Stuck Pipe

Introduction

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Stuck pipe is one of the more common and serious drilling problems. It can range in severity from minor inconvenience, which can increase costs slightly, to major complications, which can have significantly negative results, such as loss of the drillstring or complete loss of the well. A large percentage of stuck pipe instances eventually result in having to sidetrack around the stuck pipe called a *fish* and redrill the interval. Stuck pipe prevention and remedy are dependent on the cause of the problem. Therefore, to avoid stuck pipe and correct it efficiently, it is important to understand the various causes and symptoms so that proper preventive measures and treatments can be taken.

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If the pipe becomes stuck, every effort should be made to free it quickly. The probability of freeing stuck pipe successfully diminishes rapidly with time. Early identification of the most likely cause of a sticking problem is crucial, since each cause must be remedied with different measures. An improper reaction to a sticking problem could easily make it worse. An evaluation of the events leading up to the stuck pipe occurrence frequently indicates the most probable cause and can lead to the proper corrective measures.

Please refer to the "Worksheet: Freeing Stuck Pipe" and the tables of stuck pipe causes, indications and preventative measures — all at the end of this chapter. Refer to them as you review the material.

In general, pipe becomes stuck either *mechanically* or *differentially.* Mechanical sticking is caused by a physical obstruction or restriction. Differential sticking is caused by differential pressure forces from an overbalanced mud column acting on the drillstring against a filter cake deposited on a permeable formation. Mechanical sticking usually occurs when the drillstring is moving. It also is indicated by obstructed circulation. Occasionally, however, a limited amount of up/down mobility or rotary freedom is evident, even when the pipe is mechanically stuck. Differential sticking usually occurs while the pipe is stationary, such as when connections are being made or when a survey is being taken. It is indicated by full circulation and no up/down mobility or rotary freedom other than pipe stretch and torque.

Mechanically stuck pipe can be grouped into two major categories:
1. Hole packoff and bridges.
2. Wellbore geometry interferences.

Packoffs and bridges are caused by:
- Settled cuttings
- Shale instability
- Unconsolidated formations
- Cement or junk in the hole

Wellbore geometry interferences are caused by:
- Key seats
- Undergauge hole
- Stiff drilling assembly
- Mobile formations
- Ledges and doglegs
- Casing failures

Differentially stuck pipe usually occurs because of one of the following causes/high-risk conditions:
- High overbalance pressures
- Thick filter cakes
- High-solids muds
- High-density muds

Mechanical Sticking

If cuttings are not removed from the borehole, they accumulate in the well...

HOLE PACKOFF AND BRIDGES

Settled cuttings. If cuttings are not removed from the borehole, they accumulate in the well, eventually causing the hole to pack off, often around the Bottom-Hole Assembly (BHA) and sticking the drillstring (see Figure 1). This problem is encountered often in overgauge sections, where annular velocities are reduced. In deviated wells, cuttings will build up on the low side of the hole and may eventually slump down the hole, causing packoff.

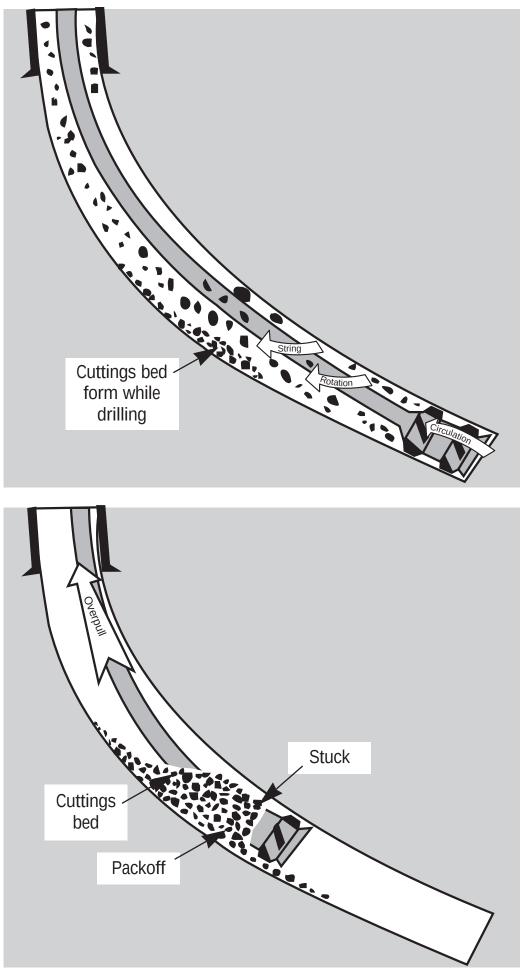


Figure 1: Settled cuttings (after Amoco TRUE®).

The causes of inadequate cleaning of cuttings from the hole are:

- Drilling at excessive Rates Of Penetration (ROP) for a given circulation rate. This generates cuttings faster than they can be circulated mechanically from the annulus.
- Inadequate annular hydraulics.
- Failure to suspend and carry cuttings to the surface with adequate mud rheology.
- Highly deviated well paths. High-angle wells are more difficult to clean, since the drilled solids tend to fall to the low side of the hole. Beds of cuttings will form, which are not easily removed.
- Formation sloughing and packing off around the drillstring.
- Not circulating enough to clean the hole before tripping out or making connections. When circulation is interrupted, cuttings may settle around the BHA and pack off, sticking the pipe.
- Drilling blind (without mud returns) and not adequately sweeping the hole periodically with a viscous mud.
- Unintentionally drilling without circulation.

The major warning signs and indications of cuttings settling are:

- Fill on bottom after connections and tripping.
- Few cuttings returning at the shakers relative to the drill rate and hole size.
- Increase in torque, drag and pump pressure.
- Overpull on connections and while tripping out.
- Increase in Low-Gravity Solids (LGS) and possible mud weight and/or viscosity increases.

The main indication that reactive shale has been drilled are increases in the funnel viscosity, yield point, gel strengths...

Preventive measures to minimize the possibility of settled cuttings are:

- Maintain proper mud rheology in accordance with hole size, ROP and hole inclination.
- In near-vertical wells, sweep the hole with high-viscosity mud. In highly deviated wells, sweep with low-viscosity/high-viscosity pills. Always circulate until the sweeps have returned to the surface and the shakers are clean.
- Use optimized hydraulics compatible with the respective hole size, inclination and ROP. Higher circulation rates always provide improved hole cleaning.
- Control drilling in high ROP or marginal hole-cleaning situations.
- Use aggressive drillstring rotation for improved hole cleaning.
- Make a wiper trip after all long motor runs.
- Use drillstring motion (rotate and reciprocate), while circulating at the maximum rate to disturb cuttings beds and reincorporate them into the flow stream.

Shale instability. Unstable shales can cause packing off and sticking when they fall into the wellbore. They may be classified as follows:

- **Reactive shales.** These are water-sensitive shales drilled with insufficient inhibition. Shales absorb water, become stressed and spall into the wellbore (see Figure 2).

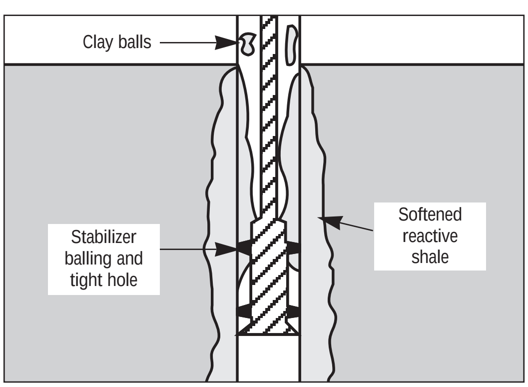


Figure 2: Reactive formation (after Shell UK).

The main indication that reactive shale has been drilled are increases in the funnel viscosity, yield point, gel strengths, Methylene Blue Test (MBT) and, possibly, the mud weight. This will be reflected by increases in torque, drag and pump pressure.

- **Pressured shales.** These shales are pressured and mechanically stressed by several different factors, including the weight of overburden, *in-situ* stresses, angle of bedding planes and tectonic stresses. When drilled with insufficient mud weight, these shales will slough into the wellbore (see Figure 3).

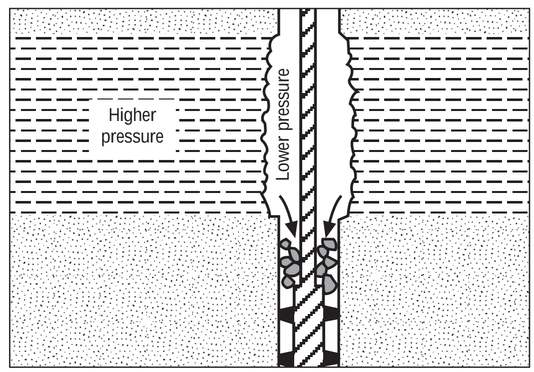


Figure 3: Pressured formations.

- **Fractured and faulted formations.** These are fragile formations which are mechanically incompetent. They are particularly unstable when the bedding planes dip at high angles (see Figure 4).

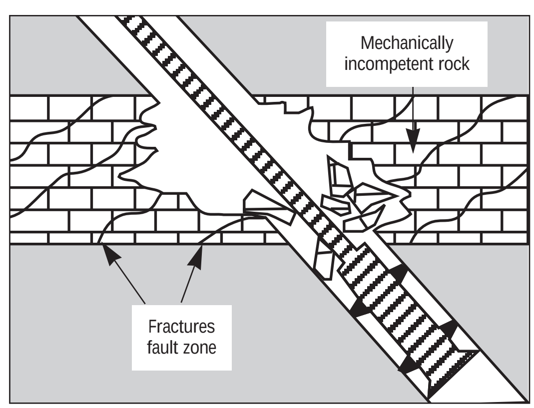


Figure 4: Fractured and faulted formations (after Shell UK).

Control of formation instability should start during the planning phase...

...suitable mud properties must be maintained to ensure good hole cleaning.

Large quantities of splintery or blocky shale will be encountered when pressured shales are drilled underbalanced or when fractured formations slough. Pump pressure, torque and drag will increase when the hole becomes overloaded with caving shale.

Control of formation instability should start during the planning phase of the well. An inhibited mud system, matched to the formation with the proper mud weight, will minimize shale instability. To balance mechanical stresses, highly deviated wells require higher mud weights than vertical wells. Although the first priority of a casing design is to ensure that the well can be drilled safely, casing points may have to be adjusted so that troublesome formations can be cased off.

Needless to say, suitable mud properties must be maintained to ensure good hole cleaning. If formation caving is detected, respond *immediately:*

1. Stop drilling.
2. Sweep the hole with viscous mud.
3. Increase the viscosity to improve the carrying capacity.
4. Increase the mud weight, when applicable.
5. Implement drilling practices to improve cuttings transport and to reduce the possibility of pipe sticking.

Unconsolidated formations. This problem involves formations that cannot be supported by hydrostatic overbalance alone. For example, unconsolidated sand and pea gravel often fall into the hole and pack off around the drillstring. Problems also occur if insufficient filter cake is deposited on loose, unconsolidated sand to prevent it from "flowing" into the wellbore and packing off the string (see Figure 5).

Generally, these types of formations are encountered at shallow depths or when drilling the production zones. Torque, drag and fill on connections are common indicators of such problems. Solids-control equipment will be overloaded with quantities of solids that do not correspond to the ROP.

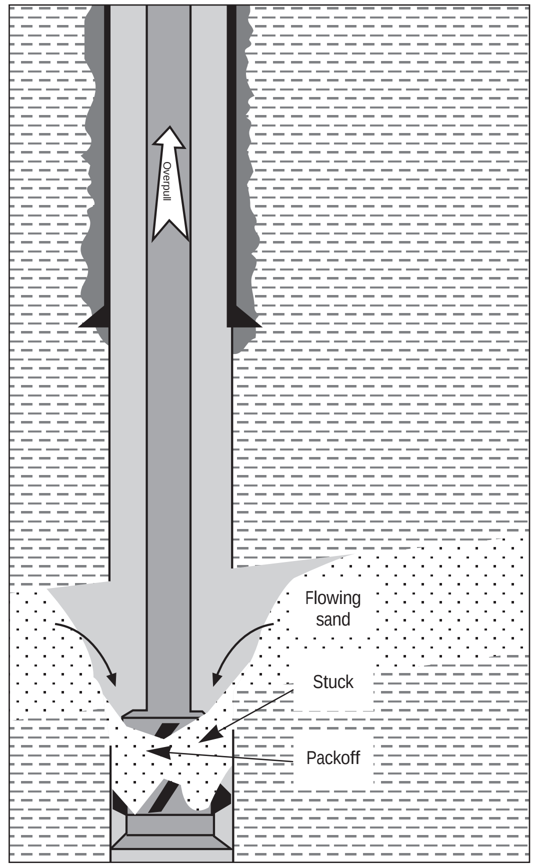


Figure 5: Unconsolidated formation (after Amoco TRUE).

To drill these formations, the mud should provide a good-quality filter cake to help consolidate the formation so that hydrostatic pressure can "push against" and stabilize the formation. Treatments with seepage-loss material, such as M-I-X-II™ fiber, will help seal these formations and provide a base for the filter cake. To minimize erosion, avoid excessive flow rates and avoid any unnecessary reaming or circulating with the BHA opposite unconsolidated formations. The hole should be swept with viscous gel sweeps to ensure good hole-cleaning, and filter-cake building.

When cement blocks or junk falls into the wellbore, they can act as a wedge and jam the drillstring.

Cement or junk in the hole. When cement blocks or junk falls into the wellbore, they can act as a wedge and jam the drillstring. This can happen when cement becomes unstable around the casing shoe or from open-hole plugs and kickoff plugs (see Figure 6).

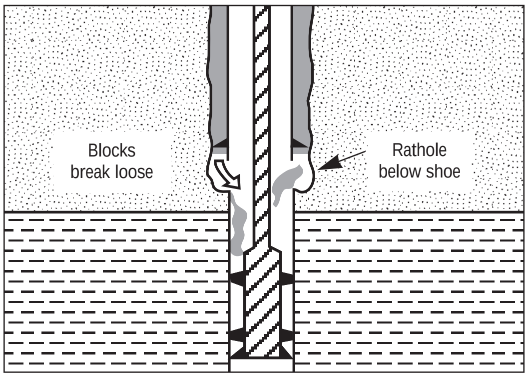


Figure 6: Cement blocks (after Shell UK).

Another type of cement packoff can occur when circulation is attempted with the BHA imbedded in soft cement. Pump pressure can cause the cement to "flash" set and stick the string (see Figure 7).

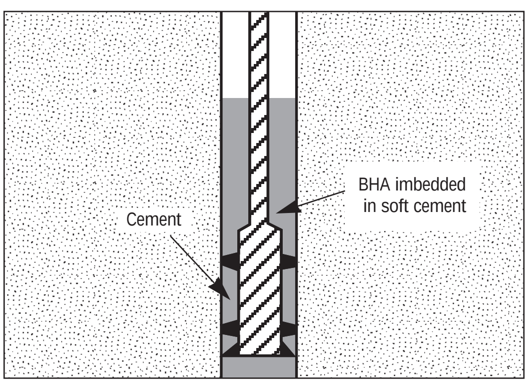


Figure 7: Soft cement (after Shell UK).

Metal junk can fall from the rig floor or come from failed downhole equipment or pieces of milled tubulars and equipment (see Figure 8).

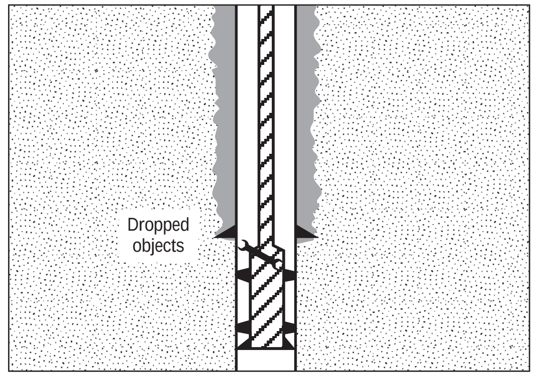


Figure 8: Junk (after Shell UK).

Some preventive measures to minimize junk in the hole are:

- Limit the casing rathole to minimize the source of cement blocks.
- Allow sufficient cement setting time before drilling out.
- Maintain sufficient distance between offset wells.
- Begin washing down at least two stands before the theoretical top of the cement.
- Pull up two stands before attempting to circulate, if set-down weight is observed when tripping in the hole after a cement operation.
- Control drilling when cleaning out soft cement.
- Keep the hole covered when the drillstring is out of the hole.
- Maintain rig floor equipment in good operating condition.

...the higher the change in well angle or direction, the higher the risk of mechanically sticking the pipe.

WELLBORE GEOMETRY

A second category of mechanically stuck pipe is related to wellbore geometry. Hole diameter and/or angle relative to the BHA geometry and stiffness will not allow passage of the drillstring. Generally, the higher the change in well angle or direction, the higher the risk of mechanically sticking the pipe. "S"-shaped wells are even worse and put an additional risk of pipe sticking due to increases in friction and drag.

The main types of well geometry interference are:

Key seating. Key seats occur when the drillstring rubs against the formation on the inside of a dogleg. The drillstring is held against the wellbore by tension as pipe rotation and movement wear a narrow groove in the side of the hole. The longer the interval below the dogleg and the more severe the dogleg, the greater the side load and the faster the development of a key seat (see Figure 9).

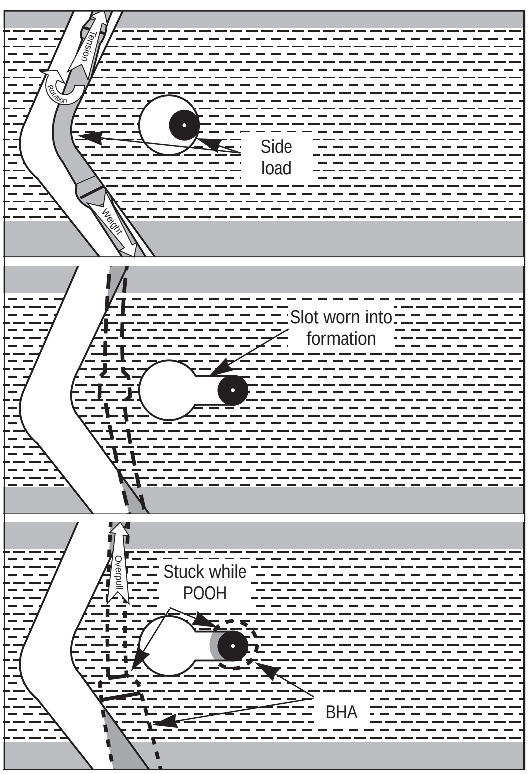


Figure 9: Key seat (after Amoco TRUE).

Key seat sticking occurs when the pipe becomes wedged into the narrow slot of the key seat as it is pulled up. Key seat sticking occurs only when the pipe is moving. The pipe also may become differentially stuck after being key seat stuck. Pipe stuck in a key seat often can be freed by jarring downward, especially if sticking occurred while picking up.

Undergauge hole. Abrasive hole sections not only will dull bits, but also will reduce the gauge of the bit and stabilizers. Pushing a bit run too far in abrasive formations leads to undergauge holes. Running a full-gauge assembly into an undergauge hole can jam and stick the string (see Figure 10).

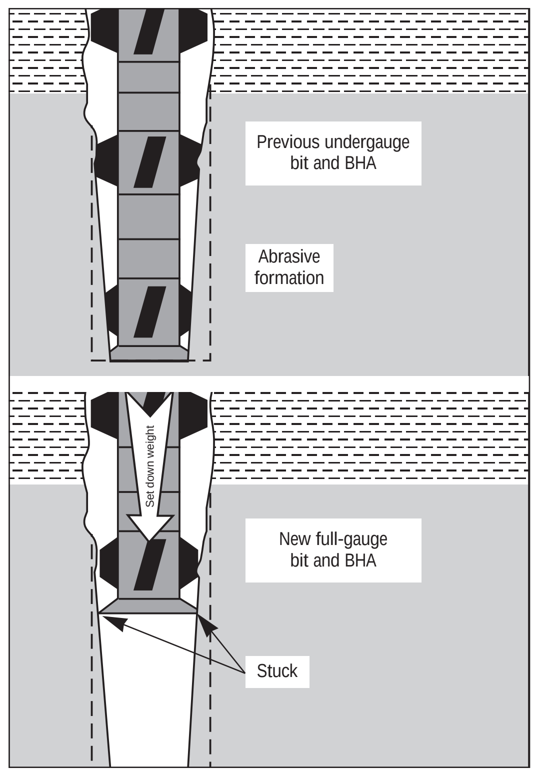


Figure 10: Undergauge hole (after Amoco TRUE).

Stiff assembly. Holes drilled with limber BHAs may appear to be straight when tripping out, but if a stiffer BHA is run, the newly drilled hole will act as if it were undergauge. Flexible

Stiff BHAs cannot negotiate sharp hole angle/ direction changes...

assemblies can "snake" around doglegs that present obstructions to stiff assemblies. Stiff BHAs cannot negotiate sharp hole angle/direction changes and can become jammed (see Figure 11).

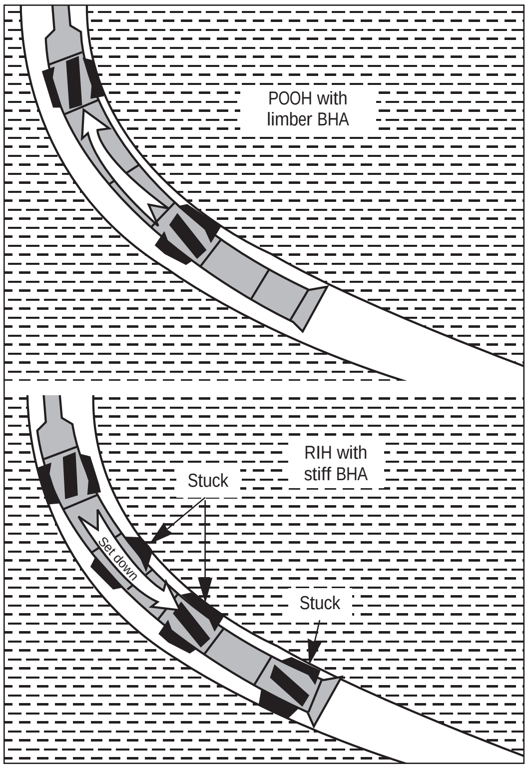


Figure 11: Stiff assembly (after Amoco TRUE).

Mobile formation. The overburden weight or tectonic forces can squeeze plastic salt or soft shale into the wellbore, sticking or jamming the BHA in the undergauge hole. The magnitude of the stresses — and hence the rate of movement — will vary from region to

Casing-related failures can stick the drillstring.

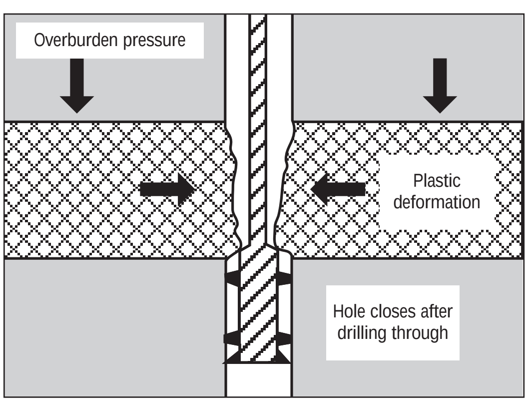


Figure 12: Mobile formation (after Shell UK).

region, but generally is greater for formations below 6,500 ft (2,000 m) and for salt formations with temperatures above 250°F (121°C) (see Figure 12).

Ledges and micro-doglegs. These are formed when successive hard/soft interbedded formations are encountered. The soft formations become washed out for various reasons (i.e. excessive hydraulics, lack of inhibition), while the hard rocks remain in gauge. This situation is aggravated by dipping formations and frequent changes in angle and direction. The stabilizer blades may become stuck under the ledges during tripping or picking up for connections (see Figure 13).

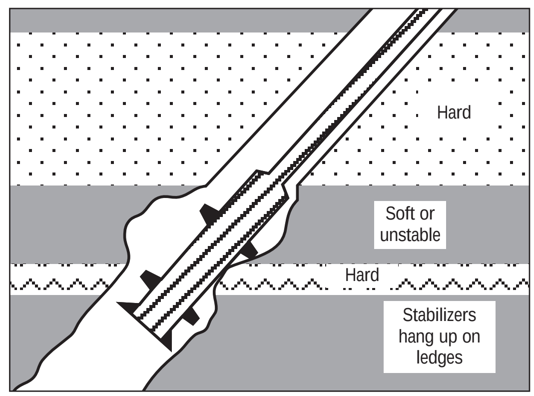


Figure 13: Ledges (after Shell UK).

Casing failures. Casing-related failures can stick the drillstring. The casing will collapse if external pressures exceed the casing strength. This situation happens often opposite plastic formations. Salt formations become increasingly plastic with pressure and temperature, and are often associated with collapsed casing.

If the casing is not cemented properly, the bottom joint or joints can be unscrewed by drillstring rotation. If this occurs, the casing below the unscrewed connection may drop and turn at an angle in the hole, catching the drillstring (refer to Figure 8). Proper casing running practices (tack welding or chemically bonding the first few collars) and a good cement job will minimize the likelihood of this problem.

The following practices are recommended to minimize wellbore geometry sticking:

- If a key seat is expected, use a key seat reamer.
- If abrasive formations are drilled, use hardfaced stabilizers and bits with extra gauge protection.
- Gauge the old bit and stabilizers as well as the new ones on every trip.
- Ream the last stand or three joints back to bottom on every trip.
- Optimize BHA design and stiffness.
- Plan a reaming trip if a stiff BHA is run and/or if a hole geometry problem is suspected.
- If mobile salt is encountered, use an undersaturated mud system to wash the zone or use a higher mud weight to stabilize it.
- Drill salt sections with eccentric, bi-centered Polycrystalline Diamond Compact (PDC) bits. Plan regular wiper trips to ream open-hole sections.
- Use higher-strength casing opposite plastic formations.
- Run a liner inside casing through the entire salt interval for additional strength.
- Drill salt with oil-base or synthetic muds to maintain a gauge hole through the salt and provide a better cement job with more even distribution of stresses on the casing through the salt.
- Slow down the running speed before the BHA enters a kickoff or dogleg.
- Minimize dogleg severity and/or sharp and frequent wellbore course changes.
- Avoid prolonged circulation opposite soft formations to prevent hole washout and formation of ledges.

Differentially Stuck Pipe

Many occurrences of stuck pipe can be attributed to differential pressure sticking…

Differential sticking is defined as stuck pipe caused by the differential pressure forces from an overbalanced mud column acting on the drillstring against a filter cake deposited on a permeable formation. Many occurrences of stuck pipe can be attributed to differential pressure sticking, which also is referred to as "wall sticking." It usually occurs while the pipe is stationary during a connection or when taking a survey, and is indicated by full circulation and no up/down mobility or rotary freedom, other than pipe stretch and torque.

For differential sticking to occur, two conditions must exist:

1) The hydrostatic pressure of the mud must exceed the pressure of the adjacent formation.
2) A porous, permeable formation must exist.

Figure 14 demonstrates the mechanics of differential sticking. In this example, the hydrostatic pressure of the mud is 500 psi greater than formation pressure. In "A", the drill collars are centered in the hole and are not stuck. The hydrostatic pressure acts equally in all directions. In "B" and "C," the collars contact the filter cake opposite a permeable zone, and become stuck. As shown in "C," the hydrostatic pressure now acts across the area of contact between the filter cake and the collars. This pressure holds the collars firmly against the wall of the hole. The segment this force acts upon is shown by the dotted line drawn across the drill collar from "a" to "b." The distance from "a" to "b" depends on the imbedded depth of the collar/pipe into the filter cake, and the hole size and the OD of the pipe. The imbedded depth depends on the thickness of the filter cake, which determines the area of contact between the pipe and the wall cake. The thickness of

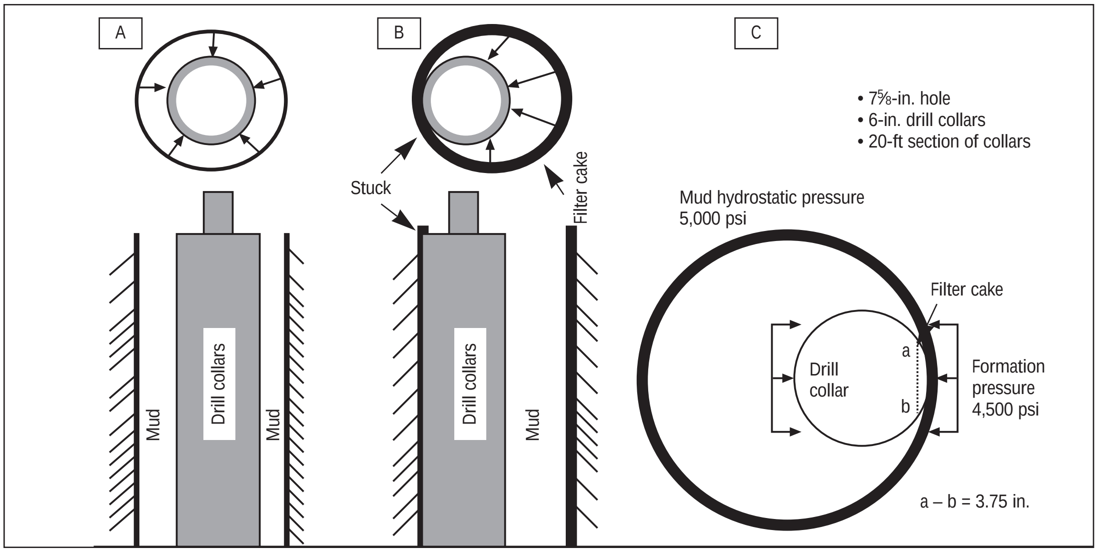


Figure 14: Mechanics of differential pressure sticking.

the filter cake is a function of the concentration of solids in the mud and the fluid loss. In this example, for every square inch of contact area, there is a confining force of 500 lb. For a 20-ft section of 6-in. collars in a 7⅝-in. hole imbedded ⅛-in. into the filter cake (a – b is 3.75 in.), the calculated differential strength force is:

(500 psi) (3.75 in.) (20 ft) (12 in./ft)
= 450,000 lb

To calculate the vertical force necessary to pull the pipe free, this force is multiplied by the coefficient of friction. The coefficient of friction is usually in the range of 0.2 to 0.35 in water-base muds and 0.1 to 0.2 in oil-base or synthetic muds. In this case, the vertical force necessary to pull the pipe free is 45,000 lb with a 0.1 coefficient of friction and 135,000 lb with a 0.3 coefficient of friction.

Excessive drill solids and high fluid loss increase filter-cake thickness...

Causes

When the pipe becomes differentially stuck, the following conditions exist:

- The hydrostatic pressure of the mud exceeds the adjacent formation pressure.
- The formation is permeable (usually sandstone) at the point where the pipe is stuck. This combination of differential pressure and a permeable formation results in fluid loss to the formation and the deposition of a filter cake.

Almost always, there is free circulation around the stuck zone when pipe is differentially stuck (i.e. no packoff).

When a filter cake builds up on the formation, it increases the contact area between the wellbore and the drill pipe. Excessive drill solids and high fluid loss increase filter-cake thickness and the coefficient of friction, making it more difficult to pull or jar the drill pipe free.

Preventive measures

All of the conditions associated with differentially stuck pipe cannot be eliminated; however, the possibility of differential sticking can be reduced by following good drilling practices. These include the following:

- Reduce the overbalance pressure by keeping the mud weight as low as good drilling practices allow. Excessive mud weights increase the differential pressure across the filter cake and increase the possibility of differentially sticking the pipe.

Filter-cake thickness can be reduced by lowering the filtration rate and drill solids content.

- Reduce the area of contact between the wellbore and the pipe by using the minimum length of drill collars needed for the required bit weight. Reduce the area of contact by using small, spiral or square drill collars; by using stabilizers; and by using heavy-weight drill pipe to supplement the weight of the drill collars.
- Reduce filter-cake thickness. Thick filter cakes increase the contact area between the pipe and the side of the hole, which effectively reduces wellbore diameter. The contact area between the wellbore and pipe can be decreased by reducing the thickness of the filter cake. Filter-cake thickness can be reduced by lowering the filtration rate and drill solids content.
- Maintain a low filtration rate. Filtration rates should be monitored on a regular basis at downhole temperatures and differential pressures. Mud treatment should be based on the results of these tests relative to desired properties.
- Control excessive ROP to limit the concentration of drill solids and an increase of mud weight in the annulus. This affects differential pressure and filter-cake composition.
- Minimize the mud's coefficient of friction by keeping a good quality filter cake with low drill solids and by using the proper lubricants in sufficient quantities.
- Keep the pipe moving when possible and use good drilling practices to minimize differential sticking.
- Run drilling jars when possible.
- Watch for depleted pressure zones, where differential sticking occurs frequently. The mud weight used to drill these zones must be sufficient to balance the normal pressure gradient of the open hole. The difference in pressure of the normally or abnormally pressured zones exposed in the wellbore and the pressure of the depleted zone can be several thousand pounds per square inch. Seepage-loss materials such as asphalt, gilsonite, M-I-X II fiber and bridging agents such as sized-calcium carbonate have been used with success to drill depleted zones with high differential pressures. Depleted zones should be isolated with casing whenever possible.

Common Stuck Pipe Scenarios

...it is critical...to determine why the pipe is stuck.

Stuck pipe can often be freed. However, it is critical first to determine why the pipe is stuck.

Some of the most common stuck pipe situations, with the most common ways to free it, are as follows:

1. Pipe sticks while tripping into the hole **before** the bit reaches the casing shoe.
   - If it is possible to circulate, the casing probably has collapsed.
   - If it is not possible to circulate, and the mud is cement-contaminated or contains a high lime concentration, the pipe is probably stuck in cement or contaminated mud.
2. Pipe sticks while tripping into the hole (pipe moving) with the bit and BHA below the casing shoe. It is impossible to rotate the pipe.
   - If stuck off bottom, and the BHA has been lengthened or stiffened, the string probably has been wedged into a dogleg. Circulation should be possible, but may be restricted.
   - If the pipe is stuck close to bottom, it may be jammed into an undergauge hole or dogleg. Circulation should be possible, but may be restricted.

- If it is not possible to circulate, pipe is stuck in fill or if the mud has been contaminated with cement, the mud or cement probably has set up.

3. If the pipe sticks while making a connection or taking a survey.
   - If the pipe can be rotated with restricted circulation, it is an indication of rocks, cement blocks or junk in the hole.
   - If the pipe cannot be rotated with full circulation, it is probably differentially stuck.
4. The pipe sticks when circulating kill mud during a well-control operation while the pipe was not being worked or rotated. It is probably differentially stuck.
5. The pipe sticks while picking up or tripping, and it is still possible to rotate, circulate and move the pipe a limited amount. It is probably junk in the hole.
6. The pipe sticks suddenly while pulling out of the hole on a trip and cannot be worked up or down, with full circulation, and usually can be rotated. It is probably key seated.

Methods and Procedures for Freeing Stuck Pipe

Freeing stuck pipe mechanically

When it is determined that the pipe is differentially stuck or has been pulled into a key seat, the most successful method for freeing it is jarring downward with drilling jars while torquing the pipe. This should be started immediately after the pipe sticks. Frequently, this will free the pipe without the need for spotting fluid. Time is critical, since the probability of freeing stuck pipe diminishes with time. Delays in initiating jarring allow additional pipe to become stuck.

Delays in initiating jarring allow additional pipe to become stuck.

NOTE: If, while running the pipe into the hole, it becomes stuck due to undergauge hole or changes in the BHA, it should not be jarred downward.

Freeing stuck pipe with spotting fluids

Once it is determined that the drillstring is differentially stuck, the annulus should be displaced with a spotting fluid from the bit to the free point. Surveys can determine the free point accurately, but running such surveys often takes a significant amount of time. A pipe-stretch method, described on page (15.23), is a quick way to estimate the depth of the stuck zone. To increase the likelihood of success, the spotting fluid should be applied as soon as possible.

Plans should be made to mix and spot a soak solution as soon as possible after differential sticking occurs. Jarring should continue while this is being done.

The soak solution to be used depends on several factors. When drilling with water-base muds, oil-base spotting fluids are preferred. If oil-base fluids present a contamination or disposal problem, alternative environmental spotting fluids must be used. Often, oils, oil-base mud, saturated saltwater, acids or surfactants can be used to spot and free stuck pipe, depending upon the situation. The line of M-I PIPE-LAX® products is specially formulated for this purpose.

PIPE-LAX can be mixed with diesel oil, crude oil or kerosene to make unweighted spotting fluids. For weighted muds, PIPE-LAX can be mixed with VERSADRIL® or VERSACLEAN® muds corresponding to the weight of the mud in the hole. This prevents the column of lighter spotting fluid from migrating through the heavier drilling fluid and maintains hydrostatic pressure.

In environmentally sensitive areas, where the use of oil-based materials is prohibited, PIPE-LAX ENV, a water-dispersible, low-toxicity spotting fluid, can be used. PIPE-LAX ENV is a single-package spotting fluid that has proven to be highly effective in offshore applications around the world. It contains no petroleum oils, is compatible with most mud systems and may be used either weighted or unweighted. If a density greater than 9 lb/gal (1.08 SG) is required, PIPE-LAX ENV should be weighted with M-I BAR® or FER-OX®. Water *should not* be added to PIPE-LAX ENV slurry for any reason, since this will cause an undesirable increase in viscosity.

The spotting method involves placing soaking solution adjacent to the stuck zone.

The spotting method involves placing soaking solution adjacent to the stuck zone. The most successful soaking solutions to date have been PIPE-LAX with diesel oil and PIPE-LAX W. Oil alone has been used for years with some measure of success, but PIPE-LAX mixed with diesel oil, VERSADRIL or VERSACLEAN has shown a much greater degree of success. One gallon of PIPE-LAX is added to each barrel of oil or oil-base mud to be spotted.

The PIPE-LAX oil spotting technique is thought to work by altering the contact area between the filter cake and the pipe. This is accomplished by cracking the filter cake (see Figure 15). Although oil alone has been partially successful, it is not as effective as a PIPE-LAX oil spot. This can be attributed to the increased filter-cake cracking when PIPE-LAX is used. The filter cakes shown in Figure 15 were run on the same mud, using a standard API filter cell containing a removable drain plug located on the top of the cell. Thirty-minute fluid losses were run, the plugs were removed, and the mud was removed without disturbing the filter cake. One cell was refilled with oil and the other with a PIPE-LAX oil-soak solution. Both cells were then placed on filter presses and pressurized to 100 psi. The PIPE-LAX oil mixture cracked the filter cake rapidly and the lubricating mixture passed through the filter cake at a fast rate. Oil alone showed little cracking and the flow rate through the filter cake was much slower. Relating this to slurries spotted in a well, a higher frequency of success should occur with a PIPE-LAX oil solution than with oil alone. Freeing of the pipe also can be expected to occur in a much shorter period of time with the PIPE-LAX oil-soaking solution.

Figure 15: Cracking effect of filter cake using oil only (left) vs. PIPE-LAX and oil (right).

Table 1 shows field data obtained from 178 cases of stuck pipe. The data is arranged by the occurrences of sticking in descending order and by the percent of the total each represents, illustrating when sticking is most likely to occur.

Statistical case history information on a total of 247 cases of stuck pipe reveals that 203 were freed by spotting a PIPE-LAX/oil soak solution. This represents an 82% success ratio in freeing the pipe. The time to free the pipe averaged 2⅓ hr, with a large percentage freed in 2 hr or less. The average mud weight was 13.2 lb/gal, with the heaviest being 18.2 lb/gal. In the latter extreme, the pipe was freed in 45 min.

Operation	Frequency	% Total	% Freed After Spot
Shut down	42	23.6	90.4
Coming out of hole	33	18.5	90.9
Going in hole	20	11.2	75.0
Making connection	18	10.1	100.0
Wash pipe stuck	16	8.9	81.2
Twist off	12	6.7	91.6
Running casing	11	6.2	72.7
Drilling or reaming	11	6.2	81.8
Lost circulation	7	3.9	57.1
Gas or salt water	6	3.3	33.3
Other	2	0.56	100.0
Total	178	100	

Table 1: Common causes of stuck pipe.

Most failures occur because the entire section of stuck pipe is not covered completely.

Spotting techniques

Pipe-Lax spotting fluids. Because of their greater contact area, drill collars become differentially stuck more frequently than the rest of the drillstring. Unless there is an indication — from a free point survey or the pipe stretch calculations — that the pipe is stuck above the drill collars, spotting fluids usually are placed around the collars. Preparing and placing a Pipe-Lax/oil solution around the drill collar annulus is relatively easy (placement of the soak solution when the drill pipe is stuck off bottom is discussed later). Regardless of where the drillstring is stuck, the volume of the soak solution used should be sufficient to cover the complete section of stuck pipe plus a reserve volume for periodically pumping an additional volume of spot. Most failures occur because the entire section of stuck pipe is not covered completely.

The following procedure is recommended to free stuck drill collars:

1. Determine the volume of soak solution required to fill the annular space around the collars. The annular volume opposite the collars can be calculated by multiplying the annular volume (bbl/ft) by the length of the collars (ft).

   Example:
   500 ft of 6-in. collars
   in 9⅞-in. hole
   (0.06 bbl/ft)(500 ft) = 30 bbl
2. This volume should be increased enough to compensate for hole enlargement and leave enough solution in the pipe so additional volume can be pumped periodically to compensate for migration of the spotted fluid. The extra volume usually ranges from 50 to 200% of the annular displacement volume, depending on hole conditions.
3. Pipe-Lax/oil solution is mixed by adding 1 gal of Pipe-Lax per barrel of oil in the spot. The solution should be mixed thoroughly before spotting.
4. Determine the pump strokes and barrels of spotting fluid and mud to be pumped to displace the entire drill collar annulus with soak solution, leaving the reserve volume inside the pipe. Spot the slurry, then shut the pump down.
5. After the Pipe-Lax/oil solution is spotted, the pipe should be worked by putting it in compression. Slack off 10,000 lb below the weight of the pipe and take ½ round of torque per 1,000 ft with tongs or the rotary table. Release the torque and pick up the 10,000 lb of weight. Repeat this

cycle about once every five minutes. The pipe usually will come free on the compression cycle. It should be noted that working the pipe in tension or pulling 10,000 to 50,000 lb over the indicated weight of the drillstring could cause the pipe to become stuck further up the hole in a key-seat or dogleg. These hole conditions are common at shallow depths.

6. Periodically, pump 1 to 2 bbl of soak solution to keep the collars covered. Continue to work the pipe as outlined above.

When premixed oil-base or invert oil muds are available and the mud weight is extremely high, PIPE-LAX can be added to these carriers and spotted. Spotting this solution would be done on a volumetric basis, since the PIPE-LAX solution would weigh the same as the drilling fluid. The advantage of using this type of solution is that it will not migrate while soaking.

PIPE-LAX W spotting fluids. PIPE-LAX W may be mixed as a weighted spot. The formulation for mineral oil/M-I BAR systems is shown in Table 2. The formulation for mineral oil/FER-OX systems is shown in Table 3. The mixing order for PIPE-LAX W is (1) oil, (2) PIPE-LAX W, (3) water (stir this mixture for 30 minutes) then add (4) M-I BAR.

Formulation:

The formulation charts are designed to produce the minimum viscosity required to support weight material. If higher viscosities are required, increase the concentration of PIPE-LAX W from 4.36 to 4.8 gal/bbl.

Example:

To mix 120 bbl of 12 lb/gal PIPE-LAX W spot using mineral oil and M-I BAR:

From Table 2 calculate:

1) Mineral oil ....0.521 x 120 = 62.52 or 63 bbl

2) PIPE-LAX W.....................4.36 x 120 = 523.2 gal or 10, 55-gal drums

3) Water...........................0.203 x 120 = 24.36 or 25 bbl

Mix for 30 min.

4) M-I BAR: ....2.53 x 120 = 304 sacks

Mud Weight (lb/gal)	Mineral Oil* (bbl)	Pipe-Lax W** (gal)	Water (bbl)	M-I Bar (sacks)
8	0.528	4.36	0.345	0.34
9	0.527	4.36	0.309	0.88
10	0.526	4.36	0.272	1.44
11	0.525	4.36	0.236	1.99
12	0.521	4.36	0.203	2.53
13	0.515	4.36	0.172	3.08
14	0.507	4.36	0.142	3.62
15	0.496	4.36	0.117	4.17
16	0.484	4.36	0.092	4.71
17	0.469	4.36	0.071	5.24
18	0.453	4.36	0.050	5.78

* In diesel oil, it is recommended that the concentration of PIPE-LAX W shown in Table 2 be decreased from 4.36 gal/bbl to 3.5 to 4.0 gal/bbl. Diesel oil will inherently provide higher viscosities. If it is necessary to reduce the viscosity of a PIPE-LAX W solution, dilute with oil or add 0.25 to 0.5 lb/bbl VERSAWET®.
** If higher viscosity is required, use 4.8 gal/bbl PIPE-LAX W.

Table 2: PIPE-LAX W formulation: mineral oil and M-I BAR (barite) (1 final barrel).

Mud Weight (lb/gal)	Mineral Oil* (bbl)	Pipe-Lax W** (gal)	Water (bbl)	Fer-Ox (sacks)
8	0.527	4.36	0.351	0.31
9	0.525	4.36	0.323	0.84
10	0.524	4.36	0.295	1.36
11	0.520	4.36	0.269	1.88
12	0.516	4.36	0.243	2.40
13	0.511	4.36	0.218	2.92
14	0.504	4.36	0.196	3.45
15	0.497	4.36	0.174	3.97
16	0.488	4.36	0.153	4.48
17	0.477	4.36	0.134	5.00
18	0.465	4.36	0.117	5.51

* In diesel oil, it is recommended that the concentration of PIPE-LAX W shown in Table 3 be decreased from 4.36 gal/bbl to 3.5 to 4.0 gal/bbl. Diesel oil will inherently provide higher viscosities. If it is necessary to reduce the viscosity of a PIPE-LAX W solution, dilute with oil or add 0.25 to 0.5 lb/bbl VERSAWET.
** If higher viscosity is required, use 4.8 gal/bbl PIPE-LAX W.

Table 3: PIPE-LAX W formulation: mineral oil and FER-OX (1 final barrel).

It is more difficult to spot the soak solution around the drill pipe... because of hole enlargement.

PIPE-LAX ENV spotting fluids. PIPE-LAX ENV spotting fluid is a low-toxicity, non-petroleum solution for use when oil or oil-base fluids are not permitted. It is a premixed solution, and needs only to be weighted to the desired density. Care should be taken not to contaminate PIPE-LAX ENV solutions with either water or mud, since this will result in excessive viscosity. Densities above 15 lb/gal (1.8 SG) require additions of LUBE-167™ to reduce final viscosity (see * Table 4). The following is the procedure for using PIPE-LAX ENV:

NOTE: Water contamination causes a significant increase in PIPE-LAX ENV viscosity. After cleaning, all mixing pump and mud lines should be drained and then filled with PIPE-LAX ENV before weighting up.

1. Calculate the volume of spotting fluid required and add at least 10% to compensate for any washout, plus at least 25 bbl (3.98 m^3) to remain in the drillstring after initial displacement.
2. In a CLEAN, DRY tank, add the required amount of PIPE-LAX ENV as determined in Table 4. Although some separation of materials may occur in the containers, transferring the product into a pit will blend the components, and product performance will not be affected.
3. If the slurry is to be weighted, add the M-I BAR or FER-OX and blend thoroughly. For densities above 15 lb/gal (1.8 SG), add the required amount of LUBE-167and add weight as needed.
4. Displace the annulus from the bit to the top of the zone at which differential sticking is suspected. Leave at least 25 bbl (3.98 m^3) inside the pipe to displace into the open hole.
5. Work the pipe while the spot is soaking. Pump 1 to 2 bbl periodically to assure that fresh soak solution is being displaced into the open hole.
6. Allow at least 24 hours for the PIPE-LAX ENV to free the stuck pipe. Generally, unweighted spotting fluids are effective in a shorter period of time.

Procedure for spotting a light fluid around the drill pipe. Occasionally, the drill pipe (rather than the drill collars) sticks. It is more difficult to spot the soak solution around the drill pipe than around the collars because of hole enlargement. Since hole enlargement is not usually uniform, it is difficult to calculate the volume of soak solution required to displace the annulus to the right place.

	Mixing Formulation (per final barrel)			
Density lb/gal	Pipe-Lax Env bbl	M-I Bar lb	Pipe-Lax ENV bbl	Fer-Ox lb
8.5	1.000	—	1.000	—
9.0	0.982	28	0.985	26
10.0	0.943	83	0.955	79
11.0	0.905	139	0.925	132
12.0	0.868	194	0.895	184
13.0	0.829	250	0.864	238
14.0	0.793	304	0.835	290
15.0*	0.754	361	0.804	343
16.0*	0.717	415	0.774	395
17.0*	0.680	471	0.744	448
18.0*	0.642	526	0.714	500

* Higher-density PIPE-LAX ENV formulations may develop high viscosity and become difficult to pump. This situation is aggravated by even small amounts of water contamination. For densities greater than 15 lb/gal (1.80 SG), LUBE-167 should be added to PIPE-LAX ENV formulations to reduce the final viscosity, then weighted to achieve the desired density.

Suggested dilution concentrations are as follows:

Density	LUBE-167 (% by volume)
15 - 16	5
16 - 17	10
17 - 18	15
>18	20

Table 4: PIPE-LAX ENV/weighting material formulations.

The following procedure may be used for spotting a lighter soak solution in a washed-out hole. This procedure involves alternatively pumping a given volume then measuring an annular differential pressure to calculate the depth of the leading edge of the spot (see Figure 16). Any type of fluid with a weight different from that of the mud being used may be spotted in the annulus by following these steps:

1. Check the weight of the fluid to be spotted and determine its gradient (psi/ft). With the weight of the mud in the hole known, the difference in the gradients of the two liquids can be established (for the purposes of this description, it is assumed that diesel oil will be used as the spotting fluid). Determine an appropriate spot volume to cover the stuck zone.
2. Pump the diesel oil into the drill pipe. Shut down, then read the pressure on the drill pipe. It is assumed that the total volume of the diesel slug will not exceed the drill pipe capacity. Length of the diesel column can be determined by:

   Length of column = (drill pipe pressure/difference in gradient)

   The purpose of this step is to determine more accurately the volume of the diesel oil inside the drill pipe instead of using what was measured in the surface tank. It is not unusual to have a difference of 5 to 10 bbl due to the inability of the pumps to get all of the liquid from the tank or due to improper allowances for the line fill. If the volume of the diesel oil is greater than the capacity of the drill pipe, then omit Step 2 and rely on tank measurements only.
3. Check and mark the level of all mud pits before beginning the displacement with mud and the annular pressure measurement procedure.
4. Using the best estimate of the volume of diesel spot inside the drill pipe, calculate the volume of mud to be pumped so that the trailing edge of the diesel just clears the bit.

Shut down the pump and close the annular preventers to measure the annular differential pressure. Also check the mud pit level. Record these values in a tabular manner.

The annular height of the diesel oil spot can be calculated by:

Length of column = (annular pressure/difference in gradient)

The leading edge of the spot is now at a depth equal to the Total Depth (TD) minus the length of column calculated above. Record these values.

5. Pump a volume of mud equal to the original spot volume minus any observed mud loss in the pits. (This assumes that all pit losses are diesel being lost in the open hole.)
6. Shut down the pump and close the annular preventers to measure the annular differential pressure and check the mud pit level. Calculate the length of the column again. Record these values.

The depth of the leading edge of the spot is calculated by subtracting each calculated length of the spot column from the previous leading-edge depth. Keep a careful record of all measurements (volumes pumped, pressures, pit-volume changes) and calculations.

The diesel oil spot can be moved up the annulus accurately to any suspected stuck pipe joint by repeating Steps 5 and 6 as many times as necessary.

The following cautions should be observed when using this method:

- Corrections for the vertical height of the column must be made when working in a directional hole.
- Displacement volumes should be measured accurately by using a pump-stroke counter and/or measuring tanks.
- The mud weight needs to be uniform throughout the system.

Example:

An 8½-in. hole is being drilled with 4½-in. drill pipe and the pipe is stuck with the bit at 10,000 ft. The pipe is free at 7,300 ft. A 100-bbl slug of diesel oil is to be spotted, with the top of the slug near the stuck point (see illustrations and steps in Figure 16).

Using the procedure outlined above:

(1) Weight of diesel oil = 6.8 lb/gal; gradient = 0.3536 psi/ft
Weight of mud = 10 lb/gal; gradient = 0.5200 psi/ft
Difference in gradients = 0.5200 – 0.3536 = 0.1664 psi/ft

(2) Approximately 100 bbl of diesel oil are pumped into the 4½-in. drill pipe, the pump is shut down, and the drill pipe pressure is 1,170 psi. (see Figure 16A)

Length of column = (1,170 psi/ 0.1664 psi/ft) = 7,031 ft

The calculated length of a 100-bbl column in 4½-in. drill pipe is 7,032 ft; therefore, it is concluded that 100 bbl is the actual volume in place.

(3) Pit levels are marked.

(4) The diesel is displaced from the drill pipe by pumping the drillstring capacity volume (see Figure 16B) and the annular pressure is 185 psi.

Length of column = (185 psi/ 0.1664 psi/ft) = 1,112 ft
The bottom of the column is at 10,000 ft
The top is at 10,000 – 1,112 ft = 8,888 ft

(5) There are no mud pit losses, so the diesel spot is displaced by the original volume, 100 bbl.

(6) The annular pressure is now 100 psi (see Figure 16C).

Length of column = (100 psi/ 0.1664 psi/ft) = 601 ft
The bottom of the column is at 8,888 ft
The top is at 8,888 – 601 = 8,287 ft

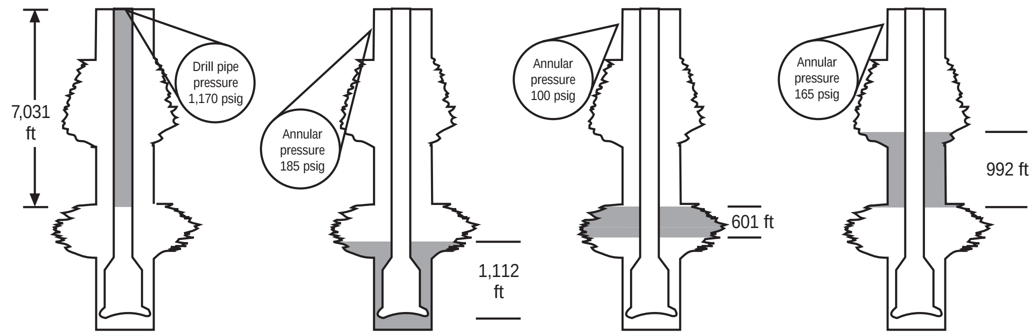
It is noted that 10 bbl of mud have been lost from the pits; therefore, the diesel spot is displaced by only 90 bbl instead of 100 bbl, as before. The annular pressure is now 165 psi (see Figure 16D) and the length of the column is again calculated.

Length of column = (165 psi/ 0.1664 psi/ft) = 992 ft

The bottom of the column is at 8,287 ft

The top is at 8,287 – 992 = 7,295 ft

Since the stuck point is 7,300 ft, the diesel has been positioned in the desired area.



Procedure:
1. Spot diesel oil in drill pipe.
2. Measure pressure in drill pipe annulus accurately.
3. Move diesel slug in 100-bbl increments, calculating fluid column lengths.
4. Spot diesel oil at desired interval.

A

Problem: Spot diesel oil at 7,300 ft

Approach: Pump 100 bbl diesel oil into drill pipe

Measure pressure:
Drill pipe = 1,170 psig
Annulus = 0

Diesel column length = $\frac{\text{Pressure difference}}{\text{Gradient difference}} = \frac{1,170}{.1664} = 7,031$ ft

B

Pump drillstring capacity volume to displace 100 bbl diesel spot from drill pipe

Read: Drill pipe pressure = 0
Annular pressure = 185 psig

Diesel column length = 185/.1664 = 1,112 ft

Leading edge of spot: 10,000 – 1,112 = 8,888 ft

C

Displace spot volume 100 bbl

Read: Drill pipe pressure = 0
Annular pressure = 100 psig

Diesel column length = 100/.1664 = 601 ft

Leading edge of spot: 8,888 – 601 = 8,287 ft

D

Displace another 100 bbl *(NOTE: mud pit lost 10, so pump only 90)*

Read: Drill pipe pressure = 0
Annular pressure = 165 psig

Diesel column length = 165/.1664 = 992 ft

Leading edge of spot: 8,287 – 992 = 7,295 ft

Spot is properly placed

Figure 16: Method for spotting pipe-freeing solution accurately in irregular hole.

One technique for freeing stuck pipe in carbonate formations is to spot HCl…

Spotting hydrochloric acid to free stuck pipe in carbonate formations. One technique for freeing stuck pipe in carbonate formations is to spot hydrochloric acid (HCl) opposite the stuck zone. HCl will react and degrade/ dissolve the formation. The pipe/ formation contact area is reduced and the pipe could be jarred free.

NOTE: High-strength pipe is subject to hydrogen embrittlement and catastrophic failure in acidic environments. If this procedure is attempted, the appropriate ***acid inhibitors*** *should be used.*

1. Pump a predetermined spacer of approximately 10 to 30 bbl (generally water or diesel).
2. Spot 20 to 50 bbl of 15% HCl around the suspected stuck zone. Allow at least 2 hr for the acid to react before the pipe is jarred. It is critical not to move the pipe during this soak period. If the pipe is moved, it could embed itself in the wellbore as the wall is eroded.
3. An adequate volume of HCl should be left inside the drillstring to provide a second soak opportunity.

Certain precautions should be taken when spotting acid to free stuck pipe...

4. Follow the HCl pill with the same spacer used in Step 1.
5. When the pill is displaced from the hole, it can be incorporated into the mud system. The HCl probably will be completely depleted and the resultant pH can be adjusted using soda ash, caustic soda or lime.

Certain precautions should be taken when spotting acid to free stuck pipe:

1. For safety reasons, diluting concentrated HCl should always be made by adding the acid to the water. ***Never** add water to acid.*
2. The pill should be circulated out through the choke at a slow pump rate, since carbon dioxide (CO_2) gas is generated when the acid reacts with the carbonate formation and could behave like a gas influx.
3. Use the proper safety equipment when handling HCl.
4. Maintain enough caustic soda, soda ash or lime on location to neutralize the pill when it is circulated out of the hole.

FREEING STUCK PIPE BY REDUCING DIFFERENTIAL PRESSURE

The reduction of differential pressure also frees differentially stuck pipe. This can be accomplished in several ways. One method is to spot a fluid that is lighter than the drilling fluid in the hole above the stuck point. Water and oil are the most common fluids used for this procedure.

Reduced-density fluids

I. If diesel oil is spotted, the following procedure can be used:
1. Assume 500 psi reduction in differential pressure, 15.0 lb/gal mud weight and annular volume of 0.05 bbl/ft.
2. Convert the mud weight to a pressure gradient by:
   15.0 x 0.052 = 0.7800 psi/ft
3. Convert the weight of diesel to a pressure gradient by:
   6.8 x 0.052 = 0.3536 psi/ft
4. Differential pressure gradient = 0.7800 - 0.3536 = 0.4264 psi/ft
5. Annular length of diesel required =
   $$\frac{500 \text{ psi}}{0.4264 \text{ psi/ft}} = 1{,}173 \text{ ft}$$
6. Volume of diesel required =
   1,173 ft x 0.05 bbl/ft = 58.7 bbl
7. Spot the diesel in the annulus above the stuck zone.

II. To reduce the differential pressure by reducing the mud weight above the stuck point:
1. Assume 500 psi reduction in differential pressure, 15 lb/gal mud weight, annular volume of 0.05 bbl/ft and stuck point at 7,000 ft.
2. Convert the mud weight (lb/gal) to psi/ft by:
   15 x 0.052 = 0.7800 psi/ft
3. Solve for pressure gradient (X) of reduced mud weight by:
   (0.7800 - X) 7,000 = 500
   5,460 - 7,000X = 500
   -7,000X = 500 - 5,460 = -4,960
   X = 0.7086 psi/ft
4. Reduced mud weight =
   $$\frac{0.7086}{0.052} = 13.63 \text{ lb/gal}$$
5. Volume of reduced mud weight spot: 7,000 ft x 0.05 bbl/ft = 350 bbl
6. Spot the lighter fluid in the annulus above the stuck zone.

Caution should always be exercised when reducing the differential pressure. If the differential pressure is reduced too much, the well can kick. Contingency plans should be made in advance before attempting these procedures.

DRILL STEM TEST TOOL

Another method used to free differentially stuck pipe by reducing the differential pressure is to use a Drill Stem Test (DST) tool. Although not as widely used as the techniques discussed above, the DST tool is considered to be operationally safe, since the well is kept under strict control while differential pressure is reduced across the stuck zone. The

Caution should always be exercised when reducing the differential pressure.

disadvantages of using this technique are the time involved in mobilizing special DST equipment and personnel, as well as having to back off, run a caliper log (i.e. selecting packer seat) and making a conditioning trip before the operation can be carried out.

This procedure should be carried out only by an experienced technician who understands the entire procedure, appropriate tools and safety procedures. After backing off above the stuck zone, a caliper is run to select a near-gauge zone for setting the packer. An appropriate fishing assembly is run below the packer, and the DST string is filled with a lower-density fluid, depending on the desired reduction in differential pressure. The fishing assembly is attached to the fish, and the packer is set to relieve the hydrostatic pressure. The fish may come free immediately, unseating the packer and causing a sudden increase in hook load. If the packer is unseated, the hydrostatic pressure is once again applied, causing another overbalanced pressure situation. If the fish comes free, the packer should be released and the pipe should be worked up and down immediately.

U-TUBE TECHNIQUE

Another method to free differentially stuck pipe by reducing the differential pressure is to reduce the height of the mud column in the annulus to below the bell nipple. This procedure is referred to as the “U-Tube Technique.” In this procedure, mud is displaced from the annulus by pumping a light fluid (such as diesel oil, water or nitrogen) down the drillstring. After pumping the required volume of low-density fluid, the pressure (and some liquid) is bled off the standpipe. The heavier mud in the annulus is then allowed to “U-Tube” back into the drillstring, resulting in a reduction in the height of the mud in the annulus.

Caution should always be exercised when reducing the differential pressure. In this case, precise calculations should be made to determine the volume of light fluid to pump before allowing the annulus to U-Tube. This procedure should not be attempted with a small-nozzle bit in the hole due to the possibility of plugging the bit. The technique can be performed safely in most situations, provided it has been thoroughly discussed and planned.

Consideration must be given to formation pressures and possible productive zones (gas/oil) above the stuck point, as well as estimated or known formation pressures at the stuck point. If the formation pressure gradient is not known, then an approximate pressure can be determined by multiplying a normal formation gradient (0.47 psi/ft) times the stuck depth. This pressure, subtracted from the mud hydrostatic pressure, will give an approximation of the maximum pressure reduction necessary to free the stuck pipe. The objective of this technique is to free stuck pipe prudently and safely without losing control of the well.

The following procedure is recommended to free differentially stuck pipe if it has been determined that the U-Tube technique can be applied safely and there are no known obstructions inside or outside the drillstring to prevent fluid movement in either direction (see Figure 17):

1. Circulate and condition mud in hole.
2. Determine a maximum safe hydrostatic pressure reduction.
3. Calculate the following:
   a) Total barrels of light fluid to be displaced down the drillstring initially that will ultimately reduce hydrostatic pressure in both the annulus and drillstring on equalization of flowback.
   b) Maximum expected back-pressure on the drill pipe gauge after this volume has been displaced, due

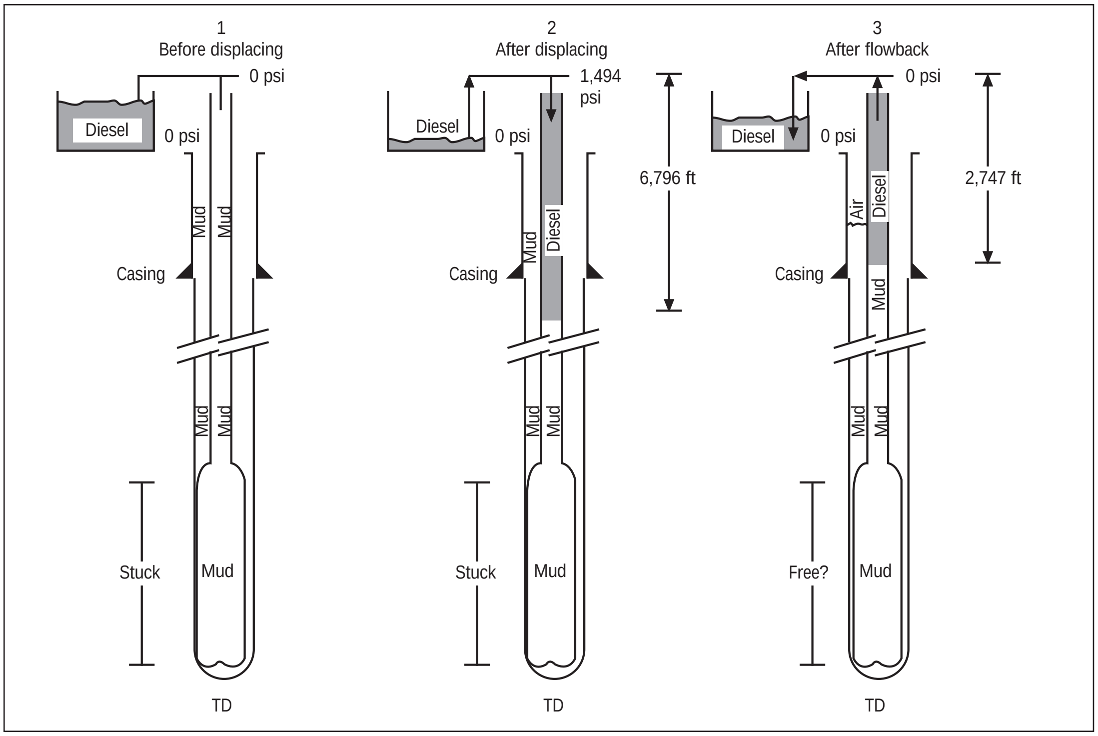


Figure 17: Sequence of U-Tube displacement to free differentially stuck pipe.

to differential pressure between the annulus and drill pipe.

c) Barrels of light fluid to be flowed back to the pits during equalization.

d) Barrels of light fluid to be left in the drillstring after equalization.

e) Fluid level drop (ft) in the annulus after the light fluid and mud in the drillstring and mud in the annulus have equalized.

4. Rig up lines between the drill pipe and the rig floor manifold so the lighter fluid can be displaced with the cementing unit. Also be prepared or rigged up to control the flow-back of light fluid through a choke or valve during equalization.
5. Displace the light fluid slowly down the drill pipe until the total calculated volume has been displaced. Note the back-pressure on the drill pipe gauge at this point.
6. Rig up to back-flow the light fluid.
7. Pull up to the maximum safe tension for the drill pipe and back-flow the fluid from the drill pipe at a controlled rate through the choke or valve. Stop the back-flow periodically and observe the back-pressure on the drill pipe and observe the annulus for any indication of upward fluid movement. If the well is static (i.e. no formation fluid flow), the drill pipe pressure should decline with back-flow. If the well is trying to kick, the drill pipe pressure will either stabilize or increase with back-flow. In the desired situation, the annular fluid level will continue to drop, simulating a vacuum during periods of back-flow. Continued observation of the annulus is very important in case it becomes necessary to abort back-flow operations and implement well-control procedures.
8. Work the pipe and jar on stuck pipe, if possible.
9. If the drillstring does not come free, then:

a) Fill the annulus to the surface with mud, slowly reverse the light fluid from the drill pipe, and circulate one full well volume. Observe the returns to see if any formation fluid (gas/oil) has entered the wellbore.

b) Consider reducing the hydrostatic pressure even further if it is deemed safe to do so, and repeat Steps 1 through 8.

10. If the drillstring comes free, then work the pipe and condition the hole before tripping and/or drilling ahead.

Example (see Figure 17) given:

- Total Vertical Depth (TVD) = 13,636 ft
- Mud weight = 11.0 lb/gal, 11.0 x 0.052 = 0.5720 psi/ft
- Diesel wt = 6.8 lb/gal, 6.8 x 0.052 = 0.3536 psi/ft
- Differential gradient = 0.5720 – 0.3536 = 0.2184 psi/ft
- 9⅝-in. casing at 2,000 ft, Annular volume = 0.0548 bbl/ft
- Capacity of 4½-in. drill pipe = 0.01422 bbl/ft
- Hydrostatic pressure = 0.572 x 13,636 = 7,800 psi

Purpose

Reduce hydrostatic pressure at TD by 600 psi to free stuck pipe.

Procedure

- Reduced hydrostatic pressure: 7,800 – 600 = 7,200 psi
- Length of mud for 7,200 psi: 7,200/0.572 = 12,587 ft
- Mud column reduction for 7,200 psi: 13,636 – 12,587 = 1,049 ft
- Volume of 1,049 ft in annulus: 1,049 x 0.0548 = 57.5 bbl diesel (to be bled off after flow-back)
- Length of diesel to be left in drill pipe to balance annulus at 7,200 psi: 600/0.2184 = 2,747 ft
- Volume of diesel in drill pipe for 600-psi reduction: 2,747 x 0.0142 = 39 bbl
- Total volume of diesel required: 57.5 + 39 = 96.5 bbl
- Total length of diesel in drill pipe: 96.5/0.0142 = 6,796 ft
- Length of 11.0-lb/gal mud in drill pipe: 13,636 – 6,796 = 6,840 ft
- Hydrostatic pressure of diesel: 6,840 x 0.3536 = 2,419 psi
- Hydrostatic pressure of mud: 6,796 x 0.5720 = 3,887 psi
- Hydrostatic pressure in drill pipe: 2,419 + 3,887 = 6,306 psi
- Back pressure on stand pipe w/all diesel in pipe: 7,800 – 6,306 = 1,494 psi
- Bottom-hole pressure after bleed-off:
  - Annulus: 12,587 x 0.572 psi/ft = 7,200 psi
  - Drill pipe: 2,747 x 0.3536 = 971 psi
    10,889 x 0.5720 = 6,229 psi
    971 + 6,229 = 7,200 psi

WASHING OVER PIPE AND SIDETRACKING

If the pipe fails to come free after working and jarring for a reasonable period of time (usually 24 to 48 hr) with a soak solution in the hole, the operator must decide whether to attempt to back off above the stuck point and wash over the stuck pipe, or plug back and sidetrack the hole. Usually, this decision is based on economics. The estimated cost of a successful washover operation is weighed against the cost of replacing the stuck pipe plus the estimated cost of redrilling to the same depth.

Wash pipe is made up of casing and mill with an Outside Diameter (OD) of less than that of the drilled hole, and an Inside Diameter (ID) greater than the largest OD of the fish. Wash pipe is run into the hole on the drill pipe. The amount of wash pipe run at one time depends on the length of the fish to be washed over.

After circulation has been established, the wash pipe is rotated slowly over the fish. Minimum weight should be applied and the amount of binding action observed in order to avoid sticking the wash pipe.

Pipe-Stretch Estimate of Stuck Zone

CAUTION: Use the following procedure only after carefully evaluating the maximum safe tension for the weakest element in the drillstring and working limits of the drilling equipment.

The following procedure for determining the depth of the stuck zone is accurate enough to be used in vertical wellbores. It is based on pulling up on the stuck pipe and measuring the pipe stretch due to the change:

1. Fix a base point for measurement that will not be changed by increased load on the derrick.
2. Attach a lath or strip of paper to the drill pipe so that accurate stretch measurements can be marked from the base point.
3. Pull sufficient tension to overcome the weight of the pipe in the hole. Record the weight-indicator reading and mark this point on the measuring strip as Point A.
4. Pull additional tension on the pipe, and then slack off to the same weight-indicator reading as recorded when marking Point A. Mark the measuring strip at this point as Point B. The difference between the two marks is accounted for by friction in the sheaves and pipe in the hole. Draw a line midway between these points, Point C, and use it as the upper point of measurement.
5. Pull a predetermined safe tension in excess of the pipe weight and mark the pipe stretch and record the weight indicator reading.
6. Repeat Step 5 several times and record the measured pipe stretch in each case.
7. Average these values as "S" for the following equation:

$$\text{Depth} = \frac{735{,}300 \times Wt_{DP} \times S}{\Delta P}$$

Where:

- Depth = Depth of free pipe (ft)
- Wt_{DP} = Weight per foot, drill pipe (lb/ft)
- S = Average pipe stretch (in.)
- ΔP = Differential pull (lb)

This method is for *vertical wellbores*, and is not applicable in highly deviated wells or wells with severe doglegs.

Example:

Drill pipe: 4½-in., 16.60 lb/ft, Grade "G"

String weight: 154,000 lb (buoyed)

1. Pick-up 160,000 lb to overcome buoyed weight of drillstring and mark pipe.
2. Pick-up an additional 40,000 lb to make the pipe stretch a measurable amount.
3. Slack-off and repeat several times, average values and calculate free point.

Average pipe stretch = 39.7 in.

$$\text{Depth} = \frac{735{,}300 \times 16.60 \times 39.7}{40{,}000}$$

$$= 12{,}115 \text{ ft}$$

NOTE: The maximum allowable tension for 4½-in., 16.60 lb/ft, Grade "G" drill pipe is 463,000 lb (no safety factor). The 200,000 lb (160,000 + 40,000) tension used in this example is well below the mechanical limits of the pipe.

Worksheet: Freeing Stuck Pipe

	Stuck Pipe Mechanism (after Amoco TRUE)		
Pipe Motion Prior to Sticking?	**Packoff/ Bridge**	**Differential**	**Wellbore Geometry**
Moving up	2	0	2
Rotating up	0	0	2
Moving down	1	0	2
Rotating down	0	0	2
Static	2	2	0
Pipe Motion After Sticking?			
Down free	0	0	2
Down restricted	1	0	2
Down impossible	0	0	0
Pipe Rotation After Sticking?			
Rotate free	0	0	2
Rotate restricted	2	0	2
Rotate impossible	0	0	0
Circ. Pressure After Sticking?			
Circulation free	0	2	2
Circulation restricted	2	0	0
Circulation impossible	2	0	0
Totals			

Instructions:

Answer the shaded questions by circling all the numbers in the row with the correct answer.

Add the columns.

The column with the highest number indicates the most likely sticking mechanism. See freeing action tables on next page.

ing Wellbore Geometry

action:

- king occurred while mov-
p, apply torque and jar
N with max. trip load.
- king occurred while mov-
own, do not apply torque
ar UP with max. trip load.
- reduce circulation when
g the jar and when jarring

*Pump pressure will
ASE the hydraulic jar
, and DECREASE the
low.*

- nue jarring until the string
e or an alternative decision
de. Jarring for 10+ hours
be necessary.

ary action:

- id if stuck in limestone
k. Spot fresh water with
salt.

the string comes free:

- ase circulation to max. rate,
e and work the string.
- /back ream the hole
n thoroughly.
- late the hole clean.

Freeing Packoff/Bridge	
Stuck while *moving up* or with string *static*	**Stuck while *moving down***
Action to establish circulation: • Apply low pump pressure (200 to 400) psi. Maintain pressure if restricted circulation is possible. • DO NOT JAR UP!! APPLY TORQUE!!! Slack-off to MAXIMUM set down weight. Allow sufficient time for a hydraulic jar to trip (4 to 6 min for long cycle, see jar manual). • If the string does not come free, DO NOT JAR UP!!! Jar DOWN until the string comes free or an alternative decision is made. Jarring down for 10+ hours may be necessary.	***Action to establish circulation:*** • Apply low pump pressure (200 400) psi. Maintain pressure if restricted circulation is possible. • DO NOT JAR DOWN!!! APPLY TORQUE!!! Apply MAXIMUM overpull to jar. Allow sufficient time for a hydraulic jar to trip (4 to 8 min for long cycle, see jar manual). • If the string does not come free, DO NOT JAR DOWN!!! Jar up until the string is free or an alternative decision is made. Jarring up for 10+ hours may be required.
When circulation is established: • Slowly increase pump speed to max. rate. When possible, work the string and circulate the hole clean from bit depth. • Ream the section until the hole is clean. • If POOH to log and/or run casing, return to bottom and circulate the hole clean.	***When circulation is established:*** • Slowly increase pump speed to max. rate. When possible, work the string and circulate the hole clean from bit depth. • Ream the section until the hole is clean. • Continue RIH, staging-in and circulating bottoms up. If excessive set down weight is observed, stop and circulate the hole clean. Ream as needed.

Freeing Different

Initial action:

- Circulate at norm
- Work MAXIMUM
down to the stuck
hold the torque in
- Stop or reduce pu
minimum.
- Slack-off MAX. se
- Allow sufficient tim
lic jar to trip (4 to
cycle, see jar manu
- If the string does
hold torque in the
continue jarring d
max. trip load.
- If the string does
after 5 to 10 jars b
jarring while prep
releasing pill.

Secondary action:

- Mix and spot a Pı
solution as soon a

When the string is

- Rotate and work t
- Circulate to clean
- Condition mud to
appropriate prope

(After Amoco TRUE.)

l Cuttings	Shale Instability	Unconsolidated, Fractured Formation	Cement (Blocks or Soft)	Junk in Hole
o fast e annular rheology ccumulation h time nd without thout	- Drilling reactive shale with non-inhibitive mud - Drilling pressured shale with insufficient mud weight	- Drilling uncemented formation - Little or no filter cake - Drilling naturally fractured formation	- Cement blocks fall from around casing shoe, squeeze plugs or sidetrack plugs - Attempt to circulate while the drillstring is immersed in soft cement (flash set)	- Accidental junk falli in hole - Downhole equipme failure
with poor turn torque, drag pressure n connection tripping tom after n and trips n restricted LGS and nt	- Increase in FV, PV, YP, gels and CEC - Increase in torque, drag and pump pressure - Overpull on connection and when tripping - Bit and BHA balling - Pore pressure increase - Fill on connection and after trips - Large cavings at shakers - Circulation restricted	- Solids-control equipment loaded with sand and cuttings - Seepage losses - Fill on connections and after tripping - Sudden increase in torque and drag - Circulation restricted - Large caving at shakers	- Excessive casing rathole - Increase in torque and drag - Circulation restricted - Restricted pipe movement	- May occur any time - Metal parts at the sh - Partial motion is po
d rheology num GPM ce OP if needed eps to clean after s illstring onger	- Use inhibitive mud - Increase the mud weight - Minimize open hole exposure time - Use sweeps to clean the hole - Increase mud rheology	- Provide good filter-cake quality - Use appropriate bridging materials - Avoid excessive circulating time - Use sweeps to keep the hole clean - Increase mud rheology	- Limit casing rathole - Allow sufficient time for cement to set - Reduce tripping speed opposite cement section - Calculate top of cement and start circulate two stands above - Control drilling in soft cement	- Use good practices - Keep hole covered - Check downhole to on regular basis

(After Amoco TRUE.)

ating	Undergauge Hole	Stiff Assembly	Mobile Formation	Doglegs and Ledges	Collapsed Ca
vears a key- formation ciated with s jam into groove of	- RIH with a full-gauge bit and BHA in an undergauge hole	- BHA change from limber to stiff cannot tolerate changes in angle and direction	- Drilling plastic salt or shale formation	- Drilling hard/soft interbedded formation - Frequent change in hole angle/direction - Drilling fractured/ faulted formation - High dip angles	- External forma pressure (often opposite plastic formation) exc casing strength - Failed cement
leg section ng at the for eriod	- Undergauge bit pulled out - Tight hole - Sudden loss of string weight	- New BHA is run in hole - Presence of doglegs - Sudden loss of string weight - Tight hole	- Increase in torque and drag - Overpull when tripping out of hole	- Overpull on connec- tions and trips - Increase in torque and drag	- Drilling plastic formation - Cement chunk - Lost circulation - Tight hole inside casing
 erity /ream tions t wiper	- Gauge old and new bits - Ream last three joints at least to bottom - Never force bit through tight spots, ream	- Minimize BHA changes - Limit dogleg severity - Plan a reaming trip if a stiff BHA will be used	- Maintain sufficient mud weight - Select the proper mud system - Frequent reaming/ tripping - Use eccentric bit - Minimize open hole exposure time	- Minimize sharp and frequent wellbore course changes - Avoid prolonged circulation opposite soft formation - Minimize BHA changes	- Use proper casi strength oppos plastic formatio

	Differentially Stuck	
static pressure exceeds pressure	- Porous, permeable formation - High fluid loss	- Thick, poor quality filter cake - Pipe stationary too long
n is not restricted when stuck torque and drag	- Drilling with high overbalance - Poor filtration properties	- Overpull opposite porous formation - Hole sticky on connection
overbalance wnhole filtration time pipe is stationary	- Minimize area of contact by using heavy-weight drill pipe and spiral collars - Maintain optimum hydraulics - Proper casing design	- Improve filter-cake quality - Minimize coefficient of friction, use lub - Use proper bridging agents - Minimize drill solids content