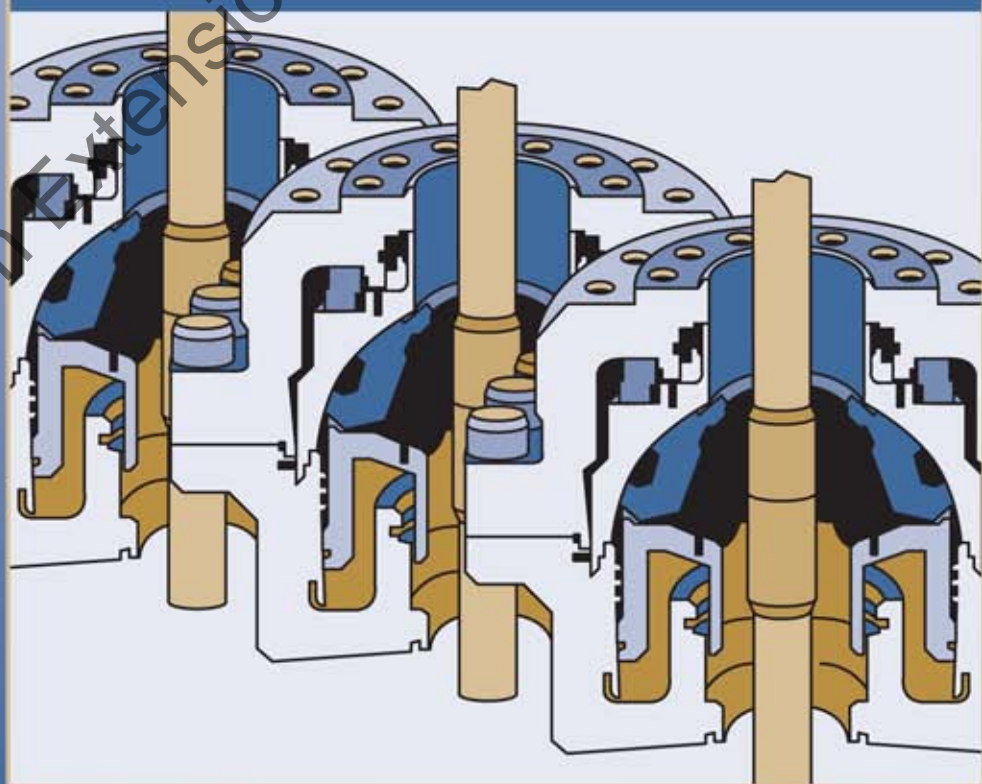


FOURTH EDITION

# Practical Well Control

Petroleum Extension Service



Petroleum Extension The University of Texas at Austin

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# Pressure Concepts

In well control, the two pressures of primary concern are formation pressure and hydrostatic pressure. *Formation pressure* is the force exerted by fluids in a formation. It is measured at the depth of the formation with the well shut in. It is also called reservoir pressure or, since it is usually measured at the bottom of the hole with the well shut in, shut-in bottomhole pressure.

In drilling, *hydrostatic pressure* is the force exerted by drilling fluid in the wellbore. When formation pressure is greater than hydrostatic pressure, formation fluids may enter the wellbore. If formation fluids enter the wellbore because formation pressure is higher than hydrostatic pressure, a kick has occurred. If prompt action is not taken to control the kick, or kill the well, a blowout may occur. To control a well, a proper balance between pressure in the formation and pressure in the wellbore must be maintained; hydrostatic pressure should be equal to or slightly higher than formation pressure.

## ORIGIN OF FORMATION PRESSURE

One generally accepted theory of how pressures originate in subsurface formations relates to how sedimentary basins are formed. As layer upon layer of sediments are deposited, overburden pressure on the layers increases, and compaction occurs. *Overburden pressure* is the pressure exerted at any given depth by the weight of the sediments, or rocks, and the weight of the fluids that fill pore spaces in the rock. Overburden pressure is generally considered to be 1 pound (lb) per square inch per foot (psi/ft). Overburden pressure can vary in different areas because the amount of pore space and the density of rocks vary from place to place. In deepwater formations just below the seafloor, the overburden is almost entirely seawater. Overburden pressure is therefore about the same as the pressure caused by the weight of seawater—about 0.45 psi/ft depending on its sa-

linity. Regardless of the actual value of overburden pressure, as it increases, compaction occurs, and the porosity of the rock layer decreases.

As compaction occurs, any fluids in the formation are squeezed into permeable layers, such as sandstone. If the permeable layer into which the fluids are squeezed is continuous to the surface—that is, if the layer eventually outcrops on the surface—pressure higher than normal cannot form (fig. 1.1). If, however, a layer's fluid is trapped because of faulting or some other anomaly, pressure higher than normal can form; the formation can become overpressured.

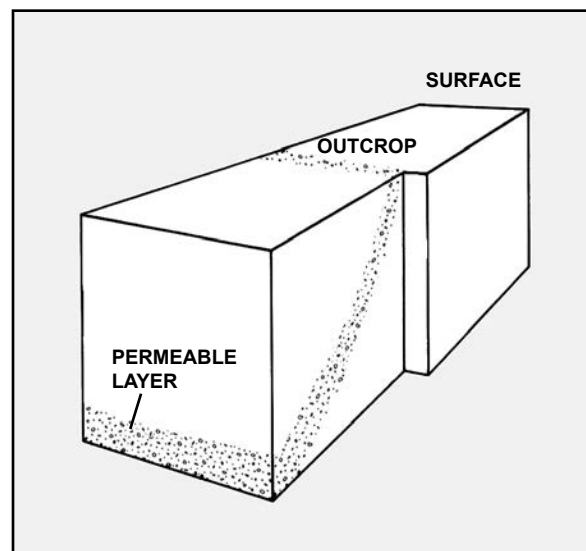


Figure 1.1 Pressure higher than normal cannot form if the layer outcrops on the surface.

# Causes and Warning Signs of Kicks

Drilling personnel should know the causes and warning signs of kicks and be able to identify them readily. Since the well and the mud-circulating equipment are a closed system, any formation fluid that intrudes into the system usually shows up as a change in the flow rate of fluid returning from the well and as a change in the total volume of fluid in the pits. Exceptions can occur. For example, when oil-base drilling mud is in use, a kick composed mainly of methane and other light hydrocarbon gases may dissolve in the oil in the mud and may not be evident until the gas nears the surface, comes out of solution, and expands. While not as soluble as light hydrocarbon gases, hydrogen sulfide ( $H_2S$ ) and carbon dioxide ( $CO_2$ ) gases can also dissolve in oil-base mud and come out (evolve) as they near the surface. The same thing can happen with  $H_2S$  and  $CO_2$  kicks in water-base muds, because they also dissolve in these types of mud.

Gas kicks that dissolve in mud can be difficult to detect, especially if the kick is relatively small. Since they are absorbed by the mud, little or no pit gain occurs. Also, no measurable increase in the flow rate of the mud being pumped out of the well occurs. Later, however, as the dissolved gas in the mud nears the surface, it begins evolving from the mud and rapidly expands. This rapid expansion suddenly increases the return flow rate and can create a large pit gain if the well is not rapidly shut in.

Also, when a gas kick dissolves in the mud, and crewmembers do detect it, they may believe that the well has taken a saltwater kick: the pit gain may be relatively small and the difference between the shut-in drill pipe pressure and the shut-in casing pressure may be small. When dissolved gases come out of solution, however, they expand rapidly. As a result, the shut-in casing pressure rises quickly. Crewmembers should be aware of the problem and keep close surveillance on the casing pressure. Because gases can dissolve in mud, most operators and contractors prefer to consider all kicks as gas kicks and react appropriately.

It is important to anticipate the possibility of rapidly increasing *SICP* and to have a plan in place to deal with it before circulating out a kick.

Surface indications depend on the kick's size and on the temperature and pressure. A gain in pit volume is probably the most reliable indicator of a gas kick in oil-base mud. In any case, training of personnel, specific procedures, and good supervision are the most effective means of detecting kicks and preventing blowouts.

## CHARACTERISTICS OF KICKS

A *well kick* is an influx of formation fluids such as oil, gas, or salt water into the wellbore from a formation that has been penetrated by the wellbore. It occurs when the pressure exerted by the column of drilling fluid in the wellbore is lower than the pore pressure in the formation, and when the formation is permeable enough to allow fluids to flow through it. Once a kick occurs, the intruded fluid further reduces the hydrostatic pressure of the mud column, since formation

# Shut-In Procedures and Shut-In Pressures

If a well's casing is set and adequately cemented in competent formation, usually the well can be shut in safely when a kick occurs. Although shut-in procedures are basically the same for every well, well conditions and company policies often dictate variations. Therefore, many operators post their shut-in procedures for each well on the rig floor and require crewmembers to learn them. Since land rigs and offshore bottom-supported rigs use surface-mounted blowout preventers (BOPs), basic shut-in procedures for these types of rigs are the same. Special shut-in procedures are required for floating rigs, however, because the BOP stack is usually mounted on the seafloor. Regardless of whether a surface stack or a subsea stack is in use, different shut-in procedures are required for a kick that occurs while drilling and for a kick that occurs while tripping.

## SHUT-IN PROCEDURES WITH SURFACE STACKS WHILE DRILLING

A surface stack is normally used on land rigs and on bottom-supported offshore rigs like jackups and platforms. Since there are several variations in the procedures used to shut in a well with a surface stack while drilling, it is important that everyone be familiar with and adhere to the procedures on the rig. For instructional purposes, an example shut-in procedure (a soft shut-in) that has been successfully used follows:

1. Stop the rotary and sound the alarm.
2. Pick up the drill string until the kelly saver sub is above the rotary table. (Prior spaceout should be made to ensure that a tool joint is not in a ram BOP when the string is picked up.) On rigs with top drives, raise the string to the first space out point that ensures the bit is at least a few feet off bottom.
3. Stop the pumps.
4. Check for flow.
5. If the well flows, open the line from a BOP outlet to the choke manifold.

6. Close the BOP (usually the annular preventer).
7. Close the choke. (The choke to be used, as well as other valves in the intended flow path through the manifold, should initially be in the open position.)
8. Confirm that all flow from the well has stopped. No flow should occur from the choke manifold, the bell nipple, or back through the drill stem.
9. With the well fully shut in, allow a few minutes for pressures to stabilize; then, record shut-in drill pipe pressure (*SIDPP*).
10. Record shut-in casing pressure (*SICP*).
11. Record the pit-level increase.
12. Notify supervisor.

## SHUT-IN PROCEDURES WITH SURFACE STACKS WHILE TRIPPING

Just as many variations in procedure are available to shut in a surface stack while drilling, so are many variations available to shut in a surface stack while a trip is being made. Again, it is important for ev-

# Circulation and Well Control

Because the mud pump is used to circulate kick fluids out of the hole and to circulate kill-weight mud into the hole, it is one of the basic tools of well control. Also, because the rate, or speed, at which the pump is run affects pressures, the pump rate is one of the basic values in well control. It is usually measured in strokes per minute (spm). Pump rate plays a vital role in the successful control of a well, because even small changes in pump speed can cause large changes in pressure at the bottom of the hole, where constant pressure is especially critical. Since the fundamental goal of most well-control procedures is to maintain a constant bottomhole pressure equal to or only slightly higher than formation pressure, accurate control of the pump's speed is necessary.

## KILL RATE

To circulate a well that has kicked, most operators require that the pump rate be reduced to a speed below that used for normal drilling. Called the *kill rate*, this reduced pump rate affords several advantages to any well-control method: (1) it reduces circulating friction losses so that circulating pressures are less likely to cause excessive pressure on exposed formations; (2) it gives the crew more time to add barite or other weighting materials to the mud; (3) it reduces strain on the pump; (4) it allows more time for the crew to react to problems; and (5) it allows adjustable chokes to work within proper orifice ranges. Often, only one kill-rate speed will be required during a well-killing operation; however, most operators recommend that several kill rates be selected. For example, one recommendation is to select kill rates of  $\frac{1}{2}$ ,  $\frac{1}{3}$ , and  $\frac{1}{4}$  the normal drilling pump rate. Sometimes an even slower rate may be recommended—for example, two to four barrels per minute—to reduce pressure further and allow more time for weighting up.

## KILL-RATE PRESSURE

When the pump rate is reduced to the kill rate, circulating, or pump, pressure is also reduced. This reduced pump pressure is *kill-rate pressure*. It is obtained by pumping down the drill pipe and drill collars, out of the bit nozzles, and up the annulus. Running the pump at a reduced speed and breaking circulation will produce the kill-rate pressure. While kill-rate pressure can be easily read on the standpipe gauge or the drill pipe pressure gauge, the relationship between pump rate and pump pressure can also be estimated by the following equation:

$$P_2 = P_1 \times SPM_2^2 \div SPM_1^2 \quad (\text{Eq. 32})$$

where

$P_1$  = original pump pressure at  $SPM_1$ , psi

$P_2$  = reduced or increased pump pressure at  $SPM_2$ , psi

$SPM_1$  = original pump rate, spm

$SPM_2$  = reduced or increased pump rate, spm.

# Formation Fracture Gradient

**F**ormation fracture pressure is the amount of pressure that causes a formation to break down, or fracture. In well control, the fracture pressure of the weakest formation exposed to the wellbore must be known, because the pressures developed during well-control procedures may exceed the fracture pressure of the formation. Should fracture pressure be exceeded, the formation fractures, and lost circulation and an underground blowout or broaching could result.

Formation fracture pressure can be expressed in psi, equivalent mud weight, or fracture gradient. If fracture gradient is used, it is usually expressed in psi/ft. For example, assume that a formation 5,000 ft deep fractures when 3,640 psi is exerted on it. Thus, the fracture pressure of this formation is 3,640 psi. Its fracture gradient is 0.728 psi/ft, because 3,640 psi divided by 5,000 ft equals 0.728 psi/ft. Further, in terms of equivalent mud weight, the pressure developed by 14.0-ppg mud will fracture this example formation because  $14.0 \text{ ppg} \times 0.052 \times 5,000 \text{ ft} = 3,640 \text{ psi}$ .

## FRACTURE DATA

The point at which a formation fractures has been the subject of considerable study and research since the 1960s. Large amounts of data from breakdown pressures on squeeze cementing jobs and from wells in which lost circulation occurred have been used to develop correlations between fracture pressure, well depth, and pore pressure for a given area.

One such relationship has been developed for the Louisiana Gulf Coast (fig. 5.1). Fracture data for normal pore pressure—in this example, the pressure developed by mud with a weight of 9.0 ppg—versus depth are shown as the heavy black line at the extreme left of the group of curves on the graph. This 9.0-ppg curve indicates that at 4,000 ft on the Louisiana Gulf

Coast, the fracture pressure could be expected to be equivalent to about 14.4-ppg mud. An equivalent mud weight of 14.4 ppg corresponds to a fracture pressure of 2,995 psi at 4,000 ft, or to a fracture gradient of 0.749 psi/ft. The remaining curves show how fracture pressure increases at any given depth when abnormal pore pressures are encountered. A higher pore pressure at a given depth results in a correspondingly higher fracture pressure at that depth.

## KICK TOLERANCE

*Kick tolerance* is a calculated estimate of the size of potential kick that could fracture an exposed formation and lead to serious well-control problems. Kick tolerance is expressed in terms of ppg, volume of influx, or a combination of both. It is a way in which to express the fact that, when a well kicks and is shut in, *SICP* will be greater if a larger volume of influx is allowed to enter the wellbore. *SICP* is also greater if the kicking formation's pressure is a great deal higher than hydrostatic pressure. The worst case occurs when both formation pressure is relatively higher and a large kick is taken. With a reasonable understanding of wellbore strength, it is possible to estimate the combinations of increasing formation pressure and influx volume that will likely cause formation fracture. When calculations suggest that

# Well-Control Methods

The goal of any well-control method is to kill the kick and bring the well under control. To accomplish this, the well-control method must allow personnel to (1) remove kick fluids from the hole and (2) fill the hole with mud of sufficient weight to exert pressure equal to or greater than formation pressure. Many well-control methods are available, including the driller's, wait-and-weight, concurrent, volumetric, top-kill, and low choke pressure; however, the three most often used are the driller's, wait-and-weight, and concurrent. In any event, shutting in the well stops the entry of additional formation fluids into the well. By closing in the well, bottomhole pressure becomes equal to formation pressure.

Although differences exist between the three methods, they have several similarities. For example, all three share the basic principle that constant bottomhole pressure must be maintained throughout the well-control operation, regardless of the nature of the influx. Constant bottomhole pressure is maintained by circulating the well at a constant pump rate through a choke orifice, and by changing the size of the choke orifice when necessary to adjust the back-pressure held throughout the wellbore. Further, all three methods make it possible for personnel to stop the pump, close the choke completely, and analyze a problem without jeopardizing the well at any time during the procedure. All three also require that a final circulating pressure be maintained after kill-weight mud reaches the bit.

Regardless of which of the three methods is used, after a well kicks and is shut in, *SIDPP* and *SICP* are given time to stabilize (usually a matter of a few minutes) and are read and recorded. *KRP*, which is the pressure indicated on the drill pipe or standpipe gauge when the pump is run at a reduced rate, is usually determined and recorded prior to the kick. When a kick occurs, *SIDPP* is added to *KRP* to obtain *ICP*. During circulation, constant bottomhole pressure is maintained by keeping the pump speed constant and by adjusting the choke as required. Well-control worksheets for all methods are helpful because *SIDPP*, *SICP*, *KRP*, well depth, casing data, and other

information needed to kill a well successfully can be recorded on the sheet and used as a reference during kill procedures.

When noting readings from the various gauges used to indicate *SIDPP*, *SICP*, pump speed, and the like, crewmembers should check for errors in the readings. For example, *SIDPP* can be checked by noting the readings on the drill pipe pressure gauge in the remote choke control panel and the standpipe pressure gauge. They should both read very close to the same. Similarly, *SICP* can be checked by a casing pressure gauge on the choke panel and a gauge installed on the wellhead that reads annular pressure.

The main difference between the three methods lies in how and when kill-weight mud is pumped down the drill stem and to the bit. In the driller's method, the kick is circulated out with the same mud that was in the hole when the kick occurred. Kill-weight mud is then circulated to control the well. In the wait-and-weight method, the kick is circulated out at the same time kill-weight mud is pumped in. In the concurrent method, instead of increasing mud weight to kill weight all at once, it is increased in steps, usually a point at a time. Each time mud weight is increased, the new mud is immediately circulated down the drill stem and circulating pressures recalculated. This process of increasing the mud weight in steps and circulating continues until kill weight is achieved.



# Unusual Well-Control Operations

During a well-control operation, the characteristics of the well or kick may call for procedures that deviate from normal. Rig supervisors and crews should be aware of such procedures and be prepared to initiate them if necessary. While it is impossible to cover every unusual situation that could occur, this chapter covers several.

## A HOLE IN THE DRILL STRING

When a kick is being circulated out of the well and a hole is washed through the drill string, a decrease in *SIDPP* occurs without a corresponding decrease in *SICP*. Because *SIDPP* decreases, the choke operator may close the choke in an attempt to bring *SIDPP* back to the previous value. Closing the choke, however, causes casing pressure to increase to a value higher than that required to prevent the entry of additional kick fluids into the well. If the hole in the pipe is large, the choke may be closed to the point that the additional back-pressure causes formation fracture and lost circulation. Therefore, it is important to be alert to the possibility of a hole's being washed through the pipe and to be able to react properly to the problem.

Once it is certain that a hole has appeared in the string, the next step is to determine whether the hole is above or below the kick fluids, because the location of the hole bears on how the situation should be handled. For example, if the hole in the pipe is above the kick, it becomes difficult or impossible to maintain constant bottomhole pressure while circulating the kick in the conventional manner.

Since the hole opens the pipe to annular pressure, drill pipe pressure gauge readings may help to locate the hole. For example, if *SIDPP* is much higher than expected and does not decrease when a small amount of mud is bled from the well, it is likely that the hole in the pipe is above the kick. In fact, if no kill-weight

mud is in the drill pipe, *SIDPP* may be the same as *SICP*. If, on the other hand, the hole in the pipe is below the kick, it is likely that *SIDPP* will be near the previous shut-in value.

Since a slower-than-normal pump speed is usually employed when circulating a kick out, and since the hole in the drill stem may be quite small, detection of the problem may be difficult. If the location of the hole is determined to be below the kick, however, many operators recommend that circulation be continued until the kick has been circulated out. A change to the slower kill rate reduces the flow rate of mud through the hole in the pipe and reduces the likelihood of the hole's being washed larger. Keeping the hole in the pipe from getting larger may make it possible to continue circulating the well without excessive back-pressure.

## A PLUGGED BIT

When a well kicks and a large amount of barite and chemicals are added to the mud in the pits, and when mud in the pits is stirred during weight-up, it is possible for relatively large lumps of solid material to form. When circulated down the drill stem, these solid masses may totally or partially plug the jets of the bit. Fortunately, plugging is not common and, when it does occur, the jets usually are only partially plugged.

When the bit plugs, either partially or totally, while circulating a kick out of the well, pump pressure sud-

# Well Control for Completion and Workover

Just as in drilling operations, the fluid that is circulated in a well being completed or worked over has many applications. For example, fluids are employed in perforating, cementing, fracturing, and acidizing. They are also used in well killing, recompletion, drilling, deepening, plugging back, and cleaning out. Further, fluids serve as packer fluids, completion fluids, and circulating fluids. Completion and workover fluids may be gases, oils, brines, muds, or other chemical solutions.

Packer and completion fluids are different from the fluids used in drilling and working over a well. Packer fluids are placed in the well between the tubing and the casing above the packer to offset formation pressure below the packer. Usually, a packer fluid remains in the annulus over the life of the well. Since packer fluids stay in the well for a long time, they are specially formulated to remain liquid. They must remain liquid so they can be circulated months or years after they are placed in the completed well. Packer fluids must also be noncorrosive to prevent them from harming the casing and the tubing with which they are in contact. Completion fluids are similar to packer fluids, but they are used opposite productive formations to prevent permanent damage to the zone.

## CHARACTERISTICS

A drilling or a completion and workover fluid has several important characteristics. For example, it should be dense enough to control well pressures but not so heavy that it fractures the formation and flows into it. It should balance formation pressures but not fracture a formation. Further, the fluid should be cost effective. Sometimes, expensive fluids are necessary to prevent damage to especially sensitive formations; less expensive fluids, however, may also be available

that cause little or no formation damage. Experience in the area is very valuable in determining which fluid to use. Also, a fluid should be as free of solid particles as possible. Solids can plug perforations as well as reduce production after fracturing or gravel packing. Moreover, it should be noncorrosive to prevent failure of tubular goods and subsequent fishing jobs. It should also be stable if it is to be left in the hole for an extended period. Fishing for packers and tubing that are stuck because of fluid breakdown can be expensive and may even lead to abandonment of the well before production is fully depleted. Completion and workover fluids should also be filtered or cleaned and have few or no solids. Some fluids have large amounts of suspended solid particles, which can be harmful to the producing formation, as well as being abrasive to equipment. Even though a fluid has a low solids content, it can still cause plugging if it reacts adversely with the formation.

Some fluids that are excellent for normal operations can be incompatible with cement slurries or acids. In such cases, it may be necessary to use a fluid spacer to separate them. The spacer, which is usually salt water or a special mud, is placed behind the cement or acid to keep the completion or workover fluid from contacting, and thus contaminating, the cement or acid.

# Well Control and Floating Drilling Rigs

Drilling operations from floating vessels such as drill ships and semisubmersibles present special problems in well control. The problems occur because of hole depth, water depth, geology, and the design and operation of the subsea BOP stack and control system. While well-control procedures on floaters and land rigs are similar, several additional factors occur on floaters that must be taken into account if well control is to be successful.

## SHALLOW-HOLE CONSIDERATIONS

When the first part of a well is being drilled offshore, this shallow section of hole presents a number of problems that must be dealt with. Two of the most serious are controlling a kick when only a short casing string has been set, and drilling an open-hole section prior to setting a long protective string. A number of blowouts have been caused by influxes of overpressured shallow gas into the wellbore. Because the hole is shallow, gas can quickly reach the surface with little warning. Often, because of pressure limitations at the casing shoe, it is not advisable to shut the well in on a shallow-gas kick. In such cases, the gas can be vented through some type of diverter system; or pilot holes may be drilled. Pilot holes do not involve using diverters.

Diverters are special annular BOPs that can be used on top of the marine riser or on top of the well in a subsea position. Surface diverters close the annulus around the tubular in the hole and direct (divert) gas flow into the atmosphere through vent lines. A pilot hole is a small diameter hole drilled out below drive pipe or conductor casing run into the well. No riser or subsea BOP stack is run; instead, the pilot hole is drilled and if it encounters shallow gas, the gas is allowed to flow into the sea.

## Shallow Gas

The existence of gas in shallow zones can be an especially dangerous situation when drilling. Because the zone is shallow, the gas can escape to the surface within a very short period. Warning signs exist, but prompt action is necessary to prevent a blowout. Also, because of the possibility of formation fracture and broaching in shallow zones, the well often cannot be shut in safely. Since a shallow-gas kick can be so dangerous, rig crews should be especially alert for signs of a kick when surface hole is being drilled. Most well-control specialists recommend immediately shutting down the pump and making a flow check if any doubt exists about whether a shallow well has kicked. Since shallow gas reaches the surface so fast, the driller should also be especially careful to fill the hole properly when pulling the first few stands off bottom in the upper part of the hole. The hole should be filled carefully and watched between stands.

Most BOP stacks are capable of handling much more pressure than is found in underground formations. In the case of shallow gas, where the pressures are usually not excessively high, most BOPs are adequate. Further, the conductor or surface casing on which the BOP stack is mounted is usually capable of handling the pressures associated with shallow gas.

# Blowout Prevention Equipment

Today's blowout prevention equipment is rugged, reliable, simple to operate, and widely employed throughout the industry. While the BOP stack is usually the first item thought of when BOP equipment is discussed, other equipment must also be included. Equipment such as chokes, accumulators, pit-volume indicators, gas detectors, and flow detectors make it possible to detect and handle kicks with confidence. When modern equipment is coupled with good well design and thorough training, rig personnel are more able than ever before to control any well.

The BOP stack itself must be able to control high formation pressures and have an internal diameter, or bore, large enough to allow the passage of tools required to drill and complete the well. Because some wells require large-diameter tools and encounter high pressures, large-diameter stacks with high pressure ratings may be employed. Further, since a well that is shut in must be pumped into, that is, circulated with the BOPs closed, outlets to the stack must be provided. Spools located between the ram preventers are sometimes used to provide the outlets; at other times, the outlets in the body of the preventers are used. In any case, when all the requirements of a BOP stack are met, it can be a large, heavy piece of equipment.

Of course, not all blowout prevention equipment is as large and heavy as the stack, but as the pressure rating of any piece of equipment increases, it tends to become heavier, more complex, and less forgiving of operational misuse. Therefore, it is the job of every crew member to be familiar with the equipment and to be aware of its operational limitations.

It is important for crew members to know the rated working pressure of all the equipment used in their rig's well-control system, its wellhead components, and the casing strings in the well. Blowout preventers, other well-control equipment, wellhead equipment, and casing generally have rated working pressures

ranging from 2,000 psi to 20,000 psi. Briefly stated, rated working pressure is the highest pressure that the equipment can reliably withstand. Thus, if a BOP has a rated working pressure of 15,000 psi, a shut-in well could place 15,000 psi on the preventer and the preventer should continue to operate. Sometimes the term maximum allowable pressure is used, which indicates the greatest pressure that may be safely applied to a piece of equipment. Pressure in excess of this amount risks failure and should never be permitted.

## STACK ARRANGEMENTS

*API RP 53 Blowout Prevention Equipment Systems for Drilling Wells* is a document whose purpose is "to provide information that can serve as a guide for installation and testing of blowout prevention equipment systems on land and marine drilling rigs." In addition to giving installation guidelines and equipment requirements for various BOP components, it illustrates example arrangements of surface and subsea blowout preventer stacks with rated working pressures from 2,000 psi to 20,000 psi. Regarding the use of spools, RP 53 points out that, "Choke and kill lines may be connected to side outlets of the BOPs, or to a drilling spool installed below at least one preventer capable of closing on pipe. Utilization of the blowout preventer side outlets reduces the number of stack connections

# Organizing and Directing Well-Control Operations

During well-control operations, it is imperative that operators and contractors carefully organize rig personnel so that everyone knows where to be and what to do. Station and duty assignments and knowledge of the operator's and contractor's well-control policies and procedures are essential parts of successful kick control and blowout prevention. During well-control drills, the effectiveness of the crew's organization should be a part of the drill. In addition, general well-control procedures should be posted as part of emergency safety station bills for the rig. In some cases, station bills may be required by a regulatory body, such as the U.S. Coast Guard.

## ORGANIZING CONSIDERATIONS

When organizing the crew for well control, the following points should be raised by supervisory personnel on the rig:

1. Who is directly responsible for well-control operations, the contractor or the operator?
2. If the toolpusher or operator's representative is designated to operate the choke, who is responsible for duties that the toolpusher or representative would normally perform if not operating the choke?
3. Have the rig supervisors participated in all well-control drills, and do they understand who is responsible for various actions?
4. How are communications with the office to be handled?
5. Does every person on the crew thoroughly understand where to be and what to do?

The crew and the rig are the responsibility of the toolpusher, but he or she must work closely with the operator to ensure that the crew has a clear understanding of applicable well-control procedures and policies.

The drilling crew's reaction time to a kick plays a major role in getting the well properly shut in to prevent a blowout; however, the crew must also give proper attention to equipment. Blowout prevention equipment is primarily intended for emergencies and, as such, it is useful only if it is adequate for the pressures involved, only if it is in good operating condition, and only if it is used correctly. Ensuring that the BOP system is in good condition and adequate for its job involves the operating company, the drilling contractor, and the drilling crews. If just one person fails to do his or her part, the good work of everyone else—for example, those who designed and installed the mud program, the casing, the wellhead equipment, and the blowout preventers—may be canceled out. The company representative, the toolpusher, and the drillers are key persons in performing well-control duties; however, every person on the crew should know how to operate the basic preventer equipment and be alert for the signs of a well kick. Trial operation of the preventers and thorough pressure testing ensure that the equipment is in good operating condition and ready for use.

*Italicized page numbers indicate illustrations or photographs.*

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