CHAPTER 10
WELL CONTROL COMPLICATIONS AND SPECIAL PROCEDURES

Previous chapters have dealt primarily with a relatively uncomplicated situation in which a kick was taken with the drill string at or near the hole bottom, and no additional problems occurred during the well control operations. Unfortunately, when some kicks are being handled, additional complications can develop which may require departure from standard well control procedures. While it is not possible to anticipate all problems that can occur, a discussion of well control procedures would not be complete without covering some of the more common complications which have occurred in the past. Complications to the control of kicks taken with the drill string at or near the bottom of the hole will be discussed first. This will be followed in the next chapter by a discussion of the additional problems associated with kicks taken with the drill string significantly above the bottom of the hole or entirely out of the well. Additional problems associated with well control operations on floating drilling vessels will be covered in **Chapter 12**.

Complications to the control of kicks encountered with the drill string at or near the hole bottom, which will be discussed in this chapter, include:

1. upward gas migration during shut-in period;
2. surface equipment problems;
3. subsurface well problems; and
4. excessive well pressures.

For each complication, criteria for recognizing the problem and special well control techniques which may be applicable to the situation will be presented.

Upward Gas Migration During Shut-in Period

After a kick is detected and the well is shut-in, the well pressures initially increase in response to formation afterflow. As discussed previously, afterflow refers to transient flow from the formation into the well bore at the hole bottom just after the well is closed at the surface. As shown in **Figure 10-1**, pressures rise more rapidly at first because of a larger pressure drawdown on the formation, which results in a higher formation flow rate. As the fluids trapped in the well are compressed and the well pressures rise, this flow gradually decreases and finally stops.

In some cases, problems may develop which prevent the initiation of kick circulation for long periods of time. In other cases, problems may develop during kick circulation which require that the well be shut-in again with kick fluids still in the well. If the kick fluid is gas and the well remains shut-in for a long period of time, the gaseous zone trapped in the well may migrate a significant distance towards the surface. This movement occurs because the gas zone has a much lower density than the drilling fluid. Gas rising in a shut-in well will cause a gradual increase in pressure at all points in the well. This pressure increase occurs because the gas cannot expand if the well remains closed. The pressure of a gas held at constant volume and temperature must also remain constant. The example illustrated in **Figure 10-2** shows that unacceptably large increases in well pressure can result, in which case formation fracture or equipment failure will probably take place. In order to avoid this unacceptably large increase in well pressure, the gas should be allowed to expand under controlled conditions to keep the BHP constant at a value slightly above the formation pressure.

Controlled expansion of a gas zone rising in a shut-in well is best accomplished using a hand-adjustable choke. After the drill pipe pressure has increased approximately 150 psig above the initial stabilized shut-in drill pipe pressure which was recorded, a small volume of mud (approximately 0.5 bbl) should be bled through the hand-adjustable choke, and the choke returned to the closed position. After a few minutes have been allowed for the well pressures to stabilize, the drill pipe pressure should be checked. If the drill pipe pressure remains or again rises more than 100 psi above the initial recorded drill pipe pressure, the bleeding sequence should be repeated. This procedure will maintain the BHP slightly above the formation pressure and prevent further feed-in from the formation to the well. Although the casing pressure will tend to increase over the initial shut-in casing pressure, much lower casing pressures will result than if no mud was released. The chance of formation breakdown or equipment failure will be greatly reduced.

The approximate pressures which would result from following this procedure are shown in **Figure 10-3**, for the same kick conditions used in **Figure 10-2**. Note that if the drill pipe pressure is held constant as recommended, the detrimental aspects of upward gas migration are eliminated.

When bleeding mud, there is a tendency for the choke operator to want to open the choke until the drill pipe pressure falls to the desired value rather than work the pressure down slowly by bleeding mud in 0.5 bbl increments. However, because of the lag time involved between choke manipulation and the corresponding response in drill pipe pressure, this should not be done. Too much mud may be released before the drill pipe pressure responds, resulting in additional influx of formation fluid into the well.

After all of the gas has collected in the upper portion of the casing, casing pressure will remain static. The well should then remain shut-in until well circulation is possible. Although gas is at the surface, well circulation can be initiated in the conventional manner, i.e., by holding the casing pressure constant while bringing the pump up to speed. Probably, very little initial choke adjustment will be required while starting the pump, because of the large volume of compressible, low-viscosity gas at the surface.

Just before the gas zone reaches the surface, the casing pressure may tend to be increasing rapidly, requiring more frequent intervals of bleeding mud through the choke. It may be difficult to initiate well circulation properly during this period. Under these conditions, it may be best to allow all of the gas to reach the surface before starting the pump.

Surface Equipment Problems

Perhaps the most frequent complications experienced during well control operations are related to problems with the surface well control equipment. The more common surface equipment problems include:

1. plugged choke;
2. cut-out choke or choke manifold;
3. pump problem;
4. leak in the BOP stack.

Usually, these problems are not serious if quickly diagnosed and corrected. Surface equipment problems not evident from leaks or power failures are generally detected by a departure of the drill pipe pressure and/or casing pressure from normal behavior. **As soon as a problem with the surface equipment is suspected, the pump should be stopped immediately and the well closed carefully so as not to trap any pressure created by the pump.** The pump operator should always remain at his station and be ready to stop the pump immediately if so instructed by the choke operator.

Plugged Choke

Formation fragments carried by the drilling fluid will sometimes lodge in the choke, creating a plug. This situation can be detected by a rapid rise in both the drill pipe pressure and choke pressure. When this situation exists, it is very important to stop the pump immediately to prevent the creation of a subsurface fracture or exceeding the maximum allowable surface pressure. The choke can be opened in an attempt to dislodge the plug. If this fails, surface flow should be re-routed to the standby choke. Any trapped pressure should be released by periodically bleeding a small volume of mud until the shut-in drill pipe pressure returns to approximately the proper shut-in value. The well control operations can then be resumed.

Cut-out Choke or Choke Manifold

Abrasive solids, such as sand carried by the drilling fluid, can cause erosive wear in the high pressure flow system. A cut-out choke can result in a decrease in drill pipe pressure and casing pressure which cannot be corrected by choke manipulation. After stopping the pump and closing the choke, it will probably be necessary to also close a valve in the choke manifold to stop the flow completely. Well control operations can normally be resumed after re-routing the surface flow to the standby choke.

In the event fluid abrasion results in a leak in the choke manifold system at a location that cannot be conveniently bypassed, the well can remain shut-in until the problem can be corrected. However, the shut-in well should be continually monitored for pressure increases due to upward gas migration. When possible, a small volume of mud should be periodically released to prevent the drill pipe pressure from rising more than 100 psi above the proper shut-in value.

Pump Problems

In the event of pump failure, the well should be shut-in until the stand-by pump can be employed. Since the pump factor of the second pump may be different than for the first pump, it may be necessary to use a different circulating drill pipe pressure. The new drill pipe pressure can be determined by bringing the pump up to speed while adjusting the choke to hold the casing pressure constant. After the new pump is running smoothly at the desired kill speed, the new circulating drill pipe pressure should be equal to the observed drill pipe pressure reading at that time. The reduced pump pressure, p_r, for that pump speed is the difference between the observed circulating drill pipe pressure just after pump start-up and the shut-in drill pipe pressure. If heavy mud has not yet reached the bit, a new drill pipe pressure schedule should be computed, based on the new value for reduced pump pressure.

In some cases, the pump may not fail completely, but change significantly in displacement efficiency because of a bad check valve or some other problem. This problem can usually be detected by erratic drill pipe pressure behavior or by a gradually decreasing drill pipe pressure. If the problem goes undetected, the choke operator will tend to compensate by closing the choke in order to increase the drill pipe pressure back to the desired value. This procedure will result in more pressure being held against the well than is necessary.

Leak in BOP Stack

Occasionally, as casing pressure increases during the circulation of the kick, a leak may be developed across the annular preventer or at a connection in the BOP stack. After stopping the pump, pressure at the leak can usually be bled off by closing one of the lower rams below the leak. When the leak is below the lowest pipe rams, it can often be

Subsurface Well Problems

In addition to problems with the surface well control equipment, mechanical problems with the subsurface well circulation can and occasionally do occur during the well control operations. Some of the more common subsurface well problems discussed in this section include:

1. plugged bit;
2. bit nozzle washout;
3. hole in the drill string;
4. bore hole fracture, cement failure, or casing failure.

Subsurface well problems generally must be detected and diagnosed from the behavior of the drill pipe and casing pressure, and from records of pit volume changes. As in the case of surface equipment failures, **the first step taken when well problems are detected is to stop the pump immediately and shut-in the well**, being careful not to trap any pressure created by the pump.

Plugged Bit

Debris which enters the drill string during a kick or is circulated down the drill string will result occasionally in a plugged bit. In some cases, only partial plugging results, while, in others, well circulation is completely stopped. Bit plugging can be detected at the surface by a sudden increase in the circulation drill pipe pressure without a corresponding increase in casing pressure.

If only partial plugging is present, it may be possible to continue kick circulation at a higher drill pipe pressure or a lower circulation rate. The pump can be brought up to speed while simultaneously holding the casing pressure constant at the shut-in value in order to determine the new reduced circulating pressure p_r. The new value for p_r can be determined as the difference between the observed drill pipe pressure just after start-up and the shut-in drill pipe pressure. If heavy mud has not yet reached the bit, a new drill pipe pressure schedule should be computed based on the new value for reduced pump pressure. The choke operator should also remain alert for a sudden decrease in drill pipe pressure, which indicates that the plug may be breaking free. The choke operator can verify the current value of p_r at any time by stopping the well control operation and then restarting the pump at constant casing pressure.

If a partially plugged bit or drill string is not correctly diagnosed, the choke operator will tend to open the choke in order to get the drill pipe pressure back on schedule. This will result in a decrease in the casing pressure and BHP, allowing the influx of formation fluid into the well to resume. Should this condition continue unnoticed for a long period of time, a very large pit gain may be taken.

A completely plugged drill string may have to be perforated so that well circulation can be resumed. The hole should be placed as close to the bottom of the drill string as possible, to insure that most of the kick fluids are above the hole. Otherwise, it may not be possible to maintain the BHP constant using conventional well control procedures. The new reduced circulating pressure, p_r, which results after perforating the drill string, should be established as discussed previously by maintaining a constant casing pressure during pump start-up.

Bit Nozzle Washout

A bit nozzle washout results in a sudden decrease in drill pipe pressure without a corresponding decrease in casing pressure. As in the case of a partially plugged bit, the well control operation can be continued after the new value for the reduced circulating pressure, p_r, is established.

Hole in Drill String

In a few instances, well control operations have been complicated by the development of a washout hole in the drill string. This can be detected at the surface by a rapid decrease in drill pipe pressure without a corresponding decrease in casing pressure. The location of the hole with respect to the kick fluids can sometimes be estimated from the drill pipe pressure after shut-in. If the drill pipe pressure is much higher than the expected shut-in drill pipe pressure and does not respond to bleeding a small volume of mud, a hole above the position of the kick fluid is indicated. If all of the mud in the well is the same weight, the drill pipe pressure may be the same as the shut-in casing pressure. If the hole is below the position of the kick fluid, the drill pipe pressure will return to near the expected shut-in value. In this case, it will not be possible to distinguish a hole in the drill pipe from a washed-out jet nozzle. However, both of these situations should be handled in the same manner.

When a hole is above the kick zone, it is no longer possible to maintain the BHP constant while circulating the kick in the conventional manner. If well pressures are not too great and the hole is not too deep, it may be possible to set a wireline packer above and below the hole, strip out to replace the damaged pipe joint, and finally strip back to bottom. Another suggested solution involves snubbing small-diameter pipe into the drill pipe to a depth below the hole and then setting a packer.

If upward gas migration is evident, it is not possible to maintain a constant BHP by bleeding mud while observing the drill pipe pressure. However, the upward gas migration can be handled using the same procedure as when the drill string is off bottom or completely out of the hole. This procedure is presented later in this chapter. In some cases, it may be practical to wait until the kick zone migrates up past the hole in the drill pipe.

Borehole Fracture, Cement Failure, or Casing

The selection of proper casing setting depths is often critical to the success of a well. In some cases, when a large kick is taken with a long interval of open bore hole and just prior to the next scheduled casing setting depth, it may not be possible to circulate the kick to the surface without exceeding the fracture pressure of the weakest exposed formation. Once formation fracture occurs, the resulting loss of annular pressure usually allows additional influx of fluids from the high pressure zones into the well bore. This can lead to an underground blowout situation in which formation fluids flow uncontrolled from the deeper high pressure zone to the more shallow, fractured formation. The pressurizing of shallow formations can lead to dangerous problems for subsequent wells in the area and should be stopped as soon as possible.

Underground blowout situations can also result from failure of the protective casing or a cement failure near the bottom of the casing string. Examples illustrating these situations are shown in **Figure 10-4**.

A failure in the subsurface well bore, cement, or casing, which causes an uncontrolled loss of well fluids from the subsurface annulus, can be detected from an unexpected drop in surface pit volume, casing pressure, and drill pipe pressure. If the fluid level in the annulus begins falling, mud should be pumped into the annulus to maintain the well full and keep the surface pressures from later building up due to the loss of mud.

Control or isolation of the zone of lost circulation from the high pressure zone which is kicking is critical. One effective means to accomplish this is through the use of a barite plug to seal the lower portion of the well. A barite plug is a slurry of barite and fresh water mixed to a density of about 21 ppg. A phosphate thinner, such as sodium acid pyrophosphate (SAPP), is usually added to the fresh water at a concentration of about 0.7 lb/bbl of water. After the acidic phosphate thinner is added, the pH of the fresh water should be increased to about 9.0 by the addition of caustic. Approximately 0.25 lb of caustic per barrel of water would be required. The phosphate thinner promotes rapid settling of the barite as soon as slurry agitation is stopped. When settled, barite forms an almost impermeable seal in the bore hole. Since a barite plug requires vigorous agitation to prevent settling of the barite, mixing and pumping equipment normally used for cement slurries should be used to place the plug.

Operators vary greatly in the volume of the barite plug employed. Often, the first attempt to seal the well is made using a slug volume designed for a plug of settled barite a few hundred feet in length. **Table 10-1** gives the recommended mixture for a 21 ppg slurry needed for each 100-ft of plug desired.

The smaller barite plugs are often placed in a manner similar to a balanced cement plug. The slurry is under-displaced to prevent contamination of the annular plug, and the pipe is then pulled quickly above the plug. The heavy plug should fall free of the drill pipe as the pipe is pulled. The well is then circulated above the plug for several hours.

When conditions are more severe, a small barite plug may not result in a successful seal. Large barite plugs involving the use of several thousand sacks of barite are sometimes used when very high subsurface well flow rates are involved. When using a large plug, no attempt is made to withdraw the drill pipe, and the drill pipe is allowed to become stuck. The drill pipe is over-displaced to prevent the barite from settling in the drill pipe so that if the plug fails, another attempt can be made. These procedures are illustrated in **Figures 10-5** and **10-6**.

Table 10-1
BARITE SLURRY COMPOSITION REQUIRED PER 100 FT OF PLUG FOR A 21 ppg SLURRY DENSITY

Hole Size in.	Settled Volume ft^3	Settled Volume bbl	Barite Sacks	Phosphate or SAPP lb	Fresh Water bbl	Slurry Volume bbl
32	558.5	100	1,480	79	113	212
26 1/2	379	67.3	1,000	53.3	76.3	144
16	140	24.9	372	19.8	28.3	53.5
15	122.5	21.9	325	17.3	24.8	46.8
14	107	19.0	284	15.2	21.6	40.9
13 1/2	100	17.7	265	14.2	20.2	38.1
13	92	16.4	244	13.0	18.6	35.1
12	78.5	14	208	11.1	15.9	30.0
11	66.0	11.8	175	9.4	13.3	25.2
10	54.5	9.7	145	7.7	11.0	20.8
9 1/2	49.6	8.8	131	7.0	10.0	18.9
9	44.2	7.9	117	6.3	8.9	16.9
8	34.9	6.2	93	4.9	7.1	13.3
7	26.7	4.75	71	3.8	5.4	10.4
6	19.6	3.5	52	2.8	4.0	7.5
5	13.6	2.4	36	1.9	2.8	5.2

If the barite plug is successful, it is followed by a small cement plug designed to seal off the inside of the lower portion of the drill string. The drill string is backed off above the zone where it is stuck, and the well is circulated for several hours.

The use of barite slurries for sealing high pressure zones in well control operations has developed over the past two decades as an alternative to the use of cement slurries. Cement slurries are still used by some operators. However, an effective seal often cannot be accomplished using cement when the subsurface flow is primarily gas. Gas tends to form channels through the cement plug before it sets. Generally better results are obtained with the rapid-settling barite slurries.

Excessive Well Pressures

Occasionally, because of equipment problems or human error, a very large volume of kick fluids enter the well bore before the well is shut-in, or during the well control operations. When a large volume of low-density kick fluids has displaced mud from the

Excessive Casing Pressure

The effect of gas zone volume on surface casing pressure is given in **Figure 10-7** for the previously presented example kick situation. This example shows that if a very large gas kick is circulated to the surface in the conventional manner, excessive annular pressures can result. Thus, the fracture pressure at the casing seat and/or the maximum allowable surface casing pressure may be exceeded. Usually, the design of the casing is such that formation fracture will occur before the maximum casing pressure before casing burst is reached. However, in some cases, this maximum casing pressure may also be reached.

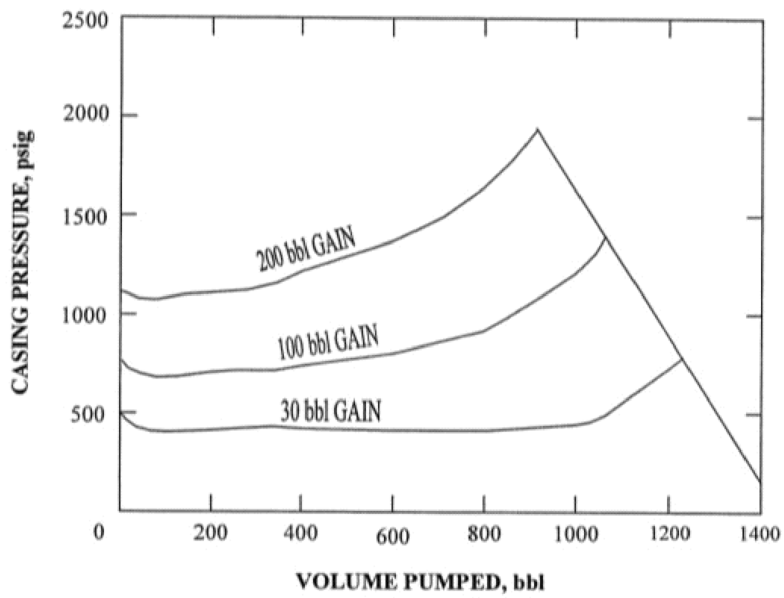

Figure 10-7: Effect of Gas Zone Volume on Surface Casing Pressure for Example Problem

If the casing pressure ever reaches the maximum allowable value to avoid bursting the casing during kick circulation, the drill pipe pressure schedule must be abandoned and the low choke pressure method of well control employed. When using this method, the choke operator adjusts the choke to hold the casing pressure at the maximum allowable surface pressure, and the pump speed is increased to the maximum possible rate. Abandoning the drill pipe pressure schedule at this time will cause the BHP to fall, allowing additional kick fluids to enter the bottom of the well. Once the first kick surfaces and is produced, the situation may begin to improve. Circulating the well at the highest possible rate will tend to minimize the time the well is underbalanced and thus the size of the second kick. If the drill pipe pressure returns to or exceeds the normal pump pressure associated with the pump rate and mud density in use, this signifies that the subsurface flow has stopped. At this point, the pump rate can be returned to the kill speed, and control of the choke should again be based on the drill pipe pressure. A plot of reduced pump pressure versus flow rate, such as the example shown in **Figure 10-8**, is useful in identifying the normal pump pressure at the higher flow rate chosen for the low choke pressure method.

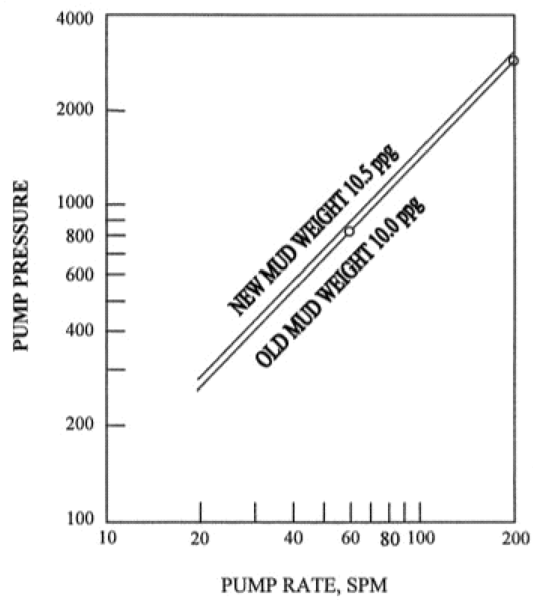

Figure 10-8: Plot of Reduced Pump Pressure Versus Flow Rate for Example Problem

In most cases, use of the low choke pressure method may result in a second kick which is even larger than the kick which initially caused the excessive casing pressure problem, which will cause the casing pressure after circulating out the first kick to be higher than the initial shut-in casing pressure. When this is true, the well should be shut-in and a different kill method should be used. If the second kick is smaller than the first, conventional well control procedures can be continued.

If pumping at the maximum allowable casing pressure continues for a long period of time, the surface mud volume will probably be exhausted, and well circulation should be continued with water to reduce the flow rate and minimize the fire hazard. Auxiliary pumping equipment and mud storage and special procedures will probably be needed to bring the well under full control. In some instances, the well bore eventually forms a bridge, thereby stopping the flow.

The Wait and Weight method of well control is much superior to the Drillers method of well control for handling large gas kicks. With the Wait and Weight method, kill mud is already entering the bottom portion of the annulus, helping to overcome the formation pressure when the kick fluids reach the surface. The extra hydrostatic pressure resulting from the use of kill mud means that less pressure has to be held on the casing by the choke in order to maintain the BHP at the desired value.

When excessive annular pressures during well circulation are anticipated while the gas zone is still deep and relatively compressed, additional options may be available to the operator. Two options which have been discussed in the literature involve 1) the use of mud densities in excess of kill mud density and 2) creating an intentional formation fracture in an attempt to keep the kick fluids underground. However, before either of these techniques is used, the operator should be relatively sure that 1) the kick fluid is predominantly gas and 2) the kick cannot be circulated to the surface in the conventional manner without exceeding the maximum allowable pressure. The usual technique employed to identify the type of kick fluid is to compute the density of the kick fluid using the shut-in well data as discussed in **Chapter 7**. The computed density of a predominantly gas kick will generally be less than 4.0 ppg. The surface casing pressure experienced for a 100% gas kick circulated to the surface can be estimated using the following equations:

$$b = \frac{P_{dps} V_{ds}}{C_a D} \tag{10.1a}$$

$$c = (0.052) \times (\rho_2) \times (G_i) \times (P_{bh}) \,/\, C_a \tag{10.1b}$$

$$P_{max} = \frac{\left(b + \sqrt{b^2 + 4c} \right)}{2} \tag{10.1c}$$

where:

P_{dps}	=	the static drill pipe pressure, psia
V_{ds}	=	the total capacity of the drill string, bbl
C_a	=	the annular capacity in the casing, bbl/ft
D	=	the total vertical depth of the well, ft
ρ_2	=	the kill mud density, ppg
G_i	=	the pit gain initially after shut-in, bbl
P_{bh}	=	the BHP after shut-in, psia

Since Equation 10-1c is relatively complex, the solution of this equation is given graphically in **Figure 10-9**.

The use of mud densities in excess of kill mud density for reducing the maximum pressure experienced at the surface or casing seat has been discussed by several authors. Reductions in casing pressure are possible if 1) a modified drill pipe pressure schedule is used in conjunction with the heavy mud and 2) kick circulation is never stopped after the heavy mud reaches the bit. The final drill pipe pressure used when heavy mud reaches the bit must be computed using:

$$P_{dp2} = P_r \frac{\rho_2}{\rho_1} - 0.052\,(\rho_2 - \rho_k)\,D \qquad (10\text{-}2)$$

where:

P_r	=	reduced circulating pressure, psi
ρ_1	=	old mud density, ppg
ρ_2	=	new mud density, ppg
ρ_k	=	kill mud density, ppg
D	=	vertical well depth, ft

The initial drill pipe pressure required upon pump start-up is determined in the conventional manner.

Unfortunately, when using mud density in excess of the kill mud density, the well cannot be shut-in after the new mud density reaches the bit without the excess hydrostatic pressure being applied to the annulus. Thus, if because of equipment problems it becomes necessary to stop the pump and close the choke, the pressure at the casing seat and at the surface may be higher than if kill mud was used. Shown in **Figure 10-11** is the surface casing pressure profile resulting from the use of a mud having a density exceeding the kill mud density by 1.0 ppg. In addition, the surface casing pressure, which would result using this mud density if well circulation had to be stopped at any point in the well control operation, is indicated (dashed lines). The casing pressure profile which would result from the use of a mud density equal to the kill mud density is also shown for comparison.

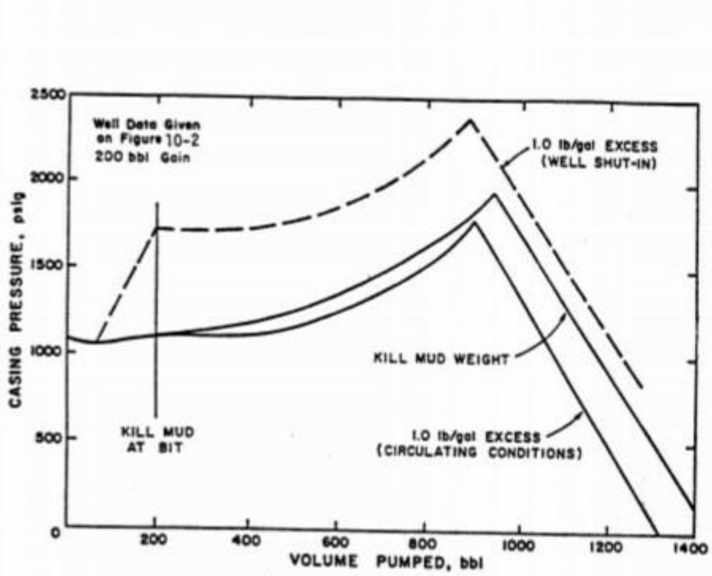

Figure 10-11: Effect of Excess Mud Density on Casing Pressure Profile

Since in some cases it may not be possible to bring a gas kick to the surface without fracturing the formation and perhaps exceeding the maximum allowable surface pressure, some operators prefer to fracture the bore hole intentionally while the kick fluids are still deep and relatively compressed. Another situation in which this option may be considered is when the presence of H_2S is suspected in quantities greater than can be safely handled at the surface. An attempt is made to pump as much of the kick fluids as possible into the fractured formation. This is sometimes accomplished by simultaneously pumping weighted mud down the drill pipe and the original mud down the annulus. If this procedure leads to a persistent underground blowout situation, the previously discussed techniques applicable to underground blowouts can be used. In general, an underground blowout situation is preferred to an uncontrolled well flow at the surface, as long as sufficient casing has been set to insure that the flow will remain underground.

Excessive Drill Pipe Pressure

Normally, the highest shut-in pressures occur on the casing rather than the drill pipe. However, excessive drill pipe pressure is possible when large quantities of mud are displaced from an open drill string before shut-in, when the drill string is off bottom, or when there is a hole in the drill string. In the drill string, the rotary hose and swivel generally have the lowest working pressure. If the shut-in drill pipe pressure is within 2,000 psi of the working pressure of swivel and rotary hose, the drill pipe safety valve should be closed and a high pressure chicksan line should be installed on the drill pipe.

Cases have been reported where the drill pipe safety valve has failed to operate properly under high pressures. In the event this occurs, a sealing plug can be created in a section of the drill string by freezing. A viscous bentonite plug is usually displaced into the section of pipe to be frozen. Freezing is accomplished by packing dry ice around the drill pipe over about a 3-ft length or through use of a commercially available refrigeration unit designed for this purpose. A 50-gal drum can be sectioned and placed around the pipe to hold the dry ice in contact with the pipe. Once a sealing plug has formed, new valves and a high pressure chiksan flow line can be installed.