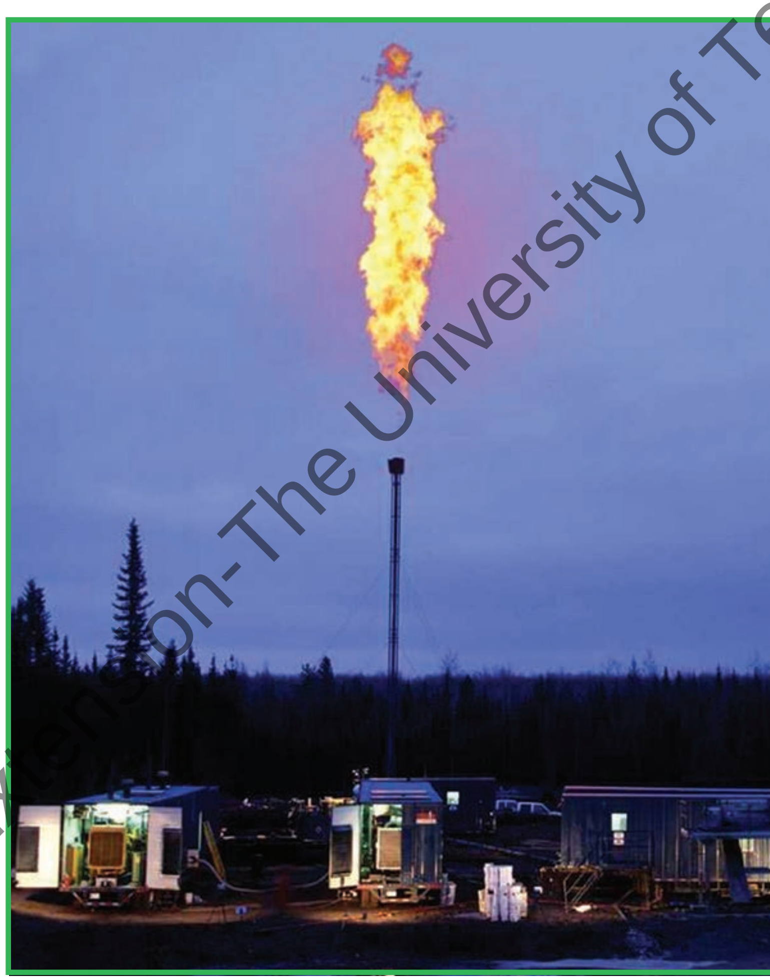
PRACTICAL UNDERBALANCED DRILLING AND WORKOVER



PETROLEUM EXTENSION SERVICE
The University of Texas at Austin
Continuing & Extended Education
Austin, Texas

Contents

Chapter 1

TERMS AND CALCULATIONS

Underbalanced drilling (*UBD*) and *well control* are similar technologies. That is, the well is shut in against pressure in the wellbore and the well is circulated through a choke (fig. 1.1). Thus, the basic concepts of pressure in well control are also basic to UBD. However, the terms used in UBD can be confusing because they may be defined in a different manner. For example, in UBD, simply using the term pressure is usually not precise enough because many kinds of pressure exist. To avoid confusion, this chapter defines terms used in UBD. For easy reference, italicized terms are defined in the glossary.

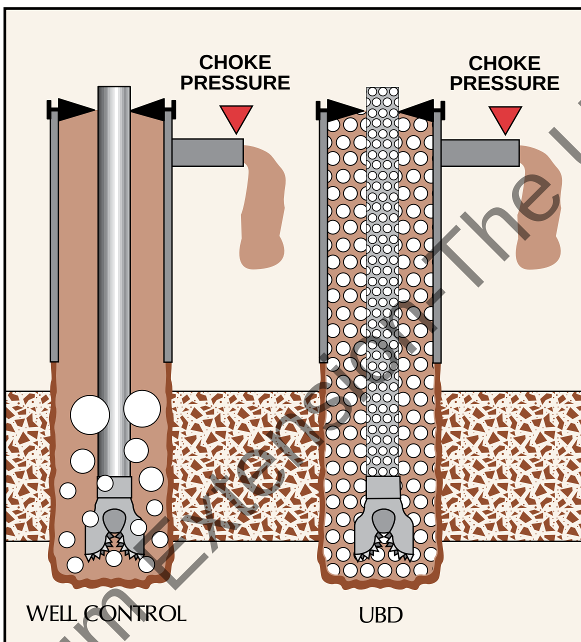


Figure 1.1. Choke controls pressure against standpipe gauge.

DEFINITION

UBD is drilling into any formation where the pressure exerted by the drilling fluid is less than the formation pressure. Examples of UBD include—

- drilling with air or gas. The pressure exerted by the column of gas and cuttings is almost always less than the formation pressure.
- drilling with cable tools. Because no mud column exists, cable-tool drilling is a form of UBD.
- drilling with any type of fluid where the pressure of the fluid column is less than formation pressure.

FORMATION PRESSURE

Formation pressure is the force exerted by fluids in the formation. Field personnel often use *pore pressure* and *reservoir pressure* as synonyms for formation pressure (fig. 1.2). Pore pressure actually means the pressure of the fluids in the pores of the formation. Pore pressure often refers to the pressure of water within shale, or within sandstone. Formation pressure is

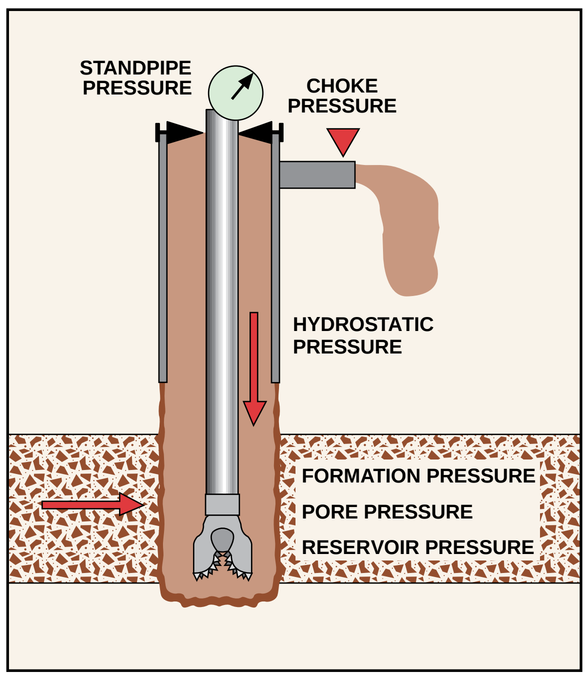


Figure 1.2. Pressures

Chapter 2

UBD GUIDELINES

UBD requires more equipment and attention to the drilling process than conventional overbalanced drilling. To justify the extra cost of equipment and personnel, a major economic advantage must exist for UBD. Further, UBD must be done in a geological climate where a maximum chance of success exists. Finally, the drilling program must be set up to maximize the underbalanced advantage and minimize other drilling and completion problems. This chapter discusses the uses of UBD, the proper geology or hole conditions for UBD, and the best drilling program for UBD.

USES OF UBD

The best uses for underbalanced drilling are to—

- increase the drilling rate,
- avoid or limit lost circulation,
- limit or avoid reservoir damage,
- reduce completion enhancement costs,
- avoid differential sticking, and
- find masked potential reservoirs.

Areas that fulfill several or all of these conditions include—

- horizontal drilling,
- geothermal drilling,
- depleted reservoirs, and
- old or poorly logged hydrocarbon producing sections.

Increased Drilling Rate

Most drilling personnel know that the drilling rate slows when the mud weight increases. However, it may not always be clear that when the mud weight decreases, the drilling rate increases (fig. 2.1). The critical point for the drilling rate is about 500-psi (3,500-kPa) overbalance. That is, after overbalance pressure decreases to values of less than 500 psi, the drilling rate continually increases. The drilling-rate increase continues into the underbalanced range until a point is reached where more *bit energy* (weight and speed) is needed, or where the bit begins to flounder. *Bit flounder* occurs when the cuttings are not cleaned out from under the bit fast enough and the bit redrills cuttings. (*Bit balling*, as normally seen by the driller, occurs when a clay or soft shale gums up the cutting surfaces and the bit body.)

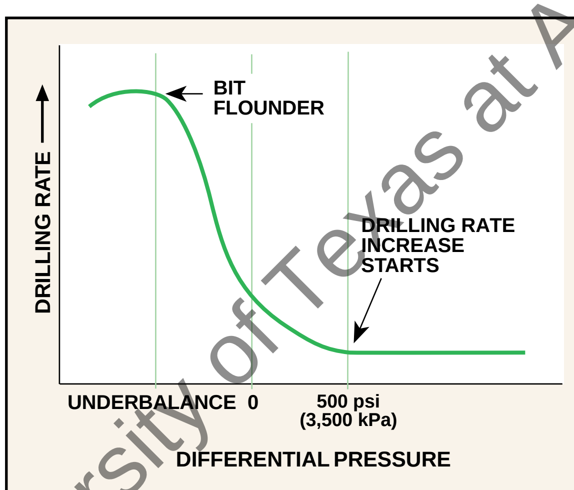


Figure 2.1. The effect on drilling rate of reduced mud weight or reduced differential pressure

In the early 1950s, two examples revealed the advantages of reduced mud weight. In the Permian Basin of West Texas and Eastern New Mexico, drillers encountered redbeds, which were 2,000 to 5,000 ft (600 to 1,500 m) thick and were composed mainly of sandstone, siltstone, and shale. Iron oxide made them red in color. These redbeds had a pore pressure (formation pressure) equal to a 16-ppg (1,920-kg/m^3) mud. When drilled with 16-ppg mud, the drilling rate, or rate of penetration (ROP), was less than 3

Chapter 3

SURFACE CONTROL EQUIPMENT

Operators have used rotary tools to drill underbal-anced since the early 1900s; but, initially, only with partial success. One problem was that drilling rig controls, as well as equipment for controlling the well, were not adequate for UBD. Since 1985, improvement in equipment has progressed rapidly in a climate where new technology is readily accepted. Present surface equipment is excellent and constantly improving. Because UBD technology is constantly improving, rig personnel should make staying up to date a routine part of their jobs.

This chapter covers—

- BOP stacks in UBD,
- rotating heads and rotating blowout preventers,
- annular preventers,
- ram preventers,
- stack arrangements,
- choke and choke manifolds,
- atmospheric and closed separators,
- cutting catchers, and
- standpipe and blooey line arrangements.

This chapter also introduces the concept of *barriers*. Operators use the barrier concept, especially in Europe and Canada, as a means of planning and implementing safe drilling and workover operations. In normal drilling, the mud system is the primary barrier against an *event*, which is a governmental agency term for a well kick or blowout. In UBD, however, operators deliberately make the mud too light to control downhole pressures. Therefore, a *rotating control head*, or a *rotating blowout preventer*, becomes the primary barrier, and the annular and ram preventers become secondary barriers.

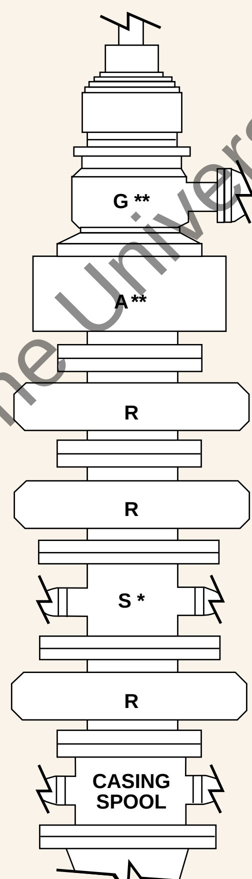


FIG. 2.C.9
ARRANGEMENT RS*RRA**G**
Double Ram-Type Preventers
R_d Optional

Figure 3.1. Typical underbalanced blowout preventer stack

BOP STACKS IN UBD

BOP stacks are usually arranged in conformance with American Petroleum Institute (API) *Recommended Practice (RP) 53, Blowout Prevention Equipment Systems for Drilling Operations.* RP 53 shows example arrangements of several kinds of BOP stacks. Readers can order the publication from Global Engineering Documents, 15 Inverness Way East, Mail Stop C303B, Englewood, Colorado 80112-5776.

UBD Stacks

BOP stacks used in UBD with liquid, gas-liquid fluids, or foam are not much different from the BOP stack used with conventional drilling mud (fig. 3.1). They are taller

Chapter 4

DOWNHOLE TOOLS

Several downhole tools are required for successful UBD. This chapter covers drill pipe valves including deployment, or downhole safety, valves, and the Halliburton downhole safety valve. The chapter also covers the use of downhole motors in UBD, snubbing units, air hammers, special equipment used in gaseated mud systems, drill bits, and measurement-while-drilling (MWD) systems.

DRILL PIPE VALVES

Drill pipe valves include bit floats, string floats, retrievable floats, inside blowout preventers (IBOPs), lower kelly valves, and deployment valves. They are used to prevent flow up the drill string or to the swivel.

Bit Floats

When drilling underbalanced, a *bit float* should always be run (fig. 4.1). In an under- or near-balanced condition, mud is not a barrier to flow up the drill pipe. The bit float stops flow up the drill pipe and protects bits and drilling motors from being plugged by cuttings. On some wells, two bit floats are placed in the bottomhole assembly (BHA); the second float serves as an additional barrier. The bit float is a plunger float that is reliable and trouble free.

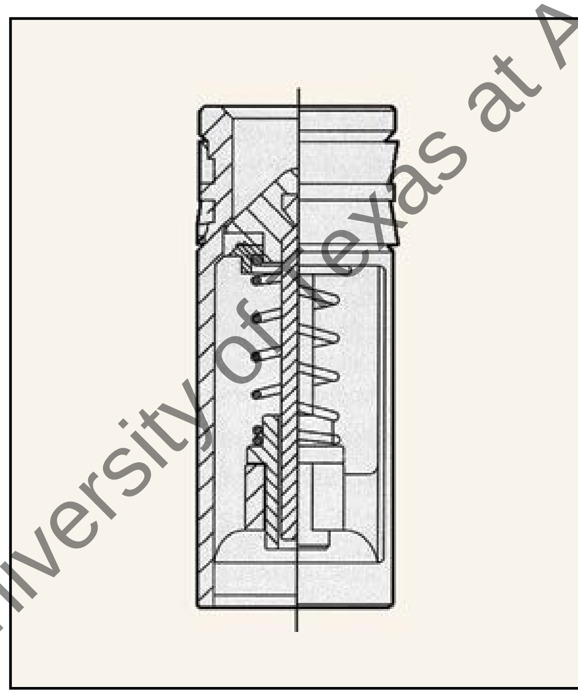


Figure 4.1. Bit float

Workover rigs also use a bit float as a standard piece of equipment. The biggest problem with a bit float in workover is that the spring in the float is so strong that it makes the last 500 to 1,500 ft (150 to 500 m) of pipe pull wet. If the rig does not have a mud box, pulling wet pipe can be messy, cold, and hazardous. Ideally, a workover rig should have a mud box that discharges to the flow line. Normally, a workover rig does not have barite or heavy mud available to slug the pipe. Moreover, slugging the pipe may not be desirable because the slug is hard to get out of the hole. Blowing the pipe dry with air is a poor procedure because, while it guarantees dry pipe, it increases corrosion because of the air blown into the annulus. (Blowing the pipe dry with cryogenic nitrogen is probably suitable.)

The easiest solution is to use a *string float* as a bit float. The string float has essentially no spring and does not hold the mud up. Another, but not as good, solution is to weaken or cut down the spring on the bit float. Weakening or disabling the spring allows mud to drain past the piston.

String Floats

The string float is the key to crew safety on connections. The string float is used when drilling with gas or when gas is injected into the standpipe. It is

Chapter 5

GASES AND EQUIPMENT

INTRODUCTION

Generally, operators use one of five gases for drill pipe injection in UBD: (1) air, (2) membrane-generated nitrogen, (3) cryogenic nitrogen, (4) natural gas, and (5) exhaust gas. Historically, air is the most common gas for UBD; natural gas is the second most common. Air is losing favor because of oxygen corrosion and the danger of fire. Nitrogen gas in the form of membrane nitrogen is replacing air. Cryogenic nitrogen, delivered to the rig in refrigerated tanks, is attractive for short jobs and some workovers, but it is limited because of high costs. Natural gas, possibly one of the best UB gases, is used less when its price is relatively high; however, even when natural gas prices are high, it is often less expensive than other gases. In Canada, operators use exhaust gases, which this text includes, because it may gain widespread use.

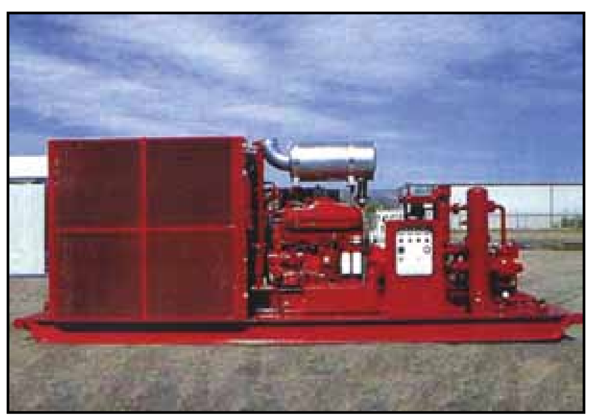
AIR

As stated earlier, air is the most common gas used in UBD. Air is about 78 percent nitrogen, 21 percent oxygen, and contains carbon dioxide, water vapor, and a trace of rare gases. Air is the least expensive of gases, because it only has to be compressed to be used in drilling. Measurement and recording of air pressure and volumes is generally done in a haphazard manner. However, if realistic measurement of air pressure and volume is done, the values can be used as a troubleshooting tool in the present drilling operation as well as a planning tool for the next well. Always measure and record the actual volume and pressure of the air (or gas) injected into the system.

Air Compressors

Large portable air compressors step up the pressure of the air with several stages of compression. Generally, each stage compresses the air only to about three and one-half times its previous pressure, because much heat is generated by compression that it causes seals and lubrication to fail in the cylinder. Traditional oilfield compressors use pistons moving inside cylinders to create positive-displacement compression (fig. 5.1). Some new systems use rotary compressors for the first and second stage and pistons for the booster stages (fig. 5.2). The rotary first stage allows higher pressure for succeeding stages. While compressors

Figure 5.1. Portable air compressors appeared about 1954 working out of Grand Junction, Colorado. They were two stage compressors that could reach about 200-250 psi. A booster raised air pressure to about 700 psi.



Courtesy Weatherford Air Drilling

Figure 5.2. Modern air compressors usually use a rotary compressor for the first stage, called the primary compressor, and a piston compressor as the booster stages. This is one of several different setups.

Chapter 6

CIRCULATION AND THE FLUID COLUMN

When circulating with a regular mud system, the conditions at the flow line generally bear a close relationship to what is going on in the hole. In underbalanced operations, the continual addition of gas or oil to the system changes or modifies all mud flow rules. So, what occurs at the flow line in UBD may or may not be related to what is actually going on downhole (fig. 6.1).

Courtesy Jerry Haston

Figure 6.1. Gas and liquid exit the blooey line on a UBD rig. What occurs at the blooey line is not necessarily an indication of what is occurring downhole.

UBD BOTTOMHOLE PRESSURE REDUCTION

In UBD, replacing part of the mud in the hole with gas reduces bottomhole pressure. The gas can be injected in the standpipe with the mud, it may come from the formation, or it may come from both. So, if gas displaces one-fourth of the mud out of the hole, then the rest of the mud exerts only three-fourths as much pressure as a full column of mud.

With no circulation, the gas separates from the mud. When circulating, the gas is dispersed through the mud (fig. 6.2). In either case, static bottomhole pressure is calculated as though the two fluids were separated. Gas bubbles at the bottom of the hole are small and do not displace much mud. As they go up the hole, the bubbles get larger because they are under less pressure and displace more mud (fig. 6.3).

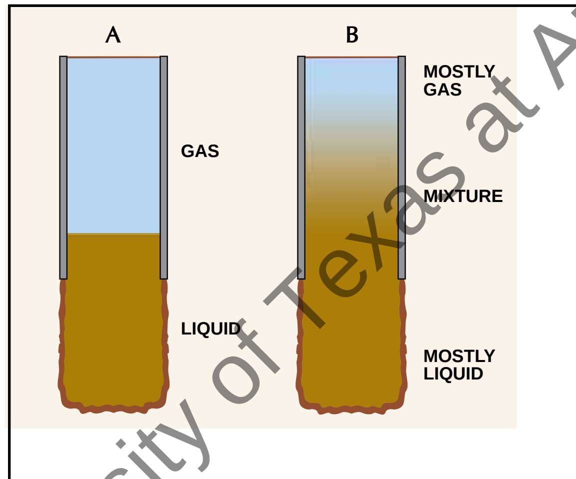


Figure 6.2. In UBD, gas displaces mud from the hole and reduces hydrostatic pressure. Bottomhole pressure calculates as though part of the hole contains only liquid and part contains only gas (*A*), which could be the case when the well is at rest. However, when circulated, a mixture exists (*B*).

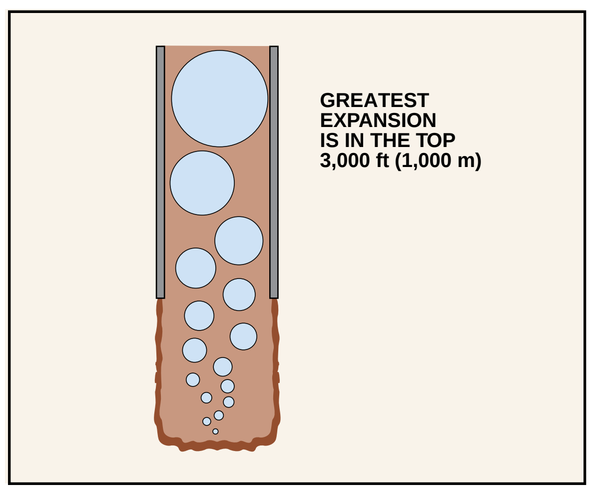


Figure 6.3. As gas bubbles go up the hole, they get larger because pressure is less near the surface.

Chapter 7

FLOW AND MUD-CAP DRILLING

DRILLER'S METHOD

To understand how to control a UB well, you have to understand the *driller's method* of well control. As a quick review, remember the following points about the method.

- Maintain a constant pump volume.
- Know the kill rate circulating pressure, add it to the shut-in drill pipe pressure (SIDPP) to obtain the initial circulating pressure (ICP), and maintain that pressure on the standpipe by opening or closing the choke.
- If a kill rate circulating pressure is not known, hold annulus (casing) pressure constant until you can determine an ICP.

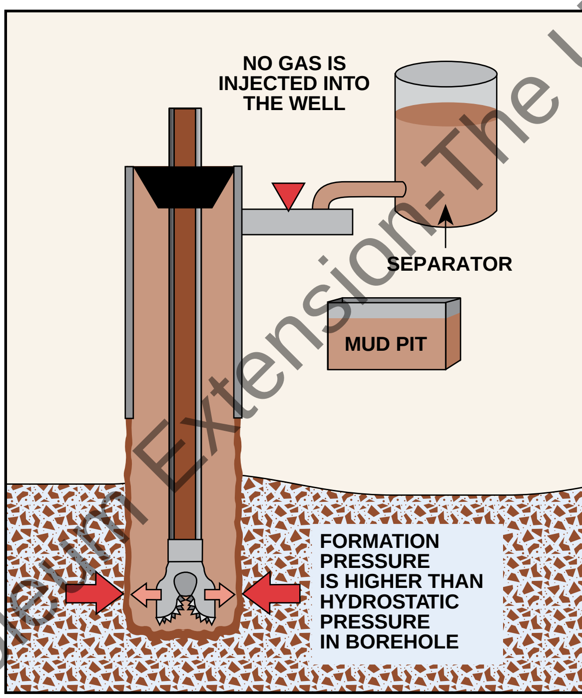


Figure 7.1. In flow drilling, the hydrostatic pressure of the mud is lower than formation pressure; consequently, formation fluids flow into the wellbore. No gas is injected down the drill stem.

- Keep the pump rate constant and control the bottomhole pressure by controlling the standpipe (drill pipe) pressure with the choke on the annulus.
- Allow for lag time between changing the choke pressure and seeing the results of the change on the standpipe gauge.

For more information about the driller's method, refer to chapter 6 in the Petroleum Extension Service (PETEX) publication, *Practical Well Control*, fourth edition, entitled "Well-Control Methods."

The driller's well-control technique controls bottomhole pressure by using the choke and standpipe pressure. Likewise with UBD, the driller can control bottomhole pressure by increasing or decreasing standpipe pressure, as long as the driller keeps the volume of fluid going down the drill pipe constant. The reduction in standpipe pressure while circulating is the same as the reduction in bottomhole pressure. It is important to keep a list of standpipe pressure variations with time as a record of bottomhole pressure variations.

LIQUID, OR FLOW, DRILLING

Underbalanced liquid, or flow, drilling is drilling near balanced or underbalanced with a liquid into which no gas is injected on the surface (fig. 7.1). Underbalanced drilling with a liquid can be used in several situations. For example—

- avoiding or limiting lost circulation and differential sticking,
- increasing the drilling rate, and
- limiting reservoir damage.

Further, liquid UBD can be used—

- when no gas or fluid flows from the formation,

Chapter 8

LIQUID-GAS FLUIDS

INTRODUCTION

In their simplest form, gas-cut mud and well kicks are liquid-gas, or gaseated, systems. Earlier, the manual pointed out that when formation gas flowed into the mud system, and drilling continued, flow drilling was occurring. When gas is injected into the mud system at the surface to lighten the mud column during drilling, a liquid-gas, or gaseated, system is being used. (Note that no foaming agent is used to tie the gas to the liquid.) The injection method may be down the drill pipe, by parasite string, in a dual casing string, or by some other method.

The injected gas lightens the fluid column by displacing mud out of the hole. As the amount of gas injected is increased, it displaces more mud out of the annulus and further lightens the mud column (fig. 8.1). Many different gases can be used as the gas fraction.

The advantage of gaseated fluids is that any mud system—water, oil, water-base mud, or oil-base mud—can be used to take advantage of a particular mud's properties and chemistry. Further, gaseated fluids are not temperature sensitive. Because gaseated systems are simple mixtures of gas and fluid, the system does not have special temperature limits. A fluid's *temperature limit* is the temperature at which the fluid or mud material breaks down and no longer behaves as expected. Diesel oil and natural gas gaseated systems have operated well in temperatures ranging up to 300°F (150°C).

Liquid-gas systems, or *gaseated fluids*, have a long history in drilling. In the late 1920s and early 1930s, gaseated systems were used in Iran to avoid lost circulation. In 1938 in the Sour Lake Field near Beaumont, Texas, natural gas and mud were used as a gaseated fluid to avoid lost circulation.

Gaseated systems are unstable systems because nothing ties the gas and fluid together. The more gas that is in the system, the more easily it separates from the fluid. A limit exists to the amount of gas that can be added to a gaseated system before it becomes too unstable. The upper limit is about 50 parts of gas to 1 part of mud. In practical terms, this 50-to-1 ratio works out to about 670 cubic ft (ft^3) of gas to every 100 gallons (gal) of liquid mud. In SI units, the limit is about 50 cubic m (m^3) of gas to 1 m^3 of liquid mud. On the other hand, enough gas must be added to the system for it to be effective. To obtain an effective gaseated system, at least a 5-to-1 ratio is required—for example, about 65 ft^3 of gas to 100 gal of mud or 5 m^3 of gas to 1 m^3 of mud (fig. 8.2).

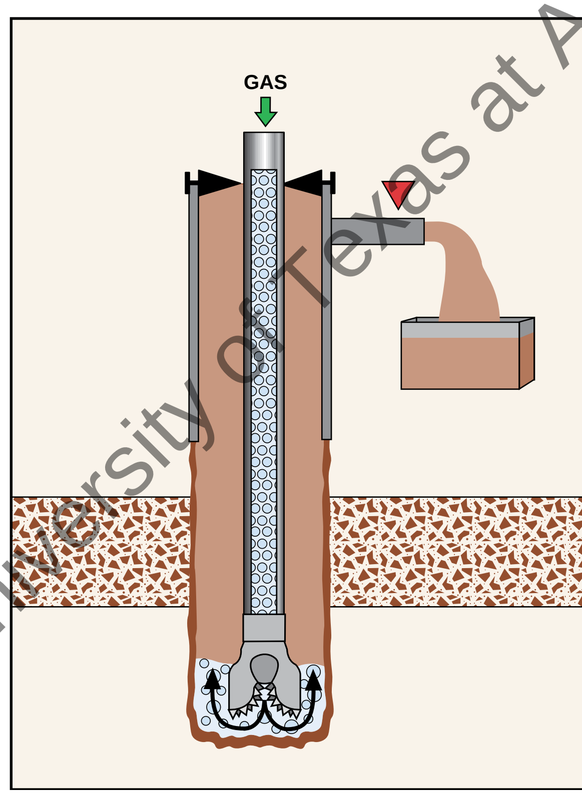


Figure 8.1. When gas is injected into the well, it displaces mud from the hole, and lightens the hydrostatic column.

Chapter 9

FOAM DRILLING

INTRODUCTION

Foam is a relatively new fluid to the drilling industry. Evidently, it was first used at the Atomic Energy Commission's nuclear test site near Las Vegas, Nevada in 1965. Foam was used to avoid lost circulation and to lift cuttings out of the large holes being drilled for underground nuclear explosions. Some of the holes eventually reached 12 ft (3.5 m) in diameter and were 5,000 ft (1,500 m) deep. In 1966, Chevron Oil Company used the newly developed foam technology as a workover fluid to clean sand out of producing oilwells in California's Kettleman Hills field. In the late 1990s, foam became the fluid of choice in drilling depleted reservoirs in Alberta, Canada. Foam is now a standard drilling and workover fluid that becomes more popular every year.

FOAM SYSTEMS

The following terms describe foam systems.

- *Ratio* is the amount of liquid to gas under *standard conditions*. It is usually expressed as so many units of gas to one unit of water or liquid. The units are usually ft^3 or m^3. For example, foam is often designed as having a 100-to-1 ratio, where there is 100 ft^3 (m^3) of gas and 1 ft^3 (m^3) of mud. Ratio is used to plan or measure the amount of liquid and gas pumped into the standpipe.
- *Quality* of foam is the percentage of gas in the foam at a particular depth or pressure. For example, foam with a quality of 75 percent means it is 75 percent gas and 25 percent water. The same foam deeper in the hole might have a quality of only 60 percent, because increased pressure compresses the gas. Therefore, foam quality varies with hole depth.
- *Texture* is a measure of the properties of foam, somewhat like the viscosity and gel strength of a mud. Unfortunately, no generally accepted measurements for texture in foam are currently available.
- *Half-life* of foam compares foams and the effect of foaming agents. Foam half-life can be determined by using a food blender, a stopwatch, and a 1,000-millilitre (mL) graduated cylinder. First, 0.5 mL of foaming agent is added to 100 mL of water in the blender. Next, the solution is mixed for 30 seconds. Finally, the solution is poured into the graduated cylinder and the time it takes for 50 mL of water to appear in the cylinder is the foam's half-life. Note that foam half-life cannot be used to compare the downhole effects of foam.

Foam is a unique fluid. It is an emulsion; an emulsion is a mixture in which one fluid is uniformly distributed in another fluid. Unlike an ordinary mixture, the fluids in an emulsion do not separate easily. In the case of foam, gas is tied up in a liquid. Because foam is an emulsion, it is more stable than gaseated mud, which is a simple mixture of gas in water. Foam has a structure. It is made up of bubbles

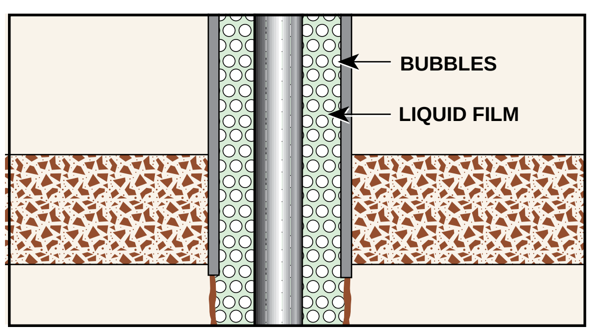


Figure 9.1. Foam consists of bubbles that are surrounded by a liquid film.

Chapter 10

AIR-GAS, MIST, AND FOAMED MIST DRILLING

INTRODUCTION

Air or gas drilling uses air, nitrogen, or natural gas as a drilling fluid. Because neither fluid exerts significant hydrostatic pressure, drilling with air or gas is UBD. In drilling and workover, air and gas are commonly used interchangeably because, from a drilling standpoint, their characteristics are virtually the same. Thus, little distinction is made between the two fluids; consequently, the term air-gas drilling is used to describe generally both air drilling and gas drilling.

The first formal indication of the use of air drilling in the U.S. was a patent filed in 1866 for “the use of compressed air to clean a hole.” Most early air drilling was probably related to mining and quarries. Air drilling was carried out in the Tampico, Mexico field in the 1920s. The wells were air drilled to the top of the reservoir and casing was set before drilling into the limestone.

El Paso Natural Gas Co. in the San Juan Basin of New Mexico likely started modern U.S. gas drilling in about 1950. It spread from there to West Texas and California. Technology improved rapidly and by 1960 most of the basic elements of air or gas drilling, as we now know it, was in use. Also, most of the basic problems in air-gas drilling that occurred in 1960 are the same today.

Currently, more air-gas drilling occurs in the Appalachian region of the U.S. than anywhere else. Many small rigs in the area have air compressors instead of mud pumps. Drilling is primarily for shallow gas in conventional formations, but drilling for coal bed methane is also growing.

ADVANTAGES TO AIR-GAS DRILLING

Several advantages can come about when drilling with air or gas. They include—

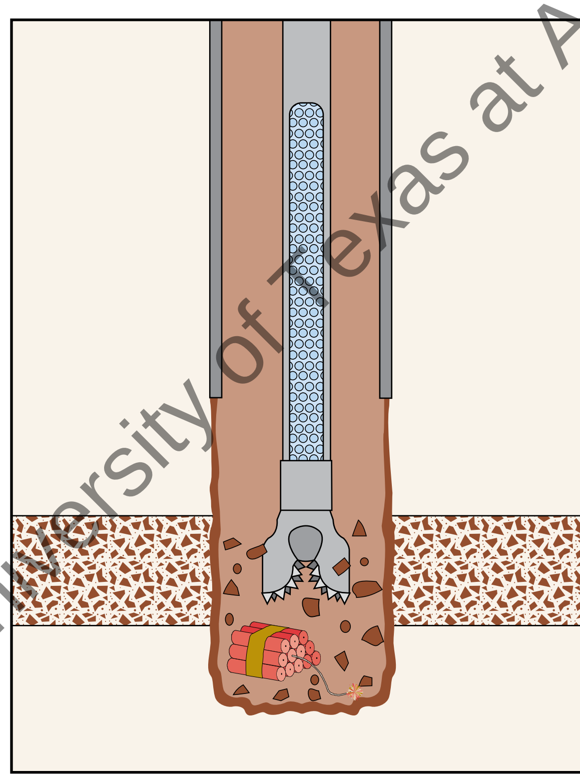


Figure 10.1. When drilling with air or gas, the cuttings explode almost like dynamite, from under the bit, which increases the rate of penetration.

- *faster penetration rate*. The reduction in hydrostatic head leads to spectacular increases in the drilling rate as the chips explode from under the bit (fig. 10.1).
- *longer bit life.* Lighter bit weights can be used with air or gas than with mud.
- *straight holes with high-speed drilling in crooked-hole country using a hammer drill*. A hammer drill requires light weight on the bit—only enough to keep the hammer on bottom. With light weight, a pendulum assembly with maximum drilling rates can be employed.

Chapter 11

PROBLEMS

With experience, UBD becomes routine. However, just as problems occur in normal drilling and workover operations, they also occur in UBD. Table 11.1 shows the effect on the well when various equipment fails and other problems occur in well control and UBD. Black arrows (↑, ↓, →) show well control and UBD changes; red arrows (↑, ↓, →) show changes unique to UBD. Be aware that in UBD, some of the effects are different from well-control situations. The table applies directly to UBD and workover problems when no gas is injected into the drill pipe and the well is on the choke. The arrows indicate an increase (↑), a decrease (↓), and no change (→) in pressure, weight, pit level, or pump rate. Readers should review the table before reading about more complex problem identification when gas is in the system. The table assumes that the well is closed in and circulating under drill pipe pressure control with a constant pump rate controlled by a throttle setting.

CHOKE WASHES OUT

When the choke washes out and air or gas is in the system, the same conditions can be expected as those that occur in normal drilling operations (see table 11.1). Drill pipe pressure and casing pressure go down, pit level and return line volume go up, pump strokes may go up, and drill stem weight stays the same. If a separator is being used, the separator may have to handle the full volume of the hole unloading.

Table 11.1
Effect of Well-Control and UBD Problems on Pressures, Weight, Pit Level, and Pump Rate

Problem	Drill Pipe Pressure	Casing Pressure	Drill Stem Weight	Pit Level	Pump Rate, strokes per minute (spm)
Choke washes out	↓	↓	→	↑	↑
Choke plugs	↑	↑	→	→	↓
Gas reaches surface	↓	↓	↓	↓	→
Loss of circulation	↓ ↓→	↓ ↓→	↑ →	↓	↑
Hole in drill stem	↓ →	→	→	→	↑ →
Pipe parts	↓ →	→	↓	→	↑
Bit nozzle plugs	↑	→	→	→	↓
Bit nozzle washes out	↓	→	→	→	↑
Pump damage or gas-cut mud	↓ ↑	↓	→	→	↑
Gas feeding in	↑ ↓	↑	↑	↑	
Hole caves in	↑	→	•	↓	↓

Chapter 12

CORROSION AND SCALE

Corrosion and scale are often encountered on drilling and workover rigs. The chemical and biochemical reactions that cause corrosion vary from simple to complex. Many corrosion inhibitors are available from various chemical and service companies and each company uses a trade name for the inhibitor. Thus, a mud or corrosion engineer usually has to determine the correct inhibitor to use for a given situation. However, toolpushers and drillers should be able to recognize when corrosion problems occur and take immediate action.

CORROSION

Corrosion ruins pipe by changing the steel in the pipe to rust or another iron compound. Metal loss, primarily in deep pitting of the pipe, causes weakness and failure. The hidden cost of corrosion is on casing, which cannot be observed directly, but which causes failure over the course of time. Do not confuse corrosion with scale. Scale occurs when saturated formation water precipitates material on the pipe surface as temperature or pressure drops.

Corrosion on pipe occurs as a reaction between the drill water and gases present in the borehole, such as oxygen, carbon dioxide (CO_2), or hydrogen sulfide (H_2S). Corrosion can also occur from microbial action in contaminated water. Drill pipe corrosion can occur with formation gas or fluids, or with surface fluids.

Erosion can occur wherever high gas flow rates are present—for example, in steam geothermal wells that have hard quartz cuttings, the cuttings erode the pipe as the steam flows. Erosion also occurs with air and mist drilling. Erosion-corrosion occurs when high-velocity fluid and solids wash corrosion inhibitor off the pipe.

Coiled tubing is a thin-walled, high-strength tube that bends when wound on or off a reel. Corrosion is a particular problem with coiled tubing, which can shorten tube life or even cause failure on a single job.

In most areas, corrosion is not a problem with normal drilling fluids. Many mud products, especially lignosulfonates, are good oxygen scavengers. Thus, if crew members keep the mud's pH at 9 or higher, visible corrosion usually does not occur. Also, the oxygen content of a mud is normally low enough so that it cannot cause major corrosion problems. However, corrosion can sometimes start when air, which contains 20 percent oxygen, is beat into the mud by guns or hoppers.

In balanced drilling operations, formation gases and formation water usually do not enter the wellbore because drilling fluid density is high enough to keep them out. Corrosion occurs when contaminated water is used to make up the mud system or when a well kick or gas cut mud lets CO_2 or H_2S into the wellbore.

Gaseated systems and foam systems inject gas into the well. Natural gas and cryogenic nitrogen have no oxygen and therefore do not pose an oxygen corrosion problem. Diesel oil-membrane nitrogen systems, such as those used in Canada, do not support corrosion because no free water is present in the system and the steel pipe is oil wet. On the other hand, air with 20 percent oxygen and membrane nitrogen with 5 percent oxygen, if not treated, allow oxygen corrosion to occur.

Keep in mind that dissolved oxygen in water causes most drill stem and casing corrosion. In general, if no water is present, corrosion does not occur. Similarly, if no oxygen is present, corrosion does not occur. Further, oxygen accelerates other types of corrosion, such as that caused by CO_2 and H_2S and that caused by the microbes in sewer water or any water with a high microbe content.

Therefore, the first defense against corrosion is to use the best possible water. Ideally, water should

Chapter 13

RIGGING UP

Manuals are available that cover planning and organizing UBD from an administrative, safety, or engineering viewpoint. This manual, however, is for the rig site; thus, it addresses practical UBD issues that rig crew members will likely face in the field. While toolpushers and drillers do not design the system, they do affect its operation and safety at the location, so it is worth discussing how rigs are set up for underbalanced operations (UBO).

UBO can be confusing because it adds additional equipment, people, and techniques to a drilling or cleanout operation. When setting up a rig for UBO, important factors and equipment to consider include the details of—

- the size of and arrangement of equipment and mud pits.
- the gas source—that is, whether air compressors and a nitrogen unit or a natural gas source will be used. Of course, with flow drilling, no gas source may be required.
- the BOP stack, the rotating head, and other special spacers and valves. A workover rig may use an annular preventer or stripping head in place of a rotating head.
- the blooey and choke line and how they are staked down and whether a flare is to be used.
- the standpipe and standpipe manifold.
- the separator system.

LOCATION CONSIDERATIONS

Compared to balanced operations, underbalanced operations require more room on the location for setting the gas source—usually, compressors—the separator, the blooey line, and the flare line. Also, the site should be large enough so that, after the reserve pit is located, enough room is still available for—

- trucks to load and unload pipe and to rig up extra equipment.
- supply trucks to drive on location without driving over gas or mud lines; or are the lines to be buried.
- remote parking for cars and pickups.
- compressors, if used (also, allow enough room for operators to move around each unit).
- extra housing for personnel.
- a safe assembly point for emergencies.

Also—

- place signs at enclosed spaces where gas might accumulate.
- bury and cover with a board mat any gas, air, or mud lines where trucks or cars cross them. Such lines should be buried at least 18 in. (0.5 m) deep.
- stake and weight down blooey or flow lines.

GAS SOURCES

Compressors

Place compressors on the site so that they are upwind or crosswind from traffic and the blooey or flare line. Also, compressors take in large volumes of air, which should be as clean as possible. When using membrane nitrogen, the membrane units must be clear of diesel exhaust fumes, dust, and gases.

Compressor discharge valves are hot as are the lines to the heat exchangers. Crew members should be aware of hot air-compressor lines. High-pressure air or

Chapter 14

FLARES AND FLARING

INTRODUCTION

Flares are often used to dispose of combustible gases from UBD (fig. 14.1). API RP 521, *Guide for Pressure-Relieving and Depressuring Systems*, states:

> The primary function of a flare is to use combustion to convert flammable, toxic, or corrosive vapors to less objectionable compounds. Selection of the type of flare and design of the flare system will be influenced by several factors, including the availability of space; the terrain; the characteristics of the flare gas (namely, composition, quantity, and pressure level); economics, including both the initial investment and operating costs; and public relations. Public relations may be a factor if the flare can be seen or heard from residential areas or navigable waterways.

Figure 14.1. A flare from a vertical flare stack disposes of combustible gas from a well.

Gas around a drilling rig or the surrounding area can explode when exposed to an open flame or a heat source, such as a diesel engine exhaust or a catalytic converter on a gasoline engine. It can also enter an engine's intake and cause a runaway engine.

The Environmental Protection Agency (EPA) regulates the handling of *volatile organic compounds* (*VOC*). The EPA accepts flaring as a primary means of VOC disposal. In addition to the disposal of gas, flare design may also be required to address problems of smoke, odor, noise, light, environmental damage, and burning liquids. Moreover, the flare must be configured to prevent injuries to rig personnel and to protect equipment.

Few publications in the U.S. address flare line design for drilling or workover rigs. RP 521 is the primary source of information, but it deals primarily with refinery and plant design. Few state regulations cover flaring on land drilling or workover rigs. The U.S. Coast Guard and U.S. Geological Survey's Minerals Management Service (MMS) publishes, administers, and enforces specific regulations for offshore flaring.

In Canada, the Alberta Energy and Utilities Board (EUB) has issued "Guide 60, Upstream Petroleum Industry Flaring Guide," which lists strict rules for vertical gas flares and flare tanks in drilling. Canadian rules discourage horizontal flare lines, and require a vertical flare stack. The height of the stack must be great enough to disperse the gas if the flare should temporarily go out.

COMMON FLARE PRACTICES

The text that follows describes common practices in the U.S. These practices may not be followed all over the world, but they are inexpensive and represent a large majority of the flares used in U.S. drilling.

To obtain additional training materials, contact:

PETEX
THE UNIVERSITY OF TEXAS AT AUSTIN
PETROLEUM EXTENSION SERVICE
1 University Station, R8100
Austin, TX 78712-1100

Telephone: 512-471-5940
or 800-687-4132
FAX: 512-471-9410
or 800-687-7839
E-mail: petex@www.utexas.edu
or visit our Web site: www.utexas.edu/ce/petex

To obtain information about training courses, contact:

PETEX
HOUSTON TRAINING CENTER
THE UNIVERSITY OF TEXAS
2700 W. W. Thorne Blvd.
Houston, TX 77073

Telephone: 281-443-7144
or 800-687-7052
FAX: 281-443-8722
E-mail: petexhtc@www.utexas.edu
or visit our Web site: www.utexas.edu/ce/petex

ISBN 0-88698-198-0

9 780886 981983

Catalog No. 2.60110
ISBN 0-88698-198-0