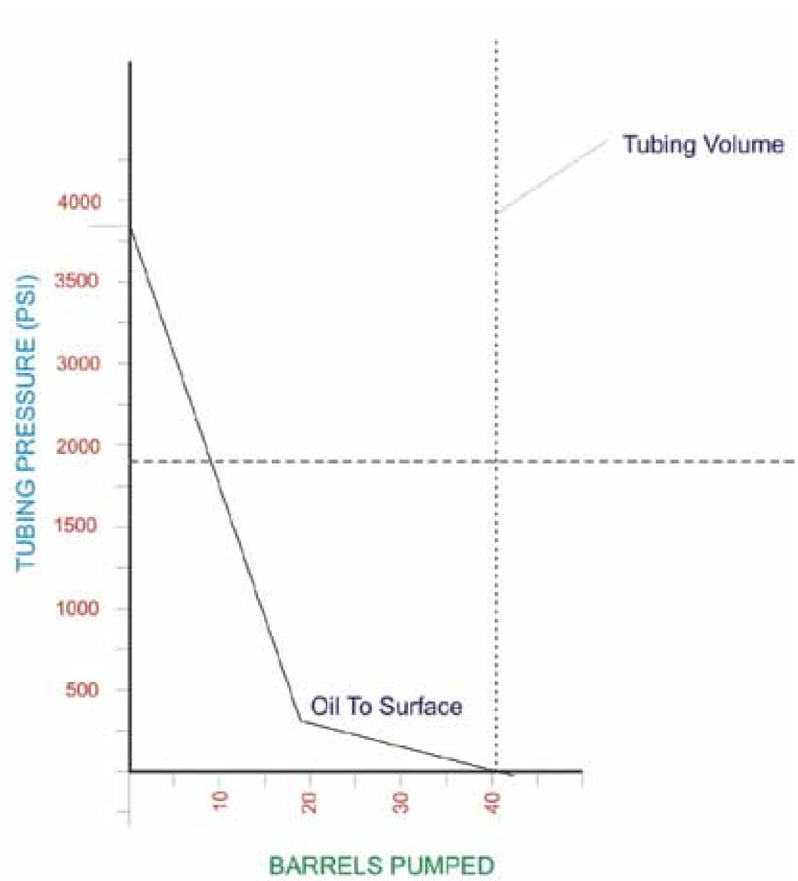
This may require pumping at a very fast rate in order to catch up with the dropping fluid level in the annulus. The problem may be minimized by keeping the choke closed until the pump start-up procedure begins.

When bringing the pump on line, tubing pressure should be held constant. This may not be easy when the tubing string is full of gas. Once the pump is running at the desired speed (also accounting for the time lag throughout the system), casing pressure is held constant until the tubing has been displaced.

The only pump pressure required is to equalize across the circulation device before opening and, when the kill fluid is near in balance, tubing-to-tubing/casing annulus and circulating friction losses need to be overcome.

The well is circulated with a back-pressure maintained on the tubing so that a constant bottomhole pressure can be maintained to eliminate any further flow of reservoir fluids into the well. In other words, maintaining a hydrostatic head on a formation that is greater than the actual formation pressure, but not too much greater, otherwise there will be excessive fluid loss, or even fracturing of the formation. To prevent any further inflow of formation fluids it is common practice to maintain a tubing pressure that is some 150 to 200 psi higher than the shut-in pressure. This will ensure that when pumping is started, the kill fluid pressure on the formation will be higher than the formation pressure. As the kill fluid is pumped to the tubing the surface pressure can be slowly reduced in proportion to the amount of fluid rise in the tubing.

Figure 9.21. Typical reverse circulation chart.




The slightly higher hydrostatic head on the formation is maintained during the kill operation reducing the chance of influx of the formation fluids. As the kill fluid moves up the tubing, the back-pressure held on the tubing head is reduced. This can be shown in the form of a graph with tubing head pressure against time (assuming a constant pumping rate) or tubing head pressure against quantity pumped (refer to figure 9.21).

The operator on the choke will reduce pressure in accordance with the graph that is based on tubing capacity and the pumping rate. If there is a fluctuating pump rate there will have to be communication between the pump operator and the operator on the tubing head so that the pressure is reduced at the correct rate.

The reverse circulation method can be used for all types of wells, except possibly those with very high production rate and very low reservoir pressure. In this case, it is not possible to have a kill fluid of sufficiently low hydrostatic head to kill the well without heavy losses, or where it is not possible to fill the tubing without exceeding the reservoir pressure. Reverse circulation is not commonly used as a well control method in drilling situations with an exposed open hole.

### Procedure for Reverse Circulation with Little or No Gas

1. Assure proper standpipe and manifold line-up.
2. Bring the pump to the kill rate while holding a constant back-pressure on the tubing (SITP).
3. When the pump is at the desired speed, circulating pressure on the casing is held constant until the tubing is displaced.

If the annulus fluid is not of sufficient density, and the goal is to kill the well in one circulation, it will be necessary to get the tubing full of liquid before standard constant bottomhole pressure methods can be used.

### Procedure for Reverse Circulation a Gas Filled Well

In workover operations, reverse circulation is often used to kill a well filled with gas. In this case it may not be easy to hold tubing pressure constant (as the pump is brought up to speed) when the tubing is filled with gas. The procedure would require first filling the tubing string with a liquid.

1. Hold constant circulating (casing) pressure until the tubing is displaced with liquid.
2. Hold the tubing pressure constant until the annulus is filled with kill weight fluid.
3. Hold the casing pressure constant until kill fluid has been circulated throughout the system.
4. Shut-in the well and check for pressure build-up. If pressures are zero, the well may be opened and checked for flow.

### Calculating Reverse Circulation Strokes

Surface Line Strokes

$$\boxed{\text{Surface Line ID}^2 \div 1{,}029.4 * \text{Surface Line Length}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Surface Line Strokes}}$$

Annular Stokes

$$\boxed{(\text{Casing ID}^2 - \text{Tubing OD}^2) \div 1029.4 * \text{Sliding Sleeve MD}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Annular Strokes}}$$

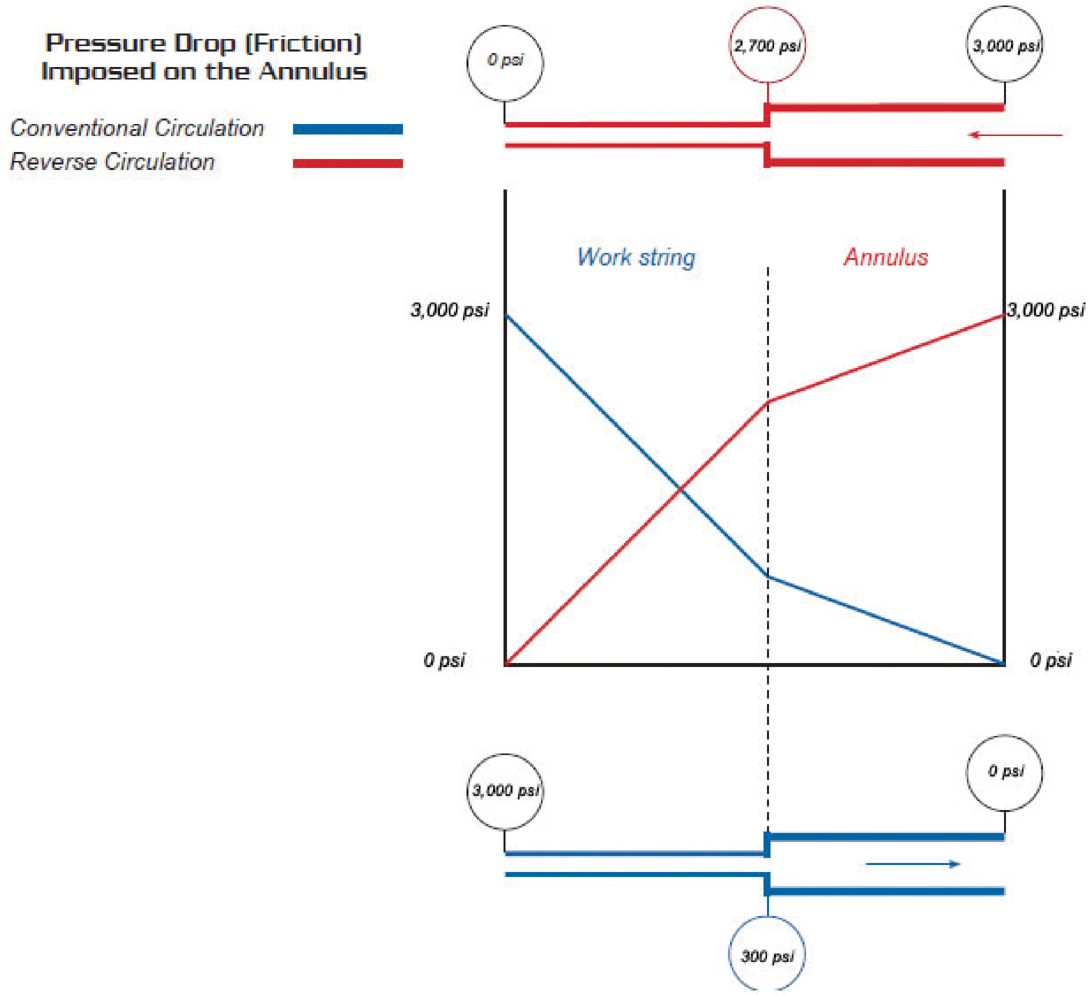
Tubing Strokes

$$\boxed{\text{Tubing ID}^2 \div 1029.4 * \text{Sliding Sleeve MD}_{ft} \div \text{Pump Disp.}_{bbl/stk} = \text{Tubing Strokes}}$$

Reverse Circulation Total Strokes

$$\boxed{\text{Surface Line Strokes} + \text{Annular Stokes} + \text{Tubing Strokes} = \text{Total Strokes}}$$

Figure 9.22.




Some advantages of reverse circulation are:

- It is the shortest or quickest route to circulate from the end of tubing to the surface.
- It gets the influx inside the strongest pipe from the beginning.
- Many times the annular fluid (packer fluid) is sufficiently dense to control the formation, which minimizes fluid mixing on the rig.
- The increased velocity with which the fluid travels up the tubing improves the carrying capacity of brines that have insufficient gel strength.
- There is less pit gain.

Disadvantages of reverse circulation include:

- The largest percentages of pressure losses are inside the smallest diameter. Usually, this will be in the tubing.
- When reversing, the majority of pump (friction) pressure is exerted on the annulus and the bottom of the well.
- Reverse circulation can cause higher formation pressures, since it equals the tubing friction at the formation.

- In open hole, weak formations may not withstand the extra pressure. In remedial operations, weak or bad casing may fail, or if high rates (resulting in high pressures) are attempted, gas filled and/or weak tubing may collapse from the pressure differential.
- Reverse circulation is generally not recommended where there is danger of plugging circulating ports, perforations, or bit nozzles with debris from the well. The potential for lost circulation or stuck pipe is also a concern in an open borehole.
- Establishing and maintaining circulating rates and pressures may be difficult due to the compressive nature of gas in the tubing. The choke operator should expect that slight choke adjustments can result in great changes in circulating pressure.
- Calculating the correct circulating pressure can be difficult if there are fluids of different density in the circulating system.
- If there is gas in the annulus, it may migrate upward faster than the pumping rate. The addition of viscosifiers may ease the problem; however friction pressures are likely to increase due to the increased viscosity of the fluid.

### Fluid Density and Choosing the Circulation Method

The density of the fluid being pumped and the density of the fluid displacing it determine if forward circulation or reverse circulation should be used.

- When the displacing fluid is lighter than the fluid being displaced, use the reverse method. The heavier fluid must be below the lighter weight fluid during reverse circulation to prevent commingling.
- When the fluid is static (not pumping) the heavier fluid will sink below the lighter fluid due to gravity.
- When the displacing fluid is heavier than the fluid being displaced, use the forward circulating method.
- The decision of which circulating path to use should also be based on pressure calculations and tubing burst and collapse strength.

## Bullheading (or Squeeze Kill)

This method consists of pumping kill fluid to the well and forcing the well fluids back into the formation at a rate that will not fracture the formation. Obviously, it is not a constant bottomhole pressure method. Bullheading is often used on completed wells in which perforation depths, well geometry, and formation characteristics are well known. In some areas, bullheading is a common technique used to kill a producing well prior to beginning workover operations. Bullheading is often used on wells that have not been completed with tubing, as it is easier to organize and accomplish compared to, for example, a coiled tubing well kill. It can also be used when the tubing has been landed in a packer and the circulation device, such as a sliding sleeve, cannot be opened, hence a circulation kill would not be possible without a tubing perforating service. This method is difficult to use on a well with fracture production.

Bullheading should be considered when:

- An hydrogen sulfide influx cannot be handled safely if brought to the surface.
- The influx volume is too large to be circulated out.

- When the MAASP will be greatly exceeded if other well control methods are used and will not be exceeded by bullheading pressure.
- A kick has been swabbed in by tripping out of the hole.
- An influx is taken when the tubing/bit is not on the bottom and it is not possible to strip back to the bottom or there is no communication between tubing and annulus.
- It is necessary to reduce surface pressures before implementing other well control procedures.
- Bullhead pressures will not exceed the surface equipment limitations and casing burst rating.

Bullheading has the following advantages. It can be used when:

- An hydrogen sulfide influx is present.
- The MAASP will be exceeded using other well control methods.
- When the tubing is off bottom or there is no tubing annulus communication.
- High influx pressures may overcome the surface and subsurface pressure limitations.

Bullheading has the following disadvantages:

- The fluid will go into the weakest formation, which is not necessarily where the influx originated.
- High pressures may exceed the surface and subsurface equipment limitations.
- The formation anywhere along the open hole section may be fractured, causing a blowout.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

### Bullheading

In a well kill operation, a kill weight fluid is selected that will provide a column of fluid that has a hydrostatic pressure greater than the formation pressure, once the wellbore has been fully displaced with the kill weight fluid. When the bullhead technique is selected to kill the well, the kill fluid's density and pumping rates must be chosen to avoid excessive surface pressure, yet have sufficient downhole pressure to exceed the formation fracture integrity. It is preferred to pump the fluids back into the pore spaces without exceeding the formation integrity. Very few wells have sufficient permeability to allow this to happen. In virtually all cases, the reservoir must be micro-fractured to yield the *injectivity* required for bullheading. On the other hand, be careful not to exceed the overburden stress in the rock, which would allow it to develop large horizontal fractures, or fractures that extend vertically from one reservoir to another.

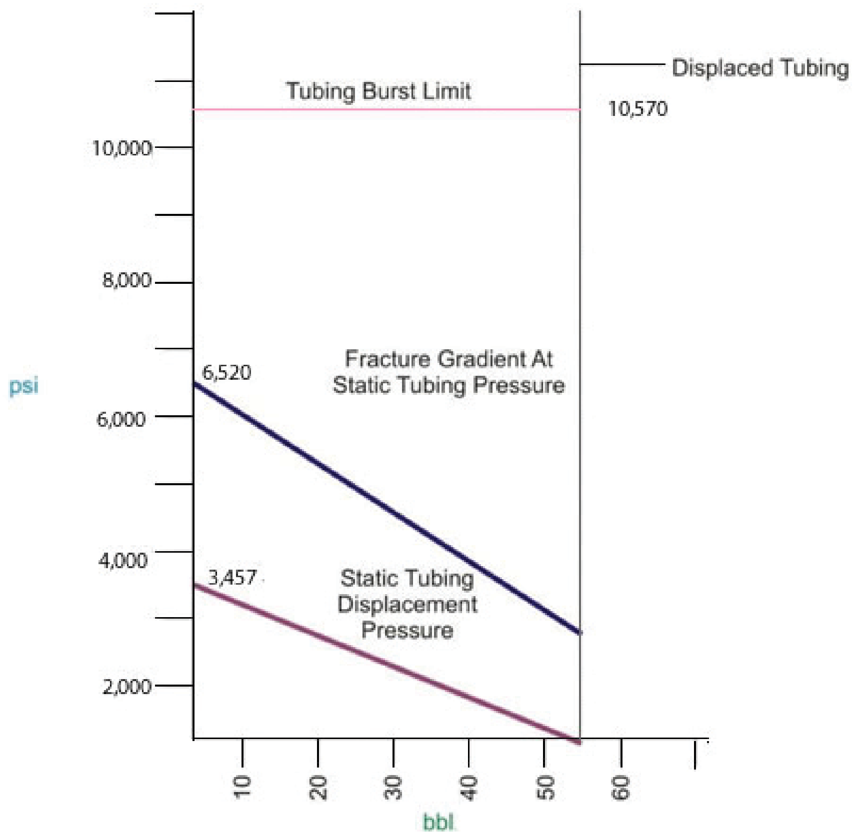
The most straight-forward and commonly used technique for killing a live well prior intervention work is to bullhead the well prior to entry with the tubing.

When bullheading, the pump rate has to be high enough to ensure that the rate the kill fluid is moving down the tubing is faster than it can free fall. This prevents contaminating the kill fluid with hydrocarbons in the tubing. In effect, the kill fluid displaces the hydrocarbons back into the formation. If the pump rate is not fast enough, slippage of the hydrocarbons past the front of the kill fluid will occur and lessen the kill efficiency. An example of a bullhead/squeeze kill graph is shown in figure 9.23.

Normally, this method is used only in wells with small tubing and with high permeability that allows adequate pumping rates. This method is more time consuming and difficult in larger tubing (greater than 3½ inches) and especially in low permeability wells, gas wells and wells with high gas/oil ratios. This method also has the potential drawback that some of the kill fluid is inevitably pumped into the formation.

A bullhead kill graph is very simple to produce as the pump pressure line is simply drawn from the initial shut-in tubing head pressure (SITHP) to the second point which is the overbalance at the volume of fluid required to the top of the formation. The fracture pressure gradient should also be plotted to ensure that pressure is not exceeded during the operation.

Figure 9.23. A typical bullhead pressure chart.




### Planning a Bullhead Operation

The following discussion addresses the planning of a routine bullhead operation in order to kill a previously completed well. Although it is not possible to develop a predictable bullhead kill operation to the same extent as when using a constant bottomhole pressure method, it is possible to adopt a structured approach when planning the operation. The bullhead procedure can be separated into three distinct elements for consideration:

- Pressure
- Volume
- Pumping rate

The following pressure limitations can be estimated with a high degree of accuracy.

- Shut-in tubing pressure
- Shut-in casing pressure
- Maximum anticipated surface pressure
- Maximum pumping pressure available at the desired injection rate
- Friction pressure loss versus pumping rate
- Pressure rating of wellhead (tree) equipment
- Production tubing internal yield (burst) pressure rating
- Remediation tubing internal yield (burst) pressure rating
- Remediation tubing collapse pressure rating
- Casing internal yield (burst) pressure rating
- Formation integrity (fracture pressure)
- Overburden (fracture) stress

During bullheading operations, all the pressure limits listed above should be monitored. A bullhead worksheet (figures 9.27 – 9.35) can be used as a guide to monitoring the operation. A pumped volume versus pressure schedule, based on known and estimated data, is constructed on the worksheet and actual pressures are recorded during the operation.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

### Support Pressure in the Casing by Tubing Annulus

When bullheading down production tubing, it is a generally recommended practice to apply some pressure to the production tubing through the casing annulus before beginning the kill operation, especially if the tubing burst pressure is a limiting value. This supporting pressure may be required during the initial stages of pumping. Supporting pressure on the backside accomplishes three goals:

1. The trapped pressure will support the tubing string,.
2. The production packer or downhole isolation device will be tested.
3. Changes in annular pressure can be monitored, enabling early identification of potential problems.

### Fluid Volume Considerations

The following volumes should be considered to enable an accurate estimate of the fluid volume required to complete the bullheading operation:

- Production tubing string volume
- Casing or liner volume from end of tubing to the perforations
- Overflush or overdisplacement volume to allow for gas/fluid slippage and provide a reasonable safety factor for the operating conditions
- Surface line volume

To bullhead a production tubing string, it is obvious that the volume of the string being displaced must be calculated. If there is significant surface line length between the pump(s) and the tubing head, the volume of this surface line must be included in the calculations.

In most wells, there is also a gap between the end of the tubing string and the top of the perforations. The volume inside the casing from the tubing exit and the end of the protective casing string must also be included when making the calculations of the total volume to be pumped. In addition, there should always be a safety factor, called *overdisplacement*.

The appropriate overdisplacement volume should be as small as practical. Excess volumes may create damage to the reservoir as kill fluids are pumped into the reservoir and subsequently, make it more difficult to bring the well back on production. Unfortunately, gas/fluid slippage and migration cannot be predicted with confidence.

Flushing is never perfect. The best values for over-displacement are usually determined by field experience and in known reservoirs.

### Pump Considerations

Accurate estimates of the volume of fluid to be pumped can also be made.

- Surface line volume
- Internal tubing volume
- Casing volume from end of tubing (EOT) to perforations

All of the volume considerations, except over-displacement are known quantities that can be calculated or found in data tables. The amount of over-displacement pumped is strictly a matter of field experience. The high pressure/high volume gas wells in the Middle East may require more than 100 barrels. In the Gulf of Mexico over-displacements of three to five barrels will often do the job. The amount of over-displacement should be limited to the amount necessary to keep formation fluids from re-entering the wellbore. Excess volume may cause damage to the reservoir, the environment, and make it more difficult to bring the well back on production.

The pump rate to use during the operation is also considered. The primary considerations when selecting pumping rates are:

- Pressure limits due to friction
- Overcoming gas migration

Gas in the tubing will migrate against the pumped fluid unless the pump rate is high enough to force the fluid into turbulent flow. The flow pattern of the fluid is mainly dependent upon the flow properties (viscosity and density), the pumping rate, and the inside diameter of the tubing. Hydraulic calculations can be made to determine the pumping rate that will result in turbulent flow. Some operators use a rule of thumb that recommends pumping one barrel per minute for each inch of inside diameter of the tubing. Special viscosifiers are sometimes added to the fluid to lessen the chances of gas migration however these changes in fluid properties will likely result in higher tubing pressures during the job.

When the pump is first started and brought up to the planned rate, the tubing pressure will increase because well fluids are being compressed. The pressure may increase several hundred psi over the shut-in tubing pressure. Maximum allowable pressures must be carefully monitored during the startup procedure. As the operation continues, the increasing hydrostatic pressure of the pumped fluid will cause a decrease in the tubing pressure, which in turn will result in an increase in pump rate.

*Excerpt from "Well Control for Coiled Tubing Operations" manual by Well Control School*[2]

## Bullhead Pump Schedule

It has been demonstrated that there is a desirable pump pressure schedule to follow versus total volume pumped into the well. The only way to control the pump pressure schedule is by adjusting the pumping rate. Adjustments to the pumping rate may be required to achieve the desired pumping schedule; i.e., stay within the limiting pressure values.

A theoretical volume pumped versus pump discharge pressure can be calculated based on known and/or estimated parameters. As the job progresses, actual pressures are recorded versus volume pumped to track the operation. The objective is to ensure pumping pressure and increasing hydrostatic pressure as the wellbore fills with the kill weight fluid, do not exceed one of the equipment or formation fracture limits.

Usually, if the job is going well, this pump rate increase can be tolerated within limits until the kill fluid is at the EOT. It is considered good practice to record the actual pressure values at the proper volume intervals until the kill fluid has filled the tubing. The kill fluid will not enter the formation at the same injection rate as well fluids because in most cases, it is not the same type of fluid. If the pump rate has been allowed to increase, many operators reduce it to the planned rate until the kill fluid and over-displacement have been pumped.

When the calculated barrels to complete the bullheading have been completed, the final pumping pressure should represent the friction pressure required to pump the kill weight fluid from the pump, through the surface piping and down the tubing. When the pumping is stopped, the surface pressure should be zero if the well has been killed and there is no trapped pressure in the system.

A test for trapped pressure should be made, even if the well appears dead. Line up to catch any potential back-flow into a tank. Open a bleed line and allow the tubing fluid to flow back through a manual choke. Use the manual choke to control the rate of bleed off.

If there is pressure and it does not quickly bleed off, then perhaps the well is not dead. If the pressure bleeds off to zero in a minute or so, and the back-flow completely stops, the well is dead.

### *BULLHEAD PUMP SCHEDULE*

A theoretical volume pumped versus pump discharge pressure can be calculated based on known and/or estimated parameters. As the job progresses, actual pressures are recorded, versus volume pumped to track the operation. The objective is to ensure the pumping pressure and the increasing hydrostatic pressure as the wellbore fills with the kill weight fluid, do not exceed one of the equipment or formation fracture limits.

### *BULLHEADING LEARNING EXAMPLE PROBLEM 1:*

The well illustrated in figure 9.25 is to be killed by bullheading down the production tubing.

The SITP is 2,700 psig. The well has a TVD of 7,200 feet. The top of the perforations in the tubing are at 7,000 feet TVD and MD, the bottom of the perforations are at 7,200 feet TVD and MD. The tubing extends to the bottom of the perforated zone. The well has been shut-in and the density of the shut-in wellbore fluids is 5.1 psig (a natural gas condensate). The formation integrity (LOT) is equivalent to 14.0 ppg. The formation fracture pressure is equivalent to 14.4 ppg.

(a) What kill weight fluid is required to produce an overbalance of 200 psig in the well?

Solution to (a):

KMW = 5.1 ppg + [(Overbalance Pressure$_{psi}$ + SITP$_{psi}$) ÷ 0.052 ÷ TVD$_{ft}$ top of perfs]

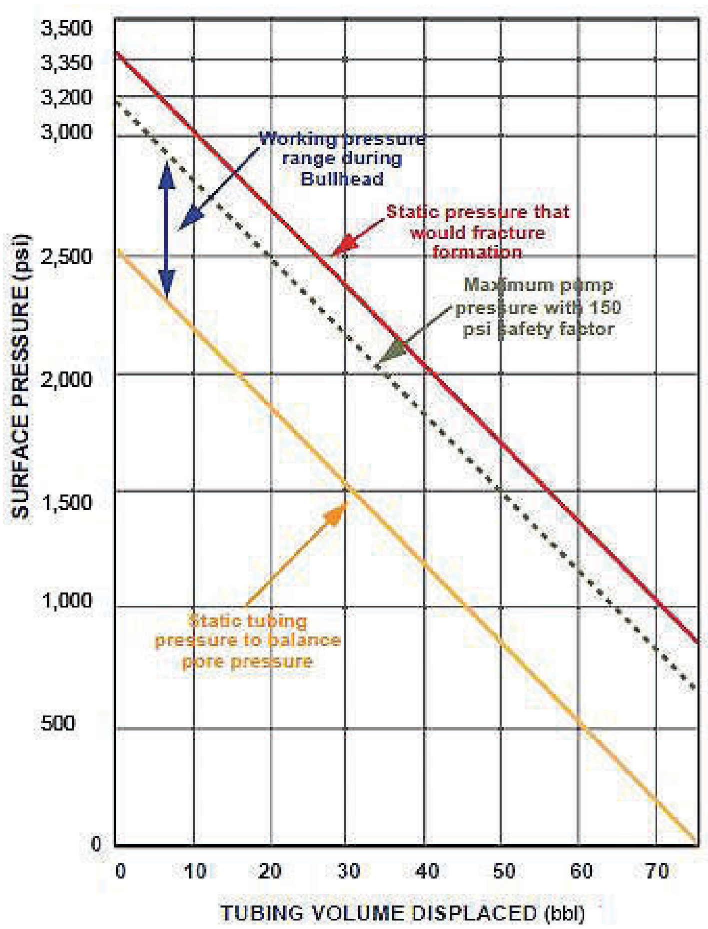
KMW = 5.1 ppg + [(200 psi + 2,700 psig) ÷ 0.052 ÷ 7,000 ft]

KMW = 5.1 ppg + 7.96 = 13.1 ppg

(b) The diameter of the tubing (ID) in the well is 3.15 inches. What is the minimum pump rate the operator should use to overcome the possibility of migration of any free gas during the circulation? Assume the migration rate is 1,000 feet per hour.

Solution to (b):

Figure 9.24




The velocity of the gas/kill fluid interface should be 1,000 ft per hour divided by 60 minutes/hour.

Velocity = 1,000 ft per hour ÷ 60 minutes/hour = 16.7 ft per minute.

The capacity of the tubing is calculated:

Tubing Capacity = ID$^2$ ÷ 1,029.4

Tubing Capacity = 3.15$^2$ ÷ 1,029.4 = 9.9225 ÷ 1,029.4

Tubing Capacity = 0.00964 bbl/ft

Minimum Pump Rate = 0.00964 bbl/ft * 16.7 ft/min

Minimum Pump Rate = 0.16 bbl/minute

(c) What initial surface pressure (pumping pressure) must be applied to exceed the formation integrity of the reservoir and drive the wellbore fluids back into the rock? (The permeability of the reservoir alone cannot be counted on to take the fluid.)

Solution to (c):

The BHP required to exceed the formation integrity is calculated from the formation integrity data and the TVD of the top of the perforations.

BHP to match formation integrity = 0.052 * 14.0 ppg * 7,000 ft TVD = 5,096 psig

The minimum initial surface pumping pressure, to achieve this BHP and slightly exceed the formation integrity and create the micro-fractures is:

Minimum Initial Pump Pressure$_{psi}$ (IPP) = BHP$_{psi}$ – Wellbore Fluids HP$_{psi}$

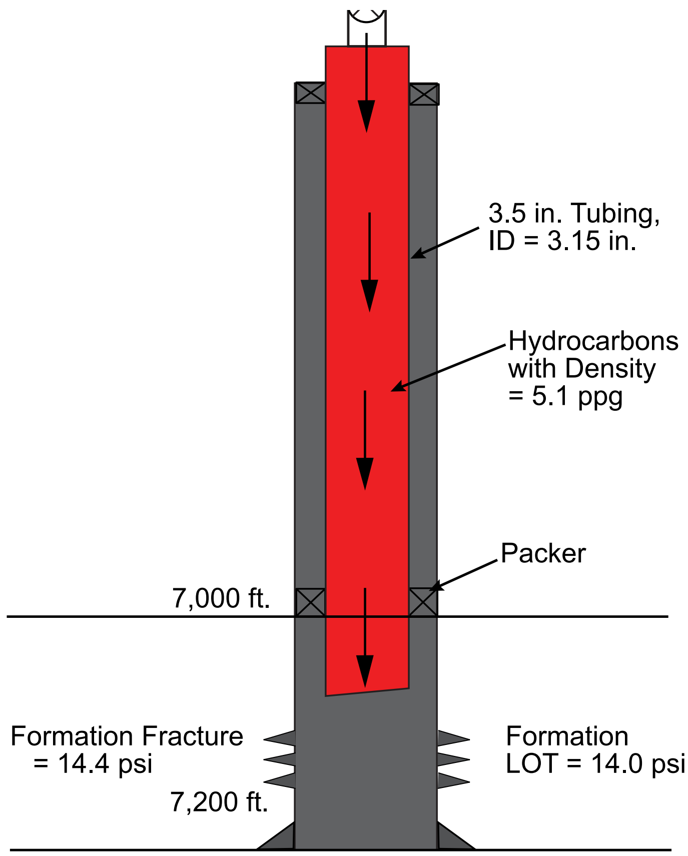
Minimum IPP = 5,096 psig – ( 0.052 * 5.1 ppg * 7,000 ft TVD)

Minimum IPP = 3,239 psig

The minimum IPP is a theoretical value; it represents the pumping pressure at zero pump rate. The actual IPP will be somewhat greater, depending on the pumping rate.

Frictional pressure losses down the tubing will cause the actual IPP to be greater.

Figure 9.25. Bullhead example problem.



*NOTE: The formation injectivity index is a measure of a formation's ability to accept fluids and is defined as the number of barrels per day per psi differential pressure between the injection pressure and the formation pressure. If the formation injectivity index is available, the injection rate versus bottomhole pressure can be determined. This can be used to provide a more accurate estimate of the surface pumping pressure required to flush the wellbore fluids back into the rock. In the absence of a formation injectivity index, the formation integrity (fracture pressure as measured in a LOT) can be used to provide an acceptable estimate of the initial pumping pressure, per the example calculations in part (c) on the previous page.*

(d) What final minimum pumping pressure is required when the kill weight fluid reaches the top of the perforations?

Solution to (d):

The minimum final pumping pressure (when the kill weight fluid reaches the reservoir rock) is equivalent to the surface pressure required to hold the micro-fractures open when the wellbore fluids have been replaced by the kill weight fluids and is calculated by:

Minimum Final Pumping Pressure$_{psi}$ = BHP$_{psi}$ – Kill Weight Fluid HP$_{psi}$

Minimum FPP = BHP$_{psi}$ – 0.052 * KMW$_{ppg}$ * TVD of perfs

Minimum FPP = 5,096 – 0.052 * 13.1 ppg * 7,000 ft TVD

Minimum FPP = 5,096 – 4,768

Minimum FPP = 328 psig

(e) What are the initial maximum static pressure and final maximum static pressure that can be applied without creating large, undesired fractures in the formation while pumping?

Solution to (e):

Initial Max Static Pressure$_{psi}$ (IMST) = BHP$_{psi}$ for gross fracture – Initial HP$_{psi}$

IMST = (0.052 * 14.4 * 7,000) – (0.052 * 5.1 * 7,000)

IMST = 5,241 psi – 1,856 psi

IMST = 3,385 psi

Final Max Static Pressure$_{psi}$ (FMST) = BHP$_{psi}$ for gross fracture – Final HP$_{psi}$

FMST = 5,241 – (0.052 * 13.1 * 7,000)

FMST = 5,241 – 4,768

FMST = 473 psi

(f) How much kill weight fluid must be pumped down the tubing to displace the original wellbore fluids (the condensate) with kill weight fluid? Assume 100% displacement efficiency.

Solution to (f)

The total volume of kill weight fluid that must be pumped, theoretically, to displace the wellbore fluids initially in the tubing is the tubing capacity * its length.

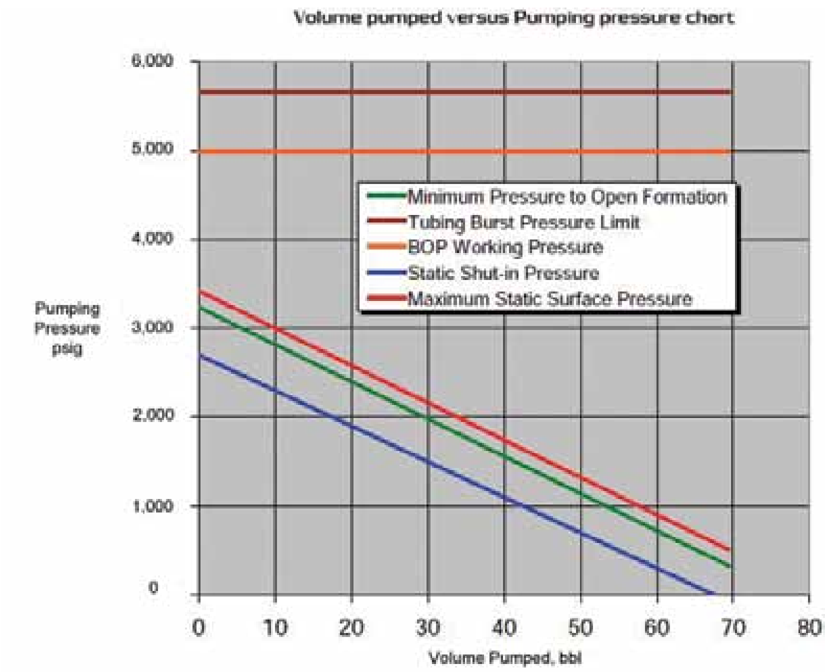
$\text{Volume Pumped}_{bbl} = \text{Tubing Capacity}_{bbl/ft} * \text{Tubing Length}_{ft}$

Volume Pumped = 0.00964 bbl/ft * 7,200 ft

Volume Pumped = 69.4 barrels

The above data can be used to produce a volume pumped versus minimum pumping pressure chart that can be used to track the operation and ensure pumping pressures are within equipment limits. On a chart, plot volume pumped versus the minimum required surface pumping pressure values at the beginning and the end. Connect the two points with a straight line. This results in a line that represents the surface pumping pressure required to open, and hold open, the micro-fractures in the formation. This limit is represented by the green line in figure 9.26.

Figure 9.26. Volume pumped versus pumping pressure chart.




It is interesting to know the maximum static pressure that can be applied. This line is constructed by plotting the maximum initial static pressure and the maximum final static pressure that can be applied during the bullhead operation. The line is obtained by plotting the maximum static pressure to fail the reservoir formation at zero barrels pumped and at the final total barrels pumped. This line is shown as the red line.

The chart's blue line represents the static shut-in pressure versus volume pumped. This line depicts the values of the shut-in tubing pressure at any point in the displacement should the pumping be shut down. It is created by plotting the value of the SITP at zero barrels pumped, and then constructing a line parallel to the minimum pump pressure line. The intercept of the line with the horizontal axis represents the number of barrels of kill weight fluid that must be pumped to balance the well exactly. The line is a useful reference, should it become necessary to stop the bullhead operation (and remove pump pressure) before it has been completed. Other limit lines that can be constructed on the chart are the BOP working pressure limit (orange line) and the tubing burst pressure limit (brown line).

The pumping process should track the green line as closely as possible, but may fall anywhere between the blue and red lines. (Pressures below the green line are possible if the formation injectivity is good). If pressures go too far above the green line, there is danger of fracturing the overburden that lies above the reservoir formation failure limit (red line). Pumping pressures above the red line may be acceptable if friction pressure losses down the tubing are very high. If pumping pressures go too far below the green line, there may be insufficient pressure at the bottom to open the reservoir's micro-fractures and inject the wellbore fluids. The only way to control the pumping pressure is to vary the pumping rate. Ideally, rates should be sufficient to overcome a 16.7 feet per minute migration rate (0.16 barrels per minute in this specific example). Pumping at higher rates is acceptable, so long as pressures do not exceed the red line. Pumping at rates slower than the estimated migration rate (to stay on, or slightly below, the red line) may be necessary, but displacement efficiency may be very poor.

### Summary of the Bullhead Method

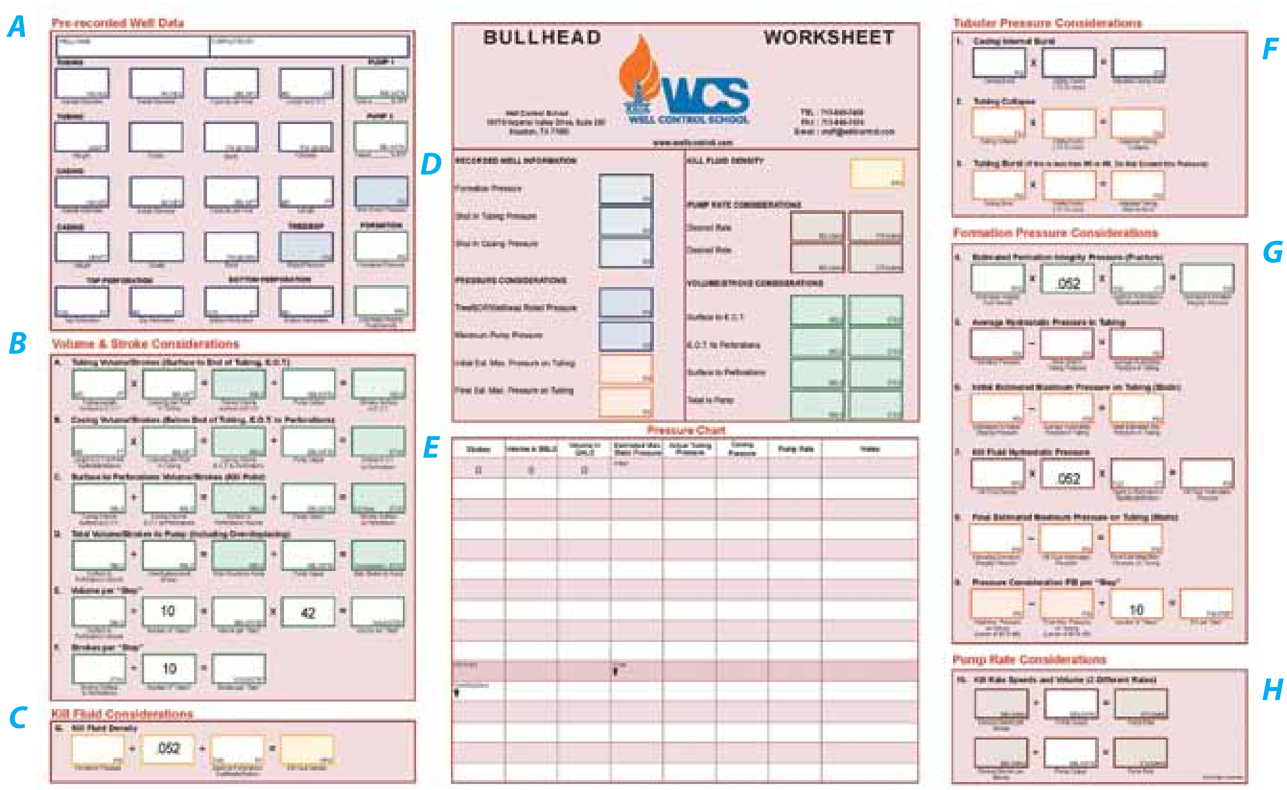
1. Determine the static tubing pressure (if bullheading down casing, determine casing pressure).
2. Prepare a bullhead worksheet and pressure chart.
3. Apply and trap pressure on the annulus.
4. Start pumping by carefully increasing the pump speed to the planned rate.
5. Monitor all maximum allowable pressures.
6. Record pump rate changes as well as pressure changes at the predetermined volume check points.
7. If the pump rate has been allowed to increase, reduce it to the planned rate as the bullhead (kill) fluid approaches the end of tubing (EOT).
8. When the planned volume (including the overdisplacement) has been pumped, stop pumping.
9. Bleed the surface pressures to zero, shut-in the well and monitor for pressure build-up.

The *bullhead worksheet*[4] is a job aid designed to assist field personnel plan and execute a bullhead kill down the tubing of a completed well. Although pressures cannot be accurately predicted when bullheading, it is possible to take a structured approach to the operation by organizing known data and carefully monitoring actual pressures in order to quickly identify problems that might occur. This is the purpose of the worksheet.

The bullhead worksheet (kill sheet) includes these areas:

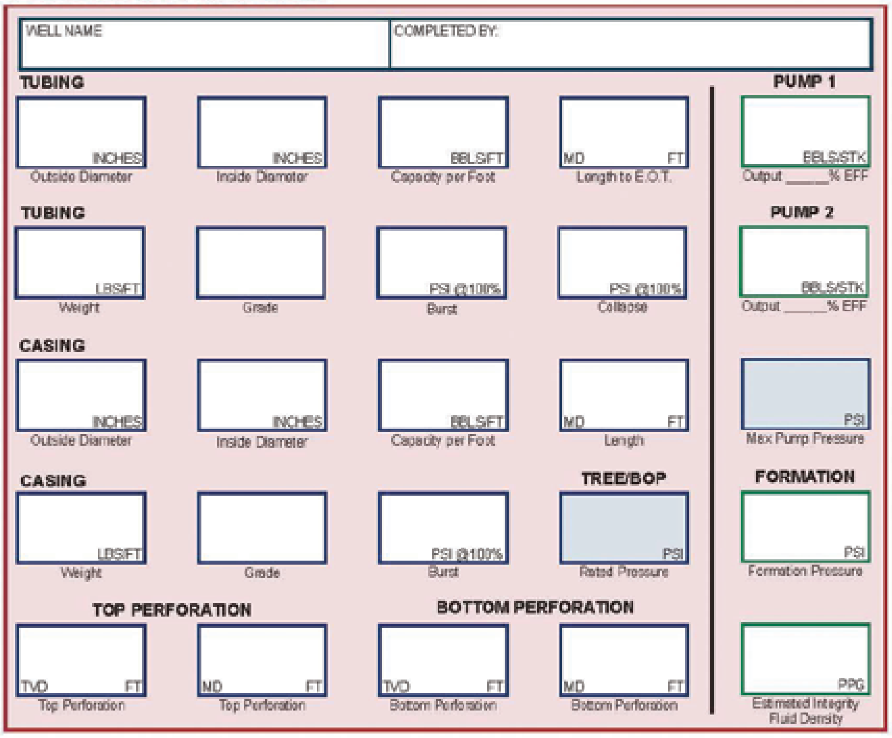
A. Prerecorded Well Data
B. Volume and Stroke Considerations
C. Kill Fluid Considerations
D. Recorded Well Information
E. Pressure Chart
F. Tubular Pressure Considerations
G. Formation Pressure Considerations
H. Pump Rate Considerations

Figure 9.27. Bullhead Worksheet



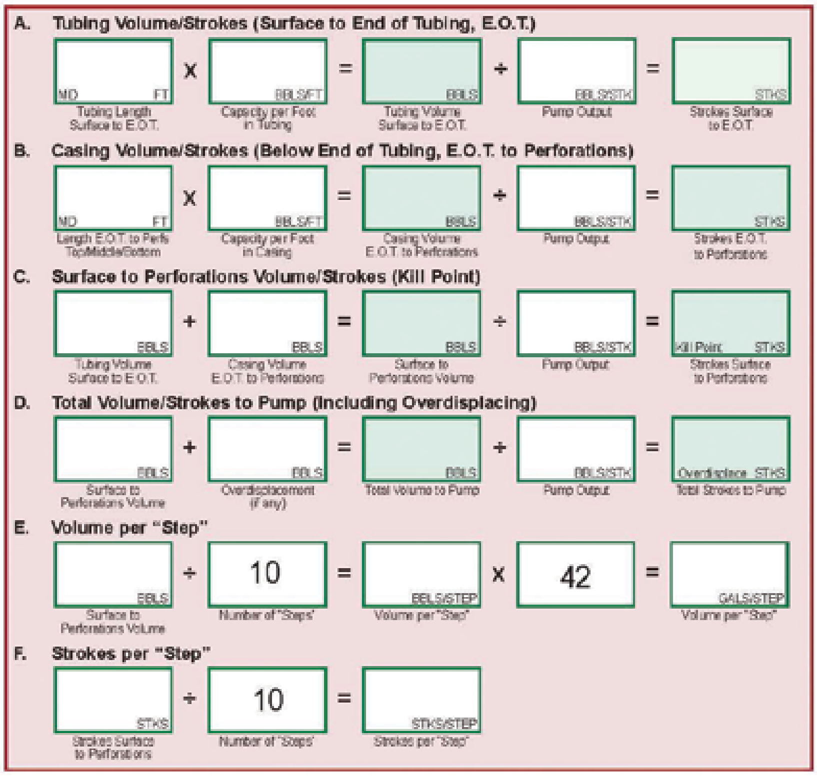
The prerecorded section (labeled *A*)on the upper left of the worksheet provides essential well data that is organized for quick reference when completing the worksheet.

Figure 9.28. A, The prerecorded information seciton of the kill sheet.



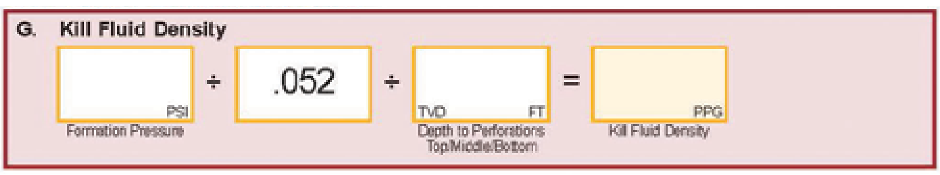
Volume-to-pump calculations appear below the pre-recorded data on the worksheet including over-displacement (A through F). Depending on the rig, or unit, volumes may be calculated in barrels, pump strokes, or gallons. It is assumed that the operation will be monitored in ten steps from the surface to the end of tubing (EOT). Therefore calculations E and F determine the volume per step to be entered on the pressure chart.

Figure 9.29. B, Volume and Stoke Considerations.




Calculation G, on the bottom left of the worksheet, is used to determine the density of the kill fluid.

Figure 9.30. C, Kill Fluid Considerations.



The section on the top right of the worksheet contains burst and collapse calculations for the tubular goods in the well (calculations 1 through 3). Although a safety factor of seventy percent is assumed, in reality, this factor will vary depending on the estimated strength of the tubing and casing.

Figure 9.31. F, Tubular Pressure Considerations.

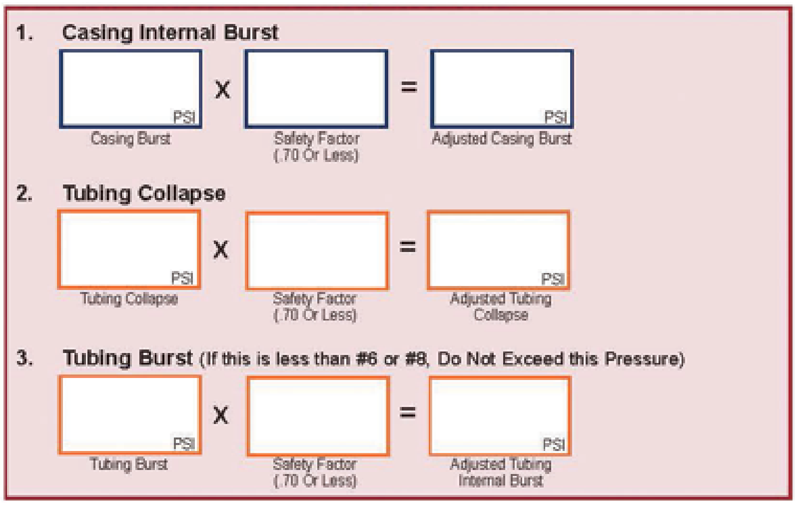
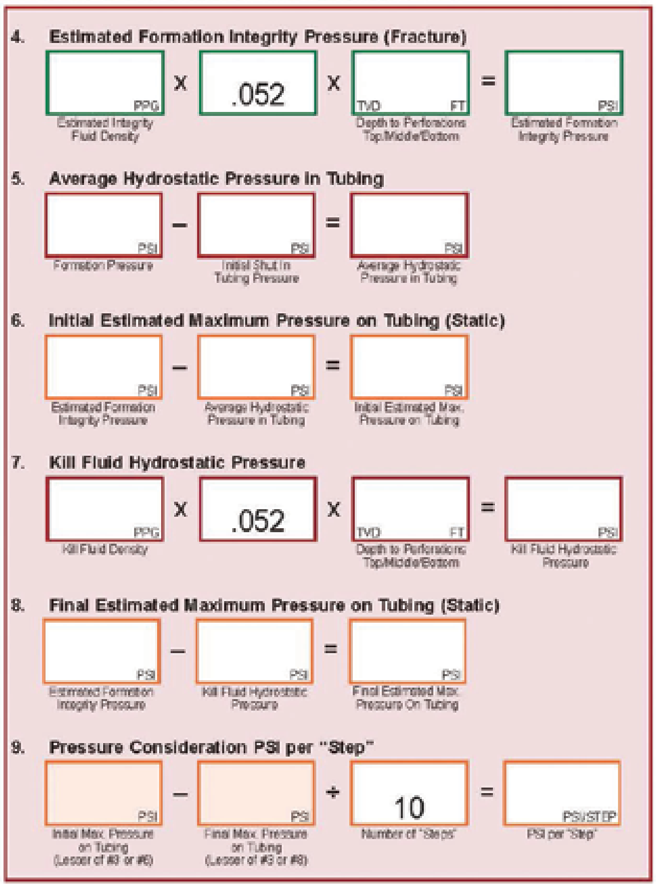


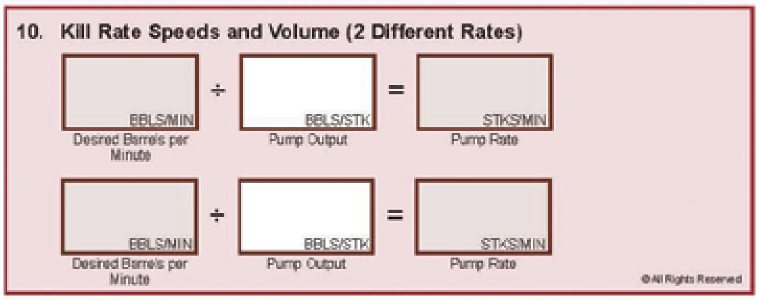

Figure 9.32. G, Formation Pressure Considetations.




The middle section on the right side of the worksheet is used to estimate descending pump pressure during the bullhead operation (calculations 4 through 9). Once the operation begins and fluid starts entering the formation, the actual circulating pressures should be much lower than those projected. The projected pressures derived from this section are based on assumed formation pressure, estimated formation strength, and changes in hydrostatic pressure as the kill fluid fills the tubing.

Calculation 10, at the bottom of the worksheet converts barrels per minute to pump strokes per minute.

Figure 9.33. H. Pump Rate Considetations.




The pressure chart at the bottom center of the worksheet provides columns for pumped volumes per step as determined in the volume and stroke section arranged opposite the pressure change per step derived from the formation pressure considerations section. Columns are also provided for documentation of actual pressures throughout the operation.

Figure 9.34. E, Pressure Chart.

| Strokes | Volume in BBLS | Volume in GALS | Estimated Max. Static Pressure | Actual Tubing Pressure | Casing Pressure | Pump Rate | Notes |
|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | Initial | | | | |
| | | | | | | | |
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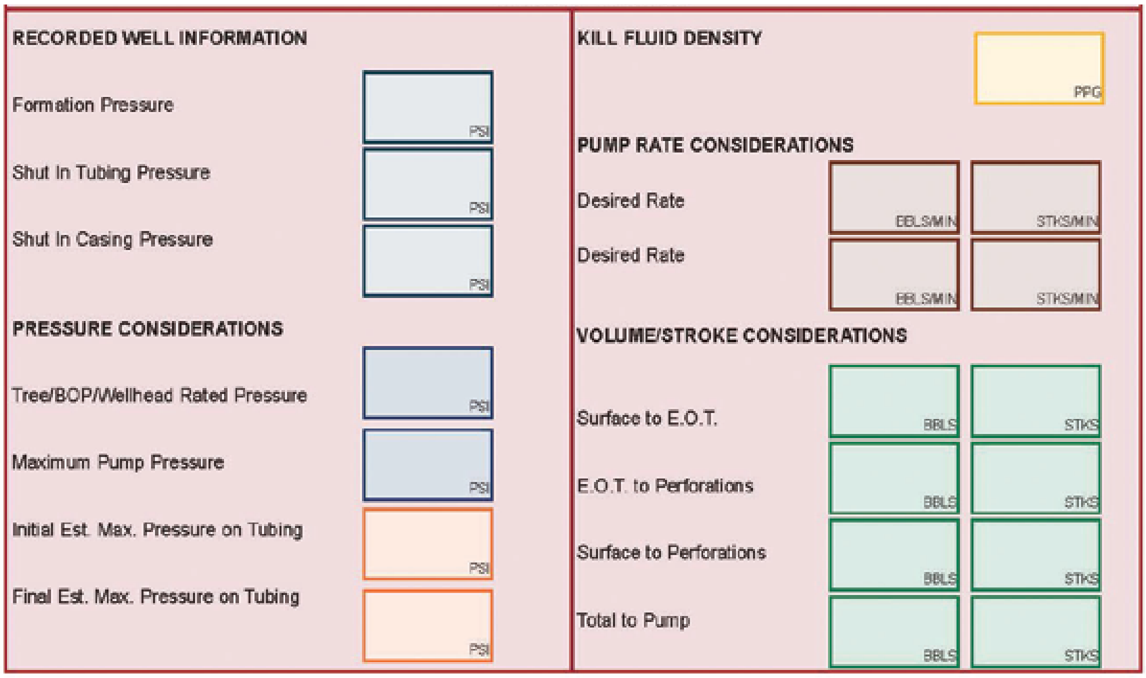
| | | | | | | | |
| | | | | | | | |
| Kill Point | | | Final ↓ | | | | |
| Overdisplace ↓ | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

The worksheet is designed to be double-folded after calculated data has been transferred to the top center section. In this way, supervisors have a handy easy-to-track guide to the entire bullhead operation.

Figure 9.35. D. Recorded Well Information.



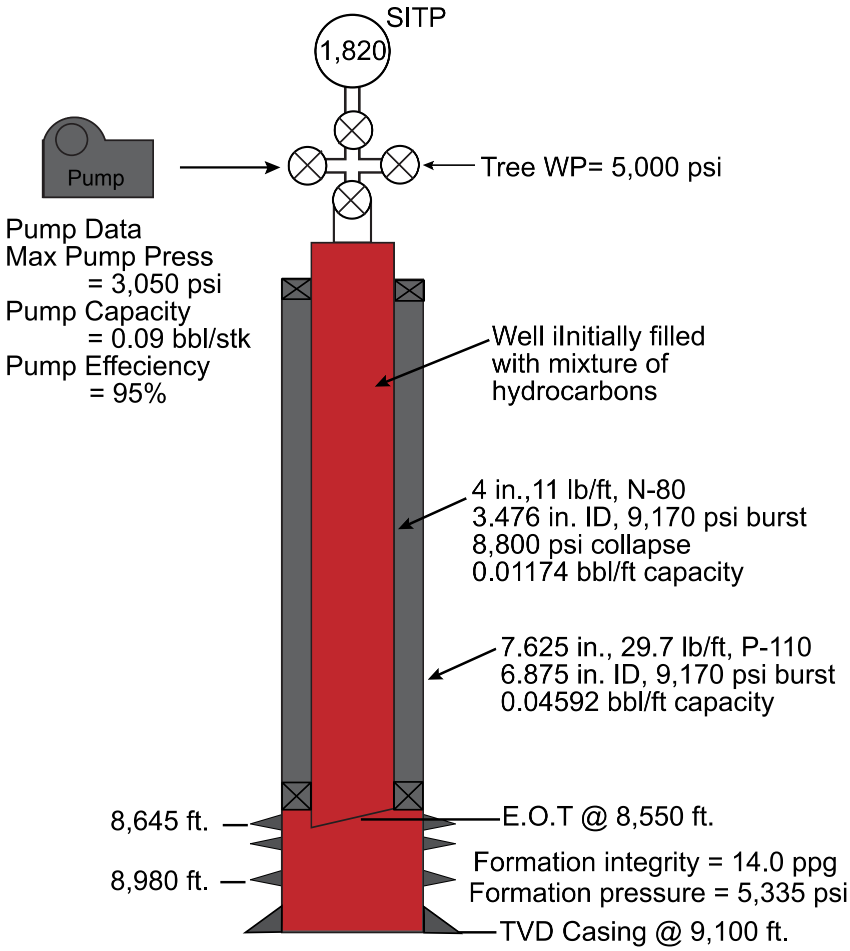

*BULLHEADING LEARNING EXAMPLE PROBLEM 2:*

Use the well data illustrated in figure 9.36., and the Well Control School (WCS) Bullhead Kill Sheet[4] to prepare a pumping plan for killing a well by pumping down the production tubing prior to well entry for remediation. For this problem, the maximum pressure that the pump can deliver is 3,050 psig. Note that prerecorded well data are needed to make the required calculations.

Solution

From the drawing of the well, along with the data about the well given on the drawing, the first step is to fill in the section of the kill sheet entitled, "Pre-recorded Well Data". After filling in this section, use the information from the Pre-recorded section and well information sheet to fill in the remainder of the kill sheet.

Figure 9.36. Well data for learning example problem 2.




## The Volumetric Method

The volumetric method is a method of well control in which bottomhole pressure is kept constant when circulation is not possible and gas is migrating up the hole. Bottomhole pressure is maintained slightly higher than formation pressure while the gas is allowed to expand in a controlled manner as it moves to the surface.

The volumetric method provides for the controlled expansion of gas during migration. It can be used from the time a well is shut in after a kick until the well can be circulated. The gas may be brought to the surface safely without using a pump. The method trades pressure for mud volume at the appropriate time in order to maintain a bottomhole pressure that is equal to, or slightly greater than, the formation pressure.

Chapter 5 "Gas Behavior" pointed out that if a gas kick is allowed to migrate in a shut-in (closed) well the pressures throughout the well will increase significantly. The formation may fracture, resulting in lost returns and an underground blowout. In the worst case, the casing and/or wellhead equipment may fail resulting in a surface blowout. The volumetric method reduces these high pressures by bleeding a volume of liquid in order to allow controlled expansion of the gas.

The volumetric method is not a kill method, but rather it is a method of controlling downhole and surface pressures until kill procedures can be started. It can be used to bring the influx to the surface, providing no additional influx is allowed. The volumetric principle can also be used to replace the gas with liquid in order to bring the well back under control.

Advantages, the volumetric method can be used:

- When the work string is out of a well and gas is migrating upward
- When the pumps are inoperative
- When the work string is plugged
- During a long shut-in period such as weighting up drilling fluid or making repairs to equipment
- When there is a washout in the work string that prevents displacement of the kick by a circulating method
- When the work string is a considerable distance off bottom and the kick is below the string
- When annulus pressure develops on a production or injection well because of a tubing or packer leak
- During stripping and/or snubbing operations.
- When the shut-in well pressure approaches the MAASP

Volumetric method disadvantages include:

- Does not kill the well; only controls downhole and surface pressures until kill procedures can be started
- Calculations must be performed.
- Does not work well if the kick is gas in a oil-based fluid.
- Does not work well when kick is in a highly deviated or horizontal section.

The need for the volumetric method can be determined by observing the shut in casing pressure. If the casing pressure does not increase after about 30 minutes, there is probably little gas associated with a kick. However it should be noted that if the well is highly deviated, or if the working fluid is oil-based, the gas might migrate very slowly, or not at all. If the casing pressure continues to increase above its original shut-in value, it may be assumed that gas is present and is migrating towards the surface.

A few basic assumptions are made when considering the volumetric method:

1. Boyle's gas law is used to describe and predict gas expansion. It should be noted that Boyle's Law does not consider temperature or compressibility factors.

Boyle's law

$$\boxed{P_1 V_1 = P_2 V_2}$$

Where:

$P_1$ = pressure at position 1

$V_1$ = volume at position 1

$P_2$ = pressure at position 2

$V_2$ = volume at position 2

Boyle's law states that if a certain volume of gas is allowed to expand, the pressure within the gas will decrease. This is the basis of the volumetric method. A gas bubble is allowed to expand by bleeding off a calculated volume of liquid at the surface, thereby reducing pressure throughout the well.

2. For simplicity, this discussion will assume that there is a single bubble of gas in a vertical well. It is also assumed that a kick comes from the bottom of the well. Actually a kick may be strung out in the form of many bubbles over thousands of feet. In that case, considerable gas expansion has been allowed by the time the well is shut in, which would result in lower surface pressure.
3. Bottomhole pressure has been defined as the sum, or total, of all pressures exerted on the bottom of a well. The values on the surface gauges represent lack of hydrostatic pressure. At this point the well is balanced, that is, it is mechanically balanced by the closed blowout preventers. The shut-in tubing pressure reflects the difference between the formation pressure and the hydrostatic pressure of the liquid inside the tubing. The hydrostatic pressure in the annulus is less than the hydrostatic pressure inside the tubing due to the gas influx. Therefore, the shut-in casing pressure is greater than the shut-in tubing pressure.

The density of gas is usually much less than the density of the liquid in a well, therefore gas will have a tendency to rise, or migrate up the wellbore. As the bubble of gas rises in the well, the length of the column of liquid below the bubble increases. According to Boyle's law the pressure within the bubble remains the same because the volume of the gas remains unchanged. Bottomhole pressure increases as the bubble rises and is now made up of the unchanged pressure within the bubble, plus the hydrostatic pressure of the liquid below the bubble.* At the same time, the hydrostatic pressure of the column of liquid above the gas is reduced as the bubble rises in the well.

** NOTE: The gas itself also exerts hydrostatic pressure, which is a component of bottomhole pressure, which is a component of bottomhole pressure, but it is ignorred here because this value is very small and not practical to calculate.*

Shut-in casing pressure increases reflect the higher downhole pressure being brought to the surface by the rising gas bubble. The shut-in tubing pressure will also increase proportionately because pressure is exerted equally in all directions in a closed vessel (the shut-in well).

When using the driller's method to circulate out a gas kick, the pump is used to remove the gas from the well. Bottomhole pressure is held constant by maintaining a constant circulating pressure. The correct minimum circulating pressure is the sum of the shu- in tubing pressure plus the friction pressure at a selected pumping rate.

The SITP component of the circulating pressure controls the formation as the pump moves the gas out of the well. Expansion is controlled as the gas rises. A migrating gas situation in which it is not possible or desirable to circulate may be handled in essentially the same way. Theoretically, liquid can be bled out of the annulus maintaining a constant tubing pressure in order to keep bottomhole pressure constant. In practice, safety margins are applied because it is not possible to keep the gauge pressure perfectly stable when the choke opening is changed.

There are no standard safety margins that would be appropriate for all wells. When safety margins are selected, the following considerations apply to all well control situations.

- Formation characteristics, i.e. pressure and relative permeability
- The depth and deviation of the well
- The rate at which the gas may be moving upwards in the well
- The estimated strength of the formation (MAASP)

- The type and condition of equipment to be used, especially the choke and choke manifold
- The relative accuracy of pressure gauges
- The type of working fluid in the well

The illustrated well (figure 9.37) is shut in with a gas influx on bottom. The string is on bottom. The SITP is 250 psi and the SICP is 450 psi. A working margin is selected; it is a pressure margin used in addition to the safety margin for each bleed cycle. The working margin is a number between a range of 50 psi to 100 psi that can easily be read on the gauge. The safety margin is used only on the first bleed cycle. A safety margin of 100 psi and a further working margin of 50 psi have been chosen. After some time passes, migration of the gas causes both tubing and casing pressures to increase. No bleed-off is attempted until the tubing pressure reaches 400 psi, the combination of the safety and working margins (250 + 100 + 50). Bottomhole pressure has now increased by 150 psi. At this point the choke is opened carefully and liquid is bled off from the well at a rate that allows the tubing pressure to remain between 400 and 350 psi. It may be difficult to maintain the tubing pressure perfectly, but if it stays within the 50 psi working margin, the kicking formation will be dominated by the 100 psi safety margin. Bottomhole pressure is not actually being held constant at the initial shut-in value, but is varying between 100 psi and 150 psi overbalance in order to ensure that no further gas enters the well. The casing pressure is allowed to increase during the operation. In this way the gas may be brought to the surface safely, but the gas at the surface cannot be removed until there is a means of replacing it with liquid. Figure 9.37 illustrates this constant drill pipe method.

Figure 9.37.

**Well Data**

Depth: 10,000 ft. MD/TVD

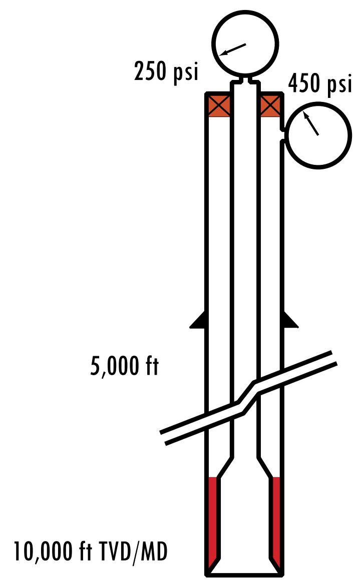
Casing: 9⅝ in. @ 5,000 ft.

Tubing: 4½ in.

BHA: 6½ in. 360 ft.

Mud: 12.5 ppg

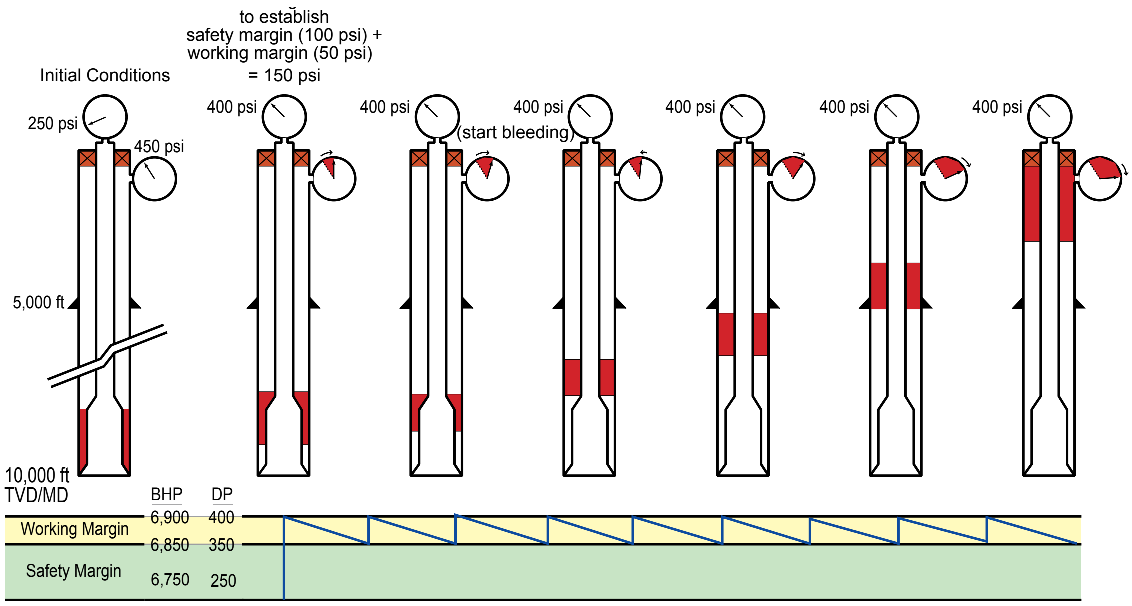
Pit Gain: 10.5 bbl




Assume that the work string in the illustrated well is plugged and no accurate shut-in tubing pressure is available. If the same volume of liquid were bled off at the choke as in the example, the gas would expand to the same degree and the resulting casing pressures would have the same values in each case. The volume of liquid bled off represents the hydrostatic pressure removed from the well, which is balanced by the rising casing pressure. This is the goal of the volumetric method. If there is no SITP available to monitor bottomhole pressure, calculations must be made in order to estimate the changing hydrostatic pressure in the well due to the removal of liquid through the choke. Gas expansion is controlled in steps by bleeding off pre-calculated amounts of liquid from the annulus. Casing pressure is intentionally held constant while bleeding off through an adjustable choke. Each barrel of liquid that is bled from the annulus causes:

- The gas to expand by one barrel
- Pressure within the gas bubble to decrease proportionately
- The hydrostatic pressure of the liquid in the annulus to decrease
- Wellbore pressures to decrease.

Figure 9.38. Gas migration.




The volume of liquid to bleed is the gas expansion required to return bottomhole pressure to formation pressure plus a predetermined overbalance. Accurate volume measurements are critical. A manual choke is sometimes preferred for greater control when bleeding the liquid. The returning liquid must be measured accurately in a small, calibrated tank. Note that it is important to bleed off liquid from the annulus at a rate that permits the casing pressure to be held constant, but casing pressure is held constant *only* while bleeding liquid. At other times, the casing pressure is allowed to increase, reflecting the effects of gas expansion and the reduction of hydrostatic pressure in the well. Thus, volumetric control is accomplished in a series of steps that causes the bottomhole pressure to rise and fall in succession. To calculate the hydrostatic pressure reduction if one barrel of 12.5 ppg liquid is removed from the well (figure 9.39):

$$\boxed{\text{psi/bbl} = \text{pressure gradient}_{\text{psi/ft}} \div \text{cylindrical capacity}_{\text{bbl/ft}}}$$

Solve for the pressure gradient of the working fluid:

12.5 * 0.052 = 0.65 psi/ft

There are three annular capacities given in the example, therefore:

- Casing/DP annulus is 0.05451 bbl/ft therefore:

  5,000 * 0.05451 = 272.55 bbl

- OH/DP annulus is 0.04934 bbl/ft therefore:

  4,640 * 0.04934 = 228.94 bbl

- OH/BHA annulus is 0.02908 bbl/ft therefore:

  360 * 0.02908 = 10.47 bbl

- 272.55 + 228.94 + 10.47 = 511.96 bbl in the annulus
- 511.96 ÷ 10,000 = 0.0512 bbl/ft average annular capacity
- 0.65 ÷ 0.0512 = 12.69 psi/bbl average pressure exerted per barrel in the annulus

Figure 9.39. Sample well.

**Well Data**

Depth: 10,000 ft. MD/TVD

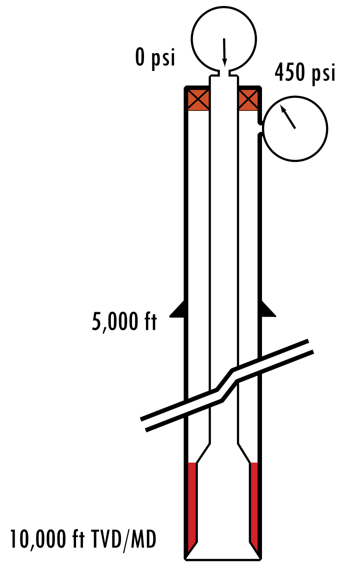
Casing: 9⅝ in. @ 5,000 ft.

Drill pipe: 4½ in.

BHA: 6½ in 360 ft.

Mud: 12.5 ppg

Pit Gain: 10.5 bbl.




The annulus around the BHA represents the highest pressure per barrel (0.65 ÷ 0.02908 = 22.35 psi/bbl) and therefore provides the greatest safety, however the BHA is only 360 feet long and in this case it is probably safe to use the lower value. However, it must be stressed that this is a well-specific judgment. Other factors, such as formation strength must be considered when selecting pressures and bleed-off cycles.

Convert the working margin of 50 psi to bleed-off barrels per cycle:

50 psi ÷ 12.69 psi/bbl = 3.94 bbl

Let four barrels be equivalent to 50 psi. Once safety and working margins are selected and the bleed-off cycle versus pressure per volume values are determined, the method is implemented by repeating two distinct steps.

Step 1. The gas is allowed to migrate and wellbore pressures increase.

Step 2. Liquid is bled (holding casing pressure constant with the choke) and the wellbore pressures decrease. The steps are repeated until gas reaches the surface or other kill operations are initiated. In this way bottomhole pressure is held within a range of values that is high enough to prevent another influx and, ideally low enough to prevent formation breakdown.

The examples given are simple and offered only as an explanation of the volumetric principle. Other factors in the field will influence the selection of safety margins, bleedoff volumes, etc. For example, the rate of the gas migration rate can be estimated by timing the pressure increase on the casing gauge, but there is no assurance that the gas will continue to migrate at a constant rate.

The rate of migration may be estimated. Suppose the gauge value increased 100 psi in 40 minutes.

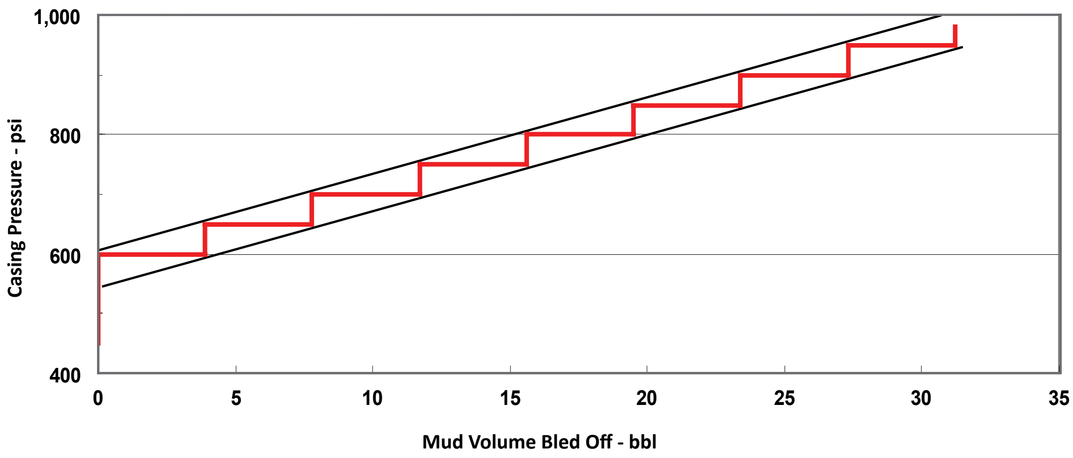
$$\boxed{\text{Migration}_{ft/hr} = \text{Gauge Increase}_{psi} \div \text{Minutes} \div \text{Pressure Gradient}_{psi/ft} * 60 \text{ min/hr}}$$

100 psi ÷ 40 min ÷ 0.65 psi/ft * 60 min/hr = 231 ft/hr

If the gas influx is at the bottom of a cased hole, a fairly accurate estimate of the original kick height may be made, providing the measured pit gain is accurate. Even so, other factors (many unknowable) come in to play when the gas begins to rise in the well. The pressure within the gas is affected by changes in temperature as well as the type(s) of gas encountered and also by the degree of solubility of the gas. Hydrocarbon gases are highly soluble in oil-based fluids, especially in deep wells. With regard to drilling in open hole, the length of the rising gas (assuming it remains a unified bubble) will change with changes in annular diameters. The bubble would obviously be longer around a large diameter bottomhole assembly and shorter in a washed out section of open hole. These changes in height affect the annular hydrostatic pressure and consequently, the casing pressure.

Figure 9.40 plots casing pressure against liquid volume bled off. Note that no liquid is bled until the casing pressure has increased from its shut-in value of 450 psi to 600 psi, the combination of the safety and working margins. At that point, 4 barrels of liquid is bled from the well while holding casing pressure constant at 600 psi. When 4 barrels have been removed from the well, the choke is closed and the casing pressure is allowed to increase to 650 psi before the next bleed-off begins. The

Figure 9.40. Volumetric well control.



maximum pressure in the illustration is about 980 psi. At that point in the example, the gas is at the surface. If the safety and working margins were removed at this point, an estimate of the barrels required to fill the well can be made.

Figure 9.41 is a plot of bottomhole pressure against liquid bled off during the operation. Although the BHP is approximately constant throughout, the graph indicates a slight increase over the entire operation. The increase is due in part to our selecting 4 barrels as a practical bleed cycle volume. Calculations indicated that 50 psi is actually equivalent to 3.94 barrels in this well. Also, as the gas migrated up the well and moved into different annular dimensions, the true hydrostatic pressure per barrel changed. However, when planning the operation, we used an average hydrostatic pressure per barrel over the entire well.

Figure 9.41. Volumetric well control.

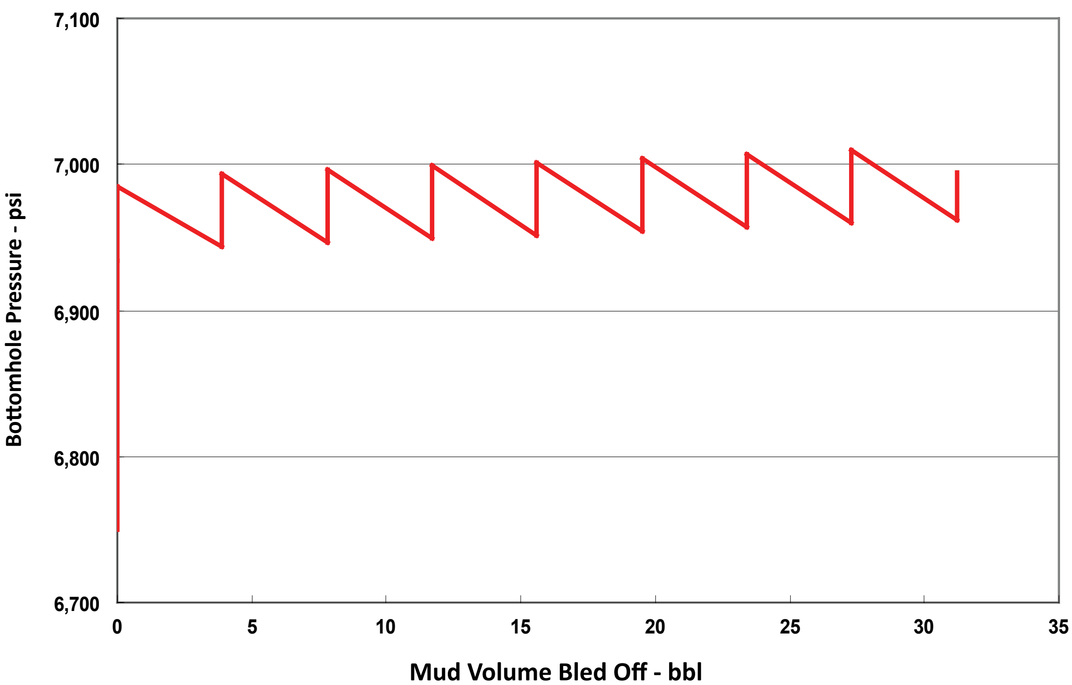
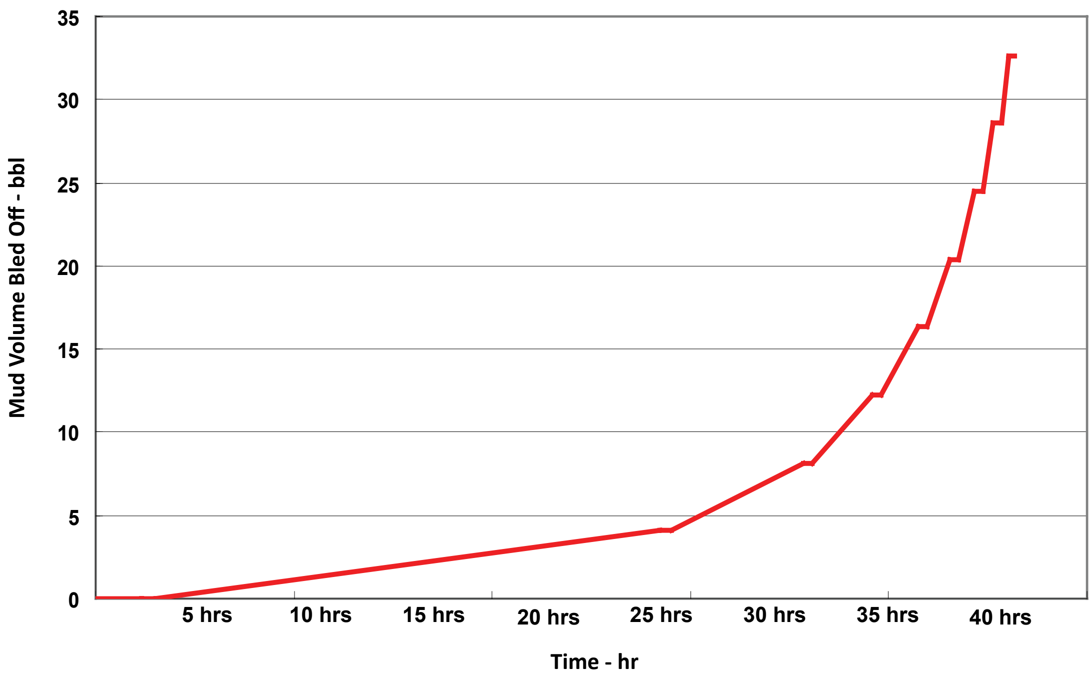


Figure 9.42, a plot of liquid bled off versus time, illustrates several interesting facts. Assuming that the gas was migrating steadily at a rate of 250 ft/hr, it required more than two hours (about 150 minutes) before the casing pressure increased by the safety and working margins, and that 1,400 minutes, more that 23 hours, passed before we finished bleeding off our first four barrels of liquid (at a constant casing pressure of 600 psi). At the end of the operation a total of about 31 barrels of liquid were bled from the well.

Figure 9.42. Volumetric well control.




## Summary of the Volumetric Method

Procedure for volumetric method:

1. Calculate the hydrostatic pressure increase:

$$HP_{psi/bbl}\ \text{Increase} = \text{Pressure Gradient}_{psi/ft} \div \text{Annular Capacity}_{bbl/ft}$$

2. Calculate volume to bleed each cycle:

$$\text{Volume to bleed}_{bbl/cycle} = \text{Working Margin}_{psi} \div \text{Hydrostatic Pressure}_{psi/bbl}$$

3. Make a casing pressure vs. volume to bleed schedule. See the example figure 9.40.
4. Shut in the well.
5. Allow SICP to increase by the safety margin without bleeding. (Used only on the first bleed cycle.)
6. Allow SICP to increase by the working margin without bleeding. Go to step 7 when the working margin is reached.
7. Maintaining SICP constant, bleed calculated volume of fluid from step 2 into tank until the volume is bled.*
8. Repeat steps 6 and 7 until gas is at surface or another procedure is implemented.

*Hold SICP constant while bleeding fluid, open the choke enough to bleed volume and still maintain the SICP. If the SICP goes below the safety margin another kick will result.

Failure to maintaining constant bottomhole pressure equal to formation pressure, whether due to not following the well control procedure, using the incorrect procedure for the well conditions or equipment failure, may result in an additional influx (pressure maintained too low) or lost circulation (pressure maintained too high).

### Summary

The volumetric method is used to control bottomhole pressure while allowing migrating gas to expand as it rises in a well.

### The Lubricate-and-Bleed Method

For a gas well, or gas filled tubing, an alternative method is to use the lubrication kill. In this method, varying amounts of mud are lubricated into the well, and the well pressure is bled off after each batch of mud has been lubricated into it.

The lubricate-and-bleed method is an application of the volumetric method and is used to remove gas safely at the surface when it is not possible or practical to circulate the gas out. Liquid is pumped into the well and allowed to fall down through the gas into the annulus. Sufficient time must be allowed for the liquid to fall through the gas, thus increasing the annular hydrostatic pressure. Once the annular hydrostatic pressure is increased as a result of the pumped liquid, casing pressure may be reduced by that value.

The operation entails pumping a carefully measured volume of liquid into the well. The height of the pumped liquid is estimated, and then converted to hydrostatic pressure. This value will subsequently be bled off on surface.

It is important to avoid excessive pressures when pumping liquid into the well. There will be some compression of the gas when injecting the liquid. The pump forces liquid into the well, which increases the pressure imposed throughout the well. Pressure, and therefore injected liquid volume, should be limited according to the specific well characteristics.

A high-pressure/low-volume pump is best for this operation. After injecting the liquid, a judgment must be made as to the time it takes the liquid to fall through the gas. It is important for the liquid to fall below the gas to ensure that only gas is bled off. Waiting time will vary depending on well geometry, the type of fluid injected, and the section of the well into which it finally settles. This may take 30 minutes or longer. When bleeding gas, the casing pressure is reduced by the hydrostatic gain, *plus* the increase in pressure from gas compression that was noted when the liquid was injected, *plus* any increase due to gas migration. The operation is completed when the gas has been removed and the well is full of liquid.

Advantages, the lubricate-and-bleed method can be used:

- When the work string is out of the hole.
- When the work string is plugged.
- When there is a washout in the work string that prevents displacement of the kick by a circulating method.
- When the work string is a considerable distance off bottom and the kick is below the string.

- When the SITP pressures approaches the rated working pressure of the wellhead or tubing.
- When the pump pressure may exceed the wellhead or tubing rated working pressure limits.
- When there is lost circulation in the upper annulus and rated working pressure of the wellhead or tubing cannot withstand pressures of conventional circulation.

Lubricate-and-bleed can also be used to remove persistent casing pressure and still maintain constant bottomhole pressure on production wells.

Lubricate-and-bleed method disadvantages include:

- Long waiting time required for lubriating kill liquid to fall through the gas
- Will not kill the well if the current fluid weight is used
- Weight materials must be on hand
- Kill fluid must be mixed

*EXAMPLE*

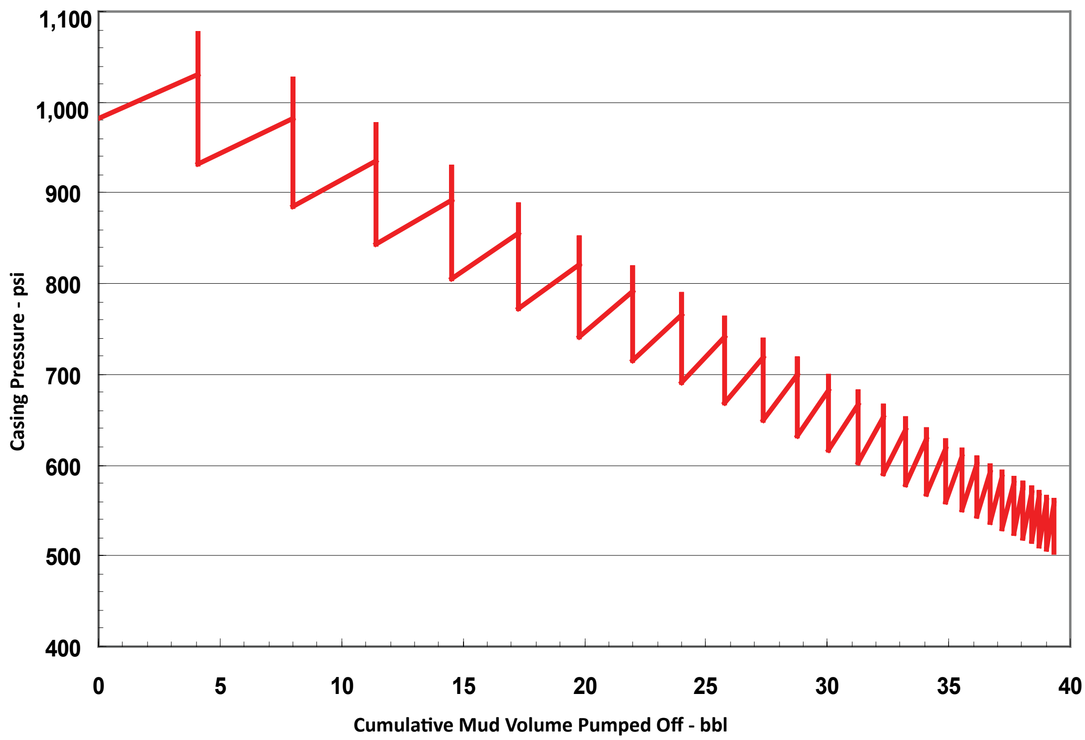
Using data from previous examples:

Surface pressure (SICP): 1,000 psi

Open hole: 8.5 in

Tubing: 4.5 in, 16.6 lb/ft

Figure 9.43. Lubricate-and-bleed.

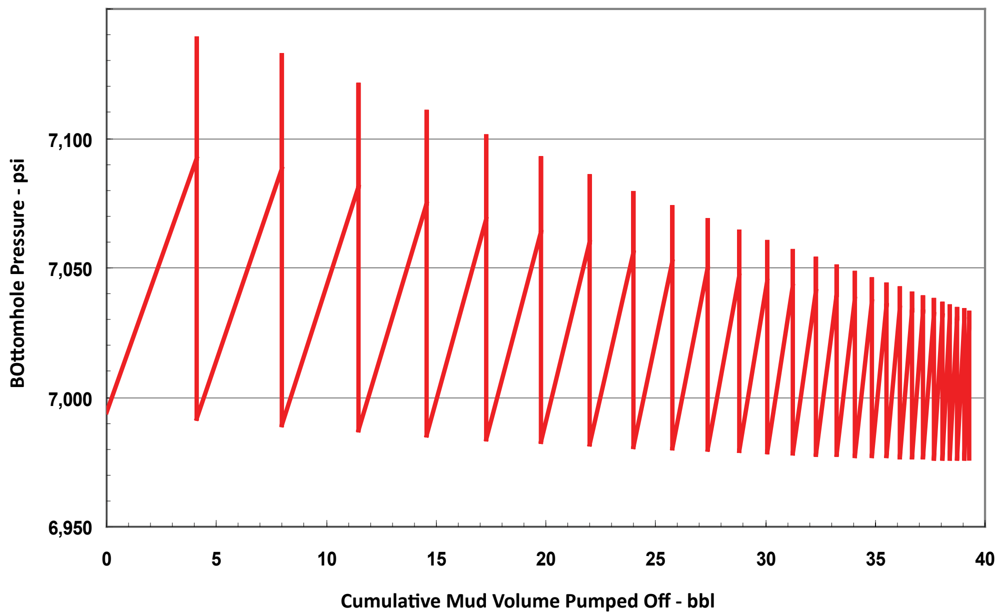


BHA: 6.5 in 360 ft

Mud weight: 12.5 ppg

Pump output: 0.044 bbl/stroke

Figure 9.44. Lubricate-and-bleed.




If it is decided to increase surface pressure by a given value, e.g., 100 psi, throughout the procedure, less and less liquid per pumping cycle will be required to achieve the 100 psi increase as the gas volume in the well is reduced.

It is impossible to accurately predict the volume/pressure relationship during the entire operation. In the example below, 50 psi is chosen because, 1) it is a relatively low-pressure increase and, 2) it is our chosen working margin.

Determine the pressure exerted by one barrel in the casing/tubing, annulus.

0.65 psi/ft ÷ 0.05451 bbl/ft = 11.9 psi/bbl

Determine the volume of liquid equivalent to 50 psi hydrostatic pressure.

50 psi ÷ 0.65 psi/ft = 76.9 ft

76.9 * 0.05451 bbl/ft = 4.19 bbl

Determine the pump strokes required to pump 4.19 bbl

4.19 bbl. ÷ 0.044 bbl/stroke= 95.3 or 95 strokes

The pump is brought online carefully to overcome wellbore pressure and liquid is pumped into the well until the casing pressure increases by 50 psi or until 95 strokes have been pumped, whichever comes first. At this point a judgment must be made as to the time to allow the injected liquid to fall beneath the choke and the full hydrostatic effect has been gained. After the allotted time has passed and the casing pressure stabilized, the choke is opened and the casing pressure is reduced according to the increase in hydrostatic pressure plus the pressure increase due to compression. As the operation continues, the volume per stage will decrease and the pressure due to compression will increase.

This procedure, injecting fluid, waiting for it to change place with the gas in the well, and then reducing casing pressure, is repeated until the annulus is full of fluid and casing pressure is reduced as much as feasible.

If the well was underbalanced, the space that the gas occupies in the wellbore must be replaced with a liquid heavy enough to compensate for the underbalance. This may not be predictable or possible if the well is to be killed. Figure 9.44 illustrates the lubricate-and-bleed operation. Notice that if 50 psi is used as the target pressure increase throughout, the volume of liquid pumped into the well on each step must be reduced. As the well is filled with liquid, less pumped volume is required to achieve the 50 psi target. Some well-specific decisions must be made as to how the final bleed-offs will be accomplished. The techniques used to remove the last of the surfacing gas will depend upon the pumps being used and company preference.

Summary of the lubricate-and-bleed method:

1. Determine a working margin (usually the same margin as used for the volumetric procedure.)
2. Calculate the volume of fluid to equal working the margin.
3. Calculate the number of stokes required to pump the volume calculated in step 2.
4. Slowly pump fluid into annulus of the shut-in well to increase SICP by the working margin or calculated number of stokes.
5. Wait for the fluid to fall through the gas (be patient--it may take 30 minutes or longer.)
6. Measure the tank and calculate the hydrostatic pressure increase in the wellbore.

$$\boxed{HP_{psi}\ \text{Increase} = \text{Volume Pumped}_{bbl} * HP_{psi/bbl}}$$

7. Bleed dry gas from the choke to reduce casing pressure by the working margin, plus the hydrostatic pressure increase. (The wait time was not sufficient if fluid comes up with the gas.)
8. Repeat steps 4 through 8 until gas is removed and the well is full of fluid.

The method consists of the following steps:

1. Calculate the capacity of the tubing and pump half this volume of kill fluid to the well.
2. Observe the well (0.5 to 1 hour), the tubing head pressure will drop due to the hydrostatic head of the initial kill mud pumped. When the tubing head pressure is constant, the next step is taken.
3. Pump kill fluid for about three to five minutes, and not more than about 10 barrels, and making sure that the tubing head pressure does not go more than 200 psi above the observed static pressure taken in step 2.
4. Bleed off gas from the tubing at a high rate immediately after pumping the batch of kill fluid.
   - The amount of drop in tubing head pressure could be equal to the amount of hydrostatic head of the mud pumped. If the bleeding off is not carried out quickly, the additional pressure due to the extra hydrostatic head will cause mud losses and the sooner the tubing head is reduced, the smaller the loss will be.
5. Repeat the pump and bleed and observe the tubing head pressure after each step. If necessary, reduce the quantity of kill fluid if the amount of gas being bled off is excessive. After repeated pumping of batches of mud and the well is deemed dead, observe the well for a considerable period before starting any further work.

6. If the fluid level is too low, then the kill fluid has been too heavy and additional lighter fluid should be added until the well is full of fluid.
7. Alternatively, if the well is not killed, it could be that too much gas was bled off or some of the kill fluid was blown out of the well during the bleed off cycle, resulting in gas flowing into the wellbore. Wait for the well to settle and after reappraising the situation, carry on with the batch and bleed procedure until the well is completely dead.

## Pump Requirements

The normal pump equipment required for a well kill is:

- Pump unit
- Storage tank
- Pill tank (if necessary)
- Mixing tank
- Interconnecting pipe work with valving.
- Refer to figure 9.47 for a typical pumping hook-up.

### *LUBRICATE-AND-BLEED LEARNING EXAMPLE PROBLEM:*

A well has a MD and TVD of 9,445 feet A production packer is at 9,300 feet. Perforations begin at 9,310 feet TVD and extend to the bottom of the well. Tubing with an ID of 2.025 inches extends down to the top of the perforations. The SITP is 3,380 psig.

(a) Assuming the well contains dry gas with an average gradient of 0.12 psi/ft, what is the bottomhole pressure (formation pressure)?

Solution (a):

$FP_{psi} = BHP_{psi} = SITP_{psi} + HP_{psi}$

$FP_{psi} = BHP_{psi} =$ SITPpsi + Pressure $Gradient_{psi/ft}$ * $Depth_{ft}$ (TVD) to top of perfs

FP = 3,380 psi + 0.12 psi/ft * 9,310 ft

FP = 3,380 psi + 1,117 psi

FP = 4,497 psi

(b) What kill weight fluid is required to achieve a 200 psi overbalance?

Solution (b):

$KMW_{ppg} = (FP_{psi} + Overbalance_{psi}) \div (0.052 * TVD)$

KMW = (4,497 + 200) ÷ (0.052 * 9,310)

KMW = 4,697 ÷ 484.12

KMW = 9.7 ppg

(c) Inside the tubing, what hydrostatic pressure is equivalent to 1 barrel of kill weight fluid?

Solution (c):

Calculate the number of vertical feet in the tubing occupied by 1 barrel of kill weight fluid. Then find the hydrostatic pressure of that one 1 barrel.

Capacity (in tubing) = $ID^2 \div 1{,}029.4$

Capacity (in tubing) = 2.025 * 2.025 ÷ 1029.4 = 0.00398 bbl/ft

Feet = Barrels ÷ Capacity bbl/ft

Feet = 1 barrel ÷ 0.00398 bbl/ft = 251 ft (per barrel of fluid)

$HP_{psi/bbl}$ = 0.052 * KMW * Feet of KMW per barrel kill weight fluid

HP = 0.052 * 9.7 * 251

HP = 126.6 psi/bbl (hydrostatic pressure of 1 barrel of kill weight fluid)

(d) How many barrels of kill weight fluid must be added to the well initially to provide a safety margin of 200 psi?

Solution (d):

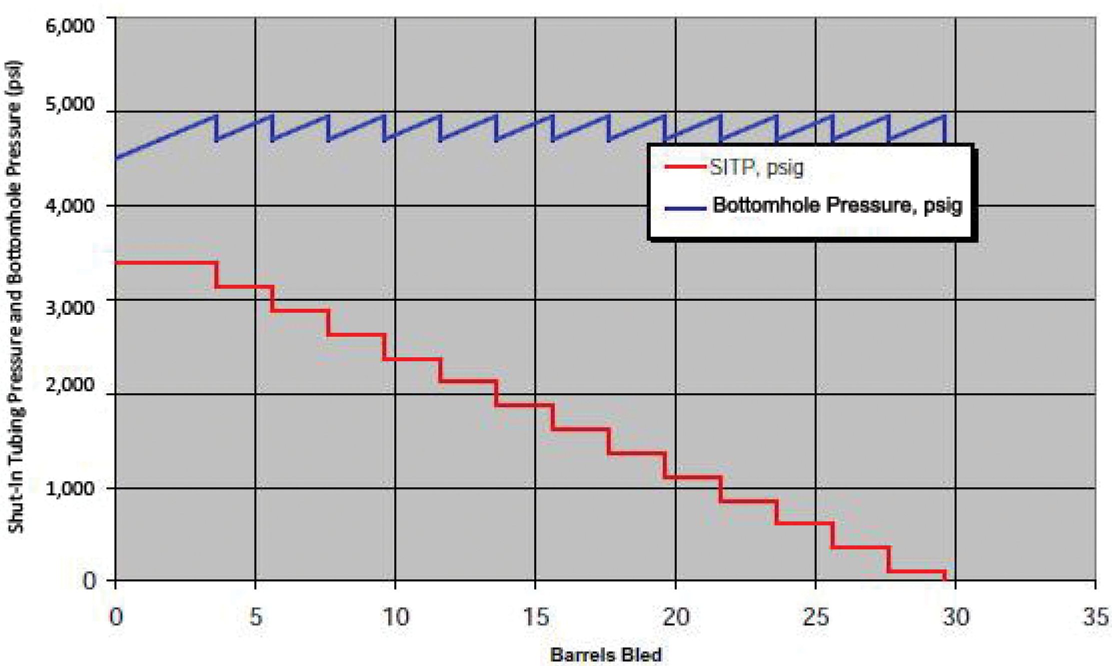
Barrels for 200 psi safety margin = Safety Margin psi ÷ hydrostatic pressure per 1 barrel

Barrels for 200 psi safety margin = 200 psi ÷ 126 psi/barrel

Barrels for 200 psi safety margin = 1.59 barrels

(e) Construct a table and chart showing surface pressures and bottomhole pressures for the steps in the lubricate-and-bleed process for this well; identify the safety margin and the working margin. Neglect compression of gas.

Figure 9.45. Chart for lubricate-and-bleed example problems.



The example worksheet uses a safety margin of 200 psi and a working margin of 252 psi. Margins this large are possible only with relatively strong reservoir fracture pressures (formation integrity). Often, safety margins must be only 50 to 100 psi and working margins 100 psi or less.

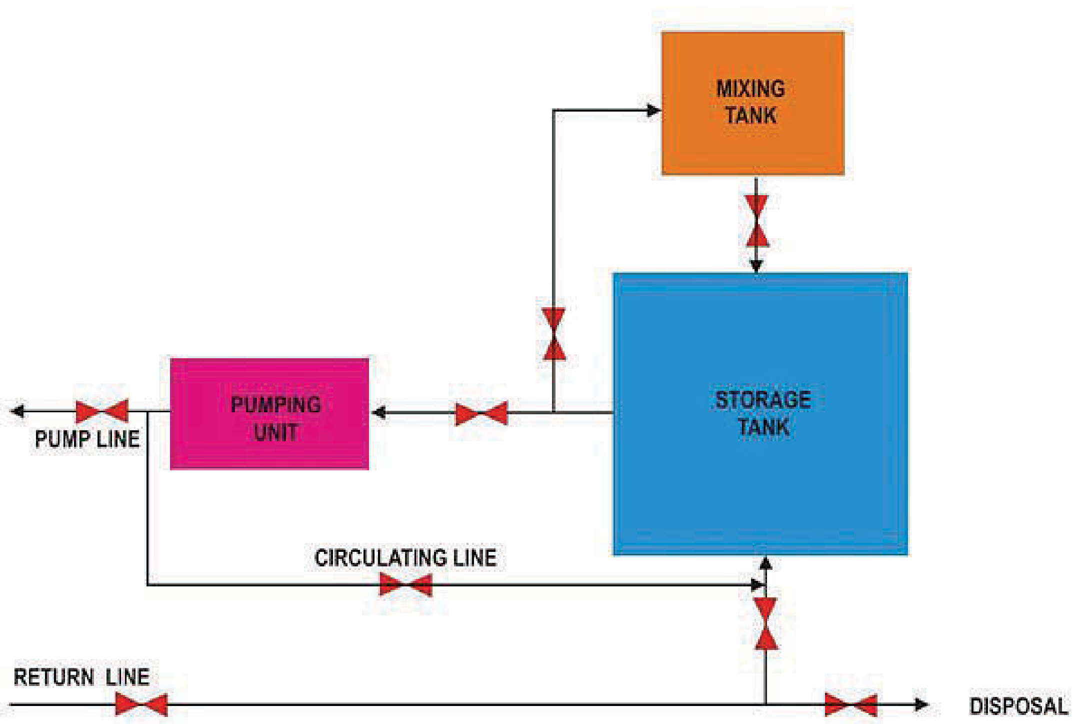
Figure 9.46.

*EXAMPLE LUBRICATE-AND-BLEED WORKSHEET*

| Step | Activity | Safety Margin psig | Working Margin psig | Volume Pumped bbl | Total Vol Pumped bbl | Pressure Bled psig | SITP psig | BHP psig |
|---|---|---|---|---|---|---|---|---|
| 0 | Well shut-in | 0 | | 0 | 0 | 0 | 3,380 | 4,497 |
| 1 | Add safety margin | 200 | | 1.59 | 1.59 | 0 | 3,380 | 4,697 |
| 2 | Pump 2 barrels | 200 | 252 | 2 | 3.59 | 0 | 3,380 | 4,979 |
| 3 | Bleed equivalent HP | 200 | | 0 | 3.59 | 252 | 3,128 | 4,697 |
| 4 | Pump 2 barrels | 200 | 252 | 2 | 5.59 | | 3,128 | 4,979 |
| 5 | Bleed equivalent HP | 200 | | 0 | 5.59 | 252 | 2,876 | 4,697 |
| 6 | Pump 2 barrels | 200 | 252 | 2 | 7.59 | | 2,876 | 4,979 |
| 7 | Bleed equivalent HP | 200 | | 0 | 7.59 | 252 | 2,624 | 4,697 |
| 8 | Pump 2 barrels | 200 | 252 | 2 | 9.59 | | 2,624 | 4,979 |
| 9 | Bleed equivalent HP | 200 | | 0 | 9.59 | 252 | 2,372 | 4,697 |
| 10 | Pump 2 barrels | 200 | 252 | 2 | 11.59 | | 2,372 | 4,979 |
| 11 | Bleed equivalent HP | 200 | | 0 | 11.59 | 252 | 2,120 | 4,697 |
| 12 | Pump 2 barrels | 200 | 252 | 2 | 13.59 | | 2,120 | 4,979 |
| 13 | Bleed equivalent HP | 200 | | 0 | 13.59 | 252 | 1,868 | 4,697 |
| 14 | Pump 2 barrels | 200 | 252 | 2 | 15.59 | | 1,868 | 4,979 |
| 15 | Bleed equivalent HP | 200 | | 0 | 15.59 | 252 | 1,616 | 4,697 |
| 16 | Pump 2 barrels | 200 | 252 | 2 | 17.59 | | 1,616 | 4,979 |
| 17 | Bleed equivalent HP | 200 | | 0 | 17.59 | 252 | 1,364 | 4,697 |
| 18 | Pump 2 barrels | 200 | 252 | 2 | 19.59 | | 1,364 | 4,979 |
| 19 | Bleed equivalent HP | 200 | | 0 | 19.59 | 252 | 1,112 | 4,697 |
| 20 | Pump 2 barrels | 200 | 252 | 2 | 21.59 | | 1,112 | 4,979 |
| 21 | Bleed equivalent HP | 200 | | 0 | 21.59 | 252 | 860 | 4,697 |
| 22 | Pump 2 barrels | 200 | 252 | 2 | 23.59 | | 860 | 4,979 |
| 23 | Bleed equivalent HP | 200 | | 0 | 23.59 | 252 | 608 | 4,697 |
| 24 | Pump 2 barrels | 200 | 252 | 2 | 25.59 | | 608 | 4,979 |
| 25 | Bleed equivalent HP | 200 | | 0 | 25.59 | 252 | 356 | 4,697 |
| 26 | Pump 2 barrels | 200 | 252 | 2 | 27.59 | | 356 | 4,979 |
| 27 | Bleed equivalent HP | 200 | | 0 | 27.59 | 252 | 104 | 4,697 |
| 28 | Pump 2 barrels | 200 | 252 | 0.8524 | 29.59 | | 104 | 4,979 |
| 29 | Bleed equivalent HP | 200 | | 0 | 29.59 | 104 | 0 | 4.697 |

The example ignores gas compressibility, which does not affect the results in the early stages of the lubricate-and-bleed method. However, in the later stages, compressibility effects may become important. In practice, the volume pumped per pumping cycle may need to be reduced as the volume of liquid in the well increases. A reduction is often necessary because the volume of gas is continually reduced. When the fluid pumped into the well per cycle becomes a larger fraction of the volume of gas in the well, gas compressibility will cause the surface pressures to increase significantly. The total surface pressure plus the hydrostatic pressure of the kill fluid can exceed the reservoir fracture pressure and result in massive fluid losses. Hence, be prepared to adjust (decrease) the volume pumped into the well per pumping step in the later stages of the kill process. Lubricate-and-bleed is usually a very slow process.

Figure 9.47. Typical pump hookup.




An alternative method of using a circulation kill method is to use coiled tubing that can be run into the well under pressure. The well can then be killed by pumping mud down the small bore coiled tubing and backup the tubing/coiled tubing annulus. The procedure is the same as for the reverse circulation kill, though, it is actually a forward circulation procedure. The back-pressure is held as before on the tubing to control the bottomhole pressure.

This method would be used where it was not possible to establish communication around the tubing shoe or through a sliding sleeve, and where it is not desirable to bullhead.

### Well Control Methods when Running or Pulling Casing

Well control procedures should be a part of the pre-job safety meeting prior to running, pulling or cementing casing. Well control methods to consider when a kick occurs when running or pulling casing include:

- Circulate out the kick. Reverse circulation will not be possible if there is a float valve.
- Strip the casing to the bottom: this should only be attemped if the casing guide shoe is within a few joints of the bottom of the hole. Due to the large size of the casing, the weight of the casing may not be sufficient to overcome the wellbore force, pushing the casing out. If the casing is being forced out of the wellbore, it will need to be tied down to the substructure and filled with drilling fluid immediately.
- Strip out the casing and strip in or snub in a kill string.
- Use the lubricate-and-bleed method to kill the well.
- Use the volumetric method to control downhole and surface pressures until kill procedures can be started.

### Well Control Methods when Cementing Casing

It may not be possible to circulate out a kick during a cementing operation or waiting for cement to dry. Well control methods to consider when a kick occurs while cementing casing include:

- Shut in the well and allow the cement to set.
- Displace out the cement if the top wiper plug has not been dropped.
- Use the lubricate-and-bleed method to kill the well
- Use the volumetric method to control downhole and surface pressures until kill procedures can be started.

BOPs should not be removed until the cement has dried and the cement has been pressure tested.

### Well Types and Kill Method Selection

The technique chosen to kill a producing well prior to a conventional well intervention depends on the following (but not limited to) factors:

1. The type of well, (oil, gas, oil and gas, liquid-filled)
2. Formation characteristics (permeability, injectivity)
3. Potential of the kill fluid to damage the formation, and
4. Pumping capability

There is no “cookbook” procedure to determine the best kill method for any well. The following “rules of thumb” serve as guidelines in making a selection:

*Oil wells*: Oil may prove difficult to inject back into a formation, especially if the reservoir has low permeability. The viscosity of oil also decreases its ability to flow into the tiny micro-fractures created when the formation integrity is exceeded. Also, low pumping capability may also increase the difficulty of injection of the wellbore fluids into the rock from which they came. Hence, oil wells are often a good candidate for removal by circulation using either the driller’s method or the wait-and- weight method.

*Gas wells*: When a gas well is shut in, there may be a column of gas extended all the way to the surface. The SITP is likely to be very high. Working around high-pressure gas is always uncomfortable and risky. For this reason, bullheading may be good choice if the pump can deliver the necessary pressure needed to push the gas back into the well at a rate high enough to overcome the slip velocity of the gas in the fluid. Such a gas well might be a good candidate for using the bullhead method. For dry gas wells, lubricate-and-bleed is often used to kill the well prior to rigging up for a well intervention. If the coiled tubing is already in the well, circulation of the well is a feasible option.

*Oil/gas wells:* If shut in for a period of time, there will probably be separation of the oil and gas, with the gas rising above the oil. Generally, circulation is the preferred method for oil, but having a layer of gas on top of the oil may complicate things, especially if the gas fills the wellbore all the way to the surface. Because gas is compressible, starting circulation with gas all the way to the surface makes choke control very difficult. Hence, the lubricate-and-bleed method might be used initially to remove the majority of the gas in the well, followed by the driller's method to remove the remainder of the wellbore fluids.

*Liquid-filled wells*: For the purposes of well control, a liquid-filled well is defined as a well filled with water, brine, mud, workover fluid or completion fluid. If the well is underbalanced, then there will be surface pressure, even if there are no hydrocarbons in the well. It is not desirable to bullhead these liquids into the formation, not even into a formation with high-permeability, because the liquids may damage the reservoir's pore spaces. In this case, a circulation with the driller's method or alternately the wait-and-weight method would be appropriate.

Proceed with care when applying any of the above guidelines to a well; there are always exceptions to the rule.

# Special Situations 10

## Upon completion of this chapter, the student should be able to:

- Discuss indicators of lost circulation.
- Explain the differences between swabbed kicks in horizontal and vertical sections.
- Identify possible processes to reestablish circulation.
- Discuss methods and techniques to stop underground flows.
- Identify procedures of the low choke method.
- Explain how to shut in a well when it is off bottom.
- Discuss the process of stripping back into the well.
- Identify kick results relative to the hole size.

*Excerpt from "Guide to Blowout Prevention, Second Edition, Revised November 2011" manual by Well Control School*[1]

The previous chapters have discussed the basic causes of blowouts and techniques commonly used to control kicking wells. The examples given have been based on the simplest of conditions, that is, vertical wells with the influx of formation fluids near the bottom of the well, consistent well dimensions, and all rig equipment functioning properly. Such perfect conditions only apply to a small percentage of the wells drilled around the world. Data analyzed in one area indicated that over a three-year period only twenty-two percent of well control incidents fell into this "classic" category. This chapter discusses situations in which basic well control techniques are adapted to some common field problems and complications that may arise during a well killing operation.

To minimize the potential for a well control situation during any operation, it is beneficial to develop a checklist of factors to consider. An example checklist might include the following:

1. How will the wellbore be monitored during this operation?
2. What can happen or go wrong during this operation?
3. Is there a plan in place to mitigate what might go wrong?
4. Is the right equipment installed or on site and has it been tested?
5. Have the hazards of and procedures for the operation been communicated to the crew?

## Safety Factors When Circulating

There has been a good deal of research concerning the recommendation of adding a safety factor when killing a kicking well. The question that arises is: “What is an appropriate safety factor and how is it selected and applied?” If it were decided that extra pressure should be applied by choke manipulation, say 200 psi, it must be realized that in this case the safety factor not only increases bottomhole pressure but also exerts an extra 200 psi throughout the well including at the casing shoe. The casing shoe is often considered to be the most fragile area in the open borehole. This extra 200 psi safety factor could also be detrimental to weak formations and surface pressures.

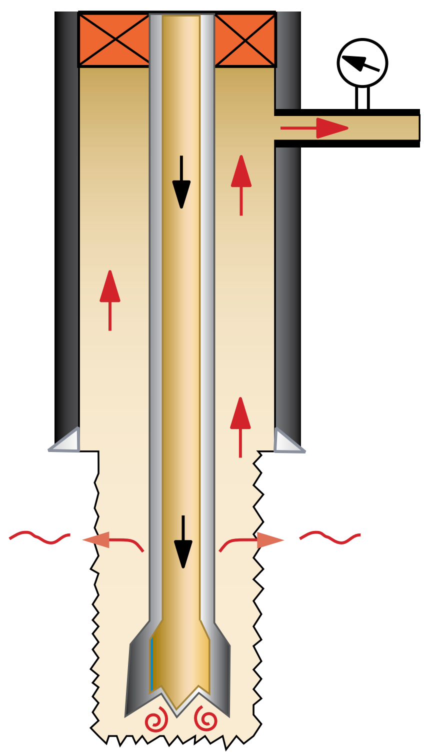
Another means of adding a safety factor is to circulate a heavier kill mud than calculated to balance the formation. Circulating the heavier fluid would also result in greater pressure at the casing seat than if the calculated kill mud was used. However, if the hydrostatic pressure increase due to the heavy fluid were substracted from the annular pressure loss, there would be no safety factor exerted on the formation. Total pressure at the casing shoe might actually be less due to the increased hydrostatic pressure in the annulus. Also, circulating time would be less if the heavier kill fluid represented a trip margin. But, if for some reason the well had to be shut in after the kill fluid had reached the bit, pressure on the casing shoe would increase.

Major operators consulted for this text prefer to kill a well with the calculated kill fluid and then add trip margins or safety margins after the kill operation has been completed. Once the safety of personnel and the equipment have been assured, avoiding an underground blowouts becomes a primary goal of the operation.

## Lost Circulation and Underground Blowouts

Partial lost circulation is not always easy to diagnose when it first begins during a well kill operation. Although the casing pressure may fluctuate, the circulating pressure will not indicate a problem immediately because the loss is in the annulus. Therefore, the circulating friction has not changed appreciably. If there is gas associated with the kick, the gas will expand as it rises and one might expect the mud pits will gain volume. Also, if barite is being added to the system, it will cause a pit gain of about one barrel for every 15 sacks (1,500 pounds) mixed. In this case, the increase in pit gain can mask losses to the formation. As the losses continue to worsen and the casing pressure decreases steadily the drill pipe pressure will also decrease. By the time all this happens, the formation may be taking fluid steadily.

Figure 10.1. Partial loss of return.



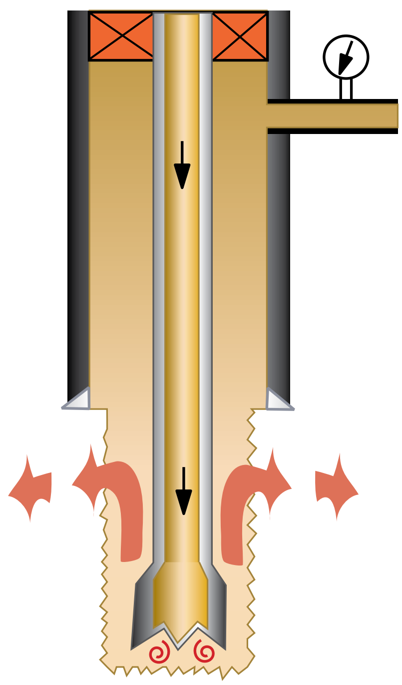
Underground blowouts occur when there are both a kicking zone and a thief zone in the same open annulus. The thief zone may be above or below the kick zone. Both cases are sometimes difficult to recognize promptly and nearly always difficult to control or cure. Once a subsurface blowout develops the accompanying costs are staggering. The potential damage to the environment is unacceptable and future production of the well is lost.

In the case of total lost returns, depending on the severity of the developing underground blowout, pressures may change rapidly.

- The casing pressure may increase to high levels.
- Communication between drill pipe and annulus may be lost.
- Drill pipe pressure, after decreasing suddenly, may go on vacuum.
- Raising or lowering the work string cause no change in casing pressure.
- There may be sudden drill pipe vibration or drag when moving the pipe against blowout zones.
- The BOP stack may vibrate violently.
- Shut-in pressures will be lower than otherwise expected.
- The annulus pressure may begin to increase due to gas migration as formation fluid fills the wellbore. Fluids may have to be pumped down the annulus to keep pressure below surface and/or casing limitations.

It is difficult to diagnose and recomment the proper treatment for lost circulation in a kicking well because there is no accurate communication between circulating pressure and casing pressure. The U-tube model does not apply, therefore accepted bottomhole pressure methods cannot be used. If pumping slowly into the drill string does not cause an increase in annulus pressure the well should be shut in. An underground blowout is likely the cause.

Figure 10.2. Full loss of return.



Some techniques that have been used successfully are listed below. However, there is no substitute for specific field experience. A technique that has worked in one area might very well be a huge mistake somewhere else.

- If extra pressure has been held on the well as a safety margin it should be removed. It is possible that if the extra pressure is removed, especially when the losses first begin, the thief zone will heal and the kill can continue as planned.
- The circulating rate can be reduced in order to reduce the annular friction exerted on the wellbore. The rate is reduced by holding the casing pressure at its present value while the pump rate is adjusted. When the pump rate is correct and the casing pressure is at the correct value, the new circulating pressure will be correct.
- Allow the well to "rest". Pick up off bottom and shut the well in. Sometimes the thief zone will heal. It goes without saying that during this static period pressure gauges must be monitored carefully and any pressure changes documented. If the wellbore pressure begins to increase, bottomhole pressure can be controlled by bleeding off at the choke, holding the drill pipe pressure constant.
- In some areas, a slug of heavy fluid has been spotted on bottom in order to suppress, or kill the kick. Although rare, this has worked in certain areas and where the kick is small

and the loss zone is above the kick zone. Once the kicking formation is controlled, steps can be taken to repair the higher thief zone.

- Although used in some areas, *lost circulation material (LCM)* is not usually recommended. There are two major concerns: circulating the LCM will increase the annular pressure loss, and the material may plug bit nozzles.

If these initial attempts fail, the thief zone must be identified in order to attempt to regain control of the well. In most cases, electric logs are run on wireline in order to locate the thief zone. Once the loss zone has been defined, various techniques have been used to reestablish circulation.

1. Cementing service companies can set special cements designed to stop underground flows.
2. Barite plugs, a mixture of barite and water, are sometimes used to plug the wellbore above the kick zone and stop the flow into the well. The time the barite takes to settle makes it difficult to get a good plug with large water flows, but barite plugs often work well with gas flows. Correct displacement is critical because the barite will settle out quickly when the pump is shut down. Bit nozzles may plug or the bottomhole assembly can become stuck.
3. A gunk plug, a mixture of bentonite and diesel oil, can be effective in temporarily shutting off a water flow. When the gunk comes in contact with water, the bentonite sets up like thick clay cement. Gunk plugs weaken over time. If the gunk plug is effective, a permanent cement plug is often set above it.
4. It is sometimes possible to kill a well dynamically by pumping at a high rate in order to dominate the blowing zone by generating high annular friction.
5. In the most severe cases relief wells are drilled and dynamic techniques are used.

## The Low Choke Method

The low choke procedure can be used on certain wells when the shut-in casing pressure approaches or exceeds the maximum allowable annular surface pressure. It is not a constant bottomhole pressure method and is only applicable in situations in which formation fracture or casing/wellhead equipment failure is likely.

Once the decision to use the low choke method is made, the MAASP is held constant with a choke while circulating at the highest practical pump rate, simultaneously increasing the mud weight as rapidly as possible. The increased annular pressure loss due to high pumping rates is a crucial part of the method. During this time formation fluids will continue to enter the well until the fluid is properly weighted. This may require more than one complete circulation. The correct kill fluid density is not known when the operation begins because no stabilized shut-in drill pipe pressure was established on initial shut-in. An estimate of the correct fluid density must be made. After the heavier fluid has been circulated to the surface, the well is shut in and the correct kill fluid density can be determined. The low choke method should not be used unless it is determined that the rig has adequate gas separation equipment. A recommended procedure is listed below:

1. Circulate using the maximum practical pump rate.
2. Start increasing the density of the fluid to an estimated kill density as soon as possible.
3. Hold the casing pressure at the MAASP by means of choke adjustments. Monitor the mud pit level closely. A decrease in mud volume before the kick is at the surface would indicate lost circulation.

4. Continue circulating until using a reduced choke opening to maintain the maximum allowable pressure.
5. Shut the well in and read the shut-in pressures. The correct kill mud weight can then be determined and the wait-and-weight method* used to circulate kill mud throughout the well.
6. If the well cannot be killed, or the casing pressure cannot be reduced in order to shut the well in safely, consider setting barite or cement plugs.

$$\boxed{ICP = (SCR_{psi} * MW_{ppg\ present}) \div MW_{ppg\ (original)} + SITP_{psi}}$$

** NOTE: The correct ICP is determined using a prerecorded SCR pressure and original mud weight.*

## Well Kicks When the Work String is Off Bottom

Kicks that are detected when the work string is off bottom are usually the result of swabbing on trips or repeated runs with wireline tools when the work string is completely out of the well. In either case the kick should have been detected by measuring the fill-up during the trip or otherwise monitoring the annulus. It has been said that to get complete control of a well two things must be accomplished: 1) the drill pipe must be close to bottom and, 2) it must be possible to circulate.

Figure 10.3.

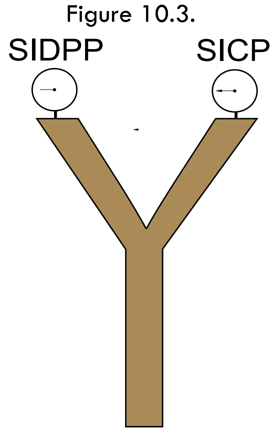


Figure 10.4. Decision Analysis Flow Chart.

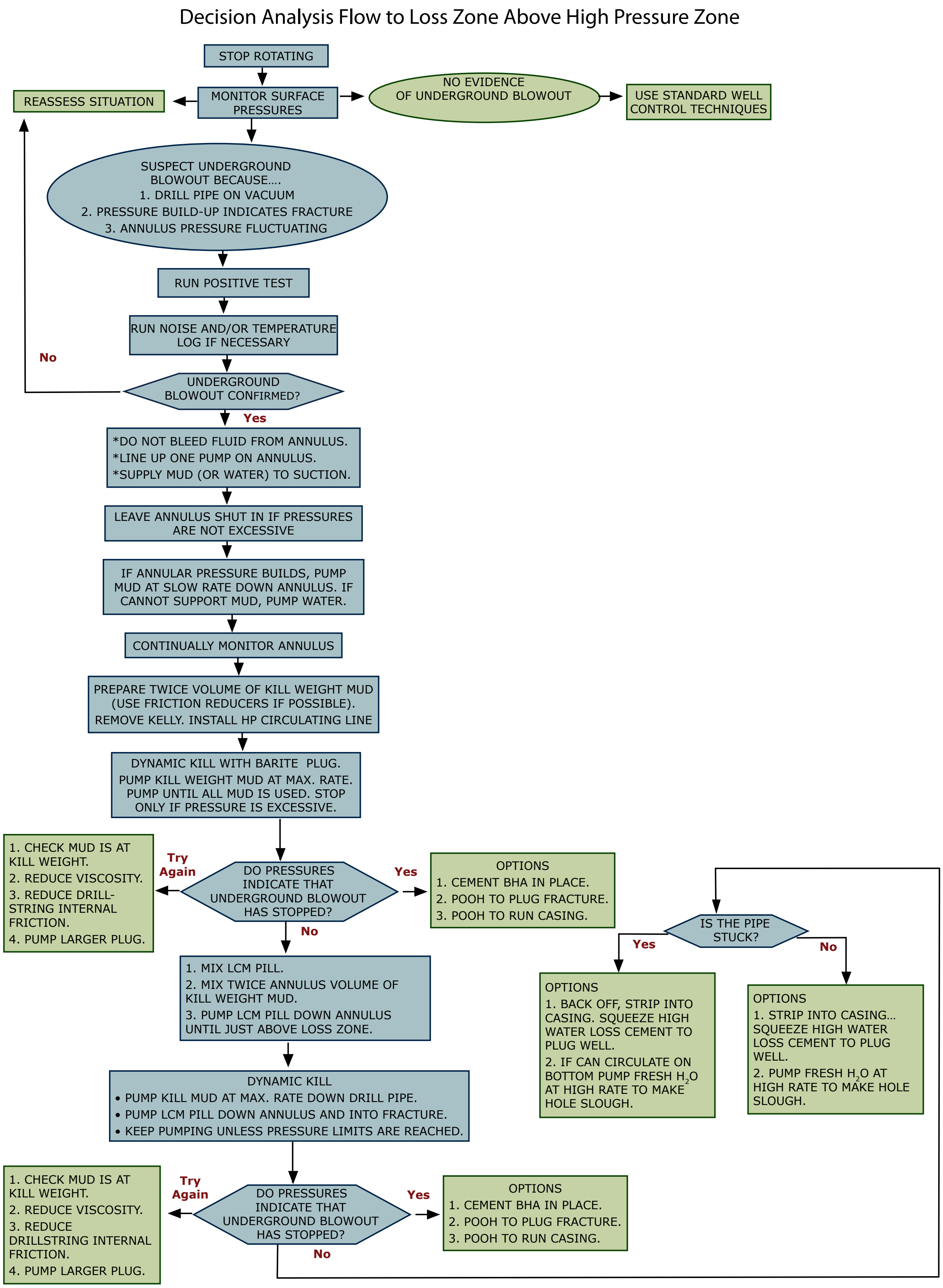
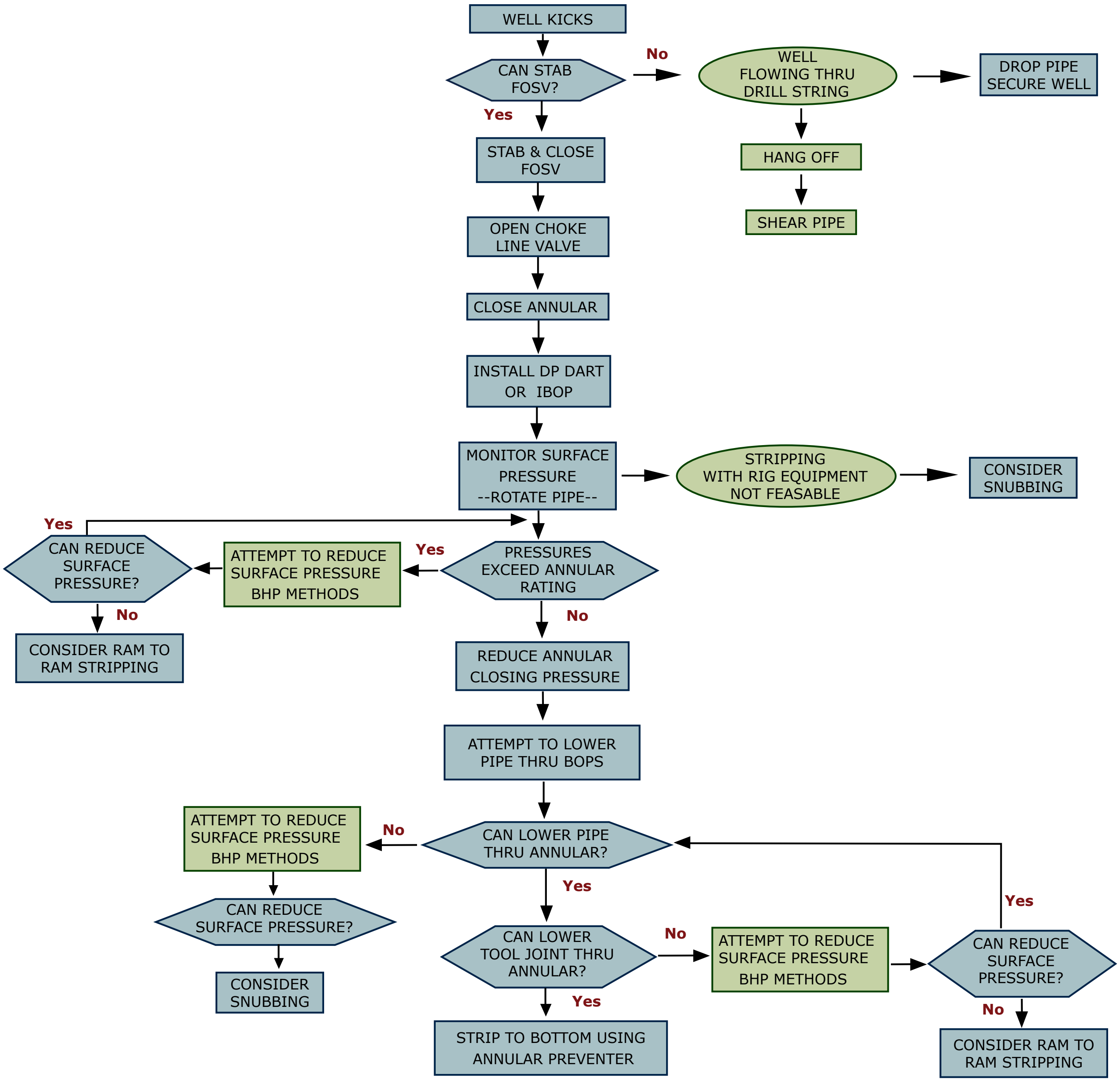


Figure 10.5. Kick off bottom (drill pipe in stack)



## Stripping

*"Stripping in* is the process of lowering the drill stem into the wellbore when the well is shut in on a kick and when the weight of the drill stem is sufficient to overcome the force of well pressure. *Stripping out* is the process of removing the drill stem from a well under pressure"[2].

The expression used to describe the situation that requires stripping is *pipe heavy*. If the forces from the well are greater than the weight of the pipe the situation is considered *pipe light*. In pipe light conditions, the operation of moving pipe into or out of a well is known as snubbing. Snubbing is a highly specialized operation requiring special equipment, e.g., hydraulic workover units or coiled tubing units, and will not be addressed in this discussion.

Some of the most serious well control events have occurred when tripping pipe out of a well. When tripping out, bottomhole pressure (BHP) is reduced in three distinct ways: 1) annular friction loss disappears when the pump(s) are stopped, 2) there is some decrease in BHP due to the upward movement of the pipe, and 3) the level of liquid in the well goes down as pipe is removed. Improper fill-up on trips out of a well, especially when the bottomhole assembly (BHA) is being pulled through the rotary table, has led to many blowouts. Also, the reduction of BHP due to the upward movement of the pipe, that is, the *swabbing effect*, if handled improperly, can lead to disastrous consequences. The main contributors to swabbing are:

- the rate at which the pipe is pulled
- the flow properties of the working liquid (viscosity and gel strength)
- annular clearances

*Swabbing* is a piston-like effect caused by pulling the pipe faster than the liquid can fall below it. The opposite effect, surging, which causes an increase in BHP, can also lead to well control problems, but not as often as swabbing.

Swabbing or surging can only be detected early by carefully monitoring a calibrated trip tank as the pipe is moved into or out of a well. On trips out, if the well does not take the pre-determined correct volume of liquid for fill-up, it can be assumed that swabbing of formation fluids into the wellbore has occurred.

It has long been known that the only way to get complete control of a well is to have a work string near bottom and to have the means to circulate. It is necessary to have the work string near bottom; however, the means by which the pipe is run to bottom is critical.

Running back to bottom in an open well, that is, "outrunning the kick" has led to many disastrous blowouts. If it is okay to run in so long as the well is not flowing "too bad", then "too bad" begs a definition. How bad is too bad? The following figures illustrate how a common swabbing incident can turn into a dangerous well control event.

Consider a trip out of a well with a drilling rig. If, during the trip, the volume of liquid pumped into the well is less than the pre-determined correct volume displacement of the pipe (considering the particular well's normal characteristics) the trip should be stopped, a full opening safety valve made up on the work string, and the well checked for flow. If the well is flowing, it must be shut in so that the flow is stopped as quickly as possible and so that the situation can be analyzed under static conditions. *Even though the well is not flowing, once it has been determined that formation fluid has been swabbed into a well, the pipe should be stripped back near bottom and the influx circulated out using a constant bottomhole pressure method.*

Figure 10.6.

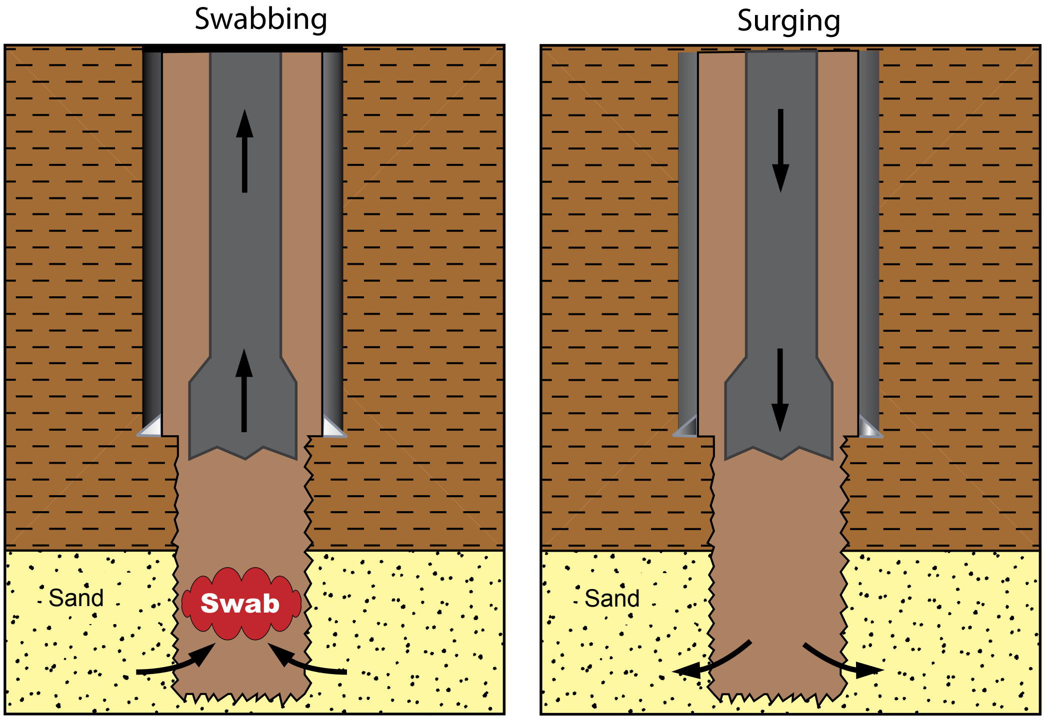



Figure 10.7a. Outrunning a Kick - Stage 1.

## Stage 1

When drilling an 8½-inch hole, the bit penetrated a different formation and a trip had to be made for a bit change. The TVD was 9,186 feet. The mud weight was 14.9 ppg, which provided approximately 494 psi overbalance, or trip margin. The formation pressure gradient was estimated to be 0.721 psi/ft. The formation contained gas with an estimated density of 2.5 ppg.

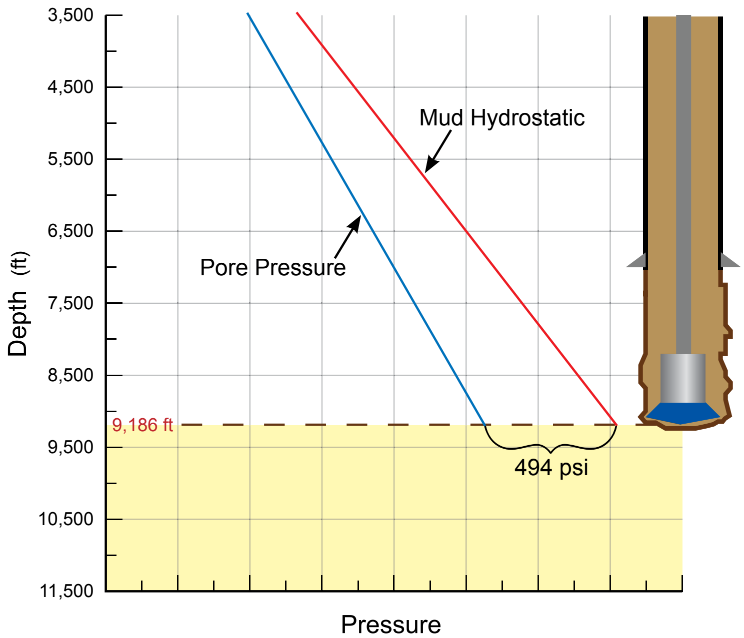


Figure 10.7b. Outrunning a Kick - Stage 2.

## Stage 2

After pulling out of the hole to 5,577 feet, it was noticed that the well was not taking the correct volume for fill-up and the well was flowing slowly. The pits had gained about 9.4 barrels due to incorrect fill-up and possible gas expansion. The open hole was now filled with gas cut drilling fluid. The on-bottom overbalance was reduced to 290 psi.

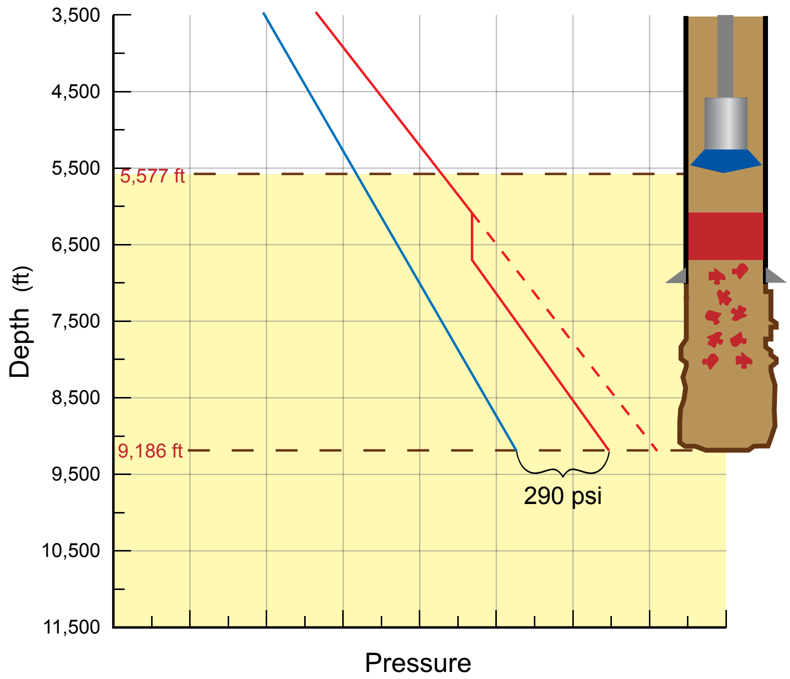



Figure 10.7c. Outrunning a Kick - Stage 3.

## Stage 3

A decision is made to trip into the hole since the flow is not considered excessive. The pit gain on the surface is now 25 barrels. All the overbalance has been lost and the open hole is completely full of gas cut mud.

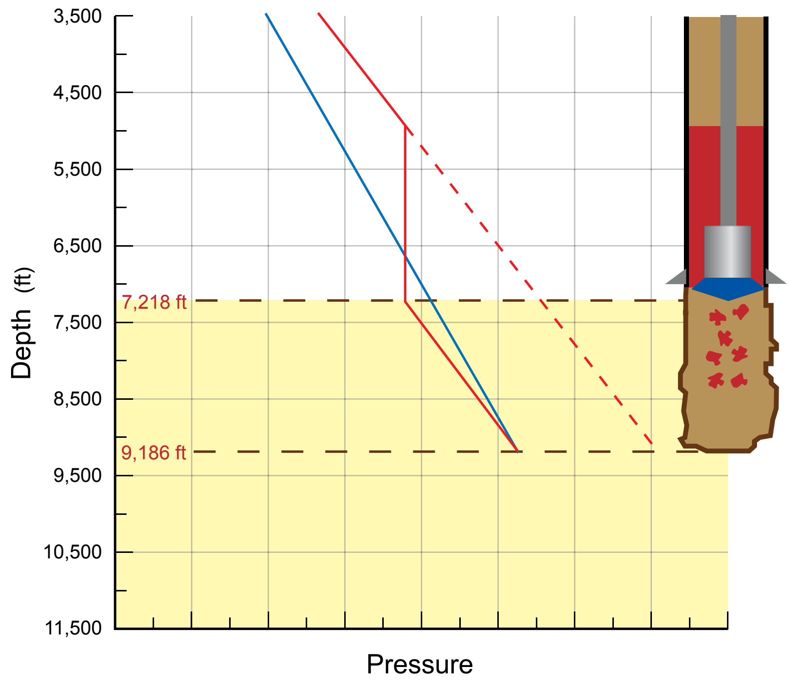


Figure 10.7d. Outrunning a Kick - Stage 4.

### Stage 4

The crew continued running into the well as the rate of flow from the well continually increased. All overbalance is now completely lost and a second kick enters the wellbore. The well is producing gas constantly from bottom. The pit gain is now 63 barrels and growing rapidly.

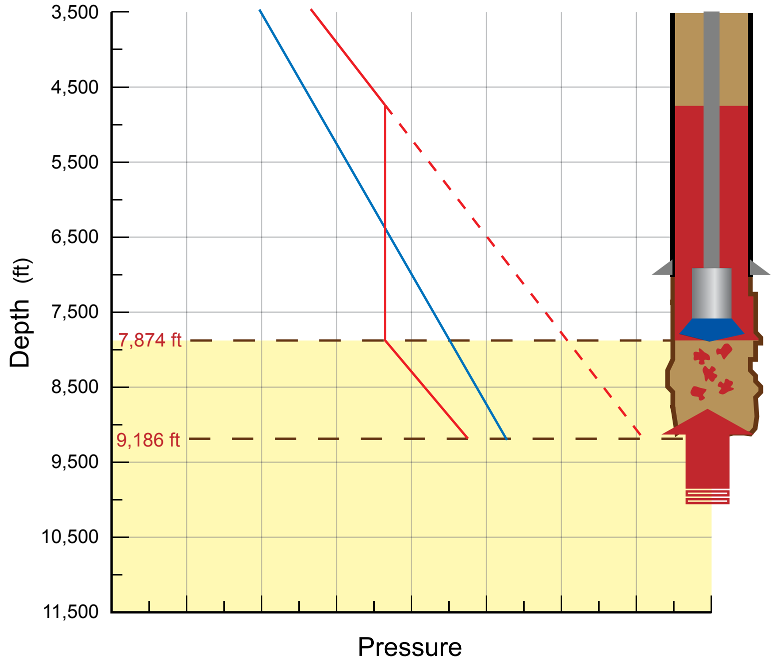
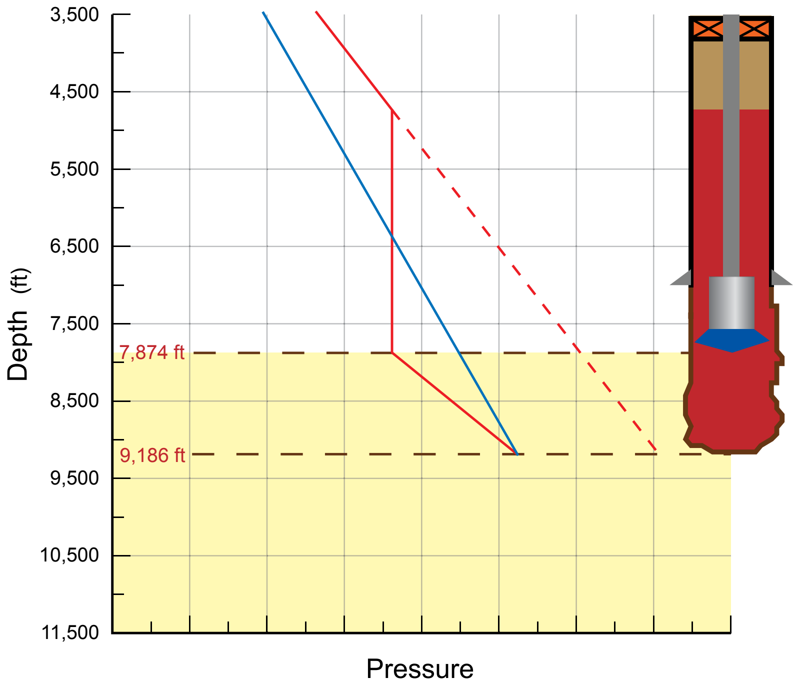



Figure 10.7e. Outrunning a Kick - Stage 5.

### Stage 5

The well is closed in with the BOPs. Total volume gained is now 94 barrels. The shut-in casing pressure (SICP) is 725 psi with the bit still 1,312 feet from bottom. The open hole is loaded with gas and control has effectively been lost. Recovery from this situation is now difficult and very risky.



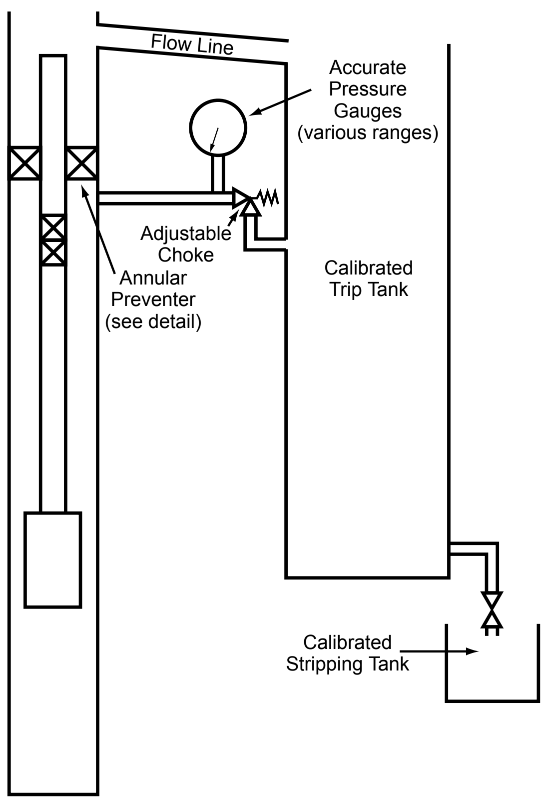
Safe stripping practices involve two primary concerns. There is the mechanical operation itself that consists of the rig-up and operation of equipment, specific assignments for the crew, and careful displacement and volume calculations. Also, since some gas is associated with most formation fluids, consideration must be given to controlling bottomhole pressure in the event of gas migration during the stripping operation.

Although both of these concerns are addressed simultaneously during actual operations, here they are discussed separately for the sake of simplicity and clarity. The basic equipment requirements for stripping pipe into a well using an annular preventer against relatively low pressure are:

- A fluid-discharge system from the wellhead (BOP) into a dedicated and accurately calibrated tank, in order to allow controlled bleed-off.
- A BOP control system that allows fast response and guarantees a seal when a tool joint is stripped through the sealing element.
- Additional equipment to ensure efficient operations.

It goes without saying that it is vitally important that supervisors know the limits of their well control equipment and that maintenance and operational manuals are readily available. Unnecessary damage to the sealing elements of preventer(s) during stripping has been the cause of more than one blowout. A brief description of the equipment requirements and operating limitations are discussed on the following page. Figure 10.8 is a schematic layout of the fluid discharge from the wellhead, via the choke line and choke-manifold into a calibrated trip tank. A calibrated trip tank is used to monitor and record volumes of the closed-end displacement of the pipe to be stripped into the well. The trip tank contains the volume increase of gas expansion (as a result of choke manipulation applying the volumetric method) and is monitored and recorded separately from the pipe displacement volume.

Figure 10.8. Rig layout for combined stripping and static volumetric method.



In many operations, some leakage will occur as a tool joint passes through the annular preventer. This liquid must be measured and added to the volume bled from the annulus. Figure 10.9, below, illustrates a line directing any preventer leakage back into the calibrated trip tank.

Figure 10.9. Trip tank.

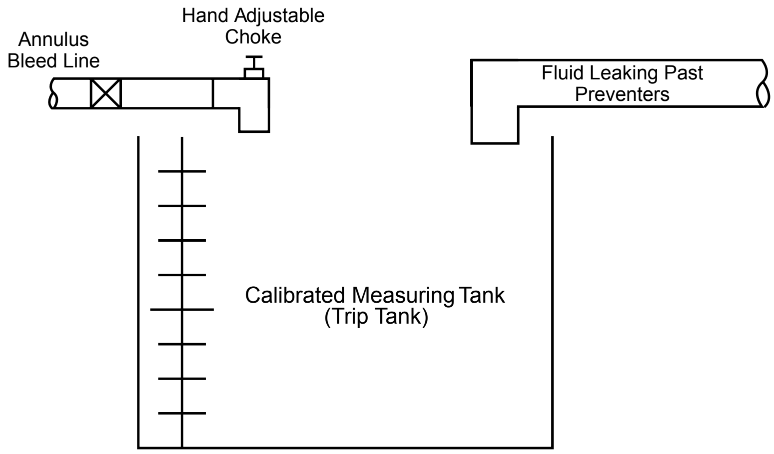



Figure 10.10 is a schematic layout of a pressure regulating system used to ensure a fast, guaranteed seal when a tool joint is stripped through the annular preventer. In order to minimize wear on the sealing element, the closing pressure should be reduced as much as possible and the element allowed to expand, and then contract, as the tool joint passes through. Lubricating the drill pipe before and during the operation can further reduce potential wear. If there is leakage around the pipe, the fluid should be collected in the trip tank and considered as liquid from the well. A ten-gallon surge accumulator bottle is installed in the closing line as close as possible to the preventer. The precharge pressure of the surge accumulator depends on the type of preventer in use. As rule of thumb, the surge accumulator bottle should be precharged to fifty percent of the minimum required preventer closing pressure. The surge bottle is isolated under normal operating conditions, and is used to ease the expansion and contraction of the sealing element.

Figure 10.10. Equipment requirements for stripping with an annular preventer.

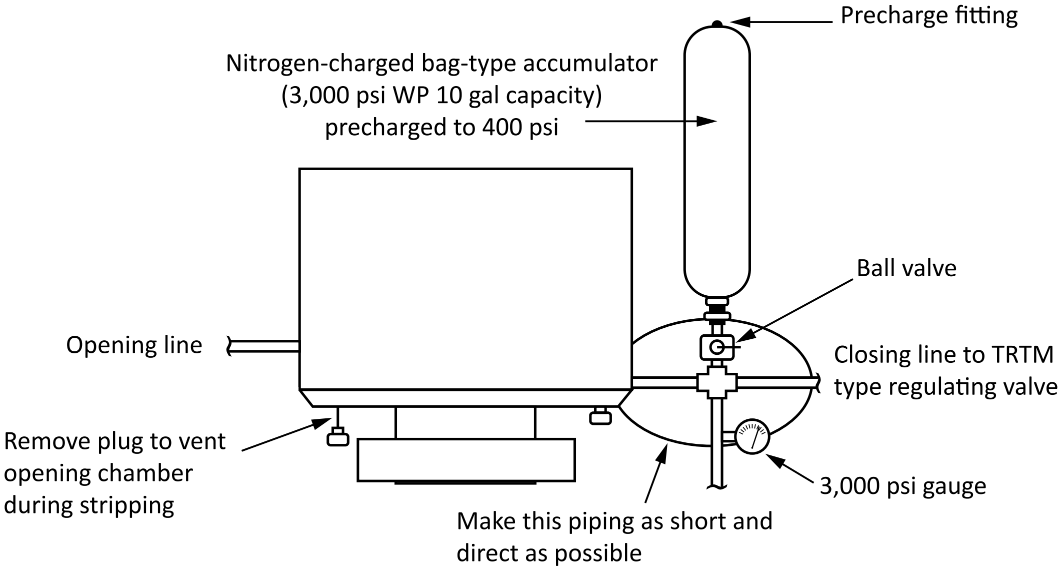
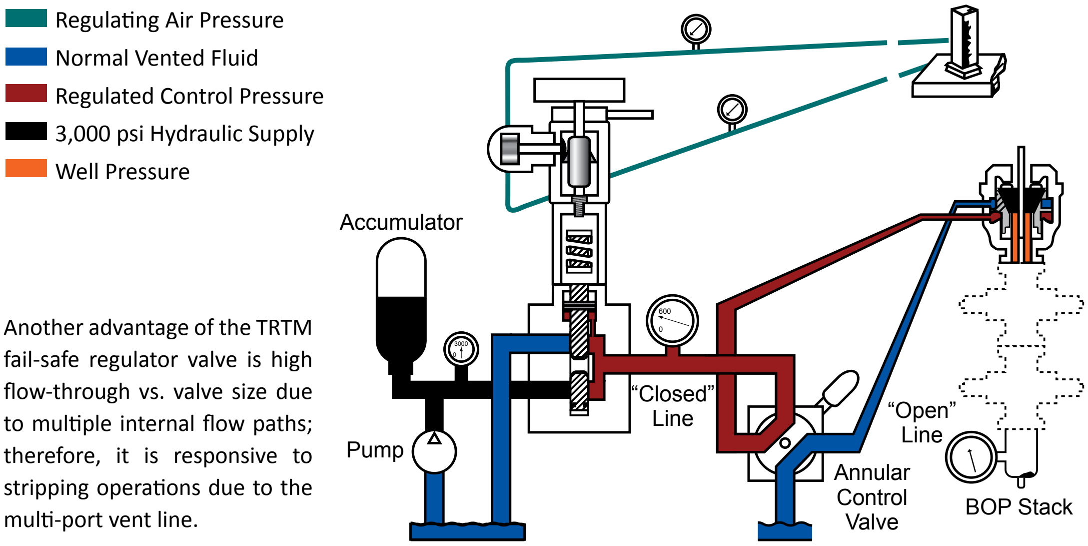


Figure 10.11 illustrates a fail-safe type of regulating valve used when operating the BOPs remotely. The fail-safe valve will maintain the closing pressure in the event that air or hydraulic signals to operate the valve is lost. The TRTM pressure regulation valve illustrated here incorporates a fail-safe feature. With the TRTM regulator, if the pilot pressure is lost, the manual adjusting screw remains in position, thereby maintaining the last regulated pressure setting. An important feature is that the mechanical lock screw remains locked to ensure that the last setting remains.

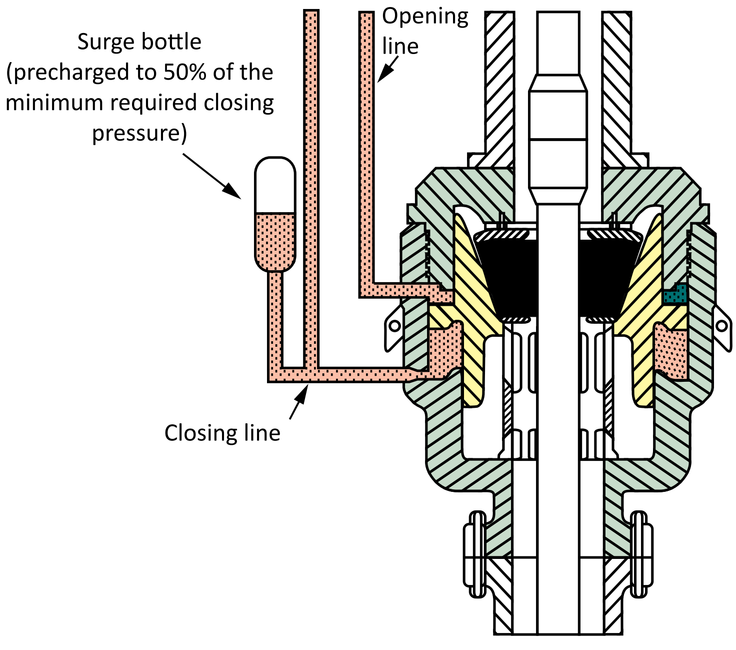
Figure 10.11. Fail-safe regulator valve.




Another advantage of the TRTM fail-safe regulator valve is high flow-through vs. valve size due to multiple internal flow paths; therefore, it is responsive to stripping operations due to the multi-port vent line.

The Hydril GK preventer, illustrated in figure 10.12, was developed especially for use on surface installations. Pack-off is effected by hydraulic pressure applied to the closing chamber that raises the piston, forcing the packing element into a seal around the tubular pipe (the GK will also seal on the open hole, but this is normally avoided because of the potential for extreme packer wear). The GK preventer is designed to be pressure-assisted so that pressure from the well acts up on the packing element. As well pressure increases, closing force increases and therefore the friction forces developed by the moving pipe also increase. Longer packing unit life is obtained by lowering the closing chamber pressure.

Figure 10.12. Blowout preventer.



Manufacturer's tables are available for various make and model preventers and should be used as guides for establishing the initial closing pressure.

## Stripping Examples

In this first example assume the same well geometry taken from the previous volumetric discussion, in chapter 9, "Well Kill Methods" (p. 9-48) and that a fifteen-barrel gas influx was swabbed into the well and detected 25 stands (2,325 feet) off bottom. The decision is made to strip back into the well and circulate the kick out. Also assume that the 12.5 ppg mud balanced the formation before the trip was started and that the gas will not migrate. The 120 psi casing pressure is relatively low surface pressure so the annular preventer will be used as the stripping head. A safety margin of 100 psi and a working margin of 50 psi are chosen. These assumptions may not reflect a true situation; they are used here for illustration purposes only.

Figure 10.13. Sample well.

### Well Data:

Depth: 10,000 ft

Casing: 9⅝ in, 40 lb/ft set at 5,000 ft

Drill Pipe: 4½ in 16.6 lb/ft, closed-end displacement 0.02084 bbl/ft

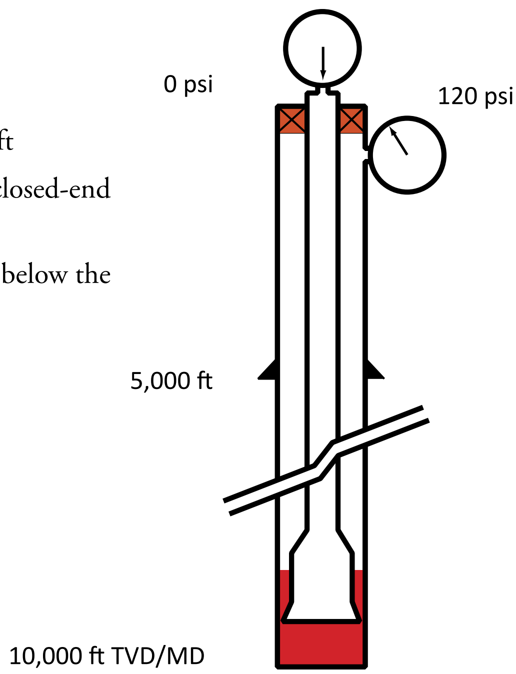
Off bottom, an influx is swabbed in below the work string.

Mud: 12.5 ppg

SICP: 120 psi

Final pit gain after shut-in: 15 bbl

Formation pressure: 6,500 psi

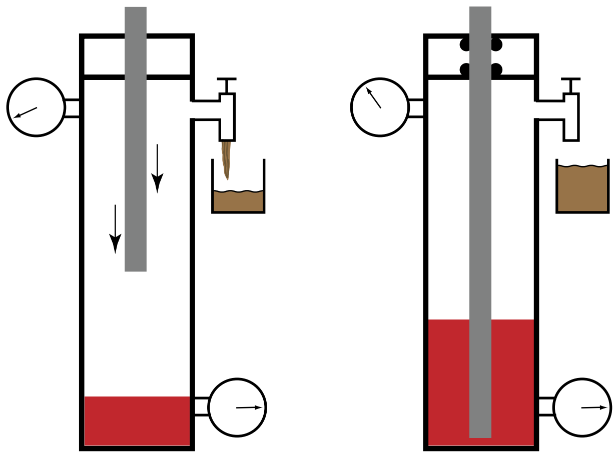



The closed-in displacement of the 4½-inch drill pipe with tool joints is 0.02084 bbl/ft, therefore each 93 feet stand displaces 1.94 barrels (0.02084 * 93 = 1.94). After the proper equipment is rigged up, a detailed safety meeting is held. During this meeting the crew is informed as to the details of the operation and individual tasks are assigned and explained.

The operation begins by stripping the drill pipe through the annular preventer with the choke closed until the casing pressure has increased by the safety margin (100 psi) and the working margin (50 psi), that is, to 270 psi. From this point onward, the choke is opened as the pipe is moved into the well in order to bleed off exactly the drill pipe displacement. The trip tank should be approximately one-third (⅓) full before stripping begins.

In this ideal situation (no migration) the casing pressure would remain approximately constant as the pipe is stripped until the BHA stings into the top of the influx. At that point the annular hydrostatic pressure would be reduced as a result of the longer (higher) influx. The casing pressure would then increase, reflecting the changing wellbore geometry. It can be seen that accurate measurement of the displaced liquid is crucial to the operation and that communication between the choke operator and the men measuring the liquid must be excellent. Bottomhole pressure remains constant so long as the returning liquid equals the actual pipe displacement until the work string is at, or near, the bottom of the well. Any changes in casing pressure are due to changes in annular hydrostatic pressure as pipe is moved into the well.

Figure 10.14. Pipe displacement.



The example on the previous page assumed that no gas was associated with the swabbed-in influx and therefore, there was no upward migration. However, almost all kicks contain some gas and stripping operations must be prepared to control bottomhole pressure if the gas begins to rise in the well. Since circulation is not possible, the volumetric principle is incorporated into the stripping operation. In this situation there are two separate concerns: 1) careful measurement of pipe displacement and, 2) the application of the volumetric method in order to allow for gas expansion and control of bottomhole pressure.

When planning a stripping operation, it is not practical to consider every geometric change in the wellbore, even though the migrating gas may move into different annuli, for example, above the BHA. Also, as mentioned in the previous example, consideration must be given to the potential pressure change that will likely occur when the BHA stings into the main body of the gas. If the vertical length of the gas increases, it will result in a decrease in the effective annular hydrostatic pressure, which in turn, results in an increase in casing pressure. It is important to realize that this increase in surface pressure is not due to gas migration.

Although it is possible to estimate the rate of migration, there is no assurance that this rate will continue. Also, the exact top (or bottom) of the bubble cannot be known.

Since a well may have various annuli, the hydrostatic pressure per barrel of liquid will vary depending on the position of the bubble. When selecting a hydrostatic pressure value versus volume to be used (psi/bbl), some operators simplify matters by using the annulus between the BHA and open hole, considering the smallest annulus to be the safest. Others use an average, or the longest annulus. In most wells the pressure per barrel differences between the various annuli are small. At any rate, the choke operator should anticipate a significant pressure change when the BHA enters the gas bubble. Well characteristics dictate the appropriate safety and working margins. For example, formation strength (MAASP) is always a concern in drilling because there is exposed open hole. There is no hard rule, but if the MAASP were 1,200 psi, and the SICP were 800 psi, the selection of 200 psi total margins would likely be safe since 1,200 – 800 = 400 psi, which should provide ample tolerance. If casing pressure does not increase after a few stands are tripped in, it could mean that the well is already taking liquid and that the fracture pressure has been exceeded. Once it is established that the well is taking working fluid, stripping may continue by bleeding just enough fluid to equal the total displacement of the pipe. In this situation, less fluid would be forced into the formation and losses might stop once the gas rises above the fracture point.

Some basic assumptions are made in the following example:

- The annular preventer is used for stripping.
- The influx will be considered to be gas and therefore back-pressure will be added, allowing for migration and expansion as in the volumetric method.
- The influx remains in a continuous bubble, occupying the entire annulus cross-section.
- Safety and working margins will be added at the very start of the operation and the influx will be in the open hole at the beginning of the operation. An average psi/bbl will be used for volumetric guidelines. Here the average was determined by dividing the formation pressure of 6,500 psi by the total annular volume when the work string is on bottom (512 barrels).

Like safety margins, this must be a well-specific judgment. Some of the additional considerations required are: estimates of the bubble position, maximum allowable pressures, and length of open hole in relation to the casing seat. Suppose the crew has received orders to strip back to bottom before circulating the gas influx out. During the stripping operations pipe will be moving, gas may be migrating, and fluid will be bled off at the choke. A planned stripping pressure schedule should be developed.

The well is shut in with 120 psi casing pressure. In designing a bleed off schedule, a safety margin and a working margin are chosen. In this example we have decided to use 200 psi safety margin (because of the hydrostatic loss of 100 to 150 psi associated with the bit passing through the kick) and a 50 psi working margin. In other words, the choke will not be opened for any bleed off until the casing pressure has been allowed to rise to 370 psi. During the first bleed off, casing pressure will be maintained within the working margin, that is, between 320 and 370 psi. It is necessary to carefully measure any fluid bled from the well and to estimate its equivalent hydrostatic pressure. The drill pipe will be fitted with at least one back-pressure valve so total displacement will be that of the full outside diameter.

0.02084 bbl/ft * 93 ft = 1.9 bbl/stand, closed-in pipe displacement

6500 psi ÷ 512 bbl = 12.7 psi/bbl, pressure equivalent chosen for volumetric adjustments

50 psi ÷ 12.7 psi/bbl = 3.9 bbl., working margin equivalent in barrels

With this information, a stripping/bleed off schedule is created. Using the schedule, the following steps describe the procedure when the drill pipe is continuously stripped into the well.

1. Strip into the well without bleeding fluid until casing pressure increases by 250 psi (200 psi for safety margin and 50 psi for working margin) from 120 psi to 370 psi.
2. Once the casing pressure has reached 370 psi, continue bleeding at a rate to hold casing pressure between 320 and 370 psi. After bleeding the equivalent of 50 psi (working margin) of liquid, that is, four barrels, allow the casing pressure to increase by another 50 psi to 420 psi.

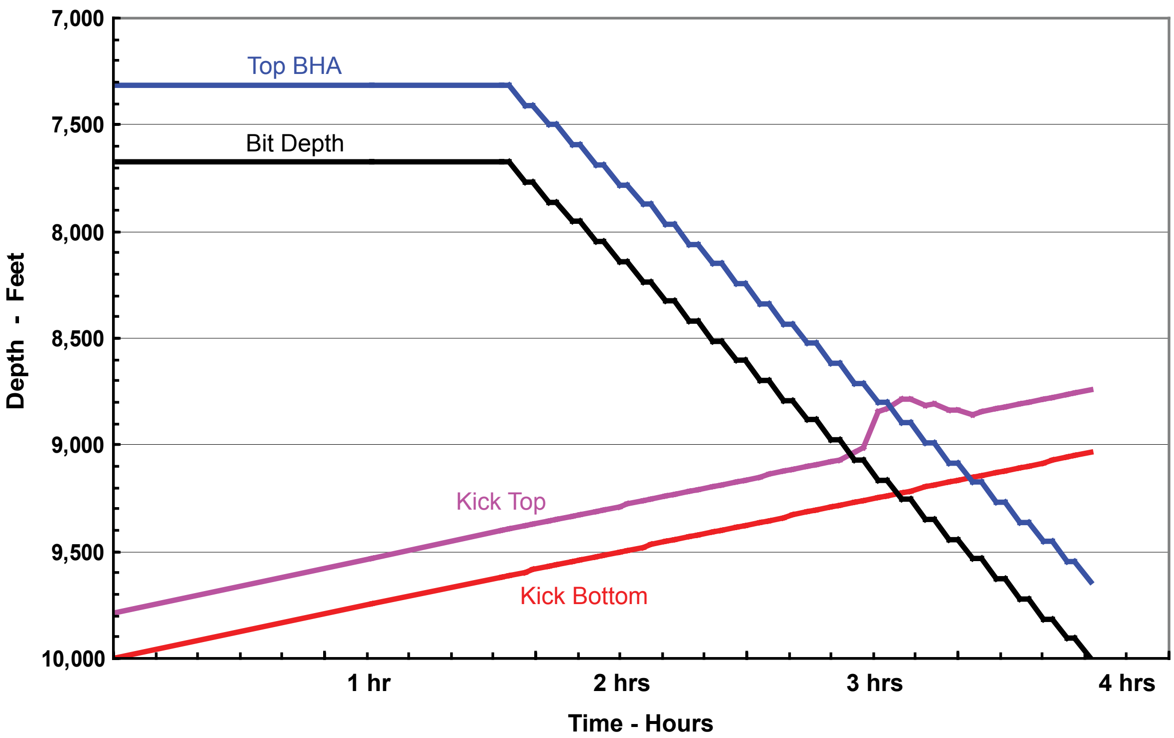
3. As pipe is lowered, carefully bleed off the amount of tubing displacement (1.9 barrels per 93-foot stand) as it is run into the well. The casing pressure is allowed to increase. If the casing pressure has not increased by 50 psi after the stand is lowered and set on the slips, close the choke, and make up the next stand. Continue bleeding only pipe displacement when the connected stand is lowered.
4. When casing pressure has increased to 420 psi while continuing to strip, maintain casing pressure between 370 and 420 psi while bleeding until a gain of four barrels is noted. At this point, casing pressure is once again allowed to increase as the bubble migrates and pipe is run into the well.

The steps are repeated until drill pipe has been run to bottom or gas reaches surface. It is important to note that these are not recommendations, but are offered to demonstrate the complexity of the operation, and the critical need for thorough preparation before beginning to strip into a well.

The following three graphs (figures 10.15, 10.16 and 10.17) illustrate a computer simulation using the data in our example. Figure 10.15 illustrates the movement of the BHA into the well as the kick migrates upward. Some assumptions were made in order to develop the plots:

1. The bubble is migrating at a rate of 250 ft/hr.
2. Pipe is being stripped at a rate of 1,000 ft/hr.
3. Each connection takes two minutes and a stand is moved into the well in 3.8 minutes, making the total stripping time 5.8 minutes per stand.

Figure 10.15. Stripping in the hole.



Notice in figure 10.16, which illustrates pipe displacement only, that approximately 3 hours into the operation both the casing pressure and the kick height increase for about 30 minutes and then begin to decrease. As the BHA enters the gas, the length (height) of the kick increases, effectively reducing the annular hydrostatic pressure. The decrease in hydrostatic pressure is offset by the resulting increase in casing pressure. As the BHA exits the bottom of the gas, the kick becomes shorter, mud hydrostatic pressure increases, and the casing pressure decreases. Once the gas is completely above the BHA, the gas occupies the larger annulus around the drill pipe only. At that point, the kick height remains constant (because for clarity it is assumed that no bleeding is done for kick migration), hydrostatic pressure is constant, and casing pressure increases as the kick brings its pressure up the hole. It is important to note that this necessary increase/decrease in casing pressure that occurs when the BHA passes through the bubble is one reason why pipe stripping is based on volume calculations, not on forced changes in casing pressure.

Figure 10.16. Bit penetrates the kick.

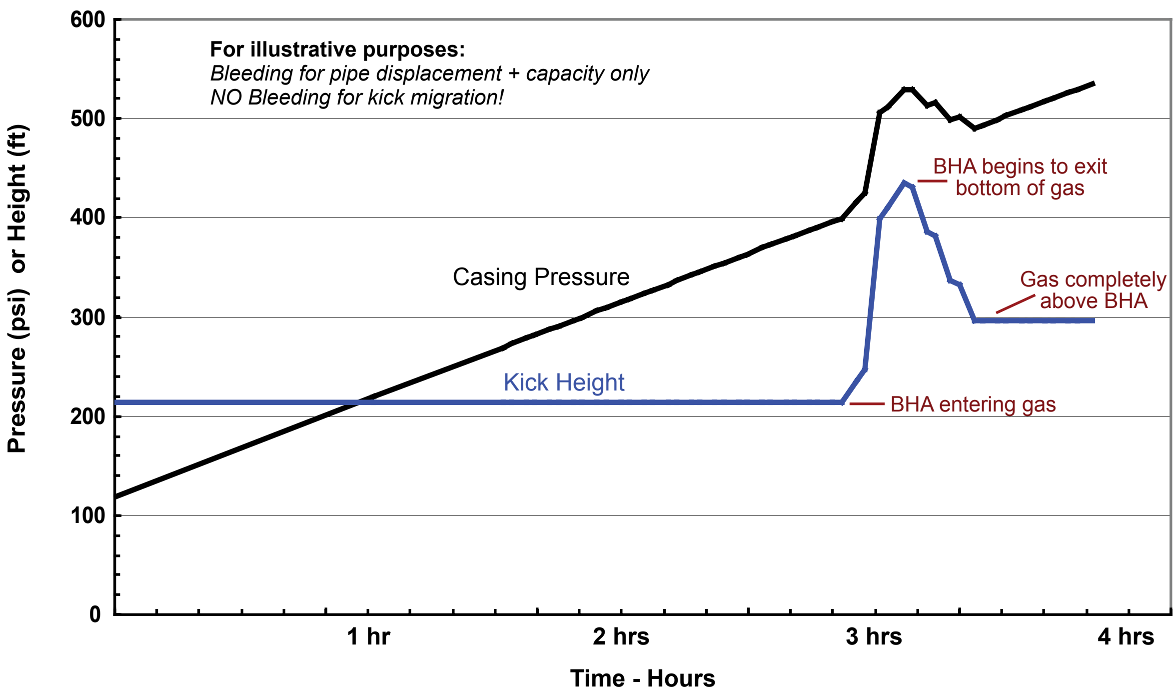
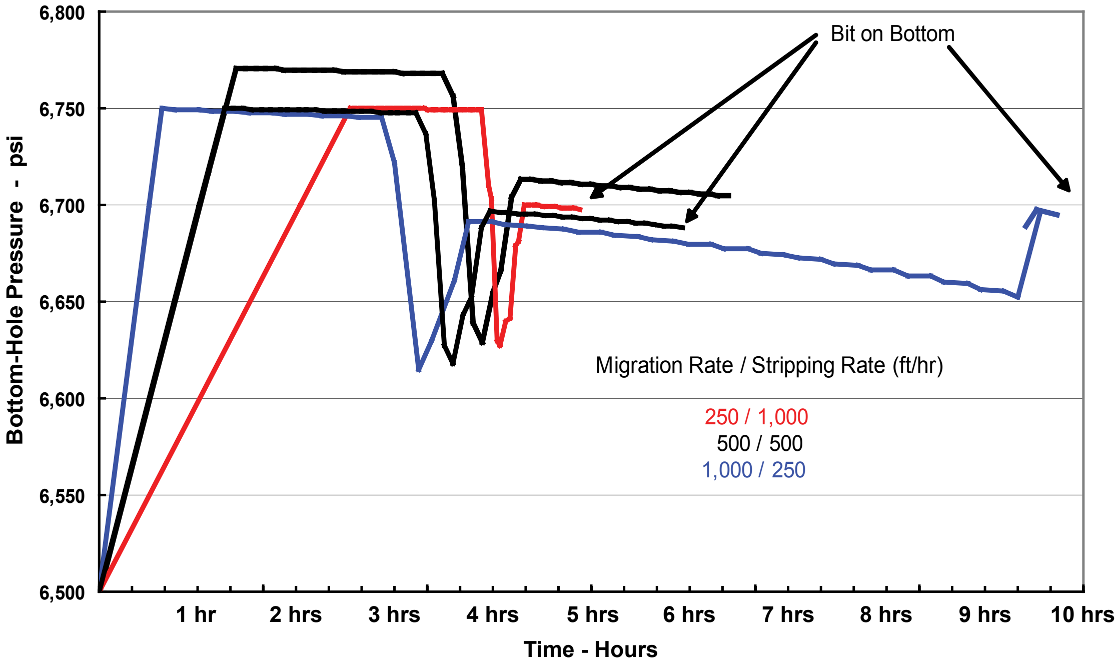



Figure 10.17 was developed using 1.94 bbl/stand as calculated. It is interesting to note that if the closed-in displacement were rounded up to two bbl/stand — a seemingly small adjustment — the well would be underbalanced by 150 psi by the time the bit was at bottom.

The bottomhole pressure/time plot in figure 10.17 assumes three different gas migration and stripping rates. The graph was generated using the following assumptions:

- Safety margin – 200 psi
- Working margin – 50 psi
- Bleed-off for stripping – 1.9 bbl/stand
- Bleed-off for migration – 3.9 barrels for the 50 psi working margin
- Assumed connection times were two, five, and eight minutes for stripping rates of 1,000, 500, and 250 ft/hr respectively.

Figure 10.17. Volumetric stripping.




The safety and working margins were established by migration only. No stripping began until the bottomhole pressure had increased to 6,750 psi. Note that at the slowest assumed migration rate (depicted in red) about two hours were required to achieve the 250 psi overbalance. Continuing to follow the 250 ft/min rate, it can be seen that the BHA had been stung through the gas in about four hours and that in less than five hours the bit was on bottom even though the working margin of 50 psi (3.9 bbl.) had not yet been bled from the well.

Doubling the migration rate to 500 ft/hr and slowing the stripping time by half, i.e., 500 ft/hr required approximately five hours in order to reach bottom but still, the working margin equivalent had not been completely bled from the well.

In the third case (blue), the migration rate has increased 4 times while the stripping speed has been reduced to only 250 ft/hr. In this case, it was about 9 hours into the operation before the 3.9 barrels were bled. Less than an hour later the bit was at bottom. The increase in BHP after the 3.9 barrels (for migration) is achieved is due to stripping and bleeding pipe displacement only, re-establishing the working margin.

It can be seen from these illustrations that volumetric stripping can be a complicated operation, and that it is impossible to predict exactly what will happen once the operation begins. Although the plotted data are generated by computer modeling and not from actual case studies, they demonstrate the complexity of stripping into a well safely while maintaining bottomhole pressure within a designed range or “window” for optimum safety, protecting not only the crew and equipment, but also the environment.

The following steps represent a summary of recommended low pressure stripping procedures developed by a major operator. They are offered here as information only since specific procedures differ among operators.

1. After the well is shut in, casing pressure is monitored carefully. Pressure is recorded every 5 minutes in order to determine if the influx is migrating.
2. Rig up equipment for stripping and prepare a stripping schedule, determining safety and working margins, closed-pipe displacement, psi/barrel calculations, etc.
3. Reduce the closing pressure on the annular preventer and open the surge accumulator bottle.
4. Conduct a safety meeting for all personnel, explaining the operations, assigning tasks, and establishing paths of communication for the operation.
5. Install an Inside BOP (IBOP) on top of the full-opening safety valve (FOSV)
6. Open the FOSV slowly, checking that the IBOP is holding. If a non-ported check valve (float) is in the BHA, it is unlikely that there will be pressure below the FOSV.
7. Consider circulating for a short time to confirm that the work string is not plugged before beginning to strip.
8. Ensure that the choke line and manifold are properly aligned to discharge bled off liquid into the trip tank and that the trip tank is approximately one-third full.
9. Install a stand of drill pipe, making sure that pipe rubbers are removed, tong and slip marks are smoothed as much as possible, and the tool joints are lubricated.
10. Allow the casing pressure to increase until it equals SICP + safety margin + working margin while stripping the first stand.
11. Fill each stand stripped with fluid from the active system.
12. Move the tool joints slowly through the preventer, avoiding excessive pressure surges.
13. While stripping, the volume increase due to the closed-end displacement of the pipe and the expansion volume are purged into the trip tank. After stripping the entire stand, bleed the displacement volume into the stripping tank. This ensures that any increase in the trip tank volume is due to gas expansion and the resulting loss of hydrostatic pressure in the well.
14. While stripping the next stand, allow the casing pressure to increase from its present value plus the working margin.
15. Continue stripping, repeating steps 11through 15 as often as necessary, allowing migration and volumetric control until the string is near bottom.
16. Prior to circulating, close a ram preventer in order to have full closed-in integrity when the gas is near the surface.
17. Route the returns from the annulus through the mud-gas separator.
18. Once the influx is circulated out and before opening the preventer, be aware that pressure may be trapped in the BOP stack and/or below the IBOP.

Because stripping is a complex operation, many operators choose to conduct stripping drills. It is important that the drill be conducted only when the open hole is protected, such as before drilling out a casing shoe. Steps 1 - 18 in the discussion above can be used as a guide to developing the details of the drill. The drilling crew only need to strip enough stands to ensure the crew understands the operation. Additionally, at least one stripping exercise should be conducted during well control training.

### High-Pressure Stripping

Previous discussions have outlined the basics of stripping into a well against relatively low wellbore pressure using an annular preventer. In high-pressure situations, two preventers are used to strip into or out of a well. When two preventers are used the operation is more critical and much more complex. High-pressure stripping is discussed briefly below, but it must be stressed that each well is different and a detailed explanation of high-pressure stripping operations is beyond the scope of this text.

### Stripping With an Annular and One Ram Preventer

If the force required to pass the combination of FOSV, IBOP and tool joint through the annular preventer is too great, i.e., there is not enough string weight available, a ram preventer can be used in conjunction with the annular preventer. Spaceout distances permitting, the steps are:

1. Close the appropriate ram.
2. Bleed off pressure trapped between the annular preventer and the ram.
3. Lower the closing pressure of the ram to a predetermined value.
4. Open the annular preventer.
5. Strip pipe slowly through the ram, until the upset of the tool joint is just above the ram block.
6. Pick up to the original hookload and close the annular preventer.
7. Using a high-pressure/low-volume pump, apply pressure between the closed preventers equal to the casing pressure.
8. Open the ram.
9. Use tags to indicate which preventer contains the wellbore pressure.
10. Continue repeating the cycle until enough string weight is available to strip with the annular preventer alone.

### Stripping in with Pipe Rams

High-pressure stripping operations and properly arranged BOP stacks are required for ram-to-ram stripping. Often, a trained stripping crew conducts the operation. BOP stack arrangement is crucial. The rams must be spaced far enough apart so that tool joints will not be trapped in either ram when both are closed. This requires a single ram with a spacer in the stack. Adjacent rams in double or triple sets cannot be used for stripping. If the lower rams are reserved as a master valve, or safety ram, ram-to-ram stripping would require a four-ram stack.

Although the packing elements in pipe ram blocks are designed to extrude and hold a seal for a long period of time, pressure on the closing side of the rams is reduced to avoid burning the ram packing as the pipe is sliding through. There are no rules about pressure on the closing side of rams, but 400-500 psi is recommended by some operators. The upper ram set is used for the majority of stripping and the lower set is primarily used to seal the well as tool joints pass through. Bottomhole pressure is controlled by carefully measuring liquid returns and making the necessary volumetric corrections.

## Stripping Out of a Well

Before stripping out of a well, consideration must be given to the fact that, at some point, there will not be enough pipe weight for the pipe to stay in the well against the wellbore pressure. Calculations are made in order to estimate the balance point. The crew and equipment must be fully prepared to handle the change in well conditions. Prior to beginning, precautions must be taken to ensure that the work string is closed. Pump-down type back-pressure valves (BPV), properly seated, are often used for this purpose. Safety valves, made up on the string are kept open when pulling the pipe so that if the BPV leaks, it will not pressure up the string. Liquid is pumped into the annulus to keep the hole full. There are numerous ways to do this. A common technique is to arrange to circulate across the BOP stack from the kill to the choke line. A high-pressure/low-volume pump, like a cementing pump, generally works better than a rig pump. The pump is kept running throughout the stripping operation.

Back-pressure, greater than the casing pressure, is controlled by choke adjustments. The well is kept full of liquid as the pump circulates across the BOP stack. The liquid is pumped from a single accurately calibrated tank. After each stand, the total pipe displacement is compared to liquid actually taken by the well. Casing pressure is held constant and corrections to volume pumped into the well can be made by choke adjustments.

The casing pressure will decrease as the large diameter BHA is pulled out of the kicking fluid. However, the upward migration of gas and some upward drag may cause an increase in casing pressure. Corrections to the casing pressure are made according to the principles of the volumetric method.

It may become necessary to use the pipe rams as rubber protectors are pulled through an open annular preventer. The pressure between the pipe ram and the annular preventer is released before opening the annular preventer.

## Summary of Stripping Operations

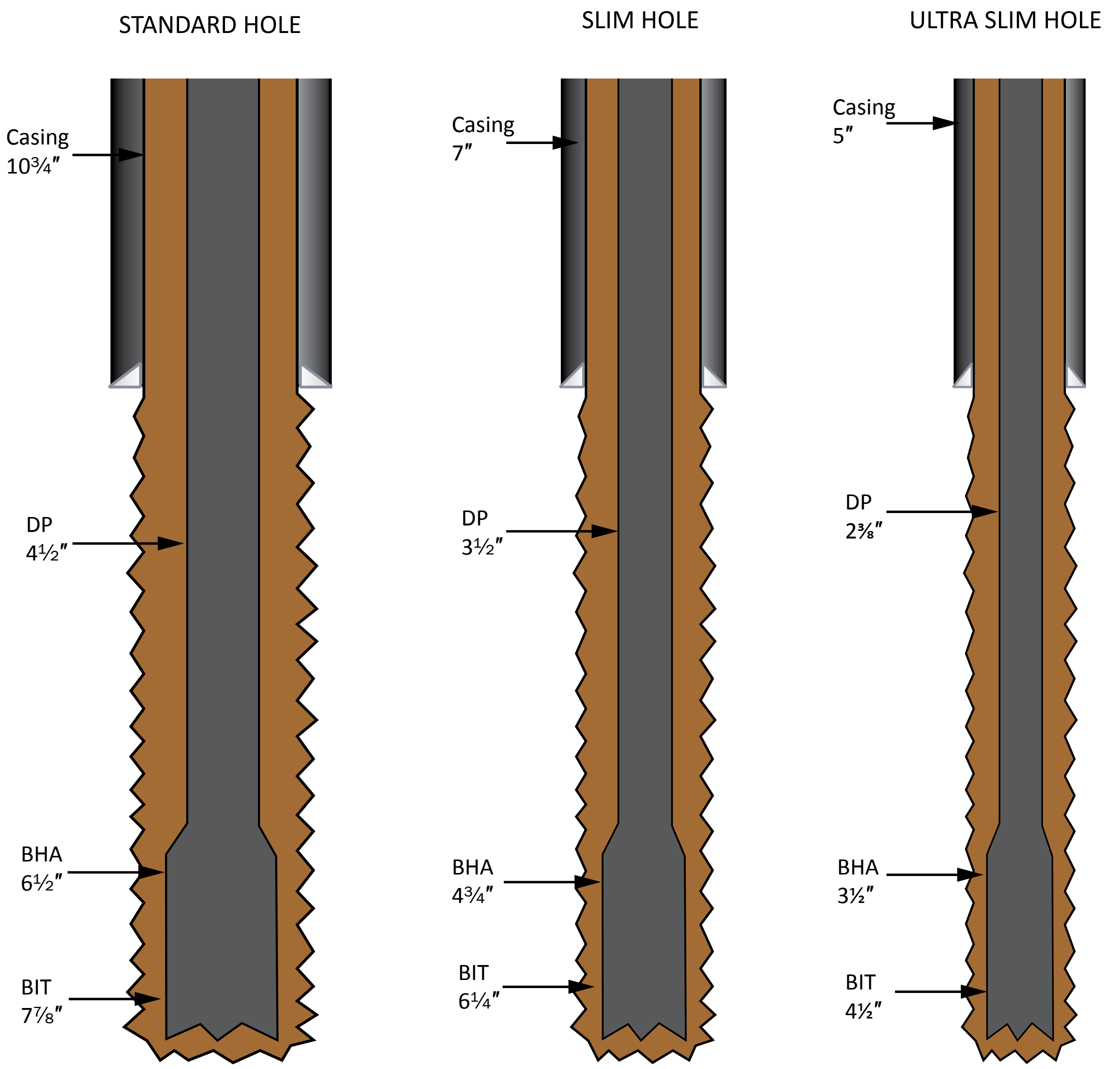
Stripping operations can range from a fairly simple low-pressure operation with a salt water kick, to an extremely dangerous high pressure gas situation. Each case is different, just as each well is different. For example, in most low-pressure operations, pipe can be stripped into a well much faster than the gas can migrate. Some operators may choose to circulate out gas once the pipe has been run into, or below, the gas. Detailed procedures for various stripping operations are beyond the scope of this text. However, three well-worn universal statements can be made: 1) prevention is always better than a cure, 2) trying to "outrun" a kick to bottom is not a safe practice, and 3) there is no substitute for careful planning before stripping operations begin.

## Slim-Hole Drilling Considerations

Definitions of slim-hole drilling are somewhat vague. Generally speaking, wells that are drilled with bit sizes less than those that might be used in a standard well at the same depth are considered *slim holes*. A *miniaturized completion* refers to a well in which the production casing is less than 4.5 inches in diameter. For the purpose of this discussion, boreholes that are less than 7 inches are considered slim holes and wells in which the borehole is 4.5 inches or less are considered *ultra slim*.

The primary difference between slim-hole operations and standard operations is the potential for things to happen much more quickly in the smaller annuli. Any intrusion of formation fluids into the well, especially around the BHA, will rapidly displace the drilling fluid from the annulus. A kick in a slim hole that is not recognized and shut in immediately can turn into an extremely dangerous situation in minutes. It goes without saying that the crew should work with heightened awareness and that all kick detection equipment is properly maintained. The various kick warning signs that apply to standard wells also apply to slim hole work. The alarms on monitoring equipment, i.e., flow sensors, PVTs, gas detectors, etc. should be set very carefully in order to give instant notice if there are changes in downhole conditions.

Figure 10.18. Difference in well geometry.




The annular friction losses (APL) are high in small annuli and can present a serious concern in slim hole work. The charts in tables 10.1, 10.2, and 10.3, compare the equivalent circulating densities (ECD) between standard wellbore, slim hole, and ultra slim-hole drilling. The values on the charts assume that a rig was drilling with a circulation rate of 250 gpm (5.6 bbl/min) and an average ROP of 25 ft/hr. It can be seen that the high annular pressures experienced in slim hole work could not only increase the likelihood of lost returns, but could also hide a potential kick. If the hydrostatic pressure was about the same value as the formation pressure, the well would be controlled by the annular pressure loss while circulating. If the pumps were shut down, the well would go underbalanced.

Referring to chart in table 10.1, the ECD is 9.89 ppg when drilling with 9.5 ppg fluid at a total depth (TD) of 9,250 feet. When the pump is turned off as when making a connection, bottomhole pressure would be reduced by 188 psi [(9.89 – 9.5) * 0.052 * 9,250 = 188 psi], that is, the value of the APL. If the volume of cuttings carried in the fluid is considered, the ECD is 9.93 ppg, the equivalent of 207 psi at 9,250 feet of depth.

Table 10.1.

| Sample ECD Data<br>Data based on 250 gpm, ROP 25 ft/hr | | | |
|---|---|---|---|
| Standard Well - MW 9.5 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 9.68 | 9.77 |
| If TD = | 9,250 | 9.76 | 9.85 |
| If TD = | 11,040 | 9.76 | 9.85 |
| Slim-Hole Well - MW 9.5 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 9.80 | 9.84 |
| If TD = | 9,250 | 9.89 | 9.93 |
| If TD = | 11,040 | 9.89 | 9.93 |
| Ultra Slim-Hole Well - MW 9.5 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 9.71 | 9.74 |
| If TD = | 9,250 | 10.57 | 10.60 |
| If TD = | 11,040 | 10.57 | 10.60 |

In table 10.2, note that as the density of the mud increases, the differential between the ECD and the mud weight also increases. If the same rig were drilling with 10.6 ppg mud, the ECD as a result of pumping and rotating would be 11.23 ppg without cuttings, resulting in an increase in bottomhole pressure of 303 psi. The rapid loss of a 300 psi overbalance when circulation is stopped could result in an extremely high flow rate of gas into the well. In fact, the circulating pressure may actually increase as the gas enters the annulus - just the opposite of a warning sign when drilling a standard bore well. In this situation, consideration should be given to shutting the well in immediately without performing a routine flow check.

Migration rates are greater in slim holes than in standard wells. In one test 0.34 barrels of nitrogen (87 feet high) was introduced into the bottom of a well which was circulating relatively light drilling mud. The flow was very difficult to detect while pumping, and in the two or three minutes required to perform a normal flow check, a significant influx of gas entered the well before it could be shut in. The gas migration rate in the open well was computed to be 366 ft/min. The gas continued to migrate at rate of 6.7 ft/min after the well was closed.

As formation fluids flow into a kicking slim hole well, each barrel of influx will extend upwards many more times in length than in standard wells which, in turn, results in higher initial SICP and higher pressures at weak points along the wellbore (so long as the influx is below those points). Figures 10.19 and 10.20 illustrate the relationship between various kick volumes and the resulting SICP.

Tables 10.2.

| Sample ECD Data<br>Data Based on 250 gpm, ROP 25 ft/hr | | | |
|---|---|---|---|
| Standard Well - MW 10.6 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 10.91 | 10.97 |
| If TD = | 9,250 | 11.04 | 11.09 |
| If TD = | 11,040 | 11.04 | 11.09 |
| Slim-Hole Well - MW 10.6 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 11.10 | 11.13 |
| If TD = | 9,250 | 11.23 | 11.27 |
| If TD = | 11,040 | 11.23 | 11.27 |
| Ultra Slim-Hole Well - MW 10.6 ppg | | | |
| Depth | FT | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 10.96 | 10.98 |
| If TD = | 9,250 | 11.85 | 11.87 |
| If TD = | 11,040 | 11.85 | 11.87 |

When a gas kick is circulated upward in the relatively small slim hole annulus, it will reach the surface much more quickly than in a standard well, unloading fluid above the influx as the rate of expansion accelerates. High gas flow rates at the surface will require rapid and frequent choke adjustments in order to maintain control of bottomhole pressure.

Table 10.3.

| Sample ECD Data<br>Data Based on 250 gpm, ROP 25 ft./hr. | | | |
|---|---|---|---|
| Standard Well - MW 10.0 ppg | | | |
| Depth | Feet | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 10.28 | 10.35 |
| If TD = | 9,250 | 10.38 | 10.45 |
| If TD = | 11,040 | 10.38 | 10.45 |
| Slim-Hole Well - MW 10.0ppg | | | |
| Depth | Feet | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 10.44 | 10.47 |
| If TD = | 9,250 | 10.55 | 10.58 |
| If TD = | 11,040 | 10.55 | 10.58 |
| Ultra Slim-Hole Well - MW 10.0 ppg | | | |
| Depth | Feet | ECD (ppg) | ECD + Cutting (ppg) |
| Csg Shoe | 1,500 | 10.32 | 10.34 |
| If TD = | 9,250 | 11.07 | 11.09 |
| If TD = | 11,040 | 11.07 | 11.09 |

Figure 10.19. Five barrel gas kicks.

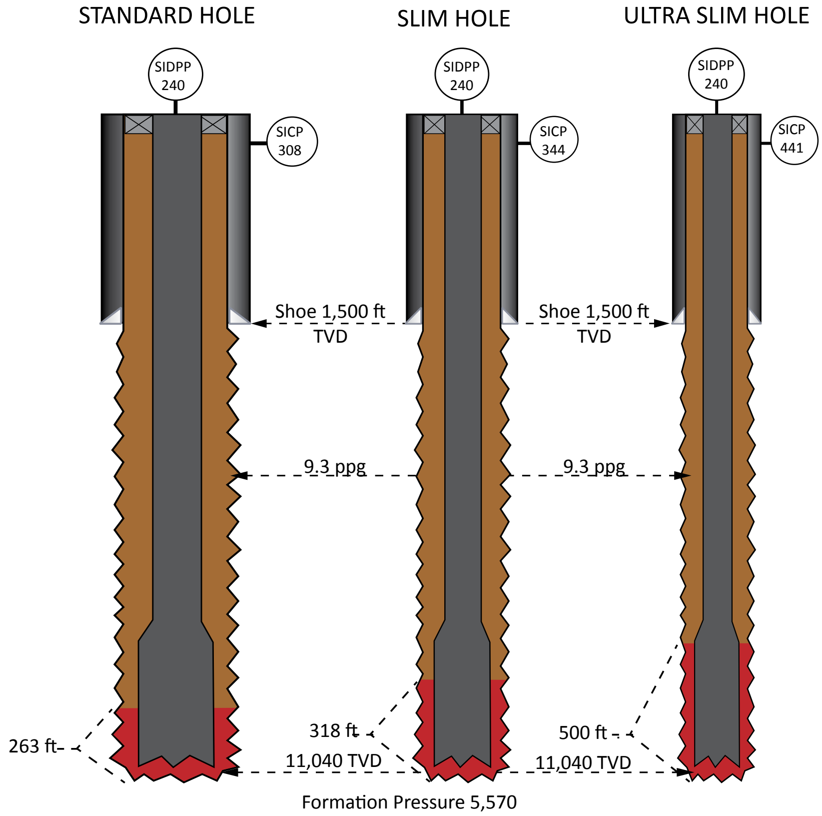
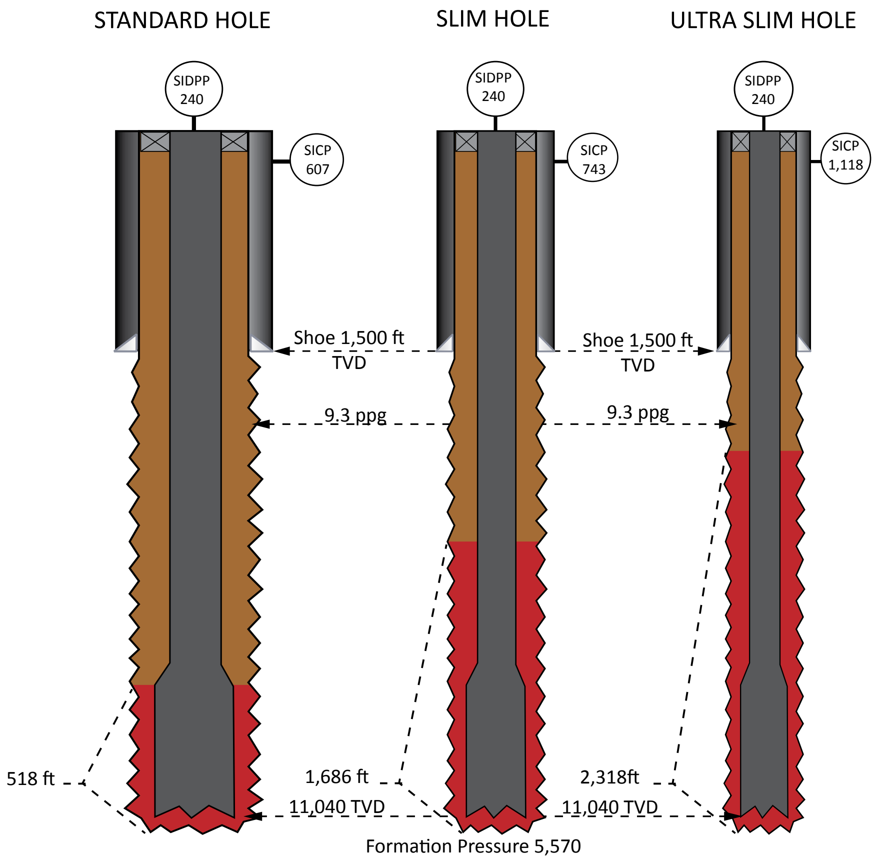



Figure 10.20. Thirty barrel gas kicks.

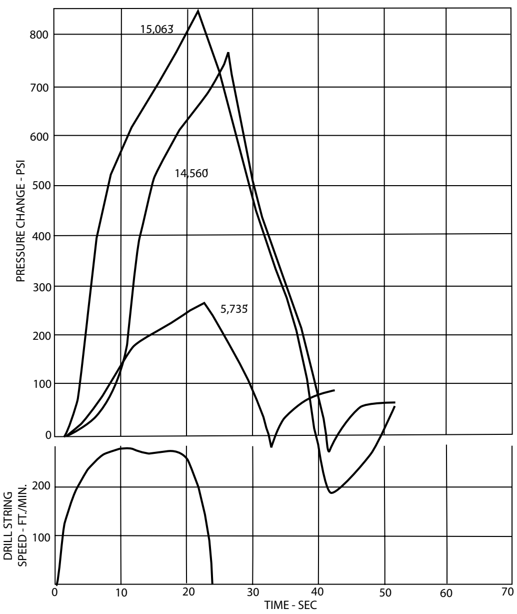


When the drill string is moved up or down within a slim hole, as when tripping, swab and surge pressures are significant due to small downhole clearances. In some instances, the only way to avoid swabbing on a trip is to pump out of the hole. Tripping practices, always an important component of blowout prevention, are of special concern in slim hole work.

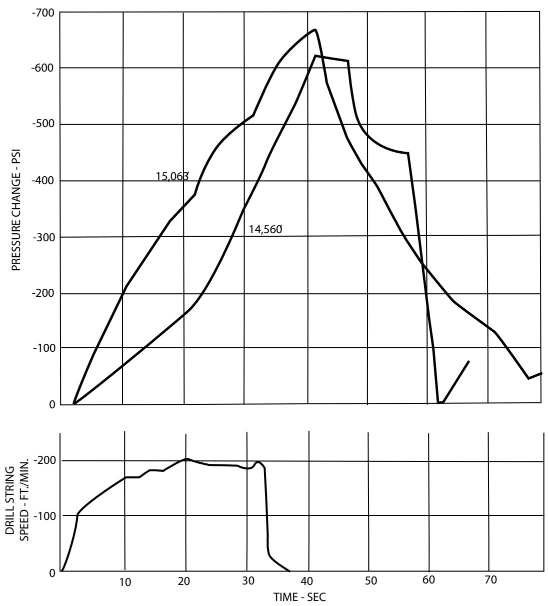
Two of the three primary contributors, to swab and surge pressures are the rate at which the work string is moved, and downhole clearances. The effects of both are increased when working in a slim hole. The graphs in figure 10.21 clearly illustrate the effects of pipe movement with regard to changes in bottomhole pressure. This data was collected on test wells in the Rocky Mountain region assuming 90 feet of pipe movement in 14.2 ppg water-based fluid. The casing was five-inch OD.

When sophisticated downhole instruments and computer generated hydraulic data are available, crucial information can be projected to the surface in real time. But whether these downhole tools are available or not, the ultimate key to safe slim hole work is the heightened awareness of the crew.

Figure 10.21. 14.2 ppg water-based mud, 5-inch casing based on 90 ft. of pipe movement.




Drill string speed and downhole pressure profiles for surging.




Drill string speed and downhole pressure profiles for swabbing.

## Highly Deviated and Horizontal Wells

Kicks taken in highly deviated wells require special consideration even though the basic principles of blowout prevention do not change. Wells deviated less than sixty degrees from the vertical can usually be treated as straight holes for the purposes of well control but as the inclination increases, well control operations can become more complex. Some of the major well control concerns in high angle wells are listed below.

- More producing formation is exposed in high angle holes. The potential for increased flow, compared to vertical wells, can result in larger influxes as well as the increased likelihood of lost circulation.
- Early kick detection is difficult if a kick occurs in the high angle section of a well. Drillers must be especially alert to changes in drilling rate and circulating pressure variations.

- Once a high angle well is shut in on a kick there may not be a significant difference between the SIDPP and SICP. If there is a great difference in shut-in pressures it indicates either that the volume of the influx is greater than the total volume of the deviated section, or that the influx extends up into the vertical portion of the well.
- If the kick enters weak spots along the deviated wellbore it may result in unreliable pressure readings on the surface. Decreases in SIDPP or SICP soon after shut in may indicate that the formation is taking fluid, which may then lead to stuck pipe or an underground blowout in the high angle section.
- Gas will migrate slower or not at all in a horizontal section. If the influx is circulated with a constant bottomhole pressure method, little or no gas expansion will occur while the influx remains in the lateral section of the well. Once the kick enters the vertical section, the gas will expand rapidly, therefore it may be difficult to maintain a constant circulating pressure while pumping the kick out well
- Gas in a horizontal section may collect along the "roof" of the wellbore. This is especially true if the section is "wavy", that is, contains rises and dips. In these cases it is difficult to circulate all the gas out of the well efficiently. The gas, lying in pockets along the top of the wellbore, will have a tendency to be strung out along the horizontal annulus. Gas may be pulled into the vertical section when the pipe is tripped out of the well .
- The make-up of the drill string in a horizontal well may be radically different from that used in conventional drilling. The drill collars may be near the surface, heavy weight drill pipe (HWDP) below the collars, and the drill pipe and tools below the HWDP. Differences in drill string design will affect annular volumes and, consequently, annular velocities when circulating. When the gas enters the vertical section, (perhaps around the drill collars in the vertical section) the influx will lengthen. The increased flow rate through the choke can result in rapidly increasing casing pressure. In this case the choke will have to be adjusted quickly to maintain a constant bottomhole pressure and to minimize pressure on the casing seat and weak formations.
- Formation fluids may continue to flow into the annulus if the kill fluid enters a depleted fracture.

The driller's method is well suited for controlling kicks in high angle or horizontal wells. It minimizes shut-in time and does not require a detailed pumping schedule. As in a vertical well, the influx is pumped out of the annulus holding the circulating pressure constant at a constant pump rate. Often horizontal wells are drilled underbalanced or near balanced, therefore, once the influx has been removed from the annulus, drilling operations can continue.

If the well is to be killed after the influx has been removed, bottomhole pressure can be controlled by maintaining a constant casing pressure as the kill fluid is pumped to the end of the drill string. Once the drill string is full of heavier mud, the circulating pressure is maintained until the kill fluid returns to the surface.

Using the wait-and-weight (W&W) method to kill high directional wells can be complicated because until the drill string is full of kill mud, there is a mixed column of fluid on both sides of the U-tube. If bottomhole pressure is to remain constant as the kill fluid is pumped to the end of the string, adjustments must be made to the normal pumping schedule.

A primary advantage of the W&W method on near-vertical wells is that it may result in lower pressures being exerted on the open hole if the kill fluid enters the annulus before a gas influx reaches the surface. In horizontal or high angle wells, the effect of increased hydrostatic pressure, due to the kill fluid in the annulus, is not realized until the heavier fluid starts up into the vertical section of the well. If the drill string volume, plus the annular volume, from TD up to the horizontal point (HOP) is greater than the annular volume from the HOP to the surface, then the influx will be circulated out of the well before the kill mud enters the vertical annulus. The main benefit derived from using the W&W method in highly deviated wells is the possibility of killing a well in one circulation because surface pressures will have already reached their highest value.

When the W&W method is used in vertical wells, it is assumed that the changing hydrostatic pressure inside the drill string and the resulting increase in friction pressure occur simultaneously as kill fluid is pumped to the end of the string. This is true if the length of the column of heavier fluid increases to the same degree for each pump stroke. Calculations (kill sheets) are used to predict the decreasing circulating pressure as the heavier fluid is pumped from the surface to the end of the drill string.

The standard pressure chart used for the W&W method (from ICP to FCP) is an over-simplification. Although they may not be scientifically accurate, they are practical and the errors are insignificant in vertical wells. In most cases, the developed pumping schedule results in exerting slightly higher pressures against the formation as the kill fluid is pumped to the bit. However, if a standard kill sheet is used on highly deviated wells, it would result in greater pressure exerted on the open hole because most of the increase in hydrostatic pressure is realized at the kickoff point (KOP) but the friction will continue to increase until the heavier fluid reaches the end of the string. If the W&W Method is to be used in a horizontal well, the changes in hydrostatic and friction pressures are treated separately as the kill mud is pumped.

The ideal circulating pressure schedule for a horizontal well would have a linear pressure schedule for the vertical section, a separate schedule for the radius from the KOP to the HOP, and a linear schedule from the HOP to the end of the string. In order to construct the chart, the true vertical depth and the measured depth at various points along the angle-building radius must be known. Modern advances in downhole instruments and computer technology have made it possible for supervisors to have access to data that was unavailable just a few years ago. Computer programs and electronic worksheets can accurately predict circulating pressures.

If the difference between the pressure to the KOP on a standard pressure schedule and the pressure calculated at KOP is more than 100 psi, then a deviated pressure chart is probably justified. If it is less than 100 psi, it may be better to use the standard method of calculating the pressure schedule unless the SICP approaches the MAASP. The chart in table 10.4 illustrates the differences in circulating pressure at the end of the angle build-up (EOB) under different well conditions. It can be seen that special deviated pressure change calculations may not be called for when the average angle is less than 60° and/or the density of the kick is less than 1.0 pound per gallon more than the original fluid density.

The following calculations may be used as a means of estimating the circulating pressure difference between a standard vertical and a deviated pressure schedule when the MD and TVD at various points along the radius of angle buildup are known.

1. Calculate the increase in circulating friction per each foot in the work string.

$$\boxed{\text{Increase in Friction}_{psi/ft} = (\text{FCP}_{psi} - \text{Original SCR Pressure}_{psi}) \div \text{Length of string}_{ft}}$$

2. Calculate the gain in hydrostatic pressure in the vertical section.

$$\boxed{\text{Gain in Hydrostatic Pressure}_{psi} = \text{SIDPP}_{psi} \div \text{TVD}_{ft} \text{ of well}}$$

Or

$$\boxed{\text{*Gain in Hydrostatic Pressure}_{psi} = (\text{KMW}_{ppg} - \text{OMW}_{ppg}) * 0.052}$$

*This may result in a heavier kill fluid than calculated from SIDPP, due to rounding decimals in the kill mud calculation.

3. Calculate the circulating pressure (CP) at a given depth (requires both MD and TVD to several points along the wellbore)

$$\boxed{\text{CP}_{psi} = \text{ICP}_{psi} + (\text{Increase in Friction}_{psi/ft} * \text{MD}_{ft}) - (\text{Gain in Hydrostatic Pressure}_{psi/ft} * \text{TVD}_{ft})}$$

Calculation 3 is repeated for several equal lengths along the curve of the directional well in order to determine the correct circulating pressure.

Table 10.4

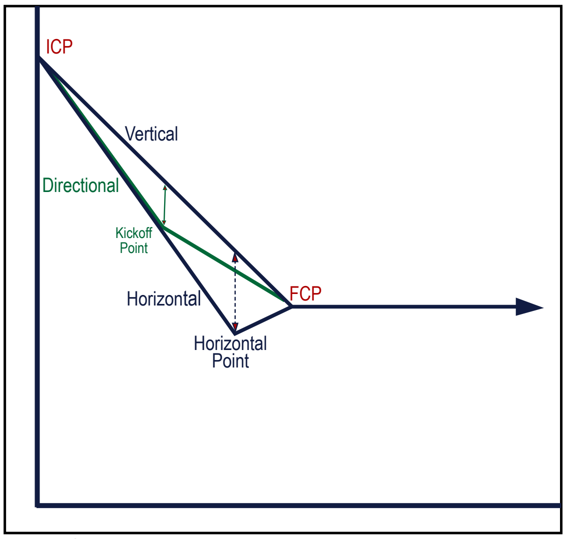
| Comparison of Maximum Pressure Discrepancy vs Straight and High-Angle Well Pressure Plots | | | | | | |
|---|---|---|---|---|---|---|
| | | | | Calculated Circulating Pressure at EOB | | |
| MD (ft.) | TVD at EOB (ft) | Kick Intensity (ppg) | Average Angle (degrees) | Straight Hole Method PT. A (psi) | Deviated Hole Method PT. B psi | If Straight Hole Method, A-B psi |
| 12,000 | 7,654 | 1.0 | 60 | 878 | 825 | 53 |
| | 5,786 | 1.0 | 75 | 804 | 721 | 83 |
| | 3,910 | 1.0 | 90 | 738 | 622 | 116 |
| | 7,654 | 2.0 | 60 | 1,156 | 1,051 | 105 |
| | 5,786 | 2.0 | 75 | 1,008 | 841 | 167 |
| | 3,910 | 2.0 | 90 | 876 | 643 | 233 |
| | 7,654 | 3.0 | 60 | 1,435 | 1,276 | 159 |
| | 5,786 | 3.0 | 75 | 1,212 | 961 | 251 |
| | 3,910 | 3.0 | 90 | 1,014 | 659 | 355 |
| 15,000 | 9,154 | 1.0 | 60 | 959 | 900 | 59 |
| | 6,563 | 1.0 | 75 | 828 | 757 | 95 |
| | 3,910 | 1.0 | 90 | 738 | 583 | 155 |
| | 9,154 | 2.0 | 60 | 1,316 | 1,200 | 119 |
| | 6,563 | 2.0 | 75 | 1,104 | 914 | 190 |
| | 3,910 | 2.0 | 90 | 876 | 635 | 241 |
| | 9,154 | 3.0 | 60 | 1,679 | 1,500 | 179 |
| | 6,563 | 3.0 | 75 | 1,356 | 1,071 | 285 |
| | 3,910 | 3.0 | 90 | 1,054 | 652 | 402 |
| Calculations use 11.5 ppg Original Fluid, $3^0$ /100 ft. Rate of Angle Build, 2,000 ft. KOP | | | | | | |

When the horizontal length is longer than the well's vertical portion, the circulating pressure at KOP may actually be less than the FCP value. The pressure will increase from that point to the FCP, as a result of the gain in friction as the kill fluid moves to the end of the string. The hydrostatic effect of the kill fluid is realized at the KOP, but the friction continues to increase until the heavier fluid enters the annulus.

Figure 10.22 illustrates a graphic method of determining the pressure decrease necessary to balance, or slightly overbalance formation, pressure while pumping the kill mud from the surface to the bit in a deviated well.

The first step when constructing the graph is to plot both ICP and FCP versus strokes (or volume) on graph paper. Next, determine the greatest discrepancy which would occur in the vicinity of the end of the angle build-up. Calculation 3, above, will predict the circulating pressure. The circulating pressure is plotted against the volume (using MD). The maximum difference between the standard pumping schedule and the deviated schedule can then be determined.

Figure 10.22.




Straight versus high-angle well pressures

Regardless of which pressure chart is used, the ICP and FCP are the same as that determined by a standard kill sheet. The difference between vertical well control calculations and deviated/horizontal wells occurs between ICP and FCP, with the greatest discrepancy at the end of angle buildup.

High angle and horizontal wells can exhibit unexpected behavior after a kick has been circulated and brought back under hydrostatic control. Irregular washed out sections may contain pockets of gas in washouts and wavy sections of the borehole. At slow kill rates, gas may have migrated into the washed out sections.

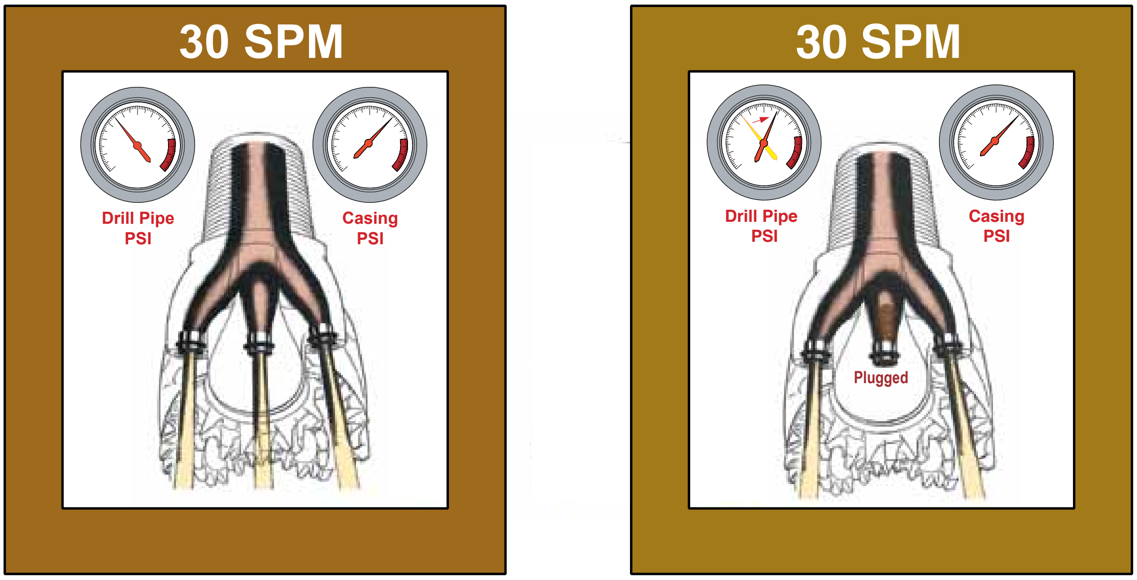
After the well is dead and the BOPs are opened, another circulation is recommended at a higher circulating rate in order to sweep the gas out of the washout pockets. As the gas nears the surface, it will expand freely. If the return flow and the level in mud pits increase significantly, it might become necessary to shut the well in again and bring the gas out under controlled conditions to avoid allowing a new kick to enter the well. Since the mud will be at the kill weight, the driller's method can be used to finish circulating the gas out of the well. The temptation to increase mud weight should be resisted.

## Plugged Bit Nozzle

If a bit nozzle were to plug while a kick is being circulated out the circulating pressure would rise suddenly but the casing pressure would not change significantly. Since the greater part of the circulating pressure is a result of friction in the drill string, bottomhole pressure would not change. The choke operator should resist the temptation to open the choke because opening the choke will allow bottomhole pressure to decrease and induce another kick.

If the new circulating pressure is not considered too high, the higher pressure is theoretically correct and the operation can continue. The choke operator would simply maintain the new, higher drill pipe pressure at the same pump rate. The best procedure would be to shut the well in safely, analyze the situation and then start up again, holding the casing pressure constant until the pump is at some selected rate. When the pump rate is correct and the casing pressure is at its shut-in value, the circulating pressure will be correct. If a nozzle were to plug while pumping kill fluid down the drill string, the pumping schedule would have to be adjusted to accommodate the new circulating pressure(s).

Figure 10.23. Before and after a partial blockage in the string. If pump rate and casing pressure do not change, BHP remains constant.




If the all the bit jets are obstructed and the amount of pressure increase cannot be tolerated at kill rate speed, the bit jets can be cleared by using wireline to blow out the bit jets or perforate the drill pipe above the bit. The casing pressure must be controlled while waiting on a wireline unit to perforate the drill pipe or blow out the bit jets.

### Sand Bridges when Circulating out a Kick

Sand or other debris may accumulate and bridge-off in the tubing or fall and begin to fill the inside of the annulus. With complete blockage, there is no communication between the tubing and annulus. Gas bubbles or other formation fluid trapped below a sand bridge will result in a higher differential pressure below the sand bridge. Lost circulation may occur below the bridge if pumping is continued, due to excessive pressures below the bridge.

If the kick occurs below the bridge when circulating, the:

- tubing pressure slowly increases.
- casing pressure decreases.
- pump speed decreases.

Working the pipe without applying excessive pump pressure may free the bridge.

Partial circulation and gas migration may cause casing pressure fluctuations.

If the kick occurs above the bridge, the tubing pressure will increase rapidly when circulating. Casing pressure will decrease slowly and steadily if the choke is used to maintain the SIDPP.

### Tubing or Bit Obstructed when Circulating out a Kick

Sand bridges or other obstructions can also occur in the tubing or in the bit. With complete tubing blockage, there is no communication between the tubing and the formation pressure. The pump pressure will increase without an increase in casing pressure if the tubing or bit is obstructed. Casing pressure may also decline and return flow may slow down.

Barite additions without enough suspension agents during a well kill operation may cause barite plugging in tubing. Blocked tubing will result in increased SIDPP/SITP when circulating out a kick. Another influx may occur if the choke is opened to maintain the same SIDPP/SITP pressure as before tubing plugging occurred.

The blockage may be cleared by:

- Washing and circulating out the blockage by snubbing in smaller diameter tubing string or running coiled tubing into the blocked tubing
- Running a wireline tool into the tubing to clear the plug
- Rapidly increasing and decreasing the pump rate to surge the tubing
- Perforating directly above the obstruction in the tubing
- Blowing out the bit jets, if bit is plugged.
- Pulling the tubing string

Casing pressure must be controlled while preparing to clear the blockage. When the bit or tubing becomes unplugged the choke operator should try to maintain the casing pressure at the pressure before the tubing/bit was plugged.

### Partial Tubing or Bit Obstruction when Circulating out a Kick

Note the pressure increase if a partial tubing obstruction or if all the bit jets are not obstructed. If the pressure increase can be tolerated at kill rate speed, note the pressure increase and redo the killsheet, using the increased pressure reading.

If the pressure increase cannot be tolerated, adjust the pump to a slower kill rate speed while hold the existing casing pressure constant. Note the new kill rate speed and new tubing pressure. Determine the pump pressure and redo the killsheet, using the reduced pressure reading.

### Drill String Washout

If a washout occurs in the drill string while killing a well the indication is similar to that when a nozzle plugs. Only in the case of a washout, the circulating pressure will decrease but the casing pressure will not change appreciably, indicating that the problem is in the string. No immediate action should be taken before shutting the well in and thoroughly analyzing the situation.

If the well is being killed using the driller's method and the washout is above the kick, the shut-in pressures will be equal. Like a kick taken while off bottom, the U-tube model cannot be applied in this case. One solution might be to allow the kick to migrate (if gas) to the surface using the volumetric principle and then to safely remove the gas either by circulation or by the lubricate-and-bleed method in chapter 9, "Well Kill Methods".

If on the other hand, the kick is above the washout, the SIDPP will be less than the SICP. Circulation can begin again by ascertaining a new circulating pressure (since the circulating friction will have changed) and finishing the kill by holding the pump rate and new circulating pressure constant with the choke.

If the wait-and-weight method is being used analysis becomes more complex because the position of the kill fluid will influence the shut-in pressures. It may be difficult or even impossible to determine accurate pressures or the relationship between the shut-in pressures. Eventually the decision as to how to proceed comes down to the same choices as in the driller's method, i.e., whether to continue the kill operation or to control gas migration using volumetric techniques. There is no one, sure solution that can be applied to drill string washouts that occur during well control operations. Procedures can only be decided upon in the field because of the many specific questions that arise, for example:

- Is it possible to finish the kill?
- At what depth is the washout? Is some kill fluid returning to the surface early?
- What is the size, the magnitude, and material of the kick?
- What is the general condition of the drill string?
- What are the chances of parting the string if the kill operation is continued?

It can be seen that a washout in the drill string is a serious problem and there is no one simple action that can be recommended.

Figure 10.24 can be used as a troubleshooting guide when analyzing some of the common complications that may arise during a well control kill operation.

Figure 10.24.

## SPECIAL SITUATIONS PROBLEM ANALYSIS AID

| Symptom | Drill pipe pressure | Casing pressure | Drill String weight | Pit Level | Pump rate |
|---|---|---|---|---|---|
| Plugged choke | ▲ | ▲ | | | ∨ |
| Washed choke | ▼ | ▼ | | ▲ | ∧ |
| plugged nozzle | ▲ | ▬ | | | ∨ |
| blown bit nozzle | ▼ | ▬ | | | ∧ |
| washout in string | ▼ | ▬ | | | ∧ |
| parted string | ▼ | ▬ | ▼ | | ∧ |
| reduced pump output (damage) | ∨ | ∨ | | | ∧ |
| Gas feeding in | ▬ | ∧ | ∧ | ▲ | |
| Gas at surface | ▼ | ▼ | ∨ | ▼ | ∧ |
| Loss of circulation | ▼ | ∨ | ▲ | ▼ | ∧ |
| Hole packed off | ▲ | ∨ | Stuck | ∨ | ∨ |

Source: API RP 59[3]

| Key to the chart | |
|---|---|
| ▼ | Strong indicator |
| ∨ | Lesser indicator |
| ▬ | Little or no change |

### Blockages and Trapped Pressure in Tubing/Wellbore

In well intervention work, it is often possible to encounter many situations that cause blockages and/or trapped pressure. In some coiled tubing applications it is possible that well pressure trapped below a blockage, plug or obstruction will be suddenly released during the operation. Provided that the pressure control equipment has been properly selected and operated, trapped pressure should not create significant additional risk. However, the following general precautions should be considered if well conditions are likely to include trapped pressure.

- Always ensure that pressure control equipment is selected on the basis of the maximum anticipated surface pressure.
- Attempts should be made to equalize any pressure differential slowly.
- If a potential for very large differential pressure exists, consider applying pressure to the upper wellbore before removing the obstruction to reduce the potential for the release of high-energy fluids.

### Wireline Plugs

Special attention should be given to the possibility of trapped pressure when entering into a well in which a wireline plug has been previously set. It is virtually impossible to measure the pressure that might be trapped below the plug. A conservative estimate can be made by calculating the maximum value of the trapped pressure. The maximum value is the reservoir pressure minus the hydrostatic pressure of a column of reservoir fluids between the reservoir and the set plug. Remember that the TVD of these points in the well must be used rather than measured depths to make the hydrostatic pressure calculation. Prior to release/removal of the plug, the wellbore above the plug should be pressured by either: (1) adding an imposed surface pressure or (2) filling the well with a heavier fluid that will equalize the pressure across the plug.

### Subsurface Safety Valves (Offshore Completions)

The subsurface safety valve is a device installed in the upper wellbore to provide emergency closure of the producing conduits in the event of an emergency. There are two general types of subsurface safety valves available.

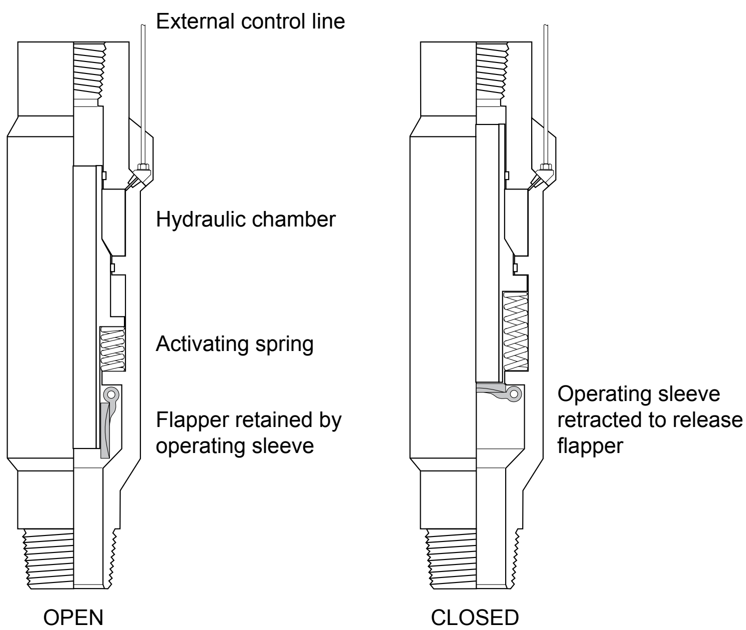
1. Surface-controlled subsurface safety valve (SCSSV)
2. Subsurface controlled safety valves (SCSV)

The SCSSV is operated from surface facilities through a control line strapped to the external surface of the production tubing. The control system operates in a fail-safe mode, with hydraulic control pressure used to hold open a ball or flapper assembly that will close if the control pressure is lost. The hydraulic control system used to maintain the valve in the open position is typically connected to a control and monitoring system that may include several wells, such as on an offshore production platform.

During well intervention work, such as coiled tubing operations, it is common for the temporary control of the safety valve operation to be taken over by the coiled tubing operator to prevent the accidental closure of the safety valve while the coiled tubing is in the wellbore.

The hydraulic control line pressure required to operate the SCSSV is typically dependent on the well pressure within the valve body. For example, if the well pressure is low, then a relatively low control line pressure will maintain the valve in the open position. However, if the well pressure changes significantly during an injection of treatment fluid, the change in pressure may be sufficient to overcome the control line pressure and inadvertently operate the safety valve. An illustration of the operation of an SCSSV is provided in figure 10.25.

Figure 10.25. An illustration of a general configurartion of a subsurface safety valve.




*NOTE: Dependant on the type of SCSSV it is recommended to follow the manufactures operating procedures.*

In well control events, the capability to circulate is highly desired. Failure of an SCSSV due to control line pressure loss should not impede circulation when coiled tubing is inside the production tubing. However, the flapper could damage the CT and make BHA retrieval difficult.

There are two basic types of SCSSV – wireline retrievable and tubing retrievable. Wireline retrievable SCSSV can be run and retrieved on slickline. Tubing retrievable SCSSV are installed in the tubing string and can only be retrieved if the production tubing is pulled.

When approacheing subsurface safety valves or gas mandrels, the coiled tubing running speed could be reduced to avoid damage of the tool string and the subsurface safety valve ot gas lift mandrel that might partially obstruct the wellbore.

The surface controlled subsurface safety valves (SCSSV) use two basic operating mechanisms for actuating the valves. The valves are either operated by an increase in flow velocity or by a decrease in the local pressure. They are often called *storm chokes*. It is difficult to confirm operation with subsurface controlled subsurface safety valves. Therefore, the SCSSV are much more commonly used, Subsurface controlled valves sometimes run in a well as a contingency supplement to SCSSV that have failed or otherwise become inoperable. Both SCSSV and SCSV valves are designed to be fail-safe., so that the wellbore is isolated in the event of any surface control systemn failure or damage to the production-control facilities.

## Bridge Plugs, Sand Bridges

Bridge plugs are often set in the lower section of a well, below the zone that is to be treated during the intervention. Preset bridge plugs are relatively safe and likely to be only a minor complication to the treatment activity. They can be of concern when removed. The possibility of trapped pressure below the plugs should be recognized and considered upon removal. After removal, the coiled tubing should be run to TD below the bridge plug and the entire well circulated with a kill fluid through an open choke prior to pulling the coiled tubing from the well. When a rat hole or sump has been isolated with a bridge plug during the treatment of the higher zone(s) of a live well, circulation of these zones following treatment is of no value ans shoudl not be done. If some production has been coming from a zone below the bridge plug, and it is desired to get this production back on line after removal of the plug, then lifting this zone with nitrogen gas might be considered following treatment of the upper zone.

Some bridge plugs are permanent. A leaking permanent bridge plug can cause a significant problem if the well above the plug is killed prior to treatment. Generally, a continuous flow og gas from below the plug cannot be mitigated without setting a second plug above the leaking plug or removal/replacement of the leaking bridge plug.

Another type of plug that might be encountered in a well is a brisge formed by either collapse of the wellbore wall (open-hole completion) or ineffective circulation of produced sand in a low flow rate well. Coiled tubing is often used to remove these sand bridges. As with the mechanical bridges, there is always the possibility of trapped gas below. Hence, eithere a kill fluid should be prepared and circulated (after estimateing the maximum possible pressure below the bridge) or the well control equipment and operator should be prepared to immediately handle the influx after the sand bridge has been washed through (If the bridge is sand, with little or no shale, it will very likely not form a seal, and gas or other hydrocarbons will permeate through before any washing has begun.) To cope with any gas permeating the sand plug, the well should be circulated through a choke prior to washing throught. To circulate (wash) through, a highly gelled fluid should be considered to increase the carrying capacity of the working fluid as the sand is circulated out of the well.

## Paraffin Wax

Produced oils generally contain some temperature-dependent substances like praffin or asphaltenes. These substances create problems in a wellbore when the temperatures drop as they flow up production tubing and they underfo a phase change from liquid to solid. Paraffin waxes may plug surface equipment or reduce the effective diameter of production tubing. If a well is to be entered with coiled tubing and there is a thick buildup of paraffin, the coiled tubing BHA may hang up and become stuck.

Paraffin can affect coiled tubing well control operations. Buildup of the wax on the inside of the production tubing effectively decreases the ID of the tubing. Sufficient buildup can cause a very large friction pressure in the annulus. In many instances, this high annulus friction could affect the ability to circulate an influx with either the driller's method or wait-and-weight method (Recall that these methods assume and rely on there being a negligible amount of friction pressure in the annulus.)

When paraffin buildup is believed to be present, coiled tubing can wash the paraffin by pumping solvents as the tubing enters the well. Prior to a well intervention, samples of the produced fluids should be examined to determine the best type the best type of solvent to be pumped when the paraffin must be removed.

## Hydrates

*Hydrates* are solid ice-like structures that form in the precense of gas, water and pressure of cool temperatures. The formation of hydrates differs from crystallization in brines. Formation of hydrates also depends on the type of working fluid in use, how much free water the fluid contains, and the type of hydrocarbon gas. When temperatures fall below about 40 °F (4.4 °C), the process of hydrate formation is possible when fluids are exposed to hydrocarbon gases. Lower temperatures, heavier gases and longer time periods without circulation all increase the probability of the formation of hydrates. Hydrate formation is much more likely in water-based fluids than in oil-based or synthetic oil-based fluids.

Hydrates may hamper or even shut down well control operations. If a choke or a line to a choke within the choke manifold become plugged, it may be possible to switch to an alternate choke. When plugging of a BOP cavity or fail-safe valve on a choke line occurs, resolution of the problem is much more difficult. Pumping down an alternate line and spotting methanol can break up packed hydrates, but is difficult, and in many situations unsafe, due to the toxicity of the methanol. Hydrates may alse be dissolved by pumping hot fluids into the well and circulating the hot fluid past the location where hydrates have formed (typically in the BOP stack, choke manifold or flow lines).

The better choice for hydrate control is to use an inhibitive fluid and thus prohibit hydrate formation when conditionsf or hydrate formation are known to exist. Inhibitive fludis contain salts and glycerol to preven the formation of gas hysrates in the fluid, Typical salt concentrations needed are 20 to 26 percent by weight. If greater inhibiting properties are required, up to 10% glycerol may be added.

When the potentional for hydrate formation exists, it is strongly recommended the well not be shut in for long periods of time should an influx occur. The influx should be circulated out quickly so that gas (which is required for hydrate formation) is removed quickly. The driller's method should be considered for the well control technique for circulating influxes with hydrate formation potential.

## Pressure on Casing

Prior to and during coiled tubing operations, the pressure between the production tubing and the coiled tubing should be monitored. The casing by tubing annulus is usually filled with packer fluid. The annulus containing a fluid of sufficient density to minimize the pressure difference across the packer, prevent tubing burst and/or preven the collapse of the casing due to external pressure such as expanding salt formations and formation pressures which have leaked from below the casing shoe.

If packer fluid leaks into the producing stream, the loss of fluid over time would defeat the original purpose of the packer. Conversely, production gases may leak into the packer fluid column from the tubing or through the packer itself. The gas will migrate, creating pressure above the column that tintroduces the potentional to collapse the production tubing, or possible burst the casing. During coiled tubing operation, the tubing-by-casing annulus pressure should be monitored at all times at the casing head to ensure no surface pressure buildup occurs during the well intervention operation.

A hole in the production casing can cause heavy packer fluids to leak into an intermediate casing that may not have been cemented to surface. This can cause the intermediate casing to build an internal pressure for which is was not designed to handle. Also, high pressure behind the leaking production casing may cause a failure of the cement at the shoe or between performation interveals. This could lead to the lost circulation or underground flow of reservoir fluid from one zone to another.

If the integrity of casing or tubing strings in a well to be serviced with a coiled tubing unit is questionable, the pressure used in the well intervention and treatment may be limited. Also, entry into an old competion with coiled tubing may not be possible due to collapsed production tubing. During the initial well completion, or during a ling shut-in period, the annular pressure may alse increase due to the temperature effect on the packer fluid.

A remedial cement squeeze or similar isolation mechanism may also have failed to patch leaking tubing or a casing string, or properly cement a casing shoe. A coiled tubing unit can be used to correct these problems.

### Lost Circulation

Lost circulation occurs when a weak formation cannot withstand the bottomhole pressure exerted by the circulating fluid column. For example, when circulating fill material from a wellbore, the loading of solids in the annular fluid column effectively increases the hydrostatic pressure and the bottomhole pressure. If a weak formation is exposed and cannot support the column, some leak-off will occur and if the increase in fluid density is severe enough, fluid pumped into tht well will preferentially flow into the formation. Then, the flow rate up the annulus will decrease as a part of the fluid flows into the rock. In some cases, the decrease in flow rate will be reduced to zero and all fluid pumped will be "lost" to the formation.

# Equipment Testing

# 11

The following procedures are excerpts taken from API RP 53[1] and are general guidelines only and should not be confused with any government, state, or company policy.

On surface preventers, the closing system should be capable of closing each ram preventer within 30 seconds and should not exceed 30 seconds for annular preventers smaller than 20 inches or 45 seconds for those larger than 20 inches. For subsea preventers, each ram should close within 45 seconds and annular preventers within 60 seconds.

## Closing Units Requirements

The closing unit pump capability test should be conducted on each well before pressure testing the BOP stack. A typical test would entail the following:

1. Position a joint of drill pipe in the BOP stack.
2. Isolate the accumulators from closing unit manifold by closing the necessary valves.
3. If the pumps are powered by air, isolate the rig air system from the pumps. A separate closing unit air storage tank or bank of nitrogen bottles should be used to power the pumps during this test. If a dual power system source is used, each power supply should be tested separately.
4. Simultaneously turn the control valve for the annular preventer to the closing position and turn the control for the hydraulically controlled valve (HCR) to the open position.
5. Record the time, in seconds, for the pumps to close the annular preventer, to open the hydraulically controlled valve and record the pressure that is remaining. API recommends that this time should not be exceed two minutes.
6. Close the hydraulically controlled valve and open the annular preventer. Open the accumulator system to the closing unit, charge the system to its operating pressure, and record the time to do this.

## Accumulator Closing Test

To be conducted on a per well basis prior to testing the BOP stack. A typical test procedure follows:

1. Position a joint of drillpipe in the BOP stack.
2. Close the power supply to accumulator pumps.
3. Record the initial accumulator pressures. Adjust the annular regulator to 1,500 psi or designated pressure.
4. Depending on policy, perform the functions that are required. For example, API requires the minimum standard to close the annular, one pipe ram, and the hydraulic choke line valve.
5. Record the time required for accumulators to close and the final accumulator pressure. The final pressure should not be less than 200 psi above the precharge pressure.

*NOTE: Some regulatory agencies require than a minimum of 200 psi above the precharge pressure.*

6. After the preventers have been opened, recharge accumulator system to the designed operating pressure and record the time for complete power up.

Table 11.1.
*RECOMMENDED PRESSURE TEST PRACTICES, LAND AND BOTTOM-SUPPORTED RIGS*

| *Initial Test (prior to spud or upon installation):* | | |
|---|---|---|
| **Component to be Tested** | **Recommended Pressure Test - Low Pressure, psi[a]** | **Recommended Pressure Test - High Pressure, psi[b,c]** |
| 1. Rotating Head | 200-300 | Optional |
| 2. Diverter Element | Minimum of 200 | Optional |
| 3. Annular Preventer | 200-300) | Minimum of 70% of Annular BOP working pressure. |
| • Operating Chambers | N/A | Minimum of 1500 (10.3MPa). |
| 4. Ram Preventers | | |
| • Fixed Pipe | 200-300 | Working Pressure of ram BOPs. |
| • Variable Bore | 200-300 | Working Pressure of ram BOPs |
| • Blind/Blind Shear | 200-300 | Working Pressure of ram BOPs |
| • Operating Chamber | N/A | Maximum operating pressure recommended by ram BOP manufacturer. |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke line & Valves | 200-300 | Working Pressure of ram BOPs |
| 7. Kill Line & Valves | 200-300 | Working Pressure of ram BOPs |
| 8. Choke Manifold | | |
| • Upstream of Last High Pressure Valve | 200-300 | Working Pressure of ram BOPs |
| • Downstream of Last High Pressure Valve | 200-300 | Optional |
| 9. BOP Control System | | |
| • Manifold and BOP Lines | N/A | Minimum of 3000 (20.7MPa) |
| • Accumulator Pressure | Verify Precharge | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 10. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300 | Working pressure of component. |
| 11. Auxiliary Equipment | | |
| • Mud/Gas Separator | Flow Test | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a] *The Low Pressure test should be stable for at least 5 minutes.*
[b] *The High Pressure test should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe significant leaks.*
[c] *The rig available well control equipment many have a higher rated working pressure than site required. The site-specific test requirement should be considered for these situations.*

Table 11.2.
*RECOMMENDED PRESSURE TEST PRACTICES, LAND AND BOTTOM-SUPPORTED RIGS*

| *Subsequent Test (not to exceed 21 days):* | | |
|---|---|---|
| **Component to be Tested** | **Recommended Pressure Test - Low Pressure, psi**[a] | **Recommended Pressure Test - High Pressure, psi**[b] |
| 1. Rotating Head | N/A | Optional |
| 2. Diverter Element | Optional | Optional |
| 3. Annular Preventer | 200-300 | Minimum of 70% of Annular BOP working pressure. |
| • Operating Chambers | N/A | N/A |
| 4. Ram Preventers | | |
| • Fixed Pipe | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Variable Bore | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Blind/Blind Shear | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Casing (prior to running csg) | Optional | Optional |
| • Operating Chamber | N/A | N/A |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke line & Valves | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 7. Kill Line & Valves | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 8. Choke Maifold | | |
| • Upstream of Last High Pressure Valve | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Downstream of Last High Pressure Valve | Optional | Optional |
| 9. BOP Control System | | |
| • Manifold and BOP Lines | N/A | Optional |
| • Accumulator Pressure | Verify Precharge | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 10. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 11. Auxiliary Equipment | | |
| • Mud/Gas Separator | Optional Flow Test | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a] *The Low Pressure test should be stable for at least 5 minutes.*
[b] *The High Pressure test should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe significant leaks.*

Table 11.3.

*RECOMMENDED PRESSURE TEST PRACTICES, FLOATING RIGS WITH SUBSEA BOP STACKS*

| *Initial Test (diverter system prior to spud, et. al prior to running stack):* | | |
|---|---|---|
| **Component to be Tested** | **Recommended Pressure Test - Low Pressure, psi[a]** | **Recommended Pressure Test - High Pressure, psi[b,c]** |
| 1. Diverter Element | Optional | Optional |
| 2. Annular Preventer(s) | 200-300 | Minimum of 70% of Annular BOP working pressure. |
| • Operating Chambers | N/A | Minimum of 1500. |
| 3. Ram Preventers | | |
| • Fixed Pipe | 200-300 | Working Pressure of ram BOPs. |
| • Variable Bore | 200-300 | Working Pressure of ram BOPs |
| • Blind/Blind Shear | 200-300 | Working Pressure of ram BOPs |
| • Operating Chamber | N/A | Maximum operating pressure recommended by ram BOP manufacturer. |
| 4. BOP-to-WHD Connector | 200-300 | Working Pressure of ram BOPs |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke & Kill Lines & Valves | 200-300 | Working Pressure of ram BOPs |
| 7. Choke Manifold | | |
| • Upstream of Last High Pressure Valve | 200-300 | Working Pressure of ram BOPs |
| • Downstream of Last High Pressure Valve | 200-300 | Optional |
| 8. BOP Control System | | |
| • Manifold | N/A | Minimum of 3000 (20.7MPa) |
| • Accumulator Pressure | Verify Precharge | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 9. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300) | Working pressure of component. |
| 10. Auxiliary Equipment | 200-300 | Optional |
| • Riser Slip Joint | Flow Test | N/A |
| • Mud/Gas Separator | Flow Test | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a] *The Low Pressure test should be stable for at least 5 minutes.*

[b] *The High Pressure test should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe significant leaks.*

[c] *The rig available well control equipment many have a higher rated working pressure than site required. The site-specific test requirement should be considered for these situations.*

Table 11.4.
*RECOMMENDED PRESSURE TEST PRACTICES, FLOATING RIGS WITH SUBSEA BOP STACKS*

| *Subsequent Test [(A) BOP stack initially installing in wellhead; and (B) not to exceed 21 days):* | | |
|---|---|---|
| **Component to be Tested** | **Recommended Pressure Test - Low Pressure, psi[a]** | **Recommended Pressure Test - High Pressure, psi[b]** |
| 1. Diverter Element | Optional | Optional |
| 2. Annular Preventer | 200-300 | Minimum of 70% of Annular BOP working pressure. |
| Operating Chambers | N/A | N/A |
| 3. Ram Preventers | | |
| • Fixed Pipe | 200-300 ) | Greater than the maximum anticipated surface shut-in pressure. |
| • Variable Bore | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Blind/Blind Shear (initial installation) | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Operating Chamber | N/A | N/A |
| 4. BOP-to-WHD Connector and Casing Seals | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 5. Diverter Flowlines | Flow Test | N/A |
| 6. Choke & Kill Lines & Valves | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 7. Choke Manifold | | |
| • Upstream of Last High Pressure Valve | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| • Downstream of Last High Pressure Valve | Optional | Optional |
| 8. BOP Control System | | |
| • Manifold and BOP Lines | N/A | Optional |
| • Accumulator Pressure | N/A | N/A |
| • Close Time | Function Test | N/A |
| • Pump Capability | Function Test | N/A |
| • Control Stations | Function Test | N/A |
| 9. Safety Valves | | |
| • Kelly, Kelly Valves, and Floor Safety Valves | 200-300 | Greater than the maximum anticipated surface shut-in pressure. |
| 10. Auxiliary Equipment | N/A | N/A |
| • Riser Slip Joint | Flow Test | N/A |
| • Mud/Gas Separator | Optional | N/A |
| • Trip Tank, Flo-Show, etc. | Flow Test | N/A |

[a] *The Low Pressure test should be stable for at least 5 minutes.*
[b] *The High Pressure test should be stable for at least 5 minutes. Flow type tests should be of sufficient duration to observe significant leaks.*

# Notes

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## Chapter 11

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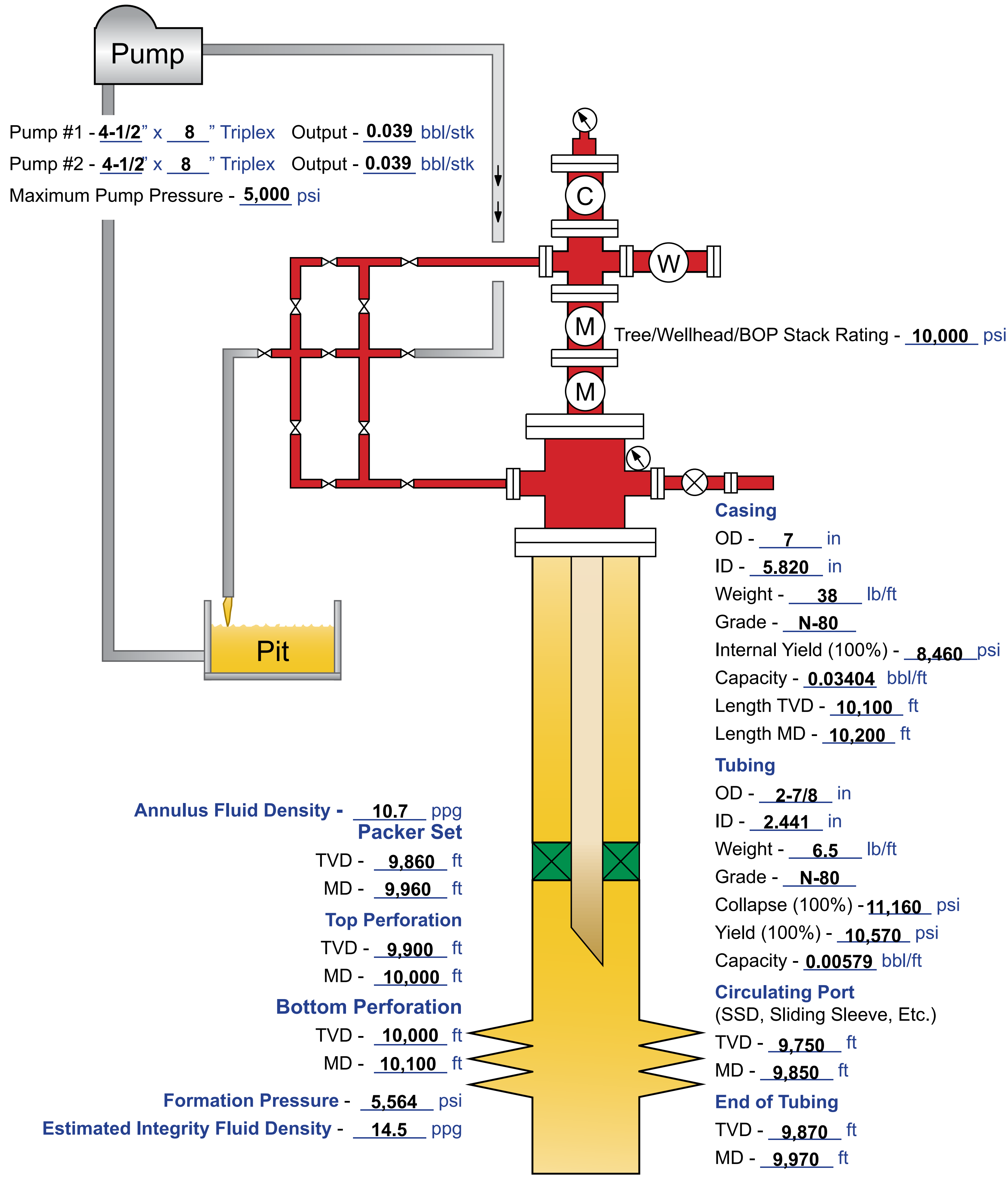
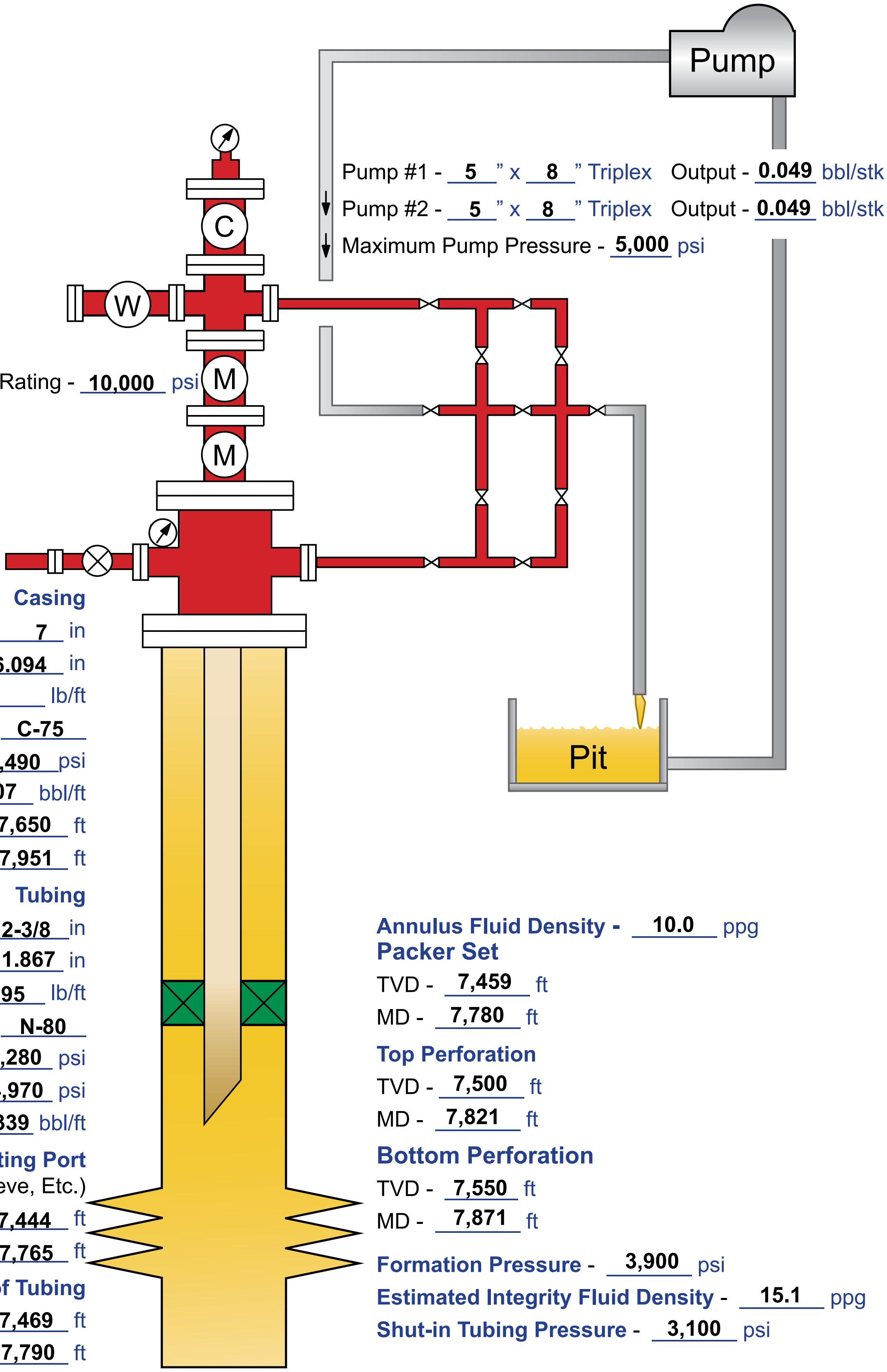
## Simulation Exercises

Well Name - **C-1 & Oklahoma**



Well Name - C- 2




Pump #1 - 5 " x 8 " Triplex Output - 0.049 bbl/stk

Pump #2 - 5 " x 8 " Triplex Output - 0.049 bbl/stk

Maximum Pump Pressure - 5,000 psi

Tree/Wellhead/BOP Stack Rating - 10,000 psi

**Casing**

OD - 7 in

ID - 6.094 in

Weight - 32 lb/ft

Grade - C-75

Internal Yield (100%) - 8,490 psi

Capacity - 0.03607 bbl/ft

Length TVD - 7,650 ft

Length MD - 7,951 ft

**Tubing**

OD - 2-3/8 in

ID - 1.867 in

Weight - 5.95 lb/ft

Grade - N-80

Collapse (100%) - 15,280 psi

Yield (100%) - 14,970 psi

Capacity - 0.00339 bbl/ft

**Circulating Port**

(SSD, Sliding Sleeve, Etc.)

TVD - 7,444 ft

MD - 7,765 ft

**End of Tubing**

TVD - 7,469 ft

MD - 7,790 ft

**Annulus Fluid Density** - 10.0 ppg

**Packer Set**

TVD - 7,459 ft

MD - 7,780 ft

**Top Perforation**

TVD - 7,500 ft

MD - 7,821 ft

**Bottom Perforation**

TVD - 7,550 ft

MD - 7,871 ft

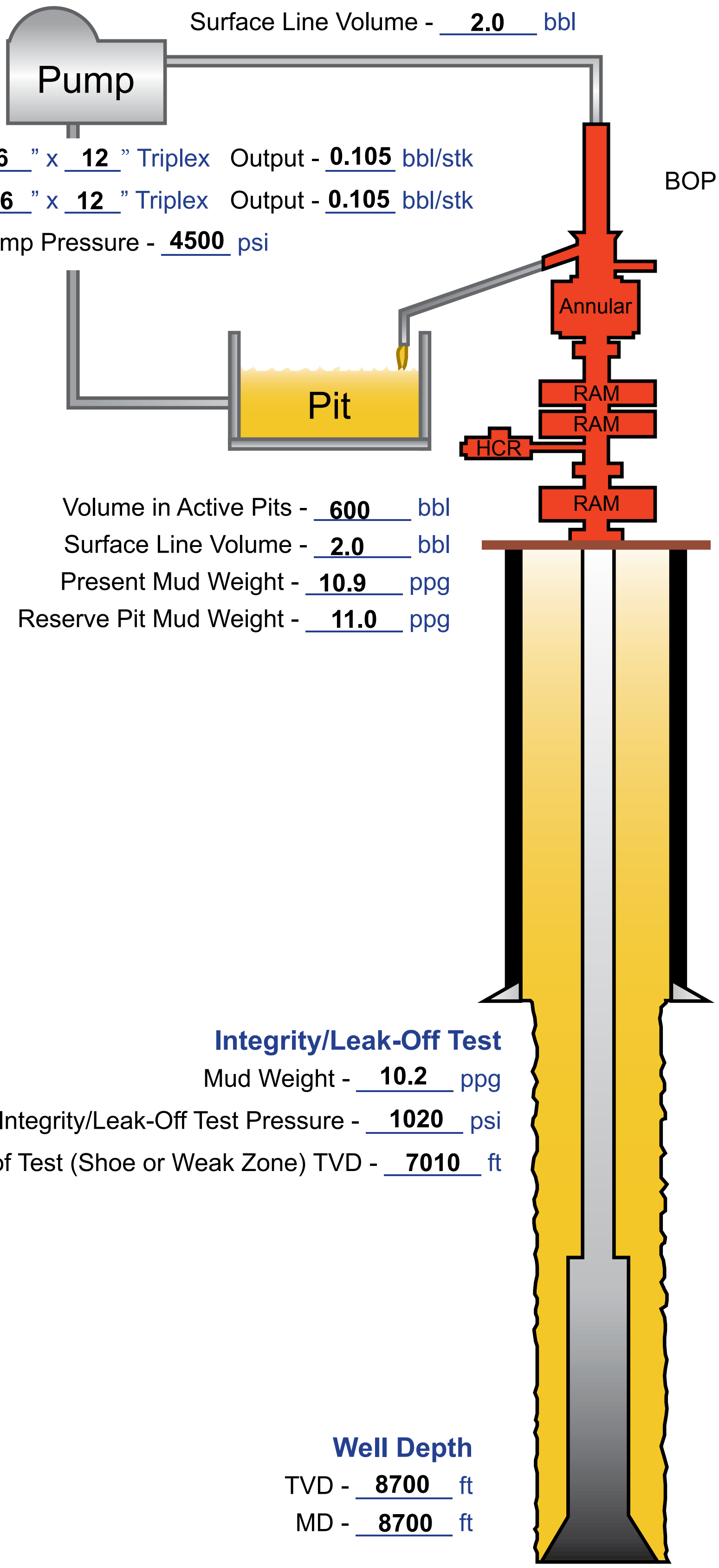
**Formation Pressure** - 3,900 psi

**Estimated Integrity Fluid Density** - 15.1 ppg

**Shut-in Tubing Pressure** - 3,100 psi

Well Name - **Beaumont/Beaumont 2**

Surface Line Volume - 2.0 bbl




Pump #1 - 6 " x 12 " Triplex Output - 0.105 bbl/stk

Pump #2 - 6 " x 12 " Triplex Output - 0.105 bbl/stk

Maximum Pump Pressure - 4500 psi

BOP Stack Rating - 10,000 psi

Volume in Active Pits - 600 bbl

Surface Line Volume - 2.0 bbl

Present Mud Weight - 10.9 ppg

Reserve Pit Mud Weight - 11.0 ppg

## Casing

OD - 9-5/8 in

ID - 8.92 in

Weight - 36 lb/ft

Grade - J-55

Internal Yield (100%) - 3620 psi

Length TVD - 7000 ft

Length MD - 7000 ft

## Drill Pipe

OD - 5 in

ID - 4.276 in

Weight - 19.5 lb/ft

Capacity - 0.01776 bbl/ft

Length - 8400 ft

## HWDP

OD - ________ in

ID - ________ in

Weight - ________ lb/ft

Capacity - ________ bbl/ft

Length - ________ ft

## Integrity/Leak-Off Test

Mud Weight - 10.2 ppg

Integrity/Leak-Off Test Pressure - 1020 psi

Depth of Test (Shoe or Weak Zone) TVD - 7010 ft

## Drill Collars

OD - 6-1/2 in

ID - 2.25 in

Capacity - 0.0049 bbl/ft

Length - 300 ft

Weight - 99.5 lb/ft

## Annular Capacities

Between CSG and DP - 0.0530 bbl/ft

Between OH and DP - 0.05009 bbl/ft

Between OH and DC - 0.03333 bbl/ft

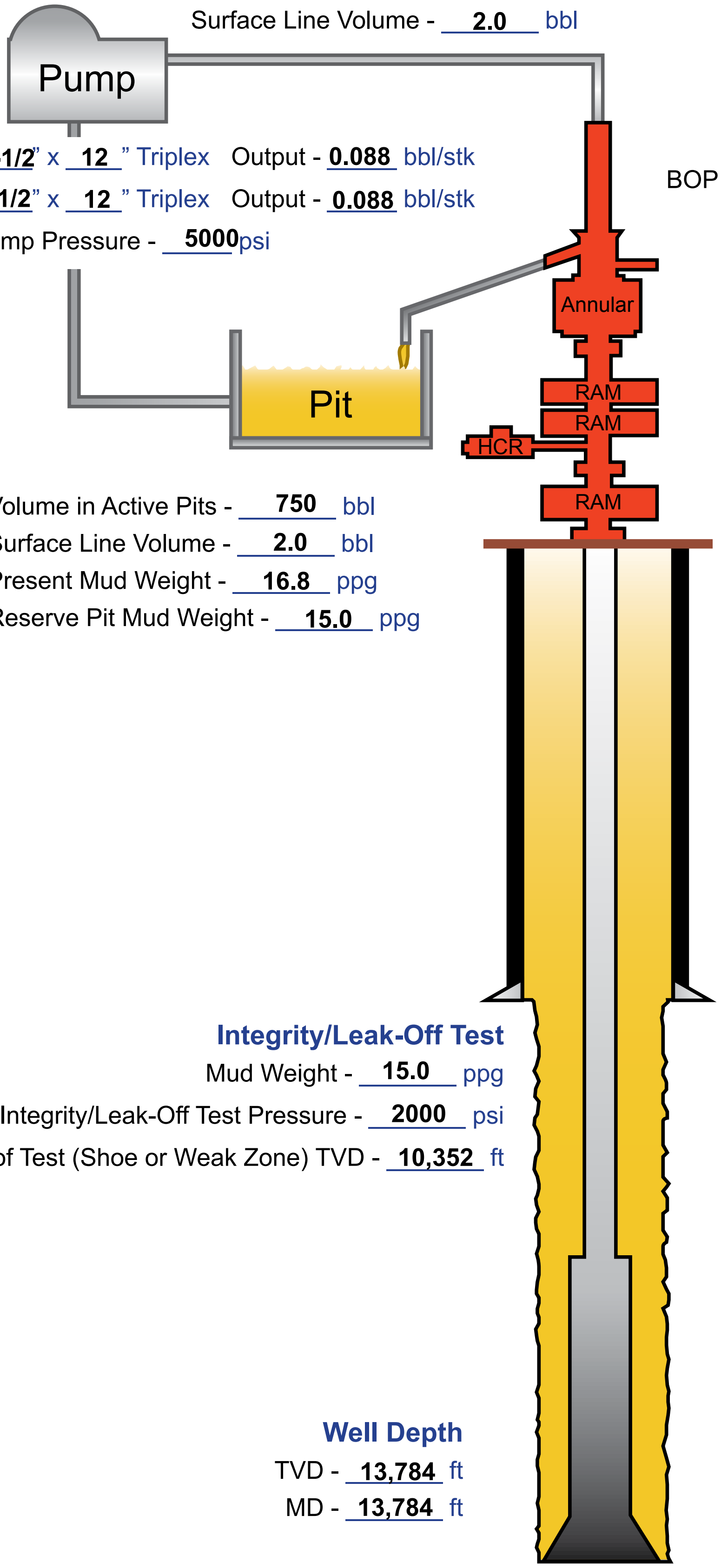
## Well Depth

TVD - 8700 ft

MD - 8700 ft

Hole Size - 8-3/4 in bit

Well Name - Redstick/Redstick 2




Surface Line Volume - 2.0 bbl

Pump #1 - 5-1/2" x 12 " Triplex   Output - 0.088 bbl/stk

Pump #2 - 5-1/2" x 12 " Triplex   Output - 0.088 bbl/stk

Maximum Pump Pressure - 5000 psi

BOP Stack Rating - 10,000 psi

Volume in Active Pits - 750 bbl

Surface Line Volume - 2.0 bbl

Present Mud Weight - 16.8 ppg

Reserve Pit Mud Weight - 15.0 ppg

## Casing

OD - 9-5/8 in

ID - 8.681 in

Weight - 47 lb/ft

Grade - N-80

Internal Yield (100%) - 6870 psi

Length TVD - 10,337 ft

Length MD - 10,337 ft

## Drill Pipe

OD - 5 in

ID - 4.276 in

Weight - 19.5 lb/ft

Capacity - 0.01776 bbl/ft

Length - 12,494 ft

## HWDP

OD - 5 in

ID - 3.0 in

Weight - 49.3 lb/ft

Capacity - 0.0088 bbl/ft

Length - 930 ft

## Integrity/Leak-Off Test

Mud Weight - 15.0 ppg

Integrity/Leak-Off Test Pressure - 2000 psi

Depth of Test (Shoe or Weak Zone) TVD - 10,352 ft

## Drill Collars

OD - 6-3/4 in

ID - 2.0 in

Capacity - 0.0039 bbl/ft

Length - 360 ft

Weight - 111.3 lb/ft

## Annular Capacities

Between CSG and DP - 0.0489 bbl/ft

Between OH and DP - 0.0459 bbl/ft

Between OH and DC - 0.0259 bbl/ft

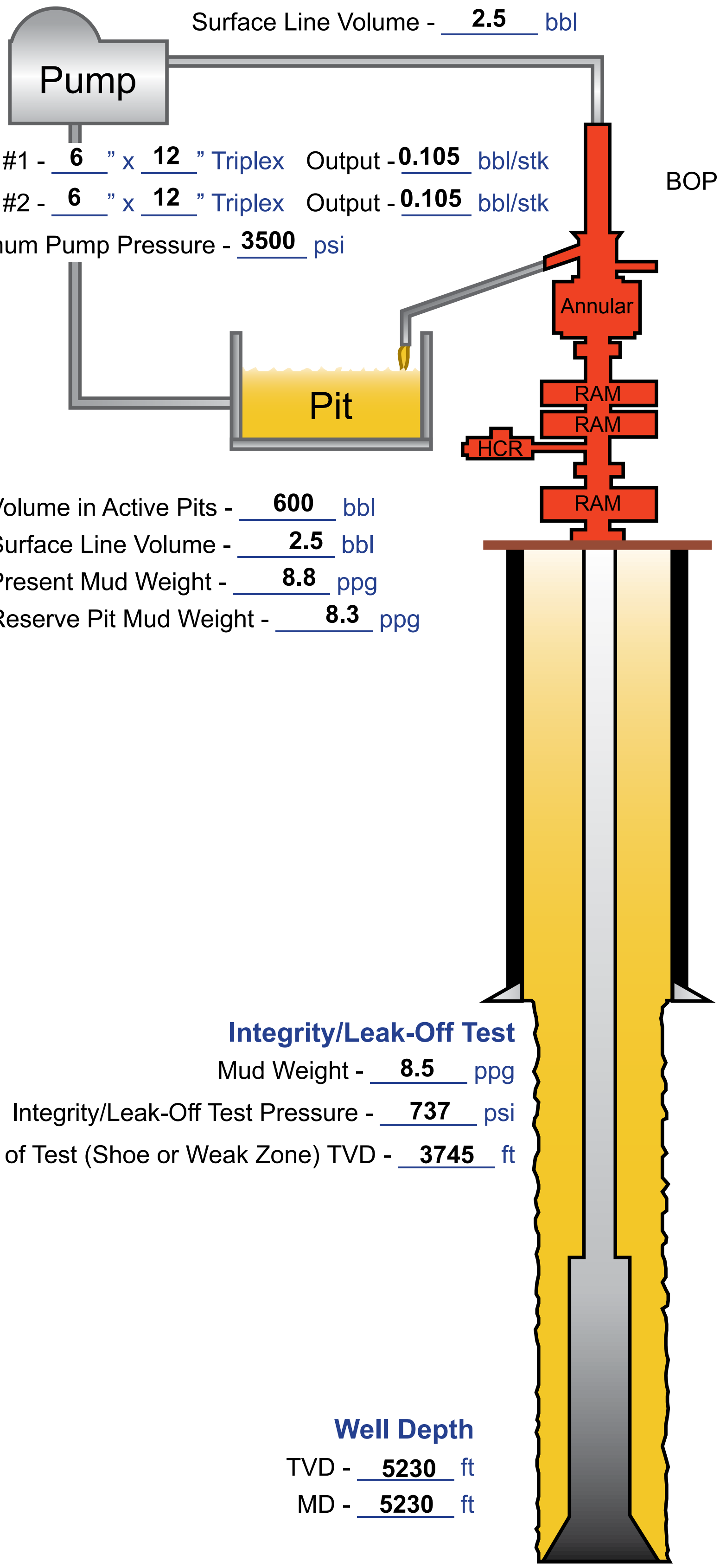
## Well Depth

TVD - 13,784 ft

MD - 13,784 ft

Hole Size - 8-1/2 in. bit

Well Name - **Tulsa/Tulsa 2**




Surface Line Volume - **2.5** bbl

Pump #1 - **6** " x **12** " Triplex  Output - **0.105** bbl/stk

Pump #2 - **6** " x **12** " Triplex  Output - **0.105** bbl/stk

Maximum Pump Pressure - **3500** psi

BOP Stack Rating - **10,000** psi

Volume in Active Pits - **600** bbl

Surface Line Volume - **2.5** bbl

Present Mud Weight - **8.8** ppg

Reserve Pit Mud Weight - **8.3** ppg

## Casing

OD - **9-5/8** in

ID - **8.681** in

Weight - **47** lb/ft

Grade - **N-80**

Internal Yield (100%) - **6870** psi

Length TVD - **3730** ft

Length MD - **3730** ft

## Drill Pipe

OD - **4.5** in

ID - **3.826** in

Weight - **16.6** lb/ft

Capacity - **0.01422** bbl/ft

Length - **4780** ft

## HWDP

OD - ________ in

ID - ________ in

Weight - ________ lb/ft

Capacity - ________ bbl/ft

Length - ________ ft

## Integrity/Leak-Off Test

Mud Weight - **8.5** ppg

Integrity/Leak-Off Test Pressure - **737** psi

Depth of Test (Shoe or Weak Zone) TVD - **3745** ft

## Drill Collars

OD - **6-1/2** in

ID - **2-1/4** in

Capacity - **0.0049** bbl/ft

Length - **450** ft

Weight - **99.5** lb/ft

## Annular Capacities

Between CSG and DP - **0.0535** bbl/ft

Between OH and DP - **0.0505** bbl/ft

Between OH and DC - **0.0291** bbl/ft

## Well Depth

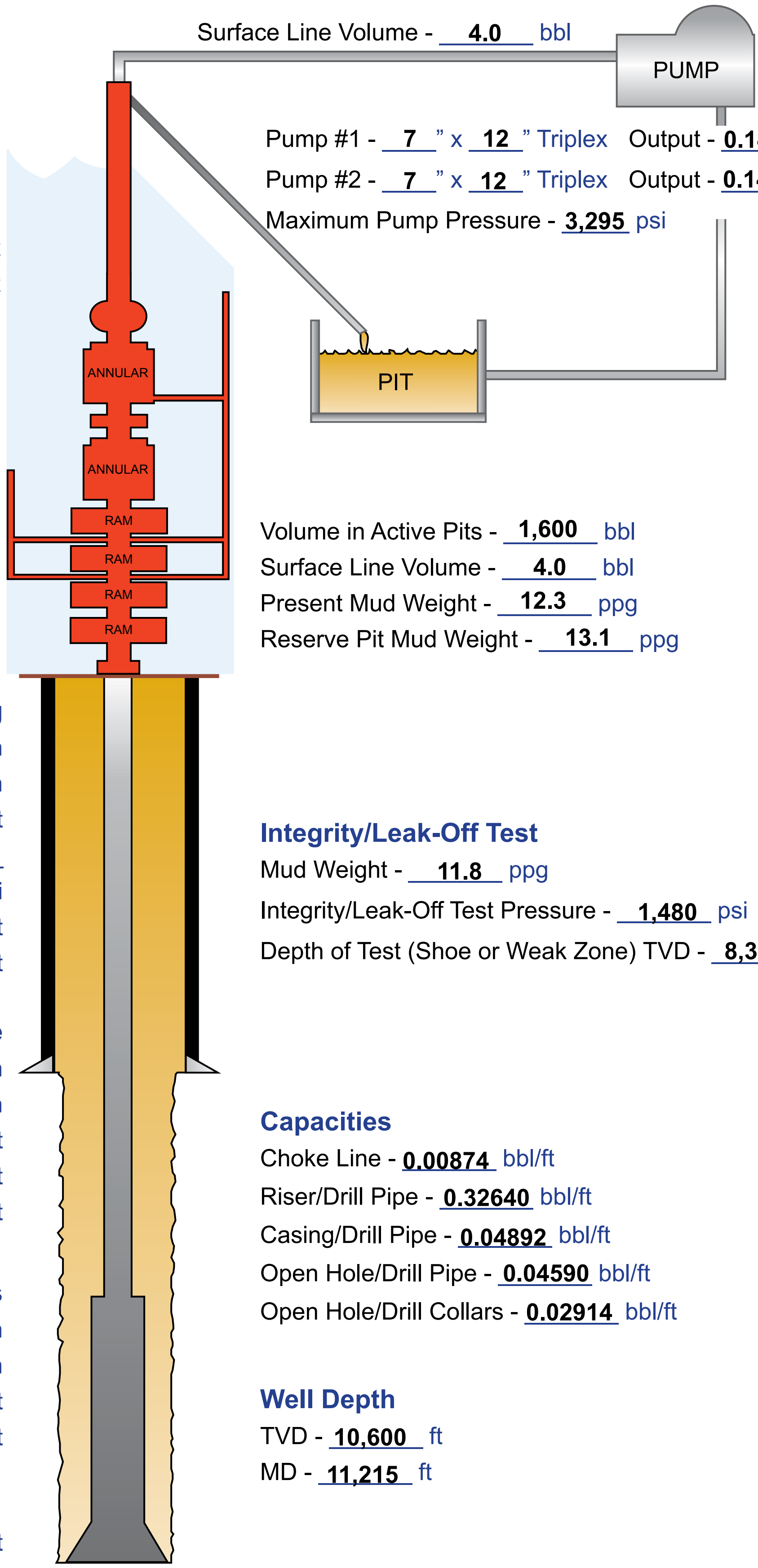
TVD - **5230** ft

MD - **5230** ft

Hole Size - **8--1/2** in. bit

Well Name - B-2

Surface Line Volume - 4.0 bbl




Pump #1 - 7 " x 12 " Triplex Output - 0.143 bbl/stk

Pump #2 - 7 " x 12 " Triplex Output - 0.143 bbl/stk

Maximum Pump Pressure - 3,295 psi

RKB to Sea Floor - 1,452 ft

Air Gap - 60 ft

Riser OD - 20 in

Riser ID - 19 in

Choke & Kill Line

OD - 4 in

ID - 3 in

BOP Stack Rating - 15,000 psi

Volume in Active Pits - 1,600 bbl

Surface Line Volume - 4.0 bbl

Present Mud Weight - 12.3 ppg

Reserve Pit Mud Weight - 13.1 ppg

## Casing

OD - 9-5/8 in

ID - 8.681 in

Weight - 47 lb/ft

Grade - P-110

Internal Yield (100%) - 9,440 psi

TVD - 8,300 ft

MD - 8,569 ft

## Drill Pipe

OD - 5 in

ID - 4.276 in

Weight - 19.5 lb/ft

Capacity - 0.01776 bbl/ft

Length - 10,115 ft

## Drill Collars

OD - 6-1/2 in

ID - 2.25 in

Capacity - 0.00491 bbl/ft

Length - 1,100 ft

Hole Size - 8-1/2 in. bit

## Integrity/Leak-Off Test

Mud Weight - 11.8 ppg

Integrity/Leak-Off Test Pressure - 1,480 psi

Depth of Test (Shoe or Weak Zone) TVD - 8,340 ft

## Capacities

Choke Line - 0.00874 bbl/ft

Riser/Drill Pipe - 0.32640 bbl/ft

Casing/Drill Pipe - 0.04892 bbl/ft

Open Hole/Drill Pipe - 0.04590 bbl/ft

Open Hole/Drill Collars - 0.02914 bbl/ft

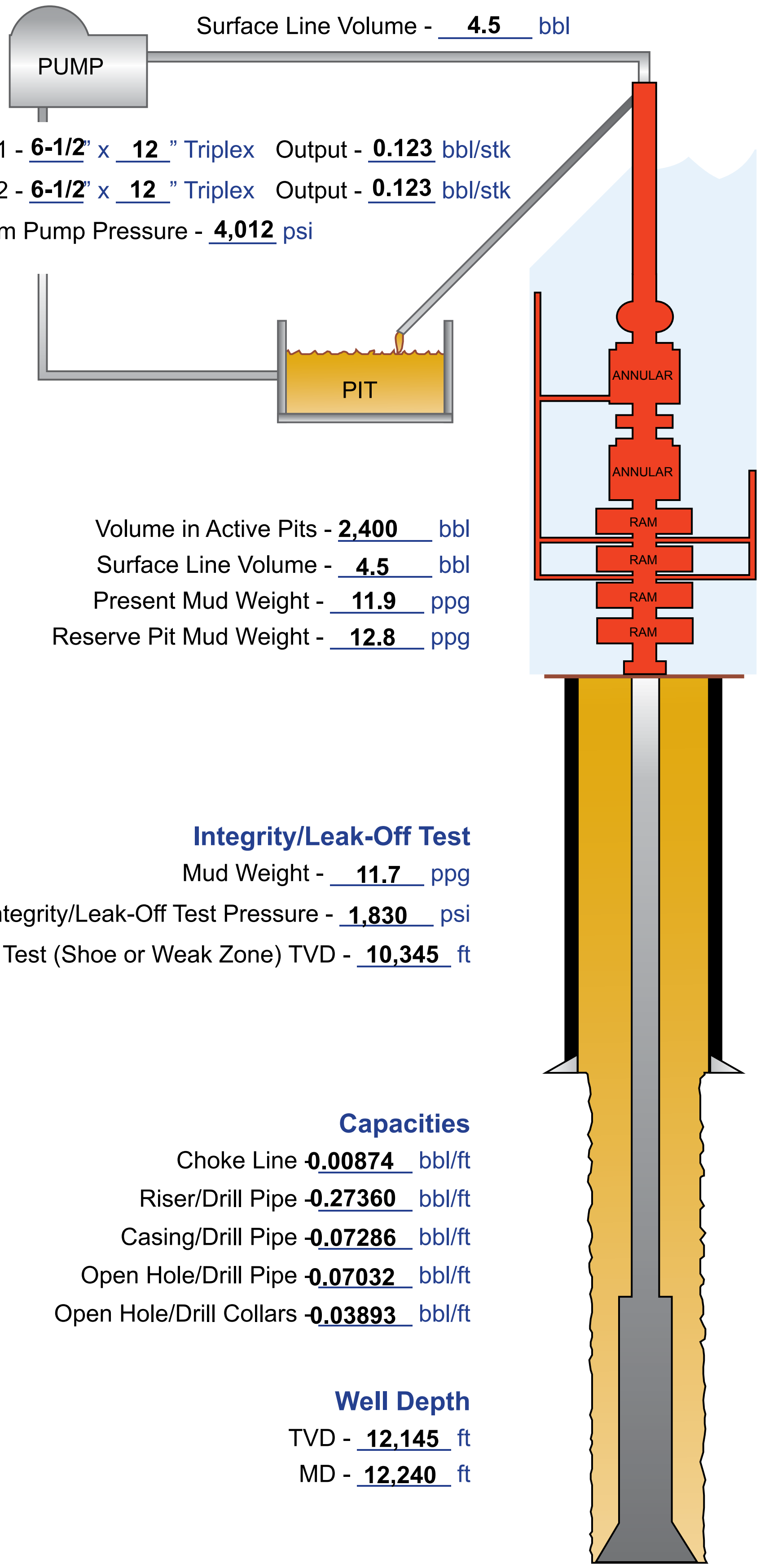
## Well Depth

TVD - 10,600 ft

MD - 11,215 ft

Well Name - **B-5**

Surface Line Volume - **4.5** bbl




Pump #1 - **6-1/2**" x **12** " Triplex Output - **0.123** bbl/stk

Pump #2 - **6-1/2**" x **12** " Triplex Output - **0.123** bbl/stk

Maximum Pump Pressure - **4,012** psi

RKB to Sea Floor - **5,100** ft

Air Gap - **60** ft

Riser OD - **18.75** in

Riser ID - **17.375** in

Choke & Kill Line

OD - **4** in

ID - **3** in

Volume in Active Pits - **2,400** bbl

Surface Line Volume - **4.5** bbl

Present Mud Weight - **11.9** ppg

Reserve Pit Mud Weight - **12.8** ppg

BOP Stack Rating - **15,000** psi

## Casing

OD - **10-3/4** in

ID - **9.760** in

Weight - **55.5** lb/ft

Grade - **V-150**

Internal Yield (100%) - **12,090** psi

TVD - **10,300** ft

MD - **10,385** ft

## Integrity/Leak-Off Test

Mud Weight - **11.7** ppg

Integrity/Leak-Off Test Pressure - **1,830** psi

Depth of Test (Shoe or Weak Zone) TVD - **10,345** ft

## Drill Pipe

OD - **4-1/2** in

ID - **3.826** in

Weight - **16.6** lb/ft

Capacity - **0.01422** bbl/ft

Length - **11,530** ft

## Capacities

Choke Line - **0.00874** bbl/ft

Riser/Drill Pipe - **0.27360** bbl/ft

Casing/Drill Pipe - **0.07286** bbl/ft

Open Hole/Drill Pipe - **0.07032** bbl/ft

Open Hole/Drill Collars - **0.03893** bbl/ft

## Drill Collars

OD - **7-1/4** in

ID - **2.8125** in

Capacity - **0.00768** bbl/ft

Length - **710** ft

## Well Depth

TVD - **12,145** ft

MD - **12,240** ft

Hole Size - **9-5/8** in bit

# Guidelines for Well Control Math

Knowledge of basic arithmetic is required to fully understand some of the topics presented in this text. It is assumed that the learner has some experience using a simple hand-held calculator. The guidelines below are intended to serve as an aid for the less experienced learner.

## Variables and Constants

Mathematical equations contain both variables and constants. Variables are words or letters that represent numbers whose values may change. Constants are numbers that do not change in the equation. For example:

$$\text{Hydrostatic Pressure}_{psi} = \text{Mud Weight}_{ppg} * 0.052 * TVD_{ft} \text{ or}$$
$$HP_{psi} = MW_{ppg} * 0.052 * TVD_{ft}$$

In the formula for hydrostatic pressure above there are two variables, the mud weight and the true vertical depth. Either one of those values may change. The constant, 0.052, does not change so long as the depth is measured in feet and the mud weight in pounds per gallon.

Some equations are quite long and complex. It is good practice to write out the equation first, and then replace the letters with all the known values before attempting to work the calculation. For example:

$$HP_{psi} = MW_{ppg} * 0.052 * TVD_{ft}$$
$$10.5 * 0.052 * 9000 = 4{,}914 \text{ psi}$$

## Parentheses ( ) and Brackets [ ]

The symbols used for adding, subtracting, multiplying and dividing (+, -, *, ÷) are called operators. Sometimes values and operators appear in parentheses or brackets. In these cases the rule is to perform the bracketed operations first, working from the inside out. For example:

$$2 * (3 + 5) =$$
$$2 * 8 = 16$$

In the example above the 3 is added to the 5 first, equaling 8 and removing the parentheses. Then 2 is then multiplied by 8 resulting in 16.

Below, values in parentheses are nested inside brackets. Following the inside-out rule, the 3 and 5 are added together first, yielding 8 and clearing the parentheses. Next, the brackets are cleared by multiplying 2 * 8 for a value of 16. Finally, 4 is added to 16 which equals 20.

$$4 + [2 * (3 + 5)] = ?$$
$$4 + [2 * 8] = 4 + 16 = 20$$
$$4 + 16 = 20$$

## Powers and Exponents

When a value is multiplied by itself it is said to be raised to a certain power. The value to be raised is the base. The power, or number of multiplications required, is written as a superscript which is a small number to the upper right of the base number. The number in superscript is the exponent. Examples of exponential expressions are $3^2$ or $ID^2$. In the first example the base is 3; in the second, it is ID. In both cases the base is raised to the second power. $3^2$ is read as "3 squared" and is solved by multiplying 3 * 3. The instructions to solve "ID squared" ($ID^2$) are to multiply ID * ID. When a value is to be raised to the third power the exponent is the superscript (3) and is read as "cubed". For example:

> $ID^2$ is read as "ID squared" and is solved by ID * ID
>
> $3^2$ is read as "3 squared" and is solved by 3 * 3 = 9
>
> $3^3$ is read "3 cubed" and is solved by 3 * 3 * 3 = 27

## Decimal Fractions

A fraction denotes a value less than a whole unit and may be expressed as one value divided by another or as a decimal fraction. Common fractions are written as one number over another separated by a horizontal or slanted line. The number above the line is the numerator and the number below the line is the denominator. For example:

$$\frac{\text{Numerator}}{\text{Denominator}} \quad \text{or} \quad \text{Numerator/Denominator}$$

$$\frac{3}{4} \quad \text{or} \quad 3/4$$

The mathematical instruction is to divide the denominator (below the line) into the numerator (above the line). When this is done on a calculator the result is a decimal fraction and it is displayed on the right of a "dot" (.) called the decimal point. It is much easier to work with decimal fractions than common fractions and hand-held calculators make the conversion simple. To convert any common fraction to its decimal equivalent, divide the numerator by the denominator. For example:

> Convert 5/8 to its decimal equivalent.
>
> The calculator entry is 5 ÷ 8 = 0.625

A mixed number is a whole number plus a fraction. To convert a mixed number to a decimal, divide the numerator of the fraction by the denominator and then add the whole number. For example:

Convert $10\frac{3}{8}$ to its decimal equivalent. Divide 3 by 8 and get the decimal 0.375 then add 10:

> The calculator entry is 3 ÷ 8 = 0.375 + 10 = 10.375

## Percentage

A percentage is a proportion of a whole when the whole is divided into 100 units. An example is the US dollar divided into pennies. Since there are 100 pennies in a dollar, half of a dollar is 50 pennies and is written as the decimal fraction $0.50. To express a decimal fraction as a percentage, move the decimal point two places to the right and replace it with the symbol for percent (%). For example:

| |
|---|
| 0.50 = 50%  Read as "fifty percent" |
| 0.25 = 25%  Read as "twenty-five percent" |
| 00.085 = 8.5%  Read as "eight and one half percent" |

# Increasing/Decreasing Mud Weight in Water-Based Muds

## Adjusting The Mud Weight in Water-Based Muds

Certain assumptions are made when estimating the sacks of barite required to increase, or the water requirements to decrease the density of water-based mud.

- The density of fresh water is 8.33 ppg (at 70 °F)
- The density of barite is 35.0 ppg (API specified 4.2 specific gravity)
- Barite is packaged in 100 lb sacks (sx)
- 14.7 (1,470 lb) sacks of barite equals one barrel of volume

## Barite Required to Increase Mud Weight

Step 1: Determine the volume of mud in the active system (barrels).

$$\text{Total volume}_{bbl} = \text{volume on surface} + \text{drillstring volume} + \text{annular volume} + \text{annular volume in riser}_{(subsea\ only)}$$

Step 2: Determine the difference between the density of barite and the desired mud weight (ppg).

$$\text{Difference in densities}_{ppg} = 35 - \text{desired MW}$$

Step 3: Determine the number of 100 lb sacks of barite per barrel.

$$\text{Required barite}_{sx/bbl} = (\text{desired MW} - \text{present MW}) * 14.7 \div \text{result of step 2}$$

Step 4: Determine the total barite required.

$$\text{Barite required}_{sx} = \text{total volume} * \text{required sacks per barrel}$$

Step 5: Determine the volume increase due to barite addition.

$$\text{Volume increase} = 14.7 * \text{total barite required}$$

A consistent mixing rate can be determined by multiplying the sacks per barrel (step 3) by the circulating rate.

$$\text{Sacks per minute} = \text{sacks per barrel} * \text{barrels per}$$

## Fresh Water Required to Reduce the Mud Weight

Step 1: Determine the difference between the desired density and the density of fresh water.

$$\text{Difference in densities}_{ppg} = \text{present MW} - 8.33$$

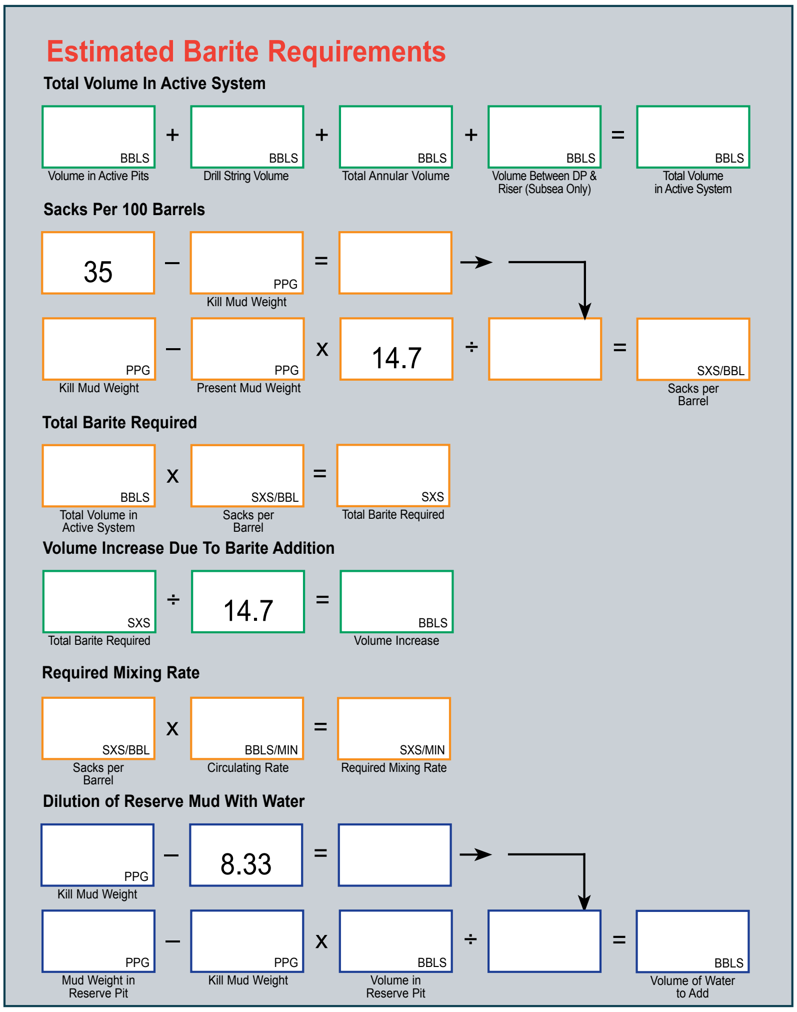
Step 2: Determine the volume of water to add to achieve the desired reduction in density.

$$\text{Volume of water to add} = \text{Original MW} - \text{desired MW} * \text{volume to be treated} \div \text{value from step 1}$$

Adding barite or water may seriously affect fluid properties other than density. If available, fluid technicians (mud engineers) should be consulted for guidance before beginning the operation.

These calculations are presented in a simplified form on the back of the WCS Killsheet as shown below.

## Estimated Barite Requirements Section



**Estimated Barite Requirements**

**Total Volume In Active System**

[ ] BBLS (Volume in Active Pits) + [ ] BBLS (Drill String Volume) + [ ] BBLS (Total Annular Volume) + [ ] BBLS (Volume Between DP & Riser (Subsea Only)) = [ ] BBLS (Total Volume in Active System)

**Sacks Per 100 Barrels**

[35] – [ ] PPG (Kill Mud Weight) = [ ] →

[ ] PPG (Kill Mud Weight) – [ ] PPG (Present Mud Weight) x [14.7] ÷ [ ] = [ ] SXS/BBL (Sacks per Barrel)

**Total Barite Required**

[ ] BBLS (Total Volume in Active System) x [ ] SXS/BBL (Sacks per Barrel) = [ ] SXS (Total Barite Required)

**Volume Increase Due To Barite Addition**

[ ] SXS (Total Barite Required) ÷ [14.7] = [ ] BBLS (Volume Increase)

**Required Mixing Rate**

[ ] SXS/BBL (Sacks per Barrel) x [ ] BBLS/MIN (Circulating Rate) = [ ] SXS/MIN (Required Mixing Rate)

**Dilution of Reserve Mud With Water**

[ ] PPG (Kill Mud Weight) – [8.33] = [ ] →

[ ] PPG (Mud Weight in Reserve Pit) – [ ] PPG (Kill Mud Weight) x [ ] BBLS (Volume in Reserve Pit) ÷ [ ] = [ ] BBLS (Volume of Water to Add)

# IADC Kill Sheets

## IADC WellCAP Well Control Worksheet
## Subsea Stack - Wait and Weight Method

Well Name: ______________________ Completed By: ______________________ Date: _____ /_____ /_____

### PRE-RECORDED INFORMATION

**TRUE PUMP OUTPUT:** ________ Bbls/Stk @ 100% **X** ________ % Efficiency **=** ________ TPO (Bbls/Stk)

Surface Line: ________(Bbls) Surface Line Capacity ÷ ________ True Pump Output (Bbls/Stk) = ________ Strokes to Pump

**DRILL STRING CAPACITY:**

Drill Pipe #1: ____ Size (in) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) = ____ DP Bbls

Drill Pipe #2: ____ Size (in) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) = ____ DP Bbls

HWDP: ____ Size (in) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) = ____ HWDP Bbls

Drill Collars #1: ____ Size (in) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) = ____ DC Bbls

Drill Collars #2: ____ Size (in) ____ Weight (lb/ft) ____ Bbls/ft **X** ____ Length (ft) = ____ DC Bbls

________ Total Drill String Capacity (Bbls)

**STROKES FROM SURFACE TO BIT:**

________ Total Drill String Capacity (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Surface to Bit

**ANNULAR CAPACITY**

Between CSG and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between Liner #1 and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between Liner #2 and DP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between OH and DP/HWDP: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Between OH and DC: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

Choke line capacity: ________ Bbls/ft **X** ________ ft **=** ________ Bbls

**STROKES FROM BIT TO SHOE:**

________ Open Hole Annular Vol. (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Bit to Shoe

**STROKES FROM BIT TO SURFACE:**

________ Total Annular Volume (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes, Bit to Surface

**ANNULAR VOL. BETWEEN DRILL PIPE & RISER:**

( ________ Riser ID² − ________ Drill Pipe OD² ) ÷ 1029.4 = ________ Capacity Drill Pipe/Riser (Bbls/ft)

________ Capacity Drill Pipe/Riser (Bbls/ft) **X** ________ Riser Length ft = ________ Volume between Drill Pipe & Riser (Bbls)

**STROKES TO DISPLACE RISER:**

________ Volume between Drill Pipe & Riser (Bbls) ÷ ________ True Pump Output (Bbls/Stks) = ________ Strokes

### CURRENT WELL DATA

**PRESENT MUD WEIGHT:** ________ ppg

**SLOW CIRCULATION RATE (SCR):**

SCR taken @ ________ (ft)

| | Stks/min | Pressure(psi) | Bbl/min | Pressure(psi) |
|---|---|---|---|---|
| Pump #1 | | | | |
| Pump #1 | | | | |
| Pump #1 | | | | |
| Pump #2 | | | | |
| Pump #2 | | | | |
| Pump #2 | | | | |
| Pump #3 | | | | |
| Pump #3 | | | | |
| Pump #3 | | | | |

**CASING DATA:**

CASING ________ size , ________ ID , ________ weight

SHOE DEPTH @ MD / TVD ________ / ________ ft

**SHOE TEST DATA:**

Depth #1 ________ (psi) @ Test MW of ________ (ppg)

Depth #2 ________ (psi) @ Test MW of ________ (ppg)

Depth #3 ________ (psi) @ Test MW of ________ (ppg)

LINER #1 ________ size , ________ ID , ________ weight

LINER #2 ________ size , ________ ID , ________ weight

LINER #1 TOP DEPTH ________ ft

LINER #2 TOP DEPTH ________ ft

LINER #1 SHOE DEPTH ________ ft

LINER #2 SHOE DEPTH ________ ft

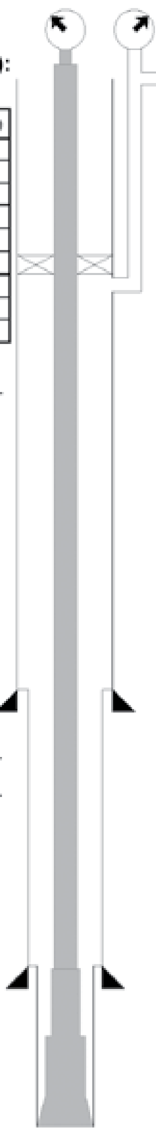
TVD CASING or LINER ________ ft

**HOLE DATA:**

TOTAL DEPTH (MD) ________ ft

TOTAL DEPTH (TVD) ________ ft

BIT DEPTH @ MD / TVD ________ / ________ ft



BIT SIZE ________ inches

### KICK DATA

**SIDPP:** ________ **psi** **SICP:** ________ **psi** **PIT GAIN:** ________ **Bbls** **Time of Incident:** ____ : ____



Field Units
(psi, ft, ppg)

Revised January 8, 2009
Page 1

# CALCULATIONS

**KILL MUD WEIGHT (KMW)**

( ______ ÷ 0.052 ÷ ______ ) + ______ = ______ ppg KILL MUD WEIGHT

SIDPP (psi) | True Vertical Depth (ft) | Present Mud Weight (ppg)

**INITIAL CIRCULATING PRESSURE (ICP)**

______ + ______ = ______ psi INITIAL CIRCULATING PRESSURE

SIDPP (psi) | Pump Pressure (psi) @ SCR of ______ SPM

**FINAL CIRCULATING PRESSURE (FCP)**

______ X ______ ÷ ______ = ______ psi FINAL CIRCULATING PRESSURE

Pump Pressure (psi) @ SCR of ______ SPM | Kill Mud Weight (ppg) | Present Mud Weight (ppg)

**MAXIMUM ALLOWABLE MUD DENSITY (ppg)**

( ______ ÷ 0.052 ÷ ______ ) + ______ = ______ ppg MAX. ALLOWABLE MUD DENSITY

Surface LOT Pressure (psi) | Shoe Depth (ft,TVD) | LOT Mud Density (ppg)

**MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (MAASP) (psi)**

( ______ - ______ ) X 0.052 X ______ = ______ psi MAX. ALLOWABLE ANNULAR SURFACE PRESSURE

Max. Allowable Mud Density (ppg) | Present Mud Density (ppg) | Shoe Depth (ft,TVD)

# SELECTED KILL PUMP DATA

| | Kill Rate Speed (STKS/MIN) | Pump Output (BBLS/STK) | Circ. Rate (BBLS/MIN) | Slow Pump Pressure (Circ. Down DP & Up Riser) | Circ. Pres thru Choke Line (PSI) | Circ. Pres thru Choke & Kill Line (PSI) | CLFP Choke Line (PSI) | CLFP Choke & Kill Line (PSI) |
|---|---|---|---|---|---|---|---|---|
| PUMP No. 1 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| PUMP No. 2 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| PUMP No. 3 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |

# PRESSURE CHART

| Stroke or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Actual Casing Pressure | Actual Pit Volume Deviation |
|---|---|---|---|---|
| SURFACE 0 | ICP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| BIT | FCP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

______ ÷ 10 = ______    ______ - ______ ÷ 10 = ______

Strokes Surface to Bit | Strokes per Step | Initial Circulation Pressure | Final Circulation Pressure | PSI per Step

| Stroke or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Actual Casing Pressure | Actual Pit Volume Deviation |
|---|---|---|---|---|
| BIT | FCP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| SURFACE | | | | |

______ ÷ 10 = ______

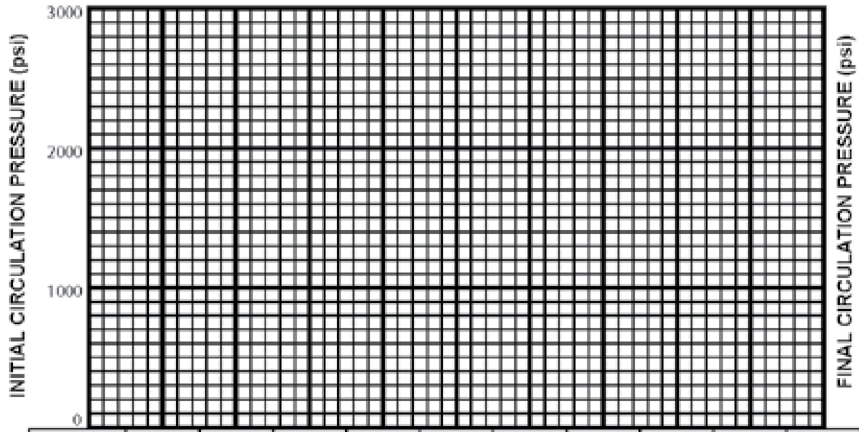
Strokes Bit to Surface | Strokes per Step



**Field Units (psi, ft, ppg)**

Revised January 8, 2009

## GRAPHIC ANALYSIS




| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Stroke | | | | | | | | | | |
| Pressure | | | | | | | | | | |
| Time | | | | | | | | | | |

## FORMULAS

1. Pressure Gradient (psi/ft) = Mud Weight (ppg) x 0.052

2. Hydrostatic Pressure (psi) = Mud Weight (ppg) x 0.052 x Depth (ft, TVD)

3. Capacity (bbls/ft) = Inside Diameter$^2$ (in.) ÷ 1029.4

4. Annular Capacity(bbls/ft) = (Inside Diameter of Casing$^2$ (in.) or Hole Diameter$^2$ (in.) - Outside Diameter of Pipe$^2$ (in.)) ÷ 1029.4

5. Pipe Displacement (bbls/ft) = (Outside Diameter of pipe$^2$ (in.) - Inside Diameter of pipe$^2$ (in.)) ÷ 1029.4

6. Maximum Allowable Mud Weight (ppg) = $\dfrac{\text{Surface LOT Pressure (psi)}}{\text{Shoe Depth (ft, TVD) x 0.052}}$ + LOT Mud Weight (ppg)

7. MAASP (psi) = [Maximum Allowable Mud Weight (ppg) - Present Mud Weight (ppg)] x 0.052 x Shoe TVD (ft)

8. Pressure Drop per Foot Tripping Dry Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg) x 0.052 x Metal Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft) - Metal Displacement (bbl/ft)}}$

9. Pressure Drop per Foot Tripping Wet Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg) x 0.052 x Closed End Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft) - Closed End Displacement (bbl/ft)}}$

10. Formation Pressure (psi) = Hydrostatic Pressure Mud in Hole (psi) + SIDPP (psi)

11. EMW (ppg) @ Shoe = (SICP (psi) ÷ 0.052 ÷ Shoe Depth (ft, TVD) ) + Present Mud Weight (ppg)

12. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\dfrac{\text{Bbls of Mud in System x 14.9 x (KMW - OMW)}}{\text{(35.4 - KMW)}}$

*NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.*

13. Volume Increase from Adding Barite (bbls) = Number of Sacks (100 lb) added ÷ 14.9

14. Equivalent Mud Weight (ppg) @ __________ depth (ft) = $\left[\dfrac{\text{Pressure (psi)}}{\text{Depth (ft, TVD) x 0.052}}\right]$ + Current Mud Weight (ppg)

15. Estimated New Pump Pressure at New Pump Rate (psi) = Old Pump Pressure (psi) x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight (psi) = Old Pump Pressure (psi) x $\dfrac{\text{New Mud Weight (ppg)}}{\text{Old Mud Weight (ppg)}}$

# IADC WellCAP Well Control Worksheet
# Surface Stack - Wait and Weight Method

Well Name: ______________ Completed By: ______________ Date: ____/____/____

## PRE-RECORDED INFORMATION

**TRUE PUMP OUTPUT:** ________ X ________ = ________
Bbls/Stk @ 100% | % Efficiency | TPO (Bbls/Stk)

Surface Line: [ ________ (Bbls) Surface Line Capacity ] ÷ ________ True Pump Output (Bbls/Stk) = [ ________ Strokes to Pump ]

**DRILL STRING CAPACITY:**

| | Size (in.) | Weight (lb/ft) | Bbls/ft | | Length (ft) | | | |
|---|---|---|---|---|---|---|---|---|
| Drill Pipe #1: | ____ | ____ | ____ | X | ____ | = | ____ DP | Bbls |
| Drill Pipe #2: | ____ | ____ | ____ | X | ____ | = | ____ DP | Bbls |
| HWDP : | ____ | ____ | ____ | X | ____ | = | ____ HWDP | Bbls |
| Drill Collars #1: | ____ | ____ | ____ | X | ____ | = | ____ DC | Bbls |
| Drill Collars #2: | ____ | ____ | ____ | X | ____ | = | ____ DC | Bbls |

[ ________ Total Drill String Capacity (Bbls) ]

**STROKES FROM SURFACE TO BIT:**

[ ________ Total Drill String Capacity (Bbls) ] ÷ ________ True Pump Output (Bbls/Stk) = [ ________ Strokes, Surface to Bit ]

**ANNULAR CAPACITY:**

| | | | | | | |
|---|---|---|---|---|---|---|
| Between CSG and DP: | ____ Bbls/ft | X | ____ ft | = | ____ | Bbls |
| Between Liner #1 and DP: | ____ Bbls/ft | X | ____ ft | = | ____ | Bbls |
| Between Liner #2 and DP: | ____ Bbls/ft | X | ____ ft | = | ____ | Bbls |
| Between OH and DP/HWDP: | ____ Bbls/ft | X | ____ ft | = | ____ | Bbls |
| Between OH and DC: | ____ Bbls/ft | X | ____ ft | = | ____ | Bbls |

**STROKES FROM BIT TO SHOE:**

[ ________ Open Hole Annular Vol. (Bbls) ] ÷ ________ True Pump Output (Bbls/Stk) = [ ________ Strokes, Bit to Shoe ]

**STROKES FROM BIT TO SURFACE:**

[ ________ Total Annular Volume (Bbls) ] ÷ ________ True Pump Output (Bbls/Stk) = [ ________ Strokes, Bit to Surface ]

**TOTAL STROKES FROM SURFACE TO SURFACE:**

[ ________ Strokes, Surface to Bit ] + ________ Strokes, Bit to Surface = [ ________ Strokes, Surface to Surface ]

### CURRENT WELL DATA

**PRESENT MUD WEIGHT:** [ ______ ppg ]

**SLOW CIRCULATION RATE (SCR):**

SCR taken @ ____________ (ft)

| | Stks/min | Pressure(psi) | Bbl/min | Pressure(psi) |
|---|---|---|---|---|
| Pump #1 | | | | |
| Pump #1 | | | | |
| Pump #1 | | | | |
| Pump #2 | | | | |
| Pump #2 | | | | |
| Pump #2 | | | | |
| Pump #3 | | | | |
| Pump #3 | | | | |
| Pump #3 | | | | |

**CASING DATA:**

CASING ______ size , ______ ID , ______ weight

SHOE DEPTH @ MD / TVD [ ____ / ____ ft ]

**SHOE TEST DATA:**

Depth #1 ______ (psi) @ Test MW of ______ (ppg)

Depth #2 ______ (psi) @ Test MW of ______ (ppg)

Depth #3 ______ (psi) @ Test MW of ______ (ppg)

LINER #1 ______ size , ______ ID , ______ weight

LINER #2 ______ size , ______ ID , ______ weight

LINER #1 TOP DEPTH [ ______ ft ]

LINER #2 TOP DEPTH [ ______ ft ]

LINER #1 SHOE DEPTH [ ______ ft ]

LINER #2 SHOE DEPTH [ ______ ft ]

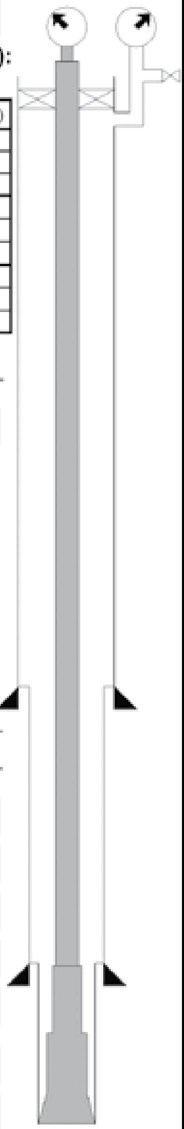
TVD CASING or LINER [ ______ ft ]

**HOLE DATA:**

TOTAL DEPTH (MD) [ ______ ft ]

TOTAL DEPTH (TVD) [ ______ ft ]

BIT DEPTH @ MD / TVD [ ____ / ____ ft ]



BIT SIZE ______ inches

**MAXIMUM ALLOWABLE MUD DENSITY (ppg)**

( ________ Surface LOT Pressure (psi) ÷ 0.052 ÷ ________ Shoe Depth (ft,TUD) ) + ________ LOT Mud Density (ppg) = [ ________ ppg MAX. ALLOWABLE MUD DENSITY ]

**MAXIMUM ALLOWABLE ANNULAR SURFACE PRESSURE (MAASP) (psi)**

( ________ Max. Allowable Mud Density (ppg) - ________ Present Mud Density (ppg) ) X 0.052 X ________ Shoe Depth (ft,TUD) = [ ________ psi MAX. ALLOWABLE ANNULAR SURFACE PRESSURE ]

DISCLAIMER: This Well Control Worksheet is intended solely for the use of the IADC and IADC accredited schools and organizations engaging in the teaching of the IADC WellCAP Well Control classes. The IADC, its employees or others acting on its behalf, makes no warranties or guarantees expressed, implied or statutory, as to any matter whatsoever, with respect to the use of this Well Control Worksheet.

Field Units
(psi, ft, ppg)

Revised January 8, 2009
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# KICK DATA

**SIDPP:** __________ **psi** **SICP:** __________ **psi** **PIT GAIN:** __________ **Bbls** **Time of Incident:** ____ : ____

# CALLCULATIONS

**KILL MUD WEIGHT (KMW)**

( ______________ ÷ 0.052 ÷ ______________ ) + ______________ = ___________ ppg KILL MUD WEIGHT

SIDPP (psi) True Vertical Depth (ft) Present Mud Weight (ppg)

**INITIAL CIRCULATING PRESSURE (ICP)**

______________ + ______________ = ___________ psi INITIAL CIRCULATING PRESSURE

SIDPP (psi) Pump Pressure (psi) @ SCR of _______SPM

**FINAL CIRCULATING PRESSURE (FCP)**

______________ X ______________ ÷ ______________ = ___________ psi FINAL CIRCULATING PRESSURE

Pump Pressure (psi) @ SCR of _______SPM Kill Mud Weight (ppg) Present Mud Weight (ppg)

# PRESSURE CHART

| Stroke or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Actual Casing Pressure | Actual Pit Volume Deviation |
|---|---|---|---|---|
| SURFACE 0 | ICP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| BIT | FCP | | | |

__________ ÷ 10 = __________ __________ - __________ ÷ 10 = __________

Strokes Surface to Bit Strokes per Step Initial Circulation Pressure Final Circulation Pressure PSI per Step

| | | | | |
|---|---|---|---|---|
| BIT | FCP | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| SURFACE | | | | |

__________ ÷ 10 = __________

Strokes Bit to Surface Strokes per Step



Field Units
(psi, ft, ppg)

Revised January 8, 2009
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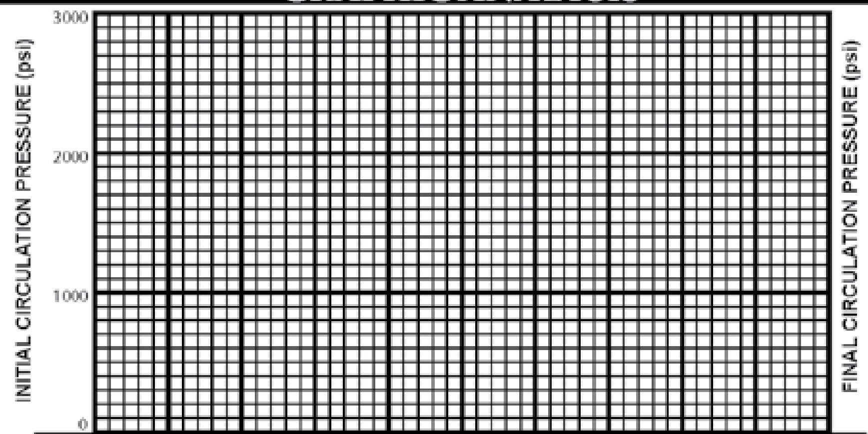
## GRAPHIC ANALYSIS




| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Stroke | | | | | | | | | | |
| Pressure | | | | | | | | | | |
| Time | | | | | | | | | | |

## FORMULAS

1. Pressure Gradient $_{(psi/ft)}$ = Mud Weight $_{(ppg)}$ x 0.052

2. Hydrostatic Pressure $_{(psi)}$ = Mud Weight $_{(ppg)}$ x 0.052 x Depth $_{(ft, TVD)}$

3. Capacity $_{(bbls/ft)}$ = Inside Diameter$^2$ $_{(in.)}$ ÷ 1029.4

4. Annular Capacity$_{(bbls/ft)}$ = (Inside Diameter of Casing$^2$ $_{(in.)}$ or Hole Diameter$^2$ $_{(in.)}$ - Outside Diameter of Pipe$^2$ $_{(in.)}$) ÷ 1029.4

5. Pipe Displacement $_{(bbls/ft)}$ = (Outside Diameter of pipe$^2$ $_{(in.)}$ - Inside Diameter of pipe$^2$ $_{(in.)}$) ÷ 1029.4

6. Maximum Allowable Mud Weight $_{(ppg)}$ = $\dfrac{\text{Surface LOT Pressure}_{(psi)}}{\text{Shoe Depth}_{(ft, TVD)} \times 0.052}$ + LOT Mud Weight $_{(ppg)}$

7. MAASP $_{(psi)}$ = [Maximum Allowable Mud Weight $_{(ppg)}$ - Present Mud Weight $_{(ppg)}$] x 0.052 x Shoe TVD $_{(ft)}$

8. Pressure Drop per Foot Tripping Dry Pipe $_{(psi/ft)}$ = $\dfrac{\text{Drilling Mud Weight}_{(ppg)} \times 0.052 \times \text{Metal Displacement}_{(bbl/ft)}}{\text{Casing Capacity}_{(bbl/ft)} - \text{Metal Displacement}_{(bbl/ft)}}$

9. Pressure Drop per Foot Tripping Wet Pipe $_{(psi/ft)}$ = $\dfrac{\text{Drilling Mud Weight}_{(ppg)} \times 0.052 \times \text{Closed End Displacement}_{(bbl/ft)}}{\text{Casing Capacity}_{(bbl/ft)} - \text{Closed End Displacement}_{(bbl/ft)}}$

10. Formation Pressure $_{(psi)}$ = Hydrostatic Pressure Mud in Hole $_{(psi)}$ + SIDPP $_{(psi)}$

11. EMW $_{(ppg)}$ @ Shoe = (SICP $_{(psi)}$ ÷ 0.052 ÷ Shoe Depth $_{(ft, TVD)}$ ) + Present Mud Weight $_{(ppg)}$

12. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\dfrac{\text{Bbls of Mud in System} \times 14.9 \times (\text{KMW} - \text{OMW})}{(35.4 - \text{KMW})}$

*NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.*

13. Volume Increase from Adding Barite $_{(bbls)}$ = Number of Sacks (100 lb) added ÷ 14.9

14. Equivalent Mud Weight $_{(ppg)}$ @ __________ depth $_{(ft)}$ = $\left[\dfrac{\text{Pressure}_{(psi)}}{\text{Depth}_{(ft, TVD)} \times 0.052}\right]$ + Current Mud Weight $_{(ppg)}$

15. Estimated New Pump Pressure at New Pump Rate $_{(psi)}$ = Old Pump Pressure $_{(psi)}$ x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight $_{(psi)}$ = Old Pump Pressure $_{(psi)}$ x $\dfrac{\text{New Mud Weight}_{(ppg)}}{\text{Old Mud Weight}_{(ppg)}}$

# IADC Driller's Method Worksheet

Well Name: ______________________ Completed By: ______________________ Date: _____ /_____ /_____

## KICK DATA

SIDPP: __________ psi SICP: __________ psi

PIT GAIN: __________ Bbls Time of Incident: ____ : ____

## PROCEDURE

**First Circulation to clear influx from well:**

1. Bring pump(s) up to slow circulation rate and attempting to hold casing pressure constant by manipulating or adjusting the choke. The slow circulation rate will normally be 50% of the rate used in drilling operations.
2. Read and record Initial Circulating Pressure on Drill Pipe. This pressure should equal the SIDPP plus the slow circulation rate pressure.

   Recorded ICP __________ psi @ rate __________ spm
3. Maintain pump rate and drill pipe pressure constant until influx is circulated out of well.
4. Shut down pump(s) while holding casing pressure constant closing the choke as required. The trapped SIDPP will represent formation pressure.
5. With the pumps off and choke closed, the casing pressure and drill pipe pressures should be equal. If not, continue to circulate out the influx.
6. Record the new shut in casing pressure.

   SICP __________ psi
7. Calculate Kill Mud Weight.

   KMW = __________ ppg
8. Increase surface mud system to required KMW density.

**Second Circulation to balance well:**

1. Bring pump(s) up to slow circulation rate and open choke as required while holding new casing pressure contant.
2. Adjust the choke to hold the new casing pressure constant until the drill pipe is full of kill mud of the required density.
3. After drill pipe is full of kill mud, record drill pipe pressure.

   __________ psi
4. Hold pump rate constant and drill pipe pressure by adjusting the choke until the annulus is filled with kill mud.
5. When kill mud reaches the surface, choke pressure, if any, is bled off.
6. Stop circulating and check for flow.

## CURRENT WELL DATA

**PRESENT MUD WEIGHT:** ______ ppg

**SLOW CIRCULATION RATE (SCR):**

SCR taken @ ____________ (ft)

| | Stks/min | Pressure(psi) | Bbl/min | Pressure(psi) |
|---|---|---|---|---|
| Pump #1 | | | | |
| | | | | |
| | | | | |
| Pump #2 | | | | |
| | | | | |
| | | | | |
| Pump #3 | | | | |
| | | | | |
| | | | | |

TOTAL DEPTH (MD) ______ ft

TOTAL DEPTH (TVD) ______ ft

**CASING DATA:**

CASING ______ , ______ , ______
size ID weight

CASING SHOE DEPTH ______ ft

**SHOE TEST DATA:**

Depth #1
______ @ Test MW of ______
(psi) (ppg)

Depth #2
______ @ Test MW of ______
(psi) (ppg)

Depth #3
______ @ Test MW of ______
(psi) (ppg)

LINER #1 ______ , ______ , ______
size ID weight

LINER #2 ______ , ______ , ______
size ID weight

LINER #1 TOP DEPTH ______ ft

LINER #2 TOP DEPTH ______ ft

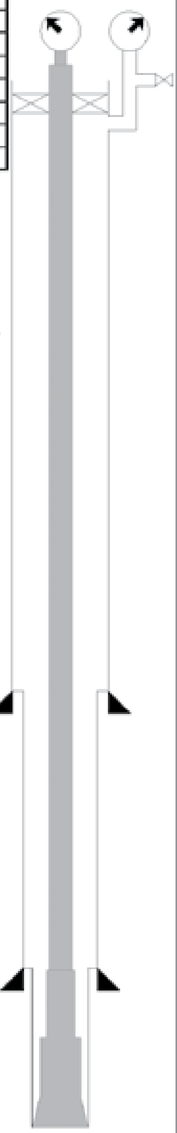
LINER #1 SHOE DEPTH ______ ft

LINER #2 SHOE DEPTH ______ ft

TVD CASING or LINER ______ ft

**HOLE DATA:**

BIT SIZE ______ inches





Field Units
(psi, ft, ppg)

Revised January 8, 2009
Page 1

## CALCULATIONS

### KILL MUD WEIGHT (KMW)

( ________ ÷ 0.052 ÷ ________ ) + ________ = ________ ppg KILL MUD WEIGHT

SIDPP (psi) / True Vertical Depth (ft) / Present Mud Weight (ppg)

### INITIAL CIRCULATING PRESSURE (ICP)

________ + ________ = ________ psi INITIAL CIRCULATING PRESSURE

SIDPP (psi) / Pump Pressure (psi) @ SCR of ______SPM

### TRUE PUMP OUTPUT:

________ X ________ = ________

Bbls/Stk @ 100% / % Efficiency / TPO (Bbls/Stk)

### DRILL STRING CAPACITY:

| | Size (in.) | Weight (lb/ft) | Bbls/ft | | Length (ft) | | | |
|---|---|---|---|---|---|---|---|---|
| Drill #1: Pipe | | | | X | | = | DP | Bbls |
| Drill #2: Pipe | | | | X | | = | DP | Bbls |
| HWDP: | | | | X | | = | HWDP | Bbls |
| Drill #1: Collars | | | | X | | = | DC | Bbls |
| Drill #2: Collars | | | | X | | = | DC | Bbls |
| Surface: Line | | | | X | | = | SL | Bbls |

________ Total Drill String Capacity (Bbls)

### STROKES, SURFACE TO BIT:

________ ÷ ________ = ________

Total Drill String Capacity (Bbls) / True Pump Output (Bbls/Stk) / Strokes, Surface to Bit

### ANNULAR CAPACITY (Between):

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| CSG and DP: | ______ Bbls/ft | X | ______ ft | = | ______ | Bbls |
| Liner #1 and DP: | ______ Bbls/ft | X | ______ ft | = | ______ | Bbls |
| Liner #2 and DP: | ______ Bbls/ft | X | ______ ft | = | ______ | Bbls |
| OH and DP/HWDP: | ______ Bbls/ft | X | ______ ft | = | ______ | Bbls |
| OH and DC: | ______ Bbls/ft | X | ______ ft | = | ______ | Bbls |

### STROKES, BIT TO SHOE:

________ ÷ ________ = ________

Open Hole Annular Volume (Bbls) / True Pump Output (Bbls/Stk) / Strokes, Bit to Shoe

### STROKES, BIT TO SURFACE:

________ ÷ ________ = ________

Total Annular Volume (Bbls) / True Pump Output (Bbls/Stk) / Strokes, Bit to Surface

### TOTAL STROKES, SURFACE TO SURFACE:

________ + ________ = ________

Strokes, Surface to Bit / Strokes, Bit to Surface / Strokes, Surface to Surface

### MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP)

( ________ - ________ ) X 0.052 X ________ = ________ psi MAASP

Max. MW from Shoe Test (ppg) / Present Mud Weight (ppg) / True Vertical Depth Shoe (ft)

### MAXIMUM ALLOWABLE ANNULUS SURFACE PRESSURE (MAASP) WITH KILL MUD

( ________ - ________ ) X 0.052 X ________ = ________ psi MAASP WITH KILL MUD

Max. MW from Shoe Test (ppg) / Kill Mud Weight (ppg) / True Vertical Depth Shoe (ft)

## COMMENTS



Field Units
(psi, ft, ppg)

Revised January 8, 2009
Page 2

## FORMULAS

1. Pressure Gradient (psi/ft) = Mud Weight (ppg) x 0.052

2. Hydrostatic Pressure (psi) = Mud Weight (ppg) x 0.052 x Depth (ft, TVD)

3. Capacity (bbls/ft) = Inside Diameter$^2$ (in.) ÷ 1029.4

4. Annular Capacity (bbls/ft) = (Inside Diameter of Casing$^2$ (in.) or Hole Diameter$^2$ (in.) - Outside Diameter of Pipe$^2$ (in.)) ÷ 1029.4

5. Pipe Displacement (bbls/ft) = (Outside Diameter of pipe$^2$ (in.) - Inside Diameter of pipe$^2$ (in.)) ÷ 1029.4

6. Maximum Allowable Mud Weight (ppg) = $\dfrac{\text{Surface LOT Pressure (psi)}}{\text{Shoe Depth (ft, TVD)} \times 0.052}$ + LOT Mud Weight (ppg)

7. MAASP (psi) = [Maximum Allowable Mud Weight (ppg) - Present Mud Weight (ppg)] x 0.052 x Shoe TVD (ft)

8. Pressure Drop per Foot Tripping Dry Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg)} \times 0.052 \times \text{Metal Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft)} - \text{Metal Displacement (bbl/ft)}}$

9. Pressure Drop per Foot Tripping Wet Pipe (psi/ft) = $\dfrac{\text{Drilling Mud Weight (ppg)} \times 0.052 \times \text{Closed End Displacement (bbl/ft)}}{\text{Casing Capacity (bbl/ft)} - \text{Closed End Displacement (bbl/ft)}}$

10. Formation Pressure (psi) = Hydrostatic Pressure Mud in Hole (psi) + SIDPP (psi)

11. EMW (ppg) @ Shoe = (SICP (psi) ÷ 0.052 ÷ Shoe Depth (ft, TVD)) + Present Mud Weight (ppg)

12. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\dfrac{\text{Bbls of Mud in System} \times 14.9 \times (\text{KMW} - \text{OMW})}{(35.4 - \text{KMW})}$

*NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.*

13. Volume Increase from Adding Barite (bbls) = Number of Sacks (100 lb) added ÷ 14.9

14. Equivalent Mud Weight (ppg) @ ________ depth (ft) = $\left[\dfrac{\text{Pressure (psi)}}{\text{Depth (ft, TVD)} \times 0.052}\right]$ + Current Mud Weight (ppg)

15. Estimated New Pump Pressure at New Pump Rate (psi) = Old Pump Pressure (psi) x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

16. Estimated New Pump Pressure with New Mud Weight (psi) = Old Pump Pressure (psi) x $\dfrac{\text{New Mud Weight (ppg)}}{\text{Old Mud Weight (ppg)}}$

## COMMENTS

# IADC WellCAP Well Control Worksheet
# Bullhead

Well Name: ______________________ Completed By: ______________________ Date: ____/____/____

## PRE-RECORDED INFORMATION

**TRUE PUMP OUTPUT:** ________ x ________ = [ ]
Bbls/Stk @ 100% — % Efficiency — TPO (Bbls/Stk)

**PUMP RATE CONSIDERATIONS:**
**Kill Rate Speeds and Volume**

________ ÷ ________ = [ ]
Desired Barrels per Minute (BBLS/MIN) — Pump Output (BBLS/STK) — Pump Rate (STKS/MIN)

________ ÷ ________ = [ ]
Desired Barrels per Minute (BBLS/MIN) — Pump Output (BBLS/STK) — Pump Rate (STKS/MIN)

________ ÷ ________ = [ ]
Desired Barrels per Minute (BBLS/MIN) — Pump Output (BBLS/STK) — Pump Rate (STKS/MIN)

**VOLUME AND STROKE CONSIDERATIONS:**
**Tubing Volume/Strokes (Surface to End of Tubing, E.O.T.)**

________ x ________ = ________ ÷ ________ = [ ]
Tubing Length Surface to E.O.T. (MD — FT) — Capacity per Foot in Tubing (BBLS/FT) — Tubing Volume Surface to E.O.T. (BBLS) — Pump Output (BBLS/STK) — Strokes Surface to E.O.T. (STKS)

**Casing Volumes/Strokes (Below End of Tubing, E.O.T. to Perforations)**

________ x ________ = ________ ÷ ________ = [ ]
Length E.O.T. to Perfs Top/Middle/Bottom (MD — FT) — Capacity per Foot in Casing (BBLS/FT) — Casing Volume E.O.T. to Perforations (BBLS) — Pump Output (BBLS/STK) — Strokes E.O.T. to Perforations (STKS)

**Surface to Perforations Volume/Strokes (Kill Point)**

________ + ________ = ________ ÷ ________ = [ ]
Tubing Volume Surface to E.O.T. (BBLS) — Casing Volume E.O.T. to Perforations (BBLS) — Surface to Perforations Volume (BBLS) — Pump Output (BBLS/STK) — Strokes Surface to Perforations (Kill Point — STKS)

**Total Volume/Stokes to Pump (Including Overdisplacing)**

________ + ________ = ________ ÷ ________ = [ ]
Surface to Perforations Volume (BBLS) — Overdisplacement — if any — (BBLS) — Total Volume to Pump (BBLS) — Pump Output (BBLS/STK) — Total Strokes to Pump (Overdisplace — STKS)

**FORMATION PRESSURE CONSIDERATIONS:**
**Kill Fluid Density**

________ ÷ 0.052 ÷ ________ = [ ]
Formation Pressure (PSI) — Depth to Perforations Top/Middle/Bottom (TVD — FT) — Kill Fluid Density (PPG)

**Estimated Formation Integrity Pressure (Fracture)**

________ x 0.052 x ________ = [ ]
Max. Allowable Mud Density (PPG) — Depth to Perforations Top/Middle/Bottom (TVD — FT) — Estimated Formation Integrity Pressure (PSI)

**Average Hydrostatic Pressure in Tubing**

________ – ________ = [ ]
Formation Pressure (PSI) — Initial Shut in Tubing Pressure (PSI) — Average Hydrostatic Pressure in Tubing (PSI)

**Initial Estimated Maximum Pressure on Tubing (Static)**

________ – ________ = [ ]
Est. Formation Integrity Pressure (PSI) — Average Hydrostatic Pressure in Tubing (PSI) — Initial Estimated Max. Pressure on Tubing (PSI)

**Kill Fluid Hydrostatic Pressure**

________ x 0.052 x ________ = [ ]
Kill Fluid Density (PPG) — Depth to Perforations Top/Middle/Bottom (TVD — FT) — Kill Fluid Hydrostatic Pressure (PSI)

**SLOW CIRCULATION RATE (SCR):**

| | STKS/MIN | Pressure(PSI) | BBL/MIN | Pressure(psi) |
|---|---|---|---|---|
| Pump #1 | | | | |
| | | | | |
| | | | | |
| Pump #2 | | | | |
| | | | | |
| | | | | |
| Pump #3 | | | | |
| | | | | |
| | | | | |

**RECORDED WELL DATA:**

Formation Pressure [ ] PSI

Max. Allowable Mud Density [ ] PPG

Maximum Pump Pressure [ ] PSI

Shut In Tubing Pressure [ ] PSI

Shut In Casing Pressure [ ] PSI

Tree/Wellhead/
BOP Stack Rating [ ] PSI

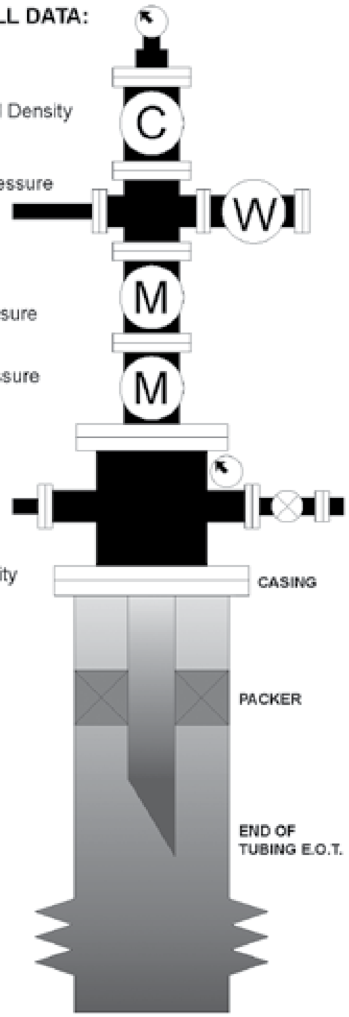
Annulus Fluid Density [ ] PPG

Packer Set [ ] TVD [ ] MD FT

Top Perforation [ ] TVD [ ] MD FT

Middle Perforation [ ] TVD [ ] MD FT

Bottom Perforation [ ] TVD [ ] MD FT




**Final Estimated Maximum Pressure on Tubing (Static)**

________ – ________ = [ ]
Est. Formation Integrity Pressure (PSI) — Kill Fluid Hydrostatic Pressure (PSI) — Final Estimated Max. Pressure on Tubing (PSI)



Field Units
(psi, ft, ppg)

Revised January 8, 2009
Page 1

# TUBING & CASING DATA

## TUBING DATA:

**Tubing**

| Outside Diameter (INCHES) | Inside Diameter (INCHES) | Capacity per Foot (BBLS/FT) | Length to E.O.T. (MD — FT) |
|---|---|---|---|
| | | | |

**Tubing Collapse**

___ x ___ = ___

Tubing Collapse (PSI) x Safety Factor (0.70 or Less) = Adjusted Tubing Collapse (PSI)

**Tubing**

| Weight (LBS/FT) | Grade | Internal Yield (PSI @ 100%) | Collapse (PSI @ 100%) |
|---|---|---|---|
| | | | |

**Tubing Yield**

___ x ___ = ___

Tubing Yield (PSI) x Safety Factor (0.70 or Less) = Adjusted Tubing Internal Yield (PSI)

## CASING DATA:

**Casing**

| Outside Diameter (INCHES) | Inside Diameter (INCHES) | Capacity per Foot (BBLS/FT) | Length (MD — FT) |
|---|---|---|---|
| | | | |

**Casing Internal Yield**

___ x ___ = ___

Casing Internal Yield (PSI) x Safety Factor (0.70 or Less) = Adjusted Casing Yield (PSI)

**Casing**

| Weight (LBS/FT) | Grade | Internal Yield (PSI @ 100%) | **TREE/BOP** Rated Pressure (PSI) |
|---|---|---|---|
| | | | |

## PRESSURE CONSIDERATIONS:

**Pressure Consideration PSI per "Step"**

___ Ⓐ − ___ Ⓑ ÷ 10 = ___

Initial Max. Pressure on Tubing (PSI) − Final Max. Pressure on Tubing (PSI) ÷ Number of "Steps" = PSI per "Step" (PSI/STEP)

Ⓐ Lesser value of "Tubing Yield" or "Initial Estimated Maximum Pressure on Tubing" results *(see page 1)*

Ⓑ Lesser value of "Tubing Yield" or "Final Estimated Maximum Pressure on Tubing (Static)" results *(see page 1)*

**Volume per "Step"**

___ ÷ 10 = ___ x 42 = ___

Surface to Perforations Volume (BBLS) ÷ Number of "Steps" = Volume per "Step" (BBLS/STEP) x 42 = Volume per "Step" (GALS/STEP)

**Strokes per "Step"**

___ ÷ 10 = ___

Stroke Surface to Perforations (STKS) ÷ Number of "Steps" = Strokes per "Step" (STKS/STEP)

## PRESSURE CHART

| Strokes | Volume in BBLS | Volume in GALS | Estimated Max. Static Pressure | Actual Tubing Pressure | Casing Pressure | Pump Rate | Notes |
|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | Initial | | | | |
| | | | | | | | |
| | | | | | | | |
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| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| Kill Point | Final ↓ | | | | | | |
| Overdisplace ↓ | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

## FORMULAS

1. Pressure Gradient (psi/ft) = Mud Weight (ppg) x 0.052

2. Hydrostatic Pressure (psi) = Mud Weight (ppg) x 0.052 x Depth (ft, TVD)

3. Capacity (bbls/ft) = Inside Diameter$^2$ (in.) ÷ 1029.4

4. Annular Capacity (bbls/ft) = (Inside Diameter of Casing$^2$ (in.) or Hole Diameter$^2$ (in.) - Outside Diameter of Pipe$^2$ (in.)) ÷ 1029.4

5. Pipe Displacement (bbls/ft) = (Outside Diameter of pipe$^2$ (in.) - Inside Diameter of pipe$^2$ (in.)) ÷ 1029.4

6. Maximum Allowable Mud Weight (ppg) = $\dfrac{\text{Surface LOT Pressure (psi)}}{\text{Shoe Depth (ft, TVD)} \times 0.052}$ + LOT Mud Weight (ppg)

7. MAASP (psi) = [Maximum Allowable Mud Weight (ppg) - Present Mud Weight (ppg)] x 0.052 x Shoe TVD (ft)

8. Formation Pressure (psi) = Hydrostatic Pressure Mud in Hole (psi) + SIDPP (psi)

9. Sacks (100 lb) of Barite Needed to Weight-Up Mud = $\dfrac{\text{Bbls of Mud in System} \times 14.9 \times (\text{KMW} - \text{OMW})}{(35.4 - \text{KMW})}$

*NOTE: This formula assumes that the average density of Barite is 35.4 ppg and the average number of sacks (100lb) per barrel is 14.9.*

10. Volume Increase from Adding Barite (bbls) = Number of Sacks (100 lb) added ÷ 14.9

11. Equivalent Mud Weight (ppg) @ __________ depth (ft) = $\left[\dfrac{\text{Pressure (psi)}}{\text{Depth (ft, TVD)} \times 0.052}\right]$ + Current Mud Weight (ppg)

12. Estimated New Pump Pressure at New Pump Rate (psi) = Old Pump Pressure (psi) x $\left[\dfrac{\text{New Pump Rate (SPM)}}{\text{Old Pump Rate (SPM)}}\right]^2$

13. Estimated New Pump Pressure with New Mud Weight (psi) = Old Pump Pressure (psi) x $\dfrac{\text{New Mud Weight (ppg)}}{\text{Old Mud Weight (ppg)}}$

## COMMENTS

# Procedures to Confirm Ballooning

1. Line up to take returns from the choke to a trip tank or other tank from which accurate measurements of mud bled can be observed.

2. Record SICP and SIDPP.

3. Station rig hand to spot where flow into the trip tank can be observed.

4. Open choke, slowly bleed five barrels of mud, watching the rate of mud returned.

5. Record choke position during bleeding.

6. Record time that it took to bleed five barrels.

7. Close choke.

8. Observe SICP and SIDPP.

9. If both SICP and SIDPP stabilize at values lower than original shut in pressure, and rate of mud returned appeared to decrease with time, ballooning is likely. If values stabilize at higher than the original shut-in pressure, and rate of returns increases with choke at the same position, then a kick might be in the well.

10. Repeat steps 4 through 9 until SIDPP is zero, or both gauges read zero and no mud flows from the well with the choke open.

11. Stop the process anytime it becomes clear that bleeding leads to increased shut-in pressures or flow increases with time during the bleeding process.

# GLOSSARY

F

## A

***abnormal pressure*** – Pore pressure in excess of that pressure resulting from the hydrostatic pressure exerted by a vertical column of water with salinity normal for the geographic area.

***absolute permeability*** – A measure of the ability of a single fluid (as water, gas, or oil) to flow through a rock formation when the formation is totally filled (saturated) with the single fluid. The permeability measure of a rock filled with a single fluid is different from the permeability measure of the same rock filled with two or more fluids. Compare ***effective permeability***.

***absorption*** – The penetration or apparent disappearance of molecules or ions of one or more substances into the interior of a solid or liquid. For example, in hydrated bentonite, the planar water that is held between the mica-like layers is the result of absorption.

***accelerator*** – A chemical additive that reduces the setting time of cement. See ***cementing materials***.

***accumulator*** – On a drilling rig, accumulator stores hydraulic fluid under pressure from compressed nitrogen for closing blowout preventer in an emergency. Accumulator is a vessel or tank to receive and temporarily store liquid used in a continuous process in a plant. A drip accumulator collects liquid hydrocarbons that condense out of wet gas travelling in a pipeline. In some countries, a storage battery is called an accumulator.

***acetic acid*** – An organic acid compound sometimes used to acidize oil wells. It is not as corrosive as other acids used in well treatments.

***acetylene welding*** – A method of joining steel components in which acetylene gas and oxygen are mixed in a torch to attain the high temperatures necessary for welding.

***acid*** – Any chemical compound containing hydrogen capable of being replaced by positive elements or radicals to form salts. In terms of the dissociation theory, it is a compound which, on dissociation in solution, yields excess hydrogen ions. Acids lower the pH. Examples of acids or acidic substances are: hydrochloric acid, tannic acid, sodium acid pyrophosphate.

***acid fracture*** – Hydraulic pressure is applied to potentially carbonate (limestone/dolomite) formations, opening cracks, or causing the formation to split open forming a fracture by using a combination of oil and acid or water under high pressure.

***acid treatment*** – A method in which chemicals are pumped into microscopic flow channels of the formation. By dissolving the rock, these passages are enlarged, increasing production. See ***acidize***.

***acid-up*** – To fracture a well using acids (acidizing).

***acidity*** – Relative acid strength of liquids, measured by pH. (pH below 7.0). See ***pH***.

***acidize*** – To treat oil-bearing limestone or other formations, using a chemical reaction with acid, to increase production. Hydrochloric or other acid is injected into formation under pressure. The acid etches the rock, enlarging the pore spaces and passages through which the reservoir fluids flow. The acid is then pumped out, and the well is swabbed and put back into production. Chemical additives and inhibitors are combined with the acid to react selectively with formation rock without attacking metal well equipment.

***acidizing*** – A wellbore formation stimulation treatment.

***acoustic survey*** – A well logging method that measures the time required for sound impulses to travel through a given length of rock to permit estimation of the rock porosity of a given formation and of the fluid type contained in the rock. This process is also called sonic logging. See ***sonic logging***.

***adapter spool*** – A joint to connect blowout preventers of different sizes or pressure ratings to the casing head.

***adjustable choke*** – A choke in which a conical needle and seat vary the rate of flow. Also called automatic choke. See ***choke***.

***adjustable spacer sub*** – A sub run below a dual, triple packer to permit spacing out and/or making connections.

***adsorption*** – A surface phenomenon exhibited by a solid (adsorbent) to hold or concentrate gases, liquids, or dissolved substances (adsorptive) upon its surface, a property due to adhesion. For example, that water held to the outside surface of hydrated bentonite is adsorbed water.

***aeration*** – The technique of injecting air or gas in varying amounts into a drilling fluid for the purpose of reducing hydrostatic head. Compare ***air cutting***.

***agglomerate*** – The larger groups of individual particles usually originating in sieving or drying operations.

***aggregate*** – Group of two or more individual particles held together by strong forces. Aggregates are stable to normal stirring, shaking or handling as powder or suspension. May be broken by drastic treatment, ball milling powder or shearing a suspension.

***air cutting*** – The inadvertent mechanical incorporation and dispersion of air into a drilling-fluid system. Compare to ***aeration***.

***air-tube clutch*** – A clutch containing an tube, which, when inflated, causes clutch to engage the driven member. When the tube in deflated, disengagement occurs.

***Alkali*** – Any compound having marked basic properties. See ***base***.

***alkalinity*** – The combining power of a base measured by the maximum number of equivalents of an acid with which it can react to form a salt. In water analysis, it represents the carbonates, bicarbonates, hydroxides, and occasionally the borates, silicates, and phosphates in the water. It is determined by titration with standard acid to certain datum points. See ***API RP 13B**** for specific directions for determination of phenolphthalein (P) and methyl orange (M1) alkalinities of the filtrate in drilling fluids and the alkalinity of the mud itself (Pm). Also see P1, M1, and Pm.

***aluminum stearate*** – Aluminum salt of stearic acid, a defoamer. See ***stearate***.

***American Petroleum Institute*** – 1. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil field drilling and producing equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas. 2. (slang) Indicative of a job being properly or thoroughly done (as, "His work is strictly API"). 3. Degrees API; used to designate API gravity. See ***API gravity***.

***analysis, mud or drilling fluid***– Examination and testing of the drilling fluid to determine its physical and chemical properties and condition.

***anchor*** – Any device that secures or fastens equipment. A device used to secure the production tubing against expansion/contraction; similar to a packer but without rubber elements. In downhole equipment, the term often refers to the tail pipe. In offshore drilling, floating drilling vessels are sometimes secured over drill sites by large metal anchors like those used on ships. See ***tail pipe***.

***anchor seal assembly*** – Seal assembly run in on production tubing to land the tubing in tension or keep the tubing inside the seal bore due to insufficient tubing weight.

***angle of defection*** – In directional drilling, the angle at which a well is deflected from the vertical by a whipstock or other deflecting tool. See ***whipstock***.

***anhydrite*** – Anhydrite is often encountered while drilling. It may occur as thin stringers or massive formations. See ***calcium sulfate***.

***anhydrous*** – Without water.

***aniline point*** – The lowest temperature at which equal volumes of freshly distilled aniline and an oil which is being tested are completely miscible. This test gives an indication of the character (paraffinic, naphthenic, asphaltic, aromatic, mid-continent, etc.) of the oil. The aniline point of diesels or crudes used in drilling mud is also an indication of the deteriorating effect these materials may have on natural or synthetic rubber. The lower the aniline point of an oil, the more severe it usually is in damaging rubber parts.

***anion*** – A negatively charged atom or radical, such as Cl-, OH-, $SO_4$=, etc., in solution of an electrolyte. Anions move toward the anode (positive electrode) under the influence of an electric potential.

***annular blowout preventer*** – A device usually installed above the ram preventers used to control wellhead pressure. Compression of a reinforced rubber packing element by hydraulic pressure actuates the device which then effects a seal. A standard annular BOP will shut off annular pressure, open hole pressure, and afford stripping of tubing/drill pipe while containing well pressure.

***annular space*** – 1. Space surrounding a cylindrical object within a cylinder. 2. Space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing; sometimes termed the annulus.

***annular valve*** – A valve used in a DST string to operate chamber sampling and spot treating fluids; for floaters where pipe rotation is not desirable.

***annular velocity*** – The velocity of a fluid moving in the annulus.

***annulus or annular space*** – The space between the drill string and the wall of the hole or casing.

***annulus*** – The space around a pipe suspended in the wellbore. The outer wall of the annulus may be either the wall of the borehole or the casing.

***anti-foam*** – A substance used to prevent foam by greatly increasing the surface tension. Compare ***defoamer***.

***AOSC*** – Association of Oilwell Servicing Contractors.

***API*** – American Petroleum Institute.

***API certified*** – A tool in compliance with the American Petroleum Institute's applicable standards.

***API gravity*** – Gravity (weight per unit volume) of crude oil or other related fluids as measured by a system recommended by American Petroleum Institute. It is related to specific gravity by the following: API gravity = (141.5 divided by specific gravity) – 131.5.

***apparent viscosity*** – The viscosity a fluid appears to have on a given instrument at a stated rate of shear. It is a function of the plastic viscosity and the yield point. The apparent viscosity in centipoises, as determined by the direct-indicating viscometer (which see), is equal to ½ the 600-rpm reading. See also ***viscosity, plastic viscosity***, and ***yield point***. In a Newtonian fluid, apparent viscosity is numerically equal to plastic viscosity.

***APR*** – A trademark name for an annular pressure-responsive valve; for a DST string.

***asbestos*** – Term applied to many fibrous silicate minerals, some forms of which are used in certain drilling fluids.

***asphalt*** – Natural or mechanical mixture of solid or viscous bitumens found in natural beds or obtained as a residue from petroleum. Asphalt, blends containing asphalt, and altered asphaltic materials (e.g., air-blown, chemically modified, etc.) have been added to certain drilling fluids for such widely different purposes as a component in oil-base muds, lost-circulation material, emulsifier, fluid-loss-control agent, wall-plastering agent, etc.

***Association of Oilwell Servicing Contractors*** – An organization that sets some of the standards, principles, and policies of oilwell servicing contractors and is based in Dallas, Texas.

***atom*** – According to atomic theory, the smallest quantity of an element capable of entering into chemical combination or that can exist alone.

***atomic number*** – The relative weight of an atom of an element as compared with the weight of 1 atom of oxygen, using 16 as the weight of 1 atom of oxygen.

***attapulgite clay*** – A colloidal, viscosity-building clay used principally in saltwater muds. Attapulgite, a special fullers earth, is a hydrous magnesium aluminum silicate.

***automatic "J"*** – A type of mechanism in packer/tools where straight pickup or set-down action will set or release the tool.

# B

***b/d*** – Abbreviation for ***barrel per day***. alternate abbreviation *bpd*

***back in unit*** – A portable servicing or workover rig that is self-propelled, using the hoisting engines for motive power. Because the driver's cab is mounted on the end opposite the mast support, the unit must be backed up to the wellhead. See ***carrier rig***.

***back off*** – Unscrew one threaded piece (e.g., pipe section) from another.

***back-pressure*** – The pressure maintained on equipment or systems through which a fluid flows.

***back-pressure valve*** – A flow-control valve to provide backflow control when running or pulling a string.

***back bp*** – To hole one section of an object (as pipe) while another is being screwed into or out of it. A backup wrench used to hold a pipe or bolt to prevent its turning while another length of pipe or a nut is being tightened or loosened.

***back-up element*** – A sealing ring on either side of the center packing element to limit its extrusion.

***back-up ring*** – A cylindrical ring, usually vice-shaped; used to backup (or assist) a sealing member against extrusion under temperature and pressure.

***back-up*** – Rotating pipe or tubing in the opposite direction of make-up; every two or three stands to prevent setting a rotational-set downhole tool.

***backing-off*** – Turning pipe in the opposite direction of makeup; possibility of unscrewing and dropping the pipe.

***backside*** – The area above a packer between casing ID and tubing OD.

***bail*** – A cylindrical steel bar (similar to the handle or bail of a bucket, only much larger) that supports the swivel and connects it to the hook. Sometimes, the two cylindrical bars that support the elevators and attach them to the hook are called bails. To recover bottomhole fluids, samples, or drill cuttings by lowering a cylindrical vessel called a bailer to the bottom of a well, filling it, and retrieving it. See ***bailer.***

***balance, mud*** – A beam-type balance used in determining mud density. It consists primarily of a base, graduated beam with constant-volume cup, lid, rider, knife edge, and counterweight.

***ball*** – A spherical object used to pump down the hole to trip, release or otherwise operate certain hydraulic-type tools.

***ball catcher*** – A cylindrical tube place around the retrieving neck of a retrievable bridge plug to "catch" debris or frac balls.

***ball sealers*** – Balls made of nylon, hard rubber, or both and used to shut off perforations through which excessive fluid is lost.

***ball valve*** – A flow-control device employing a ball with a rotating mechanism to open/close the tubing medium.

***ball-out*** – The plugging of open perforations by using ball sealers.

***barefoot completion*** – Also called open-hole completion, which see.

***barite, barytes, or heavy spar*** – Natural barium sulfate ($BaSO_4$) used for increasing density of drilling fluids. If required, it is usually upgraded to a specific gravity of 4.20 (i.e, it is 4.2 times heavier than water). Barite material occurs in white, grayish, greenish, and reddish ores or crystalline masses.

***barite plug*** – A settled volume of barite particles from a barite slurry placed in the wellbore to seal off a pressured zone.

***barite slurry*** – A mixture of barium sulfate, chemicals, and water of a unit density between 18 and 22 pounds per gallon (lb/gal).

***barium sulfate*** – 1. Chemical combination of barium, sulfur, and oxygen. Also called barite, which see. 2. Tenacious scale that is difficult to remove. $BaSO_4$.

***barrel*** – A measure of volume for petroleum products. One barrel is the equivalent of 42 U.S. gallons or 0.15699 cubic meters. One cubic meter equals 6.2897 barrels. abbreviation *bbl*

***barrel equivalent*** – A laboratory unit used for evaluating or testing drilling fluids. One gram of material, when added to 350 ml of fluid, is equivalent to 1 lb of material when added to one 42-gal barrel of fluid. abbreviation *BE*

***barrel per day*** – A measure of the rate of flow of a well; the total amount of oil produced or processed per day. abbreviation *b/d* or *bpd*

***baryte*** – Variation of barite. See ***barite***.

***base*** – A compound of metal, or a metal-like group, with hydrogen and oxygen in the proportion to form an OH radical, which ionizes in aqueous solution to yield excess hydroxyl ions. Bases are formed when metallic oxides react with water. Bases increase the pH. Examples are caustic soda and lime.

***base exchange*** – Replacement of cations associated with the clay surface by those of another species, e.g., the conversion of sodium clay to calcium clay.

***basicity*** – pH value > 7.0. Ability to neutralize or accept protons from acids.

***basket*** – Device used to catch debris from drillable tools, perforators, etc.

***basket sub*** – A fishing accessory run above a bit or mill to recover small pieces of metal or junk in a well.

***battery*** – 1. An installation of identical or nearly identical pieces of equipment (as a tank battery or a battery of meters). 2. An electricity storage device.

***bbl*** – Abbreviation for *barrel.*

***beam pumping unit*** – A machine designed specifically for sucker rod pumping, using a horizontal member (walking beam) that is worked up and down by a rotating crank to produce reciprocating motion.

***belching*** – A slang term to denote flowing by heads.

***bell nipple*** – A short length of tubular goods installed in the top of the blowout preventer. The top and end of the nipple is expanded, or belled, to guide the drill tools into the hole and usually has side connections for the fill line and mud-return line.

***bent sub*** – A short cylindrical device installed in a drill stem between the bottom-most drill collar and a downhole mud motor. The purpose of the bent sub is to deflect the mud motor off vertical to drill a directional hole.

***bentonite*** – A plastic, colloidal clay, largely made up of the mineral sodium montmorillonite (a hydrated aluminum silicate) that swells when wet. Because of its gel-forming properties, bentonite is a major component of drilling muds. For use in drilling fluids, bentonite has a yield in excess of 85 bbl/ton. The generic term “bentonite” is neither an exact mineralogical name, nor is the clay of definite mineralogical composition.

***bicarb*** – See ***sodium bicarbonate***.

***birddog*** – Someone supervising another too closely or continuously.

***bit*** – The cutting or boring element used on the end of a work string or drill pipe to remove the earth in creating or cleaning out a wellbore. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and utilizes the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill pipe column. The bit is attached to the end of the drill collars. Most bits used in rotary drilling are roller cone bits. See ***roller cone bit***.

***blank casing*** – A casing without perforations.

***blank joint*** – A heavy wall sub placed opposite flowing perforations.

***blank liner*** – A liner with no perforations.

***blanking plug*** – Plug run on wireline/block off tubing ID placed in seating profile.

***blast joint*** – A heavy-wall sub positioned in the producing string opposite perforations, to deflect the well's jetting action.

***bleed*** – To drain off liquid or gas, generally slowly, through a valve called a bleeder. To bleed down, or bleed off, is to slowly release pressure from well or pressurized equipment.

***bleeding*** – Controlled release of fluids from a closed and pressured system in order to reduce the pressure.

***bleeding-off*** – The evacuation of pressure off a well.

***blender*** – A device used to blend slurries/gels; usually mobile equipment.

***blind ram preventer*** – A blowout preventer in which blind rams are the closing elements. See ***blind rams***.

***blind rams*** – Also called "blank rams" and "master rams." They seal against each other and completely shut off the hole below.

***blind/shear rams*** – Blind rams with a built-in cutting edge that will shear against any drill pipe or casing. They seal against each other to effectively close the hole.

***block*** – Any assembly of pulleys on a common framework; in mechanics, one or more pulleys, or sheaves, mounted to rotate on a common axis. The crown block is an assembly of sheaves mounted on beams at the top of the derrick. The drilling line is reeved over the sheaves of the crown block alternately with the sheaves of the traveling block, which is hoisted and lowered in the derrick by the drilling line. When elevators are attached to a hook on the traveling block, and when drill pipe is latched in the elevators, the pipe can be raised or lowered in the derrick or mast. See ***crown block, elevators, hook, reeve, sheave,*** and ***traveling block;*** also see ***drilling block***.

***blooie line*** – Flow line for air or gas drilling. A large diameter line that diverts the flow of air or gas from the rig to a pit area. See ***diverter***.

***blowdown*** – To vent off gas in a well.

***blowout*** – 1. An uncontrolled flow of gas, oil, or other well fluids into the atmosphere, or into another zone. A blowout, or gusher, occurs when formation pressure exceeds the pressure applied to it by the column of drilling fluid. A kick warns of an impending blowout. See ***formation pressure, gusher,*** and ***kick***. 2. To expel a portion of water and steam from a boiler to limit its concentration of minerals.

***blowout preventer (BOP) control panel*** – A set of controls, usually located near the driller's position on the rig floor, that is manipulated to open and close the blowout preventers.

***blowout preventer control unit*** – A device that stores hydraulic fluid under pressure in special containers and provides a method to open and close the blowout preventers quickly and reliably. Usually, compressed air hydraulic pressure provide the opening and closing force in the unit. See *blowout preventer.*

***blowout preventer drill*** – A training procedure to determine that rig crews are completely familiar with correct operating practices to be followed in the use of blowout prevention equipment. A "dry run" of blowout preventative action.

***blowout preventer operating and control system (closing unit)*** – The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

***blowout preventer rams*** – The closing and sealing components of a preventer. Corresponds to the gate in the gate valve.

***blowout preventer stack*** – Assembly of well control equipment including preventers, spools, valves, and nipples connected to wellhead top.

***blowout preventer*** – The equipment installed at the wellhead to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole (i.e., hole with no drill pipe) during drilling and completions operations. The blowout preventer is located underneath the rig floor on land and "surface stack" marine operations, and on the sea floor for "subsea stack" or floating offshore rigs. See ***annular blowout preventer*** and ***ram blowout preventer***.

***body lock ring*** – Internal mechanism used in tools to lock cones to mandrel.

***boiler*** – A closed pressure vessel that has a furnace equipped to burn coil, oil, or gas and is used to generate steam from water.

***boll weevil*** – 1. A retrievable plug attached to drill pipe and used in testing blowout preventers. It seats on the casinghead housing. Pressure from above causes it to seal off the hole. 2. (slang) An inexperienced rig or oil field worker, sometimes shortened to "weevil."

***bomb*** – A thick-walled container, usually steel, used to hold samples of oil or gas under pressure. See ***bottomhole pressure***.

***bomb hanger*** – A device set in the tubing, particularly in collars, to facilitate the landing of pressure bombs (recorders).

***bonnet*** – On ram-type preventers, component which seals rear of ram cylinder.

***boot basket*** – A tool run just above the bit or mill in the drill stem to catch small, non-drillable objects circulating in the annulus.

***BOP stack*** – Blowout preventers employed as mechanical or automated well control during drilling; during wireline work.

***borehole pressure*** – Total pressure exerted in the wellbore by a column of fluid and/or back pressure imposed at the surface.

***borehole*** – The wellbore; hole made by drilling or boring. See ***wellbore***.

***bottom drill*** – A permanent drillable tool where the tools slips will be cut away before opening the tool's bore and potentially acting formation pressure.

***bottomhole choke*** – A device with a restricted opening placed in the lower end of the tubing to control the rate of flow. See ***choke***.

***bottomhole pressure*** – Depending upon context, either a pressure exerted by a column of fluid contained in wellbore or formation pressure at the depth of interest.

***bottomhole pressure gauge*** – A gauge to measure bottomhole pressure. See ***bottomhole pressure***.

***bottomhole pressure bomb*** – A bomb used to record the pressure in a well at a point opposite the producing formation. See ***bomb***.

***bottom sub*** – Lowest extremity of tool where accessories or tools can be coupled.

***bottom water*** – Found below oil and gas in a producing formation.

***bottoms up*** – From the bottom of the well to the top of the well.

***Bourdon tube*** – A flattened metal tube bent in a curve, which tends to straighten under pressure. By the movements of an indicator over a circular scale, a Bourdon tube indicates the pressure applied to it.

***box*** – A coupling with internal threads.

***box tap*** – 1. Female tapered self-threading tool used to screw onto a fish externally for retrieval. 2. Old-style tap with longitudinal grooves across threads. See tap and taper tap.

***bpd*** – abbreviation for barrels per day.

***bradenhead squeezing*** – The process by which hydraulic pressure is applied to a well to force fluid or cement outside the wellbore. The bradenhead, or casinghead, is closed to shut off the annulus when making a bradenhead squeeze. Although this term is still used, the term bradenhead is obsolete. See ***annular space***, ***casinghead***, and ***squeeze***.

***brake band*** – A part of the brake mechanism consisting of a flexible steel band lined with asbestos or similar material that grips a drum when tightened. On a drilling rig, the brake band acts on the flanges of the drum on the draw works to control lowering of the traveling block and its load of drill pipe, casing, or tubing. See ***casing, draw works, drill pipe, traveling block,*** and ***tubing***.

***break circulation*** – To start the mud pump to restore circulation of mud column. Because stagnant drilling fluid has solidified during the period of no circulation, high pump pressure is usually required to break circulation.

***break out*** – 1. To unscrew one section of pipe from another section, especially drill pipe while it is being withdrawn from the wellbore. During this operation, the tongs are used to start the unscrewing operation. See ***tongs***. 2. To separate, as gas from liquid.

***breaking down*** – To unscrew the drill stem into single joints and place them on the pipe rack. The operation takes place upon completion of the well, prior to running casing, when the drill pipe will no longer be used, or when changing from one size of pipe to another. Also called laying down. See ***lay down pipe***.

***breakout cathead*** – A device attached to the shaft of the draw works that is used as a power source for unscrewing drill pipe; usually located opposite the driller's side of the draw works. See ***cathead***.

***breakout, oil*** – Oil that has risen to the surface of the mud which previously has been combined in the mud as emulsion.

***bridge*** – Obstruction in well made by intrusion of subsurface formations.

***bridge plug*** – 1. A tool employed as temporary or permanent barrier in the casing string; either permanent or retrievable. 2. A downhole tool, composed primarily of slips, a plug mandrel, and a rubber sealing element that is run and set in casing to isolate a lower zone while testing an upper section.

***bridging material*** – The fibrous, flaky, or granular material added to a cement slurry or drilling fluid to aid in sealing formations in which lost circulation has occurred. See ***lost circulation*** and ***lost circulation material***.

***bridging-off*** – A restriction in casing inside diameter.

***brine*** – Water saturated with or containing a high concentration of common salt (sodium chloride); hence, any strong saline solution containing such other salts as calcium chloride, zinc chloride, calcium nitrate, etc.

***bring in a well*** – To complete a well and put it in producing status.

***broaching*** – Venting of fluid to surface/seabed through channels external to casing.

***bromine value*** – Number of centigrams of bromine which are absorbed by 1 g of oil under certain conditions. This is a test for degree of unsaturatedness of a given oil.

***Brownian movement*** – Continuous, irregular motion exhibited by particles suspended in liquid/gaseous medium, usually as a colloidal dispersion.

***BS or BS & W*** – Base sediment, or base sediment and water.

***BSEE*** – acronym for Bureau of Safety and Environmental Enforcement, formerly MMS, a division of the Department of the Interior.

***buckled-up*** – Same as buttoning-up.

***bull plug*** – A closed-end sub usually run with seal assemblies or production tubing to "bull" its way past obstruction.

***bullet perforator*** – Tubular device that, when lowered to a selected depth within a well, fires bullets through casing to provide holes through which well fluids may enter.

***bullheading*** – 1. A term to denote pumping into a closed-in well without returns. 2. The forcing of fluid down the hole under placement.

***bumper jar*** – An expansion joint, which permits vertical movement of the upper section without movement of the lower part of the tool, used to deliver a heavy blow to objects in the borehole. If the fish can be freed by a downward blow, a bumper jar can be very effective.

***bumper sub*** – A device similar to a jar but used in the normal drilling stem to compensate for vertical movement of the stem, especially in offshore drilling. It also provides jarring action but to a lesser extent than a jar in fishing operations. See ***jar***.

***BUNA-N*** – A nitrile rubber used commonly throughout the oil field as an elastometer seal; i.e., in o-rings, vee-rings, etc.

***buoyancy*** – The apparent loss of weight of an object immersed in a fluid. If the object is floating, the immersed portion displaces a volume of fluid the weight of which is equal to the weight of the object.

***burn-over*** – Using a mill to remove the outside area of a permanent downhole tool.

***burning shoe*** – Type of rotary shoe used to mill away metal in finishing operations.

***bushing*** – A pipe fitting which allows two pieces of pipe of different sizes to be connected together.

***butane*** – A paraffin hydrocarbon, $C_4H_{10}$, that is a gas in atmospheric conditions but is easily liquefied under pressure; a constituent of LPG. See ***liquefied petroleum gas***.

***button slip*** – A slip employing tungsten-carbide "buttons', in lieu of conventional wicker-type teeth, to set tools in very hard casing.

***buttoning-up*** – To secure the wellhead or other components.

***bypass*** – A built-in passageway inside a tool to facilitate the bypassing of fluids from tubing to annulus or vice versa.

# C

***cable tool drilling*** – Drilling method in which hole is drilled by dropping a sharply pointed bit on the bottom of the hole. The bit is attached to a cable, and the cable is picked up and dropped, picked up and dropped, over and over, as the hole is drilled.

***cage*** – In a sucker rod pump, device that contains and confines the valve ball and keeps it within proper operating distance from the valve seats.

***cage wrench*** – A special wrench designed for used in connecting the cage of a sucker rod pump to the sucker rod string.

***cake consistency*** – According to API RP 13B, such notations as hard, soft, tough, rubbery, firm, etc., may be used to convey some idea of cake consistency.

***cake thickness*** – The measurement of the thickness of the filter cake deposited by a drilling fluid against a porous medium, most often following the standard API filtration test. Cake thickness is usually reported in 32nd of an inch. See ***filter cake*** and ***wall cake***.

***calcium*** – One of the alkaline earth elements with a valence of 2 and an atomic weight of about 40. Calcium compounds are a common cause of the hardness of water. It is also a component of lime, gypsum, limestone, etc.

***calcium carbonate – $CaCO_3$*** – An insoluble calcium salt sometimes used as a weighing material (limestone, oyster shell, etc.), in specialized drilling fluids. It is also used as a unit and/or standard to report hardness.

***calcium chloride – $CaCl_2$*** – A very soluble calcium salt sometimes added to drilling fluids to impart special properties, but primarily to increase density of fluid phase.

***calcium contamination*** – Dissolved calcium ions in enough concentration to impart undesirable properties in fluid, such as flocculation, reduction in bentonite yield, increased fluid loss. See ***calcium sulfate, gyp, anhydrite, lime, calcium carbonate***.

***calcium hydroxide – $CaOH_2$*** – Active ingredient of slaked lime. Also the main constituent in cement (when wet). Referred to as "lime" in field terminology.

***calcium sulfate*** – (Anhydrite: $CaSO_4$; plaster of paris: $CaSO_4$ ½ $H_2O$; and gypsum: $CaSO_4$ $2H_2O$). Calcium sulfate occurs in muds as a contaminant or may be added to certain muds to impart special properties.

***calcium-treated muds*** – Calcium-treated muds are drilling fluids to which quantities of soluble calcium compounds have been added or allowed to remain from the formation drilled in ordered to impart special properties.

***caliper log*** – A record whereby the diameter of the wellbore is ascertained, indicating undue enlargement due to caving in, washout, etc. The caliper log also reveals corrosion, scaling or pitting inside tubular goods.

***Cameron gauge*** – A pressure gauge usually used in lines or manifolds.

***cap a well*** – To control a blowout by placing a strong valve on wellhead. See ***blowout***.

***cap rock*** – Impermeable rock overlying an oil or gas reservoir that tends to prevent migration of oil or gas out of the reservoir. 2. The porous and permeable strata overlying salt domes that may serve as the reservoir rock.

***carrier rig*** – A self-propelled, wheeled unit used to service oil and gas wells. Modern production rigs are usually carrier units, having the masts, hoists, engines, and other auxiliaries needed to service or work over a well mounted on a chassis powered by the engines used for hoisting. See ***back-in unit*** and ***drive-in unit***.

***casing burst pressure*** – The amount of pressure that, when applied to a string of casing, causes the wall of the casing to fail. This pressure is critically important when a gas kick is being circulated out because gas on the way to the surface expands and exerts more pressure than it exerted at the bottom of the well. See ***kick***.

***casing coupling*** – A tubular section of pipe that is threaded inside and used to connect two joints of casing.

***casing gun*** – a perforating gun run in on the casing string.

***casing head*** – A heavy, steel, flanged fitting that connects slips and packing assemblies by which intermediate strings of casing are suspended and the annulus sealed off. It also is called a spool.

***casing head gas*** – Gas produced with oil.

***casing overshot*** – See ***casing patch tool***.

***casing pack*** – A method of cementing casing in a well so that the casing may, if necessary, be retrieved with minimum difficulty. A special mud, usually an oil mud, is placed in the well ahead of the cement after the casing has been set. The mud is non-solidifying so that it does not bind or stick to the casing in the hole in the area above the cement. Since the mud does not gel even over long periods of time, the casing can be cut above the cemented section and retrieved. Casing packs are used in wells of doubtful or limited production to permit reuse of valuable lengths of casing.

***casing patch tool*** – A special tool with a rubber packer or lead seal that is used to repair casing. When casing is damaged downhole, a cut is made below the damaged casing, the damaged casing and the casing above it are pulled from the well, and the damaged casing is removed from the casing string. The tool is made up and lowered into the well on the casing until it engages the top of the casing that remains in the well, and a rubber packer or lead seal in the tool forms a seal with the casing that is in the well. The casing patch tool is an overshot like device and is sometimes called a casing overshot.

***casing pressure*** – The pressure built up in a well between the casing and tubing or casing and drill pipe. See ***back-pressure***.

***casing protector*** – Short, threaded nipple screwed into the open end of the coupling and over the threaded end to protect the threads from dirt accumulation and damage. Also called thread protector, made of steel or plastic. See ***thread protector***.

***casing roller*** – Rugged tool composed of mandrel with a series of eccentric roll surfaces, each assembled with a series of heavy-duty rollers. Used to restore buckled, collapsed, or dented casing to normal diameter/roundness. Made up on tubing or drill pipe and run into well to depth where casing is deformed, tool is rotated slowly, allowing rollers to contact all sides of casing and restore it to some semblance of original condition.

***casing scraper*** – Blade tool used to scrape away junk or debris from inside casing; run on pipe or tubing.

***casing seal receptacle*** – A casing sub containing a seal bore and a left-handed thread, run as a cross-over between casing sizes, to provide a tubing anchor.

***casing seat test*** – A procedure whereby the formation immediately below the casing shoe is subjected to a pressure equal to the pressure expected to be exerted later by a higher drilling glut density or by the sum of a higher drilling fluid density and back pressure created by a kick.

***casing seat*** – The location of the bottom of a string of casing that is cemented in a well; typically, a casing shoe is made up on the end of the casing at this point.

***casing shoe*** – A short, heavy, hollow, cylindrical steel section with a rounded bottom that is placed on the end of the casing string to serve as a reinforcing shoe and to aid in cutting off minor projections from the borehole wall as the casing is being lowered. Also called a guide shoe. See ***guide shoe***.

***casing*** – Steel pipe place in an oil or gas well as drilling progresses to prevent the wall of the hole from caving during drilling and to provide a means of extracting petroleum if the well is productive.

***casing tongs*** – The large wrenches used for turning when making up or breaking out casing. See ***tongs***.

***casinghead gas*** – Gas produced with oil.

***casinghead gasoline*** – Liquid hydrocarbons extracted from casinghead gas.

***catch samples*** – To obtain cuttings for geological information as formations are penetrated by bit. Samples are obtained from drilling fluid as it emerges from the wellbore or, in cable-tool drilling, from the bailer. Cuttings are carefully washed until free of foreign matter, dried, and labeled to indicate the depth at which they were obtained. See ***bailer, cable-tool drilling, cuttings***.

***catcher*** – A device fitted into a junk basket and acting as a trap door to retain junk.

***cathead*** – A spool-shaped attachment on a winch around which rope for hoisting and pulling is wound. See ***breakout cathead*** and ***makeup cathead***.

***cation*** – The positively charged particle in the solution of an electrolyte which, under the influence of an electrical potential, moves toward the cathode (negative electrode). Examples are: Na+, H+, NH4, Ca++, Mg++, Al+++.

***catline*** – Hoist/pull line operated from two catheads on rig. See ***cathead***.

***catwalk*** – 1. The ramp at the side of the drilling rig where pipe is laid out to be lifted to the derrick floor by the catline. 2. Any elevated walkway.

***caustic or caustic soda*** – See ***sodium hydroxide***.

***cavernous formations*** – A formation having voluminous voids, usually the result of dissolving by formation waters which may not be still present.

***CBHT*** – Abbreviation for ***circulating bottomhole temperature***.

***CBL*** – Abbreviation for ***cement bond log***.

***cc or cubic centimeter*** – A metric-system unit for the measure of volume. It is essentially equal to the millimeter and commonly used interchangeably. One cubic centimeter of water at room temperature weighs approximately 1 g.

***CCL*** – Abbreviation for ***casing collar log***.

***cellar*** – A pit in the ground to provide additional height between the rig floor and the wellhead to accommodate the installation of blowout preventers, rathole, mousehole, and so forth. It also collects drainage water and other fluids for subsequent disposal.

***cement*** – A mixture consisting of alumina, silica, clays, lime, and other substances that hardens when mixed with water. Extensively used in the oil industry to bond casing to the walls of the wellbore. Slaked cement contains about 62.5 percent calcium hydroxide, which is the major source of trouble when cement contaminates mud.

***cement bond survey*** – An acoustic survey or sonic logging method that records the quality or hardness of the cement in the annulus that is used to bond the casing and the formation. Casing that is well bonded to the formation transmits an acoustic signal quickly; poorly bonded casing transmits a signal slowly. See ***acoustic survey, sonic logging***.

***cement plug*** – Portion of cement placed in the wellbore to seal it. See ***cementing***.

***cement retainer*** – A tool set temporarily in the casing or well to prevent the passage of cement, thereby forcing it to follow another designated path. It is used in squeeze cementing and other remedial cementing jobs. See ***squeeze cementing***.

***cement retainer*** – Same as drillable squeeze packer.

***cementer*** – A generic term used to describe a retrievable service squeeze tool; used in remedial cementing.

***cementing materials*** – A slurry of portland cement and water and sometimes one or more additives, which affect either the density of the mixture or its setting time. The portland cement used may be high early strength, common (or standard), slow setting. Additives include accelerators (such as calcium chloride), retarders (such as gypsum), weighing materials (such as barium sulfate), lightweight additives (such as bentonite), and a variety of lost-circulation materials (such as mica flakes). See ***accelerator, lost circulation material, retarder,*** and ***weighing material***.

***cementing*** – Application of liquid slurry of cement and water to points inside or outside casing. See ***primary cementing, secondary cementing, squeeze cementing***.

***centipoise (cp)*** – A unit of viscosity equal to 0.01 poise. A poise equals 1 g per meter-second, and a centipoise is 1 g per centimeter-second. The viscosity of water at 20 C is 1.005 cp (1 cp = 0.000672 lb/ft-sec).

***centralizer*** – Device used to "centralize" casing to borehole or tubing to casing ID.

***centrifugal pump*** – A pump with an impeller or rotor, an impeller shaft, and a casing, which discharges fluid by centrifugal force.

***centrifuge*** – A device for mechanical separation of high specific gravity solids from a drilling fluid. Usually used on weighted muds to recover weight material and discard drill solids. Centrifuge used high-speed mechanical rotation to achieve this separation, as distinguished from cyclone-type separator in which fluid energy alone provides separating.

***certs*** – Certifications of materials on physical and chemistry properties.

***chain drive*** – A drive system using a chain and chain gears to transmit power. Power transmissions use a roller chain, in which each link is made of side bars, transverse pins, and rollers on the pins. A double roller chain has two connected rows of links, a triple roller chain three, and so forth.

***chain tongs*** – A tool consisting of a handle and a releasable chain used for turning pipe or fittings of a diameter larger than that which a pipe wrench would fit. The chain is tightened around the pipe or fitting, which is then turned by means of the handle.

***change house*** – Doghouse in which a rig crew changes clothes. See ***doghouse.***

***changing rams*** – The act of changing the size of the blowout preventer rams when putting into service drilling pipe or tubing of a different size from that previously used.

***channel*** – A fluid passageway in the cement sheath (or formation).

***cheater*** – A length of pipe fitted over a wrench handle to increase the leverage of the wrench. However, use of a larger wrench is usually preferred.

***check valve*** – A valve that permits flow in one direction only.

***chemical barrel*** – A container in which various chemicals are mixed prior to addition to the drilling fluid.

***chemical cutoff*** – Method of severing steel pipe in a well by applying high-pressure jets of a corrosive substance against wall of the pipe. The resulting cut is very smooth.

***choke*** – A device with a fixed or variable orifice installed in a line to restrict the flow and/or control the rate of production. Surface chokes are part of the Christmas tree and contain a choke nipple, or bean, with a small-diameter bore that serves to restrict the flow. Chokes are also used to control the rate the flow of the drilling mud out of the hole when the well is closed in with the blowout preventer and a kick is being circulated out of the hole. See ***adjustable choke, blowout preventer, bottomhole choke, Christmas tree, kick, nipple,*** and ***positive choke***.

***choke flowline*** – An extension from the blowout preventer assembly used to direct control the flow of well fluids from the annulus to choke.

***choke line*** – High-pressure piping between blowout preventer outlets or wellhead outlets and the choke manifold used to direct and control well fluids from the annulus.

***choke manifold*** – The arrangement of piping and special valves, called chokes, through which drilling mud is circulated when the blowout preventers are closed to control the pressures encountered during a kick. See ***choke*** and ***blowout preventer.***

***choke pressure*** – See ***back-pressure***.

***choke, wireline, retrievable*** – A bottomhole choke run on wireline and landed in a nipple profile in the tubing string.

***Christmas tree*** – The control valves, pressure gauges, and choke assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed. Also known as an "X-mas tree."

***chromate*** – A compound in which chromium has a valence of 6, e.g., sodium bichromate. Chromate may be added to drilling fluids either directly or as a constituent of chrome lignites or chrome lignosulfonates. In certain areas, chromate is widely used as an anodic corrosion inhibitor, often in conjunction with lime.

***chrome lignite*** – Mined lignite, to which chromate has been added and/or reacted. The lignite can also be causticized with either sodium or potassium hydroxide.

***circulate and weight method*** – A method for killing well pressure in which circulation is commenced immediately and mud weight is brought up gradually, according to a definite schedule. Also called ***concurrent method***.

***circulating head*** – A device attached to the top of drill pipe or tubing to allow pumping into the well without use of the kelly.

***circulating pressure*** – The pressure generated by the mud pumps and exerted on the drill stem.

***circulating rate*** – The volume flow rate of the circulating drilling fluid usually expressed in gallons of barrels per minute.

***circulation, loss of (or lost)*** – The result of drilling fluid escaping into the formation by way of crevices or porous media.

***circulation*** – The movement of drilling fluid from the suction pit through pump, drill pipe, bit, annular space in the hole, and back again to the suction pit. The time involved is usually referred to as circulation time.

***circulation valve*** – An accessory employed above a packer, permitting annulus-to-tubing circulation or vice versa.

***clabbered*** – A slang term commonly used to describe moderate to severe flocculation of mud due to various contaminants; also called "gelled-up."

***clean out*** – To remove sand, scale, and other deposits from the producing section of the well and to restore or increase production.

***close in*** – 1. Temporarily shut in a well capable of producing oil or gas. 2. Close blowout preventers on a well to control a kick. The blowout preventers close off the annulus so that pressure from below cannot flow to the surface.

***closing ratio*** – The ratio between the pressure in the hole and the operating piston pressure needed to close the rams.

***closing unit pump*** – Another term for an electric or hydraulic pump on an accumulator that serves to pump hydraulic fluid under high pressure to the blowout preventers so that the preventers may be closed or opened.

***closing unit*** – The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

***coagulation*** – In drilling-fluid terminology, a synonym for flocculation.

***coalescence*** – Change from liquid to thickened curdlike state by chemical reaction. Also combination of globules on emulsion caused by molecular attraction of surfaces.

***coiled tubing*** – Same as reeled tubing.

***collar*** – 1. Coupling device to join two pipe lengths. A combination collar has left-hand threads in one end and right-hand threads in the other. 2. A drill collar.

***collar locator*** – A logging device for depth-correlation purposes, operated mechanically or magnetically to produce a log showing the location of each casing or tubing collar or coupling in a well. It provides an accurate way to measure depth in a well.

***collet*** – A finger-like device used to lock or position certain tool components by manipulating the tubing string or downhole tool.

***colloid*** – A state of subdivision of matter which consists either of single large molecules or aggregations of smaller molecules dispersed to such a degree that surface forces become an important factor in determining its properties. The size and electrical charge of particles determine the different phenomena observed with colloids, e.g., Brownian movement. Colloid sizes range from 1 × 10-7 cm to 5 × 10-5 cm (0.001 to 0.5 microns) in diameter, although the particle size of certain emulsoid can be in the micron range.

***colloidal composition*** – A colloidal suspension containing one or more colloidal constituents.

***colloidal suspension*** – Finely divided particles of ultramicroscopic size swimming in a liquid.

***complete a well*** – To finish work on a well and bring it to productive status. See ***well completion***.

***completion fluid*** – Any fluid used during completion or workover operations of sufficient density to control reservoir pressure, and containing properties to minimize formation damage.

***concentric piston*** – Tubing pressure thereby acting upon the net piston area causes a force to be exerted upon a mandrel.

***concurrent method*** – Also called circulate and weight method. See ***circulate and weight method***.

***condensate*** – Light hydrocarbon liquid obtained by condensation of hydrocarbon vapors. Consists of varying proportions of butane, propane, pentane and heavier fractions, with little/no ethane or methane. See ***butane, ethane, methane, pentane, propane***.

***condistometer*** – A thickening-time tester having a stirring apparatus to measure the relative thickening time for mud or cement slurries under predetermined temperatures and pressures. See ***API RP 10B***.

***conductivity*** – The quantity of electricity transferred across unit area per unit potential gradient per unit time. The reciprocal of resistivity. Electrolytes may be added to drilling fluid to alter its conductivity for logging.

***conductor pipe*** – 1. A short string of large-diameter casing used to keep the top of the wellbore open and to provide a means of conveying the up-flowing drilling fluid from the wellbore to the mud pit. 2. A boot. See ***boot***.

***cone*** – Component of downhole tool, such as packer. Wedges slips into casing wall.

***connate water*** – Original water retained in the pore spaces, or interstices, of a formation from the time the formation was created and distinguished from migratory waters that have flowed into deposits after they were laid down. Compare ***interstitial water***.

***connection gas*** – A relatively small amount of gas that enters a well when the mud pump is stopped in order for a connection to be made.

***consistency*** – The viscosity of a non-reversible fluid, in poises, for a certain time interval at a given pressure and temperature.

***constant choke pressure method*** – A method of killing a well that has kicked in which the choke size is adjusted so as to maintain a constant casing pressure. This method does not work unless the kick is all or mostly all salt water; if the kick is gas, there is no way to maintain a constant bottomhole pressure because gas expands as it rises in the annulus.

***constant pit level method*** – A method of killing a well in which the mud level in the pits is held constant while the choke size is reduced and the pump speed slowed. It is not effective because casing pressure increases to the point where the formation or casing ruptures and control of the well is lost.

***continuous phase*** – The fluid phase which completely surrounds the dispersed phase that may be colloids, oil, etc.

***control head*** – An extension of a retrievable tool, such as a retrievable bridge plug, used to set and release the tool.

***control line*** – A small hydraulic line used to communicate fluid from the surface to a downhole tool, such as a subsurface safety valve.

***control panel – master or primary*** – A manifold system of valves, usually situated at the power source, which may be operated manually (or by remote control) to direct pressurized fluid to closing devices at wellhead.

***control panel*** – remote or secondary – system of controls, convenient to driller, used selectively to actuate valves at the master control panel.

***controlled aggregation*** – A condition in which clay platelets are maintained stacked by a polyvalent cation, such as calcium, and are deflocculated by used of a thinner.

***conventional gravel pack*** – A type of gravel pack where well's production packer is removed, a service packer run in with the gravel pack assembly after packing the service tool is retrieved and the production packer rerun.

***conventional mud*** – Drilling fluid, essentially clay and water.

***copolymer*** – A substance formed when two or more substances polymerize at the same time to yield a product which is not a mixture of separate polymers but a complex having properties different from either polymer alone. See ***polymer***. Examples are polyvinyl acetate-maleic anhydride copolymer (clay extender and selective and selective flocculant), acrylamide-carboxylic and copolymer (total flocculant), etc.

***core*** – A cylindrical sample taken from a formation for geological analysis. Usually a conventional core barrel is substituted for the bit and procures a sample as it penetrates the formation. See also ***sidewall coring***. To obtain a formation sample for analysis.

***core analysis*** – Laboratory analysis of a core sample to determine porosity, permeability, lithology, fluid content, angle of dip, geological age, and probable productivity of the formation.

***core barrel*** – A tubular device from 25 to 60 feet long run at the bottom of the drill pipe in place of a bit to cut a core sample.

***corkscrew*** – The buckling of tubing in a large-diameter pipe or casing.

***correlate*** – To relate subsurface information obtained from one well to others so the formations may be charted and their depths and thicknesses noted. Correlations are made by comparing electrical well logs, radioactivity logs, and cores from different wells.

***corrosion*** – A complex chemical or electrochemical process by which metal is altered or destroyed through reaction with its environment(air, moisture, chemicals, temperature, etc.). For example, rust is corrosion.

***coupling*** – 1. In piping, a metal collar with internal threads used to join two sections of threaded pipe. 2. In power transmission, a connection extending longitudinally between a driving shaft and a driven shaft. Most are flexible and compensate for minor misalignment of the two shafts.

***crater*** – (slang) To cave in; to fail. After a violent blowout, the force of the fluids escaping from the wellbore sometimes blows a large funnel shaped cavity or hole in the ground. In this case, the well is said to have cratered. Equipment craters when it fails.

***creaming of emulsions*** – The settling or rising of the particles of the dispersed phase of an emulsion as observed by a difference in color shading of the layers formed. This can be either upward or downward creaming, depending upon the relative densities of the continuous and dispersed phases.

***created fractures*** – Induced fractures by means of hydraulic or mechanical pressure exerted on the formation.

***crew chief*** – The driller or head well pusher in charge of operations on a well servicing rig employed to pull sucker rods or tubing.

***crooked hole*** – A wellbore that has deviated from vertical. It usually occurs where there is a section of alternating hard and soft strata steeply inclined from the horizontal.

***crossover*** – A coupling used to cross over between various types of threaded connections; also a device used in gravel packing tools allowing fluids to "crossover" from tubing to annulus or vice versa.

***crossover joint*** – Length of casing with one thread on field end and a different thread in coupling used to make a changeover from one thread to another in casing string.

***crown block*** – An assembly of sheaves mounted on beams at the top of the derrick over which the drilling line is reeved.

***crude oil*** – Unrefined liquid petroleum, with gravity from 9-55 API and color from yellow to black. May have a paraffin, asphalt, or mixed base. If a crude oil contains a sizeable amount of sulfur or sulfur compounds, it is called a sour crude; if little or no sulfur, it is a sweet crude. Also, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having higher gravities. See ***sour crude oil*** and ***sweet crude oil***.

***cubic foot*** – The volume of a cube all edges of which measure 1 foot. Natural gas in North America is usually measured in cubic feet, the standard cubic foot being a unit of gas at 60<198>F and 14.65 psia.

***cup packer*** – A device made up in the drill stem that is lowered into the well in order to allow the casing and blowout preventers to be pressure-tested. The sealing device is cup shaped and is therefore called a cup.

***cup-type elements*** – Rubber seals energize by pressure only, not mechanical force; plugs and wash tools.

***custodian*** – Also called a lease operator or pumper. See ***pumper***.

***cut drilling fluid*** – Well control fluid which has been reduced in density or unit weight due to entrainment of less dense formation fluids or air.

***cuttings*** – Fragments of rock dislodged by a bit and brought to surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

***cycle time, drilling -fluid*** – The time of a cycle, or down the hole and back, is the time required for the pump to move the drilling fluid in the hole. The cycle in minutes equals the barrels of mud in the hole divided by barrels per minute.

***cyclone*** – Device for separation of various particles from drilling fluid, commonly used as a desander. The fluid is pumped tangentially into a cone, and fluid rotation provides enough centrifugal force to separated particles by mass weight. See ***centrifuge***.

# D

***darcy*** – Unit of permeability. A porous medium has a permeability of 1 darcy when pressure of 1 atm on a sample 1 cm long and 1 sq cm in cross section forces liquid of 1-cp viscosity through the sample at 1 cc per sec.

***dart*** – A device, similar to a pumpdown ball, used to manipulate hydraulically operated downhole tools.

***dart-type blowout preventer*** – Blowout preventer installed on top of drill stem when well is kicking through drill stem. It is stabbed in the open position and then closed against the pressure. The valve that closes is dart-shaped, therefore the name.

***dead well*** – 1. A well that has ceased to produce oil or gas, either temporarily or permanently. 2. A well that has kicked and been killed.

***deadman*** – Buried anchor to which guy wires are tied to steady derrick, mast, stacks.

***deflection*** – A change in the angle of a wellbore. In directional drilling, it is measured in degrees from the vertical.

***deflocculation*** – Breakup of flocs of gel structures by used of a thinner.

***defoamer or defoaming agent*** – Any substance used to reduce or eliminate foam by reducing the surface tension. Compare ***anti-foam***.

***degasser*** – Equipment that removes undesired gas from a liquid, especially from drilling fluid/completion fluid. It is a vessel which utilizes pressure reduction and/or inertia to separate entrained gases from the liquid phases.

***deliquescence*** – The liquefaction of a solid substance due to the solution of the solid by adsorption of moisture from the air, e.g., calcium chloride.

***density*** – Mass or weight of a substance; often expressed in weight per unit volume; e.g., density of drilling mud may be 10 lb. per gal (ppg), 74.8 lb. per cubic ft (lb/ft$^3$), or 1,198.2 kilograms per cubic meter (kg/m$^3$). Specific/API gravity are other units of density. See ***API gravity*** and ***specific gravity***.

***depletion allowance*** – A reduction in U.S. taxes for producers of minerals to compensate for the exhaustion of an irreplaceable capital asset.

***depthometer*** – A device used to measure the depth of a well or depth at a specific point in a well (as to the top of a liner or to a fish) by counting the turns of a calibrated wheel rolling on a wireline as it is lowered into or pulled out of a well. See ***liner*** and ***fish***.

***derrick*** – Large load-bearing structure, usually of bolted construction. In drilling, the standard derrick has four legs at the corners of substructure and reaching to crown block. Substructure is an assembly of beams that elevate the derrick and provide space for blowout preventers, casing head, etc. Because derrick must be assembled, it has largely been replaced by the mast, which can be lowered/raised without disassembly. See ***crown block, mast, substructure***.

***derrickman*** – The crew member who handles the upper end of the drill stem as it is being hoisted out of or lowered into the hole. He is also responsible for the conditioning of the drilling and/or completion fluid and the circulating machinery.

***desander*** – See ***cyclone***.

***development well*** – 1. A well drilled in proven territory in a field to complete a pattern of production. 2. An exploitation well, which see.

***deviation survey*** – An operation made to determine the angle from which a bit has deviated from the vertical during drilling. There are two basic deviation, or drift, survey instruments: one reveals the angle of deviation only, the other indicates both the angle and direction of deviation.

***deviation*** – Inclination of wellbore from vertical. The angle in degrees that shows the variation from the vertical as revealed by a deviation survey. See ***deviation survey***.

***diameter*** – Distance across a circle measured through center. In measurement of pipe diameters, inside diameter (ID) is diameter of interior circle, and outside diameter (OD) is diameter of circle formed by exterior surface of pipe.

***diatomaceous earth*** – An infusorial earth composed of siliceous skeletons of diatoms and being very porous. Sometimes used for combatting lost circulation and as an additive to cement; also has been added to special drilling fluids for a particular purpose.

***die*** – A tool used to shape, form or finish other tools or pieces of metal. For example, a threading die is used to cut threads on pipe.

***die collar*** – A collar or coupling of tool steel, threaded internally, that is used to retrieve pipe from the well on fishing jobs; the female counterpart of a taper tap. The die collar is made up on the drill pipe and lowered into the hole until it contacts the lost pipe. Rotation of the die collar on top of the pipe cuts threads on the outside of the pipe, providing for a firm attachment. The pipe is then retrieved from the hole. See ***taper tap***.

***diesel-oil plug*** – See ***gunk plug***.

***differential displacing valve*** – A special-purpose valve used to facilitate spacing out and flanging up the well, run in on the tubing string.

***differential pressure (wall) sticking*** – Sticking which occurs because part of the drill string (usually the drill collars) becomes embedded in the filter cake resulting in a non-uniform distribution of pressure around the circumference of the pipe. The conditions essential for sticking require a permeable formation and a pressure differential across a nearly impermeable filter cake and drill string.

***differential pressure*** – The difference in pressure between the hydrostatic head of drilling-fluid column and the formation pressure at any given depth in the hole. It can be positive, zero, or negative with respect to the hydrostatic head.

***dilatant fluid*** – A dilatant or inverted plastic fluid is usually made up of a high concentration of well dispersed solids which exhibits a non-linear consistency curve passing through the origin. The apparent viscosity increase instantaneously with increasing rate of shear. The yield point, as determined by conventional calculations from the direct indicating viscometer readings, is negative; however, the true yield point is zero.

***direct-indicating viscometer*** – See ***viscometer, direct-indicating***.

***directional drilling*** – Intentional deviation of wellbore from the vertical. Wellbores are normally drilled vertically; it is sometimes necessary or advantageous to drill at an angle from vertical. Controlled directional drilling allows access to subsurface areas laterally remote from point where bit enters the earth. It involves use of turbodrills, Dyna-Drills, whipstocks, or other deflecting tools. See ***Dyna-Drill, turbodrill, and whipstock***.

***directional survey*** – A logging method that records hole drift, or deviation from the vertical and direction of the drift. A single-shot directional survey instrument makes a single photograph of a compass reading of the drift direction and the number of degrees the hole is off vertical. A multishot survey instrument obtains numerous readings in the hole as the device is pulled out of the well. See ***directional drilling***.

***dispersant*** – Any chemical promoting dispersion of the dispersed phase.

***dispersed phase*** – Scattered phase (solid, liquid, gas) of a dispersion. The particles are finely divided and surrounded by the continuous phase.

***dispersion (of aggregates)*** – Subdivision of aggregates. Dispersion increases specific surface of particle; hence results in an increase in viscosity and gel strength.

***dispersoid*** – A colloid or finely divided substance.

***displacement*** – The volume of steel in the tubular and devices inserted and/or withdrawn from the wellbore.

***dissociation*** – The splitting up of a compound or element into two or more simple molecules, atoms, ions. Applied usually to effect of the action of heat or solvents upon dissolved substances. The reaction is reversible and not permanent as decomposition; i.e., when solvent is removed, ions recombine.

***distillation*** – Pocess of first vaporizing a liquid, then condensing vapor into liquid (the distillate), leaving behind non-volatile substances, the total solids of drilling fluid. The distillate is the water and/or oil content of a fluid.

***diverter*** – A device attached to the wellhead or marine riser to close the vertical access and direct any flow into a line away from the rig. It is often used to control well blowouts encountered at relatively shallow depths and to protect floating rigs during blowouts by directing the flow away from the rig. The diverter line may be referred to as a "blooie line." See ***blooie line***.

***dizzy nut*** – A mechanism used in packers to lock components together.

***dog leg*** – 1. A crooked casing section; a deviated wellbore. 2. The "elbow" caused by a sharp change of direction in the wellbore.

***dog(s)*** – Small components in tools to lock/release rig equipment, and also downhole tools into position in tubing string; also to move components through tubing movement.

***doghouse*** – 1. Small enclosure on rig floor used as an office for driller or storehouse for small objects. 2. Any small building used as office or storage.

***dolomite*** – A type of sedimentary rock similar to limestone but rich in magnesium carbonate, sometimes a reservoir rock for petroleum.

***double*** – A length of pipe, casing, or tubing, consisting of two joints screwed together. Compare ***thribble***, and ***fourble***. See ***joint***.

***double grip*** – a tool employing gripping devices which limit tool movement from pressure either above or below the tool.

***double-pole mast*** – Well servicing unit whose mast consists of two steel tubes. Double-pole masts provide racking platforms for handling rods and tubing in stands and extend from 65 to 67 feet so that rods can be suspended as 50-foot doubles and tubing set back as 30-foot singles. See ***pole mast***.

***dovetail*** – A cutout section in a cone enabling positive slip movement without the aid of conventional slip return springs.

***downhole*** – Inside or pertaining to the wellbore.

***drag spring*** – A friction spring used to provide a "drag" on the casing ID enabling both tool support, centralization, and/or resistance to rotation.

***dragblock*** – Components used to provide drag on a tool; similar to drag springs but more durable.

***draw works*** – Hoisting mechanism on a drilling rig. It is essentially a large winch that spools off or takes in drilling line and thus raises or lowers the drill stem and bit.

***dressing*** – The replacement of certain parts (such as o-rings) on tools; the use of specific size components for a given casing size and weight range.

***drift*** – the smallest diameter of casing, drill pipe or tubing.

***drill bit*** – The cutting or boring element used for drilling. See ***bit***.

***drill collar*** – Heavy, thick-walled tube, usually steel, used between drill pipe and bit in drill stem to provide weight/pendulous effect to drill stem.

***drill pipe safety valve*** – An essentially full-opening valve located on the rig floor with threads to match the drill pipe in use. This valve is used to close off the drill pipe to prevent flow.

***drill pipe slips*** – Wedge-shaped pieces of metal with various gripping elements that are used to prevent drill pipe from slipping down into the hole or to hold drill pipe in place. See ***slips***.

***drill pipe*** – Heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft. long are coupled together by tool joints.

***drill ship*** – A ship constructed to permit a well to be drilled from it at an offshore location. While not as stable as other floating structures (a semisubmersible), drill ships, or shipshape, are capable of drilling exploratory wells in relatively deep waters. They may have a ship hull, a catamaran hull, or a trimaran hull. See ***semisubmersible drilling rig***.

***drill stem*** – All members in the assembly used for drilling by the rotary method from the swivel to the bit, including the kelly, drill pipe and tool joints, drill collars, stabilizers, and various subsequent items.

***drill stem test (DST)*** – A method of gathering data on the potential productivity of a formation before installing casing in a well to determine whether oil and/or gas in commercial quantities has been encountered in the wellbore. See ***formation testing***.

***drill string float*** – A check valve in the drill string that will allow fluid to be pumped into the well but will prevent flow from entering the string.

***drill string*** – The column, or string, of drill pipe with attached tool joints that transmits fluid and rotational power from the kelly to the drill collars and bit. Often, especially in the oil patch, the term is loosely applied to include both drill pipe and drill collars. Compare ***drill stem***.

***drill-out*** – Removal of a permanent downhole tool with rockbit/drill bit.

***drill-pipe pressure*** – Amount of pressure exerted inside drill pipe as a result of circulating pressure, entry of formation pressure into well, or both.

***drill-stem safety valve*** – Also called lower Kelly cock. See ***kelly cock***.

***drillable*** – Pertaining to packers and other tools left in the wellbore to be broken up later by the drill bit. Drillable equipment is made of cast iron, aluminum, plastic, or other soft brittle material.

***drillable squeeze packer*** – Permanent drillable packer, capable of high working pressures, for remedial work; positive flow-control valve built-in.

***drilled show*** – Showing of gas/oil from drilling a formation. Oil or gas from formation becomes mixed in mud circulated to the surface when formation pressure is slightly greater than hydrostatic pressure of mud column.

***driller*** – Employee directly in charge of a drilling or workover rig and crew. His/her main duty is operation of the drilling and hoisting equipment, but he is also responsible for the downhole condition of the well, operation of downhole tools, and pipe measurements.

***driller's method*** – A well-killing method involving two complete and separate circulations; the first vents the kick out of the well, and the second circulates heavier mud through the wellbore.

***drilling block*** – Lease/number of leases of adjoining land tracts that constitute a unit of acreage sufficient to justify the cost of drilling a wildcat.

***drilling break*** – A sudden increase in the rate of penetration by the drill bit. It sometimes indicates that the bit has penetrated a high-pressure zone and thus warns of the possibility of a blowout.

***drilling crew/workover crew*** – A driller, a derrickman, and two or more helpers who operate a drilling or workover rig for one tour each day. See ***derrickman, driller*** and ***tour***.

***drilling fluid/mud*** – Circulating fluid used in rotary drilling to perform various functions required in drilling. One function is to force cuttings out of wellbore and to surface. While a mixture of clay, water, and other chemical additives is the most common drilling fluid, wells can also be drilled using air, gas or water as the drilling fluid. Also called circulating fluid. See ***mud***.

***drilling foreman*** – The supervisor of drilling or workover operations on a rig; also the tool pusher or rig superintendent.

***drilling in*** – The operation during the drilling procedure at the point of drilling into the pay formation.

***drilling mud*** – The liquid circulated through the wellbore during rotary drilling operations. See ***drilling fluid, mud***.

***drilling out*** – Operation during drilling procedure when the cement is drilled out of the casing before further hole is made or completion attempted.

***drilling spool*** – BOP stack connection having both ends equipped with flanges. Usually same bore diameter as blowout preventer. May or may not have side outlets for connecting auxiliary lines. An accessory used as a spacer in wellhead equipment, providing room between wellhead devices so devices in the drill stem can be suspended in it.

***drive bushing*** – Also called Kelly bushing. See ***kelly bushing***.

***drive-in unit*** – A type of portable servicing or workover rig that is self-propelled, using power from the hoisting engines. The driver's cab and steering wheel are mounted on the same end as the mast support; thus the unit can be driven straight ahead to reach the wellhead. See ***carrier rig***.

***dry hole*** – Well that does not produce oil or gas in commercial quantities. A dry hole may flow water, gas, or oil, but not enough to justify production.

***dual/dual completion*** – Single well producing from two separate formations at the same time. Production from each zone is segregated by running two tubing strings with packers inside the production casing, or one tubing string with a packer may be run through one zone while the other is produced through the annulus. In a miniaturized dual completion, two separate 4½ inch or smaller casing strings are run and cemented in the same wellbore.

***dummy valve*** – A blanking valve placed in a gas lift mandrel to block off annular communication to the tubing.

***dump bailer*** – Bailing device with release valve, usually of disk or flapper type, used to place or spot material (as cement slurry) at the bottom of the well.

***duplex pump*** – A reciprocating pump having two pistons or plungers, used extensively as a mud pump on drilling rigs.

***dutchman*** – A piece of tubular pipe broken or twisted off in a female connection. It may also continue on past the connection.

***DV tool*** – A generic term, originally a trademark name, used to describe a stage tool, used in selective zone primary cementing.

***Dyna-Drill*** – Downhole motor driven by drilling fluid that imparts rotary motion to a drilling bit connected to the tool, thus eliminating the need to turn the entire drill stem to make hole. The Dyna-Drill, a trade name, is used in straight and directional drilling.

***dynamic positioning*** – Method by which a floating offshore drilling rig is maintained in position over an offshore well location. Generally, several motors call thrusters are located on hull(s) of structure and are actuated by a sensing system. A computer to which the system feeds signals then directs the thrusters to maintain the rig on location.

***dynamic*** – The state of being active or in motion; opposed to being static.

# E

***edgewater*** – Water that touches edge of oil in lower horizon of a formation.

***effective permeability*** – Measure of the ability of a single fluid to flow through a rock when pore spaces of the rock are not completely filled or saturated with the fluid. Compare ***absolute permeability*** and ***relative permeability***.

***eight-round*** – A tapered connection with eight (8) threads per inch, one turn equals .125 inches of travel; very common oil field connection.

***elastomer*** – A seal; a rubber sealing member such as an o-ring, vee ring, face seal, etc.

***electric line*** – A wireline with an electrical conductor inside.

***electric log*** – Also called an electric well log. See ***electric well log***.

***electric logging*** – Electric logs are run on a wireline to obtain information concerning the porosity, permeability, fluid content of the formations drilled, and other information. The drilling-fluid characteristics may need to be altered to obtain good logs.

***electric well log*** – A record of certain electrical characteristics of formations traversed by the borehole, made to identify the formations, determine the nature and amount of fluids they contain, and estimate their depth. Also called an electric log or electric survey.

***electrolysis*** – Decomposition of a chemical compound brought about by the passage of an electrical current through the compound or through the solution containing the compound. Corroding action of stray currents is caused by electrolysis. See ***corrosion***.

***electrolyte*** – A substance which dissociates into charged positive and negative ions when in solution or a fused state and which will then conduct an electric current. Acids, bases, and salts are common electrolytes.

***elevator bails*** – Linkage between elevator and traveling block. See ***traveling block***.

***elevators*** – Set of clamps that grip a stand, or column, of casing, tubing, and drill pipe or sucker rods so the stand can be raised/lowered into the hole.

***emulsifier*** – Substance used to produce an emulsion of two liquids which do not mix. Emulsifiers may be divided, according to their behavior, into ionic and non-ionic agents. The ionic types may be further divided into anionic, cationic, and amphoteric, depending upon the nature of the ion-active groups.

***emulsion*** – Heterogeneous liquid mixture of two or more liquids which do not normally dissolve in each other but are held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by adding small amounts of substances known as emulsifiers. Emulsifiers may be mechanical, chemical, or a combination. They may be oil-in-water or water-in-oil types.

***emulsoid*** – Colloidal particles which take up water.

***end point*** – End of some operation or when a definite change is observed. In titration this change in frequently a change in color of an indicator which has been added to the solution or the disappearance of a colored reactant.

***engineer, mud or drilling fluid*** – One versed in drilling fluids who manages and maintains the various types of oil-well mud programs.

***entrained gas*** – Formation gas entering drilling fluid in annulus. See ***gas-cut mud***.

***equivalents per million (EPM)*** – Unit chemical weight of solute per million unit weights of solution. The epm of a solute in solution is equal to ppm (parts per million) divided by equivalent weight. Refer also to ppm.

***equivalent circulating density (ECD***) – Sum of pressure exerted by hydrostatic head of fluid, drilled solids, and friction pressure losses in annulus divided by depth of interest and by 0.052, if ECD is to be expressed in pounds per gallon (lb/gal).

***equivalent weight*** – The atomic or formula weight of an element, compound, or ion divided by its valence. Elements entering into combination always do so in quantities proportional to their equivalent weights. Also called ***combining weight.***

***ethane*** – Light hydrocarbon, $C_2H_6$, in natural gas. A gas at atmospheric conditions.

***expansion joint*** – A sliding jointed sub run in on the tubing string to permit tubing expansion/contraction.

***expendable plug*** – A temporary plug set on a PSA, landed inside a production packer converting it to a bridge plug.

***exploitation well*** – Well drilled to permit more effective oil extraction from reservoir. Sometimes called a development well. See ***development well***.

***extensions*** – Tubular components attached to bottom of a packer to extend its bore.

***external cutter*** – A fishing tool, containing metal-cutting knives, that is lowered into the hole and over the outside of a length of pipe to cut it. The severed portion of the pipe can then be brought to the surface.

***extreme pressure lubricant*** – Additives which, added to drilling fluid, impart lubrication to bearing surfaces when subjected to extreme pressure conditions.

# F

***fault*** – A geological term denoting a formation break, upward or downward in subsurface strata. Often strata on one side of the fault line have been displaced (upward, downward, or laterally) relative to their original positions. Faults can significantly affect the area mud and casing programs.

***feed-in (influx, inflow)*** – Fluid flow from formation into wellbore.

***feeler, wireline*** – A tool used to gage, and clean junk and debris from the casing in conjunction with a junk catcher.

***fermentation*** – Decomposition process of certain organic substances, e.g., starch in which a chemical change is brought about by enzymes, bacteria, or other micro-organisms. Often referred to as "souring."

***fiber or fibrous material*** – Tough stringy material used to prevent loss of circulation or restore circulation. In field use, generally refers to larger fibers of plant origin.

***field*** – Geographical area where a number of oil or gas wells produce from a continuous reservoir. May refer to surface area only or underground productive formations One field may have separate reservoirs at varying depths.

***fill-up line*** – The smaller of the side fittings on a bell nipple, used to fill the hole when drill pipe is being removed from the well.

***filling the hole*** – The pumping of fluid into the wellbore as the pipe is withdrawn in order to maintain the fluid level inside the casing near the surface. The purpose is to avoid danger of blowout, water intrusion, and/or caving of the wellbore, e.g., as the pipe is withdrawn.

***fill-up line*** – The line through which fluid is added to the hole.

***filter cake*** – 1. Mud solids deposited by filtration on the permeable wall of wellbore by the drilling fluid. 2. The suspended solids that are deposited on a porous medium during process of filtration. See also ***cake consistency***.

***filter cake thickness*** – A measurement of the solids deposited on filter paper in 32nd of an inch during standard thirty-minute API filter test. See ***cake thickness***. In certain areas the filer-cake thickness is a measurement of the solids deposited on filer paper for a 7½-minute duration.

***filter paper*** – Porous unsized paper for filtering liquids. API filtration test specifies one thickness of 9-cm filter paper Whatman #50, or S & S #576.

***filter press*** – A device for determining fluid loss of a drilling fluid having specifications in accordance with API RP 13B.

***filtrate*** – The liquid that is forced through a porous medium during the filtration process. For test, see Fluid Loss.

***filtration qualities*** – The filtration characteristics of a drilling mud. Generally these qualities are inverse to the thickness of the filter cake deposited on the face of a porous medium and the amount of filtrate allowed to escape from the drilling fluid into or through the medium.

***filtration rate*** – See ***fluid loss***.

***filtration*** – Process of separating suspended solids from liquid by forcing the latter through a porous medium. Two types of fluid filtration occur in a well: dynamic filtration while circulating, and static filtration when at rest.

***final circulation pressure*** – Drill pipe pressure required to circulate at the selected kill rate adjusted for increase in kill drilling fluid density over the original drilling fluid density; used from the time kill drilling fluid reaches the bottom of the drill string until kill operations are completed or a change in either kill drilling fluid density or kill rate is effected.

***fingering*** – Phenomenon occurring in an injection well in which the fluid being injected does not contact the entire reservoir but rather bypasses sections of the reservoir fluids in a finger-like manner. Fingering is not desirable in that portions of the reservoir are not contacted by the injection fluid.

***fish*** – 1. Object left in wellbore during drilling/workover that must be recovered before work can proceed. It can be anything from piece of scrap metal to a part of the drill stem. 2. To recover from a well any equipment left there during drilling operations, such as a lost bit or drill collar or part of the drill string. 3. To remove from an older well certain pieces of equipment, such as packers, liners, or screen pipe, to allow reconditioning of the well.

***fishing*** – Operations on rig for the purpose of retrieving from the wellbore sections of pipe, collars, junk, or other obstructive items in the hole.

***fishing magnet*** – A powerful permanent magnet designed to recover metallic objects lost in the well.

***fishing neck*** – Portion of pipe used to overshot during fishing operations.

***fishing tap*** – A tap that goes inside pipe lost in a well to provide a firm grip and permit recovery of fish; sometimes used in place of a spear. See ***fish, spear, tap***, and ***taper tap***.

***flag*** – 1. A piece of cloth, rope, or nylon strand used to mark the wireline when swabbing or bailing. 2. An indicator of wind direction used when drilling or performing a workover where hydrogen sulfide (sour) gas may be encountered. 1. To signal or attract attention. 2. In swabbing or bailing, to attach a piece of cloth to the wire rope to enable the operator to estimate the position of the swab or bailer in the well.

***flange*** – A rim or edge (as on pipe fittings or openings in pump and vessels) projecting at right angles to provide strength or means of attachment to another part. Flange is drilled with holes for bolting to other flange fittings.

***flange up*** – To join pipes by means of flanges in making final connections on the piping system; also, in oilfield slang, to complete any operation.

***flapper valve*** – A hinged closure mechanism operating in a pivot manner, used to shut off tubing flow.

***flash set*** – Rapid dehydration of cement downhole.

***flat gel*** – A condition wherein the ten-minute gel strength is substantially equal to the initial gel strength.

***flipped*** – When the opposite occurs of what is intended in a drilling fluid. In an invert water-in-oil emulsion, the emulsion is said to be flipped when the continuous and dispersed phases reverse.

***float collar*** – A coupling placed in the casing string used in primary cementing operations to land wiper plugs and limit cement flow-back.

***float shoe*** – A cylindrical tool integral poppet valve run on end of casing string to provide a floating action while reducing the rig's hookload.

***flocculating agent*** – Substances, such as most electrolytes, some polysaccharides, certain natural or synthetic polymers, that bring about thickening of consistency of a drilling fluid. In Bingham plastic fluids, the yield point and gel strength increase.

***flocculation*** – Loose association of particles in lightly bonded groups, non-parallel association of clay platelets. In concentrated suspensions, such as drilling fluids, flocculation results in gelatin. In some fluids, flocculation may be followed by irreversible precipitation of colloids and certain other substances from fluid, e.g., red beds.

***flood*** – 1. Drive oil from a reservoir into a well by injecting water under pressure into reservoir formation. See ***water flood***. 2. Drown a well with water.

***floor man*** – Drilling crew member who works on derrick floor; three or more are used on most rigs.

***flow bean*** – An orifice restriction available in 1/64-inch incremental openings for bottomhole chokes.

***flow coupling*** – A sub placed in the production string to limit flow velocities above and/or below other downhole tools.

***flow line*** – The surface pipe through which well effluent travels from a well to processing equipment or storage.

***flow tank*** – The storage tank to which produced oil is piped.

***flow test*** – Confirms flow rate through a tool prior to going downhole.

***flow treater*** – A single unit that acts as an oil and gas separator, and oil heater, and an oil-and water-treating vessel.

***flow tube*** – Interval device commonly found in subsurface safety valves used to protect the tool's closure mechanism from the wellbore mediums.

***flowback*** – Fluids backing up the well.

***flowing well*** – A well that produces oil or gas by its own reservoir pressure without employing an artificial lift.

***flowline*** – A flow line from the tree for fluid movement.

***flowline sensor*** – A device to monitor rate of fluid from the annulus.

***fluid*** – Substance that flows/yields to a force tending to change its shape. Liquids and gases. A substance which the application of every system of stresses (other than hydrostatic pressure) will produce a continuously increasing deformation without any relation between time rate of deformation at any instant and magnitude of stresses at that instant. Drilling fluids are usually Newtonian, plastic, seldom pseudoplastic, rarely dilatant.

***fluid density*** – The unit weight of fluid; e.g., pounds per gallon (lb/gal).

***fluid flow*** – State in fluid dynamics of a fluid in motion is determined by fluid type (Newtonian, plastic, pseudolastic, dilatant), properties such as viscosity and density, geometry of system, velocity. Under a given set of conditions, fluid flow can be described as plug, laminar (Newtonian, streamline, parallel, or viscous) or turbulent flow. See above terms and ***Reynolds number***.

***fluid level*** – Distance from earth's surface to the top of the liquid in the tubing or casing in a well. The static fluid level is taken when the well is not producing and has stabilized. The dynamic, or pumping, level is the point to which the static level drops under producing conditions. See ***static fluid level***.

***fluid loss*** – Measure of relative amount of fluid lost (filtrate) through permeable formations or membranes when drilling fluid is subjected to a pressure differential. For standard API filtration-test procedure, see ***API RP 13B***.

***fluid saturation*** – The amount of the pore volume of a reservoir rock that is filled with water, oil or gas and measured in routine core analysis.

***fluidity*** – The reciprocal of viscosity. The measure of rate with which a fluid is continuously deformed by a shearing stress. Ease of flowing.

***flush production*** – A high rate of flow from a newly drilled well.

***flush-joint casing*** – The amount of the pore volume of a reservoir rock that is filled by water, oil, or gas and measured in routine core analysis.

***flush-joint pipe*** – Pipe in which outside diameter of joint is the same as outside diameter of the tube. Pipe may also be internally flush-joint.

***foam*** – A foam is a two-phase system, similar to an emulsion, where the dispersed phase is a gas or air.

***foaming agent*** – A substance that produces fairly stable bubbles at the air-liquid interface due to agitation, aeration, or ebullition. In air or gas drilling, foaming agents are added to turn water influx into aerated foam. This is commonly called "mist drilling."

***formation*** – A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

***formation breakdown*** – an event occurring when borehole pressure is of magnitude that the exposed formation to withstand applied pressure.

***formation competency*** – The ability of the formation to withstand applied pressure. Also called ***formation integrity.***

***formation competency test*** – Application of pressure by superimposing a surface pressure on a fluid column in order to determine ability of a subsurface zone to withstand a certain hydrostatic pressure. Also called ***formation integrity test.***

***formation damage*** – The reduction of permeability in a reservoir rock caused by the invasion of drilling fluid and treating fluids to the section adjacent to the wellbore. It is often called skin. See ***skin***.

***formation fluid*** – Fluid (as gas, oil, or water) in a subsurface rock formation.

***formation fracture pressure*** – The point at which formation will crack from pressure in the wellbore.

***formation fracturing*** – Method of stimulating production by increasing permeability of producing formation. Under high hydraulic pressure, fluid (water, oil, alcohol, diluted hydrochloric acid, liquefied petroleum gas, foam) is pumped down through tubing or drill pipe and forced through perforations in casing. Fluid enters formation and parts or fractures it. Sand grains, aluminum pellets, glass beads, or similar materials are carried in suspension by fluid into fractures. These are called propping agents or proppants. When pressure is released at surface, fracturing fluid returns to well, and fractures partially close on proppants, leaving channels for hydrocarbon to flow through them to well. This process is called a ***frac job***. See ***propping agent***.

***formation integrity*** – See ***formation competency***.

***formation pressure*** – The force exerted by fluids in a formation, recorded in the hole at the level of the formation with the well shut in. It is also called reservoir pressure or shut-in bottomhole pressure. See ***reservoir pressure*** and ***shut-in bottomhole pressure***.

***formation sensitivity*** – The tendency of certain producing formations to adversely react with invading filtrates.

***formation testing*** – The gathering of data on a formation to determine its potential productivity before installing casing in a well. The conventional method is the drill stem test. Incorporated in the drill stem testing tool are a packer, valves or ports that may be opened and closed from the surface, and a pressure-recording device. The tool is lowered to bottom on a string of drill pipe and the packer set, isolating the formation to be tested from the formations above and supporting the fluid column above the packer. A port on the tool is opened to allow the trapped pressure below the packer to bleed off into the drill pipe, gradually exposing the formation to atmospheric pressure and allowing the well to produce to the surface, where the well fluids may be sampled and inspected. From a record of the pressure readings, a number of facts about the formation may be inferred.

***formic acid*** – A simple organic acid used for acidizing oil wells. It is stronger than acetic acid but much less corrosive than hydrofluoric or hydrochloric acid and usually is used for high-temperature wells. See ***acidize***.

***fourble*** – A section of drill pipe, casing, or tubing consisting of four joints screwed together. Compare ***single, double***, and ***tribble***. See ***joint***.

***fracture gradient*** – The pressure gradient (psi/ft) at which the formation accepts whole fluid from the wellbore. Also called ***frac gradient.***

***free point*** – The depth at which pipe is stuck, or more specifically the depth immediately above the point at which pipe is stuck.

***free-point indicator*** – A tool designed to measure the amount of stretch in a string of stuck pipe and to indicate the deepest point at which the pipe is free. The free-point indicator is lowered onto the well on a conducting cable. Each end of a strain-gauge element is anchored to the pipe wall by friction springs or magnets, and, as increasing strain is put on the pipe, an accurate measurement of its stretch is transmitted to the surface. The stretch measurements indicate the depth at which the pipe is stuck.

***free-water knockout*** – A vertical or horizontal vessel into which oil or emulsion is run in order to allow any water not emulsified with the oil (free water) to drop out.

***freeze point*** – The depth in the hole at which the tubing, casing, or drill pipe is stuck. See ***free-point indicator.***

***functions of drilling fluids*** – The most important function of drilling fluids in rotary drilling is to bring cuttings from the bottom of the hole to the surface. Some other important functions are: control subsurface pressures, cool and lubricate the bit and drill string, deposition of an impermeable wall cake, etc.

***funnel viscosity*** – See ***marsh funnel viscosity***.

***fusible plugs*** – A thermal device employed on surface flowlines as part of an ESD.

**FWKO** – Abbreviation for ***free-water knockout***.

# G

***gage joint*** – The heaviest-wall casing section of the string, usually located just below the preventers or tree.

***gage ring*** – Cylindrical metal ring to guide, centralize packers/tools inside casing.

***gage trip*** – Running of a gage on tubing or slickline to verify casing dimensions.

***galena*** – Lead sulfide (PbS). Technical grades (specific gravity about 7) are used for increasing the density of drilling fluids to points impractical or impossible with barite.

***galvanic corrosion*** – A type of corrosion that occurs when a small electric current flows from one piece of metal equipment to another. It is particularly prevalent when two dissimilar metal objects are joined together in an environment in which electricity can flow (as two dissimilar joints of tubing in an oil or gas well).

***gas*** – Fluid, compressible substance that completely fills any container in which it is confined, its volume being dependent on extent of pressure exerted on container.

***gas anchor*** – A tubular, perforated device attached to the bottom of a sucker-rod pump that helps to prevent gas lock. The device works on the principle that gas, being lighter than oil, rises. As well fluids enter the anchor, the gas breaks out of the fluid and exits the anchor through perforations near the top. The remaining fluids enter the pump through a mosquito bill (a tube within the anchor), which has an opening near the bottom. In this way, all or most of the gas escapes before the fluids enter the pump. See ***gas lock, mosquito bill***, and ***sucker-rod pump***.

***gas buster*** – A slang term to denote a mud-gas separator.

***gas cut*** – Gas entrained by a drilling fluid. See ***air cutting***.

***gas cutting*** – See ***gas-cut mud***.

***gas drive*** – The use of the energy that arises from gas compressed in a reservoir to move crude oil to a wellbore. Gas drive is also used in a form of secondary recovery, in which gas in injected into input wells to sweep remaining oil to a producing well. See ***input well*** and ***secondary recovery***.

***gas lift*** – Process of raising or lifting fluid from a well by injecting gas down well through tubing or through tubing-casing annulus. Injected gas aerates fluid to make it exert less pressure than formation; consequently, higher formation pressure forces fluid out of wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics on well and arrangement of gas-lift equipment.

***gas lift valve*** – An artificial-lift device by which injected annular gas enters the valve, passing into the tubing string to reduce the hydrostatic head.

***gas lock*** – A condition sometimes encountered in a pumping well when dissolved gas, released from solution during the upstroke of the plunger, appears as free gas between the valves. If the gas pressure is sufficient, the standing valve is "locked" shut, and, consequently, no fluid enters the tubing.

***gas well*** – A well that primarily produces natural gas.

***gas-cut mud*** – A drilling mud that has entrained formation gas giving the mud a characteristically fluffy texture. When entrained gas is not released before the fluid returns to the well, the weight or density of the fluid column is reduced. Gas cut mud is often a sign of a formation with the potential to flow and/or blowout, and as such, should be treated as a warning sign of changing formation pressure.

***gas-injection well*** – Well in which gas is injected for purpose of maintaining or supplementing pressure in an oil reservoir; more commonly called a gas-injection well.

***gas-oil ratio*** – A measure of the volume of gas produced with the oil; expressed in cubic feet per barrel or in cubic meters per metric ton, or in cubic meters per cut meter.

***gassing-up*** – Injection of nitrogen for gas lift valve.

***gasket*** – Material (paper, cork, asbestos, rubber) used to seal two stationary surfaces.

***gate valve*** – Valve with a sliding gate to open or close the passage in it.

***gel*** – 1. Semisolid, jellylike state assumed by some colloidal dispersions at rest. When agitated, gel converts to fluid state. 2. State of colloidal suspension in which shearing stresses below certain finite value fail to produce permanent deformation. Minimum shearing stress that will produce permanent deformation is known as shear or gel strength. Gels commonly occur with bentonite in water. 3. Term to designate high colloidal, high yielding, viscosity-building commercial clays, such as bentonite added as a filler and/or to reduce slurry weight. See ***gel strength-initial, gel strength-ten-minute***, ***thixotropy, gunk plug***.

***gel strength-ten-minute*** – Measured ten-minute gel strength of a fluid is the maximum reading (deflection) taken from a direct-reading viscometer after fluid has been quiescent for ten minutes. Reading is reported in lb/100 sq. ft. See ***API RP 13B*** for test procedure.

***gel strength-initial*** – The measured initial gel strength of a fluid is the maximum reading (deflection) taken from a direct-reading (deflection) taken from a direct-reading viscometer after fluid has been quiescent for 10 sec. It is reported in lb/100 sq ft. See ***API RP 13B*** for details of test procedure.

***gel strength*** – Ability or measure of ability of a colloid to develop and retain a gel form. The gel, or shear, strength, of a mud determines its ability to hold solids in suspension. Bentonite and other colloidal clays are added to drilling fluid to increase gel strength. Gel strength is a pressure unit usually reported in lb/100 sq ft. A measure of the same interparticle forces of a fluid as determined by yield point, except gel strength is measure under static conditions, yield point under dynamic. Common gel-strength measurements are initial and 10-min gels (which see). See ***shear***, ***shearometer***, and ***thixotropy***.

***gelled up*** – Oil-field jargon usually referring to any fluid with high gel strength and/or highly viscous properties. Often a state of severe flocculation.

***gelling-up*** – Getting fluids in a gelled state ready for pumping.

***geologist*** – Scientist gathering/interpreting data pertaining to strata of earth's crust.

***geology*** – Science of the study of the structure, origin, history, and development of earth and its inhabitants as revealed in rocks, formations, fossils.

***getting-a-bite*** – Setting tools in casings.

***gland*** – A device used to form a seal around a reciprocating or rotating rod (as in a pump) to prevent fluid leakage; specifically, the movable part of a stuffing box by which the packing is compressed. See ***stuffing box***.

***glass disc*** – A sub with a glass blockage in the bore, used to isolate a surge chamber in gravel packing or perforation cleaning operations.

***GLR*** – Abbreviation for gas-liquid-ratio.

***go devil*** – 1. Device which is dropped or pumped down a borehole, usually through drill pipe or tubing. 2. Any type of tool "dropped" into well.

***gooseneck*** – The curved connection between the rotary hose and swivel. See ***rotary hose*** and ***swivel***.

***gpg*** – Abbreviation for ***grains per gallon .*** ppm (which see) equals gpg × 17.1.

***grapple*** – 1. A tool used to fish a stuck tool by grabbing it. 2. The part of a catching tool (such as overshot or spear) that engages the fish.

***gravel pack*** – 1. To place a slotted or perforated liner in the well and surround it with small-sized gravel. See ***gravel packing***. 2. A mass of very fine gravel placed around a slotted liner in a well. See ***liner***.

***gravel packing*** – Method of well completion in which a slotted or perforated liner is placed in well and surrounded by small-sized gravel. Well is enlarged by under-reaming at point where gravel is packed. The gravel mass excludes sand from intruding in well but allows continued rapid production.

***gravel-pack packer*** – A packer used for the well completion method of gravel packing. See ***gravel packing***.

***gravity drainage*** – The movement of oil in a reservoir toward a wellbore resulting from the force of gravity. In the absence of water drive of effective gas drive, gravity drainage is an important source of energy to produce oil. It is also called segregation drive.

***gravity, specific*** – Weight of a volume of a substance compared to weight of an equal volume of water at reference temperature. For gases, air is usually taken as reference substance, although hydrogen is sometimes used.

***gravity*** – The attraction exerted by the earth's mass on objects at its surface; the weight of a body. See ***API gravity*** and ***specific gravity***.

***grease injector*** – A surface device used in pressure control for slickline.

***greasing out*** – Certain organic substances, usually fatty-acid derivatives, added to drilling fluids as emulsifiers, e.p. lubricants, etc., may react with such ions as calcium and magnesium that are in or will subsequently come into the system. An essentially water-insoluble greasy material separates out.

***GRN*** – Gamma-Ray-Neutron (a well log).

***gross production*** – The total production of oil from a well or lease during a specified period of time.

***guar gum*** – A naturally occurring hydrophilic polysaccharide derived from the seed of the guar plant. The gum is chemically classified as a galactomannan. Guar gum slurries made up in clear fresh or brine water possess pseudoplastic flow properties.

***guide ring*** – Metal ring guiding packers past casing obtrusions.

***guide shoe*** – A short, heavy, cylindrical section of steel, filled with rubber or concrete and rounded at the bottom, which is placed at end of casing string. It prevents casing from snagging or irregularities in borehole as it is lowered. A passage through center of shoe allows drilling fluid to pass up into casing while it is being lowered and cement to pass out during cementing operations. Also called casing shoe.

***gum*** – Hydrophilic plant polysaccharides which, dispersed in water, swell to produce a viscous dispersion or solution. Unlike resins, soluble in water, insoluble in alcohol.

***gumbo*** – Relatively sticky formation, such as clay, encountered in drilling.

***gun-perforate*** – To create holes in casing and cement set through a productive formation. A common method of completing a well is to set casing through oil-bearing formation and cement it. A perforating gun is then lowered into the hole and fired to detonate high-powered jets or shoot steel projectiles (bullets) through casing and cement and into pay zone. Formation fluids flow out of the reservoir through the perforations and into the wellbore. See ***jet-perforate*** and ***perforating gun***.

***gunk plug*** – 1. A slurry in crude or diesel oil containing any of the following: bentonite, cement, attapulgite, and guar gum (never with cement). Used primarily in combatting lost circulation. 2. A volume of a gunk slurry placed in the wellbore. The plug may or may not be squeezed.

***gunk slurry*** – Slang term to denote a mixture of diesel oil and bentonite.

***gunk squeeze*** – Procedure where gunk slurry is pumped into a subsurface zone.

***gunning the pits*** – Mechanical agitation of the drilling fluid in a pit by means of a mud gun, electric mixer, or agitator.

***guns*** – Explosive devices used in perforating.

***gusher*** – Oil well that has come in with such pressure that oil jets out of well like a geyser; also called a wild well. In reality a blowout and waste of reservoir fluid and drive energy. In the early oil industry, gushers were common and often the only indication of a large reservoir of oil and gas. See ***blowout***.

***guy line*** – A wireline attached to a mast or derrick to stabilize it. The lines that provide the main support for the structure are load guys; the lines attached to ground anchors for lateral support are wind guys.

***guy-line anchor*** – Buried weight to which guy line is attached. See ***deadman***.

***gyp or gypsum*** – See ***calcium sulfate***. Gypsum is often encountered while drilling. It may occur as thin stringers or massive formations.

# H

***$H_2S$*** – An abbreviation for ***hydrogen sulfide***.

***half mule shoe*** – A cut off pup joint below a packer as a fluid entry device and/or seal assemblies guide.

***hammering-up*** – Connection of treating line during well servicing, from pump trucks to tree/well.

***hang rods*** – To suspend sucker rods in a derrick or mast on rod hangers rather than place them horizontally on a rack.

***hanger*** – Device used to “hang” and/or position tools in casing or tubing.

***hanger plug*** – A device placed or hung in the casing below the blowout-preventer stack to form a pressure-tight seal. Pressure is then applied to the blowout-preventer stack in order to test it for leaks.

***hard shut-in*** – To close in a well by closing a blowout preventer with the choke and/or choke line valve closed.

***hardness (of water)*** – The hardness of water is due principally to calcium and magnesium ions presenting water and is independent of accompanying acid ions. The total hardness is measured in terms of parts per million of calcium carbonate or calcium and sometimes equivalents per million of calcium. For hardness tests, see ***API RP 13B***.

***hay pulley*** – Top of a slickline gin pole where line from truck passes over.

***heat treated*** – Material treated in a furnace to increase its physical properties.

***heater*** – A container or vessel enclosing an arrangement of tubes and a firebox in which an emulsion is heated before further treating.

***heater-treater*** – Vessel that heats an emulsion and removes water/gas from oil to raise it to a quality acceptable for pipeline transmission. Combination of heater, free-water knockout and oil/gas separator. See ***free-water knockout, heater, oil and gas separator***.

***heaving*** – Partial or complete collapse of walls of a hole resulting from internal pressures due primarily to swelling from hydration or formation gas pressures. See ***sloughing***.

***heterogeneous*** – A substance that consists of more than one phase and is not uniform, such as colloids, emulsions, etc. It has different properties in different parts.

***hi-lo cam*** – Mechanism in some packers to set/release tool with minimum rotation.

***high-pH mud*** – A drilling fluid with a pH range above 10.5. A high-alkalinity mud.

***high-yield drilling clay*** – A classification given to a group of commercial drilling-clay preparations having a yield of 35 to 50 bbl/ton and intermediate between bentonite and low-yield clays. High-yield drilling clays are usually prepared by peptizing low-yield calcium montmorillonite clays or, in a few cases, by blending some bentonite with the peptized low-yield clay.

***hoist*** – An arrangement of pulleys and wire rope or chain used for lifting heavy objects; a winch or similar device; the draw works. See ***draw works***.

***hoisting drum*** – The large, flanged spool in the draw works on which the hoisting cable is wound. See draw works.

***hold-down*** – A mechanical arrangement that prevents the upward movement of certain pieces of equipment installed in a well. A sucker rod pump may use a mechanical hold-down for attachment to a seating nipple.

***homogeneous*** – Of uniform or similar nature throughout; or a substance or fluid that has at all points the same property or composition.

***hook*** – A large, hook-shaped device from which the elevator bails or the swivel is suspended. It is designed to carry maximum loads ranging from 100 to 500 tons and turns on bearings in its supporting housing. A strong spring within the assembly cushions the weight of a stand (90 feet) of drill pipe, thus permitting the pipe to be made up and broken out with less damage to the tool joint threads. Smaller hooks without the spring are used for handling tubing and sucker rods. See ***bail, stands***, and ***swivel***.

***hook load*** – The weight of pipe suspended in well as read on rig's weight indicator.

***hook-wall packer*** – Packer equipped with friction blocks or drag springs and slips and designed so rotation of pipe unlatches slips. Friction springs prevent slips and hook from turning with pipe and assist in advancing slips up a tapered sleeve to engage wall of outside pipe as weight is put on packer. Also called a wall-hook packer. See ***packer***.

***hopper, jet*** – A device to hold/feed drilling-mud additives. See ***mud-mixing devices***.

***hot oil treatment*** – Injection of a heated, paraffin free oil down a tubing string to dissolve, or melt paraffin deposits.

***humic acid*** – Organic acids of indefinite composition in naturally occurring leonardite lignite. Humic acids are most valuable constituent. See ***lignin***.

***hydrate*** – Substance containing water combined in molecular form (such as $CaSO_4$ $2H_2O$). A crystalline substance containing water of crystallization.

***hydration*** – Act of substance to take up water by absorption and/or adsorption.

***hydraulic*** – 1. Of or relating to water or other liquid in motion. 2. Operated, moved, or affected by water or liquid.

***hydraulic fracturing*** – An operation in which a blended liquid is pumped down a well and into a formation under pressure high enough to cause the formation to crack open. Resulting cracks or fractures serve as passages through which oil flows into wellbore. See ***formation fracturing***.

***hydraulic head*** – Pressure exerted by the weight of a column of liquid.

***hydraulic holddown*** – An accessory or integral part of a packer used to limit the packer's upward movement under pressure.

***hydraulic jar*** – Also called mechanical jar. See ***mechanical jar***.

***hydraulic workover*** – A series of hydraulic rams to restrain and pull tubing under well pressure, temporarily attached to the wellhead for workover. Abbreviation ***HWO***

***hydro-set tool*** – A wireline pressure setting tool for downhole tools.

***hydro-trip pressure sub*** – A sub with a ball seat run on top of a hydraulically set packer to provide a means to set the packer.

***hydrochloric acid*** – An acid compound commonly used to acidize carbonate rocks; prepared by mixing hydrogen chloride gas in water; also known a muriatic acid. Chemical symbol is HCl. See ***acidize***.

***hydrofluoric hydrochloric acid*** – A mixture of acids used for removal of mud from the wellbore. See ***mud acid***.

***hydrogen ion concentration*** – A measure of the acidity or alkalinity of a solution, normally expressed as pH. See ***pH***.

***hydrogen sulfide*** – Gaseous compound, $H_2S$, of sulfur and hydrogen commonly found in petroleum, which causes the foul smell of sour petroleum fractions. Has a specific gravity of 1.189, is extremely poisonous and corrosive.

***hydrolysis*** – Hydrolysis is the reaction of a salt with water to form an acid and base. For example, soda ash ($Na_2CO_3$) hydrolyzes basically, and hydrolysis is responsible for the increase in the pH of water when soda ash is added.

***hydrometer*** – A floating instrument for determining the specific gravity or density of liquids, solutions, and slurries. A common example is the mudwater hydrometer used to determine the density of mud.

***hydrophile*** – A substance usually in the colloidal state or an emulsion, which is wetted by water; i.e., it attracts water or water adheres to it.

***hydrophilic*** – A property of a substance having an affinity for water or one that is wetted by water.

***hydrophilic-lipophilic balance (HLB)*** – Hydrophilic-lipophilic balance (HLB) is one of the most important properties of emulsifiers. An expression of relative attraction of an emulsifier for water and oil, determined largely by chemical composition and ionization characteristics of a given emulsifier. The HLB of an emulsifier is not directly related to solubility, but determines the type of emulsion that tends to be formed. An indication of the behavior characteristics and not an indication of emulsifier efficiency.

***hydrophobe*** – Substance, usually in colloidal state, not wetted by water.

***hydrophobic*** – Descriptive of a substance which repels water.

***hydrostatic head*** – Pressure exerted by a column of fluid, usually expressed in pounds per square inch. To determine hydrostatic head at a given depth in psi, multiply depth in feet by density in pounds per gallon by 0.052. The hydrostatic head of fresh water is 0.433 pounds per foot (9.81 kPa per meter) of height. See ***pressure gradient***.

***hydrostatic pressure*** – The force exerted by a body of fluid at rest; hydrostatic pressure increases directly with the weight and depth of the fluid. In drilling, the term refers to the pressure exerted by the drilling fluid in the wellbore. See ***hydrostatic head***.

***hydroxide*** – A designation that is given for basic compounds containing the OH radical. When these substances are dissolved in water, they increase the pH of the solution. See ***base***.

***hygroscopic*** – Property enabling a substance to absorb water from the air.

# I

***IADC*** – Abbreviation for International Association of Drilling Contractors.

***impermeable*** – Preventing passage of fluid. Formation may be porous yet impermeable if there is an absence of connecting passages between voids. See ***permeability***.

***impression block*** – Tool made of a soft material such as lead or coal tar and used to secure an imprint of a fish.

***impression tool*** – Lead-filled device used to ascertain the shape of a fish.

***indexing valve*** – Same principle as annular valve, except necessitates pipe rotation for opening and closing operations.

***indicator*** – 1. Dial gauge used on rig to measure hookload. 2. Substances in acid-base titrations which, in solution, change color or become colorless as hydrogen ion concentration reaches a definite value, these values varying with indicator. In other titrations such as chloride, hardness, and other determinations, these substances change color at the end of the reaction. Common indicators are phenolphthalein, potassium chromate, etc.

***inflatable packer*** – Used for open-hole work, with inflatable packing elements.

***influx*** – See ***feed-in***.

***inhibited acid*** – An acid that has been chemically treated before acidizing, or acid fracturing, a well to lessen its corrosive effect on the tubular goods and yet maintain its effectiveness. See ***acid fracturing*** and ***acidize***.

***inhibitor (corrosion)*** – Agent which, when added to a system, slows down or prevents chemical reaction or corrosion. Used in drilling and producing operations to prevent corrosion of metal equipment exposed to hydrogen sulfide, carbon dioxide, saltwater, etc. Inhibitors added to drilling fluids are filming amines, chromates, and lime.

***inhibitor (mud)*** – Substances generally regarded as drilling-mud contaminants, such as salt and calcium sulfate, are called inhibitors when purposely added to mud so that filtrate from drilling fluid will prevent or retard hydration of formation clays shales.

***inhibitor*** – Additive used to retard undesirable chemical action in a product. Added in small quantities to gasolines to prevent oxidation and gum formation, to lubricating oils to prevent color change, and to corrosive environments to decrease corrosive action.

***initial circulating pressure*** – Drill pipe pressure required to circulate initially at selected kill rate while holding casing pressure at shut in valve; equal to kill rate circulating pressure plus shut in drill pipe pressure. Abbreviation ***ICP***.

***injected gas*** – A high-pressure gas injected into a formation to maintain or restore reservoir pressure; gas injected in gas-lift operations.

***injection valve*** – A poppet spring-loaded subsurface valve run in on wireline, landed in a profile, to shut the well in if injection ceases.

***injection well*** – A well in which fluids have been injected into an underground stratum to increase reservoir pressure.

***inside blowout preventer*** – A valve installed in drill stem to prevent a blowout inside stem. Flow is thus possible only downward, allowing mud to be pumped in but preventing any flow back up stem. Also called internal blowout preventer (IBOP).

***instrument hanger*** – A hanger used to lock instruments into seating nipple (pressure/temperature bombs, etc.)

***insulating flange*** – A flange equipped with plastic pieces to separate its metal parts, thus preventing the inflow of electric current. Insulating flanges are often used in cathodic protection systems to prevent electrolytic corrosion and are sometimes installed when a flow line is being attached to a wellhead.

***intensifier*** – A pressure-multiplier type well servicing mobile pump.

***interfacial tension*** – The force required to break the surface between two immiscible liquids. The lower the interfacial tension between the two phases of an emulsion, the greater the ease of emulsification. When the values approach zero, emulsion formation is spontaneous. See ***surface tension***.

***intermediate casing string*** – String set in a well after surface casing; sometimes called protection casing. It keeps the hole from caving in, and sometimes affords a strong string of pipe for blowout preventer attachments.

***internal blowout preventer*** – Also inside blowout preventer, which see.

***internal cutter*** – A fishing tool, containing metal-cutting knives, that is lowered into the inside of a length of pipe stuck in the hole to cut the pipe. The severed portion of the pipe can then be returned to the surface.

***internal preventer*** – Also inside blowout preventer. A check valve placed in the drill string which permits circulation down the hole, but which prevents any back flow.

***interstitial water*** – Water contained in the interstices of reservoir rock. In reservoir engineering, it is synonymous with connate water. See ***connate water.***

***invert oil-emulsion*** – A water-in-oil emulsion where fresh or salt water is dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

***iodine number*** – The number indicating the amount of iodine absorbed by oils, fats, and waxes, giving a measure of the unsaturated linkages present. Generally, the higher the iodine number, the more severe the action of the oil on rubber.

***ion*** – Acids, bases, and salts (electrolytes) when dissolved in certain solvents, especially water, are more or less dissociated into electrically charged ions or parts of the molecules, due to loss or gain of one or more electrons. Loss of electrons results in positive charges producing a cation. A gain of electrons results in the formation of an anion with negative charges. The valence of an ion is equal to the number of charges borne by it.

***isolate*** – To pack off above and below a zone of interest.

# J

***J-slot*** – A type of mechanism in packer/tools where tubing rotation moves the tool's mandrel thru a series of motions, similar to a letter J, to set and release the tool.

***jacket*** – A steel, tubular piece in a tubing-liner type of sucker rod pump, inside of which is placed an accurately bored and honed liner. In this type of sucker rod pump, the pump plunger moves up and down within the liner; and the liner is inside the jacket.

***jack-up drilling rig*** – Offshore drilling structure with tubular or derrick legs that support the deck and hull. When positioned over drilling site, bottoms of legs rest on seafloor. A jackup rig is towed or propelled to a location with its legs up. Once legs are firmly positioned on bottom, deck and hull height are adjusted and leveled.

***jar*** – 1. A mechanical device used to impart a blow (or hit) to a stuck tool. 2. A percussion tool operated mechanically or hydraulically to deliver a heavy hammer blow to objects in the borehole. Jars are used to free objects stuck in the hole or to loosen tubing or drill pipe that is hung up. Blows may be delivered downward or upward, the jar being controlled at the surface. To apply a heavy blow to the drill stem by use of a jar.

***jar accelerator*** – A hydraulic tool used in conjunction with a jar and made up on the fishing string above the jar to increase the impact, or, power of the hammer blow.

***jaying-up*** – Getting ready to se a J-slot packer or tool.

***jet*** – 1. A hydraulic device operated by pump pressure to clean mud pits and tanks in rotary drilling and to mix mud components. 2. In a perforating gun using shaped charges, a highly penetrating, fast-moving stream of exploded particles that cuts a hole in the casing, cement, and formation.

***jet cutoff*** – A procedure for severing pipe stuck in a well by detonating special shaped-charge explosives similar to those used in jet perforating. The explosive is lowered into the pipe to the desired depth and detonated. The force of the explosion makes radiating horizontal cuts around the pipe, and the severed portion of the pipe is retrieved.

***jet cutter*** – A tool used to cut casing, pipe, tubing for stuck or salvage reasons; usually chemical or sand cutter hydrolysis.

***jet-perforate*** – To create a hole through casing with a shaped charge of high explosives instead of a gun that fires projectiles. Loaded charges are lowered into the hole to desired depth. Once detonated, the charges emit short, penetrating jets of high velocity gases that cut holes in the casing and cement and some distance into the formation. Formation fluids then flow into the wellbore through these perforations. See ***bullet perforator*** and ***gun-perforate***.

***jetting*** – Process of periodically removing a portion, or all of, water, mud and/or solids, from pits, usually by means of pumping through a jet nozzle arrangement.

***jetting-the-well-in*** – Circulating a lower-density fluid to underbalance the well's formation pressure to initiate flow.

***joint*** – A single length (30 feet, or 9.1 meters) of drill pipe or drill collar, casing, tubing, or rod that has threaded connections at both ends. Several joints screwed together constitute a stand of pipe. See double, thribble, and fourble.

***Jones effect*** – Net surface tension of salt solutions first decreases with an increase of concentration, passes through minimum, then increases as concentration is raised.

***junk*** – 1. Metal debris lost in a hole. Junk may be a lost bit, pieces of a bit, milled pieces of pipe, wrenches, or any relatively small object that impedes drilling or completion operations and must be fished out of the hole. 2. To abandon (as an nonproductive well).

***junk basket*** – A cylindrical tool designed to aid in the removal of junk, cuttings or foreign objects in a wellbore. It is commonly run when drilling or milling drillable or non-drillable tools.

***junk pusher*** – Scraper device below retainers/packers, cleans debris from casing ID.

***junk sub*** – Also called ***boot basket.*** Tool run just above bit or mill in drill stem to catch small, non-drillable objects circulating in annulus.

# K

***Kalrez*** – A trademark for a specially compounded fluro-elastomer for extreme temperature/pressure/hostile environment service.

***kelly bushing*** – A special device fitted to rotary bushing that transmits torque to kelly and simultaneously permits vertical movement of kelly to make hole. It may be square or hexagonal to fit the rotary opening or have pins for transmitting torque. Also called drive bushing. See ***kelly*** and ***master bushing***.

***kelly cock*** – A valve installed between the swivel and the kelly. When a high-pressure backflow begins inside the drill stem, the valve is closed to keep pressure off the swivel and rotary hose. See ***swivel*** and ***kelly***.

***kelly or kelly joint*** – A heavy square pipe or other configuration that works through a like hole in the rotary table and rotates the drill stem.

***kelly*** – The heavy steel member, four- or six-sided, suspended from the swivel through the rotary table and connected to the topmost joint of drill pipe to turn the drill stem as the rotary table turns. It has a bored passageway that permits fluid to bee circulated into the drill stem and up the annulus, or vice versa. See ***drill stem, rotary table,*** and ***swivel***.

***kelly valve, lower*** – An essentially full-opening valve immediately below the kelly, with outside diameter equal to the tool joint outside diameter.

***key seat*** – 1. A channel or groove cut in the side of the hole parallel to the axis of the hole. Key seating results from the dragging of pipe on a sharp bend in the hole. 2. That section of a hole, usually of abnormal deviation and relatively soft formation, which has been eroded or worn by drill pipe to a size smaller than the tool joints or collars. This keyhole type configuration will not allow these members to pass when pulling out of the hole.

***key-seat barge*** – A barge in which the mast is placed over a channel cut out of the side of the barge through which the drilling and workover operations are performed.

***kick*** – Unscheduled, unwanted entry of water, gas, oil, or other formation fluid into wellbore. It occurs because pressure exerted by column of drilling fluid is not great enough to overcome the pressure exerted by the fluids in the formation drilled. If prompt action is not taken to control the kick or kill the well, a blowout will occur. See ***blowout***.

***kill*** – 1. In drilling/well servicing, to prevent a threatened blowout by taking suitable preventative measures (e.g., to shut in well with blowout preventers, circulate kick out, and increase weight of drilling/completion/workover fluid). 2. In production, to stop a well from producing oil and gas so that reconditioning of the well can proceed.

***kill drilling fluid density*** – The unit weight, e.g., pounds per gallon (lb/gal), selected for the fluid to be used to contain a kicking formation.

***kill line*** – A high pressure line that connects the mud pump and the blowout-preventer assembly through which drilling fluid can be pumped into the hole to subdue well pressure while the preventers are closed.

***kill rate*** – A predetermined fluid circulating rate, expressed in fluid volume per unit time, which is to be used to circulate under kick conditions; kill rate is usually some selected fraction of the circulating rate used while drilling.

***kill rate circulating pressure*** – Pump pressure required to circulate kill rate volume under non kick conditions.

***killing a well*** – Bringing a well under control that is blowing out. Also procedure of circulating water and mud into a completed well before starting well-service operations.

***kinematic viscosity*** – The kinematic viscosity of a fluid is the ratio of the viscosity (e.g., cp in g/cm-sec.) to the density (e.g., g/cc) using consistent units. In several common commercial viscometers the kinematic viscosity is measured in terms of the time of efflux (in seconds) of a fixed volume of liquid through a standard capillary tube or orifice. See ***marsh funnel viscosity***.

***knock-out plug*** – A plugging device used to effect a dry tubing during run in, and being opened by knocking it out of the tubing; used with retainer and packers.

***knuckle joint*** – A hinged joint made up in the string above a fishing tool to allow it to be thrust out at an angle.

# L

***laminar flow*** – Fluid elements flowing along fixed streamlines which are parallel to the walls of the channel of flow. In laminar flow, the fluid moves in plates or sections with a differential velocity across the front which varies from zero at the wall to a maximum toward the center of flow. Laminar flow is the first stage of flow in a Newtonian fluid; it is the second stage in a Bingham plastic fluid. This type of motion is also called parallel, streamline, or viscous flow. See ***plug*** and ***turbulent flow***.

***land casing*** – To install casing so that it is supported in the casinghead by slips. The casing is usually landed in the casinghead at exactly the position in which it was hanging when the cement plug reached its lowest point. See ***casinghead*** and ***slips***.

***landing nipple*** – A sub for landing inside tubing tools, such as plugs, flow meters, logging tools etc.

***lay down pipe*** – To pull drill pipe or tubing from the hole and place it in a horizontal position on a pipe rack. Compare ***set back***.

***laying down*** – Removal of work string or production tubing from the well and laying them on a rack. See ***lay down pipe***.

***leak-off rate*** – The rate at which a fracturing fluid leaves the fracture and enters the formation surrounding the fracture. Generally, it is desirable for fracturing fluids to have a low leak-off rate (i.e., very little fluid should enter the formation being fractured) so that the fracture can be better extended into the formation.

***leak-off test*** – Application of pressure by superimposing surface pressure on a fluid column in order to determine pressure at which exposed formation accepts whole fluid.

***lease*** – 1. A legal document executed between a landowner, a lessor, and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. 2. The area where the production wells, stock tanks, separators, LACT units, and other production equipment are located.

***lease automatic custody transfer*** – Measurement and transfer of oil from the producer's tanks to the connected pipeline on an automatic basis without a representative of either having to be present. See ***LACT***, ***LACT unit***.

***lease operator*** – Also called a pumper. See ***pumper***.

***leonardite*** – A naturally occurring oxidized lignite. See ***lignins***.

***lignins, mined*** – Naturally occurring special lignite, e.g., leonardite, produced by strip mining from special lignite deposits. Used primarily as thinners, which may or may not be chemically modified. However, they are also widely used as emulsifiers.

***lignosulfonates*** – Organic drilling-fluid additives derived from by-products of sulfite paper manufacturing process from coniferous woods. Some of the common salts, such as the ferrochrome, chrome, calcium, and sodium, are used as universal dispersants while others are selectively for calcium-treated systems. In large quantities, the ferrochrome and chrome salts are used for fluid-loss control and shale inhibition.

***lime-treated muds*** – Commonly lime-base muds. These high-pH systems contain most of the conventional fresh-water additives to which slaked lime has been added to impart special properties. The alkalinities and lime contents vary from low to high.

***limestone*** – The sedimentary rock rich in calcium carbonate that sometimes serves as a reservoir rock for petroleum. See ***calcium carbonate***.

***limited exposure*** – A generic term to describe certain types of packers where the packing element is positioned in such a fashion as to "limit" wellbore mediums "exposed" to the tool's setting/releasing mechanisms.

***limited-entry technique*** – Fracturing method where fracturing fluid is injected into formation through a limited number of perforations (fluid not injected through all perforations at once, injection is confined to a few, selected perforations). This special technique can be useful when long, thick, or multiple producing zones are to be fractured.

***liner*** – 1. String of casing whose top is below surface. A liner may serve as oil string, extending from producing interval up to next string of casing. 2. A smaller-size casing run inside production casing to complete deeper. 3. An extension of casing string, usually for line completions to a deeper zone or casing repair. 4. In jet-perforating guns, a conically shaped, metallic piece that is part of a shaped charge. It increases efficiency of charge by increasing penetrating ability of jet. See ***blank liner, jet, perforated liner, screen liner.***

***liner hanger*** – A slip or holding device used to attach or hang liners off the casing inside wall; can be mechanical or hydraulically operated. See ***liner***.

***liner patch*** – A stressed-steel corrugated tube that is lowered into existing casing in a well in order to repair a hole or leak in the casing. The patch is cemented to the casing with glass fiber and epoxy resin.

***lipophile*** – A substance usually colloidal and easily wetted by oil.

***lipophilic*** – Having an affinity for oil.

***liquefied petroleum gas*** – Mixture of heavier, gaseous, paraffinic hydrocarbons, principally butane and propane. These gases, easily liquefied at moderate pressure may be transported as liquids but converted to gases on release of pressure. Thus, liquefied petroleum gas is a portable source of thermal energy that finds wide application in areas where it is impractical to distribute natural gas. Also used as a fuel for internal-combustion engines and has many industrial and domestic uses. Principal sources are natural and refinery gas, from which liquefied petroleum gases are separated by fractionation.

***live oil*** – Crude oil that contains gas and has not been stabilized or weathered. Can cause gas cutting when added to mud and is a potential fire hazard.

***load oil*** – The crude or refined oil used in fracturing a formation to stimulate a well, as distinguished from the oil normally produced by the well.

***locating*** – Positioning tubing in order to tag or sting into a packer bore.

***locator*** – Describes locating, but not anchoring, of production tubing into packer.

***locator tubing seal assembly*** – A seal assembly used to locate inside the seal of a packer to prevent tubing movement.

***lock segment*** – Device to lock packer's mandrel to its dragblock housing.

***locking mandrels*** – Slickline tools with slips and rubber cups to contain pressure and pack-off tubing in wells not equipped with landing nipples.

***lockset (lokset)*** – Trademark packer with bidirectional slips used in completion.

***log*** – 1. A systematic recording of data, as from the driller's log, mud log, electrical well log, or radioactivity log. Many different logs are run in wells being produced or drilled to obtain various characteristics of downhole formations. 2. To record data.

***logging*** – See ***mud logging*** and ***electric logging***.

***long string*** – 1. Last string of casing set in well. 2. String of casing set through the producing zone, often called the oil string or production string.

***long way*** – Displacing fluid from the tubing up the annulus.

***lost circulation material*** – A substance added to cement slurries or drilling mud to prevent the loss of cement or mud to the formation. See ***bridging material***.

***lost circulation*** – The loss of quantities of whole mud to a formation, usually in cavernous, fissured, or coarsely permeable beds, evidenced by the complete or partial failure of the mud to return to the surface as it is being circulated in the hole. Lost circulation can lead to a blowout and, in general, reduce the efficiency of the drilling operation. It is also called lost returns. See ***blowout***.

***lost returns*** – Lost circulation caused by drilling fluid passing from hole into a porous, fractured, or cavernous formation. Also lost circulation. See ***lost circulation***.

***lost-circulation additives*** – Materials added to the mud to control or prevent lost circulation. These materials are added in varying amounts and are classified as fiber, flake, or granular.

***low-solids muds*** – A designation given to any type of mud where high performing additives, e.g., CMC, have been partially or wholly substituted for commercial or natural clays. For comparable viscosity and densities (weighted with barite), a low-solids mud will have a lower volume-percent solids content.

***low-yield clays*** – Commercial clays chiefly of the calcium montmorillonite type having a yield of approximately 15 to 30 bbl/ton.

***lower kelly cock*** – Also called drill-stem safety valve. See ***drill-stem safety valve***.

***lubrication*** – Alternately pumping a small volume of fluid into a closed wellbore system and waiting for the fluid to fall toward the bottom of the well.

***lubricator stack*** – A surface device used in slickline operations to keep the line lubricated and provide grease for pressure control.

***lyophilic*** – Having an affinity for suspending medium, such as bentonite in water.

***lyphobic colloid*** – A colloid that is readily precipitated from a solution and cannot be redispersed by an addition of the solution.

# M

***$M_f$*** – The methyl orange alkalinity of the filtrate, reported as the number of millimeters of 0.02 Normal (N/50) acid required per millimeter of filtrate to reach the methyl orange end point (pH 4.3).

***macaroni rig*** – A workover rig, usually lightweight, that is specially built to run a string of ¾ inch and 1 inch diameter tubing. See ***macaroni string***.

***macaroni string*** – String of tubing or pipe of small diameter, usually ¾ or 1 inch and capable of well servicing through 2⅜ production tubing.

***magnet*** – A permanent magnet of electromagnet fitted into a tool body so that it may be run to retrieve relatively small ferrous metal junk.

***make a connection*** – To attach a joint of drill pipe/tubing onto the drill stem/work string suspended in the wellbore to permit deepening of the wellbore.

***make a trip*** – To hoist drill/work string out of the wellbore to perform one of a number of operations such as changing bits, taking a core, servicing downhole tools, etc., and then to return the drill/work string to the wellbore.

***make-up*** – Connecting pipe together by hand or rotary table.

***makeup cathead*** – Device attached to shaft of draw works; a power source for screwing together pipe joints; usually located on driller's side of draw works. See ***cathead***.

***mandrel*** – 1. Cylindrical bar, spindle, or shaft around which other parts are arranged or attached or that fits inside a cylinder/tube. 2. Pressure-containing member of a packer; also component used to transfer energy into slips; also locating member of gas lift valve.

***manifold*** – An accessory system of piping to a main piping system (or another conductor) that serves to divide a flow into several parts, to combine several flows into one, or to reroute a flow to any one of several possible destinations. See ***choke manifold***.

***marginal well*** – A well that is approaching depletion of its natural resource to the extent that any profit from continued production is doubtful.

***Marsh funnel*** – An instrument used in determining the Marsh funnel viscosity. The Marsh funnel is a container with a fixed orifice at the bottom so that when filled with 1,500 cc fresh water, 1 qt. (946 ml) will flow out in 26± 0.5 sec. For 1,000 cc out, the efflux time for water is 27.5 ± 0.5 sec. See ***API RP 13B*** for specifications.

***Martin-Decker*** – A common term for a rig weight indicator.

***mast*** – Portable derrick capable of being erected as a unit, as distinguished from a standard derrick, which cannot be raised to a working position as a unit. For transporting by land, mast can be divided into two or more sections to avoid excessive length extending from truck beds on highway. See ***derrick***.

***master bushing*** – A device that fits into the rotary table. It accommodates the slips and drives the Kelly bushing so that to rotating motion of the rotary table can be transmitted to the Kelly. Also called rotary bushing. See ***slips*** and ***kelly bushing***.

***master choke line valve*** – Valve on choke and flowline which is nearest to preventer assembly. Its purpose is to stop flow through choke and flowline.

***master gate*** – 1. A large valve located on the Christmas tree used to control the flow of oil and gas from the well. 2. The blind or blank rams of a blowout preventer.

***mcf*** – Abbreviation for 1,000 cubic feet of gas, commonly used to express the volume of gas produced, transmitted, or consumed in a given period.

***measure in*** – To obtain an accurate measurement of the depth reached in a well by measuring the drill pipe or tubing as it is run into the well.

***measure out*** – To measure drill pipe or tubing as it is pulled from the hole, usually to determine the depth of the well or the depth to which the pipe or tubing was run.

***mechanical jar*** – Percussion tool operated mechanically to permit upward impact on a fish by sudden release of a tripping device inside tool. If fish can be freed by an upward blow, mechanical jar can be very effective. Also called a ***hydraulic jar***.

***mechanical rig*** – A drilling rig in which the source of power is one or more internal-combustion engines and in which the power is distributed to rig components through mechanical devices (as chains, sprockets, clutches, and shafts). It is also called a ***power rig***.

***meniscus*** – The curved upper surface of a liquid column, concave when the containing walls are wetted by the liquid and convex when not.

***mesh*** – Measure of fineness of woven material, screen, or sieve. A 200-mesh sieve has 200 openings per linear inch. A 200-mesh screen with wire diameter of 0.0021 in. (0.0533 mm) has an opening of 0.074 mm, or will pass a particle of 74 microns. See ***micron***.

***methane*** – A light, gaseous, flammable paraffin hydrocarbon, CH4, with a boiling point of -258<198>F, that is the chief component of natural gas and an important basic hydrocarbon for petrochemical manufacture.

***MFE*** – A trademark name for multiple formation evaluation; a DST.

***mica*** – A naturally occurring flake material of varying size used in combatting lost circulation. Chemically, an alkali aluminum silicate.

***micelles*** – Organic and inorganic molecular aggregates occurring in colloidal solutions. Long chains of individual structural units chemically joined to one another and laid side by side to form bundles. When bentonite hydrates, certain sodium or other metallic ions go into solution, clay particle plus its atmosphere of ions is known as a micelle.

***micron U = MU*** – A unit of length equal to one millionth part of a meter, or one thousandth part of a millimeter.

***migration*** – 1. The movement of hydrocarbons from the area in which it formed to a reservoir rock where it can accumulate. 2. Movement from one zone to another.

***mill*** – A downhole tool with rough, sharp, extremely hard cutting surfaces for removing metal by grinding or cutting. Mills are run on drill pipe or tubing to grind up debris in the hole, remove stuck portions of drill stem or sections of casing for sidetracking, and ream out tight spots in the casing. They are also called junk mills, reaming mills, and so forth, depending on what use they have. To use a mill to cut or grind metal objects that must be removed from a well.

***mill-out extension*** – A pinned-end pup joint used to provide additional length and inside diameter necessary to accommodate a standard milling tool.

***mill-out*** – Use of mill on end of a work string to remove a permanent tool or fish.

***millidarcy*** – 1/1000 darcy. See ***darcy***.

***milling shoe*** – See ***rotary shoe*** and ***burning shoe***.

***milling tool*** – 1. Tool used in operation of milling. 2. A cutter used to remove drillable tools and for pushing tools to bottom. Also for milling-over retrievable tools. See ***mill***.

***mineral rights*** – Rights of ownership, conveyed by deed, of gas, oil, and other minerals beneath the surface of the earth. In the United States, mineral rights are the property of the surface owner unless disposed of separately.

***minimum internal yield pressure*** – The lowest internal pressure at which a failure (of pipe) will take place.

***mist drilling*** – A method of rotary drilling whereby water and/or oil is dispersed in air and/or gas as the drilling fluid.

***ml*** – Abbreviation for milliliter. Metric system unit for measure of volume. Literally 1/1000 of a liter. In drilling-mud analysis work, this term is used interchangeably with cubic centimeter (cc). One quart is about equal to 946 ml.

***modular space workover rig*** – A platform rig designed in equipment packages or modules light enough to be lifted onto a platform by a platform crane. In most cases, the maximum weight of a module is 12,000 pounds. Once lifted from the work boat, the rig can be erected and working within 24 to 36 hours. As in all mast-type rigs, the working depth is limited by the strength of the mast, typically 12,000 to 14,000 feet.

***molecular weight*** – The sum of the atomic weights of all the constituent atoms in the molecule of an element or compound.

***molecule*** – When atoms combine they form a molecule. In the case of an element or a compound, a molecule is the smallest unit which chemically still retains the properties of the substance in mass.

***montmorillonite*** – A clay material commonly used as an additive to drilling muds. Sodium montmorillonite is the main constituent in bentonite. The structure of montmorillonite is characterized by a form which consists of a thin plate-type sheet with the width and breadth indefinite, and thickness that of the molecule. The unit thickness of the molecule consists of three layers. Attached to the surface are ions that are replaceable. Calcium montmorillonite is the main constituent in low-yield clays.

***mosquito bill*** – A tube mounted at bottom of a sucker rod pump and inside a gas anchor to provide a conduit for well fluids (that contain little or no gas) into the pump.

***mousetrap*** – A fishing tool used to recover a parted string of sucker rods or other tubular-type fish from a well.

***mud*** – Liquid circulated through wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, mud used in modern drilling is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain conditioners. See ***drilling fluid***.

***mud acid*** – A mixture of hydrochloric and hydrofluoric acids and surfactants used to effect mud removal from the wellbore.

***mud analysis*** – Examination and testing of the drilling mud to determine its physical and chemical properties.

***mud circulation*** – The act of pumping mud downward to the bit and back up to the surface by normal circulation or reverse circulation. See ***normal circulation*** and ***reverse circulation***.

***mud density*** – Weight per unit volume of drilling fluid usually expressed in pounds per gallon or pounds per cubic foot. See ***hydrostatic head***.

***mud flow indicator*** – Device that continually measures and records volume of mud returning from annulus and flowing out of mud-return line. If mud does not flow at a fairly constant rate, a kick may have occurred.

***mud flow sensor*** – Also called mud-flow indicator, which see.

***mud gas separator*** – A device that separates free gas from the mud coming out of a well when a kick is being circulated out.

***mud hose*** – Also called the rotary hose and kelly hose. See ***rotary hose***.

***mud house*** – Structure at rig to store/shelter sacked materials used in drilling fluids.

***mud log*** – A record of information derived from examination of drilling fluid and drill-bit cuttings. See ***mud logging***.

***mud logging*** – The recording of information derived from examination and analysis of formation cuttings made by the bit and mud circulated out of the hole. A portion of the mud is diverted through a gas-detecting device. Cuttings brought up by the mud are examined under ultraviolet light to detect the presence of oil or gas. Mud logging is often carried out in a portable laboratory set up at the well.

***mud mixing devices*** – The most common device for adding solids to the mud is by means of the jet hopper. Some other devices for mixing are: educators, paddle mixers, electric stirrers, mud guns, chemical barrels, etc.

***mud pits*** – Series of open tanks, earthen or steel storage facilities, through which the drilling mud, or fluid is cycled to allow sand and sediments to settle out. Additives are mixed with the mud in the pits, and the fluid is temporarily stored there before being pumped back into the well. Modern rotary drilling rigs are generally provided with three or more pits, usually fabricated steel tanks fitted with built-in piping, valves, and mud agitators. Mud pits are also called shaker pits, settling pits, and suction pits, depending on their main purpose. Also called mud tanks. See ***shaker pit, settling pit*** and ***suction pit***.

***mud program*** – Proposed or followed plan for type and properties of drilling fluid used in drilling a well with respect to depth. Some factors that influence mud program are casing program and formation type, competence, solubility, temperature, pressure.

***mud pump*** – A large, reciprocating pump used to circulate the mud on a drilling rig and completion/workover fluid on a service rig. A typical mud pump is a single or double acting, two or three cylinder piston pump whose pistons travel in replaceable liners and are driven by a crankshaft actuated by an engine or motor. Also called a slush pump.

***mud return line*** – A trough or pipe placed between the surface connections at the wellbore and the shale shaker, through which drilling mud flows upon its return to the surface from the hole.

***mud scales*** – See ***balance, mud***.

***mud screen*** – Also called a shale shaker. See ***shale shaker***.

***mud still/retort*** – Instrument used to distill oil, water and other volatile material to determine oil, water, total solids contents in volume-%.

***mud weight*** – A measure of the density of a drilling fluid expressed as pounds per gallon (ppg), pounds per cubic foot (lb/ft$^3$), or kilograms per cubic meter (kg/m$^3$). Mud weight is directly related to the amount of pressure the column of drilling mud exerts at the bottom of the hole.

***mud weight recorder*** – An instrument installed in the mud system which mechanically weighs the mud and records its weight.

***mudding off*** – Commonly thought of as a reduced productivity caused by the penetrating, sealing, or plastering effect of a drilling fluid.

***mudding up*** – Process of mixing mud additives to achieve desired purpose not possible with former fluid, which usually has been water, air, or gas.

***mule shoe*** – A pup joint cut in such a fashion as to provide an opening below the packer for fluid entry.

***multiple completion*** – An arrangement for producing a well in which one wellbore penetrates two or more petroleum-bearing formations that lie one over the other. The tubing strings are suspended side by side in the production casing string, each a different length and each packed off to prevent the commingling of different reservoir fluids. Each reservoir is then produced through its own tubing string.

# N

***NACE certified*** – A tool in compliance with certain National Association of Corrosion Engineers standards.

***natural clays*** – Natural, as opposed to commercial clays, that are encountered when drilling various formations. The yield of these clays varies greatly, and they may or may not be purposely incorporated into mud system.

***natural gas*** – Highly compressible, high expansible mixture of hydrocarbons with low specific gravity and occurring naturally in a gaseous form. Principal component gases of natural gas, with approximate percentages: methane, 80.0%; ethane, 7.0%; propane, 6.0%; butane, 2.5%; isobutane, 1.5%; pentane plus, 3.0%.

In addition to these gases, natural gas may contain nitrogen, helium, carbon dioxide, and contaminants (hydrogen sulfide, water vapor). Although gaseous at normal temperatures and pressures, certain gases comprising the mixture that is natural gas are variable in form and may be found as gases or liquids under suitable conditions of temperature/pressure.

***natural gasoline*** – The liquid hydrocarbons recovered from wet natural gas; casinghead gasoline. See ***casinghead gasoline***.

***neat cement*** – A slurry composed of portland cement and water.

***necking*** – The tendency of a metal bar or pipe to taper to a reduced diameter at some point when subjected to excessive longitudinal stress.

***needle valve*** – A globe valve that incorporates a needlepoint disk to produce extremely fine regulation of flow.

***neutral*** – Position of the rig's weight indicator where hookload is zero.

***neutralizatio***n – Reaction in which the hydrogen ion of an acid and the hydroxyl ion of a base unite to form water, the other ionic product being salt.

***Newtonian fluid*** – Simplest fluids from the standpoint of viscosity consideration in which shear force is directly proportional to shear rate. These fluids immediately begin to move when pressure or force in excess of zero is applied. Examples are water, diesel oil, and glycerine. The yield point as determined by direct-indicating viscometer is zero.

***fipple*** – Tubular pipe fitting threaded on both ends, less than 12 inches long.

***nipple up*** – To assemble blowout preventer stack on wellhead at surface.

***nitro shooting*** – A formation stimulation process first used about a hundred years ago in Pennsylvania. Nitroglycerine is placed in a well and exploded to fracture the rock. Sand and gravel are usually placed above the explosive charge to improve the efficiency of the shot. Today nitro shooting has been largely replaced by formation fracturing. See ***formation fracturing***.

***nitrogen*** – An inert gas ($NO_2$) used for jetting wells.

***no-go*** – A gauge run downhole to verify dimensions.

***no-go seating nippl***e – A sub with a profile to provide a location for various wireline flow-control devices; also stops tools from falling to bottom.

***nomograph*** – Chart representing an equation containing a number of variables in the form of scales so a straight line cuts scales at values of variables satisfying the equation.

***non conductive mud*** – Any drilling fluid, usually oil-base or invert-emulsion muds, whose continuous phase does not conduct electricity, e.g., oil. The spontaneous potential (SP) and normal resistivity cannot be logged, although such other logs as the induction, acoustic velocity, etc., can be run.

***nonlocator*** – Terminology to describe the passage entry of seal assemblies into a packer seal bore not locking into place.

***normal circulation*** – Smooth, uninterrupted circulation of fluid down the drill stem, out the bit, up the annular space between pipe and the hole, and back to the surface. See ***mud circulation*** and ***reverse circulation***.

***normal pressure*** – Formation pressure equal to the pressure exerted by a vertical column of water with salinity normal for the geographic area.

***normal solution*** – A solution of such a concentration that it contains 1 gram-equivalent of a substance per liter of solution.

***nozzle*** – Passageway through jet bits that allows drilling fluid to reach the bottom of the hole and flush cuttings through the annulus. Nozzles come in different sizes that can be interchanged on the bit to allow more or less flow.

# O

***o-ring*** – A circular seal common in the oil field; requires deformation (squeeze) to energize and seal.

***OCS*** – Abbreviation for Outer Continental Shelf of United States (offshore operating areas).

***offset well*** – A well drilled on a tract of land next to another owner's tract on which there is a producing well.

***offset-well data*** – Information obtained from wells that are drilled in an area close to the point of a well being drilled or worked over. Such information can be very helpful in determining how a particular well will behave or react to certain treatments or techniques applied to it.

***offshore drilling*** – Drilling for oil in an ocean or large lake. A drilling unit for offshore operations may be a mobile floating vessel with a ship or barge hull, a semi-submersible or submersible base, a self-propelled or towed structure with jacking legs (jackup drilling rig), or a permanent structure used as a production platform after drilling. In general, wildcat wells are drilled from mobile floating vessels (as semi-submersible rigs and drill ships) or from jack-ups, while development wells are drilled from platforms. See ***drill ship, jackup drilling rig, platform, semi-submersible drilling rig*** and ***wildcat***.

***offshore*** – Situated off the shore or within a zone generally considered to extend to three miles from low water line (as offshore oil reserves).

***oil and gas separator*** – Item of production equipment used to separate liquid components of the well stream from the gaseous elements. Separators are vertical and horizontal and are a cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid level control regulates the level of oil in the bottom of the separator.

***oil-based mud*** – A special type drilling fluid where oil is the continuous phase and water the dispersed phase. Oil-based mud contains blown asphalt and usually 1 to 5 percent water emulsified into the system with caustic soda or quick lime and an organic acid. Silicate, salt, and phosphate may also be present. Oil-based muds are differentiated from invert-emulsion muds (both water-in-oil emulsions) by the amounts of water used, method of controlling viscosity and thixotropic properties, wall-building materials, and fluid loss.

***oil content*** – Oil content of any drilling fluid is amount of oil in volume-percent.

***oil emulsion water (milk emulsion)*** – A drilling fluid in which the oil content is usually kept between 3 to 7 percent and seldom over 10 percent (it can be considerably higher). The oil is emulsified into fresh or salt water with a chemical emulsifier. Sometimes CMC, starch, or gum may be added to the fresh- and saltwater systems.

***oil-in-water emulsion mud*** – Commonly called “emulsion mud.” Any conventional or special water-base mud to which oil has been added. The oil becomes the dispersed phase and may be emulsified into the mud either mechanically or chemically.

***oil zone*** – A formation or horizon of a well from which oil may be produced. The oil zone is usually immediately under the gas zone and on top of the water zone if all three fluids are present and segregated.

***oilfield*** – 1. The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area, but may include the reservoir, the wells, and production equipment as well. 2. Referring to work in the drilling, completion, workover and well service industry.

***on-off tool*** – A tool used to open or close a downhole valve; or used to set or release a downhole tool, e.g. a retrievable bridge plug.

***on-the-horn*** – Someone talking two-way radio to another remotely.

***on-the-pump*** – Of a well, being pumped.

***one-trip*** – A tool that goes downhole and is not retrievable.

***open*** – 1. Of a wellbore, having no casing. 2. Of a hole having no drill pipe or tubing suspended in it.

***open hole*** – 1. Wellbore in which casing has not been set. 2. Open/cased hole in which no drill pipe/tubing is suspended. 3. Work done in uncased, uncemented wellbores.

***open-hole completion*** – Method of preparing a well for production in which no production casing or liner is set opposite producing formation. Reservoir fluids flow unrestricted into open wellbore. An open-hole completion has limited used in special situations. Also called a barefoot completion.

***opening/closing plug*** – Rubber plug used in primary cementing operations to displace cement slurry from the casing into the borehole annulus.

***opening ratio*** – The ratio between the pressure required to open the preventer and the well pressure under the rams.

***operator*** – The person or company, either proprietor or lessee, actually operating an oil well or lease.

***orifice*** – A device with an opening in it whose diameter is smaller than that of the pipe or fitting into which it is place to partially restrict the flow through the pipe. The difference in pressure on the two sides of an orifice plate, as determined by an orifice meter, can be used to measure the volume of flow through the pipe.

***out running*** – 1. Describes a condition where fluid is free-falling down well at a faster rate than capable by pumps. 2. In wireline, trying to pull out of well faster than the wireline tools are being blown upwards by unexpected pressure. 3. Trying to pump out a gas influx before the expansion of gas reduces pressure allowing the well to kick.

***outrigger*** – Projecting member run out from sides of portable mast that provides stability to minimize possibility of the mast’s overturning. See ***mast***.

***overbalance*** – The amount by which pressure exerted by the hydrostatic head of fluid in the wellbore exceeds formation pressure.

***overburden*** – 1. The pressure of the earth’s crust on a formation. For practical purposes, it usually can be considered to be one psi per foot of depth. 2. The strata of rock that lie above the stratum of interest in drilling.

***overpull*** – Pull on pipe beyond its weight in either air or fluid.

***overshot*** – 1. A fishing tool or device that is attached to tubing or drill pipe and lowered over the outside wall of a fish, pipe, or sucker rods lost or stuck in the wellbore. A friction device in the overshot, usually either a basket or a spiral grapple, firmly grips the fish, allowing it to be pulled from the hole. 2. An outside catch tool which goes over a tubular fish and catches it on the outside surface with a slip.

# P

***P & A*** – plug and abandon; a well.

***P*** – Delta-P: difference in pressure, referred to as between casing annulus and tubing.

***$P_1$*** – The phenolphthalein alkalinity of the filtrate, reported as the number of milliliters of 0.02 Normal (N/50) acid required per milliliter of filtrate to reach the phenolphthalein end point.

***pack off or stripper preventer*** – Preventers having a unit of packing material whose closure depends upon well pressure coming from below. They are used primarily to strip pipe through the hole or allow pipe to be moved with pressure on the annulus.

***pack-off*** – A device used to pack off tubing leaks, set on slickline.

***packer*** – A piece of downhole equipment consisting of a sealing device, a holding or setting device, and an inside passage for fluids; blocks flow of fluids through annular space between tubing and wall of wellbore by sealing off space between them. Usually made up in tubing string some distance above producing zone. A sealing element expands to prevent fluid flow except through inside bore of packet and into tubing. Packers are classified according to configuration, use, method of setting and whether they are retrievable (can be removed when necessary or must be milled/drilled out and destroyed).

***packer fluid*** – Fluid placed in annulus between tubing and casing above a packer. A liquid, usually inhibited fresh water or oil, used in a well when a packer is employed between the tubing and casing. This fluid is heavy enough to shut off the pressure of the formation being produced, does not stiffen or settle out of suspended solids over long periods of time, and is noncorrosive.

***packer squeeze method*** – A squeeze cementing method in which a packer is set to form a seal between the working string (the pipe down which cement is pumped) and the casing. Another packer or a cement plug is set below the point to be squeeze-cemented. By setting packers, the squeeze point is isolated from the rest of the well. See ***packer*** and ***squeeze cementing***.

***packer test*** – A fluid-pressure test of the casing. Also called a cup test.

***packer-bore receptacle*** – A retrievable PBR anchored into the top of a production packer to land a tubing seal assembly.

***packer-type elements*** – Elastomers requiring deformation to seal.

***packing element*** – The elastomeric section of a packer.

***packing gland*** – The metal part that compresses and holds packing in place in a stuffing box. See ***stuffing box***.

***packoff or stripper*** – A device with a elastomer packing element that depends on pressure below the packing to effect a seal in the annulus. Used primarily to run or pull pipe under low or moderate pressures. This device is not dependable for service under high differential pressures.

***paraffin*** – A hydrocarbon having the formula $CnH_2n+2$ (e.g., methane, $CH_4$; ethane, $C_2H_6$; etc.). Heavier paraffin hydrocarbons (i.e., those of $C_{18}H_{38}$ and heavier) form a waxlike substance that is called paraffin. These heavier paraffins often accumulate on the walls of tubing and other production equipment, restricting or stopping the flow of desirable lighter paraffins.

***particle*** – A minute unit of matter, usually a single crystal, or of regular shape with a specific gravity approximating that of a single crystal.

***pay sand, payzone, pay formation*** – Commercially producing formation, often not even sandstone. Also called pay, pay zone, producing zone.

***PBR*** – Polished bore receptacle, a section in the casing string to facilitate landing of the production tubing (casing).

***PDC log*** – Abbreviation for perforating depth control log.

***penetration, rate of*** – Feet per hour at which drill deepens wellbore.

***pentane*** – Any of three isometric hydrocarbons $C_5H_{12}$ of the methane series occurring in petroleum.

***peptization*** – An increased dispersion due to the addition of electrolytes or other chemical substances. See ***deflocculation*** and ***dispersion***.

***peptized clay*** – Clay to which an agent has been added to increase initial yield; e.g., soda ash is frequently added to calcium montmorillonite clay.

***percent*** – For weight-percent, see ***ppm***. Volume-percent is the number of volumetric parts of any liquid or solid constituent per 100 like columetric parts of the whole. Volume-percent is the most common method of reporting solids, oil, and water in drilling fluids.

***perforate*** – To pierce the casing wall and cement to provide holes through which formation fluids may enter or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface. See ***perforating gun***.

***perforated liner*** – Liner with holes shot by perforating gun. See ***liner***.

***perforated spacer tube*** – A ported, extended production tube used as an alternative path for wireline measuring devices.

***perforating depth control log*** – A special type of radioactivity log that measures the depth of each casing collar. By knowing the depth of the collars, it is easy to determine the exact depth of the formation to be perforated by correlating casing collar depth with formation depth.

***perforating gun*** – An explosive device fitted with shaped charges or bullets that is lowered to the desired depth on a well and fired to create penetrating holes in casing, cementing, and formation. See gun-perforate.

***perforation*** – A hole made in the casing, cement, and formation through which formation fluids enter a wellbore. Usually several perforations are made at a time.

***perfs*** – Perforations in casing for inflow of hydrocarbons and gas.

***permeability*** – 1. Measure of ease or ability of a rock to transmit a one-phase fluid under conditions of laminar flow. The unit of permeability is the darcy. 2. The fluid conductivity of a porous medium. 3. The ability of a fluid to flow within the interconnected pore network of a porous medium. See absolute permeability, effective permeability, and relative permeability.

***pH*** – An abbreviation for potential hydrogen ion. The pH numbers range from 0 to 14.7 being neutral, and are indices of the acidity (below 7) or alkalinity (above 7) of the fluid. The numbers are a function of the hydrogen ion concentration in gram ionic weights per liter which, in turn, is a function of the dissociation of water as follows:

(H)(OH) Divided by ($H_2O$) = $KH_2O$ = 1 × 10-u

pH may be expressed as logarithm (base 10) of reciprocal (or negative logarithm) of hydrogen ion concentration. pH of a solution offers valuable information as to immediate acidity or alkalinity, as contrasted to total acidity or alkalinity (which may be titrated).

***phosphate*** – Certain complex phosphates, usually sodium tetraphosphate ($Na_6P_4O_{13}$) and sodium acid pyrophosphate (SaPP, $Na_2H_2P_2O_7$), are used either as mud thinners or for treatment of various forms of calcium/magnesium contamination.

***pig*** – A plug run down the work string/tubing to test connections for leaks.

***piggyback*** – Terminology to indicate the running of two downhole tools together, one on top of the other, such as a squeeze tool and bridge plug.

***pill*** – A gelled viscous fluid.

***pilot*** – Pressure monitor used to sense flowline pressure changes.

***pilot mill*** – A special mill that has a heavy, tubular extension below it called a pilot or stinger. The pilot, smaller in diameter than the mill, is designed to go inside drill pipe or tubing that is lost in the hole. It guides the mill to the top of the pipe and centers it over the pipe, thus preventing the mill from bypassing the pipe.

***pilot testing*** – A method of predicting behavior of mud systems by mixing small quantities of mud and mud additives, then testing the results.

***pin*** – A threaded exterior member.

***pipe*** – A long, hollow cylinder, usually steel, through which fluids are transmitted. Oilfield tubular goods are casing (including liners) drill pipe, tubing or line pipe. Casing, tubing, and drill pipe are designated by external diameter couplings threaded by standard tools, an increase the interval diameter. Thus, the external diameter is the same for all linear densities of the same size pipe. Linear density is expressed in kilograms per meter (kg/m). Grading depends on the yield strength of the steel.

***pipe fittings*** – The auxiliary parts (as couplings, elbows, tees, crosses, etc.) used for connecting lengths of pipe.

***pipe hanger*** – 1. Circular device with frictional gripping arrangement used to suspend casing/tubing in well. 2. Device used to support a pipeline.

***pipe ram*** – A sealing component for a blowout preventer with an indention and packing for drill pipe, drill collars, or casing that closes the annular space between the pipe and the blowout preventer or wellhead. Separate rams are necessary for each size (outside diameter) pipe in use. See ***annular space and blowout preventer.***

***pipe ram preventer*** – A blowout preventer that uses pipe rams as the closing elements. See ***pipe ram***.

***pit*** – A temporary containment for wellbore fluids, usually excavated earth.

***pit level*** – Height of drilling mud in the mud pits.

***pit-level indicator*** – A device that continuously monitors level of drilling mud in mud pits. Indicator usually consists of float devices in mud pits that sense mud level and transmit data to a recording and alarm device (called pit-volume recorder) mounted near driller's position on rig floor. If mud level drops too low or rises too high, alarm sounds to warn driller that action may be necessary to prevent a blowout.

***pit-volume recorder*** – Driller position gauge recording pit-level indicator data.

***plastic flow*** – See ***plastic fluid***.

***plastic fluid*** – A complex, non-Newtonian fluid in which the shear force is not proportional to the shear rate. A definite pressure is required to start and maintain movement of the fluid. Plug flow is the initial type of flow and only occurs in plastic fluids. Most drilling muds are plastic fluids. The yield point as determined by direct-indicating viscometer is in excess of zero.

***plastic viscosity*** – An absolute flow property indicating flow resistance of certain types of fluids. Plastic viscosity is a measure of internal resistance to fluid flow attributable to amount, type, and size of solids present in a given fluid. It is expressed as number of dynes per sq cm of tangential shearing force in excess of Bingham yield value that will induce a unit rate of shear. This value, expressed in centipoises, is proportional to the slope of the consistency curve determined in the region of laminar flow for materials obeying Bingham's Law of Plastic flow. When using the direct-indicating viscometer, the plastic viscosity is found by subtracting the 300-rpm reading from the 600-rpm reading.

***plasticity*** – The property possessed by some solids, particularly clays and clay slurries, of changing shape or flowing under applied stress without developing shear planes or fractures. Such bodies have yield points, and stress must be applied before movement begins. Beyond the yield point, the rate of movement is proportional to the stress applied, but ceases when the stress is removed. See ***fluid***.

***plug & abandon*** – To place a cement plug in dry hole and abandon it. Also called ***P&A***.

***plug*** – Any object or device that blocks a hole or passageway (such as cement plug in a borehole). A barrier; a downhole device/tool, usually a pressure-containing device such as a bridge plug, seating plug, etc.

***plug back*** – To place cement in or near the bottom of a well to exclude bottom water, sidetrack, or produce from a formation already drilled through. Plugging back also can be accomplished by a mechanical plug set by wireline, tubing, or drill pipe.

***plug container*** – Surface container used to drop cementing plugs under pressure.

***plug flow*** – The movement of a material as a unit without shearing within the mass. Plug flow is the first type of flow exhibited by a plastic fluid after overcoming the initial force required to produce flow.

***plug pucker*** – A tool used to mill over permanent bridge plugs/cement retainers while retrieving the milled-out debris.

***plug valve*** – Valve whose operating mechanism consists of a plug with a hole through it on same axis as fluid line. Turning plug 90 degrees opens or closes valve.

***plug-back cementing*** – A secondary cementing operation in which a plug of cement is positioned at a specific point in the well and allowed to set.

***plug-back*** – To place cement in/near bottom of well to exclude bottom water, sidetrack, or produce from already drilled through. Plugging back also can be accomplished by a mechanical plug set by wireline, tubing, or drill pipe.

***plunger*** – Basic component of sucker rod pump. See ***sucker rod pump***.

***PM*** – The phenolphthalein alkalinity of the mud reported as the number of milliliters of 0.02 Normal (n/50) acid required per milliliter of mud.

***points*** – Way of indicating hookload/force, read off rig indicator; 1 point = 1,000 lb.

***pole mast*** – A portable mast constructed of tubular members. A pole mast may be a single pole, usually of two different sizes of pipe telescoped together to be moved or extended and locked to obtain maximum height above a well. Double-pole masts give added strength and stability. See ***mast***.

***polished rod*** – Topmost portion of a string of sucker rods, for lifting fluid by rod pumping method. It has a uniform diameter and is smoothly polished to effectively seal pressure in the stuffing box attached to top of well.

***polymer*** – A substance formed by the union of two or more molecules of the same kind linked end to end into another compound having the same elements in the same proportion but a higher molecular weight and different physical properties, e.g., paraformaldehyde. See ***copolymer***.

***pony rod*** – 1. A sucker rod less than 25 feet long. 2. The rod joined to the connecting rod and piston rod in a mud pump.

***poppet valve*** – Opening/closing mechanism whereby springs are used to keep a poppet on its seat; commonly found in retrievable bridge plugs.

***pore*** – An opening or space within a rock or mass of rocks, usually small and often filled with some fluid (as water, oil, gas, or all three). Compare ***vug***.

***pore pressure*** – Pressure exerted by fluids within formation pore space.

***porosity*** – Amount of void space in a formation rock, usually expressed as percent voids per bulk volume. Absolute porosity refers to the total amount of pore space in a rock, regardless of whether or not that space is accessible to fluid penetration. Effective porosity refers to the amount of connected pore spaces, i.e., the space available to fluid penetration. See ***permeability***.

***porous*** – Condition of something that contains pores (as a rock formation). See ***pore***.

***portable mast*** – A mast mounted on a truck and capable of being erected as a single unit. See ***telescoping derrick***.

***ported sub*** – Or nipple; a device used to circulated fluid through.

***portland cement*** – See ***cement***.

***positive choke*** – A choke in which the orifice size must be changed to change the rate of flow through the choke. See ***choke*** and ***orifice***.

***positive-displacement meter*** – A mechanical, fluid measuring device that measures by filling and emptying chambers of a specific volume, also known as a volume meter or volumeter. The displacement of a fixed volume of fluid may be accomplished by reciprocating or oscillating pistons, by rotating vanes or buckets, by notating disks, or by using tanks or other vessels that automatically fill and empty.

***potassium*** – One of the alkali metal elements with a valence of 1 and an atomic weight of about 39. Potassium compounds, most commonly potassium hydroxide (KOH) are sometimes added to drilling fluids to impart special properties, usually inhibition.

***potential*** – Maximum column of oil or gas a well is capable of producing.

***pound equivalent*** – A laboratory unit used in pilot testing. One gram or pound equivalent, when added to 350 ml. of fluid, is equivalent to 1 lb/bbl.

***pounds per gallon*** – Measure of the density of a fluid (as drilling mud). Abbreviation ***ppg***.

***pounds per square inch gauge*** – The pressure in a vessel or container as registered on a pressure gauge attached to the container. This pressure reading includes the pressure of the atmosphere outside the container. Abbreviation ***psi***.

***power rod tongs*** – tongs that are actuated by air or hydraulic fluid and are used for making up or breaking out sucker rods. See ***tongs***.

***power sub*** – a hydraulically powered device used to turn the drill pipe, tubing, or casing in a well in lieu of a rotary. See ***rotary***.

***power takeoff*** – A gearbox or other device serving to relay the power of a prime mover to auxiliary equipment.

***ppm*** – Abbreviation for ***parts per million.*** Unit weight of solute per million unit weighs of solution (solute plus solvent), corresponding to weight-percent except basis is a million instead of a hundred. The results of standard API titrations of chloride, hardness, etc. are correctly expressed in milligrams (mg) of unknown per liter but not in ppm. At low concentrations, mg/l is about numerically equal to ppm.

***precipitate*** – Material that separates out of solution or slurry as a solid. Precipitation of solids in drilling fluid may follow flocculation or coagulation, such as dispersed red-bed clays upon addition of a flocculation agent to fluid.

***preservative*** – Usually paraformaldehyde. Any material used to prevent starch or any other substance form fermenting through bacterial action.

***pressure control*** – Commonly referred to as snubbing; running of tool and/or pulling of tubing under well pressure.

***pressure drop loss*** – Pressure lost in a pipeline or annulus due to velocity of liquid in pipeline, properties of fluid, condition of pipe wall, and alignment of pipe. In certain mud-mixing systems, loss of head can be substantial.

***pressure drop*** – Loss of pressure because of friction as a fluid passes through a pipeline or vessel.

***pressure gauge*** – An instrument for measuring fluid pressure that usually registers difference between atmospheric pressure and pressure of fluid by indicating effect of such pressures on a measuring element (as a column of liquid, a Bourdon tube, a weighted piston, a diaphragm, or other pressure-sensitive device). See ***Bourdon tube***.

***pressure gradient*** – Change of pressure with depth, usually expressed as pounds per square inch per foot. A scale of pressure differences in which there is a uniform variation of pressure from point to point. For example, the pressure gradient of a column of water is about 0.433 psi/ft of vertical elevation (9.79 kPa/m). The normal pressure gradient in a well is equivalent to pressure exerted at any given depth by a column of 10 percent salt water extending from that depth to surface (i.e., 0.465 psi/ft or 10.51 kPa/m).

***pressure loss*** – 1. A reduction in the amount of force a fluid exerts against a surface, usually occurring because the fluid is moving against the surface. 2. The amount of pressure indicated by a drill-pipe pressure gauge when drilling fluid is being circulated by the mud pump. Pressure losses occur as the fluid is circulated.

***pressure probe*** – A diagnostic tool used to ascertain if there is a gas leak in the tubing of a gas-lift well. If there is a tubing leak, the pressure on the annulus will equal the pressure on the tubing.

***pressure relief valve*** – Valve that opens at a preset pressure to relieve excessive pressures within a vessel/line; also called relief, safety or pop valve.

***pressure surge*** – A sudden, usually short-duration increase in pressure. If pipe or casing is run into a hole too rapidly, an increase in the hydrostatic pressure results, which may be great enough to create lost circulation.

***pressure*** – The force per unit area that is exerted on a surface (as that exerted against the inner wall of a container or piping system by a fluid or that exerted on a wellhead by a column of gas in the well). In the United States, pressure is usually expressed in pounds per square inch (psi), and in other countries the most common unit is kilopascal (kPa).

***primary cementing*** – Cementing operation immediately after casing has been run into the hole; used to provide a protective sheath around the casing, to segregate the producing formation, and to prevent the migration of undesirable fluids. See secondary cementing and squeeze cementing.

***primary recovery*** – Oil production in which only existing natural energy sources in the reservoir provide for movement of well fluids to wellbore.

***primary well control*** – Prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than formation pressure.

***production*** – 1. Phase of petroleum industry that deals with bringing well fluids to the surface and separating them and with storing, gauging, and otherwise preparing the product for the pipeline. 2. The amount of oil or gas produced in a given period.

***production packer*** – Any packer designed to make a seal between the tubing and casing during production.

***production rig*** – Portable servicing or workover outfit, usually mounted on wheels, self-propelled. Well servicing unit consists of hoist and engine mounted on a wheeled chassis with self-erecting mast. Workover rig is the same, plus a substructure with rotary, pump, pits, and other auxiliaries to permit handling and working a drill string.

***production seal unit*** – Same as seal nipple assemblies.

***production tank*** – Tank used in the field to receive crude oil as it comes from well; also referred to as a flow tank or lease tank. See ***flow tank***.

***production test*** – A test of the well's producing potential usually done during the initial completion phase.

***production tubing*** – A string of tubing used to produce the well, providing well control and energy conservation.

***propane*** – Paraffin hydrocarbon, $C_3H_8$, a gas at ordinary atmospheric conditions but easily liquefied under pressure. A constituent of LPG. See ***liquefied petroleum gas***.

***proppant or propping agent*** – A granular substance (as sand grains, walnut shells, or other material) carried in suspension by the fracturing fluid that serves to keep the cracks open when the fracturing fluid is withdrawn after a fracture treatment.

***proration*** – A system enforced by a state or federal agency or by agreement between operators that limits the amount of petroleum that can be produced from a well or field within a given period.

***PSA*** – A generic term for pressure setting assembly; a tool which is used to set permanent tools on electric wireline, through explosive force.

***pseudoplastic fluid*** – A complex non-Newtonian fluid that does not possess thixotropy. A pressure or force in excess if zero will start fluid flow. The apparent viscosity or consistency decreases instantaneously with increasing rate of shear until at a given point the viscosity becomes constant. The yield point as determined by direct-indicating viscometer is positive, the same as in Bingham plastic fluids; however, the true yield point is zero. An example of a pseudoplastic fluid is guar gum in fresh or salt water.

***pull-down*** – Snubbing unit; used to apply additional force to the drill stem when it is necessary to put the drill stem into the hole when there is high pressure in the well.

***pulling tool*** – A hydraulically operated tool that is run in above the fishing tool and anchored to the casing buy slips. It exerts a strong upward pull on the fish by hydraulic power derived from fluid that is pumped down the fishing string.

***pulling unit*** – A well servicing outfit used in pulling rods and tubing from the well. See ***production rig***.

***pulling-the-trigger*** – Firing wireline-operated downhole tool in a service truck.

***pump*** – A device that increases pressure on a fluid or raises it to a higher level. Various types of pumps include reciprocating, centrifugal, rotary, jet, sucker rod, hydraulic, mud, submersible and bottomhole pump.

***pump liner*** – Cylindrical, accurately machined, metallic section that forms working barrel of certain reciprocating pumps. Provide an inexpensive means of replacing worn cylinder pumps, and in some pumps provide a method of conveniently changing displacement and capacity of pumps. Sectional liners, used in some oilwell pumps afford a ready means of assembling a well pump of any given stroke by adding sections end to end.

***pump manifold*** – An arrangement of valves and piping that permits a wide choice in the routing of suction and discharge fluids among two or more pumps.

***pump-out plug*** – A device to provide running the tubing dry with a packer released by elevating tubing pressure, thereby opening the tubing to formation pressure.

***pumpdown*** – A well servicing activity "through the flowline" designed to access the well under pressure for various jobs, by pumping the slickline down the hole.

***pumper*** – The oil company employee who attends to producing wells. He supervises any number of wells, ensuring steady production, preparing reports, testing, gauging, and so forth. Also called a switcher or lease operator.

***pumping tee*** – A heavy-duty steel, T-shaped pipe fitting that is screwed or flanged to the top of a pumping well. The polished rod works through stuffing box on top of the tee and in the run of the tee to operate a sucker rod pump in the well. Pumped fluid is discharged through the side opening of the tee. See ***polished rod*** and ***stuffing box***.

***pup*** – A short section of tubing or drill pipe used for properly spacing out.

# Q

***quebracho*** – A drilling-fluid additive used to extensively for thinning or dispersing to control viscosity and thixotropy. It is a crystalline extract of the quebracho tree consisting essentially of tannic acid.

***quicklime*** – Calcium oxide, CaO. Used in oilbase muds to neutralize organic acid.

***quiescence*** – The state of being quiet or at rest (being still). Static.

# R

***rabbit*** – Same as a pig.

***rack pipe*** – 1. To place pipe withdrawn from the hole on a pipe rack. 2. To standpipe on the derrick floor when coming out of the hole.

***racking platform*** – A small platform with fingerlike steel projections attached to side of mast on a well servicing unit. When sucker rods or tubing is pulled from a well, the top end of the rods or tubing is placed (racked) between the steel projections and held in a vertical position in the mast.

***radical*** – Two or more atoms behaving as a single chemical unit, i.e., as an atom; e.g., sulfate, phosphate, nitrate.

***radioactivity well logging*** – Recording of the natural or induced radioactive characteristics of subsurface formations. A radioactivity log, also known as a radiation log, normally consists of two recorded curves: a gamma ray curve and a neutron curve. Both indicate the types of rocks in the formation and the types of fluids contained in the rocks. The two logs may be run simultaneously in conjunction with a collar locator in a cased or uncased hole.

***ram blowout preventer*** – Blowout preventer that uses rams to seal off pressure on a hole with or without pipe. Also called ram preventer. See ***blowout preventer*** and ***ram***.

***ram preventer*** – Also called a ***ram blowout preventer***, which see.

***ram*** – Closing and sealing component on a blowout preventer. One of three types – blind, pipe, or shear – may be installed in several preventers mounted in a stack on top of wellbore. Blind rams, when closed, form a seal on a hole that has no drill pipe in it; shear rams cut through drill pipe and then form a seal. See ***blind ram, pipe ram*** and ***shear ram***.

***range of load*** – In sucker rod pumping, the amount of weight the sucker rod string is capable of lifting.

***ratchet*** – Generic term used to describe tool movements, such as the cone-to-slip engagement on permanent packers/plugs.

***rate of shear*** – Rate at which an action, resulting from applied forces, causes or tends to cause two adjacent parts of a body to slide relatively to each other in a direction parallel to their plane of contact. Given in rpm.

***rathole*** – 1. Hole in rig floor 30-35 feet deep, lined with casing that projects above the floor, into which the kelly and swivel are placed during hoisting operations. 2. A hole of a diameter smaller than the main hole that is drilled in the bottom of the main hole. To reduce the size of the wellbore and drill ahead. Extra deepening operation below the casing shoe in the wellbore.

***ream*** – To enlarge wellbore by drilling it again with a special bit. Often a rathole is reamed or opened to same size as main wellbore. See ***rathole***.

***reamer*** – Tool used in drilling to smooth a well wall, enlarge the hole to the specified size, stabilize the bit, straighten the wellbore if kinks or doglegs are encountered, and drill directionally. See ***ream***.

***reciprocating pump*** – A pump consisting of a piston that moves back and forth or up and down in a cylinder. Cylinder is equipped with inlet (suction) and outlet (discharge) valves. On intake stroke, suction valves open, and fluid is drawn into cylinder. On discharge stroke, suction valves close, discharge valves open, fluid is forced out of cylinder.

***recorder carrier*** – A sub in a DST string where pressure/temperature recorders are placed for formation evaluation.

***recovery factor*** – A percentage of oil or gas in place in a reservoir that ultimately can be withdrawn by primary and/or secondary techniques; the percentage of the oil or gas in place (expressed in stock tank barrels or in thousands of cubic feet) that will ultimately be recovered.

***red lime mud*** – A red mud which has been converted to a lime-treated mud. The pH is usually 12.0 to 13.0.

***red mud*** – Clay, water-base drilling fluid with sufficient amounts of caustic soda tannate to give a red appearance. Normally a high pH mud.

***reeled tubing*** – Lighter-duty well maintenance than hydraulic workover, using small OD tubing capable of descending down production string under well pressure.

***reeve*** – To pass (as end of rope) through a hole or opening in a block or similar device.

***refracturing*** – Fracturing a formation again. See ***formation fracturing***.

***regulator*** – A device that reduces pressure or volume of a fluid flowing in a line and maintains pressure or volume at a specified rate.

***relative permeability*** – A measure of ability of two or more fluids (as water, gas, and oil) to flow through a rock formation when formation is totally filled with several fluids. Permeability measure of a rock filled with two or more fluids is different from permeability measure of same rock filled with a single fluid. Compare ***absolute permeability***.

***relief well*** – Drilled to combat blowout; channels mud to blowing well.

***remote choke panel*** – A set of controls, usually placed on the rig floor, that is manipulated to control the amount of drilling fluid being circulated out through the choke manifold. This procedure is necessary when a kick is being circulated out of a well.

***remote station*** – Auxiliary controls for operating blowout preventers.

***replacement*** – The process whereby a volume of fluid equal to the volume of steel in tubular and tools withdrawn from the wellbore is returned to the wellbore.

***reservoir pressure*** – Pressure in a reservoir under normal conditions.

***reservoir rock*** – Permeable rock containing oil/gas in quantity.

***resin*** – Semisolid or solid complex, amorphous mixture of organic compounds having no definite melting point nor tendency to crystallize. Resins may be a component of compounded materials that can be added to drilling fluids to impart special properties to the system, wall cake, etc.

***resistivity meter*** – Measures resistivity of drilling fluids and their cakes.

***resistivity*** – The electrical resistance offered to the passage of a current, expressed in ohm-meters; the reciprocal of conductivity. Fresh water muds are usually characterized by high resistivity, salt water muds by a low resistivity.

***retainer*** – A drillable squeeze packer with positive flow control.

***retarder*** – A chemical compound (as gypsum, lime sodium tannate, etc.) that is used to prolong the thickening, setting, or hardening time of oilwell cements, the opposite of an accelerator. See ***cementing materials***.

***reverse circulate*** – The method by which the normal flow of a drilling fluid is reversed by circulation down the annulus and up and out the work string (drill pipe or tubing). This is frequently used in workover in cased holes.

***reverse circulation*** – The return of drilling fluid through drill stem. The normal course of drilling fluid circulation is downward through drill stem and upward through annular space surrounding drill stem. For special problems, normal circulation is sometimes reversed, and fluid returns to the surface through the drill stem, or tubing, after being pumped down the annulus.

***reversing hand*** – A well servicing hand who cleans out wellbores.

***reversing out*** – To displace the wellbore fluid back to the surface; to displace tubing volume back to the pit.

***Reynolds number*** – A dimensionless number, Re, that occurs in the theory of fluid dynamics. The diameter, velocity, density and viscosity (consistent units) for fluid flowing through a cylindrical conductor are related as follows:

Re = diameter × velocity × density × viscosity, or Re = DV p/u

The number is important in fluid hydraulics calculations for determining the type of fluid flow, i.e., whether laminar or turbulent. The transitional range occurs approximately from 2,000 to 3,000; below 2,000 the flow is laminar, above 3,000 the flow is turbulent.

***rheology*** – The science that deals with deformation and flow of water.

***rig manager*** – Tool pusher.

***rig*** – Derrick, draw works, surface equipment of a drilling or workover unit.

***rig up*** – To prepare the rig for making hole; install tools/machinery.

***ring-joint flange*** – A flanged connection in which a metal ring (resting in a groove in the flange) serves as a pressure seal between the two flanges.

***riser*** – Pipe through which liquid travels upward; riser pipe, which see.

***riser pipe*** – Pipe and special fittings used on floating offshore rigs to establish a seal between the top of the wellbore, on the ocean floor, and drilling equipment, above the surface of the water. A riser pipe is a guide for the drill stem from the drilling vessel to the wellhead and a conductor of drilling fluid from the well to the vessel. The riser consists of several sections of pipe and includes special devices to compensate for movement of the drilling rig caused by waves. It is also called a marine riser.

***rockwell hardness*** – A measure of a ferrous material's strength when converted to yield or ultimate tensile strength in PSI.

***rod blowout preventer*** – A ram device used to close the annular space around the polished rod or sucker rod in a pumping well.

***rod elevators*** – A device used to pull sucker rods. It has a bail attached to the rod hook to pull or run sucker rods. See ***rod hook*** or ***sucker rod***.

***rod hanger*** – Used to hang sucker rods on mast or in derrick.

***rod hook*** – A small, swivel hook having a fast operating, automatic latch to close the hook opening when weight is suspended from the hook.

***rod pump*** – See ***sucker rod pump***.

***rod string*** – sucker rod string; the entire length of sucker rods, which usually consists of several single rods, screwed together. The rod string serves as a mechanical link from the beam pumping unit on the surface to the sucker-rod pump near the bottom of the well.

***rod stripper*** – A device used when rods are coated with heavy oil or when the well may flow through the tubing while the rods are being pulled. It is form of blowout preventer. See ***blowout preventer***.

***rod sub*** – Short length of sucker rod attached to top of sucker rod pump.

***rod-transfer elevator*** – Special type of elevator designed to accommodate the end of a sucker rod; it allows the derrickman to transfer the rod to the racking platform from the regular elevator being used to lift the rod out of the well. See ***racking platform***.

***rod-transfer equipment*** – Enables a workover crew to pull sucker rods from a well and hang them on workover rig's mast so that the rods never touch the ground. Two elevators are used: one elevator suspends the rod string in the well; meanwhile, the other elevator is lowered for the next pull.

***roller-cone bit*** – Bit made of two, three or four cones, cutters, mounted on rugged bearings. Also called rock bits. The surface of each cone is made up of rows of steel teeth or rows of tungsten carbide inserts. See ***bit***.

***rope socket*** – A device to connect the wireline to the tool string.

***rotary drilling*** – A drilling method in which a hole is drilled by a rotating bit to which downward force is applied. The bit is fastened to and rotated by the drill stem, which provides a passageway through which drilling fluid is circulated. Additional joints of drill pipe are added as drilling progresses.

***rotary hose*** – A reinforced, flexible tube on a rotary drilling rig that conducts drilling fluid from mud pump and standpipe to swivel and kelly; also called mud hose or kelly hose. See ***kelly, mud pump, standpipe*** and ***swivel***.

***rotary shoe*** – The cutting shoe fitted to lower end of washover pipe and "dressed" with hard-surfaced teeth or tungsten carbide.

***rotary table*** – The principal component of a rotary, or rotary machine, used to turn the drill stem and support the drilling assembly. It has a beveled gear arrangement to create the rotational motion and an opening into which bushings are fitted to drive and support the drilling assembly.

***rotary*** – The machine used to impart rotational power to the drill stem while permitting vertical movement of the pipe for rotary drilling. Modern rotary machines have a special component, the rotary bushing, to turn the kelly bushing, which permits vertical movement of the Kelly while the stem is turning. See ***rotary drilling, master bushing*** and ***kelly bushing***.

***rotating head*** – A sealing device used to close off the annular space around the Kelly when drilling with pressure at the surface, usually installed above the main blowout preventers. Their use prevents a fog of dust or fluids from forming around the rotary. A rotating head makes it possible to drill ahead even when there is pressure in the annulus that the weight of the drilling fluid is not overcoming; the head prevents the well from blowing out. It is used mainly in the drilling of formations that have low-pressure, high-volume fluids. The rate of penetration through such formations is usually rapid.

***roughneck*** – A worker on a drilling or workover rig, subordinate to the driller; sometimes called a rotary helper, floorman, or rig crewman.

***round trip*** – The action of pulling out and subsequently running back into the hole a string of drill pipe or tubing. It is also called tripping the pipe.

***roustabout*** – A worker who assists foreman in general work around producing oil wells, usually on the property of oil company. A roustabout may also be a helper on a well-servicing unit or one who does utility work on an offshore drilling rig.

***royalty*** – The part of oil, gas, and minerals or their cash value paid by the lessee to the lesser or to one who has acquired possession of the royalty rights, based on a certain percentage of the gross production from the property.

***RRC*** – Abbreviation for Railroad Commission, an oil and gas regulatory body in Texas.

***RTTS*** – A trademark name for a retrievable squeeze tool.

***running tool*** –Retrievable component of a downhole tool used in running (sometimes retrieving) operation, such as a retrievable bridge plug.

# S

***sack*** – A container for cement, bentonite, ilmenite, barite, caustic, and so forth. Sack (bags) contain the following amounts: cement, 94 lb. (1 cu. ft.), bentonite, 100 lb., ilmenite, 100 lb., barite, 100 lb.

***safety clamp*** – Used to suspend a rod string after pump has been spaced or when weight of rod string must be taken off the pumping equipment.

***safety factor*** – In the context of this publication, an incremental increase in drilling fluid density beyond the drilling fluid density indicated by calculations to be needed to contain a kicking formation.

***safety joint*** – 1. A threaded connection or sub in a tubing string which has coarse threads or other special features which will cause it to unscrew before other connections in the string. 2. An accessory to the fishing tool that is placed above it. If the tool cannot be disengaged from the fish, the safety joint permits easy disengagement of the string of pipe above the safety joint. Thus, part of the safety joint as well as the tool attached to the fish remain in the hole and become part of the fish.

***safety release*** – An emergency mechanism component enabling the retrievable of a packer (or tubing) if stuck.

***safety valve*** – Valve quickly attached to pipe in hole to stop well flow.

***salt*** – In mud terminology, the term salt is applied to sodium chloride, NaCl. Chemically, the term salt is also applied to any of a class of similar compounds formed when the acid hydrogen of an acid is partly or wholly replaced by a metal or a metallic radical. Salts are formed by the action of acids on metals, or oxides and hydroxides, directly with ammonia, and in other ways.

***salt water flow*** – An influx of formation salt water into the wellbore.

***salt water muds*** – Drilling fluid containing dissolved salt (brackish to saturated). Fluids may also include native solids, oil and/or commercial additives such as clays, starch.

***sample mud*** – Drilling fluid possessing properties to bring up samples.

***sampler*** – A sub in a DST string to obtain a sample of the formation.

***samples*** – Cuttings obtained for geological information from drilling fluid as it emerges from the hole. They are washed, dried, labeled as to the depth.

***sand*** – Loose granular material resulting from disintegration of rocks, most often silica.

***sand content*** – In a drilling fluid, the insoluble abrasive solids content rejected by a 200-mesh screen. Usually expressed as the percentage bulk volume of sand in a drilling fluid. This test is elementary in that retained solids are not necessarily silica nor may not be altogether abrasive. For additional information concerning the kinds of solids retained on the 200-mesh screen, more specific tests would be required. See mesh.

***sand control*** – Same as ***gravel packing***.

***sand cutter*** – A device to salvage casing on a P&A job.

***sand line*** – A wireline or wire rope, capable of much higher pulling loads versus electrical conductor wireline. It is used on well-servicing rigs to operate a swab or bailer. It is usually 9/16-in. in diameter and several feet long.

***sand line drill*** – Run on cable-tool drilling-line, a service machine, or sandline of a rotary rig to drill up tools, removing downhole debris, etc.

***sand thickness map*** – Contour map of thickness of subsurface sands.

***sandstone*** – A detrital, sedimentary rock composed of individual grains of sand (commonly quartz) that are cemented together by silica, calcium carbonate, iron oxide, and so forth. Sandstone is a common rock in which petroleum and water accumulate.

***saturated solution*** – Solution containing at a given temperature as much of a solute as it can retain. At 68 F it takes 126.5 lb/bbl salt to saturate 1 bbl of fresh water. See ***supersaturated***.

***SBHT*** – Static bottomhole temperature.

***Schlumberger*** – One of the pioneer companies in electric well logging, named for the French scientist who first developed the method; pronounced "slumberjay." Today, many companies provide logging services of all kinds.

***scratcher*** – Casing hardware to condition the wellbore hole.

***screen analysis*** – determination of relative percentages of substances: suspended solids of a drilling fluid, passing through or retained on a sequence of screens of decreasing mesh size. Analysis may be wet or dry. Referred to also as "sieve analysis." See ***mesh***.

***screen liner*** – Pipe that is perforated, arranged with a wire wrapping to act as a sieve to prevent or minimize entry of sand particles into wellbore. Also called a screen pipe.

***SCSSV*** – Abbreviation for surface-controlled subsurface safety valve.

***seawater muds*** – Class of saltwater mud where seawater is used as fluid phase.

***seal bore extension*** – A tube extending the effective packer seal bore; used where excessive tubing expansion/contraction is anticipated.

***seal nipple assemblies*** – Sealing members at the production tubing extremely for landing inside the packer's seal bore.

***seal units*** – Extensions of the production string with seals to travel within a packer bore and/or extensions.

***sealing agents*** – Materials added to drilling fluids to restore circulation.

***secondary cementing*** – Any cementing operation after the primary cementing operation. Secondary cementing includes a plug-back job, in which a plug of cement is positioned at a specific point in the well and allowed to set. Wells are plugged to shut off bottom water or to reduce the depth of the well for other reasons. See ***primary cementing*** and ***squeeze cementing***.

***seconds API*** – A unit of viscosity as measured with a Marsh funnel according to API procedure. See ***API RP 13B*** and ***marsh funnel viscosity***.

***seismic data*** – Detailed information obtained from earth vibration produced naturally or artificially (as in geophysical prospecting).

***seismograph*** – Detects vibrations in the earth, used in prospecting for probable oil-bearing structures. Vibrations are created by discharging explosives in shallow boreholes or by striking the surface with a heavy blow. The type/velocity of the vibrations recorded by the seismograph indicate the general characteristics of the section of earth through which vibrations pass.

***selective shear*** – Ability to selectively determine when a tool will set, by the quantity of shear screws or pins.

***self potential*** – Also called spontaneous potential, which see.

***semi-expendable gun*** – A thru-tubing perforator gun; not retrievable.

***semi-submersible drilling rig*** – Floating, offshore drilling structure with hulls submerged in water but not resting on sea floor. Living quarters, storage space, and so forth are assembled on deck. Semi-submersible rigs are either self-propelled or towed to a drilling site or both. Semi-submersibles are more stable than drill ships and are used extensively to drill wildcat wells in rough waters such as North Sea. See ***dynamic positioning***.

***separation sleeve*** – A sleeve designed to shut off tubing-to-annulus flow, should the sliding sleeve become inoperative.

***separator*** – 1. Cylindrical or spherical vessel used to isolate components in mixed streams of fluids. See ***oil and gas separator***. 2. Surface storage tank to separate oil and gas.

***sequestration*** – The formation of stable calcium, magnesium, iron complex by treating water or mud with certain complex phosphates.

***set back*** – To place stands of drill pipe and collars in a vertical position to one side of rotary table in the derrick or mast of drilling or workover rig.

***set casing*** – Installation of pipe or casing in a wellbore. Usually requires mudding up, reconditioning or at least checking the drilling-fluid properties.

***set-down tool*** – A compression-set packer.

***setting tool*** – A tool used to set drillable/permanent tools, such as packers, retainers, plugs; can be either mechanical, electric or hydraulic.

***settling pit*** – The mud pit into which mud flows and in which heavy solids are allowed to settle out. Often auxiliary equipment (as desanders) must be installed to speed this process. Also called settling tank.

***shaker pit*** – Mud pit adjacent to shale shaker, usually the first pit into which the mud flows after returning from the hole. Also called a shaker tank.

***shale*** – A fine-grained sedimentary rock composed of consolidated silt and clay or mud. Shale is the most frequently occurring sedimentary rock.

***shale shaker*** – A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

***shape charge*** – An explosive charge used in perforating, exhibiting a jetting shape to penetrate the casing wall and formation.

***shaped charge*** – A relatively small container of high explosive that is loaded into a perforating gun. Upon detonation, the charge releases a small, high-velocity stream of particles (a jet) that penetrates the casing, cement, and formation. See ***gun-perforate***.

***shear (shearing stress)*** – An action or stress, resulting from applied forces, which causes or tends to cause two adjoining parts of a body to slide relatively to each other in a direction parallel to their plane of contact.

***shear ram preventer*** – A blowout preventer that uses shear rams as closing elements. See ***shear ram***.

***shear ram*** – Component in a blowout preventer that cuts, or shears, through pipe and forms a seal against well pressure. Shear rams in mobile offshore drilling operations provide a quick method of moving the rig away from the hole when there is no time to trip the drill stem out of the hole.

***shear strength*** – A measure of shear value of fluid. The minimum shearing stress that will produce permanent deformation. See ***gel strength***.

***shearometer*** – An instrument used to determine the shear strength, or gel strength, of a drilling fluid. See API RP 13B for specifications and procedure. See ***gel strength***.

***sheave*** – (pronounced “shiv”) a grooved pulley.

***sherometer*** – An instrument used to determine the shear strength, or gel strength, of a drilling fluid. See ***gel strength***.

***shoe*** – Typically the first downhole tool employed on the casing string to guide the casing past obstructions in the wellbore. See ***casing shoe***.

***shoot*** – 1. To explode nitroglycerine or other high explosives in a hole to shatter rock and increase flow of oil; now largely replaced by formation fracturing, which see. 2. In seismographic work, to discharge explosives to create vibrations in earth's crust.

***shooting*** – Firing of perforating guns.

***shortway*** – Displacing wellbore fluids from annulus up the tubing.

***shot*** – 1. A charge of high explosive, usually nitroglycerine, detonated in a well to shatter formation and expedite the recovery of oil. Shooting has been almost completely replaced by formation fracturing and acid treatments. See ***shoot*** and ***nitro shooting***. 1. A point at which a photograph is made in a single-shot survey. See ***directional survey***.

***show*** – Appearance of oil/gas in cuttings, samples, cores, etc., of mud.

***shut in*** – 1. To close the valves on a well so that it stops producing. 2. To close in a well in which a kick has occurred. 3. To cap off the well.

***shut-in bottomhole pressure*** – The pressure at the bottom of a well when the surface valves on the well are completely closed. The pressure is caused by fluids that exist in the formation at the bottom of the well.

***shut-in casing pressure*** – Pressure of annular fluid on casing if well is shut-in.

***shut-in drill pipe pressure*** – Pressure of drilling fluid on the inside of the drill stem; used to measure the difference between hydrostatic pressure and formation pressure when a well is shut in and the mud pump is off.

***SICP*** – Abbreviation for ***shut-in casing pressure***.

***side pocket*** – Offset heavy-wall sub in production string for gas lift valves, etc.

***sidetrack*** – To drill around broken drill pipe or casing that is lodged permanently in the hole, using a whipstock, turbodrill, or other mud motor. See ***directional drilling, turbodrill*** and ***whipstock***.

***sidewall coring*** – A coring technique in which core samples are obtained from a zone that has already been drilled. A hollow bullet is fired into a formation wall to capture core and then retrieved on a flexible steel cable. Core samples usually range from ¾ to 1$^{3}/_{16}$ inches in diameter and from ¾ to 1 inch in length. Useful in soft-rock areas.

***SIDPP*** – Abbreviation for ***shut-in drill pipe pressure***; used in drilling reports.

***silica gel*** – A porous substance consisting of $SiO_2$. Used as a dehydrating agent in air or gas drilling where small amount of water is encountered.

***silt*** – Materials that exhibit little/no swelling whose particle size falls between 2 microns and API sand size, or 74 microns (200-mesh). Some dispersed clays and barites also fall into this same particle-size range.

***single*** – 1. A joint of drill pipe. Compare ***double, thribble,*** and ***fourble***. 2. A term applied to single-zone completions.

***single-grip*** – A description of packers with one slip system for supporting weight and pressure from above only.

***single-pole rig*** – A well servicing unit whose mast consists of but one steel tube, usually about 65 feet long. See ***pole mast***.

***sinker bar*** – A heavy weight or bar placed on or near a wireline tool. It provides weight so that the tool can be lowered into the well properly.

***skid*** – Moving a rig between locations, usually on tracks with little dismantling.

***skin*** – 1. The area of the formation damaged from invasion of foreign substances into the exposed section of the formation adjacent to the wellbore during drilling and completion. 2. The pressure drop from the outer limits of drainage to the wellbore caused by the relatively thin veneer (or skin) of the formation. Skin is expressed in dimensionless units; a positive value denotes formation damage, and a negative value indicates improvement. 3. A measure of a well's resistance to open flow production, the higher the skin number the lower the production potential to open flow; Darcy Flow Equations.

***sky-top mast*** – A mast on a well servicing unit that uses a split traveling block and crown block, which makes it possible to pull 60-foot stands with a 50-foot mast.

***slacking off*** – Lowering of workstring/tubing onto a packer.

***sleeve valve*** – A valve in the bottom of a retainer.

***slickline*** – A non-electrical line.

***sliding sleeve nipple*** – A ported sub with an inside sleeve which is placed in a string to open or close openings. This permits circulation between the tubing and annulus or the open or shut off production from an alternate interval in a well.

***slip ring*** – A slip system in a ring configuration.

***slip segment*** – A singular component of an entire slip system.

***slip velocity*** – The difference between the annular velocity of the fluid and the rate at which a cutting is removed from the hole.

***slips*** – Wedge shaped pieces of metal with teeth or other gripping elements used to prevent pipe from slipping down into the well or to hold pipe in place. Rotary slips fit around the pipe and wedge against the master bushing to support the pipe. Power slips are pneumatically or hydraulically activated devices that allow the crew to dispense with the manual handling of slips when making a connection. Packers and other downhole equipment are secured in position by slips that engage the pipe by action directed at the surface.

***sloughing*** – The partial or complete collapse of the walls of a hole resulting incompetent, unconsolidated formations, high angle or repose, and wetting along internal bedding planes. See ***heaving*** and ***cave-in***.

***slug the pipe*** – A procedure before pulling drill pipe whereby a small quantity of heavy mud is pumped into the top section to cause an unbalanced column. As pipe is pulled, the heavier column in the drill pipe falls, keeping the inside of the drill pipe dry at surface when the connection is unscrewed.

***slurry*** – A plastic mixture of cement and water that is pumped into a well to harden; there it supports the casing and provides a seal in the wellbore to prevent migration of underground fluids.

***slush pit*** – Mud pit in which rotary drilling cuttings are separated from mud stream or where mud is treated with additives or temporarily stored before being pumped back into well. Modern rotary drilling rigs generally have three or more pits, usually fabricated steel tanks fitted with built-in piping, valves and mud agitators. See ***mud pit***.

***snub*** – To put pipe or tools into a high-pressure well that has not been killed (i.e., to run pipe or tools into the well against pressure). Snubbing usually requires an array of wireline blocks and wire rope that forces the pipe or tools into the well through a stripper head or blowout preventer until the weight of the string is sufficient to overcome the lifting effect of the well pressure on the pipe in the stripper. See ***stripper head***.

***snubber*** – 1. A device that hydraulically forces pipe or tools into the well against pressure. 2. A device within some hooks that act as a shock absorber in eliminating the bouncing action of pipe as it is picked up. See ***snub***.

***snubbing*** – See ***stripping***.

***soap*** – Sodium or potassium salt of a high-molecular-weight fatty acid. When containing some metal other than sodium or potassium, called “metallic” soaps. Soaps are commonly used in fluids to improve lubrication, emulsification, sample size, defoaming, etc.

***soda ash*** – See ***sodium carbonate***.

***sodium bicarbonate*** – $NaHCO_3$ – A material used extensively for treating cement contamination and occasionally other calcium contamination in drilling fluids. It is the half-neutralized sodium salt of carbonic acid.

***sodium bichromate*** – $Na_2Cr_2O_7$ – Also sodium dichromate. See ***chromate***.

***sodium carbonate*** – $Na_2CO_3$ – A material used extensively for treating out various types of calcium contamination. It is commonly called “soda ash.” When sodium carbonate is added to a fluid, it increases the pH of the fluid by hydrolysis. Sodium carbonate can be added to salt (NaCl) water to increase the density of the fluid phase.

***sodium carboxymethylcellulose*** – Commonly called CMC. Available in various viscosity grades and purity. An organic material used to control filtration, suspend weighing material, and build viscosity in drilling fluids. Used in conjunction with bentonite where low-solids muds are desired.

***sodium chloride – NaCl*** – Commonly known as salt. May present in mud as a contaminant or may be added for any several reasons. See ***salt***.

***sodium chromate – $Na_2CrO_4$*** – See ***chromate***.

***sodium hydroxide – NaOH*** – Commonly referred to as "caustic" or "caustic soda." A chemical used primarily to impart a high pH.

***sodium*** – One of alkali metal elements with a valence of 1 an atomic number of about 23. Numerous sodium compounds (which see) are used as additives to drilling fluids.

***sodium polyacrylate*** – A synthetic high-molecular-weight polymer of acrylonitrile used primarily as a fluid loss control agent.

***sodium silicate muds*** – Special class of inhibited chemical muds using as their bases sodium silicate, salt, water, and clay.

***soft shut-in*** – To shut in a well by closing a blowout preventer with the choke and choke line valve open, then closing the choke while monitoring the casing pressure gauge for maximum allowable casing pressure.

***sol*** – Term for colloidal dispersions, as distinguished from true solutions.

***solids concentration or content*** – Total amount of solids in a drilling fluid as determined by distillation includes both dissolved and suspended or undissolved solids. The suspended solids content may be a combination of high and low specific gravity solids and native or commercial solids. Examples of dissolved solids are the soluble salts of sodium, calcium, and magnesium. Suspended solids make up the wall cake; dissolved solids remain in the filtrate. The total suspended and dissolved solids contents are commonly expressed as percent by volume, and less commonly as percent by weight.

***solubility*** – Degree to which a substance dissolves in a particular solvent.

***solute*** – A substance which is dissolved in another (the solvent).

***solution*** – A mixture of two or more components that form a homogeneous single phase. Example solutions are solids dissolved in liquid, liquid in liquid, gas in liquid.

***solvent*** – Liquid used to dissolve a substance (the solute).

***sonde*** – A logging tool assembly, especially the device in the logging assembly that senses and transmits formation data.

***sonic logging*** – Record of time required for a sound wave to travel through a formation. Difference in observed travel times is largely caused by variations in porosities of medium, an important determination. Sonic log, which may run simultaneously with a spontaneous potential log or a gamma ray log, is useful for correlation, often in conjunction with other logging services for substantiation of porosities. Run in uncased hole.

***sour corrosion*** – Embrittlement and subsequent wearing away of metal, caused by contact of the metal with hydrogen sulfide or another sulfur compound. Also referred to as sulfide stress cracking (SSC).

***sour crude oil*** – Oil with hydrogen sulfide or other sulfur compound.

***sour gas*** – Natural gas containing hydrogen sulfide.

***sour hole*** – A wellbore or formation with known hydrogen sulfide gas.

***souring*** – A term commonly used to mean fermentation (which see).

***SP*** – Self-potential or spontaneous potential.

***space out*** – Procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea preventer rams on which drill pipe is to be suspended (hung-off) and so that no tool joint is opposite a set of preventer rams after drill pipe is hung-off.

***space-out joint*** – The joint of drill pipe which is used in hang off operations so that no tool joint is opposite a set of preventer rams.

***spacing clamp*** – A clamp used to hold the rod string in pumping position when the well is the final stages of being put back on the pump.

***spacing-out*** – Positioning the correct number of feet or joints of pipe from the packer to the surface tree, or from the rig floor to the stack.

***spear*** – A fishing tool used to retrieve lost pipe. Spear is lowered down the hole and into lost pipe. When weight, torque, or both are applied to string to which spear is attached, the spear slips expand and grip the inside of the wall of the lost pipe. Then the string, spear, and lost pipe are pulled to surface.

***specific gravity*** – Ratio of weight of a given volume of a substance at a given temperature to weight of an equal volume of a standard substance at same temperature. For example, if 1 cubic inch of water at 39 °F weighs 1 unit and 1 cubic inch of another solid/liquid at 39 °F weighs 0.95 unit, specific gravity of substance is 0.95. In determining specific gravity of gases, comparison is made with standard of air or hydrogen. See ***gravity***.

***specific heat*** – The number of calories required to raise 1 gram of a substance 1 degree Centigrade. The specific heat of a drilling fluid gives an indication of the fluid's ability to keep the bit cool for a given circulation rate.

***speed kit*** – Dual-speed traveling block, which permits one elevator to pick up stands as they are broken out while the traveling block continues to move.

***spider*** – A circular, steel device that holds slips supporting a suspended string of dill pipe, casing, or tubing. A spider may be split or solid.

***spinning chain*** – Y-shaped chain used to tighten one joint of drill pipe into another. One end of chain is attached to tongs, another to spinning cathead, third end is free. Free end is wrapped around tool joint, and cathead pulls chain off joint, causing joint to spin rapidly and tighten up. After chain is pulled off joint, tongs are secured in same spot. Continued pull on chain (and thus on tongs) by cathead makes up joint to final tightness.

***spontaneous potential*** – A natural electrical characteristic exhibited by a formation as measured by a logging tool lowered into wellbore. Also called self-potential, it is one of the basic curves obtained by an electrical well log; usually referred by initials SP.

***spool*** – To wind or reel onto a spool or wireline drum; also a flanged joint place between the blowout preventer and drilling valve, serving as a spacer.

***spot*** – To pump a designated quantity of a substance (as acid or cement) into a specific interval in well. For example, 10 barrels of diesel oil may be spotted around an area in hole in which drill collars are stuck against wall of hole in an effort to free the collars.

***spring collet*** – A spring-actuated metal band or ring (ferrule) used to expand a line patch when making casing repairs. See ***liner patch***.

***spud in*** – To begin drilling; to start the hole.

***spud mud*** – Fluid used when drilling starts at surface, often bentonite-lime slurry.

***spud*** – To move drill stem up and down in the hole over a short distance without rotation. Careless execution of this operation creates pressure surges that cause a formation breakdown, resulting in lost circulation. See ***spud-in***.

***spudder*** – 1. A driller; a drilling rig or ship. 2. A portable cable tool drilling rig, sometimes mounted on a truck or trailer.

***squeeze*** – 1. Cementing operation where slurries of cement, mud, gunk plug, are forced into formation or behind casing under high pressure to recement channeled areas or block off uncemented zone. 2. Stimulation where fracture pressure is not exceeded.

***squeeze cementing*** – Forcing cement slurry by pressure to specified points in a well to cause seals at points of squeeze. A secondary cementing method used to isolate a producing formation, seal off water, repair casing leaks, and so forth. See ***cementing***.

***squeeze job*** – A remedial well servicing activity whereby a cement slurry is pumped into open perfs, split casing, etc., to effect a blockage.

***squeeze manifold*** – A type of manifold used in squeeze jobs.

***squeeze packer*** – A drillable service packer; a retainer.

***squeeze tool*** – A generic term to describe a retrievable service packer.

***squeezing*** – Pumping fluid into one side of the drill pipe/annulus flow system with the other side closed as to allow no outflow.

***SSV*** – Abbreviation for surface safety valve.

***stab*** – To guide the end of a pipe into a coupling or tool joint when making up a connection. See ***coupling*** and ***tool joint***.

***stability meter*** – Measures the breakdown voltage of invert emulsions.

***stabilizer*** – A centralizer-type device used to keep tool components concentric during exit and reentry.

***stack*** – A vertical pile of blowout-prevention equipment. See ***blowout preventer***.

***stacking a rig*** – Storing a drilling rig upon completion of a job when the rig is to be withdrawn from operation for a period of time.

***stage tool*** – Sliding-sleeve ported casing section used in stage cementing.

***staging*** – The positioning of several fluid mediums into a wellbore.

***stand*** – Connected joints of pipe racked in the derrick or mast, which join the discharge line leading from mud pump to rotary hose and through which mud is pumped going into the hole. 1 stand = 2 joints on a pulling/workover unit; = 3 joints on a platform derrick. See ***mud pump*** and ***rotary hose***.

***standing valve*** – A fixed ball-and-seat (back pressure) valve at lower end of working barrel of a sucker rod pump. The standing valve and its cage do not move as does the traveling valve. See ***back pressure valve, traveling valve***.

***standpipe*** – Vertical pipe rising along side of derrick or mast, which joins the discharge line leading from mud pump to rotary hose and through which mud is pumped going into the hole. See ***mud pump*** and ***rotary hose***.

***stands*** – The connected joints of pipe racked in the derrick or mast when making a trip. On a rig, the usual stand in 90 feet long (three lengths of pipe screwed together) or a thribble. See ***thribble***. Compare ***double*** and ***fourble***.

***starch*** – A group of carbohydrates occurring in many plant cells. Starch is processed (pre-gelatinized) for use in muds to reduce filtration rate and occasionally to increase viscosity. Without proper protection, starch can ferment.

***static fluid level*** – The level to which fluid rises in a well when shut in.

***static*** – Opposite of dynamic. See ***quiescence***.

***stearate*** – Salt of stearic acid which is a saturated, 18-carbon fatty acid. Certain compounds, such as aluminum stearate, calcium stearate, zinc stearate, are used in drilling fluids for the following purposes: defoamer, lubrication, air drilling in which a small amount of water is encountered, etc.

***stimulation*** – 1. Artificially enhancing flow potential by chemical injection into producing reservoir. 2. Processes to enlarge old passages or create new ones in producing formation: acidizing, fracturing, explosive treatments.

***stimulation valve*** – Same as a surge valve.

***stinger*** – Any cylindrical or tubular projection, relatively small in diameter, that extends below a downhole tool and helps to guide the tool to a designated spot (as in the center of a portion of stuck pipe).

***stinging-in*** – Lowering pipe/tubing into the bore of a downhole tool.

***stock-tank oil*** – Oil as it exists at atmospheric conditions in a stock tank. Stock tank oil lacks much of the dissolved gas present at reservoir pressure and temperatures.

***storage gas*** – Gas that is stored in an underground reservoir.

***storm choke*** – A velocity-type valve, normally open that is closed by excess well flow over its pre-set rating.

***storm packers*** – A heavy-mandrel service squeeze tool with on-off tool used in drilling operations during storm interruptions,

***storm plug*** – A retrievable, temporarily suspends drilling during a storm.

***straddle packer*** – Packer with two packing elements to straddle a set of perfs.

***streaming flow*** – See ***laminar flow***.

***streaming potential*** – Electrokinetic portion of the SP (spontaneous potential) electric-log curve which can be significantly influenced by characteristics of filtrate and mud cake of drilling fluid used to drill the well.

***string*** – 1. The entire length of casing, tubing, or drill pipe run into a hole; the casing string. Compare ***drill string*** and ***drill stem***. 2. Any number of joints of casing/pipe/tubing; i.e., production tubing.

***string shot*** – Also called ***prima-cord.*** An explosive device that uses primacord, a textile-covered fuse with a core of very high explosive, to create and explosive jar inside stuck pipe or tubing to back off the pipe at the joint immediately above the stuck point. See ***shot***.

***string up*** – Thread drilling line through sheaves of crown block and traveling block. One end of line is secured to hoisting drum, the other to derrick substructure. See ***sheave***.

***stripper*** – 1. A well nearing depletion that produces a very small amount of oil or gas. 2. A stripper head. See ***stripper head***.

***stripper head*** – Blowout prevention device consisting of a gland and packing arrangement bolted to wellhead. Used to seal annular space between tubing and casing.

***stripper rubber*** – 1. A rubber disk surrounding drill pipe or tubing that removes mud as the pipe is brought out of hole. 2. The pressure sealing element of a stripper blowout preventer. See ***stripper head***.

***stripping*** – Adding or removing pipe when well is pressured without allowing vertical flow at top of well.

***stripping in*** – The process of lowering the drill stem into the wellbore when the well is shut in on a kick.

***stripping out*** – The process of raising the drill stem out of the wellbore when the well is shut in on a kick.

***stuck*** – A condition where drill pipe, casing, or other devices inadvertently become lodged in the hole. May occur during drilling, while casing is being run, or while drill pipe is being hoisted. Frequently a fishing job results.

***stuck pipe*** – Drill pipe, drill collars, casing, or tubing that has inadvertently become immobile in the hole. It may occur when drilling is in progress, when casing is being run in the hole, or when the drill pipe is being hoisted.

***stuck point*** – Depth in hole at which drill stem, tubing, or casing is stuck.

***stuffing box*** – A packing gland screwed in the wellhead top through which the polished rod operates on a pumping well. Prevents escape of oil, diverting it into a side outlet to which is connected the flow line leading to the oil and gas separator or the field storage tank.

***sub (or substitute)*** – 1. Short section of pipe, tube, or drill collar with threads on both ends, used to connect two items having different threads; an adapter. 2. Tubing component; downhole tool component; a connection. 3. Short threaded pieces used to adapt parts to the drilling string that cannot otherwise be screwed together because of difference in thread size or design.

***sub elevator*** – Small attachment on rod transfer equipment that picks up rods after they are unscrewed from string and transfers them to rod hanger, or reverses procedure going into the hole. See ***rod transfer equipment***.

***subsea blowout preventer*** – A blowout preventer placed on the sea floor for used by a floating offshore drilling rig.

***substructure*** – Foundations on which derrick or mast and (sometimes) engines sit, containing space for storage and well control equipment.

***sucker rod*** – A special steel rod; several rods screwed together make up the mechanical link from the beam pumping unit on the surface to the sucker rod pump at the bottom of a well. Sucker rods are threaded on each end and manufactured to exact dimension standards and metal specifications set by API. Lengths are 25 to 30 feet; diameter varies from ½ to 1⅛ inches. See ***beam pumping unit***.

***sucker rod pump*** – A downhole assembly used to lift fluid to surface by the reciprocating action of the sucker rod string. Basic components are the barrel, plunger, valves, and hold-down. Two types of sucker rod pumps are the tubing pump, in which the barrel is attached to the tubing, and the rod, or insert, pump, which is run into the well as a complete unit.

***sucker rod whip*** – Undesirable whipping motion in sucker rod string that occurs when string is not properly attached to sucker rod pump.

***suction pit*** – The mud pit from which mud is picked up by the suction of the mud pumps, also called a sump pit.

***suicide squeeze*** – Squeeze cement job with open perfs above the packer.

***sulfamic acid*** – A crystalline acid, $NH_2SO_3H$, which is a derivative of sulfuric acid and is sometimes used in acidizing. See ***acid treatment***.

***Supersaturation*** – If a solution contains a higher concentration of a solute in a solvent than would normally correspond to its solubility at a given temperature this is supersaturation. It is an unstable condition, as the excess solute separates when solution is seeded by introducing a crystal of the solute. "Supersaturation" is frequently used erroneously for hot salt muds.

***surface active materials*** – See ***surfactant***.

***surface casing*** – Also called ***surface pipe***. See ***surface pipe***.

***surface pipe*** – The first string of casing (after the conductor pipe) set in a well, varying from a few hundred to several thousand feet. Some states require a minimum length to protect freshwater sands. Compare ***conductor pipe***.

***surface tension*** – Force acting within interface between a liquid and its own vapor which tends to maintain area of surface at a minimum; expressed in dynes per centimeter. Surface tension of a liquid is approximately equal to interfacial tension between liquid and air; it is common to refer to values measured against air as surface tension and to use interfacial tension for measurements at an interface between liquids, or a liquid and solid.

***surfactant*** – A substance that affects the properties of the surface of a liquid or solid by concentrating on the surface layer. Surfactants reduce surface tension thereby causing fluid to penetrate and increase "wettability." Surfactants are useful in that their use can ensure that the surface of one substance or object is in thorough contact with the surface of another substance.

***surfactant mud*** – A drilling fluid which contains a surfactant. Usually refers to a drilling fluid containing surfactant material to effect control over degree of aggregation and dispersion or emulsification.

***surge loss*** – Flux of fluids and solids which occurs in initial stages of any filtration before pore openings are bridged and a filter cake is formed. Also called "spurt loss."

***surge valve*** – A device employed with a packer to surge, or clean, open perforations.

***surging*** – 1. A rapid increase in pressure downhole that occurs when drill stem is lowered too fast or when the mud pump is brought up to speed after starting. 2. A suction method of removing debris from open perforations.

***suspensoid*** – A mixture consisting of finely divided colloidal particles floating in a liquid. The particles are so small that they do not settle but are kept in motion by the moving molecules of the liquid (Brownian movement).

***swab*** – 1. A rubber suction cup run on slickline or pumpdown to bring the well in. 2. A hollow, rubber-faced cylinder mounted on a hollow mandrel with a pin joint on the upper end to connect to the swab line. A check valve that opens upward on the lower end provides a way to remove the fluid from the well when pressure is insufficient to support flow. Swabbing is a temporary operation to determine whether or not the well can be made to flow. If the well does not flow after being swabbed, a pump is installed as a permanent lifting device to bring the oil to the surface. See ***mandrel***.

***swabbing*** – 1. Lowering of hydrostatic pressure in wellbore due to upward movement of tubular and/or tools. 2. Operating a swab, on a wireline, to bring well fluids to surface when well does not flow naturally. This is temporary operation to determine whether or not the well can be made to flow or determine the amount of fluids entering the wellbore (swab test). In the event the well does not flow after being swabbed, it is necessary then to install a pump as a permanent lifting device to bring oil to surface.

***swage*** – Also called ***swage mandrel.*** A tool used to straighten damaged or collapsed pipe or casing in a well.

***sweet corrosion*** – The deterioration of metal caused by contact with carbon dioxide and acids.

***sweet crude oil*** – Oil containing little or no sulfur and especially little or no hydrogen sulfide.

***swelling*** – See ***hydration***.

***switcher*** – (obsolete) A lease operator or pumper. See ***pumper***.

***swivel*** – A rotary tool hung from the rotary hook and traveling block to suspend and permit free rotation of drill stem. Also provides a connection for the rotary hose and a passageway for the flow of drilling fluid into drill stem.

***sx*** – Sacks; used in drilling and mud reports.

***synergism, synergistic properties*** – Term describing effect obtained when two or more products are used simultaneously to obtain a certain result. Rather than the results of each product being additive to the other, the result is a multiple of the effects.

# T

***TA*** – Temporarily abandoned.

***tagging*** – Running pipe/tubing and landing on a downhole tool.

***tail out rods*** – Pull bottom end of sucker away from well when laying rods down.

***tail pipe*** – 1. A short pup used below a squeeze tool during remedial cementing. 2. A pipe run in a well below a packer.

***tailing-in*** – Guiding a downhole tool into well or up onto rig floor.

***tally*** – To measure and record length of pipe or tubing pulled from the well prior to racking or laying down.

***tank battery*** – Group of production tanks in the field to store crude oil.

***tannic acid*** – Tannic acid is the active ingredient of quebracho and other quebracho substitutes such as mangrove bark, chestnut extract, hemlock, etc.

***tap*** – 1. A tool for forming an internal screw thread consisting of a hardened tool steel male screw grooved longitudinally so as to have cutting edges. 2. A hole or opening in a line or vessel in which a gauge or valve may be inserted and screwed tight.

***taper tap*** – A tap, not grooved longitudinally, used as a fishing tool for a hollow fish (as a drill collar). A male, tapered, self-threading tool to screw into a fish internally for retrieval. The taper tap is run into the hollow fish and rotated to cut sufficient threads to provide a firm grip, permitting the fish to be pulled and recovered. See ***tap***.

***tapered string*** – A mixed-sized string of production tubing; mixed.

***target*** – A bull plug or blind flange at the end of a tee to prevent erosion at a point where change in flow direction occurs.

***targeted*** – Refers to a fluid piping system in which flow impinges upon a lead-filled end (target) or a piping tee when fluid transits a change in direction.

***TCP*** – Tubing conveyed perforator.

***TD*** – Total depth of the well; tool depth.

***telescoping derrick*** – A portable mast that is capable of being erected as a unit, usually by a tackle that hoists the wireline or by hydraulic pistons. Generally the upper section of a telescoping derrick is nested (telescoped) inside the lower section of the structure and raised to full height either by the wireline or hydraulically. See ***production rig, portable mast,*** and ***pole mast***.

***telescoping swivel sub*** – A sub with a telescoping joint used in dual, triple completions for running additional tailpipe.

***temperature survey*** – An operation to determine temperatures at various depths in the hole. This survey is used to find the location of inflows of water into the hole, where doubt exists as to proper cementing of the casing and for other reasons.

***temporarily abandoned*** – Temporarily shut in but not plugged.

***ten-round*** – Same as an eight-round except ten threads per inch.

***tension tool*** – A retrievable or drillable packer where sufficient pipe weight is not available to set the tool in compression.

***test pressure*** – An equipment's working pressure times a safety factor.

***tester*** – A person who tests pipe and casing for leaks.

***thermal decomposition*** – Chemical breakdown of a compound or substance by temperature into simple substances or constituent elements. Starch thermally decomposes in drilling fluids as temp. approaches 300°F.

***thinner*** – Any of various organic agents (tannins, lignins, lignsulfonates, etc.) and inorganic agents (pyrophosphates, tetraphosphates, etc.) that are added to a drilling fluid to reduce the viscosity and/or thixotropic properties.

***thixotropy*** – Property exhibited by a fluid that is in a liquid state when flowing and a semisolid, gelled state at rest. That property of a fluid which causes it to build up a rigid or semi-rigid gel structure if allowed to stand at rest, yet can be returned to a fluid state by mechanical agitation. This change is reversible. Most drilling fluids must be thixotropic so that cuttings in the fluid will remain in suspension when circulation is stopped.

***thread protector*** – A device that is screwed onto or into pipe threads to protect the threads from damage when the pipe is not in use. Protectors may be metal or plastic.

***thribble*** – A stand of pipe made up of three joints and handled as a unit. See ***stands***.

***thru-tubing*** – An operation; a string of tools; capability of working through the production tubing, eliminating workover in pulling the string.

***tie-down*** – A device to which a guy wire or brace may be attached; the anchoring device for the deadline of a hoisting block arrangement.

***tight formation*** – A petroleum- or water-bearing formation of relatively low porosity and permeability. See ***porosity*** and ***permeability***.

***tighten up emulsion*** or ***mud*** – Drilling-fluid jargon to describe condition in some systems to which oil has been added and oil breaks out and rises to surface. Any chemical or mechanical means which will emulsify the free oil known as "tightening up."

***titration*** – A method, or the process of using a standard solution for the determination of the amount of some substance on another solution. The known solution is usually added in a definite quantity to the unknown until a reaction is complete.

***tongs*** – Large wrenches used for turning when making up or breaking out drill pipe, casing, tubing, or other pipe; called casing tongs, rotary tongs, according to specific use. Power tongs are pneumatically or hydraulically operated tools that serve to spin pipe up tight, and, in some instances, to apply the final makeup torque. See ***chain tongs***.

***tool hand*** – The tool man; a packer hand; a service company hand.

***tool joint*** – Heavy coupling element for drill pipe made of special alloy steel. Tool joints have coarse, tapered threads and seating shoulders designed to sustain weight of drill stem, withstand strain of frequent coupling and uncoupling, and provide a leakproof seal. The male section of the joint, or pin, is attached to one end of a length of drill pipe, and female section, or box, is attached to other end. Tool joint may be welded to end of pipe or screwed on or both. A hard metal facing is often applied in a band around outside of tool joint to enable it to resist abrasion from walls of borehole.

***tool pusher*** – Rig manager, drilling foreman or rig superintendent. The tool pusher is normally the contractor's senior representative on the lease. See ***drilling foreman***.

***toolhouse*** – A building for storing tools.

***top drill*** – A drillable tool configuration allowing the opening of formation pressure, during drillout, prior to cutting through the tools slips.

***top sub*** – A component of a packer where the tubing is connected.

***topping-off*** – Filling a wellbore up to the surface.

***torque*** – Measure of force/effort applied to a shaft causing it to rotate. On a rotary rig applies especially to rotation of drill stem in its action against bore of hole. Torque reduction can usually be accomplished by addition of various drilling fluid additives.

***torque converter*** – A connecting device between a prime mover and the machine actuated by it. The elements that pump the fluid in the torque of the engine to which the torque is applied, with an increase of load on the output shaft. Torque converters are used extensively on mechanical rigs that have a compound. See ***mechanical rig***.

***total depth (TD)*** – Maximum or total length/depth reached in a well.

***total hardness*** – See ***hardness of water***.

***tour*** – (pronounced "tower") 8-hour shift worked by drilling crew/ oil field workers. Sometimes 12-hour tours are used, especially on offshore rigs. The most common 8-hour divisions are daylight, evening, and graveyard.

***transfer*** – Lower pipe/tubing onto downhole tool transferring al/part of hookload.

***traveling block*** – An arrangement of pulleys, or sheaves, through which drilling cable is reeved and that moves up and down in the derrick or mast. See ***block, crown block*** and ***sheave***.

***traveling valve*** – One of two valves in a sucker rod pumping system. Traveling valve moves with movement of sucker rod string. On upstroke, ball member of valve is seated, supporting fluid load. On downstroke, ball is unseated, allowing fluid to enter production column. Compare ***standing valve***.

***treater*** – A well servicing person such as a fracturing stimulation hand.

***tree*** – The wellhead.

***tree-saver tool*** – A tubular device employed as an isolation tool inside the christmas tree, to increase the tree's pressure rating during stimulation.

***trip gas*** – Accumulation of gas which enters hole while a trip is made.

***trip margin*** – An incremental increase in drilling fluid density to provide an increment of overbalance in order to compensate for effects of swabbing.

***trip*** – The operation of hoisting the drill stem from and returning it to the wellbore. See ***make a trip***.

***triple*** – Three joints of pipe. See ***stand***.

***triplex*** – A three-piston well servicing pump.

***tripping-in*** – Running tools and/or pipe downhole.

***truck-mounted rig*** – A well servicing and workover rig that is mounted on a truck chassis.

***tubing elevators*** – A clamping apparatus used to pull tubing. The elevators latch onto the pipe just below the top collar. The elevators are attached by steel links or bails to the hook.

***tubing hanger*** – Arrangement of slips built into a steel housing and engaged in upper end of wellhead that serves as a support for suspended tubing string. See ***slips***.

***tubing head*** – A flanged fitting that supports the tubing string, seals off pressure between the casing and the outside of the tubing, and provides a connection that supports the Christmas tree. See ***Christmas tree***.

***tubing job*** – Act of pulling tubing out of and running it back into well.

***tubing pump*** – A sucker rod pump in which the barrel is attached to the tubing. See ***sucker rod pump***.

***tubing slips*** – Slips designed specifically to be used with tubing. See ***slips***.

***tubing*** – Small diameter pipe that is run into a well to service as a conduit for the passage of oil and gas to the surface.

***tubing spider*** – A device used with slips to prevent tubing from falling into the hole when a joint of pipe is being unscrewed and racked. See ***slips***.

***tubing tester*** – A mechanically operated (tubing rotation) valve used to shut off formation pressure above a packer, thus testing all connections from the packer to the tree.

***tubing tongs*** – The large wrenches used to break out and make up tubing. They may be operated manually, hydraulically, or pneumatically.

***tubingless completion*** – A method of producing a well in which only a small-diameter production casing is set through the pay zone, with no tubing or inner production string used to bring formation fluids to the surface. This type of completion has limited application in small-column, dry gas reservoirs.

***tubular*** – Drill pipe, drill collars, rubbing, and casing.

***tubular goods*** – any kind of pipe; also called tubular. Oilfield tubular goods include tubing, casing, drill pipe, and line pipe. See ***pipe***.

***tungsten carbide*** – A fine, hard crystalline gray powder, a compound of tungsten and carbon. This compound is bonded with cobalt or nickel in cemented carbide compositions and used for cutting tools, abrasives, and dies.

***turbodrill*** – Drilling tool that rotates a bit attached to it by the action of the drilling mud on turbine blades built into the tool. When a turbodrill is used, rotary motion is imparted only at the bit; therefore, it is unnecessary to rotate the drill stem. Although straight holes can be drilled with the tool, it is used most often in directional drilling.

***turbulent flow*** – Fluid flow in which the velocity at a given point changes constantly in magnitude and the direction of flow; pursues erratic and continually varying courses. Turbulent flow is the second and final stage of flow in a Newtonian fluid; it is the third and final stage in a Bingham plastic fluid. See ***critical velocity*** and ***Reynolds number***.

***turnkey*** – A term applied to doing the whole job, start to finish.

***twist off*** – 1. Of drill pipe or drill collars, to part or split primarily because of metal fatigue in the pipe or because of mishandling. 2. The severing in two of a joint of drill pipe by excessive force applied by the rotary table.

# U

***ultraviolet light*** – Light waves shorter than the visible blue-violet waves of the spectrum. Crude oil, colored distillates, residuum, a few drilling-fluid additives, and certain minerals and chemicals fluoresce in the presence of ultraviolet light. These substances, when present in mud, may cause the mud to fluoresce.

***underbalance*** – Term to describe the reservoir pressure being greater than the hydrostatic head of the fluid in the wellbore.

***underground blowout*** – An uncontrolled flow of formation fluids from a subsurface zone into a second subsurface zone.

***underream*** – To enlarge the wellbore below the casing.

***unit operator*** – Company in charge of development in a field in which several companies have joined together to produce.

***univalent*** – Monovalent. See ***valence***.

***unloader*** – Same as a circulation valve.

***unloading sub*** – Same as unloader; a means to equalize tubing/annulus pressure.

***unloading*** – Lightening of wellbore hydrostatic pressure to lift the fluid mediums.

***urea*** – A soluble, weakly basic, nitrogenous compound, $CO(NH_2)_2$, that is used in the manufacture of resins and plastics.

# V

***V-door*** – Opening at floor level in a side of a derrick or mast, opposite draw works and used to bring in drill pipe, casing, and other tools from the pipe rack. The name is derived from the old standard derrick where the shape of the opening was an inverted V.

***V-G meter (viscosity gravity viscometer)*** – The name commonly used for direct-indicating viscometer (which see).

***valence effect*** – The higher the valence of an ion, the greater the loss of stability to emulsions, colloidal suspensions, these polyvalent ions will impart.

***valence (valency)*** – Number representing the combining power of an atom, i.e., electrons lost, gained, or shared by an atom in a compound. Also the number of hydrogen atoms with which an atom will combine or replace, e.g., an oxygen atom combining with two hydrogens has a valence of 2.

***valve*** – Used to control rate of flow in a line, to open or shut off a line completely, or as an automatic/semi-automatic safety device. Those with extensive usage include the gate valve, plug valve, globe valve, needle valve, check valve, and pressure relief valve. See ***check valve, needle valve, pressure relief valve***.

***vapor-proof*** – Susceptible to or affected by vapors. For example, an electrical switch is made vapor-proof so a spark issuing from it will not cause an explosion in the presence of combustible gases.

***vee ring*** – An elastomer (seal) energized by pressure.

***velocity, critical*** – That velocity at the transitional point between laminar and turbulent types of fluid flow. This point occurs in transitional range of Reynolds numbers of approx. 2,000 to 3,000.

***velocity safety valve*** – Same as a storm choke.

***velocity*** – Time rate of motion in a given direction and sense. A measure of fluid flow and may be expressed in terms of linear velocity, mass velocity, volumetric velocity, etc. Velocity is a factor which contribute to the carrying capacity of a drilling fluid.

***vibrating screen*** – See ***shale shaker***.

***viscometer (viscosimeter)*** – Used to determine viscosity of a fluid or suspension. Viscometers vary considerably in design and methods of testing.

***viscometer, direct reading*** – Commonly called a "V-G meter." The instrument is a rotational-type device powered by means of an electric motor or handcrank, and is used to determine the apparent viscosity, plastic viscosity, yield point, and gel strengths (all of which see) of drilling fluids. The usual speeds are 600 and 300 rpm. See ***API RP 13B*** for operational procedures.

***viscometer, stormer*** – A rotational shear viscometer used for measuring the viscosity and gel strength of drilling fluids. This instrument has been largely superseded by the direct-indicating viscometer (which see).

***viscosity*** – The internal resistance offered by a fluid to flow. This phenomenon is attributable to the attractions between molecules of a liquid, and is a measure of the combined effects of suspended particles, and to the liquid environment. The greater this resistance, the greater the viscosity. The viscosity of petroleum products is commonly expressed in terms of the time required for a specific volume of the liquid to flow through an orifice of a specific size. See ***apparent*** and ***plastic viscosity***.

***viscous flow*** – See ***laminar flow***.

***VITON*** – A fluroelastomer capable of sealing in sour gas.

***volatile matter*** – Normally gaseous products, except moisture, given off by a substance, such as gas breaking out of live crude oil added to a mud. In distillation of drilling fluids, the volatile matter is the water, oil, gas, etc., that are vaporized, leaving behind the total solids which can consist of both dissolved and suspended solids.

***vug*** – A cavity in a rock.

# W

***W-L, W/L*** – Wireline

***waiting on cement*** – Pertaining to or during time when drilling or completion operations are suspended so cement in well can harden.

***wall cake*** – Solid material deposited along the wall of the hole resulting from filtration of the fluid part of mud into the formation.

***wall hook*** – Device used in fishing for drill pipe. If upper end of lost pipe is leaning against the side of wellbore, the wall hook centers it in the hole so that it may be recovered with an overshot, which is run on the fishing string and attached to the wall hook.

***wall sticking*** – See ***differential-pressure sticking***.

***wash pipe*** – 1. Short length of surface-hardened pipe that fits inside swivel and is a conduit for drilling fluid through swivel; 2. Sometimes means washover pipe, which see.

***wash-over shoe*** – Device to protect seals, seating nipples, during mill-out.

***washing*** – Cleaning out perforations.

***washover pipe (washpipe)*** – Pipe of an appropriate size to go over a fish in an open hole or casing and wash out or drill out obstruction so that fish may be freed.

***washover*** – Remove permanent downhole tool by milling/fluid washing.

***water-based mud*** – Conventional drilling fluids. Water is the suspending medium for solids and is the continuous phase, whether or not oil is present.

***water-in-oil emulsion*** – See ***invert oil-emulsion mud***.

***water loss*** – See ***fluid loss***.

***waterflood*** – Method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves injection of water through wells specially set up for water injection and removal of water and oil from well drilled adjacent to injection wells.

***Webb-Wilson*** – Mechanical tongs; sometime used generically for all brands of tongs.

***weevils*** – An inexperienced oil field hand; a green hand.

***weighing material*** – A material with a specific gravity greater than that of cement; used to increase the density of drilling fluids or cement slurries.

**weight cut** – The amount by which drilling fluid density is reduced by entrained formation fluids or air.

***weight*** – In mud terminology, this refers to the density of a drilling fluid. This is normally expressed in either lb/gal, lb/cu. ft., psi hydrostatic pressure per 1,000 feet of depth.

***weight indicator*** – An instrument near the driller's position on a drilling or workover rig that shows the weight suspended from the hook when the bit is off the bottom. From this reading, weight on the bit can be estimated during drilling.

***weight material*** – Any of the high specific gravity materials used to increase density of drilling fluids. Most commonly barite but can be galena, etc. In special applications limestone is also called a weight material.

***weight'n-up*** – Adding weighing material such as barite, etc. to the wellbore fluids.

***well completion*** – The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

***well logging*** – The recording of information about subsurface geologic formations. Logging methods include records kept by the driller, mud and cutting analyses, core analysis, drill stem tests, and electric and radioactivity procedures. See ***electric well log, mud logging, radioactivity well logging,*** and ***sonic logging***.

***well permit*** – Authorization, usually by a governmental conservation agency, to drill a well. A permit is sometimes required for deepening or remedial work also.

***well puller*** – Member of well servicing crew. See ***roustabout, crew chief***.

***well servicing*** – The maintenance work performed on an oil or gas well to improve or maintain the production from a formation already producing. Usually, it involves repairs to the pump, rods, gas-lift valves, tubing, packers, and so forth. Relating to well servicing work, as a well servicing company.

***wellbore*** – A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased), or a portion of it may be cased and a portion of it may be open. See ***cased*** and ***open***.

***wellhead*** – The equipment used to maintain surface control of a well; also refers to various parameters as they exist at the wellhead, such as wellhead pressure, wellhead price of oil, etc. It is formed of the casing head and Christmas tree.

***wetting agent*** – A substance or composition which, when added to a liquid, increases the spreading of the liquid on a surface or the penetration of the liquid into a material.

***wetting*** – The adhesion of a liquid to the surface of a solid.

***wheel-type back-off wrench*** – A wheel-shaped wrench that is attached to the sucker rod string at the surface and is manually turned to unscrew the string to allow it to be pulled from the well. Also called a back-off wheel or a circle wrench.

***whipstock*** – A long, steel casing that uses an inclined plane to cause the bit to deflect from the original borehole at a slight angle. Whipstocks are commonly used in controlled directional drilling, to straighten crooked boreholes, and to sidetrack to avoid unretrieved fish. See ***directional drilling, fish,*** and ***sidetrack***.

***whipstock anchor packer*** – A special-purpose packer placed in the casing to permit a sidetrack operation.

***wickers*** – 1. Term applied to the teeth of the slip. 2. Term used to describe frayed or broken strands of wire rope.

***wildcat*** – 1. Well drilled in an area where no oil/gas production exists. With present-day exploration methods and equipment, about one wildcat out of every six proves productive although not necessarily profitable. 2. (nautical) a geared sheave of a windlass used to pull anchor chain. v. to drill wildcat wells.

***wildcat*** – A well in unproved territory.

***winch*** – A machine that pulls or hoists by winding a cable around a spool.

***wing*** – The horizontal valving on a tree.

***wiper plug*** – A rubber plug used in primary cementing.

***wire rope*** – A cable composed of steel wires twisted around a central core of hemp or other fiber to create a rope of great strength and considerable flexibility. Wire rope is used as drilling line, winch line, and so on. It is often called cable or wireline; however, wireline is a single, slender metal rod, usually very flexible. Compare ***wireline***.

***wireline*** – A slender, rod-like or threadlike piece of metal, usually small in diameter, that is used for lowering special tools (such as logging sondes, perforating guns, and so forth) into the well.

***wireline entry guide*** – A flared-end sub run on the end of the tubing string to permit easy access of wireline tools into the tubing ID.

***wireline preventers*** – Preventers installed on top of well or drill string as a precautionary measure while running wireline. Preventer packing will close around wireline.

***wireline probe*** – A diagnostic tool used to ascertain the position of a gas leak in the tubing of a gas-lift well.

***wireline survey*** – A general term often used to refer to any type of log being run in a well. See ***log***.

***WOC*** – Abbreviation for ***waiting-on-cement***.

***WOE*** – Abbreviation for ***waiting-on-engineering***.

***WOG*** – Abbreviation for ***water-oil-gas***.

***work string*** – The string of drill pipe tubing suspended in a well to which is attached a spacial tool or device that is used to carry out a certain task, as squeeze cementing or fishing. Also called ***workover string***.

***working pressure*** – Rating of equipment's pressure limitation.

***workover fluid*** – Any type of fluid used in the workover operation of a well. Refer to "completion fluid."

***workover rig*** – See ***production rig*** and ***pulling unit***.

***workover string*** – The string of drill pipe or tubing suspended in a well to which is attached a special tool or device that is used to carry out a certain task, such as squeeze cementing or fishing.

***workover*** – To perform one or more of a variety of remedial operations on a producing oil well to try to increase production. Examples of workover operations are deepening, plugging back, pulling and resetting liners, squeeze cementing, and so on.

***work string*** – A string of pipe used in workover or well-servicing operations; not typically considered as production tubing.

***worms*** – Same as ***weevils***.

# Y

***yield*** – A term used to define the quality of a clay by describing the number of barrels of a given centipoise slurry that can be made form a ton of clay. Based on the yield, clays are classified as bentonite, high-yield, low-yield, etc., types of clays. Not related to yield value below. See ***API RP 13B*** for procedures.

***yield point*** – In drilling-fluid terminology, yield point means yield value (which see). Of the two terms, yield point is by far the most commonly used.

***yield value*** – Yield value (commonly "yield point") is the resistance to initial flow, or represents the stress required to start fluid movement. This resistance is due to electrical charges located on or near the surfaces of the particles. The values of the yield point and thixotropy, respectively, are measurements of the same fluid properties under dynamic and static states. The Bingham yield value, reported in lb/100 sq ft, is determined by direct-indicating viscometer by subtracting plastic viscosity from the 300-rpm reading.

# Z

***zero-zero gel*** – A condition wherein the drilling fluid fails to form measurable gels during a quiescent time interval (usually 10 minutes).

***zeta potential*** – Electrokinetic potential of a particle as determined by its electrophoretic mobility. This electric potential cause colloidal particles to repel each other and stay in suspension.

***zinc chloride – $ZnCl_2$*** – Soluble salt used to increase density of water to points more than double water. Normally added to a system first saturated with calcium chloride.

***zone*** – A section of the well's formation.

## Pre-recorded Well Data

| WELL NAME | COMPLETED BY: |
|---|---|
| | |

**TUBING**

INCHES — Outside Diameter; INCHES — Inside Diameter; BBLS/FT — Capacity per Foot; MD FT — Length to E.O.T.

**PUMP 1**

BBLS/STK — Output ______% EFF

**TUBING**

LBS/FT — Weight; Grade; PSI @100% — Burst; PSI @100% — Collapse

**PUMP 2**

BBLS/STK — Output ______% EFF

**CASING**

INCHES — Outside Diameter; INCHES — Inside Diameter; BBLS/FT — Capacity per Foot; MD FT — Length

PSI — Max Pump Pressure

**CASING**

LBS/FT — Weight; Grade; PSI @100% — Burst

**TREE/BOP**

PSI — Rated Pressure

**FORMATION**

PSI — Formation Pressure

**TOP PERFORATION**

TVD FT — Top Perforation; MD FT — Top Perforation

**BOTTOM PERFORATION**

TVD FT — Bottom Perforation; MD FT — Bottom Perforation

PPG — Estimated Integrity Fluid Density

## Volume & Stroke Considerations

**A. Tubing Volume/Strokes (Surface to End of Tubing, E.O.T.)**

MD FT Tubing Length Surface to E.O.T. x BBLS/FT Capacity per Foot in Tubing = BBLS Tubing Volume Surface to E.O.T. ÷ BBLS/STK Pump Output = STKS Strokes Surface to E.O.T.

**B. Casing Volume/Strokes (Below End of Tubing, E.O.T. to Perforations)**

MD FT Length E.O.T. to Perfs Top/Middle/Bottom x BBLS/FT Capacity per Foot in Casing = BBLS Casing Volume E.O.T. to Perforations ÷ BBLS/STK Pump Output = STKS Strokes E.O.T. to Perforations

**C. Surface to Perforations Volume/Strokes (Kill Point)**

BBLS Tubing Volume Surface to E.O.T. + BBLS Casing Volume E.O.T. to Perforations = BBLS Surface to Perforations Volume ÷ BBLS/STK Pump Output = Kill Point STKS Strokes Surface to Perforations

**D. Total Volume/Strokes to Pump (Including Overdisplacing)**

BBLS Surface to Perforations Volume + BBLS Overdisplacement (if any) = BBLS Total Volume to Pump ÷ BBLS/STK Pump Output = Overdisplace STKS Total Strokes to Pump

**E. Volume per "Step"**

BBLS Surface to Perforations Volume ÷ 10 Number of "Steps" = BBLS/STEP Volume per "Step" x 42 = GALS/STEP Volume per "Step"

**F. Strokes per "Step"**

STKS Strokes Surface to Perforations ÷ 10 Number of "Steps" = STKS/STEP Strokes per "Step"

## Kill Fluid Considerations

**G. Kill Fluid Density**

PSI Formation Pressure ÷ .052 ÷ TVD FT Depth to Perforations Top/Middle/Bottom = PPG Kill Fluid Density

# BULLHEAD WORKSHEET


Well Control School
16770 Imperial Valley Drive, Suite 290
Houston, TX 77060

WELL CONTROL SCHOOL

TEL : 713-849-7400
FAX : 713-849-7474
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www.wellcontrol.com


**RECORDED WELL INFORMATION**

Formation Pressure — PSI

Shut In Tubing Pressure — PSI

Shut In Casing Pressure — PSI

**PRESSURE CONSIDERATIONS**

Tree/BOP/Wellhead Rated Pressure — PSI

Maximum Pump Pressure — PSI

Initial Est. Max. Pressure on Tubing — PSI

Final Est. Max. Pressure on Tubing — PSI

**KILL FLUID DENSITY** — PPG

**PUMP RATE CONSIDERATIONS**

Desired Rate — BBLS/MIN — STKS/MIN

Desired Rate — BBLS/MIN — STKS/MIN

**VOLUME/STROKE CONSIDERATIONS**

Surface to E.O.T. — BBLS — STKS

E.O.T. to Perforations — BBLS — STKS

Surface to Perforations — BBLS — STKS

Total to Pump — BBLS — STKS

## Pressure Chart

| Strokes | Volume in BBLS | Volume in GALS | Estimated Max. Static Pressure | Actual Tubing Pressure | Casing Pressure | Pump Rate | Notes |
|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | Initial | | | | |
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| Kill Point | | | Final | | | | |
| Overdisplace | | | | | | | |
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## Tubular Pressure Considerations

**1. Casing Internal Burst**

PSI Casing Burst X Safety Factor (.70 Or Less) = PSI Adjusted Casing Burst

**2. Tubing Collapse**

PSI Tubing Collapse X Safety Factor (.70 Or Less) = PSI Adjusted Tubing Collapse

**3. Tubing Burst** (If this is less than #6 or #8, Do Not Exceed this Pressure)

PSI Tubing Burst X Safety Factor (.70 Or Less) = PSI Adjusted Tubing Internal Burst

## Formation Pressure Considerations

**4. Estimated Formation Integrity Pressure (Fracture)**

PPG Estimated Integrity Fluid Density X .052 X TVD FT Depth to Perforations Top/Middle/Bottom = PSI Estimated Formation Integrity Pressure

**5. Average Hydrostatic Pressure in Tubing**

PSI Formation Pressure – PSI Initial Shut In Tubing Pressure = PSI Average Hydrostatic Pressure in Tubing

**6. Initial Estimated Maximum Pressure on Tubing (Static)**

PSI Estimated Formation Integrity Pressure – PSI Average Hydrostatic Pressure in Tubing = PSI Initial Estimated Max. Pressure on Tubing

**7. Kill Fluid Hydrostatic Pressure**

PPG Kill Fluid Density X .052 X TVD FT Depth to Perforations Top/Middle/Bottom = PSI Kill Fluid Hydrostatic Pressure

**8. Final Estimated Maximum Pressure on Tubing (Static)**

PSI Estimated Formation Integrity Pressure – PSI Kill Fluid Hydrostatic Pressure = PSI Final Estimated Max. Pressure On Tubing

**9. Pressure Consideration PSI per "Step"**

PSI Initial Max. Pressure on Tubing (Lesser of #3 or #6) – PSI Final Max. Pressure on Tubing (Lesser of #3 or #8) ÷ 10 Number of "Steps" = PSI/STEP PSI per "Step"

## Pump Rate Considerations

**10. Kill Rate Speeds and Volume (2 Different Rates)**

BBLS/MIN Desired Barrels per Minute ÷ BBLS/STK Pump Output = STKS/MIN Pump Rate

BBLS/MIN Desired Barrels per Minute ÷ BBLS/STK Pump Output = STKS/MIN Pump Rate

# BULLHEAD WORKSHEET

Well Control School
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Houston, TX 77060

WELL CONTROL SCHOOL

www.wellcontrol.com

TEL : 713-849-7400
FAX : 713-849-7474
E-mail : staff@wellcontrol.com

## Pre-recorded Well Data

WELL NAME | COMPLETED BY:

**TUBING**

INCHES Outside Diameter | INCHES Inside Diameter | BBLS/FT Capacity per Foot | MD FT Length to E.O.T.

**TUBING**

LBS/FT Weight | Grade | PSI @100% Burst | PSI @100% Collapse

**CASING**

INCHES Outside Diameter | INCHES Inside Diameter | BBLS/FT Capacity per Foot | MD FT Length

**CASING**

LBS/FT Weight | Grade | PSI @100% Burst

**TREE/BOP**

PSI Rated Pressure

**TOP PERFORATION**

TVD FT Top Perforation | MD FT Top Perforation

**BOTTOM PERFORATION**

TVD FT Bottom Perforation | MD FT Bottom Perforation

**PUMP 1**

BBLS/STK Output _____% EFF

**PUMP 2**

BBLS/STK Output _____% EFF

PSI Max Pump Pressure

**FORMATION**

PSI Formation Pressure

PPG Estimated Integrity Fluid Density

## Volume & Stroke Considerations

**A. Tubing Volume/Strokes (Surface to End of Tubing, E.O.T.)**

MD FT Tubing Length Surface to E.O.T. x BBLS/FT Capacity per Foot in Tubing = BBLS Tubing Volume Surface to E.O.T. ÷ BBLS/STK Pump Output = STKS Strokes Surface to E.O.T.

**B. Casing Volume/Strokes (Below End of Tubing, E.O.T. to Perforations)**

MD FT Length E.O.T. to Perfs Top/Middle/Bottom x BBLS/FT Capacity per Foot in Casing = BBLS Casing Volume E.O.T. to Perforations ÷ BBLS/STK Pump Output = STKS Strokes E.O.T. to Perforations

**C. Surface to Perforations Volume/Strokes (Kill Point)**

BBLS Tubing Volume Surface to E.O.T. + BBLS Casing Volume E.O.T. to Perforations = BBLS Surface to Perforations Volume ÷ BBLS/STK Pump Output = Kill Point STKS Strokes Surface to Perforations

**D. Total Volume/Strokes to Pump (Including Overdisplacing)**

BBLS Surface to Perforations Volume + BBLS Overdisplacement (if any) = BBLS Total Volume to Pump ÷ BBLS/STK Pump Output = Overdisplace STKS Total Strokes to Pump

**E. Volume per "Step"**

BBLS Surface to Perforations Volume ÷ 10 Number of "Steps" = BBLS/STEP Volume per "Step" x 42 = GALS/STEP Volume per "Step"

**F. Strokes per "Step"**

STKS Strokes Surface to Perforations ÷ 10 Number of "Steps" = STKS/STEP Strokes per "Step"

## Kill Fluid Considerations

**G. Kill Fluid Density**

PSI Formation Pressure ÷ .052 ÷ TVD FT Depth to Perforations Top/Middle/Bottom = PPG Kill Fluid Density

## RECORDED WELL INFORMATION

Formation Pressure PSI

Shut In Tubing Pressure PSI

Shut In Casing Pressure PSI

## PRESSURE CONSIDERATIONS

Tree/BOP/Wellhead Rated Pressure PSI

Maximum Pump Pressure PSI

Initial Est. Max. Pressure on Tubing PSI

Final Est. Max. Pressure on Tubing PSI

## KILL FLUID DENSITY

PPG

## PUMP RATE CONSIDERATIONS

Desired Rate BBLS/MIN STKS/MIN

Desired Rate BBLS/MIN STKS/MIN

## VOLUME/STROKE CONSIDERATIONS

Surface to E.O.T. BBLS STKS

E.O.T. to Perforations BBLS STKS

Surface to Perforations BBLS STKS

Total to Pump BBLS STKS

## Pressure Chart

| Strokes | Volume in BBLS | Volume in GALS | Estimated Max. Static Pressure | Actual Tubing Pressure | Casing Pressure | Pump Rate | Notes |
|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | Initial | | | | |
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| Kill Point | | | Final | | | | |
| Overdisplace | | | | | | | |
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## Tubular Pressure Considerations

**1. Casing Internal Burst**

PSI Casing Burst X Safety Factor (.70 Or Less) = PSI Adjusted Casing Burst

**2. Tubing Collapse**

PSI Tubing Collapse X Safety Factor (.70 Or Less) = PSI Adjusted Tubing Collapse

**3. Tubing Burst** (If this is less than #6 or #8, Do Not Exceed this Pressure)

PSI Tubing Burst X Safety Factor (.70 Or Less) = PSI Adjusted Tubing Internal Burst

## Formation Pressure Considerations

**4. Estimated Formation Integrity Pressure (Fracture)**

PPG Estimated Integrity Fluid Density X .052 X TVD FT Depth to Perforations Top/Middle/Bottom = PSI Estimated Formation Integrity Pressure

**5. Average Hydrostatic Pressure in Tubing**

PSI Formation Pressure – PSI Initial Shut In Tubing Pressure = PSI Average Hydrostatic Pressure in Tubing

**6. Initial Estimated Maximum Pressure on Tubing (Static)**

PSI Estimated Formation Integrity Pressure – PSI Average Hydrostatic Pressure in Tubing = PSI Initial Estimated Max. Pressure on Tubing

**7. Kill Fluid Hydrostatic Pressure**

PPG Kill Fluid Density X .052 X TVD FT Depth to Perforations Top/Middle/Bottom = PSI Kill Fluid Hydrostatic Pressure

**8. Final Estimated Maximum Pressure on Tubing (Static)**

PSI Estimated Formation Integrity Pressure – PSI Kill Fluid Hydrostatic Pressure = PSI Final Estimated Max. Pressure On Tubing

**9. Pressure Consideration PSI per "Step"**

PSI Initial Max. Pressure on Tubing (Lesser of #3 or #6) – PSI Final Max. Pressure on Tubing (Lesser of #3 or #8) ÷ 10 Number of "Steps" = PSI/STEP PSI per "Step"

## Pump Rate Considerations

**10. Kill Rate Speeds and Volume (2 Different Rates)**

BBLS/MIN Desired Barrels per Minute ÷ BBLS/STK Pump Output = STKS/MIN Pump Rate

BBLS/MIN Desired Barrels per Minute ÷ BBLS/STK Pump Output = STKS/MIN Pump Rate

## Pre-recorded Information

### Well Data

| WELL NAME | COMPLETED BY: |
|---|---|
| | |

**DRILL PIPE #1**

| INCHES | INCHES | FT | BBLS/FT | LBS/FT | MD FT |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Weight | Total Drill String Length (DP & DC) |

**DRILL PIPE #2**

| INCHES | INCHES | FT | BBLS/FT | LBS/FT |
|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Weight |

**DRILL COLLARS / HOLE SIZE**

| INCHES | INCHES | FT | BBLS/FT | INCHES | TVD FT |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | Length | Capacity per Foot | Hole Size | True Vertical Depth (to Bit) |

**CASING #1**

| INCHES | INCHES | TVD FT | MD FT | | PSI @ 100% |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | True Vertical Depth | Measured Depth | Weight & Grade | Internal Yield |

**CASING #2**

| INCHES | INCHES | TVD FT | MD FT | | PSI @ 100% |
|---|---|---|---|---|---|
| Outside Diameter | Inside Diameter | True Vertical Depth | Measured Depth | Weight & Grade | Internal Yield |

**PUMPS / SURFACE LINES**

| X LINER X STROKE | BBLS/STK | X LINER X STROKE | BBLS/STK | PSI | BBLS |
|---|---|---|---|---|---|
| Pump #1 | Output ____%EFF | Pump #2 | Output ____%EFF | Maximum Pump Pressure | Surface Line Volume |

**MUD**

| PPG | PPG | PPG | PSI | TVD FT | BBLS |
|---|---|---|---|---|---|
| Present Mud Weight | Reserve Mud Weight | Integrity/Leak-off Test Mud Weight | Integrity/Leak-off Pressure | Depth of Test (Shoe or Weak Zone) | Volume in Active Pits |

## Pressure Considerations

**1. Maximum Allowable Mud Weight (MAMW)**

____ PSI (Integrity/Leak-off Pressure) ÷ 0.052 ÷ TVD ____ FT (Depth of Test (Shoe or Weak Zone)) + ____ PPG (Leak-off Test Mud Weight) = ____ PPG (Maximum Allowable Mud Weight)

**2. Maximum Allowable Annular Surface Pressure (MAASP)**

( ____ PPG (Maximum Allowable Mud Weight) – ____ PPG (Present Mud Weight) ) x TVD ____ FT (Depth of Test (Shoe or Weak Zone)) x 0.052 = ____ PSI (MAASP)

**3. Casing Internal Yield**

____ PSI @ 100% (Casing Internal Yield) x ____ (Safety Factor (.70 or less)) = ____ PSI (Adjusted Casing Yield)

**4. B.O.P. Test Pressure**

= ____ PSI (BOP Test Pressure)

## Slow Circulating Rate (SCR) & Pump Pressures (3 Different Rates)

Measure at beginning of each tour, after drilling 500 feet and after each mud weight and viscosity change.

| | SCR | | SCR Pump Pressure | | SCR | | SCR Pump Pressure |
|---|---|---|---|---|---|---|---|
| PUMP #1 | STKS/MIN | = | PSI | PUMP #2 | STKS/MIN | = | PSI |
| PUMP #1 | STKS/MIN | = | PSI | PUMP #2 | STKS/MIN | = | PSI |
| PUMP #1 | STKS/MIN | = | PSI | PUMP #2 | STKS/MIN | = | PSI |

# WAIT & WEIGHT WORKSHEET

WCS WELL CONTROL SCHOOL

An RPC, Inc. Company

www.wellcontrol.com

## RECORDED KICK INFORMATION

| | | | |
|---|---|---|---|
| Kick Depth | TVD FT | Kick Depth | MD FT |
| Size of Kick | BBLS | Present Mud Weight | PPG |

## SHUT IN PRESSURES

| | | | | | |
|---|---|---|---|---|---|
| SIDPP | PSI | SICP | PSI | MAASP | PSI |

## CALCULATED KILL INFORMATION

| | | | | | |
|---|---|---|---|---|---|
| KMW | PPG | SCR | STKS/MIN | SCR | BBLS/MIN |

| | | | |
|---|---|---|---|
| ICP | PSI | Total Annular Volume | BBLS |
| FCP | PSI | Strokes Bit to Casing Shoe | STKS |
| Drill String Volume | BBLS | Strokes Bit to Surface | STKS |
| Strokes Surface to Bit | STKS | Strokes Surface to Surface | STKS |

Choke Adjustment: Approximate Lag Time From Casing to Drill Pipe is ____________ Seconds.

## Pressure Chart

| Strokes or Volume | Theoretical Drill Pipe Pressure | Actual Drill Pipe Pressure | Casing Pressure | Pit Volume Deviation |
|---|---|---|---|---|
| 0 | ICP | | | |
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| BIT | FCP | | | |
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__________ ÷ 10 = __________ (Stks Surf to Bit; Strokes per Step)

__________ – __________ ÷ 10 = __________ (Initial Circ Pressure; Final Circ Pressure; PSI per Step)

## Kill Mud & Pressure Considerations

**(5) Required Kill Mud Weight**

____ PSI (SIDPP) ÷ 0.052 ÷ TVD ____ FT (True Vertical Depth (to Bit or Kick Zone)) + ____ PPG (Present Mud Weight) = ____ PPG (Kill Mud Weight)

**(6) Select Pump and Speed to Kill Well**

# ____ (Select Pump to Kill Well) ____ STKS/MIN (Kill Rate Speed) X ____ BBLS/STK (Pump Output) = ____ BBLS/MIN (Circulating Rate) AT ____ PSI (SCR Pump Pressure)

**(7) Initial Circulating Pressure (ICP)**

____ PSI (SIDPP) + ____ PSI (SCR Pump Pressure) = ICP ____ PSI (Initial Circulating Pressure)

**(8) Final Circulating Pressure (FCP)**

____ PSI (SCR Pump Pressure) X ____ PPG (Kill Mud Weight) ÷ ____ PPG (Present Mud Weight) = FCP ____ PSI (Final Circulating Pressure)

## Drill String Volume & Stroke Calculations

**(9) Drill Pipe # 1 Volume**

____ FT (Drill Pipe Length) X ____ BBLS/FT (Capacity per Foot in DP) = ____ BBLS (Volume In Drill Pipe # 1)

**Drill Pipe # 2 Volume**

____ FT (Drill Pipe Length) X ____ BBLS/FT (Capacity per Foot in DP) = ____ BBLS (Volume In Drill Pipe # 2)

____ FT (Drill Collar Length) X ____ BBLS/FT (Capacity per Foot in DC) = ____ BBLS (Volume in Collars)

**Drill String Volume**

____ BBLS (Volume in DP # 1) + ____ BBLS (Volume in DP # 2) + ____ BBLS (Volume in DC) + ____ BBLS (Volume Surface Line) = ____ BBLS (Drill String Volume)

**(10) Strokes Surface to Bit**

____ BBLS (Drill String Volume) ÷ ____ BBLS/STK (Pump Output) = ____ STKS (Strokes Surface to Bit)

## Annular Volume & Stroke Calculations

**(11) Annular Capacities and Volumes**

**A. Annular Volume Between DP and Casing # 1**

.____ BBLS/FT (Capacity per Foot Between DP & CSG # 1) X ____ FT (Length of DP in CSG # 1 (Measured Depth)) = A ____ BBLS (Volume Between DP & CSG)

**Annular Volume Between DP and Casing # 2**

.____ BBLS/FT (Capacity per Foot Between DP & CSG # 2) X ____ FT (Length of DP in CSG # 2 (Measured Depth)) = B ____ BBLS (Volume Between DP & CSG)

**B. Annular Volume Between DP and Open Hole**

.____ BBLS/FT (Capacity per Foot Between DP & OH # 1) X ____ FT (Length of DP in OH # 1 (Measured Depth)) = C ____ BBLS (Volume Between DP & OH)

**Annular Volume Between DC and Open Hole**

.____ BBLS/FT (Capacity per Foot Between DC & OH) X ____ FT (Length of DC in OH (Measured Depth)) = D ____ BBLS (Volume Between DC & OH)

**C. Total Annular Volume**

A ____ BBLS (Volume Between DP & CSG #1) + B ____ BBLS (Volume Between DP & CSG # 2) + C ____ BBLS (Volume Between DP & OH) + D ____ BBLS (Volume Between DC & OH) + E ____ BBLS (Volume in Choke Line (Subsea Only) (See back of Kill Sheet)) = F ____ BBLS (Total Annular Volume)

**(12) Strokes Bit to Casing Shoe**

( C ____ BBLS (Volume Between DP & OH) + D ____ BBLS (Volume Between DC & OH) ) ÷ ____ BBLS/STK (Pump Output) = ____ STKS (Strokes Bit to Casing Shoe)

**(13) Strokes Bit to Surface**

F ____ BBLS (Annular Volume) ÷ ____ BBLS/STK (Pump Output) = ____ STKS (Strokes Bit to Surface)

**(14) Total Strokes Surface to Surface**

____ STKS (Strokes Surface to Bit) + ____ STKS (Strokes Bit to Surface) = ____ STKS (Strokes Surface to Surface)

# Calculations For Subsea Stack

## Choke Line Volume

Choke Line ID² (ID of Choke Line Squared) ÷ 1029.4 = .____ BBLS/FT (Capacity per Foot in Choke Line) x FT (Length of Choke Line) = E BBLS (Volume in Choke Line (See front of Kill Sheet) (Line 11-E))

If both choke and kill lines are being used, multiply barrels in choke line by two.
If kill line is different than choke line (ID or length) use choke line formula and also calculate for kill line.

## Annular Volume Between Drill Pipe and Riser

Riser ID² (ID of Riser Squared) – DP OD² (OD of DP Squared) ÷ 1029.4 = .____ BBLS/FT (Capacity per Foot Between DP & Riser) x FT (Length of Riser (RKB to Sea Floor)) = BBLS (Volume Between DP & Riser)

## Strokes To Displace Riser

BBLS (Volume Between DP & Riser) ÷ BBLS/STK (Pump Output) = STKS (Strokes to Displace Riser)

Gas in BOP stack must be swept and mud in riser must be weighted to the same weight as the kill mud in the annulus before the stack is opened to avoid a possible reduction in bottom hole pressure.

## Choke Line Friction Pressure (CLFP)

CLFP = (Circulating Pressure through Choke and/or Kill Line) – (Circulating Pressure through open BOP) At ________ PPG

| | Kill Rate Speed (STKS/MIN) | Pump Output (BBLS/STK) | SCR (BBLS/MIN) | SCR BOP Open (PSI) | SCR thru Choke Line (PSI) | SCR thru Choke & Kill Line (PSI) | CLFP Choke Line (PSI) | CLFP Choke & Kill Line (PSI) |
|---|---|---|---|---|---|---|---|---|
| PUMP NO. 1 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| PUMP NO. 2 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |

## Corrected Choke Line Friction Pressure (if Mud Weight changes)

CLFP PSI (Choke Line Friction Pressure) x PPG (Different Mud Weight) ÷ PPG (Mud Weight When Choke Line Pressure Measured) = CLFP PSI (Corrected Choke Line Friction Pressure)

## Well Conditions vs. CLFP

CLFP is always present while circulating (Dynamic conditions) through the choke line. When bringing the pump on line, if CLFP is not considered, loss of circulation or formation breakdown may occur.

**STATIC**

PSI (Shut In Casing Pressure)

PSI (MAASP)

– PSI (Choke Line Friction Pressure) =

**DYNAMIC**

PSI (Estimated Casing (Choke) Pressure at Kill Rate Speed)

PSI (New MAASP)

Static Conditions – CLFP = Dynamic Conditions

## Pump Start-Up (Choke Pressure Schedule)

PSI (Choke Line Friction Pressure) ÷ 4 = PSI (Drop per Step)

| Choke Pressure | | Strokes per Minute |
|---|---|---|
| PSI (SICP) | Shut-In | 0 STKS/MIN |
| PSI | .5 x Kill Rate Speed | STKS/MIN |
| PSI | .75 x Kill Rate Speed | STKS/MIN |
| PSI | .875 x Kill Rate Speed | STKS/MIN |
| PSI | Kill Rate Speed | STKS/MIN |

## Well Control Worksheet Constants and Abbreviations

- .052 = factors used to convert weight to psi/ft
- 1029.4 = conversion to capacity in BBLS/FT
- 35 = weight of 1 gallon of barite (lbs)
- 14.7 = the number of sacks of barite in one barrel and conversion from pounds per barrel to sacks per barrel
- 8.33 = the weight of fresh water (lbs/gal)
- .000243 = triplex pump conversion factor to output in BBLS/STK
- .000162 = duplex pump conversion factor to output in BBLS/STK
- % EFF = percent efficiency
- BBLS = barrels
- BBLS/FT = barrels per foot
- BBLS/MIN = barrels per minute
- BBLS/STK = barrels per stroke
- CSG = casing
- CLFP = choke line friction pressure
- DC = drill collars
- DP = drill pipe
- FT = feet
- FCP = final circulating pressure
- ICP = initial circulating pressure
- ID² = inside diameter squared
- LBS/FT = pounds per foot
- MD = measured depth
- OH = open hole
- OD² = outside diameter squared
- SICP = shut in casing pressure
- SIDPP = shut in drill pipe pressure
- STKS = strokes
- STKS/MIN = strokes per minute
- (STK/MIN)² = strokes per minute squared
- SXS = sacks
- SXS/BBL = sacks per barrel
- SXS/MIN = sacks per minute
- SCR = slow circulating rate

## Estimated Barite Requirements

### Total Volume In Active System

BBLS (Volume in Active Pits) + BBLS (Drill String Volume) + BBLS (Total Annular Volume) + BBLS (Volume Between DP & Riser (Subsea Only)) = BBLS (Total Volume in Active System)

### Sacks Per 100 Barrels

35 – PPG (Kill Mud Weight) = [ ]

PPG (Kill Mud Weight) – PPG (Present Mud Weight) x 14.7 ÷ [ ] = SXS/BBL (Sacks per Barrel)

### Total Barite Required

BBLS (Total Volume in Active System) x SXS/BBL (Sacks per Barrel) = SXS (Total Barite Required)

### Volume Increase Due To Barite Addition

SXS (Total Barite Required) ÷ 14.7 = BBLS (Volume Increase)

### Required Mixing Rate

SXS/BBL (Sacks per Barrel) x BBLS/MIN (Circulating Rate) = SXS/MIN (Required Mixing Rate)

### Dilution of Reserve Mud With Water

PPG (Kill Mud Weight) – 8.33 = [ ]

PPG (Mud Weight in Reserve Pit) – PPG (Kill Mud Weight) x BBLS (Volume in Reserve Pit) ÷ [ ] = BBLS (Volume of Water to Add)

## Calculations for Pump Output and Pressures

### Single Acting Triplex Pump

Liner ID² (ID of Liner Squared) x INCHES (Length of Pump Stroke) x .000243 x % EFF (Pump Efficiency) = BBLS/STK (Pump Output)

### Double Acting Duplex Pump

Liner ID² (ID of Liner Squared) + Liner ID² (ID of Liner Squared) – Rod OD² (OD of Rod Squared) x INCHES (Length of Pump Stroke) = [ ]

[ ] x .000162 x % EFF (Pump Efficiency) = BBLS/STK (Pump Output)

### Estimated Circulating Pressure at Different Pump Speed

PSI (Pressure at Established Circulating Rate) x (STKS/MIN)² (Strokes at Different Circulating Rate Squared) ÷ (STKS/MIN)² (Strokes at Established Circulating Rate Squared) = PSI (Estimated Circulating Pressure at Different Rate)