Introduction

A blowout is an uncontrolled flow of formation fluids as the result of failure to control subsurface pressures.

Despite efforts to understand and control formation pressures, blowouts still occur. A blowout is an uncontrolled flow of formation fluids as the result of failure to control subsurface pressures. Blowouts can occur at the surface or into an underground formation.

Nearly every well drilled has the potential to blow out. Experience has shown that blowouts occur as the result of human error and/or mechanical failures. However, a carefully planned, continuously supervised pressure-control program will lessen the possibility of a blowout considerably.

The key to effective pressure control is preparation and vigilance on the part of those who are responsible for controlling formation pressures. Respect for formation pressures and the confidence that comes from training and practice in controlling pressures are the elements that minimize the frequency and severity of blowouts.

It is important to identify high formation pressures before drilling, to detect pressure changes while drilling, and to control them safely during drilling and completion operations.

Three Levels of Pressure Control

Pressure control can be divided into three categories:

1. **Primary control.** The proper use of hydrostatic pressure to overbalance the formation and prevent unwanted formation fluids from entering the wellbore. The advantages of control at this level are self-evident.
2. **Secondary control.** The use of equipment to control the well in the event primary control is lost. Formation fluids that have entered the annulus can cause a blowout quickly if not properly controlled.
3. **Tertiary control.** The use of equipment and hydrostatic pressure to regain control once a blowout has occurred. This could involve the drilling of a relief well. Although tertiary control is normally handled by experts, many things can be done during the planning and drilling of a relief well to simplify the final kill procedure and regain control of the well.

A kick is an influx of formation fluid into the well.

Failure of Primary and Secondary Control

Failure of primary control. Any event or chain of events that create a negative differential pressure between the hydrostatic pressure of the drilling fluid and the formation pressure can cause a "kick." A kick is an influx of formation fluid into the well. The most common causes of a kick are:

1. Failure to keep the hole full of mud during trips.
2. Insufficient mud weight.
3. Lost circulation causing the hydrostatic pressure to be reduced.
4. Swabbing in when pulling out of the hole.
5. Improper casing design and pore-pressure prediction.

The most common cause of blowouts is the failure to keep the hole full on trips.

...the loss of secondary control was the result of equipment failure...

A study of 55 blowouts during a 10-year period lists the following primary causes of blowouts:

Cause	Percent of Total
Failure to keep the hole full	42
Insufficient mud weight	15
Lost circulation	22
Swabbing	16
Other	5

Although geopressured wells have greater potential for blowing out, reports indicate that more than half of all blowouts occur in normally pressured wells. The most common cause of blowouts is the failure to keep the hole full on trips. It should be standard procedure on all wells to either monitor the pump strokes while filling the hole during a trip or to use a trip tank to measure the mud required to replace the volume of pipe removed from the wellbore.

Failure of secondary control. It has been estimated that 95% of the wells in which secondary control is lost arrive at that condition as the result of either poor maintenance and inadequate testing programs, which result in leaks that erode pressure-control equipment, or inadequate crew training, which results in miss-use or no use at all of pressure-control equipment.

In the 55-well study referred to earlier, evidence showed that after the wells kicked, 62% were not controlled for the following reasons:

Cause	Percent of Total
Insufficient blowout equipment	29
Improperly designed blowout equipment	5
Improper installation	11
Improper surface fittings	6
Improper well casing and cementing program	11

This record shows that the 62% of the loss of secondary control was the result of equipment failure and reflects a lack of understanding among those responsible for securing, installing, maintaining and operating blowout-control equipment.

The remainder of this chapter will discuss the various components of well control. This will include the various pressures, pressure prediction techniques, kick-detection methods, well-control methods, and some special problems and techniques used in controlling the well.

Subsurface Pressures

Many different pressures are involved in drilling and controlling oil and gas wells. It is important to understand these pressures and how they are used to detect and control formation pressures. The following is a description of the various pressures.

Pressure is defined as force per unit area:

$$\text{Pressure (psi)} = \frac{\text{force (lb)}}{\text{area (in.}^2\text{)}}$$

Example 1

How much pressure would be shown on the gauge in Figure 1?

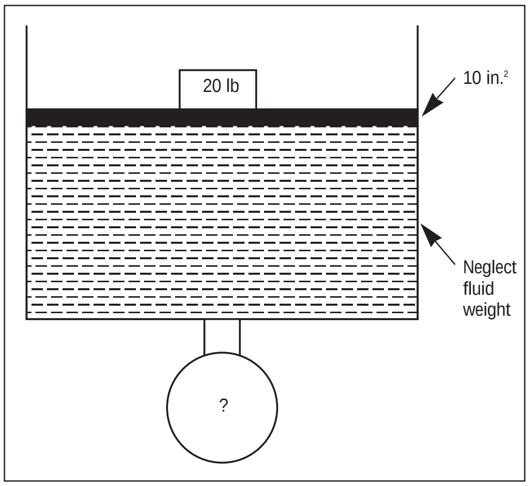


Figure 1: Example 1 — pressure.

Answer:

$$\text{Pressure on gauge} = \frac{20 \text{ lb}}{10 \text{ in.}^2} = 2 \text{ psi}$$

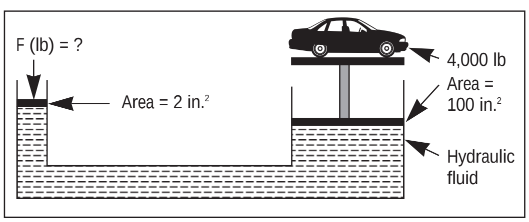


Figure 2: Example 2 — pressure.

Hydrostatic pressure is the pressure caused by the...MW and TVD of a column of fluid.

Example 2

In Figure 2, how much force must be applied on the small cylinder in order to balance the pressure created by the weight of the automobile on the large cylinder.

To balance pressures:

$P_1 = P_2$ or

$$\frac{F_1}{A_1} = \frac{F_2}{A_2}$$

$$\text{Therefore, } F_1 = \frac{F_2}{A_2} \text{ x } A_1$$

Force on small cylinder:

$$F_1 \text{ (lb)} = \frac{4{,}000 \text{ lb}}{100 \text{ in.}^2} \text{ x } 2 \text{ in.}^2 = 80 \text{ lb}$$

Hydrostatic pressure

Hydrostatic pressure (P_{HYD}) is the pressure caused by the density or Mud Weight (MW) and True Vertical Depth (TVD) of a column of fluid. The hole size and shape of the fluid column have no effect on hydrostatic pressure since, at a given depth, pressure is equal in all directions.

P_{HYD} is calculated by:

$$P_{HYD} \text{ (psi)} = 0.052 \text{ x MW (lb/gal) x TVD (ft)}$$

Where:

0.052 = The units conversion factor equal to:

$$\frac{12 \text{ in./ft}}{231 \text{ in.}^3\text{/gal}} \text{ or } 0.052 \text{ gal/(in.}^2 \text{ x ft)}$$

Formation pressure is the fluid pressure exerted within the pore spaces...

Example 3

What is the hydrostatic pressure of a fluid column for the following conditions?

MW	= 12.8 lb/gal
MD (Measured Depth)	= 14,300 ft
TVD	= 13,200 ft

The hydrostatic pressure is ***always*** calculated using the TVD.

$$P_{HYD} = 0.052 \times 12.8 \times 13{,}200 = 8{,}786 \text{ psi at TVD}$$

If the Measured Depth (MD) were used to calculate the hydrostatic pressure, this would result in significant error.

$$P_{HYD} = 0.052 \times 12.8 \times 14{,}300 = 9{,}518 \text{ psi (using MD)}$$

Incorrectly using MD to calculate hydrostatic pressure results in an error of 732 psi (9,518 – 8,786 = 732).

Hydrostatic pressure gradient is the pressure increase per unit of vertical depth.

Pressure gradient

Hydrostatic pressure gradient is the pressure increase per unit of vertical depth.

$$P_{HYDG} \text{ (psi/ft)} = 0.052 \times \text{MW (lb/gal)}$$

Example 4

What is the pressure gradient of a 12.0 lb/gal mud?

$$P_{HYDG} \text{ (psi)} = 0.052 \times 12.0 = 0.624 \text{ psi/ft}$$

Typical pressure gradients are:

Fluid	Pressure Gradient
Freshwater	0.433 psi/ft
Seawater	0.444 psi/ft
Marine formation water (100,000 mg/l salt)	0.465 psi/ft
Saturated saltwater (10 lb/gal)	0.520 psi/ft
16-lb/gal mud	0.832 psi/ft
19.2-lb/gal mud	1.0 psi/ft

Formation pressure

Formation pressure (P_{form}) is the fluid pressure exerted within the pore spaces of any oil, water or gas formation, and is commonly called *pore pressure*.

Normal pressure

Normal pressure is the hydrostatic pressure exerted by a column of fluid equal to the density of the native fluid that existed in the geological environment when the solids were deposited.

Since more wells are drilled in sediments characterized by marine formation water with about 100,000 mg/l salt, a gradient of 0.465 psi/ft will be used as the normal gradient for purposes of this discussion. Deviations from normal hydrostatic pressures are referred to as being abnormal — sur-pressures (high) and subpressures (low).

Example 5

When drilling in South Louisiana, in a normally pressured shale, at a depth of 7,000 ft, what would the expected formation pressure (P_{form}) be? What mud weight in lb/gal would be needed to balance this formation pressure?

$$P_{form} = 7{,}000 \times 0.465 = 3{,}255 \text{ psi}$$

$$MW = \frac{3{,}255}{0.052 \times 7{,}000} = 8.9 \text{ lb/gal}$$

Basin Type	Formation Fluid (lb/gal)	Pressure Gradient (psi/ft)
Saltwater	8.94	0.465 (Gulf Coast U.S.)
Fresh or brackish	8.33	0.433 (Mid-Continent U.S.)

Indications of Increasing Formation Pressures

The term "transition zone" describes a rapid change in pore pressure.

The term "transition zone" describes a rapid change in pore pressure. Transition zones are important to maintaining pressure control in geopressured drilling environments. The three types of transition zones (also illustrated in Figure 3) are:

1. The interval from the top of geopressures to the top of the first permeable sand in the geopressured section.
2. Any rapid pressure increase in an impermeable section (usually shale).
3. The interval from the top of geopressures to the depth at which the maximum pore pressure is encountered.

Usually, the initial transition zone is selected as the point at which intermediate or protective casing is set. There are two reasons for this. First, the pore pressure in the first permeable sand (Sand A) in the geopressured section is usually higher than the fracture gradient at the last casing shoe. Drilling into this sand would probably lead to the fracturing of an upper formation, losing circulation before the well could be controlled. Second, the fracture gradient increases with both depth and pore pressure. Setting the casing as deep as possible results in having the highest possible fracture gradient. This reduces the risk of fracturing the casing shoe and losing circulation while drilling the next interval.

The most critical of the three types of transition zones is the interval from the top of the pressured zone.

The most critical of the three types of transition zones is the interval from the top of the pressured zone. This is due to weak upper formations, a long interval of open hole, differential sticking problems, etc. In the following discussions of detecting abnormal pressures while drilling, the initial transition zone will be stressed, with less emphasis on the remaining two. Note that all of the methods are related, either directly or indirectly, to differential pressure.

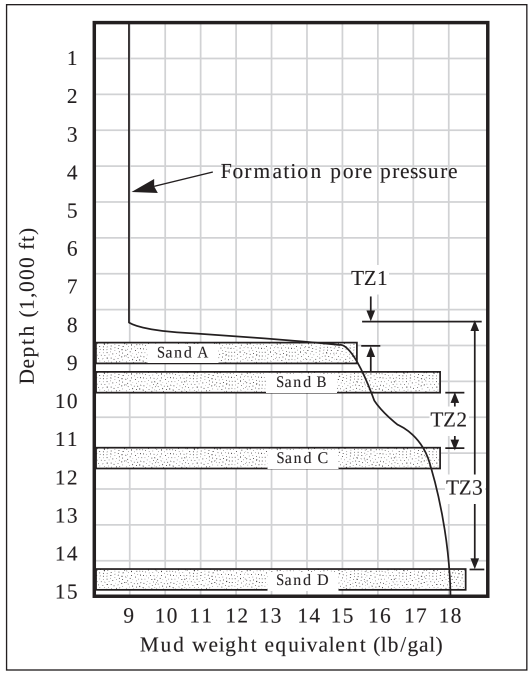


Figure 3: Three different transition zones.

PRESSURE INDICATORS

Historically, the occurrence of surnormal pressures has caused many drilling problems. Problems vary with geographical location, mud weight and type, rig type, and hole type (straight or deviated). However, a number of drilling response indicators exist that warn of a change in formation pressure. All of the indicators may not be present at one time, since they can be masked or eliminated by: (1) poor drilling practices, (2) improper mud weight, (3) wrong bit selection for the formation being drilled and (4) poor hydraulics. However, one — and usually more — of the indicators will be present. By using the proper monitoring equipment and drilling procedures and having trained personnel, the indicators can be interpreted to anticipate and identify increasing pressure and insufficient mud weight.

Abnormal compaction, the principle on which most of the pressure indicators are based, is the change of porosity

...the porosity of shale in a transition zone remains the same or shows only a slight increase, with depth.

As the differential pressure decreases, the ROP increases.

of shale with depth, as discussed in the Pressure Prediction chapter. In a normally compacted (normally pressured) sequence of rocks, the porosity of shale decreases with depth as shale density increases. If a seal is formed, the porosity of shale cannot continue the trend of reduced porosity with depth. In other words, the porosity of shale in a transition zone remains the same or shows only a slight increase, with depth.

Pressure indicators are divided into two groups:
I. Engineering.
II. Geological.

MEASURING DOWNHOLE PRESSURE

The advent of downhole, real-time measurements of drilling and geological parameters has greatly improved the ability to identify increasing pressure. These tools include Measurement While Drilling (MWD), Logging While Drilling (LWD) and Pressure While Drilling (PWD). Obviously, LWD and PWD can be used to verify sur-pressured transition zones. These tools can measure increasing pressure indicators which fall into both engineering and geological categories.

ENGINEERING INDICATORS

Engineering indicator 1: Changes in Rate of Penetration (ROP)

ROP increases while drilling the transition zone. While drilling normally pressured shale sections, the ROP will decrease with depth if drilling parameters such as weight-on-bit, RPM, bit types, hydraulics and mud weight remain fairly constant. This is due to the increased density, or compaction, of the shale. This trend will be interrupted when a sur-normal pressure zone is encountered. There will be a marked reduction in ROP as the pressure seal is penetrated. After penetrating the seal in sur-normally pressured formations, there will be an increase in ROP. This is due to the higher porosity of the sur-normal pressured zone. Higher-porosity rocks tend to be drilled faster. Also, decreases in the differential pressure increases ROP and rock fracture characteristics near the bit.

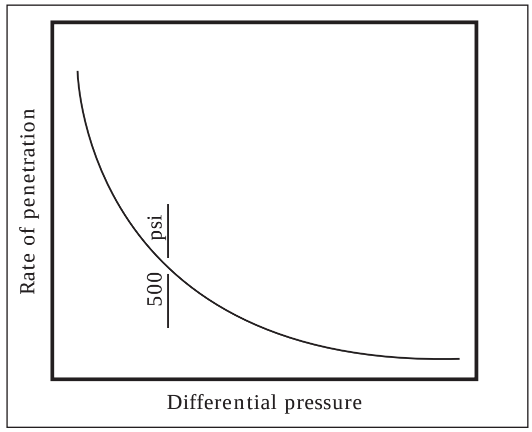


Figure 4: Typical shale drilling.

Differential pressure is an important factor in ROP. Differential pressure is the difference between the hydrostatic pressure of the drilling fluid column and the formation pressure. As the differential pressure decreases, the ROP increases. The increase follows a hyperbolic curve and often has a critical point at about 500 psi overpressure against the formation, as shown in Figure 4. A reduction in differential pressure occurs with entrance into the over-pressured zone of greater porosity. The increase in porosity and the decrease in differential pressure cause an increase in ROP.

Differential pressure affects ROP more than porosity. The ideal ROP curve should resemble Figure 5A when bit

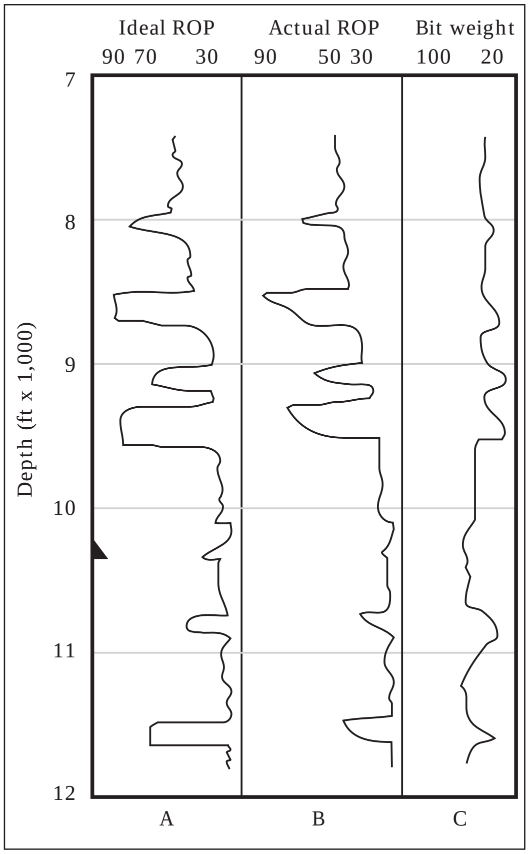


Figure 5: Ideal ROP, actual ROP and bit weight.

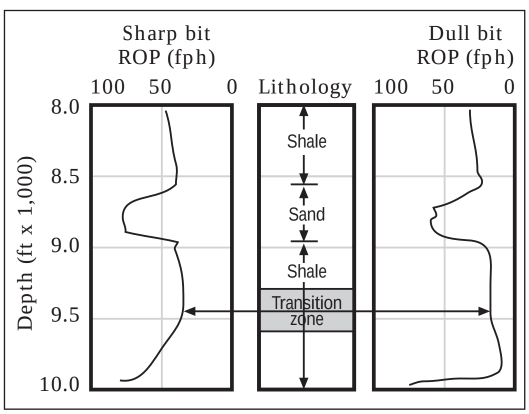


Figure 6: Comparison of sharp and dull bit ROP in the top of the transition zone (NOTE: Dull bit masked transition zone).

weight, rotary speed, hydraulics and mud properties are held constant. For economic reasons, it is not possible to hold these parameters constant over long intervals, so actual drilling curves will resemble Figure 5B. If it were possible to record bit weight on the same chart with ROP, the ROP curve would be much easier to interpret, as shown in Figure 5C. Bit dulling also can mask the transition zone, as shown later in Figure 6. The increase in ROP may not be seen due to reduced bit performance caused by the dull bit.

Engineering indicator 2: Decreases in d_{cs} exponent trend

Calculations for "d exponent" and "d_{cs} exponent" can be made to normalize ROP data and predict the magnitude of increasing formation pressure.

Many methods have been developed to resolve the problem of normalizing the ROP. All of them are effective to a degree, but each has its limitations. All methods become inaccurate when poor drilling practices are used. Most of the methods involve complex mathematical equations; however, one method uses a simplified drilling equation that is more suitable for use at the wellsite.

This method is known as the d exponent and the equation is:

$$d = \frac{\left(\frac{R}{60N}\right)}{\left(\log \frac{12W}{D10^6}\right)}$$

Where:

d = Exponent in the generalized drilling equation
D = Bit diameter (in.)
N = Rotary speed (RPM)
R = Penetration rate (ft/hr)
W = Bit load (lb)

This is not a rigorous solution to the original equation and cannot be defended mathematically. Even so, the results are as accurate as any of the more complex equations if a mud

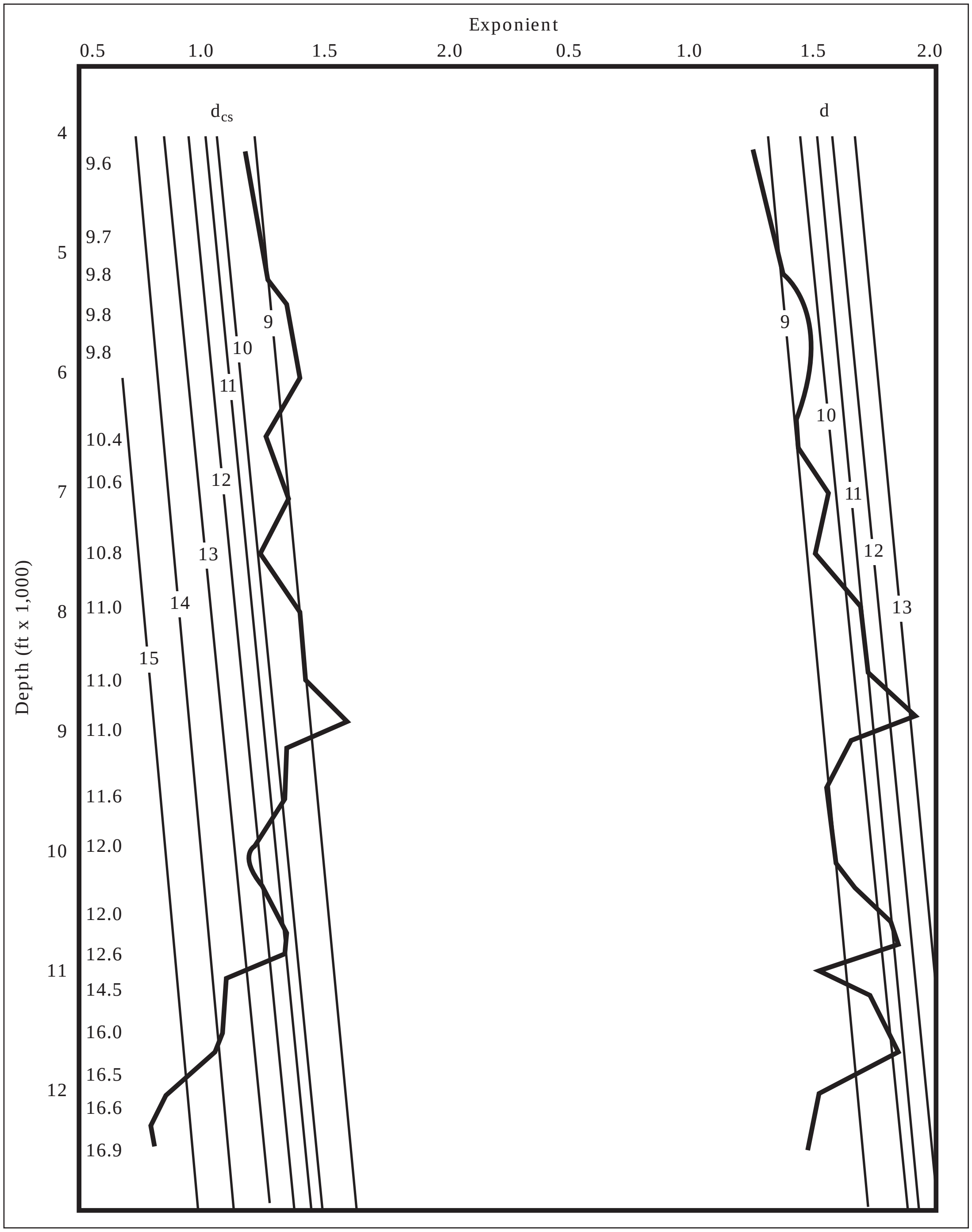


Figure 7: Plot of d and d_{cs} exponents with depth indicating formation pressure changes at the bit.

density correction is added. The d exponent calculated from the given formula is corrected for the mud density in the following manner:

$$d_{cs} = \frac{\text{normal pressure gradient (lb/gal) x d}}{\text{ECD (lb/gal)}}$$

Where:

ECD = Equivalent Circulating Density (lb/gal)

NOTE: The normal pressure gradient should be selected for the area where the well is drilled. Normally, this is considered 9.0 lb/gal in coastal areas and 8.33 lb/gal in hard rock areas.

An actual kick is the most obvious indication of an increase in pressure.

Using the d and d_{cs} plots as shown in Figure 7, a formation pressure at the bit can be predicted to an accuracy of ±0.5 lb/gal.

Another reason some methods fail is that bit weight does not exceed the threshold strength of the rock and therefore does not cause the rock to fail. This often happens with diamond bits and in crooked holes, where very low bit weights are used to control hole deviation. Polycrystalline Diamond Compact (PDC) bits require new techniques for analyzing drilling data to predict formation pressures accurately. PDC bits drill by shearing, rather than fracturing, the formation. The primary factor in ROP becomes torque instead of weight-on-bit. Several methods have been developed that correlate PDC bit drilling performance with pore-pressure prediction. These correlations depend on formations and bit types.

Rotary torque may increase rapidly in the transition zone.

Engineering indicator 3: Changes in rotary torque

Rotary torque may increase rapidly in the transition zone. Torque increases gradually with depth because the contact friction between the drillstring and the wellbore increases with depth.

Abrupt changes in torque also may indicate a twist-off of the drillstring, a locked cone on a bit, a washout in the drillstring or a change in formation pore pressure.

Experienced personnel can usually identify the problem. Torque will increase in the transition zone because a larger volume of shale cuttings will enter the wellbore. Shale tends to close-in the hole, causing additional contact with the drillstring and impeding bit rotation. It is difficult to distinguish an increase in torque in deviated holes due to contact of the drillstring with the formation face. When these cases occur, other indicators may be easier to interpret.

Engineering indicator 4: Changes in drag

An increase in drag may be experienced while making connections in the transition zone. After the kelly is drilled down, the recommended practice is to pick up 5 to 10 ft (to allow for working the drill pipe if it sticks), turn the pumps off and pull the kelly from the hole.

As previously explained, extra cuttings may enter the wellbore when the transition zone is penetrated. The hole may also tend to close-in around the drill collars and bit. Some transition zone shales tend to flow under differential pressure. There have been instances where it was necessary to backream and circulate to trip out of the hole. Again, this indicator may be masked when drilling deviated holes.

Engineering indicator 5: Kicks

An actual kick is the most obvious indication of an increase in pressure.

Any pit gain, if not accounted for, is an indication of an influx of formation fluid (kick). When this happens, the amount of fluid returning increases, and the flow sensor records the increase. The flow sensor and the Pit Volume Totalizer (PVT) are the first two indicators of a kick and should be monitored continuously while drilling. Special vigilance should be shown when approaching a

"Taking a kick" was once used as a method for finding the transition zone.

If the hole takes less mud than the calculated displacement volume for the number of stands pulled, fluid is entering the wellbore.

transition zone. If an increase in pit volume or flow is detected, drilling should be stopped and the well checked for flow. If the well continues to flow, it should be shut in.

"Taking a kick" was once used as a method for finding the transition zone. After a kick was taken, the formation pressure was calculated, the mud weight was increased, the well was controlled and protective casing was set. This technique has limitations, but it is still used inadvertently when other indicators are masked. It is not recommended.

Oil, gas or saltwater can intrude into the drilling fluid without being identified as a kick. A formation with low permeability can feed formation fluids slowly into the well without the flow being detected by the surface sensors. Monitoring the drilling fluid for gas-cut mud, formation oil in the mud and a chloride increase in the mud filtrate will alert drilling personnel of a potential underbalanced condition downhole.

Detecting and minimizing the volume of a kick reduces the potential for problems while controlling the well. This applies to any of the formation fluids. A large gas kick causes higher casing pressures in controlling the bottom-hole pressure. This can fracture the formation at the casing shoe or exceed the pressure limits of the surface equipment. A saltwater kick can seriously contaminate both water- and oil-base fluids, resulting in high treating costs to return the fluid to its original condition. The contamination will also affect the fluid-loss and filter-cake quality. This can result in differential sticking of the drillstring. A large oil kick in a water-base fluid will cause environmental concerns as well as contamination of the fluid. No matter what type of fluid invasion is experienced, the sooner a kick is detected and the well is shut in, the easier it will be to return the well to primary control and allow normal rig activities.

Engineering indicator 6: Filling the hole on trips

When pulling the drillstring out of the hole, the amount of pipe in the hole is reduced, and the mud level drops. The volume can be calculated from the size and weight of the pipe and the length of the pipe removed, so that an appropriate amount of mud can be pumped into the hole to fill it up.

If the drillstring volume is not replaced and the mud column drops, then the hydrostatic pressure is reduced and may result in a kick. If the hydrostatic pressure is reduced to less than formation pressure, formation fluids will flow into the well. Keeping the hole full of mud requires more than pumping mud into the well. The volume of mud pumped into the well should be measured and compared to the calculated displacement of the pipe pulled out of the hole. Measurement of the mud volume for this fill-up is usually taken from a graduated trip-tank or from monitoring rig pump strokes. If the mud pump method is used, count the number of strokes to arrive at the mud volume. It is a good drilling practice to stop pulling pipe every 5 to 10 stands of drill pipe (more often when pulling heavyweight drill pipe and drill collars) and to fill the hole with mud. The purpose is to limit the reduction in hydrostatic pressure and to know the amount (volume) of mud it takes to fill the hole.

If the hole takes less mud than the calculated displacement volume for the number of stands pulled, fluid is entering the wellbore. This signals an impending kick. Such deviations should be investigated immediately, and if the conditions persist, the crew should take remedial measures. Under such circumstances, the best thing to do, if possible, is to go back to the bottom immediately and circulate bottoms-up. The chances

A rapid increase in the size and a change in the shape of the drill cuttings may indicate an increase in formation pressure.

of completing a successful kill procedure are much better with the bit on bottom. If the situation seems to be getting out of control, the well should be shut in, and the appropriate well-control procedure implemented.

GEOLOGICAL INDICATORS

Geological indicator 1: Size and shape of cuttings

A rapid increase in the size and a change in the shape (angular) of the drill cuttings may indicate an increase in formation pressure. Cuttings from normally pressured shales are generally flat with rounded edges. Cuttings from a transition zone are larger and have sharp, angular edges. These cuttings should not be confused with even larger, block-shaped cuttings, which are rectangular. These block-shaped cuttings do not originate from the bottom of the well. They are formed by improper drillstring and bottom-hole assembly mechanics or existing fracturing.

Geological indicator 2: Sloughing shale and abnormal hole fill-up

Sloughing shale and abnormal hole fill-up are indications of increasing formation pressure. As the transition zone is penetrated, the pore pressure within the shale will increase. Shales have relatively low permeability, but in a transition zone, shale porosity will increase. This is reflected as a decrease in shale density, and is borne out by the acoustic log, in which the interval travel time in the pressured, water-filled shales increases. If this overpressure in the shale is not offset by increasing the hydrostatic pressure of the mud, the shale will collapse or slough into the annulus. This can cause enlarged holes through transition zones and fill on bottom during connections and trips.

Geological indicator 3: Bulk density

During normal shale compaction, water is squeezed out of the shale as the overburden pressure increases. Shale porosity decreases and density increases with depth.

If normal compaction is interrupted by the formation of a seal, the formation water cannot be squeezed out of the shale. When this occurs, the fluid supports part of the overburden load and will have higher-than-normal pressure. Since fluids remain in the shale, the shales have a higher-than-normal porosity and lower-than-normal density.

If shale densities are checked and plotted at regular intervals during drilling, a normal compaction trend is established for the predominant formation being drilled. When a seal is penetrated, the formation density will increase rapidly, followed by decreased density as the overcompacted pressure seal and transition zone are drilled.

The true cuttings density is altered by exposure to the mud. The degree of alteration will depend on the mud type and the length of exposure. Cuttings in contact with water-base muds exhibit some degree of swelling and are less dense. The resulting decrease in density is due to the absorption of water. This could be misinterpreted as an increase in formation pressure. Any cuttings exposed to the drilling fluid for a long period of time should not be used to measure the bulk density. This change of cuttings density normally occurs only with water-base mud. When oil muds are in use, the cuttings density alteration is slight. Cuttings absorb very little oil; therefore, the density will remain about the same. When water-base mud is displaced with an oil-base mud, a shift will occur in the normal compaction trend graph due to this alteration. The slope will be the same, but the trend will shift to the right to reflect the water absorption during the water mud interval.

Gas is an indication of under-balanced formation pressure.

Geological indicator 4: Gas

Gas is an indication of underbalanced formation pressure. When drilling is underway, most well-logging companies measure and record the gases entrained in the circulating fluid. It is helpful to classify this gas into one of three different categories. These are: (1) total drilled gas called *background gas*, (2) gas due to the swabbing effect when making connections called *connection gas*, and (3) gas due to swabbing and near-balanced conditions when making a trip called *trip gas*.

1. **Background gas.** This is the total gas entrained in the mud. The background gas which comes from the cuttings as the hole is being drilled is not an indication of increasing pressure and should not be compensated for with higher mud weight. Background gas from cuttings should always be circulated bottoms-up. A continued increase in background gas indicates a higher formation porosity and/or a higher hydrocarbon saturation in the available pore space. If lithology and ROP are given due consideration, an increase in background gas would indicate drilling into a transition zone.
2. **Connection gas.** Connection gas is the amount of gas in excess of the background gas. This is the increase in gas readings caused by the swabbing action of drillstring movement while a pipe connection is made. Pulling of the drillstring causes the effective bottom-hole pressure to be less than the hydrostatic pressure of the mud column. Such a reduction in hydrostatic pressure could lead to formation fluids feeding into the hole. A small but constant amount of connection gas is an indicator that the formation pressure is slightly less than the hydrostatic pressure, whereas a continuous increase of gas at each connection would indicate an increase in formation pressure. This is an excellent tool for detection of abnormal pressures when used in conjunction with background gas.
3. **Trip gas.** This is the increase in gas associated with pulling the drillstring out of the hole. Trip gas is recorded when bottoms-up is being circulated out after a trip. The time period during which trip gas is being recorded gives some idea about the amount and the migration of gases in the annulus. This parameter is used in the same manner as connection gas, but is not as useful due to the long interval between trips. In some instances, a short trip will be made (10 to 20 stands) for the purpose of determining changes in pore pressure and changes in bottom-hole conditions.

There are two basic types of gas recorders used to measure and identify gas:

A. **Total combustible gases ("hot wire").** This rugged instrument is used widely by well-logging companies and is based on the Wheatstone bridge principle. The recorder determines total "units" of combustible gases. It is not calibrated and, therefore, one "unit"of gas remains undefined. Nevertheless, the device has been in use for decades and continues to give a relative measure of the total combustible gases released at the surface from the circulating mud.

B. **Chromatograph.** This sophisticated instrument has the potential to identify the type and relative volume of gases which are present. Being a calibrated instrument, the chromatograph is more reliable and a better evaluating tool than the "hot wire." Various versions of this instrument are available, and newer, more sensitive devices are being used by some mud-logging companies.

Gas-cut mud is the reduction in mud weight due to gas entrainment.

Geological indicator 5: Gas-cut mud
Gas-cut mud is the reduction in mud weight due to gas entrainment. Gas-cut mud is checked at the flow line, where the fluid will contain the maximum amount of gas. The use of gas-removal equipment, as well as surface retention time, will normally remove most or all of the gas from the mud. This is a simple measurement that can be made by the rig crews when a mud-logging company is not being used on the well. The measurement can be made to indicate the effects of gas from drilling, connections and trips. A continued reduction in mud weight due to gas is an indication of increasing gas content in the formations and the potential of increasing pore pressures (*NOTE: A more-detailed explanation of gas-cut mud is contained in the Special Problems section of this chapter*).

Geological indicator 6: Chloride ion
Dissolved solids in the formation water are often correlated to total chloride concentration — or salinity, as it is commonly called. The salinity of water found in shale is known to increase with depth in a normally compacted sedimentary basin, but shows a decrease in a transition zone. In normally compacted formations, the salinity of water found in sandstone is known to follow the same trend, but at much higher concentrations than those found in shale. In a transition zone, the salinity of water in sands approaches that of water in the shales. The change in the salinity of the mud filtrate is not used for detecting abnormal pressures because it is affected by numerous variables and could give an erroneous indication of a transition zone.

Most logging companies indicate that measurement of mud resistivity to reflect changes in formation water salinity has not been successful. Oil, solids and chemicals present in the mud affect mud resistivity differently. Logging companies report that measurement of the changes in resistivity at both the suction line and flow line are not effective in detecting overpressure zones.

Geological indicator 7: Cation Exchange Capacity (CEC)
During compaction, the water from the shale is squeezed out, which causes the shale to become more dense with an increasing overburden load. Shales are comprised mainly of clay minerals. When compacted, clay minerals undergo mineralogical changes due to variations in temperature and pressure. Because of diagenesis of montmorillonite to illite, a continuous decline in montmorillonite content is expected with depth. Due to higher temperatures in a transition zone, the montmorillonite content decreases at a much faster rate. Therefore, such overpressure zones would have illite as the predominant clay mineral.

A direct measurement of the CEC of the shale retrieved from the shaker screen can be made with the standard methylene blue titration. A plot of shale CEC test results with depth should indicate a decline with depth in a normally pressured zone, but will show a drastic reduction in a transition zone. However, this method is only qualitative and has some serious drawbacks.

Increasing flow-line temperature is an excellent indicator of a transition zone.

Geological indicator 8: Flow-line temperature
Increasing flow-line temperature is an excellent indicator of a transition zone. Since certain other variables affect flow-line temperature, it is necessary to use an end-to-end plot. Some of the variables that affect flow-line temperature are: (1) mud weight, (2) solids content, (3) flow properties, (4) circulation rates and (5) hole geometry. An end-to-end plot is constructed by identifying changes in flow-line temperature caused by a change in the variables, rather than a change in formation

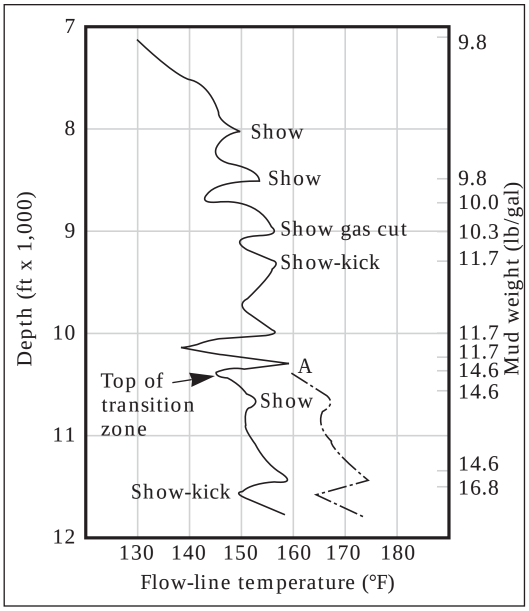


Figure 8: Flow-line temperature as an indication of transition zone and geopressures.

pressure. The cause and magnitude of the changes are noted on the plot and these amounts are added to or subtracted from the actual readings to produce a continuous plot. A normal trend can be established and departures from the normal trend can be readily recognized. An end-to-end plot will produce a curve as shown in Figure 8. There is a 5 to 6° difference between the high and low points. High points are the result of drilling porous rocks containing fluids, and low points are the result of drilling denser rocks.

At about 150 to 300 ft above the seal, a marked decrease in flow-line temperature will be noted (Point A in Figure 8). Usually, this decrease is 18 to 20°. After the seal is drilled, a very rapid increase in temperature will occur — to perhaps as much as 30 to 35° from the time the seal is drilled until a porous zone is encountered.

The porous transition zone below the pressure seal contains more fluid than the normally pressured formation above them. The fluid acts as an insulator, restricting the flow of heat. The rocks below a transition zone will have a higher temperature due to the energy being transmitted to the fluid as the pressure increases.

Numerous field investigations of differential temperature between flow line and suction pit have been made. These investigations generally are regarded as of little use due to the variables that affect the suction pit temperature. These variables, which are very difficult to track, include:

1. The amount of water being added to the mud.
2. Solids-control equipment (desilters, desanders, degassers and centrifuges).
3. Ambient temperature.
4. Volume of the mud in the pits.
5. The amount of agitation.

Changes in flow-line temperature cannot be used to estimate formation pressures directly, due to flow-line temperature variables and because each geographic area has a different temperature gradient. However, changes in flow-line temperature are a qualitative indication that a change in pressure may be occurring.

Pressure/Transition Zone Analysis After Drilling

A drill-stem test is conducted to obtain accurate information about the potential...

Shut-in pressure tests are conducted on completed wells...

A variety of methods, both direct and indirect, exist to confirm formation pressures after the well has been drilled. Some of the more common techniques are discussed below.

Drill-stem tests. A drill-stem test is conducted to obtain accurate information about the potential producing capabilities of a reservoir. The principal objectives of the test are to determine the types of fluids, the potential rate of production and the subsurface pressures.

The drill-stem test derives its name from the fact that the drillstring is used as a conduit to bring formation fluids to the surface. The zone of interest is isolated by the use of a single packer if the zone is at the bottom of the hole or by tandem packers if it is off bottom.

The subsurface pressure is recorded during the course of this test.

Shut-in pressure tests. Shut-in pressure tests are conducted on completed wells throughout their productive lives. Since pressure depletion occurs with production, producers prefer that such tests are conducted early in the life of the reservoir. Mathematical techniques are used to convert shut-in pressure tests to approximate formation pressure.

Downhole pressure bombs. A variety of instruments can be used to measure formation pressure directly under bottom-hole conditions. These "bombs" are usually run with wireline equipment.

Wireline log evaluation. Logs run on the well can be evaluated as the offset logs were, to estimate formation pressure and pick the geopressured zones. In turn, this type of information is useful in planning subsequent wells. The drilling information and wireline data should be analyzed together to improve the accuracy of the pressure-prediction techniques which were used when the well was planned.

FRACTURE PRESSURE

Fracture pressure is the pressure required to rupture a formation physically, allowing entry of drilling fluids into the formation. This pressure is a function of the fluid pressure (pore pressure) and matrix strength of the rock. Several factors affect the fracture pressure of the formation:

1. Geologic age.
2. Depth and overburden.
3. Pore pressure.

1. Geologic age

As rocks become older, many changes take place. Some of these changes are:

1. Degree of compaction as depth increases.
2. Degree of cementation due to compaction and chemical precipitation in the pore spaces.
3. Occurrence of tectonic factors such as folding, faulting and intrusion by salt or magma flows.

Generally speaking, a tectonically relaxed area such as the Gulf of Mexico would be typified by vertical fracturing. This is due to the greatest stress being approximately vertical and equal to the overburden.

2. Depth and overburden

As layers of rock are buried deeper, the increased overburden pressure (P_O) causes compaction. This process forces the rock grains closer together and makes cementation more effective. This combination of factors increases the rock matrix strength.

3. Pore pressure

Once a seal has been formed, the compaction process is reduced and the formation fluid supports part of the overburden. This process causes the fluid pressure (or pore pressure) to increase. This, in turn, causes an increase in the formation fracture pressure.

QUANTIFYING FRACTURE GRADIENTS

If, for a fracture to occur, the intergranular pressure (P_I) plus the pore pressure (P_P) must be overcome, then the fracture pressure (P_{FRAC}) should be equal to overburden pressure:

$$P_{FRAC} = P_O \text{ or } P_P + P_I, \quad (\text{since } P_O = P_P + P_I)$$

Because fracture pressures are normally less than this value, this equation is often written in the form $P_{FRAC} = P_P + (P_O - P_P)$ so that a depth multiplier (X) can be multiplied to the intergranular (or rock matrix strength) portion of the equation inside the brackets.

$$P_{FRAC} = P_P + (P_O - P_P)\ X$$

Where X is less than one, to account for fracture pressures less than overburden pressure.

The exact determination of this X multiplier (or some equivalent correction) has been made with a number of mathematical methods. Hubbard & Willis (1957) used an equation of the gradient form:

$$\frac{P_{FRAC}}{D} = \alpha\ (P_{OG} - 2P_{PG})$$

Where:
D = Depth (ft)
P_{OG} = Overburden gradient always equal to 1.0 (psi/ft)
P_{PG} = Pore pressure gradient (psi/ft)

Matthews & Kelly (1967) developed a somewhat different approach. They concluded that whenever a formation fractures horizontally, the required pressure is equal to overburden stress. However, most fracturing occur in the vertical direction, resulting in the required pressure being considerably less than overburden stress. Their equation used a "matrix-stress coefficient" multiplier (K_i) based on a variable horizontal to vertical stress ratio. The Matthews & Kelly gradient equation is expressed as:

$$\frac{P_{FRAC}}{D} = P_{PG} + (P_{OG} - P_{PG})\ K_i$$

Where:
K_i = Matrix stress coefficient

Eaton (1969) developed another approach based on the assumption that the fracture pressure gradient is a function of the overburden stress gradient, pore pressure gradient and the ratio of horizontal to vertical stress. Eaton called this *Poisson's ratio* (v), and expressed it as:

$$\frac{P_{FRAC}}{D} = P_{PG} + \frac{v}{1 - v}\ (P_{OG} - P_{PG})$$

Where:
v = Poisson's ratio of the rock

M-I's FRAC™ computer program uses a method developed by Zamora which intergrates overburden based on a power-model bulk-density curve with overburden codes (A) for each geological age and uses a matrix-stress coefficient (K) based on regional matrix-stress codes (M).

$$\frac{P_{FRAC}}{D} = P_{PG} + (P_{OG} - P_{PG})\ K$$

Where:
K = M [1.0 – C_5 exp($C_6 D_S$)]
C_5 = 0.55 and C_6 = - 0.000134

See Petroleum Engineer International, September 1989, pages 38 to 47 for a more thorough discussion of this technique.

FRACTURE PRESSURES FOR OFFSHORE OPERATIONS

The fracture pressure of offshore wells normally is less than that of wells drilled on land.

The fracture pressure of offshore wells normally is less than that of wells drilled on land. This occurs as a result of less overburden pressure due to the water depth and the air gap.

In shallow water, fracture pressure varies only slightly from the fracture pressure anticipated on land. In deeper water, the reduction in overburden pressure is significant. Reducing the overburden pressure will result in reducing

The fracture pressure estimate is used to help design a drilling program for a well...

the fracture pressure. If data are not available for a deepwater area, a rule of thumb can be used to estimate the fracture gradient. The rule is that for each 1,000 ft of water, the fracture gradient is reduced 0.8 lb/gal over the fracture gradient of a similar well on land.

MEASURING FRACTURE PRESSURE

Many problems exist in trying to estimate fracture pressures. This is because the exact values of the components that contribute to formation strength are not known. These factors are local. Data from one area cannot be readily applied to other areas.

The fracture pressure estimate is used to help design a drilling program for a well with regard to casing depths and hole sizes. Once a well has spudded, the formation fracture pressure should be determined by physical tests.

Two tests are used to measure the formation strength or fracture pressure. These are: (1) the Leak-Off Test (LOT) and (2) the Formation-Integrity Test (FIT). These tests are conducted after casing has been set and the casing shoe has been drilled out. Although procedures differ from one operator to the other, a common practice is to drill either to the first sand or 10 ft of new formation before running either test. In some cases, the test can be run again after drilling further. This is usually done when mud weights are used that exceed those planned for in the well plan or mud program.

Leak-off tests and formation-integrity tests are very similar. The difference is that the leak-off test fractures the formation and measures the actual strength of the formation, while the formation-integrity test measures the formation to a predetermined pressure but does not cause a fracture. The formation being drilled often determines which of them will be used. The formation integrity test is used more often in hard-rock formations than the leak-off test.

LEAK-OFF TEST PROCEDURES

1. Drill out the casing shoe and sufficient new formation.
2. Circulate the drilling fluid to ensure a consistent mud weight.
3. Stop the rig pumps and shut the well in.
4. Pump mud into the shut-in well at a very low rate. A typical pump rate of 0.25 to 0.5 barrels per minute (bbl/min) is used. Normally, a cementing unit is used so an accurate reading of volume and pressure can be obtained.
5. Record the pressure and volume pumped. A graphical presentation should be made of these data to determine the point at which the fluid is being pumped into the formation (leak-off). A normal leak-off test will show the pressure increasing in a straight line with the volume of mud pumped. Once the fracture pressure is reached, the pressure will stop increasing with volume pumped as the fracture is being propagated. The pressure may actually decrease as fluid is pumped into the formation. Figure 9 is an illustration of a graph obtained from a leak-off test.

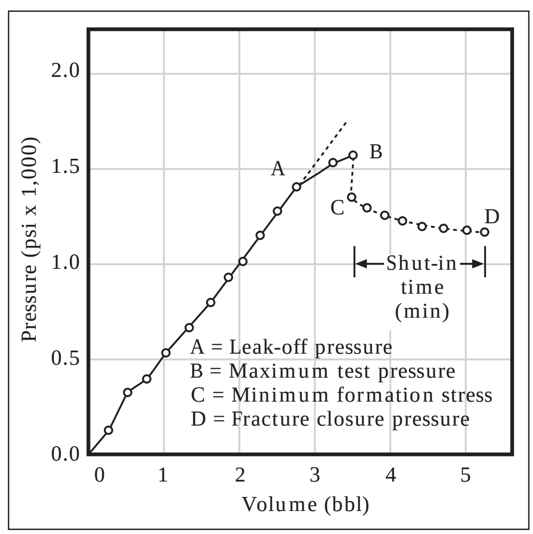


Figure 9: Example leak-off test graph (after Postler).

...it is important to know how much shut-in pressure the formation can stand prior to taking a kick.

6. Once leak-off has been observed, stop pumping and observe the well. The pressure should remain relatively the same or decrease slightly once pumping has stopped.
7. Record the pressure where the fluid started leaking off into the formation. Convert this pressure to a mud weight equivalent by using the following equation:

$$\text{Equiv. MW (lb/gal)} = \frac{\text{leak-off pressure (psi)}}{0.052 \times \text{TVD of casing shoe (ft)}}$$

The fracture mud weight is calculated by adding the equivalent mud weight to the test mud weight.

Formation-integrity test procedures

Use the same procedure as above until you reach Step 5. A predetermined maximum mud weight for the interval is determined from the well plan. Normally, 0.5 to 1.0 lb/gal is added to this value as a safety factor. The difference between this mud weight and the mud weight in the well is calculated. The difference is then converted to a pressure at the casing shoe. This pressure is then used as the maximum test pressure when conducting the formation integrity test.

FIT Example:

MW	= 13.5 lb/gal
TVD casing	= 7,500 ft
Maximum anticipated mud weight	= 16.0 lb/gal
Desired safety margin	= 0.5 lb/gal

Determine the required FIT pressure.

1. Maximum allowable mud weight = maximum anticipated MW + safety margin =
   16.0 + 0.5 = 16.5 lb/gal
2. Test pressure (psi) = MW (lb/gal) – test MW (lb/gal) x 0.052 x TVD casing shoe (ft) =
   (16.5-13.5) x 0.052 x 7,500
   = 1,170 psi.

Testing the formation physically establishes its pressure limitations (fracture pressure). If a kick occurs and the well is shut in, the sum of the shut-in pressure and the hydrostatic pressure of the mud could exceed the fracture pressure of the formation. Therefore, it is important to know how much shut-in pressure the formation can stand prior to taking a kick. The Maximum Allowable (shut-in) Casing Pressure (MACP) changes as the mud density changes. The equation for determining the MACP is:

MACP (psi) = (fracture MW (lb/gal) – MW (lb/gal)) x TVD of casing shoe (ft) x 0.052

This calculation should be made every time the mud weight is changed. It is based on the fracture gradient at the casing shoe, since it is assumed that the casing shoe is the weakest point in the well.

The MACP can be represented graphically so the pressure will not have to be calculated every time the mud weight is changed. The graph is drawn on rectangular coordinates with the MACP on the Y-axis and the mud weight on the X-axis. Figure 10 is an example of a MACP graph. To draw the graph, plot a point at the leak-off pressure and the mud weight used to run the leak-off test. Then, plot a point at the fracture gradient and 0 psi. Connect the two points with a straight line. To use the chart, find the weight of the mud in the hole and read the MACP where the line intersects the mud weight. A safety margin can be incorporated into this graph by drawing another line parallel to the maximum shut-in pressure line already drawn. This line should reflect the amount of safety margin desired, in lb/gal. In the example shown in Figure 10, 0.5 lb/gal is used as the safety margin. The advantage of using a graph is that the hydrostatic pressure of the mud does not have to be calculated each time the mud weight changes.

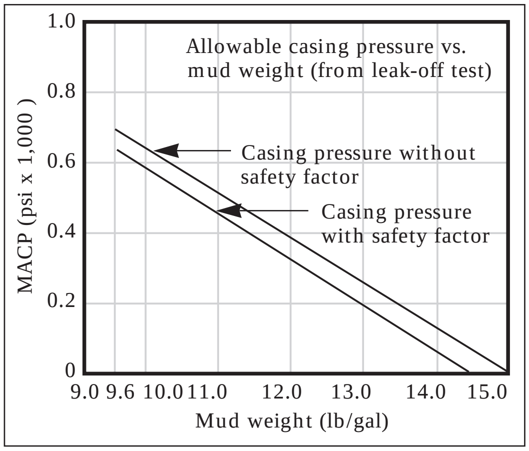


Figure 10: Example maximum allowable casing pressure graph.

The CPL... pressure is the sum of the pressure losses in the drillstring, the bit and the annulus.

The MACP should be monitored while a well is shut in on a kick and while a kick is being circulated out of the well. The casing pressure should not be allowed to exceed the MACP until the gas bubble reaches the casing shoe, when circulating a kick out. After the intrusion reaches the casing shoe, the hydrostatic pressure at the casing shoe can be reduced by the amount the intrusion reduces the hydrostatic pressure at the casing shoe. Therefore, the casing pressure can be increased by the amount of reduction in the hydrostatic pressure. The weight of the intruding fluid must be determined to calculate this reduction in hydrostatic pressure above the shoe.

Figure 10 indicates that as the mud weight approaches the fracture weight, the maximum allowable shut-in casing pressure is reduced. Therefore, casing programs should be planned to provide a safe maximum allowable shut-in casing pressure in excess of the expected mud weight. Many problems can be avoided or minimized by utilizing a program of testing casing seats, evaluating the results and making good decisions based on these results.

Pressure Loss

For this manual, pressure loss will be defined as the pressure expended in causing a fluid to flow through a pipe or other device, such as a downhole motor. The pressure loss is a function of the fluid's properties and the flow rate.

The CLPL is the frictional pressure required to move the drilling fluid from the BOP stack to the adjustable choke.

Circulating Pressure Loss (CPL)

The CPL is the pressure required to pump a fluid of given properties at a given flow rate through the circulating system. This pressure is the sum of the pressure losses in the drillstring, the bit and the annulus. It is important to remember that when the pump rate, well depth or mud properties change, the circulating pressure loss also changes.

Choke Line Pressure Loss (CLPL)

The CLPL is the frictional pressure required to move the drilling fluid from the BOP stack to the adjustable choke. For wells with surface Blowout Preventers (BOPs), this pressure loss is minimal. However, it is significant and must be taken into account on deepwater wells with subsea stacks.

The choke line friction pressure should be determined and recorded every tour or whenever there is a major change in the depth of the well or in the mud properties. The choke line friction pressure is determined when circulating at the slow pump rate by comparing the pressure of circulating through the riser with the pressure of circulating through the choke line with the BOP closed and the choke fully open. The choke line friction pressure is equal to the difference in these pressures. The back pressure on the formation while circulating through the choke is equal to the casing pressure

Surge pressures from pipe movement can fracture formations and cause lost returns.

The reduction in hydrostatic pressure from swabbing... cause the well to kick.

gauge reading plus the choke line friction pressure. Subsea-well-control schools discuss choke line friction pressures in detail.

ANNULAR PRESSURE LOSS (APL)

The pressure loss through the annulus from the bit to the bell nipple is the annular pressure loss. The APL depends on the flow rate, mud properties and hydraulic diameter. APL is expressed as psi and is an imposed pressure on the hole when circulating under normal conditions. The APL is calculated using the equations in the chapter on Rheology and Hydraulics in this manual or in the API bulletin on rheology and hydraulics, API RP 13D.

EQUIVALENT CIRCULATING DENSITY

The ECD is the pressure exerted on the formation by the hydrostatic pressure of the drilling fluid plus the annular circulating pressure losses, expressed as the mud weight which would provide a hydrostatic pressure equal to the sum of these pressures.

$$\text{ECD (psi)} = \text{MW (lb/gal)} + \frac{\text{APL (psi)}}{0.052 \times \text{TVD (ft)}}$$

Example:
MW: 10.0 lb/gal
TD: 10,000 ft
APL: 15 psi/1,000 ft

What is the ECD at 10,000 ft?

$$\text{Total APL} = \frac{15}{1{,}000} \times 10{,}000 = 150 \text{ psi}$$

$$\text{ECD (lb/gal)} = 10.0 + \frac{150}{0.052 \times 10{,}000} = 10.3 \text{ lb/gal}$$

SURGE/SWAB PRESSURES

When pipe is run into a well filled with mud, the mud is displaced upward in the annulus from the bit. The hydrostatic pressure is increased by the frictional forces of the mud flowing upward. The sum of these frictional forces of flow and the hydrostatic pressure is called the *surge pressure*. Surge pressures from pipe movement can fracture formations and cause lost returns.

When pipe is pulled from a well filled with mud, the mud column in the annulus falls to displace the pipe taken from the well. The hydrostatic pressure is reduced by the frictional forces of the mud flowing downward to displace the pipe. The hydrostatic pressure minus the reduction in pressure caused by pulling pipe from the well is called the *swab pressure*. The reduction in hydrostatic pressure from swabbing can “swab” formation fluids into the wellbore and cause the well to kick.

When tripping, the pipe is picked up from the slips and accelerated to a maximum velocity and then slowed to a stop while the slips are reset. Swab and surge pressures are calculated for the maximum velocity which is difficult to determine. Most swab and surge calculations assume the maximum velocity of pipe movement to be 50% greater than the average pipe velocity. Under these assumptions, if it takes one minute to run or pull a 90-ft stand of pipe, the average pipe velocity is 1.5 ft/sec (90/60) and the maximum pipe velocity would be assumed to be at least 2.25 ft/sec (1.5 x 90/60).

After the velocity of the mud from the pipe’s movement has been determined, the swab and surge pressures can be determined using the standard API hydraulics calculations.

TRIP MARGIN

Trip margin is the amount the mud density is increased to offset the loss in bottom-hole pressure resulting from swabbing when the drill pipe is tripped from the hole. The trip margin will change with conditions, but should be kept as low as possible. Excessive mud weights increase the surge pressures and reduce the penetration rate when drilling.

A simple equation for estimating the trip margin is:

$$\text{Trip margin (lb/gal)} = \frac{YP}{11.7(D_h - D_p)}$$

Where:
YP = Yield point (lb/100 ft^2)
D_h = Hole diameter (in.)
D_p = Pipe diameter (in.)

Example 6
YP = 17 lb/100 ft^2
D_h = 8.5 in.
D_p = 4.5 in.

What is the needed trip margin?

$$\text{Trip margin (lb/gal)} = \frac{17}{11.7(8.5 - 4.5)} = 0.36 \text{ lb/gal}$$

Shut-In Drill Pipe Pressure (SIDPP)

Shut-in drill pipe pressure is the pressure recorded on the drill pipe...when the well is shut in with a kick.

Shut-in drill pipe pressure is the pressure recorded on the drill pipe (standpipe gauge) when the well is shut in with a kick. SIDPP is the amount of pressure required to balance the formation pressure due to insufficient hydrostatic pressure in the drill pipe.

The kick is always assumed to be in the annulus due to the direction of mud movement while circulating. This leaves an uncontaminated drilling fluid column in the drill pipe. With this assumption, a direct calculation of formation pressure (P_{form}) can be made:

$$P_{form} \text{ (psi)} = P_{HYD} \text{ (psi)} + \text{SIDPP (psi)}$$

Example 7
TVD = 12,000 ft
MW = 14.0 lb/gal
SIDPP = 500 psi

What is the formation pressure?

Formation pressure (psi) = (0.052 x 14.0 x 12,000) + 500 = 9,236 psi

When using a mud motor, it may not be possible to read the SIDPP from the standpipe pressure gauge. There are three ways for formation pressure to be communicated to the column of mud in the drillstring when using a mud motor: (1) through the dump valves; (2) through the rotor, if it is bored; and (3) through the motor.

Many companies do not use dump valves. Even when they are used, however, it is estimated they will fail to open about 50% of the time after being subjected to temperature and pressure while drilling.

Bored rotors allow direct mud flow from the drillstring to the bit. Bit jets or blanks are run in the rotors. A blank will prevent formation pressures from being communicated to the drillstring through the rotor.

If the formation pressure is less than 150 psi greater than the hydrostatic pressure, it may not be communicated through the motor to the drillstring. The pressure required for communication through the motor may be higher than 150 psi for some motor designs and conditions. The process of equalizing the pressure past the rotor may take time.

Whenever a kick is taken or suspected, drilling should not be resumed until it is determined that the mud weight is adequate to control the well.

Shut-In Casing Pressure (SICP)

The shut-in casing pressure is the pressure recorded on the casing when the well is shut in with a kick in the hole. The SICP is similar to the SIDPP in that it is the amount of pressure required to balance the formation pressure due to insufficient hydrostatic pressure in the annulus. As mentioned earlier, it is assumed that the kick volume is in the annulus. This will result in fluids of unknown, differing densities and volumes in the annulus. Since the density of the kick fluid is generally less than the density of the drilling fluid, the SICP will be greater than the SIDPP due to the lower hydrostatic pressure in the annulus.

The SIDPP and the SICP can be equal under conditions where the invading fluid has the same density as the drilling fluid, or if the kick volume is zero or a negligible amount.

Example 8

TD	=	10,000 ft
MW	=	10.0 lb/gal
SIDPP	=	400 psi
Kick information	=	5.0 lb/gal (1,000 ft in the annulus)

What is the SICP?

1. Formation pressure =
$$0.052 \times 10.0 \times 10{,}000 + 400 = 5{,}600 \text{ psi}$$

2a. P_{HYD} (mud in annulus) =
$$0.052 \times 10.0 \times 9{,}000 = 4{,}680 \text{ psi}$$

2b. P_{HYD} (intrusion in annulus) =
$$0.052 \times 5.0 \times 1{,}000 = 260 \text{ psi}$$

2c. P_{HYD} (total annulus) =
$$4{,}680 + 260 = 4{,}940 \text{ psi}$$

Therefore:

$$\text{SICP} = P_{form} - P_{HYD} \text{ (annulus)} = 5{,}600 - 4{,}940 = 660 \text{ psi}$$

KILL-WEIGHT MUD

Kill-weight mud is the mud weight required to balance the formation pressure.

Kill-weight mud is the mud weight required to balance the formation pressure.

Kill MW (lb/gal) =
$$\text{MW (lb/gal)} + \frac{\text{SIDPP (psi)}}{0.052 \times \text{depth (ft)}}$$

Example 9

SIDPP	=	400 psi
MW	=	12.0 lb/gal
TVD	=	13,200 ft

What is the mud weight needed to balance the formation pressure?

Kill MW (lb/gal) =
$$12.0 + \frac{400}{0.052 \times 13{,}200} = 12.6 \text{ lb/gal}$$

WEIGHT-UP FORMULA

This formula shows the number of pounds needed to weight-up one barrel of mud:

$$\text{Barite (lb/bbl)} = \frac{1{,}471\,(MW_2 - MW_1)}{35.0 - MW_2}$$

Where:

MW_2 = Mud weight desired (lb/gal)
MW_1 = Starting mud weight (lb/gal)

VOLUME-INCREASE FORMULA

This formula can be used to determine the volume increase when adding barite:

Volume increase (bbl) =
$$\frac{\text{barite added (lb)}}{1{,}471}$$

Example 10

Starting mud weight	=	14.0 lb/gal
Desired mud weight	=	15.2 lb/gal
Mud volume	=	350 bbl

How many pounds of barite does it take to weight up this mud system?

What would be the resulting volume increase?

Barite (lb) =
$$350 \text{ bbl } \frac{1{,}471\,(15.2 - 14.0)}{35.0 - 15.2} = 31{,}203 \text{ lb}$$

Volume increase (bbl) =
$$\frac{31{,}203 \text{ lb}}{1{,}471 \text{ lb/bbl}} = 21.2 \text{ bbl}$$

The volume of a confined gas is inversely proportional to the pressure.

Density of intruding fluid

Any gas or fluid that enters the well has a density, but the well can be controlled without knowing the density of the intruding gas or fluid. The procedures for circulating the fluid out are the same for all formation fluids. The formation fluid is always assumed to be gas, since this is the worst case for well control. As it approaches the surface, the gas expands, producing high casing pressures. Gas requires more adjustments of the choke to control bottom-hole pressures than either oil or saltwater. If the density of the fluid is determined, the fluid can be isolated at the surface to prevent contamination of the drilling fluid system with saltwater or oil. In all cases, the primary objective is to regain control of the well.

Several assumptions must be made to calculate the density of the invading fluid. The first is that the kick remains a homogeneous mixture in the annulus. The second is that the kick is on bottom. An accurate kick volume also is required to ensure the accuracy of the calculation. After the height of the column is calculated from the annular volumes around the drill collars and drill pipe, the density of the formation fluid can be calculated with the following equation:

$$FW = MW - \frac{SICP - SIDPP}{0.052 \times L}$$

Where:
FW = Density of kick fluid (lb/gal)
MW = Mud weight (lb/gal)
SICP = Shut-in casing pressure (psi)
SIDPP = Shut-in drill pipe pressure (psi)
L = Length of kick in annulus (ft)

Example 11
Kick volume = 10 bbl
SIDPP = 400 psi
SICP = 500 psi
Hole size = 8.5 in.
DP = 4.5 in.
MW = 12.0 lb/gal

Find the length of the kick.

Annular volume =
$$\frac{8.5^2 - 4.5^2}{1{,}029} = 0.05 \text{ bbl/ft}$$

Length =
$$\frac{10 \text{ bbl}}{0.05 \text{ bbl/ft}} = 200 \text{ ft}$$

FW =
$$12 - \frac{500 - 400}{0.052 \times 200} = 2.38 \text{ lb/gal}$$

Pressure/volume relationship

Gases are compressible. The volume of a confined gas is inversely proportional to the pressure. If the pressure is doubled, the volume is halved. The volume of a confined gas is proportional to the absolute temperature (absolute temperature degrees Rankine = °F + 460). When a well is shut in with gas at the bottom, the gas volume is controlled by the hydrostatic pressure of the mud, the casing pressure and the temperature. If gas

The behavior of gas is important when a well is shut in on a gas kick.

is circulated to the surface without being allowed to expand, the confining pressure will be the same as it was when the gas was on bottom, but there will be no hydrostatic pressure to confine the gas, and the pressure will be on the casing. The compressibility law requires some knowledge of the particular gas under pressure to make an exact calculation of the gas volumes. The equation has been simplified to eliminate the unknown data. The simplified equation for gas compressibility is:

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2}$$

Where:
P_1 = Initial pressure
P_2 = Final pressure
V_1 = Initial volume
V_2 = Final volume
T_1 = Initial temperature (°R)
T_2 = Final temperature (°R)

Example 12
P_1 = 10,000 psi
V_1 = 20 bbl
T_1 = 750°R
P_2 = 500 psi
T_2 = 540°R

What would be the calculated gas volume V_2?

$$V_2 = \frac{P_1T_2V_1}{P_2T_1}$$

$$= \frac{10{,}000 \text{ x } 540 \text{ x } 20}{500 \text{ x } 750} = 288 \text{ bbl}$$

It is difficult to predict surface pressures and final volumes when circulating a gas kick out because the physical properties of the gas and intruding fluid are not known. The intruding fluid may be a mixture of gas, oil and saltwater, which will change the results of the calculation.

The behavior of gas is important when a well is shut in on a gas kick. Because of its low density, gas tends to migrate, or move upward, in a well. If the gas volume remains the same, the pressure also will remain the same based on the gas compressibility equation, but the casing pressure will increase as the hydrostatic pressure decreases due to the upward movement of the gas. If the gas is allowed to expand, the pressure in the gas kick will decrease (*NOTE: A more complete discussion of gas migration can be found later in this chapter*). Gas expansion is controlled on a shut-in well by controlling the backpressure with a choke while circulating.

U-Tube Analysis

It is essential to know how to calculate each of these pressures and understand how they relate to controlling pressures.

The concept of pressure control can be related to a balanced U-tube. The basic relationships can be seen readily in the following examples, which demonstrate several conditions of U-tube behavior that relate to wellbore conditions.

Sources of pressures under which a well can be controlled can be broken down into three basic types. They are:
1. Hydrostatic pressures (P_{HYD}).
2. Pressures losses (PL).
3. Imposed pressures (PI).

Imposed pressures are more commonly called *back pressures*. Using these three basic pressures, a simple equation can be written that will always hold true under both static and dynamic steady-state conditions. The equation is:

$$PT = P_{HYD} + PL + PI$$

Where:
PT = Total pressure at some point of interest in the system at a specific time

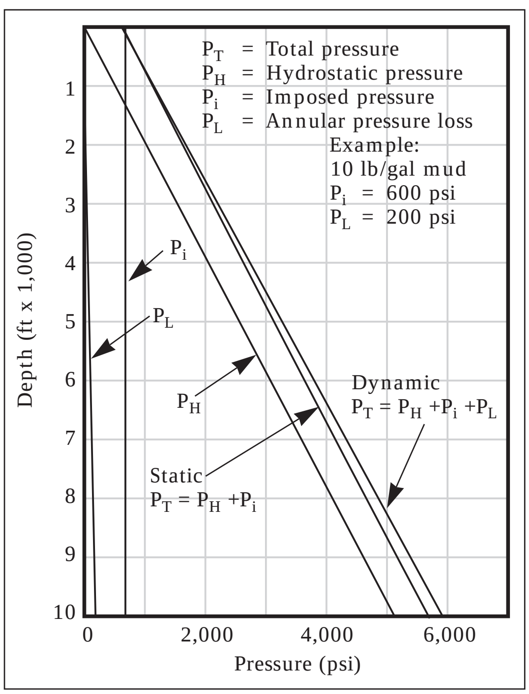


Figure 11: Pressure profile.

Virtually all pressure-control work is based on the application of this simple equation. It is essential to know how to calculate each of these pressures and understand how they relate to controlling pressures. Figure 11 shows the pressure profile for a well, which illustrates how the equation predicts the total pressure vs. depth for both static and dynamic conditions.

Balanced static condition

Figure 12 shows a balanced U-tube situation with fluid of the same density in the annulus and drill pipe sides. The drill pipe side and annular side of the U-tube are balanced because each contains the same height of fluid of the same density. Since both columns are balanced, no imposed pressures are shown on the drill pipe or casing pressure gauges.

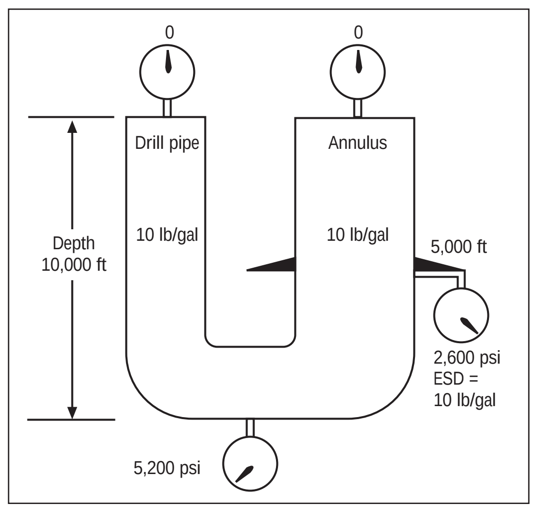


Figure 12 : Balanced static U-tube.

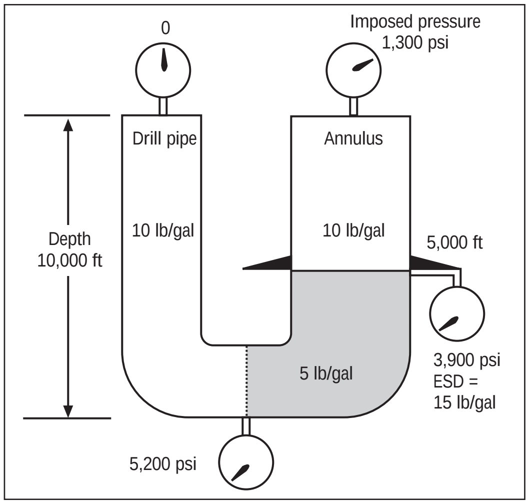


Figure 13: Unbalanced U-tube with imposed pressure.

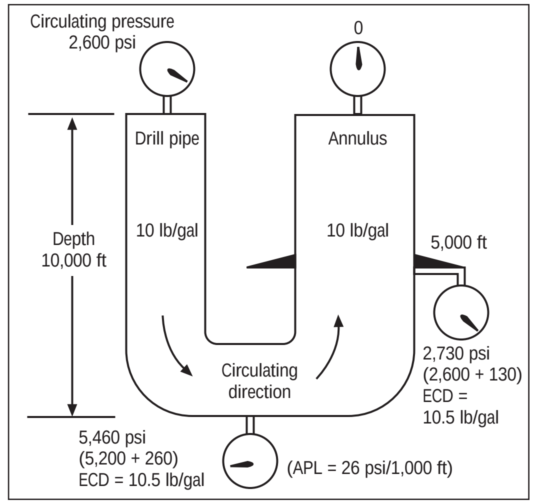


Figure 14: Circulating U-tube.

Unbalanced static condition

Figure 13 shows an unbalanced U-tube situation with two fluids that have different densities in the annulus. In this situation, there is a difference in the hydrostatic pressure of the fluid in the drill pipe and the fluid in the annulus. The hydrostatic pressure of the fluid in the annulus is the sum of the hydrostatic pressures of the 10.0 lb/gal mud (2,600 psi) and the 5 lb/gal fluid (1,300 psi) or 3,900 psi. The hydrostatic pressure of the 10.0 lb/gal fluid in the drill pipe is 5,200 psi. If the well is shut in, a pressure of 1,300 psi will be imposed on the casing pressure gauge because of the difference in the hydrostatic pressures in the two parts of the U-tube.

NOTE: The pressure at the casing shoe is 3,900 psi (the sum of the imposing casing pressure (1,300 psi) and the hydrostatic pressure of the 10.0 lb/gal mud (2,600 psi).

The Equivalent Static Density (ESD) at the casing shoe would be 15 lb/gal.

Standard circulating situation

Figure 14 shows a standard U-tube diagram for a circulating situation. A circulating pressure of 2,600 psi is required to move the mud from the pump to the flow line. The circulating pressure is the sum of the pressure losses in the surface equipment, drill pipe, mud motor, MWD, drill collars, bit nozzles and the annulus. The bottom-hole circulating pressure (5,460 psi) is the sum of the annular hydrostatic pressure and the 260 psi annular pressure loss. Similarly, the casing shoe circulating pressure (2,730 psi) is the sum of the hydrostatic pressure and the 130 psi annular pressure loss between the casing shoe and atmospheric pressure. These pressures cause the ECD to be 10.5 lb/gal at the shoe and on bottom for this example.

Circulating (annular density less than drill pipe density)

Figure 15 shows a U-tube diagram of an unbalanced circulating system using the combined examples from Figures 13 and 14. The hydrostatic pressure is unbalanced in the U-tube. In order to maintain a bottom-hole pressure of 5,460 psi, an imposed casing pressure of 1,300 psi is necessary (5,460 psi – 3,900 psi (hydrostatic pressure) – 260 psi (annular pressure loss)). The pressure at the casing shoe is 4,030 psi, with an ECD of 15.5 lb/gal.

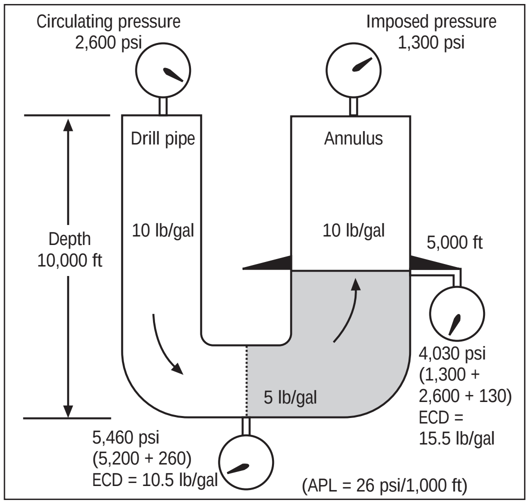


Figure 15: Unbalanced circulating U-tube situation with imposed casing pressure.

Circulating (formation fluid influx)

Figure 16 illustrates a U-tube diagram of a kicking circulating well with the BOPs open. The bottom-hole hydrostatic pressure is only 5,460 psi (as in Figure 12). A formation with a pressure of 5,720 psi bottom-hole pressure is encountered. An unbalanced pressure of 260 psi exists (5,720 psi (formation pressure) – 5,460 psi (bottom-hole pressure)). As a result, formation fluids will begin to enter the annulus, causing a kick. It should be noted that as formation fluid enters the annulus, the hydrostatic pressure in the annulus will begin to decrease due to the reduced density of the intruding fluid. Reducing the volume of the influx will reduce the surface pressures required to balance the pressure.

Shut-in formation pressure

If the well in Figure 16 is shut in, the shut-in casing pressure and the shut-in drill pipe pressure will reflect the pressures necessary to balance the formation

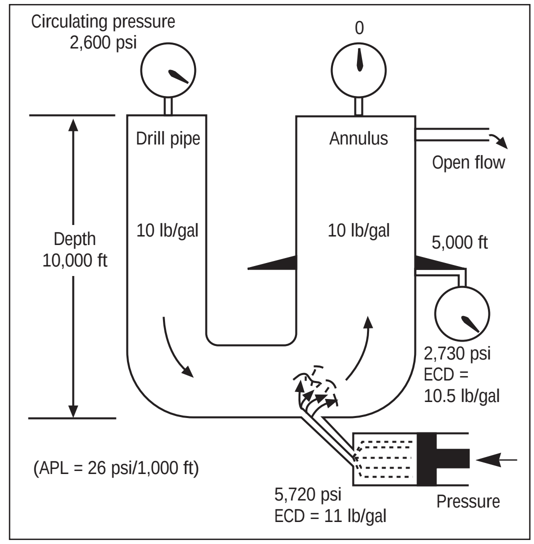


Figure 16: Circulating U-tube with influx of formation fluids.

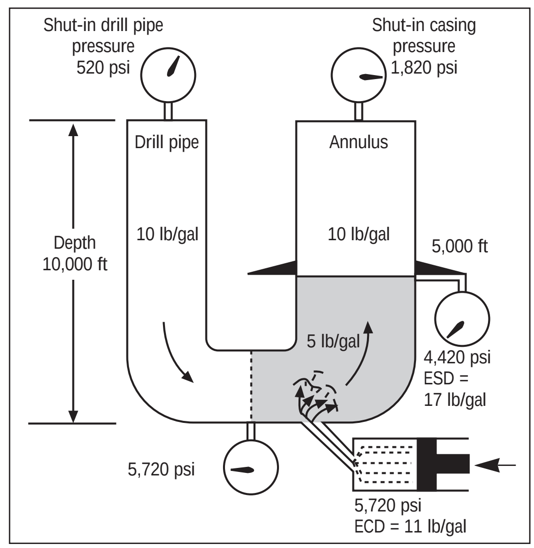


Figure 17: Shut-in kick pressures.

pressure (see Figure 17). Shutting the well in will allow both sides of the U-tube to equalize. As shown, if 5,000 ft of 5.0-lb/gal formation fluid is allowed into the well, the shut-in casing pressure would be 1,820 psi, with a casing shoe ESD of 17 lb/gal.

Pressure Control

Early detection of a kick...can... simplify regaining control of the well.

Kick detection

Early detection of a kick is important. It can reduce the size of the kick, lower the quantity of pressure exerted on the casing shoe and simplify regaining control of the well.

There are distinct warnings during drilling that indicate a kick is possible (some of them were mentioned earlier in this chapter). The first warning is an indication of increases in pore pressure. Failure to compensate for pore pressure increases with increasing mud weight can lead to a kick. Other warnings are:

1. Increases in penetration rate.
2. Increases in torque and drag.
3. Increases in the size, shape and amount of cuttings.
4. Increases in background gas.

These are not direct kick indicators; rather, they are changes in bottom-hole conditions that could result in a kick if appropriate measures are not taken.

Reducing the size of the influx is a high-priority objective.

Indications that a kick has entered the well are:

1. Increases in flow at the flow line.
2. Increases in pit volume.
3. Flow with the pump off.
4. Hole taking insufficient mud volume on trip.

When any of these indicators are recognized at the surface, immediate action must be taken to prevent the further influx of fluid. Failure to take appropriate actions can lead to a blowout.

Knowing and recognizing the stages of kick indication is important for every member of the drilling crew. It is important on every well, since every well has the potential to kick. Using good well planning and following good drilling procedures will minimize the potential for a kick.

A good well plan requires looking at all of the available information about an area — from offset wells to determine the casing program, mud weight schedule and depths where potential problems may occur.

Good drilling practices involve maintenance and testing of all of the rig components. They also involve unscheduled drills to practice the procedures for shutting a well in. The drills are determined by company or government regulations, depending upon where the well is being drilled. To increase rig crew vigilance, the frequency of such drills may be increased as an abnormal pressure zone is approached.

Shut-in procedures

When the warning signs of a kick are recognized, steps should be taken immediately to determine if the well is flowing and to shut the well in as quickly and safely as possible, to prevent any further influx into the wellbore. Reducing the size of the influx is a high-priority objective. A kick can occur while drilling or while tripping. Due to the nature of each operation, different procedures are necessary to shut the well in safely. The following are recommended procedures for a shut-in operation

NOTE: Separate procedures are listed for surface and subsea BOP stacks due to differences in well-control equipment.

While drilling

Surface BOP stacks

1. Raise the drillstring until the lower kelly cock is above the rotary table and there is no tool joint across the BOPs.
2. Shut down the pumps and check for flow. If the well is flowing, continue with Step 3.
3. Open the hydraulic valve on the choke line at the BOPs.

...it is easier to control a well when the bit is on or near bottom...

Do not risk losing control of the well in order to get the bit all the way back to bottom.

4. Close the designated BOP. This could be the annular preventer or the topmost pipe ram with the appropriate ram size for the drill pipe inside the BOP stack.
5. Close the adjustable choke on the choke manifold.

   NOTE: Closing the well with the adjustable choke precludes the possibility of imposing surge pressures on the BOP equipment.
6. Record the influx volume and the shut-in pressures on the casing and drill pipe. It may take several minutes for the pressures to stabilize. Check visually for leaks. It is also a good practice to double-check the position of all standpipe and choke-and-kill manifold valves.

Subsea BOP stack on floating units equipped with motion compensator

1. Raise the drillstring until the lower kelly cock is above the rotary table and there is no tool joint across the pipe rams.
2. Shut the pumps down and check for flow. If the well is flowing, continue with Step 3.
3. Open the outer fail-safe valve in the choke line at the BOP stack. (Normally, the inner valve should be in the open position.)
4. Close the designated BOP.
5. Land the drillstring on the top pipe rams and close the ram locks.
6. Close the second-from-top pipe rams.
7. Close the adjustable choke on the choke manifold. Set the motion compensator to mid-stroke. Record the influx volume and pressures on both casing and drill pipe. Check visually for leaks. Double-check the position of all standpipe and choke-and-kill manifold valves.

KICKS OFF BOTTOM

Well control is simplified when the bit is on bottom. The maximum column of drilling fluid can be conditioned to control the formation pressure and ensure that the intruding fluid can be circulated out of the well on the first circulation. But kicks do occur when the drill pipe is out of the hole or is being tripped. Since it is easier to control a well when the bit is on or near bottom, the drill pipe should be run back into the hole if it is possible to do so safely. This may be done if the well is not flowing or the rate of fluid flow is very low and the size of the influx is very small. Extreme caution should be taken when tripping into the well under these conditions. When the bit is run into the top of the kick fluid influx, the influx will be rapidly displaced upward. This can reduce the hydrostatic head sufficiently for the well to “unload” the mud and blow out if the well is not closed in quickly. Do not risk losing control of the well in order to get the bit all the way back to bottom. Once it has been determined that the well should be shut in, the following steps should be taken:

1. Install the drill pipe safety valve in the open position. It may be necessary to install this valve with mud flowing “through” it.
2. Close the safety valve.
3. Open the hydraulic choke line valve or outer choke line valve.
4. Space out the drillstring so that there is no tool joint opposite the BOPs.
5. Close the (upper) annular BOP or top pipe rams.
6. Close the adjustable choke.
7. Install the kelly or circulating head.
8. Open the drill pipe safety valve.
9. Re-align the standpipe manifold and choke-and-kill manifolds.
10. Record shut-in pressures on both the casing and drill pipe. Take readings at one-minute intervals until the pressures stabilize.
11. Measure pit gain in the mud tanks. On floating rigs, the drillstring should be hung on the pipe rams using normal procedures.

Once the well has been shut in, steps should be taken to circulate the intruding fluid out of the well.

WELL-CONTROL METHODS

Once the well has been shut in, steps should be taken to circulate the intruding fluid out of the well. Also, the density of the drilling fluid should be increased to provide sufficient hydrostatic pressure to control the formation pressure. Over the years, several methods have been developed to circulate the kick out and weight up the drilling fluid. All of these methods use a system of controlling the Bottom-Hole Pressure (BHP) through the use of hydrostatic pressure (P_{HYD}) and back pressure exerted by an adjustable choke (P_{CHOKE}). The back pressure exerted by the adjustable choke, along with the hydrostatic pressure in the annulus, will prevent additional formation fluid from entering the annulus.

$$BHP = P_{HYD} \text{ (annulus)} + APL + P_{CHOKE}$$

An adjustable choke is a valve that can be adjusted to vary the size of the opening through which the fluid flows. At a constant flow or pump rate, decreasing the size of the choke opening will increase the casing and drill pipe pressures. Increasing the size of the choke opening will decrease them. The pressure loss through an adjustable choke is similar to the pressure loss through the nozzles of a drill bit. The pressure loss through the choke is dependent upon the density and velocity of the mud, and the size of the opening. Maintaining a constant bottom-hole pressure is difficult with these three factors, which constantly change during the circulating process, contributing to the pressure loss through the choke. The process can be simplified by maintaining a constant pump rate during the well-control procedure. The density will change as the formation fluids are circulated through the choke. The effects of saltwater and oil will not be as dramatic as those of gas, but will be noticeable — especially with high-density drilling fluids. To maintain a constant bottom-hole pressure, the choke opening will have to change as the hydrostatic pressure in the annulus changes due to gas expansion.

All recognized well-control methods use a constant, but slow, pump rate when circulating a kick out of the hole and replacing the light mud with kill mud. Additional formation fluids must be kept from entering the wellbore while the kick is being circulated out of the well and the weighted kill mud is being circulated. Formation fluids will not enter the wellbore if sufficient pressure is maintained on the formation while circulating the kick out. If the pressure on the casing plus the hydrostatic pressure of the fluid in the annulus is equal to or greater than the formation pressure, additional formation fluid will not enter the wellbore. Unfortunately, the hydrostatic pressure of the mud in the annulus cannot be calculated accurately. The volume of gas after expansion, and the density of formation liquids (oil and saltwater) in the annulus cannot be determined with sufficient accuracy to accurately calculate the pressures needed to kill the well properly.

If the kick has not been allowed to flow back through the drill pipe and the bit is on bottom, the shut-in drill pipe pressure plus the hydrostatic pressure (P_{HYD}) of the mud in the drill pipe is equal to the formation pressure. If the adjustable choke is used to maintain a constant drill pipe pressure equal to the recorded slow pump rate circulating pressure plus the SIDPP, a constant bottom-hole kill pressure will be maintained. Although the annular pressures will fluctuate as the gas is displaced from the annulus, but additional formation fluids will not flow into the wellbore. The kick can be circulated out in this manner, but the well will not be killed. When the drill pipe pressures are

__The RCP should be measured at a slow pump rate and recorded every tour…__

used, the well can be killed without having to compensate for gas expansion in the calculations. When weighted mud is being pumped down the drill pipe, the use of a schedule to decrease the drill pipe pressure as the hydrostatic pressure in the annulus increases, will lessen the likelihood of fracturing the formation. After the kill-weight mud reaches the bit, a constant pressure is held on the drill pipe while displacing the annulus with kill-weight mud at the slow pump rate. Two methods are used to determine this pressure. These calculations will be discussed in the well-control method to which they apply.

Usually, well-control operations are conducted at a reduced pump rate of ⅓ to ½ the normal circulating rate. There are many reasons for doing this. Among them are:

__…well-control operations are conducted at a reduced pump rate of ⅓ to ½ the normal circulating rate.__

1. **Improved reaction time.** The bottom-hole pressure is controlled by opening or closing an adjustable choke. At high flow rates, small adjustments in the choke opening can result in large pressure changes. This may permit additional formation fluids to enter the annulus or fracture the formation. Reduced flow rates allow more time to analyze changes and recognize equipment problems such as pump failure, choke failure and plugged bit nozzles.
2. **Pressure limits.** The pump pressure used to circulate a kick out is the circulating pressure at a known pump rate plus the SIDPP. In most drilling operations, the pumps are operated near their maximum pressure limits. Under these conditions, the pumps would not be capable of operating at the required kill rates and pressures.
3. **Equipment failure.** When equipment is run at or near its maximum rating, the higher stress levels increase the likelihood of failure.
4. **Mud weight consistency.** To kill a well successfully, the mud weight must be increased to a density that will balance the formation pressure. At high flow rates, equipment limitations may make it impossible to add weight material fast enough to maintain the proper kill-mud weight. Reduced pump rates give the rig crew more time to maintain the correct mud weight and fluid properties during the well-control operation.

The Reduced Circulating Pressure (RCP) should be measured at a slow pump rate and recorded every tour for all mud pumps in the event that a pump breaks down during a well-control operation. The RCPs should be measured and recorded whenever well changes occur that will affect the circulating pressure. Some of these changes are mud density, drilling assembly or nozzle changes, pump repairs, and a high quantity of new hole drilled.

Several calculations are necessary for each of the well-control methods. Some of them are common to all of the well-control methods. They are:

$$\text{Kill-weight mud (lb/gal)} = \text{MW (lb/gal)} + \frac{\text{SIDPP (psi)}}{0.052 \times \text{TVD (ft)}}$$

$$\text{Surface-to-bit strokes} = \frac{\text{drillstring capacity} \times \text{measured depth}}{\text{pump output}}$$

NOTE: Calculations necessary for a particular well-control method will be described in the discussion of that method.

When a kick occurs and the well is shut in, basic information should be recorded. This information will be used to kill the well and can be used in future analysis of the operation. To assist rig personnel, worksheets have been developed for the various well-control methods. The worksheets usually include all of the information about the well, kick and rig needed to kill the well using a specific well-control procedure. The necessary calculations are included with a description of the well-control method. The worksheets are good tools for guiding rig crews through the necessary well-control procedures.

NOTE: A worksheet for each of the approved well-control procedures is included in this chapter with a discussion of the procedure.

The information that should be recorded after taking a kick are:

1. Measured depth.
2. Total vertical depth.
3. Mud weight.
4. Shut-In Drill Pipe Pressure (SIDPP).
5. Shut-In Casing Pressure (SICP).
6. Kick volume.
7. Fractured gradient.
8. Casing TVD.
9. Reduced Circulating Pressure (RCP).
10. Reduced Circulating Rate (RCR).
11. Reduced Pump Output (RPO).

If off-bottom:

12. Measured depth of bit.
13. TVD of bit.

Items 1 through 6 are taken at the time the kick is taken and the well is shut in. Items 7 through 11 should be known or measured prior to taking a kick. They must be used to make the necessary calculations to circulate the kick out of the hole and to kill the well. Items 12 and 13 apply if the kick occurs while tripping.

THE DRILLER'S METHOD

The Driller's Method is not recommended for most offshore wells.

The Driller's Method is the simplest of the approved well-control methods. It was developed to circulate the kick out of the well and circulate the kill mud into the well (in two circulations) with a minimum number of calculations. The method's original purpose was to control wells with minimal supervision, poor mixing capabilities or insufficient weighting material on location.

NOTE: The Driller's Method is not recommended for most offshore wells.

The procedure for circulating a kick out using the Driller's Method is:

1. Shut the well in and record the pertinent kick information.
2. Calculate the Initial Circulation Pressure (ICP):

   ICP = RCP + SIDPP

3. Open the adjustable choke and start pumping at the preselected slow pump rate. Adjust the choke to obtain a pump pressure equal to the ICP.
4. Circulate the kick out by maintaining the ICP using the adjustable choke. Maintain a constant pump rate throughout the circulating process.
5. Once the kick has been circulated out of the well, the well can be shut in. The SIDPP and the SICP should be equal, since the intruding fluid has been circulated out of the well.
6. Calculate the kill-mud weight and weight up the fluid in the surface system.
7. Open the adjustable choke and start pumping at the preselected slow pump rate. Adjust the choke to maintain the casing pressure at the SICP.
8. Maintain the mud weight in the surface system at the kill-mud weight.
9. Once the kill mud reaches the bit, record the pump pressure. Maintain this pump pressure by adjusting the choke until the kill mud is observed at the surface.
10. Stop pumping and shut the well in to check for pressures. If shut-in pressure exists, additional mud weight and circulation will be required. If no shut-in pressures exists, the well is under control. At this time, one or two circulations may be made to condition the mud and increase the mud weight to provide a trip margin.

The following information has been used to fill out the Driller's Method well-control worksheet as shown in Figures 18 and 19.

Given:

Depth	=	14,000 ft (TVD)
Mud weight	=	15.0 lb/gal
SIDPP	=	900 psi
SICP	=	950 psi
Pit volume increase	=	15 bbl
Kill pump rate	=	4.75 bbl/min (30 stk/min)
RCP at 30 stk/min	=	800 psi
Drill pipe	=	4½ in. x 16.6 lb/ft (capacity 0.01422 bbl/ft)

WELL NAME ______________________

DATE ______________________

WELL CONTROL WORKSHEET
DRILLER'S METHOD

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size 9 5/8 in Weight 43.5 ppf Grade N - 80 Internal Yield 6330 psi Depth, TVD 10,000 ft

Maximum Allowable Casing Pressure:

Entire Well Kill (80% of Casing Yield) 5064 psi

Initial Closure Only (Fracture Pressure Limit (1)) 1040 psi*

Approved By ______________________

* Must be changed as mud weight changes. Used only if approved.

Normal Circulating Rate and Pressure 2400 psi at 70 stks/min and 11.1 bpm at 15.0 ppg and 14,000 ft

Kill Rate and Pressure: Pump No. 1 800 psi at 30 stks/min and 4.75 bpm at 15.0 ppg and 14,000 ft (2)

Pump No. 2 ______ psi at ______ stks/min and ______ bpm at ______ ppg and ______ ft (2)

Drill Pipe Capacity: .01422 bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump, open choke line and choke (if closed), close annular preventer, close choke while observing casing pressure. Do not let casing pressure exceed maximum allowed (3).

Record: Closed-in Drill Pipe Pressure 900 psi Casing Pressure 950 psi Mud Weight 15.0 ppg
Depth, TVD 14,000 ft Size of Kick 15 bbl

III. ESTABLISH CIRCULATION

Open choke while bringing pump to selected Kill Rate. Increase pump rate slowly and hold casing pressure constant at closed-in value by slowly opening choke. After reaching Kill Rate note Drill Pipe Pressure and hold constant by holding Kill Rate constant and adjusting choke. The Drill Pipe Pressure should be the sum of Kill Rate Pressure plus Closed-in Drill Pipe Pressure (4). If not, correct by adjusting choke.

Record the New Drill Pipe Pressure 1700 psi at 30 stks/min and 4.75 bpm.

IV. CIRCULATE OUT THE KICK

While holding Kill Rate constant keep New Drill Pipe Pressure constant by varying choke. If Drill Pipe Pressure increases, open choke. If Drill Pipe Pressure decreases, close choke. Casing Pressure must be allowed to vary to maintain constant bottomhole pressure. When well is free of gas, salt water and oil, stop pump and close choke. Record New Closed-in Casing Pressure 900 psi.

V. INCREASE MUD WEIGHT

Calculate the required mud weight (5) and increase weight in suction pit (6).

VI. CIRCULATE HEAVY MUD

Establish circulation as per III using New Closed-in Casing Pressure plus 100 psi*.
Hold Kill Rate constant, and New Casing Pressure constant by varying choke.
Maintain required mud density in pits while circulating.
Circulate heavy mud to bit using strokes or time (7).
When heavy mud reaches bit read and record Final Drill Pipe Circulating Pressure 869 psi.
Hold Final Drill Pipe Pressure constant by varying choke while holding Kill Rate constant.
When uncut heavy mud reaches surface shut down pump and check for flow.

Figure 18: Driller's Method well-control worksheet – procedure.

CALCULATIONS AND NOTES

(1) Fracture Mud Weight

$$= \frac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}} + \text{Leak-off Test Mud Weight} = \frac{1560 \text{ psi}}{.052 \times 10{,}000 \text{ ft}} + 14.0 \text{ ppg}$$

$$= 17.0 \text{ ppg}$$

Fracture Pressure Limit = .052 x Casing Depth x (Fracture Mud Weight - Present Mud Weight)

$$= .052 \times 10{,}000 \text{ ft} \times (17.0 \text{ ppg} - 15.0 \text{ ppg}) = 1040 \text{ psi}$$

(2) Measure at beginning of each tour, after drilling 500 ft. and after each change of over 0.1 ppg mud weight.

(3) If casing pressure reaches maximum allowed, stop closing choke, resume circulation holding not more than maximum allowed casing pressure and start increasing mud weight. Mud weight required is estimated from maximum drill pipe pressure observed before circulating. See Low Choke Pressure Procedure.

(4) Drill Pipe Circulating Pressure = Closed-in Drill Pipe Pressure Plus Kill Rate Circulating Pressure

$$= 900 \text{ psi} + 800 \text{ psi} = 1700 \text{ psi}$$

(5) Required Mud Weight = Present Mud Weight plus $\frac{19.25 \times \text{Closed-in Drill Pipe Pressure}}{\text{Bit Depth, TVD}}$ plus Trip Margin*

$$= 15.0 \text{ ppg} + \frac{19.25 \times 900 \text{ psi}}{14{,}000 \text{ ft}} \cancel{+\ 0.3 \text{ ppg}^{**}} = 16.3 \text{ ppg}$$

(6) If two sections or pits are weighted and circulation established between, mud weight is more evenly controlled while circulating hole.

(7) Circulating Time to Bit $= \frac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}}$

$$= \frac{.01422 \text{ bbl/ft} \times 14{,}000 \text{ ft}}{4.75 \text{ bpm}} = 41.85 \text{ min}$$

(8) Strokes = Kill Rate x Time = 30 stks/min x 41.85 min. = 1256 stks

(9) Final Circulating Pressure = Kill Rate Pressure x $\frac{\text{Required Mud Weight}}{\text{Original Mud Weight}} = 800 \text{ psi} \times \frac{16.3 \text{ ppg}}{15 \text{ ppg}}$

$$= 869 \text{ psi}$$

* Note: Trip Margin and Safety Factor may be omitted, but these give little risk of loss of circulation as the hole and casing seat are subjected to higher pressures when circulating out the kick. If trip margin is used, then when heavy mud nears the surface the choke will be wide open and Final Drill Pipe Circulating Pressure can no longer be controlled. The Drill Pipe Pressure will slowly increase to compensate for the Trip Margin.

** Use 0.5 ppg for Trip Margin if hole is less than 7 in. diameter.

Figure 19: Driller's Method well-control worksheet – calculations.

After the well is shut in...the drilling fluid in the pits is "weighted" up to the kill-mud weight.

Calculations:
- Calculate initial circulating pressure (Step 4).

$$ICP = RCP + SIDPP$$
$$= 800 + 900 = 1{,}700 \text{ psi}$$

- Calculate kill-mud weight (Step 5).

$$\text{Kill-MW} = \text{MW (lb/gal)} + \frac{\text{SIDPP (psi)} \times 19.25}{\text{TVD (ft)}}$$
$$= 15.0 + \frac{900 \times 19.25}{14{,}000}$$
$$= 15.0 + 1.24 = 16.3 \text{ lb/gal}$$

- Calculate circulating time to bit (Step 7).

$$\text{Circulating time to bit} = \frac{\text{DP capacity (bbl/ft)} \times \text{MD (ft)}}{\text{kill pump rate (bbl/min)}}$$
$$= \frac{0.0142 \times 14{,}000}{4.75}$$
$$= 41.85 \text{ min}$$

- Calculate the strokes to bit (Step 8).

$$\text{Strokes to bit} = \text{kill pump rate (stk/min)} \times \text{time (min)}$$
$$= 30 \text{ stk/min} \times 41.85 \text{ min}$$
$$= 1{,}256 \text{ stk}$$

- Calculate final circulating pressure (Step 9).

$$FCP = RCP \times \frac{\text{kill mud weight}}{\text{original mud weight}}$$
$$= 800 \times \frac{16.3}{15.0}$$
$$= 869 \text{ psi}$$

Procedure:
- Open the adjustable choke and start pumping at 30 stk/min.
- Adjust the choke to obtain a pump pressure of 1,700 psi. Maintain this pressure until the kick has been circulated out of the hole.
- Shut the well in and record the shut-in pressures. The SIDPP and the SICP should be equal at 900 psi if the kick has been completely circulated out of the annulus.
- Increase the mud weight in the mud pits to 16.3 lb/gal (kill-mud weight).
- Open the choke and start circulating the kill mud at 30 stk/min. Adjust the choke to maintain the casing pressure at 900 psi.
- Once the kill mud reaches the bit (1,256 stk), record the pump pressure. Adjust the choke to maintain this pump pressure until the kill mud is observed at the surface.
- Shut the well in and determine if it is dead.

The Driller's Method requires two circulations to control the well successfully. One circulation is required to circulate the kick out of the hole and the second increases the density of the fluid in the well to the kill-mud weight.

The Wait-and-Weight Method

The Wait-and-Weight Method of well control is explained by its name. After the well is shut in, the rig crew "waits" while the drilling fluid in the pits is "weighted" up to the kill-mud weight. In order to use this method successfully, sufficient weight material must be on location and the mixing capacity must be sufficient to maintain the kill-mud weight while circulating at the slow pump rate.

This procedure is more complicated than the Driller's Method. In the Driller's Method, weighted mud is not pumped into the well until the kick has been circulated out of the well. The gas expansion is compensated for by maintaining a constant drill pipe pressure while circulating the kick out. When weighted mud is pumped into the well, the casing pressure is held constant until the weighted mud reaches the bit. This compensates for the changing hydrostatic pressure in the drill pipe.

In the Wait-and-Weight Method, gas is expanding in the annulus while the hydrostatic pressure is increasing in the drill pipe. This requires that the pump pressure needed for maintaining a

Once the kill-weight mud reaches the bit, the pump pressure is held constant at the FCP until the kill mud reaches the surface.

constant bottom-hole pressure must change as the fluid is circulated. A chart of the scheduled pump or drill pipe pressure changes simplifies the kill procedure and reduces the chance of error. The pressure schedule or graph determines the pump pressure while the kill mud is being pumped down the drill pipe. As the hydrostatic pressure in the drill pipe increases, the pump pressure necessary to maintain the correct bottom-hole pressure is reduced.

Well-control worksheets for the Wait-and-Weight Method contain a pressure schedule graph. The schedule is drawn on standard rectangular coordinates. The vertical axis is for the pump pressure and the horizontal axis is for the pump strokes. At zero (0) pump strokes, plot the ICP on the pressure scale. Plot the surface-to-bit strokes and plot the FCP on the graph. Draw a straight line between the two points. It is not practical to try to maintain too fine a control on the drill pipe pressure while killing the well. Instead, make a chart that shows the pump pressure from the schedule at a selected stroke interval (i.e. 100, 150, 200 etc.). The pump pressure is maintained according to this pressure until the selected number of strokes is pumped. The pump pressure is then reduced to the next pressure until the stroke interval is pumped. This stair-step fashion is continued until the kill mud reaches the bit. At that time, the pump pressure is held constant until the kill mud is observed at the surface. *NOTE: The pump pressure will decrease on its own as the kill-mud weight is pumped down the drill pipe. This is due to the increase in hydrostatic pressure in the drill pipe. As a result, few, if any, choke adjustments are required while pumping kill mud down the drill pipe. Some adjustments will be required to account for the changing hydrostatic pressure in the annulus due to the intruding fluid moving up the annulus.*

Once the kill-weight mud reaches the bit, the pump pressure is held constant at the Final Circulating Pressure (FCP) until the kill mud reaches the surface. This FCP is calculated with the following equation.

$$\text{FCP} = \text{RCP} \times \frac{\text{kill-mud weight}}{\text{original mud weight}}$$

This equation calculates the reduced circulating pressure using the kill-mud weight as the circulating fluid. The calculations for pressures through these two sections of the circulating system are based on turbulent pressure losses and energy changes. Since the only significant change to the drilling fluid properties used to calculate these pressure losses is the mud density, the circulating pressure is increased by the ratio of the kill-mud weight to the original mud weight.

The Initial Circulating Pressure (ICP) is calculated the same way as in the Driller's Method:

$$\text{ICP} = \text{RCP} + \text{SIDPP}$$

The pressure schedule is drawn using the ICP, FCP and the surface-to-bit strokes.

The procedure for circulating a kick out using the Wait-and-Weight Method is:

1. Shut the well in and record the pertinent kick information.
2. Calculate the kill-weight mud.
3. Begin increasing the mud weight in the surface pits to the kill-weight mud.
4. Calculate the ICP.
5. Calculate the FCP.
6. Calculate the surface-to-bit strokes.
7. Construct a pressure schedule.
8. Open the adjustable choke and start pumping at the preselected slow pump rate. Adjust the choke to obtain a pump pressure equal to the ICP.

9. Circulate out the kick following the pressure schedule using the adjustable choke. Maintain a constant pump rate throughout the circulating process.
10. Maintain the mud weight in the surface system at the kill-mud weight.
11. Once the kill mud reaches the bit, maintain the FCP until the kill mud is observed at the surface.
12. Stop pumping and shut the well in to check for pressures. If shut-in pressures exist, additional mud weight and circulation will be required. If no shut-in pressures exist, the well is under control. At this time, one or two circulations can be made to condition the mud and increase the mud weight to provide a trip margin.

The following information has been used to fill out the Wait-and-Weight Method worksheet as shown in Figures 20 and 21.

Total depth:	9,000 ft (TVD)
Hole size:	8½ in.
Casing:	9⅝ in. (43.5 lb/ft) set to 5,000 ft (capacity 0.0744 bbl/ft)
Mud weight:	13.2 lb/gal
SIDPP:	400 psi
SICP:	500 psi
Pit volume increase:	15 bbl
Drill pipe:	4½ in. (16.6 lb/ft) (capacity = 0.0142 bbl/ft)
RCP (at stk/min):	600 psi
Kill pump rate:	4.17 bbl/min

Calculations

- Calculate ICP (Step 7).

ICP = RCP + SIDPP
= 600 + 400
= 1,000 psi

- Calculate the kill-mud weight (Step 4).

$$\text{Kill-MW (lb/gal)} = \text{MW (lb/gal)} + \frac{\text{SIDPP (psi) x 19.25}}{\text{TVD (ft)}}$$
$$= 13.3 + \frac{400 \text{ x } 19.5}{9{,}000}$$
$$= 14.1$$

- Calculate FCP (Step 8).

$$\text{FCP} = \text{RCP x } \frac{\text{kill-mud weight}}{\text{original mud weight}}$$
$$= 600 \text{ x } \frac{14.1}{13.2}$$
$$= 641 \text{ psi}$$

- Calculate circulating time to bit (Step 9).

$$\text{Circulating time to bit} = \frac{\text{DP capacity (bbl/ft) x MD (ft)}}{\text{kill pump rate (bbl/min)}}$$

- Calculate time to bit (Step 10).

$$= \frac{0.01422 \text{ (bbl/ft) x } 9{,}000 \text{ (ft)}}{4.17 \text{ (bbl/min)}}$$
$$= 30.7 \text{ min}$$

Strokes to bit = kill pump rate (stk/min) x time (min)
= 30 x 30.7 = 920 stk

Prepare drill pipe pressure schedule.

Procedure:

- Open the adjustable choke and start pumping at 30 stk/min.
- Adjust the choke to obtain a pump pressure of 1,000 psi.
- Follow the pressure schedule prepared in Figure 21 as the kill mud is pumped down the drill pipe.
- After the kill mud has reached the bit (920 stk), maintain the pump pressure at 641 psi (FCP) until the kill mud is observed at the surface.
- Shut the well in and determine if the well is dead.
- If the well is dead, the mud can be circulated either through an open choke or with the BOPs open. The mud can be conditioned and/or a trip margin can be added at this time.

WELL NAME ______________

DATE ______________

WELL CONTROL WORKSHEET
WAIT & WEIGHT METHOD

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size 9 5/8 in Weight 43.5 ppf Grade N-80 Internal Yield 6330 psi Depth, TVD 5,000 ft
Maximum Allowable Casing Pressure:
Entire Well Kill (80% of Casing Yield) 5064 psi
Initial Closure Only (Fracture Pressure Limit (1)) 520 psi*
Approved By ______________
* Must be changed as mud weight changes. Used only if approved.

Normal Circulating Rate and Pressure 2000 psi at 60 stks/min and 8.34 bpm at 13.2 ppg and 9,000 ft
Kill Rate and Pressure: Pump No. 1 600 psi at 30 stks/min and 4.17 bpm at 13.2 ppg and 9,000 ft (2)
Pump No. 2 ______ psi at ______ stks/min and ______ bpm at ______ ppg and ______ ft (2)
Drill Pipe Capacity: .01422 bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump, open choke line and choke (if closed), close annular preventer, close choke while observing casing pressure. Do not let casing pressure exceed maximum allowed (3).

Record: Closed-in Drill Pipe Pressure 400 psi Casing Pressure 500 psi Mud Weight 13.2 ppg
Depth, TVD 9,000 ft Size of Kick 15 bbl

III. INCREASE MUD WEIGHT

Calculate Required Mud Weight (4) and increase weight in suction pit (5)(6).

IV. PREPARE DRILL PIPE PRESSURE SCHEDULE

Determine Initial Circulating Pressure and plot above zero time (7).
Determine Final Circulating Pressure (8) and plot above Circulating Time to Bit (9).
Draw line between points.
Read Drill Pipe Pressure at 5 min. intervals and record in blank spaces.
Calculate strokes and fill in blanks (10).

V. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump rate slowly, if possible.
Adjust choke to hold Casing Pressure constant at Closed-in value while bringing pump to Kill Rate. Hold Kill Rate.
The Drill Pipe Pressure should be the sum of the Kill Rate Pressure plus Closed-in Drill Pipe Pressure.
If not correct, adjust.

VI. CIRCULATE HEAVY MUD

Maintain mud density in suction pit while circulating at Kill Rate.
Use choke to adjust Drill Pipe Pressure to values shown at times or strokes shown.
If Drill Pipe Pressure increases, open choke; if Drill Pipe Pressure decreases, close choke.
When heavy mud reaches bit (9)(10), hold Drill Pipe Pressure constant until heavy mud reaches surface.
When uncut mud of required weight reaches surface, stop circulation and check for flow.

Figure 20: Wait-and-Weight Method well-control worksheet – procedure.

CALCULATIONS AND NOTES

(1) Fracture Mud Weight $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Mud Weight $= \dfrac{702 \text{ psi}}{.052 \times 5{,}000 \text{ ft}} + 12.5$ ppg

= 15.2 ppg

Fracture Pressure Limit = .052 x Casing Depth x (Fracture Mud Weight - Present Mud Weight)

= .052 x 5,000 ft x (15.2 ppg - 13.2 ppg) = 520 psi

(2) Measure at beginning of each tour, after drilling 500 ft. and after each change of over 0.1 ppg mud weight.

(3) If casing pressure reaches maximum allowed, stop closing choke, resume circulation at maximum rate, hold maximum allowable casing pressure and start increasing mud weight. Mud weight required is estimated from maximum drill pipe pressure observed before circulating. See Low Choke Pressure Procedure.

(4) Required Mud Weight = Present Mud Weight plus $\dfrac{19.25 \times \text{Closed-in Drill Pipe Pressure}}{\text{Depth, TVD}}$ plus Trip Margin*

$= 13.2 \text{ ppg} + \dfrac{19.25 \times 400 \text{ psi}}{9{,}000 \text{ ft}} + \cancel{\text{ppg}} = 14.1 \text{ ppg}$

(5) If two sections or pits are weighted and circulation established between, mud weight is more evenly controlled while circulating hole.

(6) If drill pipe pressure increases during weighting, reduce to initial stabilized value by bleeding casing pressure through choke.

(7) Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure

= 600 psi + 400 psi = 1000 psi

(8) Final Circulating Pressure = Kill Rate Pressure x $\dfrac{\text{Required Mud Weight}}{\text{Original Mud Weight}} = 600 \text{ psi} \times \dfrac{14.1 \text{ ppg}}{13.2 \text{ ppg}}$

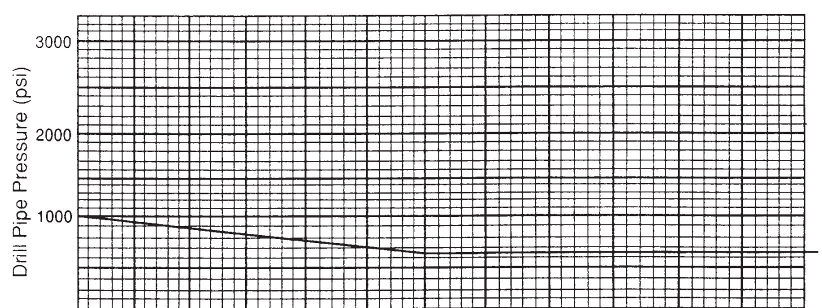
= 641 psi

(9) Circulating Time to Bit = $\dfrac{\text{Drill Pipe Capacity x Drill String Length}}{\text{Kill Rate}} = \dfrac{.01422 \text{ bbl/ft} \times 9{,}000 \text{ ft}}{4.17 \text{ bpm}} = 30.7$ min

(10) Strokes = Kill Rate x Time = 30 stks/min x 30.7 min. = 920 strokes

* Omit if only surface casing set or mud near fracture gradient.
Use 0.5 ppg for Trip Margin if hole less than 7 inches diameter.

DRILL PIPE PRESSURE SCHEDULE



Time min	0	5	10	15	20	25	30										
DP psi	1000	935	895	815	785	710	641										
Strokes	0	150	300	450	600	750	920										

Figure 21: Wait-and-Weight Method well-control worksheet – calculation.

Three calculations will be required to complete the schedule: Kill-mud weight, ICP and FCP.

DRAWING THE DRILL PIPE PRESSURE SCHEDULE

- Plot initial circulating pressure = 1,000 psi on the left-hand Y-axis.
- Plot final circulating pressure = 641 psi on the right-hand Y-axis.
- Label time across the X-axis.
- Label strokes below each time interval.
- Plot the final circulating pressure at the time-to-bit time and connect the initial and final pressures to this point.

As we pump the kill-weight mud down the drill pipe, we have to lower the drill pipe pressure according to the graph. For example, after we have pumped 8 min, or 270 strokes, the pressure should be adjusted to about 900 psi on the drill pipe gauge. Corrections should be made every few minutes. The final circulating pressure of 641 psi should be held constant until the 14.1 lb/gal reaches the surface. After the well is killed, we could continue to drill, but we would have to add an additional trip margin to the mud weight before we trip the pipe.

THE CIRCULATE-AND-WEIGHT (CONCURRENT) METHOD

The Circulate-and-Weight (Concurrent) Method is used to circulate the kick out of the hole while increasing the density of the drilling fluid gradually to the kill-mud weight. The well is shut in only long enough to obtain the pertinent information about the kick situation. The calculations and techniques used in the Wait-and-Weight Method are used in the Circulate-and-Weight (Concurrent) Method. When using the latter method for killing a kick, start circulating with the initial circulating pressure and begin adding barite to the system until you reach the kill-weight mud. This method uses a gradual increase in mud weight as the kick is circulated out.

The Circulate-and-Weight (Concurrent) Method is more complex than either the Driller's Method or the Wait-and-Weight Method due to the various densities of drilling fluid in the drill pipe. The number of different densities and the volumes of each depends upon the mixing capability and circulating rate of the drilling rig used. A complicated pressure schedule is necessary, as is a precise knowledge of when a mud density was achieved and pumped down the drill pipe. Excellent communications between the choke operator and the mud pits is required.

A pressure schedule similar to that of the Wait-and-Weight Method must be developed. The difference between the schedules is that the circulating pressure will be plotted vs. the mud weight. Use the Y-axis for the pressure and the X-axis for the mud weight. Three calculations will be required to complete the schedule: Kill-mud weight, ICP and FCP. The equations for these are the same as for the Wait-and-Weight Method.

To construct the schedule, plot the ICP at the original mud weight. Then, plot the FCP at the kill-mud weight. Use a straight edge to connect the two points. Start circulating at the reduced circulating rate. Adjust the choke to reach the ICP. While circulating, begin increasing the density of the mud in the pits. When an increase of 0.1 lb/gal is achieved in the pits, determine the time it will take to reach the bit. When this density reaches the bit, decrease the circulating pressure to the value associated with the density on the pressure schedule. Maintain this pressure until a new density reaches the bit. At this time, reduce the pressure according to the pressure schedule. Continue this process until the mud weight at the bit has been increased to the kill-mud weight. Maintain the FCP until the kill-mud weight has been observed at the surface.

Knowing the specifics about the well will determine the appropriate method...

The following information has been used to fill out the Circulate-and-Weight (Concurrent) Method well-control worksheet as shown in Figures 22 and 23.

Given:

Total depth:	8,000 ft
Hole size:	8½ in.
Casing:	9⅝ in. (43.5 lb/ft) set at 3,500 ft
Mud weight:	12.6 lb/gal
SIDPP	300 psi
SICP	400 psi
Pit volume increase:	20 bbl
Drill pipe:	4½ in. (16.6 lb/ft) (capacity = 0.0142 bbl/ft)
RCP (at 30 stk/min):	600 psi
Triplex pump #1 output:	6 in. x 8 in., 100% efficiency at 120 stk/min
RCP pump #2 at 60 stk/min:	500 psi
Triplex pump #2 output:	5½ in. x 8 in., 100% efficiency at 120 stk/min

Calculations:

- Calculate ICP (Step 4): 900 psi.
- Calculate kill-mud weight (Step 6): 13.4 lb/gal.
- Calculate FCP (Step 7): 638 psi.
- Calculate circulating time to bit (Step 8): 27.28 min.
- Calculate surface-to-bit strokes (Step 9): 818 stk.
- Prepare drill pipe pressure schedule (see Figure 23).

Procedure:

- Open the adjustable choke and start pumping at 30 stk/min.
- Adjust the choke to obtain the ICP of 900 psi.
- Start adding weight material to the surface system. When a 0.1 lb/gal weight increase is achieved, make a note of the pump strokes. When this mud weight reaches the bit, reduce the circulation pressure as per the pressure on the pressure schedule.
- Continue this procedure until the mud weight has been increased to the kill-mud weight (13.4 lb/gal). When the kill-mud weight reaches the bit, the pump pressure should be maintained at the FCP (638 psi) until the kill-mud weight is observed at the surface.
- Shut the well in and determine if the well is dead.
- If the well is dead, the mud can be circulated either through an open choke or with the BOPs open. The mud can be conditioned and or a trip margin can be added at this time.

CONCLUSIONS

The three methods outlined in this chapter have advantages and disadvantages. Knowing the specifics about the well will determine the appropriate method to be successful in circulating the intruding fluid out of the well and circulating the kill-mud into it. A brief list of advantages and disadvantages for each method is listed below.

Driller's Method

Advantages

a. Involves a minimal number of calculations (3).
b. A simple procedure that can be understood by most rig crews.
c. Removes the intruding fluid from the well in a minimum amount of time.

Disadvantages

a. Requires two circulations to kill the well.
b. Subjects the casing shoe to the maximum amount of pressure due to no additional hydrostatic pressure from additional mud weight.

WELL NAME

DATE

WELL CONTROL WORKSHEET
CONCURRENT METHOD

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size 9 5/8 in Weight 40.0 ppf Grade K-55 Internal Yield 3950 psi Depth, TVD 3500 ft
Maximum Allowable Casing Pressure:
Entire Well Kill (80% of Casing Yield) 3160 psi
Initial Closure Only (Fracture Pressure Limit (1)) 582 psi*
Approved By

* Must be changed as mud weight changes. Used only if approved.

Normal Circulating Rate and Pressure 1800 psi at 60 stks/min and 8.34 bpm at 12.6 ppg and 8,000 ft
Kill Rate and Pressure: Pump No. 1 600 psi at 30 stks/min and 4.17 bpm at 12.6 ppg and 8,000 ft (2)
Pump No. 2 ________ psi at ________ stks/min and ________ bpm at ________ ppg and ________ ft (2)
Drill Pipe Capacity: .01422 bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump, open choke (if closed), close annular preventer, close choke while observing casing pressure. Do not let casing pressure exceed maximum allowed (3).

Record: Closed-in Drill Pipe Pressure 300 psi Casing Pressure 400 psi Mud Weight 12.6 ppg
Depth, TVD 8,000 ft Size of Kick 20 bbl

III. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump speed slowly, if possible.
Adjust choke to hold Closed-in Casing Pressure while bringing pump to Kill Rate. Hold Kill Rate.
The Drill Pipe Pressure at Kill Rate should be the sum of Kill Rate Pressure plus Closed-in Drill Pipe Pressure (4).
If not, adjust. Record time when circulation started: ________ hrs. ________ min.

IV. START INCREASING MUD WEIGHT

Record time or strokes at which suction pit is increased each 0.1 or 0.2 ppg on graph (5).
Calculate Required Mud Weight (6).

V. PREPARE DRILL PIPE PRESSURE SCHEDULE

Fill in bottom of graph with even increments of mud weight from Initial to Required Mud Weight.
Plot Initial Circulating Pressure (4) above Initial Mud Weight.
Determine Final Circulating Pressure (7) and plot above Required Mud Weight (6).
Draw line between points.
Read Drill Pipe Pressure at each increment of mud weight and record in blank spaces.
Record Time (or strokes) at which suction pit has each increment of mud weight.
Calculate Circulating Time (8) (or strokes) (9) to Bit.
Fill blank spaces with ½ Circulating Time (or strokes) to Bit.
Add ½ Circulating Time (or strokes) to Bit to Time (or strokes) for each mud weight increment.

VI. KILLING THE WELL

Hold Drill Pipe Pressures shown for each mud weight increment at times (or strokes) shown by adjusting choke and while holding Kill Rate constant.
When required mud weight reaches bit hold Final Circulating Pressure constant until well dead.
When uncut mud of required weight reaches surface, stop circulation and check for flow.

Figure 22: Concurrent Method well-control worksheet — procedure.

CALCULATIONS AND NOTES

(1) Fracture Mud Weight $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}} + \text{Leak-off Test Mud Weight} = \dfrac{730 \text{ psi}}{.052 \times 3500 \text{ ft}} + 11.8 \text{ ppg}$

$= 15.8$ ppg

Fracture Pressure Limit = .052 x Casing Depth x (Fracture Mud Weight - Present Mud Weight)

$= .052 \times 3500 \text{ ft} \times (15.8 \text{ ppg} - 12.6 \text{ ppg}) = 582.4$ psi

(2) Measure at beginning of each tour, after drilling 500 ft. and after each change of over 0.1 ppg mud weight.

(3) If casing pressure reaches maximum allowed, stop closing choke, resume circulation at maximum rate, hold maximum allowable casing pressure using choke and start increasing mud weight. Mud weight required is estimated from highest drill pipe pressure observed before circulating. See Low Choke Pressure Method.

(4) Initial Circulating Pressure = Kill Rate Pressure + Closed-in Drill Pipe Pressure

$= 600 \text{ psi} + 300 \text{ psi} = 900$ psi

(5) If two sections or pits are weighted and circulation established between, mud weight is more evenly controlled while circulating hole.

(6) Required Mud Weight $= \text{Present Mud Weight plus } \dfrac{19.25 \times \text{Closed-in Drill Pipe Pressure}}{\text{Depth, TVD}} \text{ plus Trip Margin*}$

$= 12.6 \text{ ppg} + \dfrac{19.25 \times 300 \text{ psi}}{8{,}000 \text{ ft}} + 0.3 \text{ ppg*} = 13.7$ ppg

(7) Final Circulating Pressure $= \text{Kill Rate Pressure} \times \dfrac{\text{Required Mud Weight}}{\text{Original Mud Weight}}$

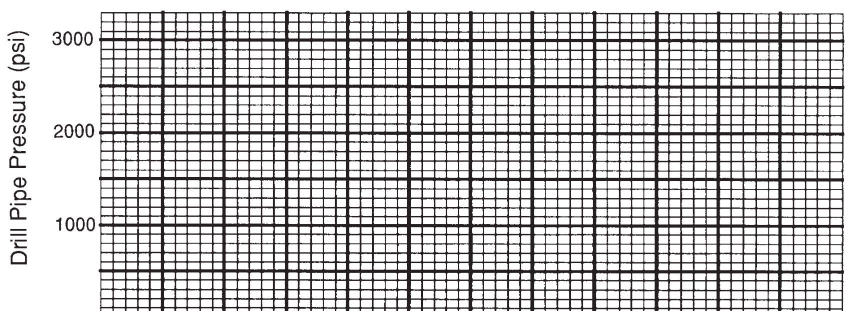
$= 600 \text{ psi} \times \dfrac{13.4 \text{ ppg}}{12.6 \text{ ppg}} = 638$ psi

(8) Circulating Time to Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \dfrac{.01422 \text{ bbl/ft} \times 8{,}000 \text{ ft}}{4.17 \text{ bpm}} = 27.28$ min

(9) Strokes = Kill Rate x Time = 30 stks/min x 27.28 min. = 818 stks

* Omit Trip Margin if only surface casing set or mud near fracture gradient.
Use 0.5 ppg for Trip Margin if hole less than 7 inches diameter.

DRILL PIPE PRESSURE SCHEDULE



Mud Wt.	12.6	12.7	12.8	12.9	13.0	13.1	13.2	13.3	13.4				
DP psi	900	870	830	800	770	730	700	670	638				
Time or Strokes	0												
½ Time or ½ Strokes to bit	408												
Total Time or Strokes	408												

Figure 23: Concurrent Method well-control worksheet — calculations.

Wait-and-Weight Method

Advantages

a. Kills the well in one circulation.

b. Subjects the casing shoe to the minimum amount of pressure due to additional hydrostatic pressure from the mud weight increase.

Disadvantages

a. The well is shut in for a long period of time with no circulation. A gas kick will migrate up the hole, increasing the pressure, unless pressures are monitored constantly. Fluids such as saltwater will contaminate the fluid, causing increases in fluid loss. This, in turn, increases the possibility of sticking the drillstring. A gas kick in oil- or synthetic-base fluid can strip the barite from the fluid due to the solubility of gas in the base fluid. Gas changes phases and acts as a liquid when it solubilizes in the oil-base mud. This dilutes the fluid and may reduce the viscosity enough to allow weight material to settle and plug the annulus.

b. Requires more calculations than the Driller's Method.

c. Requires sufficient supplies of weight material and a good mixing system to maintain the density as the fluid is circulated.

Concurrent Method

Advantages

a. Removes the intruding fluid in a minimum amount of time.

b. Subjects the casing shoe to a reduced pressure due to increasing hydrostatic pressure.

c. Weight-up can be adjusted as weight material supplies allow.

Disadvantages

a. Requires a complex pressure schedule. The location of the incrementally increased mud densities must be known on a continuous basis to determine the pressure schedule.

b. Requires more than one circulation to kill the well. Due to the drawn-out method for weighting up, the time required could take two or more circulations.

Special Problems

This expansion of gas at or near the surface gives the impression that the well is kicking when, in fact, it is not.

GAS CUTTING

When a gas-bearing formation is penetrated, the gas is incorporated into the mud in the annulus. As the gas is circulated to the surface, the hydrostatic pressure above the gas is reduced. This reduction allows the gas to expand. The degree of expansion is greatest when the gas reaches the surface, where the hydrostatic pressure is reduced to zero. As the gas expands in the mud, the density of the mud is decreased. Therefore, the density of the mud is the lowest at the surface where the gas expansion is the greatest. This phenomenon is called "gas cutting" and the mud is referred to as "gas-cut mud."

This expansion of gas at or near the surface gives the impression that the well is kicking when, in fact, it is not. If a kick were occurring, it would have started when the gas-bearing formation was penetrated. When gas-bearing formations are penetrated, an increase in the ROP usually occurs. The well should be checked for a flow when this ROP increase occurs to determine if the well is kicking. Gas cutting is most likely to occur under the following conditions:

1. Bottoms-up after trips, short trips or connections.
2. Bottoms-up after penetrating a gas-bearing formation.

Increases in connection or background gas should be the basis for increasing the mud density...

In many cases, when the mud becomes gas-cut, the mud density is increased needlessly. Increases in connection or background gas should be the basis for increasing the mud density, not gas cutting. Gas cutting usually has little effect on the hydrostatic head of the total column of mud in the wellbore, since the reduction of mud density is only at the surface. The Strong-White equation can be used to calculate the reduction in bottom-hole hydrostatic pressure due to gas cutting. The following problems are exercises in calculating this reduction:

ΔP_{HYD} = Reduction in P_{HYD} (psi)

P_{HYD} = Hydrostatic pressure with uncut mud (psi)

N = Ratio of gas to mud

$$= \frac{\text{original mud weight}}{\text{cut mud weight}} - 1$$

NOTE: ΔP_{HYD} and P_{HYD} are expressed in psi. "Δ" represents the change *in pressure or density.*

1. Strong-White equation:

$$\Delta P_{HYD} = N \text{ x } 2.3 \log\left(\frac{P_{HYD}}{14.7}\right) \text{ x } 14.7$$

2. Shortcut estimation:

$$\Delta P_{HYD} = 100 \left(\frac{\text{uncut MW}}{\text{gas-cut MW}}\right) - 1$$

3. When gas expands in the annulus, the volume increase is observed as a gain in surface volume. This pit gain can be depicted as occupying some specific annular height in the hole. A loss of hydrostatic pressure can be determined from this gain using the following equation:

$$\Delta P_{HYD} \text{ (psi)} = \frac{\text{pit gain (bbl)}}{V_{ANN} \text{ (bbl/ft)}} \text{ x MW (lb/gal) x } 0.052$$

NOTE: The results of this equation assume that the pit volume gain is due specifically to the effects of the gas-cut mud. Since the drilling fluid circulating system is in a dynamic condition, exact determination of this value will be difficult. Another assumption made with this equation is that the gas has no density. This is not the case; however, using this assumption would give you the largest decrease in hydrostatic pressure.

Figure 24 shows the effects of gas-cut mud at various depths and amounts of gas cutting. It shows the reduction in hydrostatic pressure at depth for various percentages of gas cutting. The gas percentages used in the graph were 10, 33.3 and 50%. The effects of this gas cutting were shown for 10 and 18 lb/gal. Figure 24 indicates that an 18-lb/gal mud cut to 9 lb/gal at the surface (a 50% cut) reduces the hydrostatic pressure of a 20,000-ft well by only about 100 psi. The graph does not show all of the various possibilities, but does show that the reduction in hydrostatic pressure due to gas-cut mud is minimal. The results can be extrapolated between percentages for a close estimate in bottom-hole pressure reduction.

The following example calculates the reduction in bottom-hole pressure due to gas-cut mud using the Strong-White equation and the short-cut equation. Use the graph to estimate the reduction in bottom-hole pressure and compare the results to the equation.

Example:

Depth:	10,000 ft
Hole size:	9⅞ in.
Pipe size:	5 in.
Mud weight:	14 lb/gal
Mud cut to:	10 lb/gal
Pit volume gain:	3.6 bbl

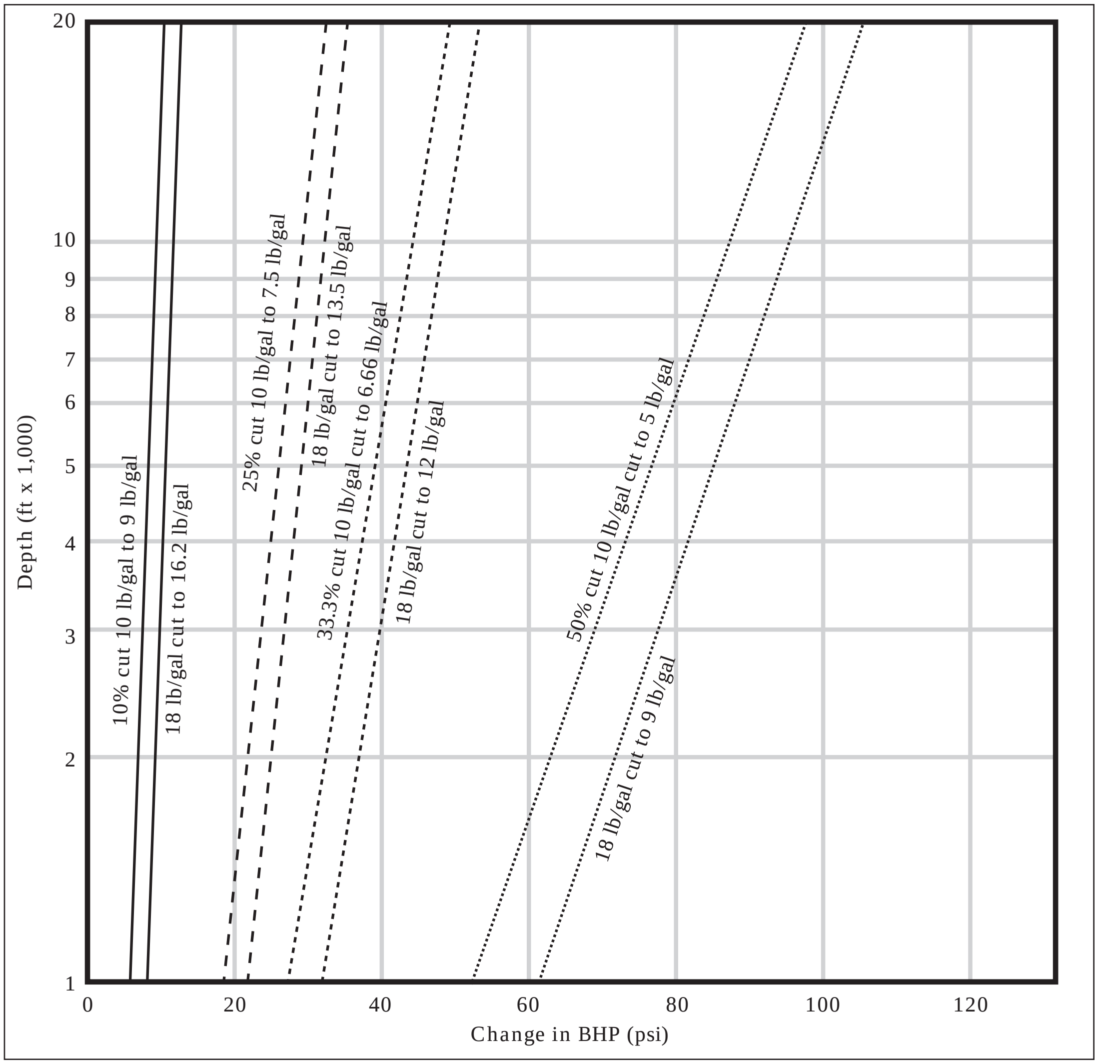


Figure 24: Actual reduction in bottom-hole pressure due to gas-cut mud.

What is the reduction in hydrostatic pressure?

1. Using Strong-White:

P_{HYD} = 10,000 x 14 x 0.052
= 7,280 psi

$$N = \frac{\text{original mud weight}}{\text{cut mud weight}} - 1$$

$$= \frac{14}{10} - 1$$

= 0.40

ΔP_{HYD} (psi) =

$$0.40 \times 2.3 \log \frac{7{,}280}{14.7} \times 14.7$$

= 0.40 x 2.3 log 495 x 14.7
= 0.40 x 2.3 x 2.695 x 14.7
= 36.44 psi

$$\Delta MW \text{ (lb/gal)} = \frac{\Delta P_{HYD} \text{ (psi)}}{0.052 \times TVD \text{ (ft)}}$$

$$= \frac{36.44}{0.052 \times 10{,}000}$$

= 0.07 lb/gal

2. Using the shortcut:

ΔP_{HYD} (psi) =

$$100 \times \frac{\text{uncut mud weight}}{\text{gas-cut mud weight}} - 1$$

$$= 100 \left(\frac{14}{10}\right) - 1$$

= 40 psi

$$\Delta MW = \frac{40}{0.052 \times 10{,}000} \; 0.077 \text{ lb/gal}$$

3. Using pit-volume increase:

$$\Delta P_{HYD}\text{ (psi)} = \frac{\text{pit-volume increase (bbl)}}{\left(\frac{D_h^2\text{ (in.)} - D_p^2\text{ (in.)}}{1{,}029}\right)} \ldots \times \text{MW (lb/gal)} \times 0.052$$

$$= \frac{3.6}{\left(\frac{9.875^2 - 5^2}{1{,}029}\right)} \times 14 \times 0.052$$

$$= \frac{3.6}{0.07} \times 14 \times 0.052$$

$$= 37.2 \text{ psi}$$

$$\Delta MW = 37.2 \div (0.052 \text{ X } 10{,}000) = 0.071 \text{ lb/gal}$$

Comments:
1. Moderate gas cutting has no major effect on hydrostatic pressure.
2. Any formation fluid entering the wellbore must displace mud from the hole into the pits.
3. A slight reduction in flow-line mud weight due to water influx may decrease bottom-hole pressure far more than a larger reduction in mud weight due to gas cutting.
4. When in doubt, check for flow, and shut-in drill pipe pressure and casing pressure.

If there was no increase in pit volume before the gas appeared at the flow line, a blowout is not occurring. The gas is expanding at the surface, but should be handled with caution.

Saltwater intrusions

Any kick should be handled as a gas kick until it is known to be another type of intrusion.

Any kick should be handled as a gas kick until it is known to be another type of intrusion. In most cases, a saltwater intrusion is less difficult to control than a gas intrusion, but intrusions of saltwater can cause problems. The saltwater usually contains sodium, calcium, magnesium and other ions. These ions react with the mud to alter its chemistry. The most common result of this reaction is increased viscosity and fluid loss. The concentration and type of ion determines how severely the mud properties will be affected. High vicosities and fluid losses may result in lost circulation and/or sticking of the pipe.

When a kick is detected, calculations should be made to identify the intruding fluid. If calculations indicate a saltwater flow, plans should be made to dispose of the saltwater and as much of the contaminated mud as possible when they reach the surface. The mud properties should be returned to the desired ranges as soon as possible by dilution and treating with the appropriate chemicals. If time allows, pilot tests should be made prior to treating the mud system.

Hydrogen sulfide and carbon dioxide

Hydrogen sulfide (H_2S) is an acid gas. It is very toxic — about the same as hydrogen cyanide. Breathing hydrogen sulfide concentrations of as low as 500 ppm can cause immediate death. Exposure to even lower concentrations can cause permanent brain and nerve damage. Hydrogen sulfide has the odor of rotten eggs. At concentrations greater than 150 ppm, it deadens the sense of smell and can no longer be detected by odor. The effects of hydrogen sulfide are cumulative. Exposure to low concentrations for a long period of time can have the same effect as short exposures to high concentrations. It is very flammable and will auto-ignite at 500°F. Explosive concentrations in air range from 4.3 to 46.0%.

Hydrogen sulfide also has a devastating effect on mud properties. Chemical reactions between hydrogen sulfide and mud can result in very high viscosities. These high viscosities increase annular pressure losses, which can result in lost circulation.

Hydrogen sulfide is very corrosive. In high-strength steels, it can cause hydrogen embrittlement catastrophic failure without warning. Any oilfield tubulars with higher strength than Grade E drill

The problems associated with hydrogen sulfide cannot be over-emphasized.

It is a common practice to bullhead the hydrogen sulfide gas back into the formation.

pipe or N-80 tubing is considered susceptible. These grades also may be susceptible when work-hardened under high loads or by rough handling such as being struck with a hammer when trying to detect a wet string.

The problems associated with hydrogen sulfide cannot be over-emphasized. It is soluble in water and liquefies at pressures of only 350 to 400 psi. Because of these characteristics, kicks containing a significant amount of hydrogen sulfide are difficult to control. The phase change from a liquid to a gas with large increases in volume occur rapidly, very near the surface. Even when alerted to the presence of hydrogen sulfide, it is difficult to work the choke fast enough to handle a hydrogen sulfide kick properly.

Once hydrogen sulfide reaches the surface, it presents an extreme hazard to personnel and animal life. These hazards are discussed in greater depth in the Corrosion and HSE chapters of this manual. In most areas where hydrogen sulfide is thought to be a hazard, strict regulations are in place as regards to safety equipment, training, and evacuation zones and procedures. If hydrogen sulfide blows out, the well should be set on fire — even though the rig will be destroyed — to reduce the hazard. It would be unusual to find an area of the world so remote that the government, operator or drilling contractor did not have plans for drilling in hydrogen sulfide environments. If such a condition should exist, regulations and procedures from Louisiana, Mississippi, Texas or Wyoming can be used as a guide.

The handling of hydrogen sulfide in drilling fluids is mentioned in other chapters in this manual. SULF-X® or another inorganic zinc sulfide scavenger should be maintained *in excess* in oil- or synthetic-base drilling fluids. The P_{OM} of oil and synthetic muds should be maintained at a suitable level for the fluid, with additions of lime. In water-base muds, the pH should be kept at >11.5 and SULF-X or another suitable zinc scavenger should be maintained (in excess). Chelated zinc may be used in water-base muds, but zinc oxide is preferable in any fluid that can suspend it, since it has twice the activity of chelated zinc. Chelated zinc is especially suited for use in clear brines and Newtonian fluid systems that lack sufficient rheology to suspend zinc oxide. Simply raising the pH will not neutralize hydrogen sulfide. It converts the hydrogen sulfide to different types of soluble sulfide ion species. A reduction in pH will allow these soluble ions to convert to poisonous hydrogen sulfide gas. On the other hand, the reaction of sulfide with zinc forms a stable zinc sulfide which will not revert to hydrogen sulfide.

It is a common practice to bullhead the hydrogen sulfide gas back into the formation. This involves pumping mud down the annulus to force the kick back into the formation. The amount of fluid pumped is equal to the amount of influx taken. Once the intruding fluid has been bullheaded back into the formation, procedures should be undertaken to restore hydrostatic control of the well.

Carbon dioxide (CO_2) is another acid gas. It can be highly corrosive and cause severe flocculation of water-base muds. It is not considered to be a lethal gas.

Carbon dioxide is treated with additions of lime or lime and caustic soda. This precipitates the carbonates as calcium carbonate. Additions of deflocculants also are required to control the rheological properties of the fluid. *NOTE: A more in-depth discussion of treating CO_2 and carbonates can be found in the Contamination and Treatment chapter of this manual.*

Lost circulation is the loss of whole mud to the formation.

Density of the intruding fluid

The approximate density of the intruding fluid can be calculated. However, the accuracy of the answer depends on several factors. These factors are: (1) the accuracy of the shut-in drill pipe and casing pressures, (2) the accuracy of the measured volume of influx, (3) the hole size (allowing for washout), (4) the assumed annular mud density above the intruding fluid, and (5) the detection of the kick before gas expansion occurs.

Usually, the mud density in the annulus is slightly heavier than in the mud pits due to the cuttings concentration and loss of filtrate to the formation. This density can usually be determined by weighing the mud at the flow line, unless it is gas-cut. The weight of gas-cut mud at the flow line is not a true indication of the weight of the mud in the annulus, because gas expansion only occurs near the surface. If the mud is gas-cut, the weight should be determined with a pressurized Halliburton scale.

The actual hole size also must be determined to calculate the length of the intruding fluid. Knowledge of the degree of washout in other wells in the area in which the same type fluid (as the current well) was used is valuable in estimating hole size.

Accuracy in determining the volume of the intruding fluid is also necessary; therefore, the use of accurate measuring equipment that totals all surface pits is important, especially when large surface volumes are used.

To determine the density of the intruding fluid, measure:

a. The shut-in drill pipe pressure.
b. The shut-in casing pressure.
c. The pit volume increase.

Example:

Given:

Total depth:	6,000 ft
Mud weight:	10.5 lb/gal
Bit size:	$7\frac{7}{8}$ in.
Drill pipe:	$4\frac{1}{2}$ in., 16.6 lb/ft
Drill collars:	5-in. OD — 400 ft
SICP:	500 psi
SIDPP:	275 psi
Pit volume gain:	20 bbl

Annular volume around drill collars = 0.0359 bbl/ft
Annular volume around drill pipe = 0.0406 bbl/ft

Calculate the length of the intruding fluid:

Find the length of the 20 bbl of kick fluid in the annulus.

a. Drill collars
400 ft x 0.0359 bbl/ft = 14.4 bbl
20 bbl – 14.4 bbl
= 5.6 bbl of intrusion above collars

b. Drill pipe
5.6 bbl ÷ 0.0406 bbl/ft = 138 ft
Total length of the kick fluid is:
400 ft + 138 ft = 538 ft

Calculate the density of the intruding fluid:

$$FW = MW - \frac{(SICP - SIDPP)}{0.052 \times L}$$

Where:
FW = Kick density (lb/gal)
MW = Mud density (lb/gal)
L = Length of kick volume (ft)

$$FW = 10.5 - \frac{(500 - 275)}{0.052 \times 538}$$

$$= 2.46 \text{ lb/gal probable gas kick}$$

Lost circulation

Lost circulation is the loss of whole mud to the formation. It is more likely to occur during well-control operations than during drilling operations. During well-control operations, it can occur at any time — from the initial shut-in until the well is dead. When lost circulation is most likely to occur depends on the following factors:

1. Type of kick (gas or saltwater).
2. Length of kick (hole geometry and volume of kick).

3. Expansion of gas kick.
4. Choke pressure applied.
5. Annular pressure.
6. Casing program.

Early detection of lost circulation during well-control operations is important. Mud losses can usually be recognized by a reduction in volume in the mud pits or by a reduction in the drill pipe pressure at a constant pump rate. The pit volume should increase as a gas kick is circulated to the surface. This is a controlled expansion of the gas. Once the gas has reached the surface, the pit volume will diminish by the same amount as the gas removed from the fluid. When determining whether a loss is underway, this gain and loss should be considered relative to the original volume and the current operation.

A major cause of kicks while tripping is the failure to fill the hole properly.

KICKS WITH THE BIT OFF BOTTOM

Most kicks occur while pulling the drillstring out of the hole. A major cause of kicks while tripping is the failure to fill the hole properly. The action of pulling the pipe out of the hole results in the mud column dropping to displace the length of the drillstring that has been pulled out of the hole. To control the well properly, *the hole must be filled with exactly the same volume of mud as the displacement of the length of drillstring pulled from the hole.* This volume is critical, so it must be *metered*, not merely measured. As a general practice, the hole should be filled after five stands of drill pipe have been pulled. The fill-up frequency should be increased when pulling heavyweight drill pipe and drill collars due to their increased displacement. The fill-up frequency also should be increased whenever a "wet string" is pulled. The volume of mud required to fill the hole should be compared to the volume of steel or steel and mud pulled from the hole. If the volume required is less than the displacement of the pipe pulled from the well, it should be assumed that formation fluids have entered the wellbore.

Another cause of kicks while tripping is the reduction in bottom-hole pressure caused by swabbing. Swabbing is a function of mud properties and the speed at which the pipe is pulled out of the hole. This can be intensified by bit and stabilizer balling. A balled-up bottom-hole assembly has a diameter equal to, or very close to, the diameter of the hole. The action of pulling the pipe out of the hole is similar to a piston. Fluid is sucked in from the formation below the bit if mud cannot fall in the hole and displace the pipe as fast as it is being pulled.

Controlling a kick with the bit off bottom is more difficult...

Monitoring the volume of mud required to displace the pipe pulled on trips is the means of determining whether formation fluids have entered the well. If a kick is detected early in the trip, the pipe can be run back to bottom and the formation fluid circulated out without having too much difficulty. A small influx normally does not reduce the hydrostatic pressure enough to result in an underbalanced condition. However, if undetected, or if the trip is continued without taking appropriate action, the volume of the intruding fluid will increase. When the volume is sufficient to reduce the hydrostatic pressure to below the formation pressure, the well will start flowing, resulting in a kick.

Controlling a kick with the bit off bottom is more difficult and complicated than with the bit on bottom. If the well starts to flow or if the hole is not taking enough mud on fill-ups, the primary objective should be to get the bit back to bottom. If the well is not flowing, the pipe may be run to bottom without problems. Monitor the hole periodically to determine if it is static. If the well is flowing, it may be possible to run the pipe back to bottom, depending upon the rate of flow and how much pipe is out of the hole. The longer the well flows, the larger the volume of intruding fluid. A heavy influx of formation fluids will result in excessive surface pressures when the well is shut in. These pressures can fracture the casing shoe or cause failure of surface equipment. Shutting the well in reduces the size of the kick and the amount of pressure on the equipment.

Caution must be exercised when running pipe back into the hole after it is determined that formation fluids have entered the wellbore. When the drillstring is run into the formation fluids, they will be displaced up the wellbore. This displacement will quickly move the fluids to a shallow depth where they will expand rapidly. This can cause the well to flow.

If the well is shut in with the bit off bottom, several options are available. One is to strip the pipe back to bottom. To do this, pipe is run back into the hole with the BOPs closed. If the pressures are not excessive, this can be done through the annular preventer without severely damaging the sealing element. It is a good practice to use some type of lubricant to ease the movement of the pipe through the closed preventer and prevent damage to the sealing element. A bentonite slurry placed on top of the preventer will lubricate the pipe as it passes through the element. Other types of lubricants can be used. Before using a lubricant, check to see if it is compatible with the sealing elements. Some sealing elements are made of compounds that can be damaged by lubricant compounds.

If the pipe is stripped into the hole, mud must be bled off to make room for the pipe as it is run into the closed well. If not, the pressure in the well will increase and can fracture the formation. The volume of mud that must be bled off is equal to the displacement and capacity of the pipe. An inside BOP must be installed in the drill pipe when shutting the well in (see Shut-In Procedures). An inside BOP is a one-way valve that allows fluid to be pumped through it but closes to prevent backflow when pumping stops.

An inside BOP is a one-way valve that allows fluid to be pumped through it but closes to prevent backflow…

If the pipe can be stripped back to bottom, the Driller's Method kill procedure should be used to circulate the invading fluid out of the well. The Driller's Method is used because the fluid density does not have to be increased to control the formation pressure. Some additional density may be required in order to trip out of the hole safely.

In some cases, it will be impossible or impractical to get the bit back to bottom, so the kick must be controlled with the pipe in place. In such cases, the following options should be considered:

1. Increase the density of the mud above the current position of the bit by normal circulation or by circulating through the choke.
2. Mix and spot a high-density, limited volume kill fluid.
3. Spot a barite plug or a cement plug.

In these cases, the sum of the hydrostatic pressures of the mud densities must equal the formation pressure, but not exceed the fracture pressure at the weakest point in the well. This is illustrated in the following examples:

EXAMPLE #1:

Depth:	10,000 ft
Mud weight:	10 lb/gal
Depth of bit:	6,000 ft
SIDPP:	150 psi
Fracture gradient:	11.2 lb/gal at 2,000 ft

Calculate the mud weight required to balance the kick based on the TVD of the bit:

$$\text{Kill weight} = 10 + \frac{150 \times 19.25}{6{,}000}$$
$$= 10.5 \text{ lb/gal}$$

In this case, option No. 1 can be used, since the kill-weight mud does not exceed the fracture gradient.

EXAMPLE #2:

Depth:	10,000 ft
Mud weight:	10.0 lb/gal
Depth of bit:	4,000 ft
SIDPP:	300 psi
Fracture gradient:	11.2 lb/gal at 2,000 ft

Calculate the mud weight required to balance the kick:

$$\text{Kill weight} = 10 + \frac{300 \text{ x } 19.25}{4,000}$$
$$= 11.44 \text{ lb/gal}$$

In this case, option No. 2 should be used, since the kill-weight mud would exceed the fracture weight.

When this situation occurs, heavy mud can be spotted below the casing shoe to balance the kick pressure.

Calculate the weight of the high-density, kill fluid:

First calculate the bottom-hole (kicking) pressure:

$$\frac{0.052 \text{ x } 10,000 \text{ x } 10 + 300}{0.052 \text{ x } 10,000}$$
$$= 5,500 \text{ psi}$$

Next calculate the length and pressure of the 10 lb/gal mud above and below the heavy mud.

Length of 10 lb/gal mud
$$= 2,000 - 0 + 10,000 - 4,000$$
$$= 8,000 \text{ ft}$$

P_{HYD} of 10 lb/gal mud
$$= 0.052 \text{ x } 8,000 \text{ x } 10$$
$$= 4,160 \text{ psi}$$

P_{HYD} of high-density mud from 2,000 to 4,000 ft
$$= \frac{5,500 - 4,160}{0.052 \text{ x } 2,000} = 1,340 \text{ psi}$$
$$= 12.9 \text{ lb/gal}$$

An option is to set a barite or cement plug. This option does not provide a way to balance the formation pressures and should only be used as a last resort. If the plug is successful, gas will probably migrate up to the plug. This can make it hazardous to drill the plug.

NOTE: Barite and cement plugs are discussed in greater detail in the reference section.

These options are only temporary steps to balance formation pressures until the bit can be run to bottom and the mud weight increased uniformly throughout the wellbore.

GAS MIGRATION

If a well is shut in on a gas kick, the pressure in the gas equals the hydrostatic pressure of the fluid above it, plus the Shut-In Casing Pressure (SICP). The specific gravity of gas is significantly less than that of the drilling fluid in the annulus. As a result, the gas will move upward, or migrate, toward the surface. The rate of migration is dependent upon several factors, such as mud weight and mud viscosity. A widely accepted migration rate for gas is 500 to 1,000 ft/hr. When the well is shut in, the volumes of mud and gas in the annulus will remain constant, unless volume is lost to the formation or released at the surface. Without being allowed to expand, the confining pressure of the gas will remain constant as it migrates up the wellbore. This has serious implications.

When the well was shut in with the bubble at the bottom of the well, the gas was confined by the hydrostatic pressure of the mud column above it, plus the SICP. When the gas migrates to the surface, its confining pressure is held by the casing. This confining pressure is added to the hydrostatic pressure of the mud column at the casing seat and at the total depth of the well.

If the drill pipe pressure is 1,000 psi and the hydrostatic pressure at TVD is 10,000 psi when a well is shut in, the confining pressure of a gas bubble at TVD is 11,000 psi. If the bubble is

The gas bubble must be allowed to expand as it rises in the wellbore.

A simple method of controlling the bottom-hole pressure of a well is referred to as the Volumetric Method.

allowed to migrate to the surface without expanding, the casing pressure will be 11,000 psi and the pressure at TVD will be 21,000 psi. If this were an actual situation, it is highly unlikely that the bubble would reach the surface without fracturing the formation, rupturing the casing or causing the BOPs to fail.

There is a natural tendency to be concerned when the surface volume increases and the pits run over as a gas bubble expands and displaces mud from the annulus. Many wells have been lost by untrained personnel who did not allow the gas to expand as it was circulated from the well in kill procedures. This method of well control is contemptuously referred to as the Constant Pit Level Method of well control. ***Under no circumstances*** *should it ever be used!* The gas bubble must be allowed to expand as it rises in the wellbore.

A simple method of controlling the bottom-hole pressure of a well is referred to as the Volumetric Method. The amount of mud that is vented from the well represents a loss of hydrostatic pressure. This loss is determined by the mud weight and the height (annular height if pipe is in the hole) it occupies in the hole. This procedure maintains near-constant bottom-hole pressure while allowing the gas to expand as it migrates to the surface. To monitor the volume of fluid vented from the well, returns should be taken to a small, calibrated pit, where the exact vented volume can be measured. A trip tank is the best choice. A slugging pit is the next-best choice.

To prevent additional formation fluid from entering the annulus, select a minimum overbalance pressure. Then, select the amount of pressure increase which will be tolerated before drilling fluid is vented. Monitor the SIDPP and the SICP as the gas migrates upward. The pressures should increase equally, since the system is closed. Once the selected pressure increase occurs, open the choke slowly and vent enough mud to reduce the casing pressure to a predetermined acceptable level. When this is done, close the choke and allow the pressure to stabilize. This practice should be continued until the mud can be circulated and the well killed.

In some instances, circulation is not possible due to mechanical problems such as:
1. Pump failure.
2. Failure of other rig components.
3. Plugged pipe or bit.
4. Washout.

In these instances, the Volumetric Method will be required to allow the gas kick to migrate out of the hole. However, this method will not kill the well. The well will not be killed until there is sufficient hydrostatic pressure in the annulus to prevent a further influx of fluid. If necessary, the gas can be allowed to migrate to the surface with this procedure. Once the gas reaches the surface, the procedure changes. Prior to venting gas to the atmosphere, a volume of mud equaling some preselected hydrostatic pressure must be pumped into the well (lubricated). The mud will replace the volume of gas that was vented. The increasing hydrostatic pressure will reduce the casing pressure. This process should continue until the gas has been vented from the well and replaced with mud. At this time, the SICP and the SIDPP should be equal. Use of this procedure will result in avoiding a dangerous well condition and satisfactory control of the well.

PIPE OFF-BOTTOM OR OUT OF THE HOLE

Another instance where this procedure can be used is when a kick was taken with the bit off-bottom or with no drill pipe in the hole. The same procedure will work as before. There will be one difference, however. With the bit off bottom, the SIDPP and the SICP will be equal if the kick is below the bit. If there is no pipe in the hole, there will be only SICP.

Follow the procedure to vent mud as the gas migrates up the hole. When gas reaches the surface, mud should be lubricated into the well to replace the gas as it is vented. Once all of the gas has been vented, the well should be dead if nothing but gas entered the well and there was sufficient hydrostatic pressure in the annulus prior to pulling out of the hole. If not, a kick would have occurred prior to the trip. A check of the SICP should indicate whether the well is dead. The well can also be checked for flow.

If drill pipe is in the hole, gas can be circulated out of the hole when it migrates above the bit. This is done by using the Volumetric Method and monitoring the SIDPP and the SICP. With the kick below the bit, the SIDPP and the SICP will be equal. Once the kick reaches the bit, the gas will usually migrate up the annulus due to the larger space, compared to jet nozzles and the ID of the drill collars. When this occurs, the hydrostatic pressure in the annulus will change while the drill pipe pressure remains the same. The SICP will then be greater than the SIDPP. If circulation is possible, the gas should be circulated out of the well.

Example

The following well is shut in on a kick. There is no drill pipe in the hole. Determine the volume of mud that should be vented to reduce the hydrostatic column in the annulus by 100 psi and to allow the gas kick to expand.

Given:
SICP: 300 psi
Mud weight: 10.0 lb/gal
Hole size: 8¾ in.

$$\text{Hole volume} = \frac{8.75^2}{1{,}029} = 0.0744 \text{ bbl/ft}$$

$$\text{Mud column length for 100 psi} = \frac{100 \text{ psi}}{0.052 \times 10.0 \text{ lb/gal}} = 192 \text{ ft}$$

A 192-ft column of 10.0-lb/gal mud is equal to a hydrostatic pressure of 100 psi.

$$\text{Mud volume for 192 ft of mud} = 192 \text{ ft} \times 0.0744 \text{ bbl/ft} = 14.3 \text{ bbl}$$

Following is a chart showing the change in the casing pressure as the mud is vented and the gas is allowed to expand in the hole:

SICP		Volume of Mud Removed From the Hole (bbl)	
Before Venting	**After Venting***	**Cumulative**	**Incremental**
300	—	0	—
500	400	14.3	—
600	500	28.6	14.3
700	600	42.9	14.3
800	700	57.2	14.3
900	800	71.5	14.3

*Includes 100-psi safety margin.

Once the gas has reached the surface, the 10.0-lb/gal mud will be used to lubricate the gas out of the hole. The chart below would indicate the SICP reduction and the amount of mud pumped into the well:

Actual volumes and pressures may not coincide precisely with calculated volumes and pressures. Therefore, this procedure should be continued until all the gas has been vented out of the hole.

SICP		Volume of Mud Lubricated Into the Hole (bbl)	
Before Venting	**After Venting***	**Cumulative**	**Incremental**
900	800	14.3	—
800	700	28.6	14.3
700	600	42.9	14.3
600	500	57.2	14.3
500	400	71.5	14.3

*Includes 100-psi safety margin.

Procedure

Allow the SICP to build from 300 to 500+ psi before venting mud from hole. (The extra 100 psi provides a minimum of 100 psi in excess of the formation pressure at all times.) Open the choke and vent mud until the pressure drops to 400 psi. Measure the amount of mud vented from the well. The volume should be equal or close to the 14.3 bbl of mud necessary for a 100-psi reduction in hydrostatic pressure. If not, repeat this procedure until 14.3 bbl of mud has been removed. Then, allow the surface pressure to increase to more than 600 psi. Follow the same procedure as before until another 14.3 bbl of mud has been removed and the surface pressure is 500 psi. Allow the pressure to increase to more than 700 psi and repeat the same procedure. Continue these cycles until the gas is at the surface.

When the gas has reached the surface, lubricate 14.3 bbl of mud into the hole and wait for the mud to settle through the gas. This should take 30 to 40 min. Then, bleed off the 100-psi gas pressure. Repeat this cycle (lubricating 14.3 bbl mud into the hole and bleeding off 100 psi of pressure) until all the gas has been lubricated out of the hole.

A volumetric balance similar to the example above should be kept throughout the operation to assure that:

1. All the gas has been removed from the hole.
2. All the mud that was removed from the hole has been returned to the hole.
3. The volume of the gas in the hole before expanding also has been replaced by mud.
4. No additional influx of gas was allowed to bleed into the hole during this operation.

The use of high-density weight-material plugs is limited to emergency conditions that require that the bottom of the well be sealed off.

WEIGHT-MATERIAL PLUGS USING M-I BAR® OR FER-OX®

Application

The use of high-density weight-material plugs is limited to emergency conditions that require that the bottom of the well be sealed off. These plugs have application under the following circumstances:

1. Simultaneous kicking and loss of circulation.
2. Abandonment procedures to allow the safe withdrawal of the drillstring from the hole and the setting of a cement plug.
3. Withdrawal of the drillstring to log, set casing or repair existing casing.
4. To plug the drillstring in an emergency situation.

For plugs to be effective, more than one-third of the weight material must settle quickly.

Function

High-density weight-material plugs are designed to form a seal in the wellbore or drillstring when the weight material settles, and/or the fluid dehydrates. These plugs also increase the hydrostatic pressure of the fluid in the hole. Possible side-effects include the sloughing of water-sensitive shales as a result of the high fluid-loss properties of these slurries. This sloughing may cause a bridge to form above the plug. In most cases this is desirable.

Water-base wellbore plugs

For plugs to be effective, more than one-third of the weight material must settle quickly. Several factors affect the settling rate of these materials. These factors must be considered when designing and mixing the slurries. Some of the factors to consider are:

1. **Density.** Settling rates will be significantly reduced if the fluid density is too high. Tests indicate that the optimum density range using M-I BAR is 14 to 18 lb/gal, and 16 to 20 lb/gal for FER-OX. Heavier-density slurries settle slower due to buoyancy and hindered settling. Always select the lowest density possible when building the plug. The slurry density in the formulation charts below should cover the optimum ranges for settling.
2. **Salinity.** High-density fluids mixed with freshwater have better settling rates. Tests show that an 18.0-lb/gal fluid mixed in freshwater has a settling rate of 67%, while the same fluid mixed in sea water has a settling rate of only 6%. Tests show that high hardness is also detrimental to the settling rate.
3. **The pH of the slurry.** Fluids with a pH of 8.5 to 11 have the highest settling rates. Fluids with a pH ranging from 8 to 11 have a settling rate of 61 to 85%, while the same fluids with a pH less than 8 have settling rates of only 3 to 18%.
4. **Deflocculants, chemicals and surfactants.**
   a) Tests show that deflocculants are required for settling to occur. In the settling tests, SPERSENE™ gave the best results, but the weight material also settled out satisfactorily when SAPP was used.
   b) Caustic soda should be used to adjust the pH to 8.5 to 11.
   c) Surfactants such as D-D® and DEFOAM-X™ enhanced the settling in the tests.
   d) The high-temperature formulation that gave the best results was:

SPERSENE	2 lb/bbl
Caustic soda	0.5 lb/gal
DEFOAM-X	0.5 lb/bbl
D-D	0.5 lb/bbl

Formulation charts for one final barrel of water-base slurry:

Slurry Weight (lb/gal)	M-I Bar (lb/bbl)	Water (gal/bbl)	Caustic (lb/bbl)	Spersene (lb/bbl)	D-D (lb/bbl)
14	312	33.2	0.5	2	0.5
15	368	31.5	0.5	2	0.5
16	423	29.8	0.5	2	0.5
17	478	28.1	0.5	2	0.5
18	533	26.9	0.5	2	0.5

Using M-I Bar.

Slurry Weight (lb/gal)	Fer-Ox (lb/bbl)	Water (gal/bbl)	Caustic (lb/bbl)	Spersene (lb/bbl)	D-D (lb/bbl)
17	455	31.1	0.5	2	0.5
18	508	29.8	0.5	2	0.5
19	560	28.6	0.5	2	0.5
20	613	27.3	0.5	2	0.5
21	665	26.0	0.5	2	0.5

Using Fer-Ox.

Mixing order

Using a ribbon blender, the caustic soda should be added to the freshwater first, followed by the Spersene, D-D and Defoam-X, in that order. The weight material should be added last. About ⅓ of the defoamer should be added initially, with the remainder added as needed to control foam.

Oil-base wellbore plugs

Weight-material plugs can also be formulated in oil. As in water-base muds, certain products and mixing procedures produce the best results. These oil-base fluids do not use water, lime or brine. They are formulated with only a wetting agent, oil and weight material. Versawet® is the preferred wetting agent, but Versacoat® can also be used.

Formulation charts for one final barrel of oil-base slurry:

Slurry Weight (lb/gal)	M-I Bar (lb/bbl)	Diesel (gal/bbl)	Versawet (gal/bbl)
14	380	30.8	0.60
15	432	29.4	0.60
16	484	28.0	0.60
17	536	26.4	0.60
18	587	25.0	0.60

Using M-I Bar.

Slurry Weight (lb/gal)	Fer-Ox (lb/bbl)	Diesel (gal/bbl)	Versawet (lb/bbl)
17	516	29.3	0.60
18	566	28.1	0.70
19	616	26.9	0.80
20	666	25.8	0.90
21	716	24.6	1.00

Using Fer-Ox.

Improper spotting techniques can destroy the effectiveness of the plug.

MIXING ORDER

The VERSAWET (wetting agent) should be mixed thoroughly with the diesel in a ribbon blender before the weight material is mixed. If the weight material is not oil-wet, the slurry will be thick and the settling rate will be very poor.

SIZE OF THE PLUG

The length of the plug is based on the severity of the problem, but experience shows that slurries which settle to form 200 to 400 ft of plug are usually adequate. The length of the slurry should not exceed the distance from the pressured zone to the lost-circulation zone. Excessively long plugs are not desirable; they increase the chances of plugging or sticking the pipe and are difficult to drill.

After the desired length of the plug has been established, the volume of the slurry can be calculated as follows:

Volume of plug = length of plug (ft) x hole volume (bbl/ft)*

* This hole volume is without the pipe in the hole.

Volume of slurry =

$$\frac{\text{volume of plug (bbl) x SG of weight material x 3.5}}{\text{weight material concentration (lb/bbl)*}}$$

* Select the density of the slurry and go to the appropriate chart to determine the concentration of weight material in one barrel of slurry. The density of the slurry should be 0.5 to 1.0 lb/gal higher than the mud weight in the hole. This ensures that the slurry will stay in place and not migrate upward after it has been spotted. One key to a successful plug is that the slurry should provide sufficient density to stop the flow of formation fluids, yet be as light as possible. If the flow of formation fluids is not stopped, the slurry will become contaminated, settling times will be increased and the success of the plug will be reduced.

MIXING PROCEDURE

The slurry is mixed in the same manner as cement. The weight material should be mixed through the hopper into the ribbon blender or recirculating mixer tub and pumped directly down the hole. The weight material should be mixed from the cementer's pneumatic bulk tank if possible, for a more uniform slurry weight. A recirculating jet system is preferred because slurry weights can be adjusted before being pumped down the hole. If a recirculating jet system is not used, the slurry will have to be mixed intermittently, since the rate of the feed water through the jet often exceeds the required feed rate of the weight material. Batch systems have also been used to mix plugs of high-density weight material, but the danger of the weight material settling in the mixing tank makes this method less desirable.

SPOTTING OBJECTIVES

Improper spotting techniques can destroy the effectiveness of the plug. Two major concerns arise when spotting the slurry. They are:

1. Spot the slurry and pull the drillstring out of it as quickly as possible to avoid sticking or plugging the pipe. The rig crew should be ready to start pulling the pipe as soon as the slurry is spotted. Rapid movement of the drill pipe could result in contaminating the slurry and increasing settling times. Sticking the drill pipe and obtaining a successful plug is more desirable than contaminating the slurry.
2. Avoid contaminating the slurry with mud from the drillstring. To avoid contaminating the slurry with mud, it should be under-displaced by two barrels. This means that displacement volumes should be adjusted so that the height of the slurry left in the pipe is greater than the height of the

slurry in the annulus. This allows the drillstring to be withdrawn with a natural slug.

SPOTTING PROCEDURES

Calculate the height at which the slurry (less two barrels) is balanced in the hole (with the drillstring in the hole):

1. Determine the volume of fluid inside and outside the drill collars
   = (capacity of hole – displacement of drill collars) x length of drill collars
2. Determine the remaining volume of slurry
   = slurry volume – volume around drill collars (Step 1) – 2 bbl
3. Height of remaining slurry =
   $$\frac{\text{remaining volume of slurry (from Step 2)}}{\text{(capacity of hole – displacement of drill pipe)}}$$
4. Check to make sure that the total height of the slurry is less than the maximum slurry length, determined by well conditions. The maximum slurry length is the length from the pressured zone to the lost-circulation zone. If this is so, continue. If not, adjust the slurry weight to increase the density and reduce the total volume of slurry.
5. Determine the length that two barrels of slurry will occupy in the drill pipe.
   Length of 2 bbl of slurry x
   $$\frac{\text{2 bbl}}{\text{drill pipe capacity (bbl/ft)}}$$
6. Determine the height of mud above the slurry after placing the slurry in the well.
   Height above slurry =
   total depth – drill collar length – height remaining slurry (Step 3) – length of 2 bbl (Step 6)
7. Determine the volume of mud that occupies this length or height of mud. This volume of mud will be pumped behind the slurry to place the slurry in the correct spot.
   Volume (bbl) =
   height above slurry (ft) x drill pipe capacity (bbl/ft)

WELL-CONTROL COMPLICATIONS

Well-control procedures, like all drilling operations, are subject to mechanical failures and problems. When these problems occur, they can quickly escalate to a level where the safety of personnel and loss of the well and rig are threatened. For these reasons, these problems must be identified, and responded to as quickly as possible.

PROBLEM IDENTIFICATION

Problem	Drill Pipe Pressure	Casing Pressure	Pump Rate
Choke plugged	Increases	Increases	Decreases
Choke washout	Decreases	Decreases	Increases
Jets plugged	Increases	Unchanged/ decreases	Decreases
Lost circulation	Decreases	Decreases	Increases
DP washout	Decreases	Unchanged	Increases

Every well should have two or more chokes manifolded together...

Chokes can become plugged when heavy muds are used.

- **Choke washout.** Every well should have two or more chokes manifolded together so that a well-control operation will not depend on the operation of a single choke. When it becomes apparent that the choke is washed out, the kill operation should be switched immediately to the second choke. The washed-out choke should be replaced immediately.
- **Choke plugged.** Chokes can become plugged when heavy muds are used. Usually, they can be unplugged by opening the choke briefly. If opening the choke does not unplug it, switch to a backup choke and take steps to unplug the first choke immediately.
- **Jets plugged.** If one or more — but not all — of the bit jets plug while killing a well, hold the casing pressure constant while adjusting the pump rate to an acceptable value that is below the pump liner limits. This will result in a new pump rate, slower than the recorded "slow pump" rate. If the kill procedure is based on time, it will have to be recalculated. Recalculation will not be necessary if the kill procedure is based on the stroke count. If all of the jets become plugged, the drillstring can be perforated or the bit can be removed with a shaped charge.
- **Lost circulation.** When lost circulation occurs while killing a well, it is generally assumed that the losses are at the casing seat unless special conditions or surveys indicate otherwise. Lost circulation while killing a well will result in underground flow, commonly referred to as an "underground blowout." Fluid will flow from the pressured zone into the loss zone.

  Lost-circulation materials that might plug the jets should not be used under these circumstances. Lost-circulation material may be bullheaded down the drill pipe/casing annulus if needed.

  If the mud weight between the loss zone and the pressured zone can be increased enough, its hydrostatic pressure, plus that of the mud above the loss zone, may be sufficient to stop the flow. When this is tried, heavy mud is usually pumped down the drill pipe. Meanwhile light mud, which the loss zone would support normally, is pumped down the drill pipe/casing annulus.

  Barite or hematite plugs are often pumped as a part of the heavy mud/fluid. Barite and hematite plugs will add to the hydrostatic pressure of the fluid in the annulus, but will not settle while gas is flowing into the well. The flow must also be stopped for cement plugs to hold.
- **Drillstring washout.** When a washout occurs during a well-control procedure, in most cases the well will have to be killed with the washout in the hole. With a washout in the drillstring, the well will flow through the drill pipe if the kelly or circulating head is broken off to make a trip. This limits the choices that can be made for killing the well.

  Continued circulation may enlarge the washout and allow the drillstring to part. This will raise a difficult problem to an even higher level of difficulty, if the washout is in the upper part of the well.

  If it can be determined by the position of a "float" or other tool in the drillstring that the washout is in the lower portion of the drillstring, the well may be killed by pumping additional kill-weight mud through the washout. If this is attempted, a new "very" slow pump rate should be established to reduce the erosion of the washout. Continued pumping, without knowing where the washout is, will be very risky.

  The well can be shut in and the kick fluid allowed to migrate up the

Gas hydrates are a solid, ice-like material that may form in water-base muds.

The greatest hazard gas hydrates pose...occurs when they form and plug the BOPs and choke lines of deep-water wells during kill procedures.

annulus, where it will be released using the "top kill" procedure.

If a packer can be snubbed down the drillstring on a work string or on coiled tubing, it should be set below the washout. This will isolate the washout and allow the well to be killed in a conventional manner.

Gas hydrates

Gas hydrates are a solid, ice-like material that may form in water-base muds. They form under conditions of lower temperatures and higher pressures in water that is in contact with a gas. The volume of gas trapped in hydrates may be 80 times the volume of the hydrates. Vast deposits of gas hydrates exist on ocean floors throughout the world. Gas hydrates usually are found at water depths greater than 800 ft, where the temperature is less than 40°F. They are found also in permafrost. Gas hydrates have the potential to cause kicks when they decompose and release gas. The greatest hazard gas hydrates pose to the drilling industry occurs when they form and plug the BOPs and choke lines of deepwater wells during kill procedures.

Although methane is the gas most frequently associated with hydrates, many different gases, including hydrogen sulfide, can form hydrates with water.

Pressure increases (higher mud weights and deeper water) raise the temperature at which hydrates form. Almost any chemical that will lower the freezing-point of water (alcohols, glycols, salts, etc.) will suppress or lower the temperature of hydrate formation. Of the common salts (sodium chloride, calcium chloride, potassium chloride and calcium bromide), sodium chloride gives the best hydrate inhibition. Low-molecular-weight glycols provide better hydrate inhibition than higher-molecular-weight glycols. In some cases, salt and glycol can be used together to provide better inhibition, but some glycols have limited solubilities in the presence of salts. Tests should be made across the full-temperature range the salt-glycol mixture will be subjected to in order to determine if they are compatible for the application.

M-I's engineering software can predict hydrate formation temperatures under a given set of conditions and can suggest the concentrations of salts and/or glycol that will suppress hydrate formation to an acceptable temperature.

Gas trapped in subsea preventers

After a gas kick has been circulated out, gas may be trapped in subsea preventers above the choke line and beneath the preventer element. Before opening the preventers, the riser should be displaced with kill-weight mud and the trapped gas removed. If the gas is not removed before opening the preventers, it can unload the riser. This may allow a second kick to enter the well and/or collapse the riser.

Shallow gas sands

On land, shallow gas sands that are drilled before casing is set present a special problem. Offshore, the problem is far more critical. "Floaters" have been lost when gas-cut water failed to provide sufficient buoyancy to keep them afloat after drilling shallow gas sands.

At the depths where these problem sands occur, the formations would not hold the kick even if it were possible to shut the well in. Rather than trying to kill the well in these cases, the flow of gas is directed away from the well, through a diverter system, to a safe distance, where it is flared.