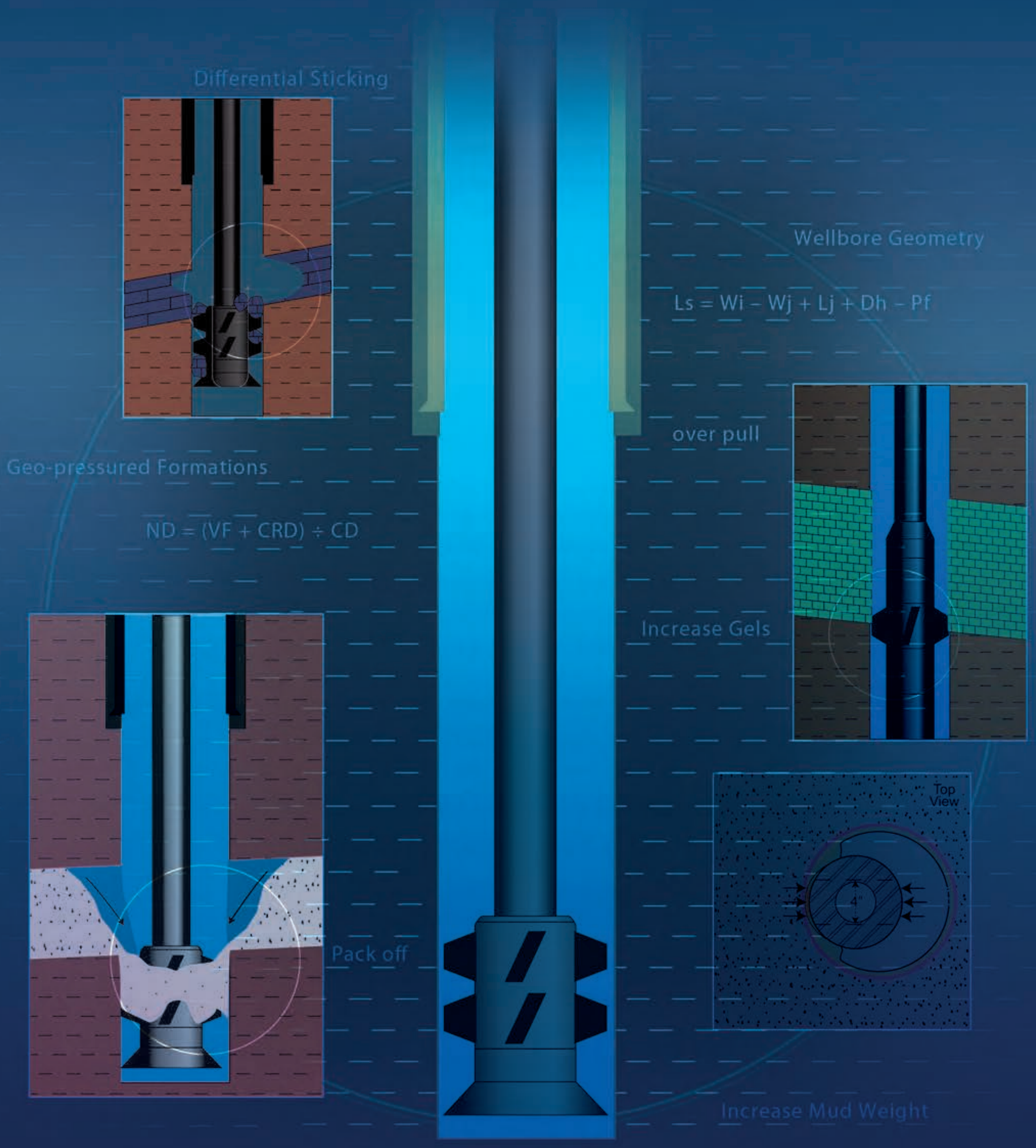
WELL CONTROL SCHOOL

STUCK PIPE PREVENTION



Stuck Pipe Prevention

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Revised November 2015
Printed 2008, 2015
Printed in the United States of America

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WCS MAN-013 REVISION 2

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Abbreviations and Acronymns

API	American Petroleum Institute
APL	annular pressure loss
AFPL	annual friction pressure loss
A	area
bbl.	barrel(s)
bbl./ft.	barrel(s) per foot
bbl./in.	barrel(s) per inch
bbl./stk.	barrel(s) per stroke
BOP	blowout preventer
BHA	bottomhole assembly
BP	bottomhole pressure
bhp	brake horsepower
BTU	British thermal unit
BF	buoyant force
CP	circulating pressure
CR	closing ratio (BOP)
CT	coiled tubing
Z	compressibility factor
CTL_S	CT length - swivel to gooseneck
CTL_T	CT length - total
CTL_W	CT length in well
cu.	cubic
cm^3	cubic centimeter (in scientific context)
cc	cubic centimeter (in clinical context)
°C	degree Celcius
°F	degree Fahrenheit
° R	degree Rankine
D	diameter
Δ	delta "p" or differential (usually pressure)
d./day	day
ECD	equivalent circulating density
ESFD	equivalent static fluid density
FSW	field salt water
FCP	final circulating pressure
FMSP	final maximum static pressure
ft.	foot/feet
FI	formation integrity
FIT	formation integrity test
FP	formation pressure
F	force
fp	freezing point
FPL	friction pressure loss
gal.	gallon(s)
GOR	gas-to-oil ratio
h./hr.	hour
hrs.	hours
hp	horsepower
H_2S	hydrogen sulfide
HP	hydrostatic pressure
in.	inch(es)
ICP	initial circulating pressure
IMSP	initial maximum static pressure
ID	inside diamter
ISIP	instant shut-in pressure
K	Kelvin
KMW	kill mud weight
l	length
L	liter
max.	maximum
MASP	maximum allowable surface pressure
MD	measured depth
MPa	megapascal
mp	melting point
m	meter
min.	minimum
mo.	month
MHA	motor-head assembly
MW	mud weight
Ω	ohm
OD	outside diameter
ppb	parts per billion
ppm	parts per million
p	pascal
∏	pi
PBTD	plug back total depth
lb.	pound(s)
lb./ft.	pound(s) per foot
ppf	pound(s) per foot

ppg	pounds per gallon
psi	pounds per square inch
PKCP	pre-kill circulating pressure
PMW	present mud weight
P	pressure
psi/bbl.	psi per barrel
psi/ft.	psi per foot
Gradient	psi/foot or psi/ft.
RP	reservoir pressure
RBP	retrievable bridge plug
rpm	revolutions per minute
sx	sacks
SM	safety margin
sec.	second
secs.	seconds
SIAP	shut-in annulus pressure
SICP	shut-in casing pressure
SICTP	shut-in coiled tubing pressure
SIDPP	shut-in drill pipe pressure
SITP	shut-in tubing pressure
SIWHP	shut-in wellhead pressure
∑	sigma or ("sum of')
SCR	slow circulating rate
sq.	square
sq. ft.	square foot/feet
sq. in.	square inch
stk	stroke
spm	strokes per minute
T	temperature
temp.	temperature
TD	total depth
TMD	true measured depth
TVD	true vertical depth
V	volume
wt.	weight
WCS	Well Control School
w	width
WP	working pressure
yr.	year
yrs.	years
YP	yield point

Chemical Elements

Ac	actinium
Al	aluminum (US)
	aluminium (IUPAC)
Am	americium
Sb	antimony (stibium)
Ar	argon
As	arsenic
At	astatine
Ba	barium
Bk	berkelium
Be	beryllium
Bi	bismuth
Bh	bohrium
B	boron
Br	bromine
Cd	cadmium
Ca	calcium
Cf	californium
C	carbon
Ce	cerium
Cs	cesium
Cl	chlorine
Cr	chromium
Co	cobalt
Cu	copper
Cm	curium
Ds	darmstadtium
Db	dubnium
Dy	dysprosium
Es	einsteinium
Er	erbium
Eu	europium
Fm	fermium
F	fluorine
Fr	francium
Gd	gadolinium
Ga	gallium
Ge	germanium
Au	gold (aurum)
Hf	hafnium
Hs	hassium
He	helium
Ho	holmium
H	hydrogen
In	indium
I	iodine
Ir	iridium
Fe	iron (ferrum)
Kr	krypton
La	lanthanum
Lr	lawrencium
Pb	lead (plumbum)
Li	lithium
Lu	lutetium
Mg	magnesium
Mn	manganese
Mt	meitnerium
Md	mendelevium
Hg	mercury (hydrargyrum)
Mo	molybdenum
Nd	neodymium
Ne	neon
Np	neptunium
Ni	nickel
N	nitrogen
No	nobelium
Os	osmium
O	oxygen
Pd	palladium
P	phosphorus
Pt	platinum
Pu	plutonium
Po	polonium
K	potassium (kalium)
Pr	praseodymium
Pm	promethium
Pa	protactinium
Ra	radium
Rn	radon
Re	rhenium
Rh	rhodium
Rg	roentgenium
Rb	rubidium
Ru	ruthenium
Rf	rutherfordium
Sm	samarium
Sc	scandium
Sg	seaborgium
Se	selenium
Si	silicon
Ag	silver (argentum)
Na	sodium (natrium)
Sr	strontium
S	sulfur
Ta	tantalum
Tc	technetium
Te	tellurium
Tb	terbium
Tl	thallium
Th	thorium
Tm	thulium
Sn	tin (stannum)
Ti	titanium
W	tungsten (wolfram)
Uub	ununbium
Uuh	ununhexium
Uuo	ununoctium
Uup	ununpentium
Uuq	ununquadium
Uus	ununseptium
Uut	ununtrium
U	uranium
V	vandium
Xe	xenon
Yb	ytterbium
Y	yttrium
Zn	zinc
Zr	zirconium

Introduction

Stuck pipe is the inability to move a work string into or out of a well. Worldwide, it is the most common cause of downtime in drilling and workover operations today. Statistics indicate that it is also one of the most costly events that can occur during rig operations. Once the pipe is stuck, the cost of getting unstuck and back on track can exceed the amount budgeted for the entire operation. If the decision is made to back off, or if the string is parted, there is usually less than a 50% chance of getting the fish out of the hole. Time and money are not the only cost. Crew morale sags when problems occur and nobody does their best when morale is low.

Statistical data from operations conducted in the Gulf of Mexico and in the North Sea reveal some striking similarities. For example, it is interesting to note that statistics for one major operator in the Gulf of Mexico indicate that most stuck pipe incidents (68%), occurred on crew change day, within about 2 hours of the fresh crew coming to work.

In both the Gulf and the North Sea stuck pipe incidents were on the increase throughout the 1990s until training programs were established. After the companies began to emphasize stuck pipe training, there was a noticeable reduction in these incidents. This was the case even though the areas of operation are vastly different and the specific drilling problems, including stuck pipe, vary widely. Today the incidents in both areas are on the rise again. Demand for rigs and crews is steadily increasing and the inexperience of crews is showing up in the number of stuck pipe incidents.

Most cases of stuck pipe are avoidable; therefore the most important factor in preventing stuck pipe is a well trained rig crew that understands how and why a drillstring gets stuck. A trained crew recognizes the warning signs and communicates with their supervisors. A formal stuck pipe prevention plan creates a sense of interdependency and teamwork among all rig personnel, whatever their job position. There is abundant proof that a rig crew that has been trained to work together as a team, a team that shares information up and down the chain of command, can often avoid stuck pipe situations.

Causes of Stuck Pipe

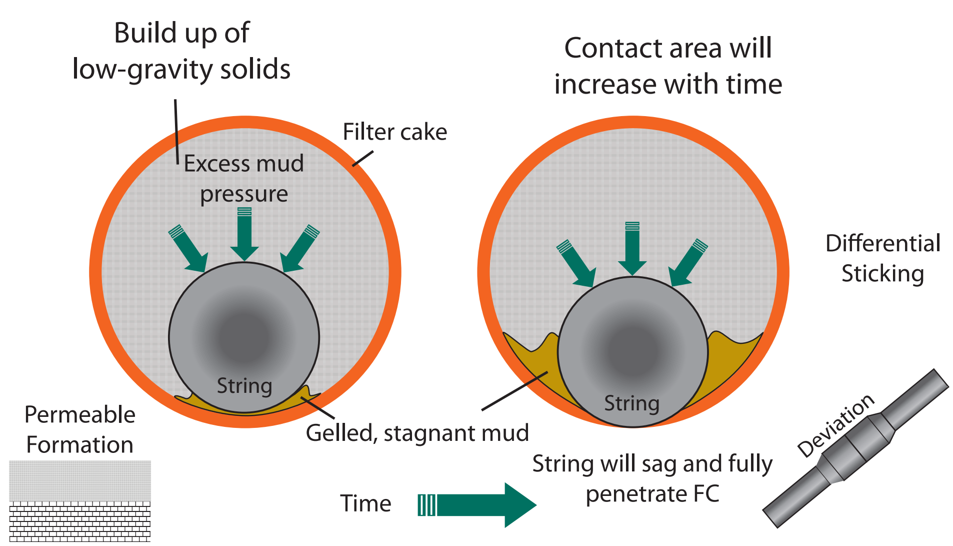
1

Although there are many individual situations in which a workstring may become stuck in a well, there are three main causes:

- Differential sticking, sometimes called wall-sticking
- Sticking as a result of, or related to, the drilled formation
- Mechanical sticking

Differential Sticking

Differential sticking, as the name implies, is a result of the difference between the hydrostatic pressure exerted by the working fluid and the formation pressure. The solids content of the fluid, the fluid density, wall cake thickness and quality, formation permeability, the length and components of the bottomhole assembly (BHA) and hole inclination all contribute to the likelihood of differential sticking. In a permeable formation, especially sandstone, the liquid phase of the fluid enters the formation depositing solids on the wall of the hole. The greater this water loss, the thicker and softer the wall cake deposit. The portion of the BHA that lies on the low side of the hole can become embedded into the soft wall cake. If the hydrostatic pressure of the fluid is greater than the formation pressure, the net force exerted on each square inch of the embedded BHA can be tremendous and no practical amount of vertical pull will free the string and it cannot be rotated although full circulation is still possible. It is unlikely that the string will stick differentially when it is in motion, so experienced drillers keep connection times to a minimum and keep the pipe moving whenever possible.



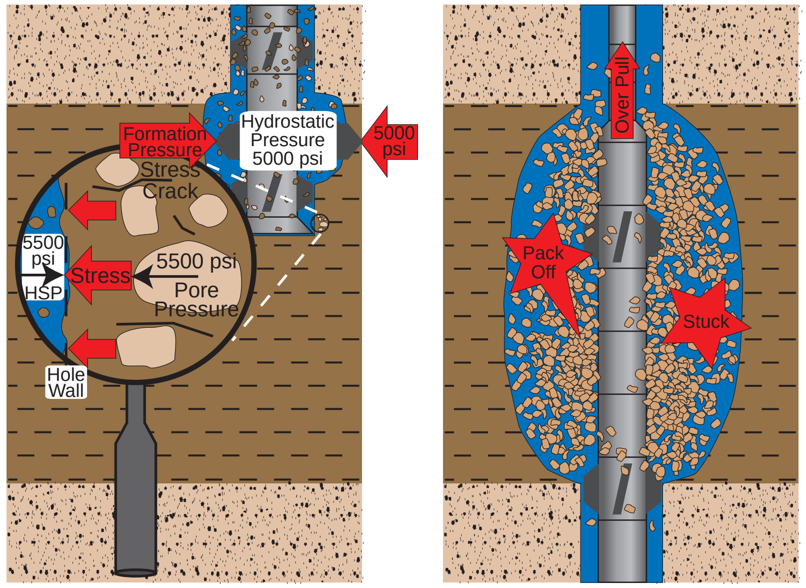
Formation-Related Sticking

Formation-related sticking refers to the several ways in which the drilled formation can contribute to pipe sticking problems. Five of these are discussed on the following pages.

1. Geopressured Sticking

When drilling an impermeable formation like shale, pieces of the rock can be forced into the wellbore if the formation pressure is greater than the hydrostatic pressure exerted by the working fluid. This condition is referred to as overpressured or *geopressured*. As the cavings build up around the work string, especially around the BHA, the string can become stuck.

Geo-Pressured Sticking

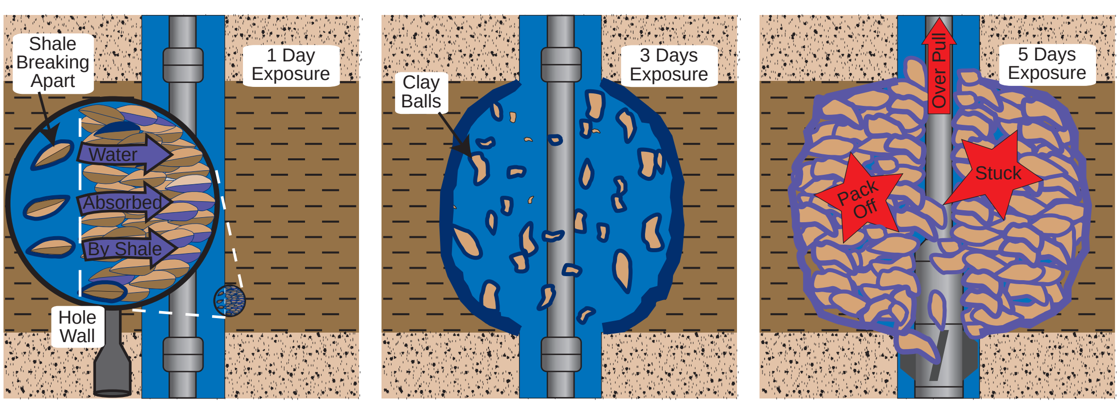


2. Reactive Formations

Some formations react to the liquid phase of the working fluid causing the formation to hydrate, or "swell". When this happens, some sections of the hole will be undergauge. These bentonitic, swelling clays, called *gumbo*, are common in offshore drilling, especially at shallow depths. The soft, hydrated clay not only reduces the wellbore diameter, but can also cling to the bit, the BHA, and the drill pipe, thus increasing the potential for stuck pipe. The bit and string is said to be "balled up".

Reactive Formations

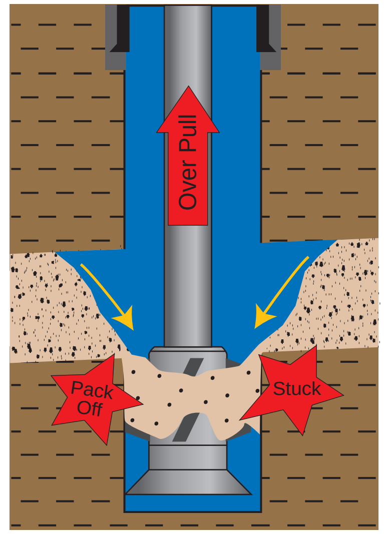
Reactive Formations



3. Unconsolidated Formations

Some formations, for example, unconsolidated sandstone or gravel can collapse around the work string. When this happens a packed-off section or a bridge is formed. If the pack-off is severe, it may be impossible to pull the work string out of the bridge.

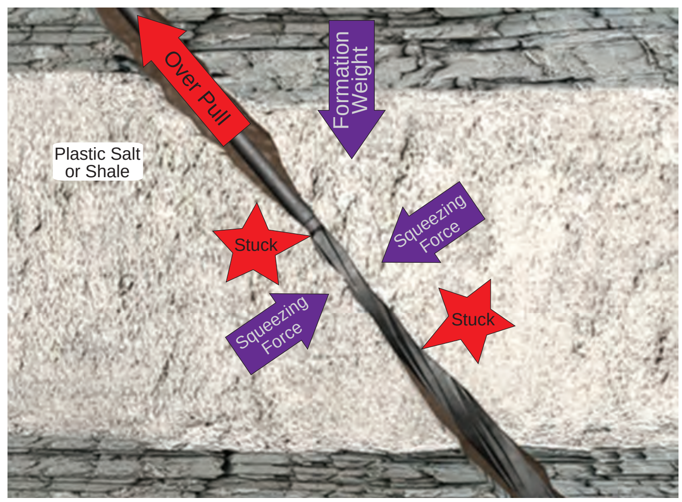
Unconsolidated Formations



4. Plastic Formations

Various salt formations and some shale formations are referred to as being plastic. That is, they will move or "flow" into a wellbore when it is drilled and the restraining force is removed. The work string can become stuck in these formations as it is trapped by the decreased diameter of the hole.

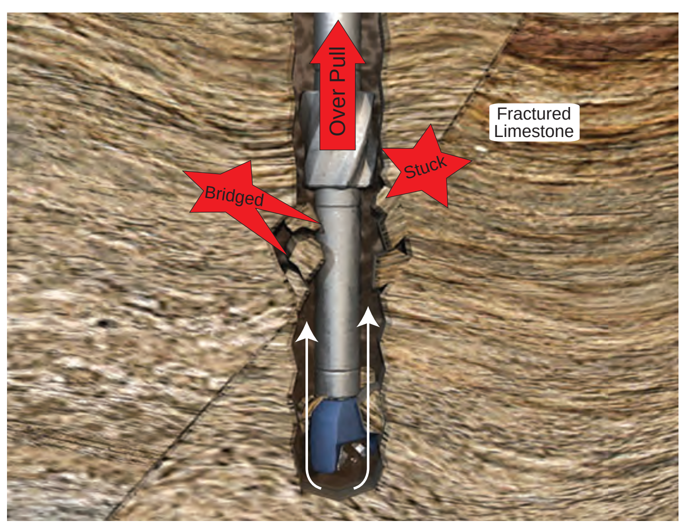
Plastic Formations



5. Fractured Formations

Pieces of naturally fractured formations, especially limestone and shale formations that are in or near a fault zone, can break off and cause a work string to be jammed and then eventually stuck in a wellbore.

Fractured Formations



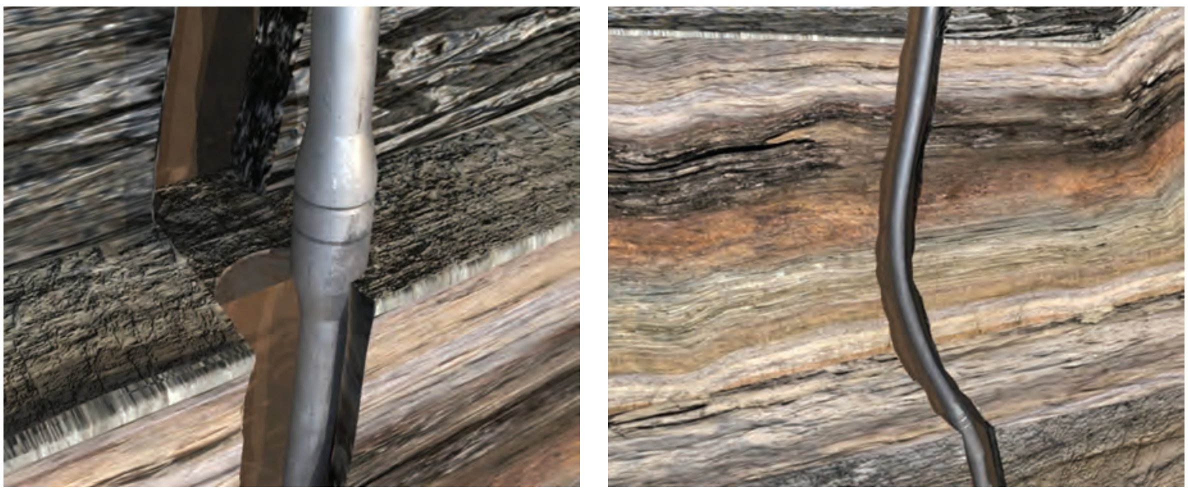
Mechanical Sticking

Mechanical sticking is man-made, that is, it is a result of drilling practices employed when drilling a well. Seven of the many specific causes of mechanical sticking are discussed below.

1. Keyseats

A keyseat is an undergauge groove cut into the side of the wellbore that runs parallel to the axis of the hole. It is caused by rotating the string on a sharp bend in the wellbore. When a tooljoint or the BHA is pulled up into the keyseat, the work string can become stuck since the keyseat groove has been worn by the smaller body of the drill pipe.

Keyseats

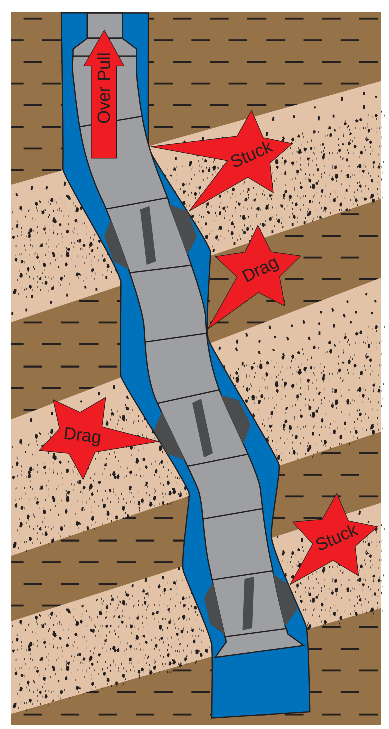


2. Wellbore Geometry

Sudden large changes in wellbore inclination are called *doglegs*. When running into a well the work string is in compression and is fairly flexible. However, when the string is pulled out it is in tension, and therefore, less flexible. It may be difficult to pull stiff bottomhole assemblies through the sharp doglegs. Dogleg severity is a consideration in all directional wells.

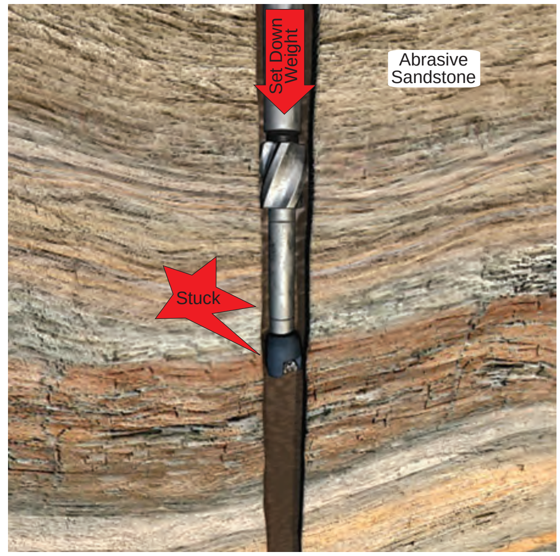
Wellbore Geometry

Doglegs



Also, when drilling through formation changes, that is, from a hard formation to a softer formation or vice versa, ledges can be formed. The ledges created by the washout either side of the hard formations, can cause the work string to hang up on the ledges of harder rock.

Undergauge Hole

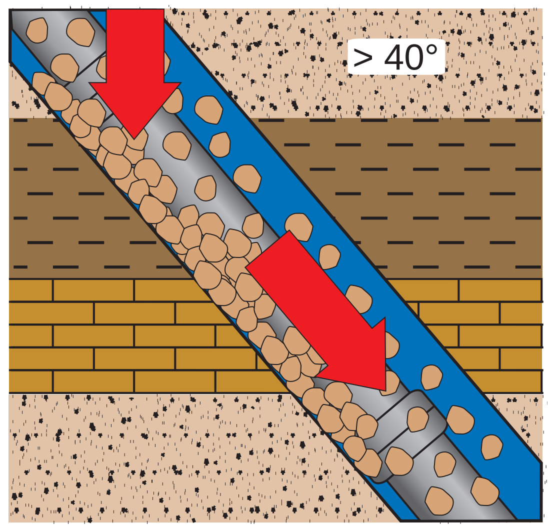


3. Undergauge Hole

Drilling long sections in an abrasive formation can result in effectively wearing the gauge protection off a bit. This may not present a problem when the string is pulled from the well, however when a new bit is run into the well, care must be taken not to jam the new bit into the undergauge section.

4. Inadequate Hole Cleaning

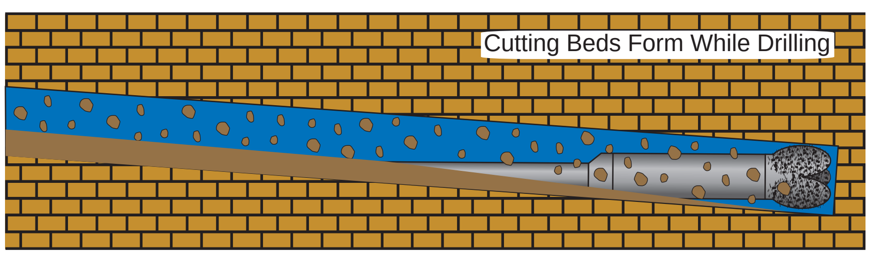
Inadequate Cleaning

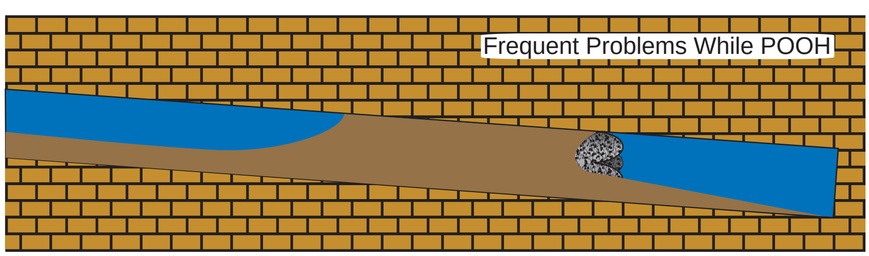


There are many factors that determine the efficiency of removing cuttings as a well is being drilled. Some of the factors that must be considered when designing the drilling program are fluid properties in the various sections of the well, hole inclination, and the various formations to be penetrated. The carrying capacity of the working fluid is estimated by considering a combination of two separate things: the viscosity of the fluid and the annular velocity (the rate at which the fluid is moving up the annulus). Both considerations are complex.

There is no one true viscosity that can be applied to most drilling fluids. The viscosity of shear thinning fluids varies as it moves up the annulus. Generally speaking we can say that the faster the fluid moves, the lower the viscosity of fluid. Also, the annular velocity of the fluid is variable because of changes in the wellbore diameter.

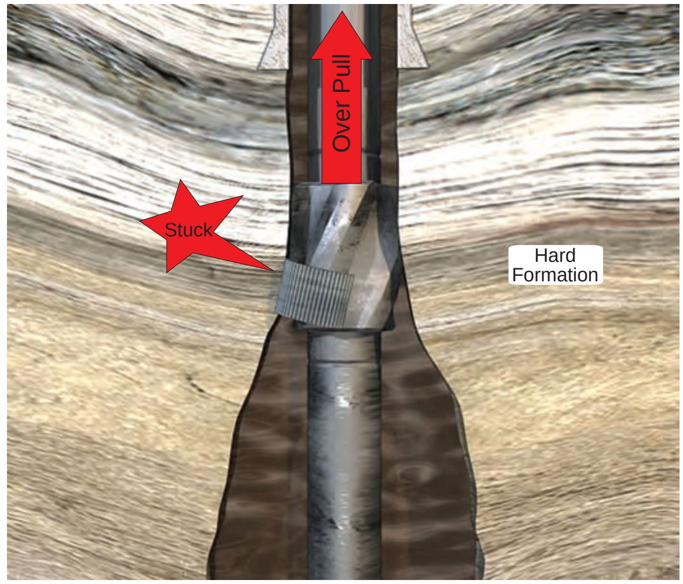
For example, at a constant pump rate the cuttings would move upward much faster in the small space around the BHA than in the larger annular space inside the surface casing.





In directional wells, cuttings may build up on the low side of the hole. Also, the workstring, lying on the low side of the hole, prevents good circulation around the string. In certain wells the cutting beds may move up the hole and form hills like sand dunes. Obviously the formation characteristics and the size and shape of the bit cuttings influence this "dune effect". Inadequate hole cleaning eventually results in increased drag and rotary torque, all warnings of potential pipe sticking problems.

Junk



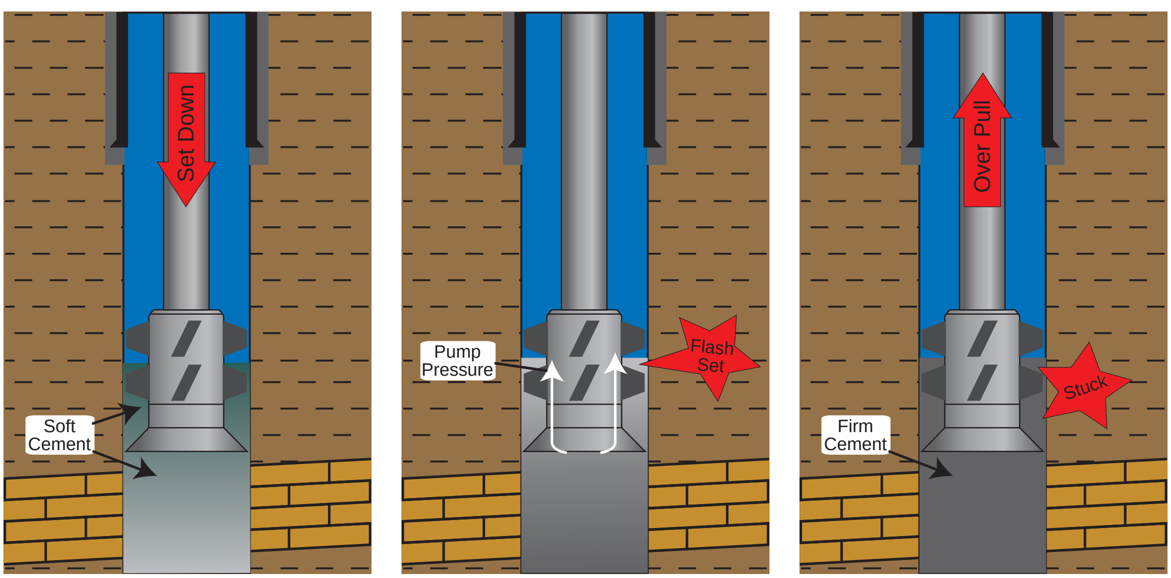
5. Junk

Junk may be defined as any metal debris that has fallen into a well. Downhole clearances are often very close. For example, the clearance between 8½-inch drill collars and 9⅝-inch, 47 ppf casing is barely more than an inch. The drill string may become stuck if it "hangs up" on a piece of junk.

6. Cement Problems

Sometime chunks of hardened cement in the vicinity of a casing seat can break off and fall downhole. When this happens, the effect is the same as junk in the well. Also, it is possible that the string is run into soft (green) cement. It is not always easy for the driller to recognize the soft cement when the pipe is lowered into it. Later, when pressure is applied, the cement can "flash set", resulting in stuck pipe.

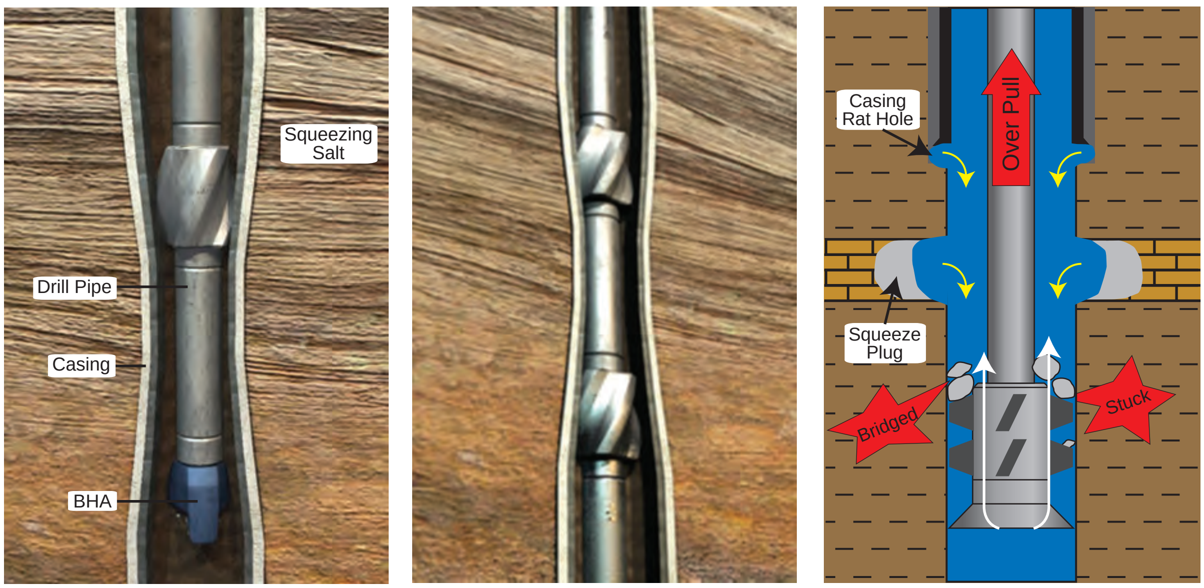
Cement Problems



7. Collapsed Casing

When the formation pressure exceeds the casing collapse pressure rating, the inside diameter of the casing will be reduced. When this occurs the pipe may become stuck if run in fast enough to jam it into the casing, or when pulling out of the hole, if the string is pulled too far into the collapsed section.

Collapsed Casing



NOTES

Identifying Stuck Pipe Mechanisms

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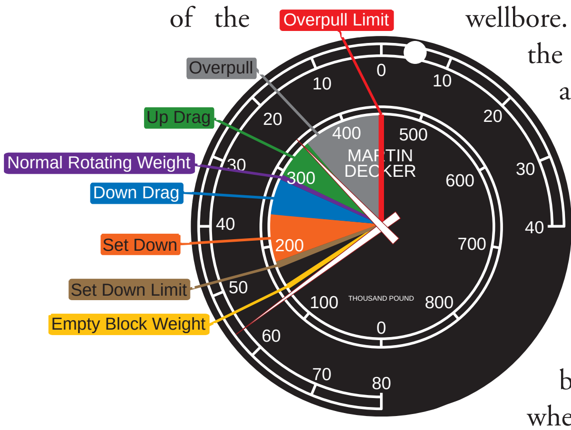
It can be said that the work string is not stuck in a well so long as it is possible to move the pipe up or down. Before the pipe is actually stuck there are almost always rig floor indicators that can be observed by experienced personnel. Once the potential for stuck pipe is recognized and identified, preventive action can be taken. The three basic types, or mechanisms, of stuck pipe were discussed in Section I. These mechanisms are differential sticking, formation related sticking, and mechanical sticking. Each of the mechanisms exhibits certain characteristics that can be used to help identify a developing stuck pipe incident.

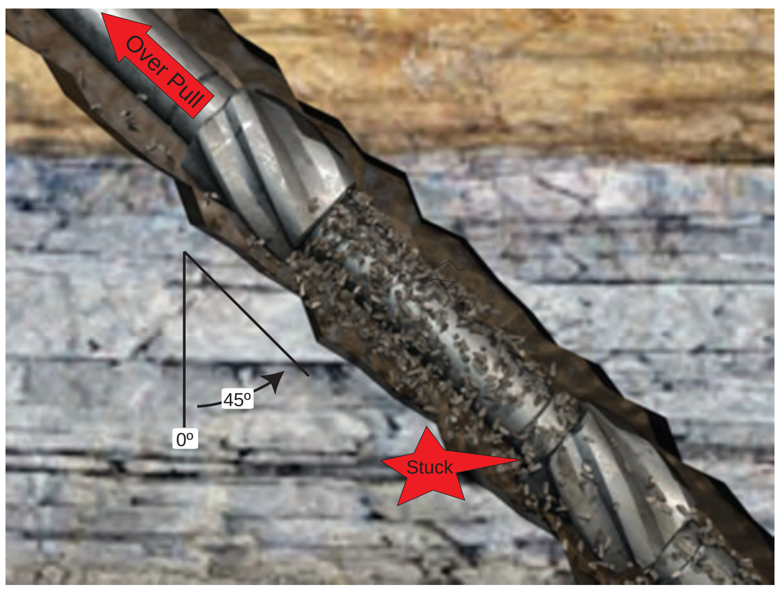
Most stuck pipe problems are preventable if the operator and the contractor make stuck pipe prevention a priority before a well is drilled. It all begins with the well program itself. Obviously pertinent geological data and field history are considered when a well is designed. The types of formations to be penetrated and the anticipated formation pressures are always predicted. Each well interval can be analyzed from the standpoint of stuck pipe prevention. An alert driller who is properly trained in stuck pipe prevention can save a well. Nowadays, sophisticated downhole tools may be run in the work string. These tools can relay drilling data to the surface in real time but the data does little good if it is not properly interpreted and appropriate action is not taken.

In most drilling operations a driller is given instructions to achieve optimum rates of penetration (ROP). These include the weight to be run on the bit (WOB), rotary rpm, and the circulating pump pressure (or pumping rate). The idea is that if these parameters are maintained within certain tolerances an experienced driller is able to "feel the hole" as drilling progresses. When there are significant changes in downhole conditions, some, or all of the indications observed on the surface will change. In this way developing stuck pipe incidents can often be recognized.

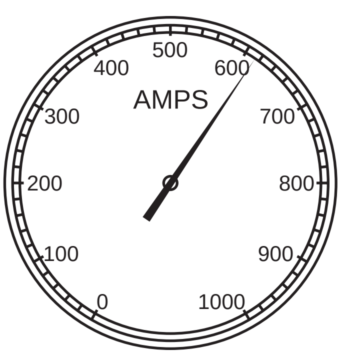
When the drill string hangs in a vertical well the driller's weight indicator displays the buoyed weight of the string suspended in the fluid. As the driller touches bottom and then slacks off to allow the predetermined weight with which to drill, the indicator reflects the change. The actual weight displayed may vary depending on the true hookload. It can be seen that in a directional well some of the weight may be resting on the low side of the wellbore. However much the displayed weight may be, when the driller lifts the string, as when making a connection, there will always be a certain amount of overpull, or drag, as the string is lifted. In other words, the weight indicator briefly displays some weight greater than the actual hookload. Under normal conditions, the overpull will drop off as the bit clears the new, gauge hole. Although the total string weight increases as a vertical well is deepened and more drill pipe added to the string, the overpull should remain approximately the same provided that downhole conditions have not changed. There may be some gradual increase in overpull in directional wells, but the increases should be nearly constant. Changes in overpull, whether sudden or gradual, should alert the driller to some changing condition downhole.



Sometimes the driller finds increasing fill on bottom after making a connection and especially after making a routine round trip. Although fill is not necessarily directly related to increases in overpull, many times it is a signal that something is amiss downhole.

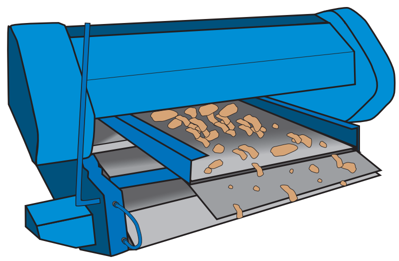


Once the rotary is engaged and the correct weight is applied to the bit the rotary torque developed is displayed to the driller. Depending on the rig, torque may be measured in the electrical current (amperage) drawn by the rotary motor or expressed as work, e.g., foot-pounds. In any case the torque readout should remain relatively stable at a constant rotation rate (rate per minute or rpm) once the weight on bit is stabilized and the fluid circulation rate is established. Sudden or erratic fluctuations in rotary torque indicate that the rotating drill string is encountering increased resistance for some reason. Often increases in torque while rotating and increased overpull on connections warn of impending pipe sticking problems.



Drilling rigs use positive displacement pumps, that is, a specific amount of liquid is displaced for each pump stroke. If the strokes per minute (spm) do not change, then the rate of return flow at the shale shaker should remain constant. Also, the pressure drop in the system, which is a result of friction, should remain approximately the

Shale Shaker



Cuttings   Cavings

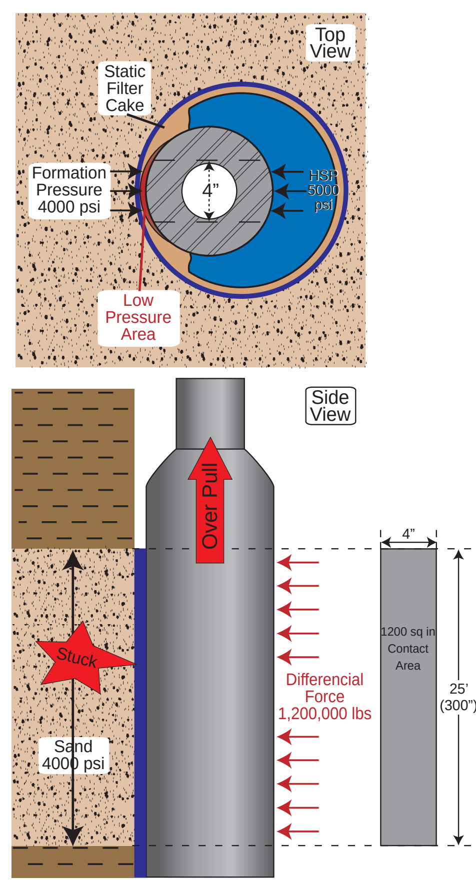
same. It is true that as drilling continues and more pipe is added to the workstring, friction increases slightly but this increase is gradual and does not radically change the pressure observed on the standpipe gauge. Sudden or erratic changes in pump pressure may be caused by changes downhole. Experienced drillers note these changes and try to determine the cause.

Careful observation of the return flow at the shale shakers can often yield important information about changing downhole conditions. Changes in fluid density (mud weight) and funnel viscosity, the size, shape, and volume of bit cuttings as well as the changes in return flow, are all good clues as to downhole conditions.

Taken alone, none of the common symptoms of developing "hole trouble" discussed previously are necessarily indicative of stuck pipe. However careful observation and analysis of these warning signs may help identify some of the conditions for the various stuck pipe mechanisms. Common symptoms for each mechanism are listed on the following pages.

Conditions and Warning Signs of Differential Sticking

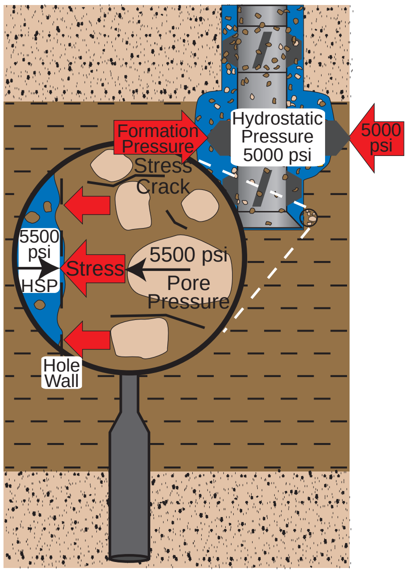
- The hydrostatic pressure of the working fluid (mud weight) is significantly greater than the anticipated formation pressure
- The BHA is across a permeable formation e.g., sandstone
- Drag (overpull) is increasing after connections
- Rotary torque is increasing
- Circulating pressure is not affected
- The string begins to stick any time it is stationary
- Decrease in overpull after reaming

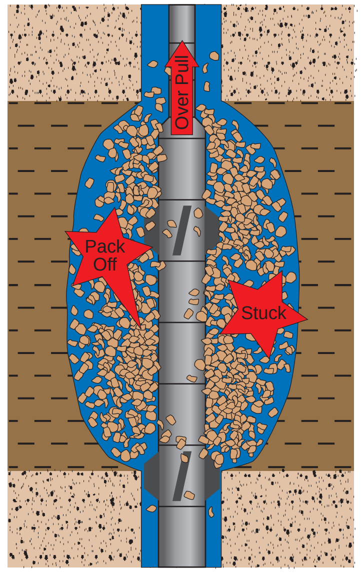


Conditions and Warning Signs of Formation-Related Sticking

1. Geopressured Sticking

- Large, brittle cuttings at the shale shaker
- High drag (overpull) on connections
- Restricted returns
- Increase in pump pressure
- Increased rotary torque
- Pipe sticks shortly after pumps are shut down

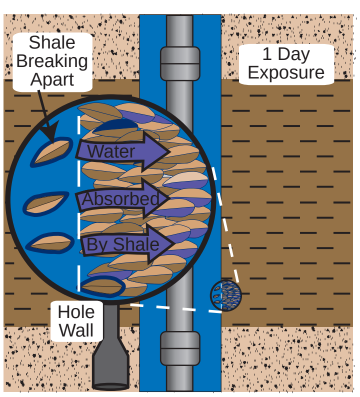


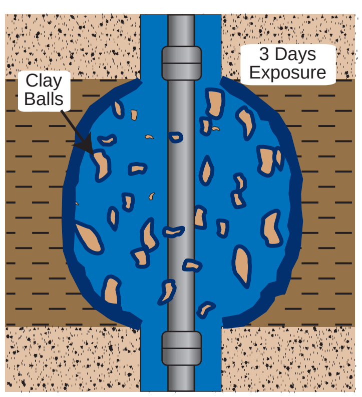


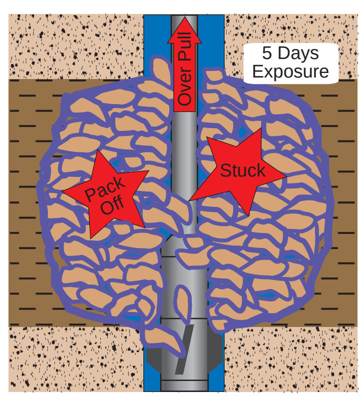
2. Reactive Formations

- Large clumps of clay (gumbo) at the shale shaker
- ROP slows due to less weight on bit
- BHA packed off with balled clay
- Increased pump pressure
- Increased rotary torque due to reduced annular diameter
- Circulation is not possible
- Increase in drag (overpull)

Reactive Formations



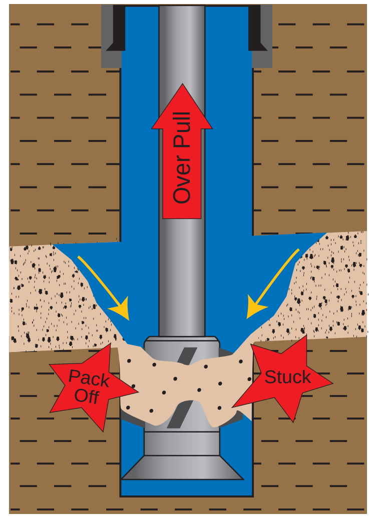




3. Unconsolidated Formations

- High drag (overpull) on connections
- Increased pump pressure
- Unconsolidated, un-cemented sands in the cuttings
- When stuck, circulation is not possible
- Pipe sticks shortly after pump is shut down

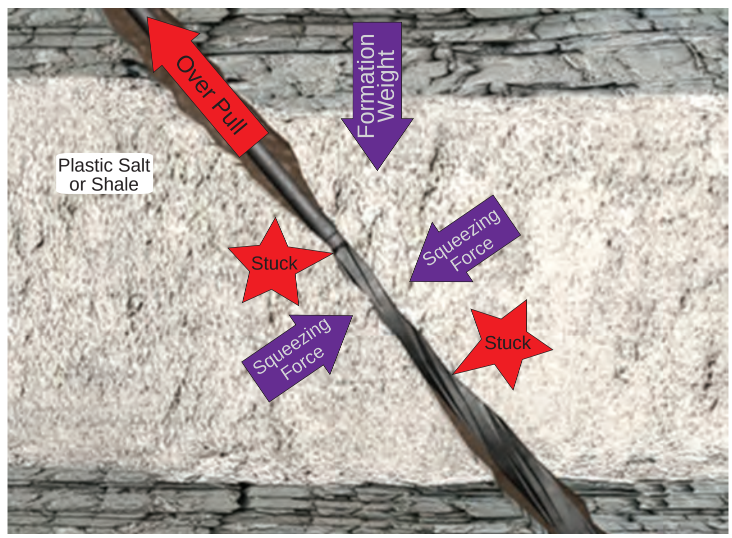
Unconsolidated Formations



4. Plastic Formations

- Increased/high chloride content in the drilling fluid
- High drag (overpull) at connections
- Increased pump pressure
- Rotation is possible but only with high torque
- ROP decreases
- Pipe sticks shortly after the pump is shut down

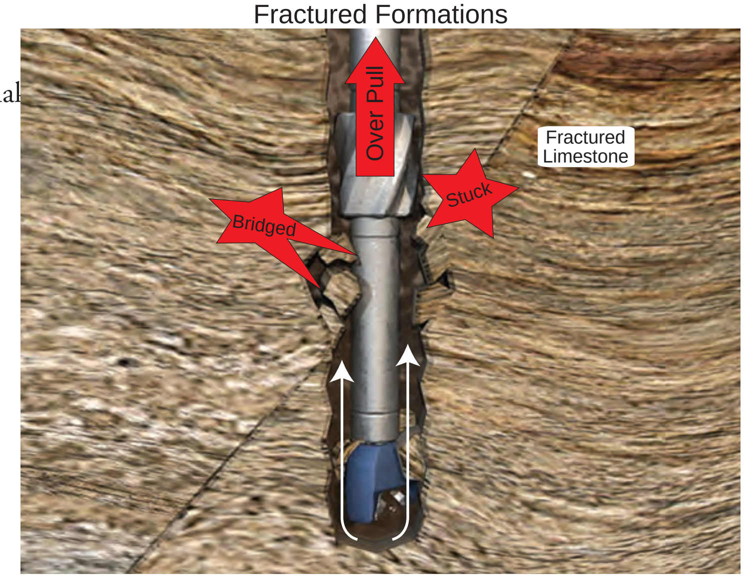
Plastic Formations



5. Fractured Formations

- Large, blocky cuttings at the shale shal
- Hole fill on connections
- Possible fluid loss (or gain)
- Sudden increase in drag
- Sudden increase in torque

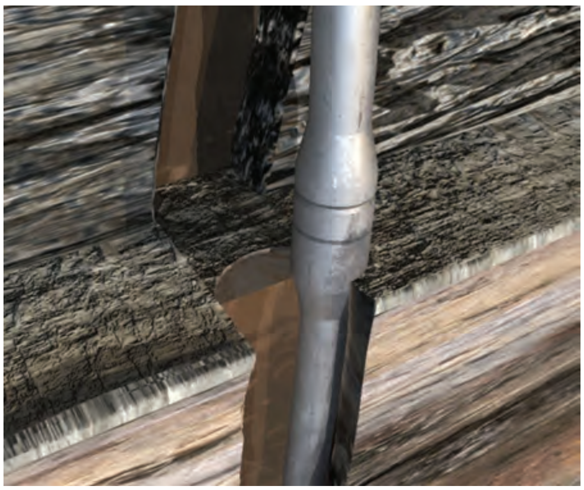
Fractured Formations



Conditions and Warning Signs of Mechanical Sticking

1. **Keyseats**
   - Highly deviated wells
   - Erratic overpull
   - Severe doglegs in the borehole
   - Circulation is normal
   - Pipe sticks while on trips in or out of the well

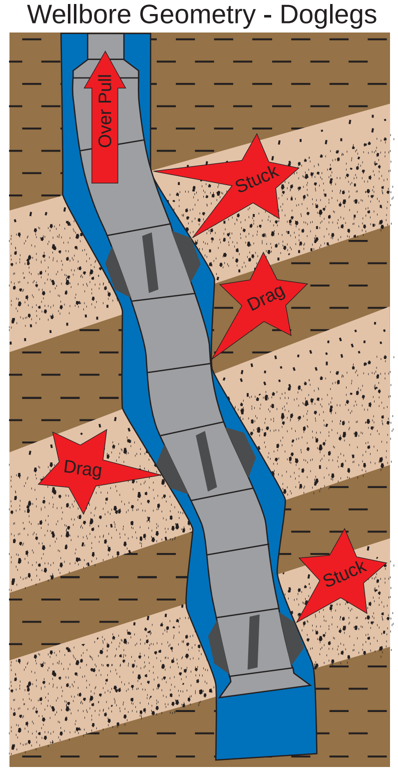
Keyseats



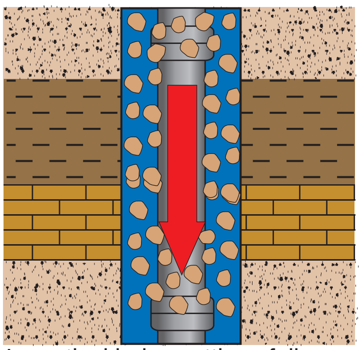
2. **Wellbore Geometry**
   - Sudden, erratic overpull
   - Problems at certain specific depths
   - Pipe sticks after a change in bottomhole assembly
   - Pipe sticks during trips out of the hole

Wellbore Geometry

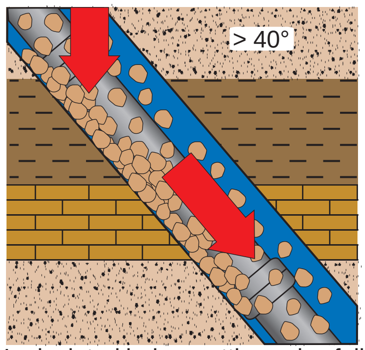
Wellbore Geometry - Doglegs



3. **Undergauge Hole**
   - Undergauge bit
   - Undergauge stabilizers
   - Reduced ROP
   - Bit takes weight before touching bottom when running in the hole
   - Rotation is difficult if not impossible
   - Cannot pull or rotate out of the stuck spot

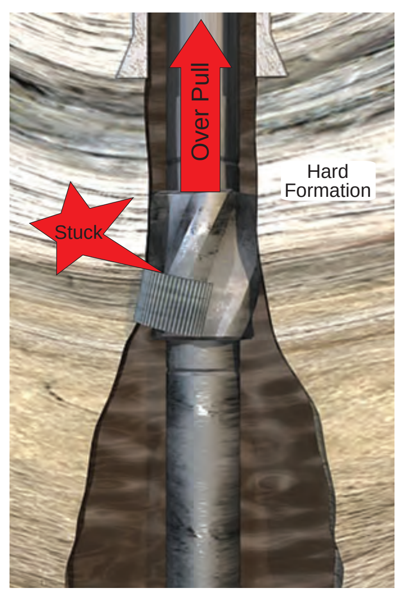


In vertical holes cuttings fall vertically.



In deviated holes, cuttings also fall vertically, but form cuttings beds where they meet the wellbore wall and then “avalanche” downhole.

4. **Inadequate Hole Cleaning**
   - Increased pump pressure
   - Spikes in pump pressure
   - Drag (overpull) is reduced when pumping
   - Decrease in amount of cuttings returning at the shale shaker
   - May see increase in pump pressure
   - Increase in torque
   - Decrease in ROP
   - Excessive drag (overpull) on connections and trips
   - Lost circulation
   - Pipe sticks shortly after the pump is shut down

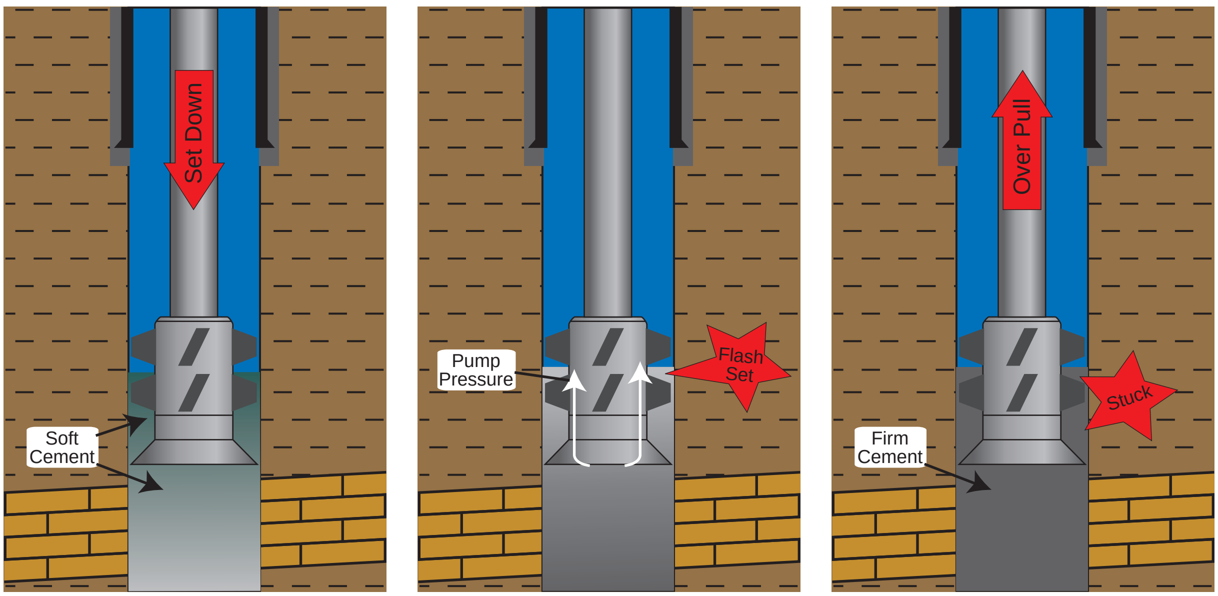


5. **Junk**
   - Missing equipment from the rig floor
   - Metal shavings at the shale shaker
   - Sudden, erratic rotary torque
   - Sudden increase in drag
   - ROP decreases
   - Pipe sticks shortly after a failure of downhole equipment

6. Cement Problems

- Cement blocks, fragments at the shale shaker
- Erratic rotary torque
- Increase in drag
- Soft (green) cement in the returns at the shale shaker

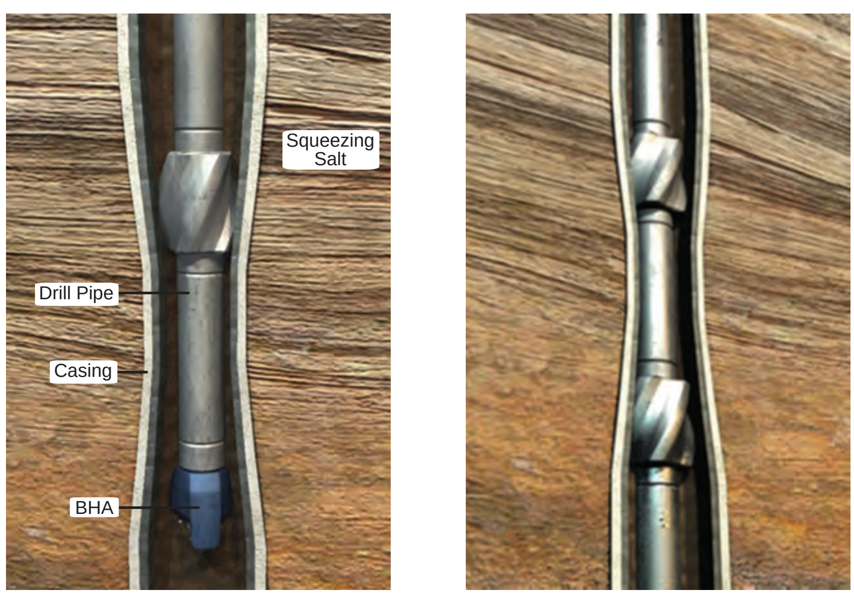
Cement Problems



7. Collapsed Casing

- Bottomhole assembly hangs up when running into the well
- Caliper logs indicate casing collapse

Collasped Casing



Stuck Pipe Prevention

3

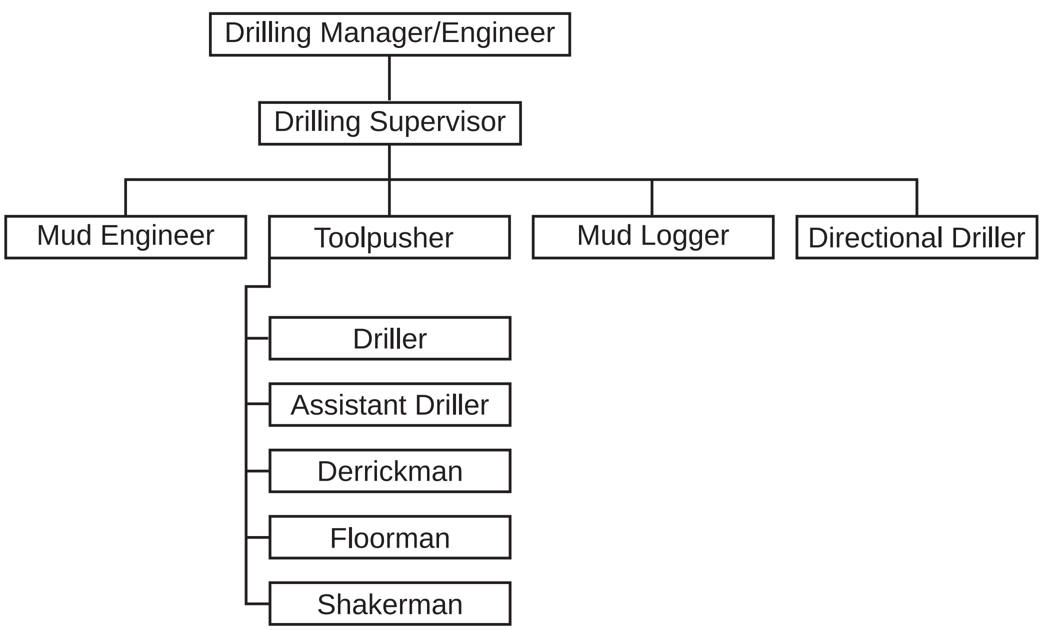
Planning a Stuck Pipe Prevention Program

An effective stuck pipe prevention program can be compared to a good football team. The various members of the team have separate responsibilities which, when put together as a whole, results in winning the game and all members of the team share the benefits of winning.

The following chart lists job positions for a typical crew on a drilling rig. All crewmembers are also members of the stuck pipe prevention team. Each team member must understand his or her role in preventing stuck pipe if the plan is to work effectively. Since there is a great variety in drilling rigs and drilling operations, some operations do not have all the positions listed; some have more, some less. In any case, the drilling supervisor and toolpusher will assign the duties and responsibilities according to the specific needs of the job.

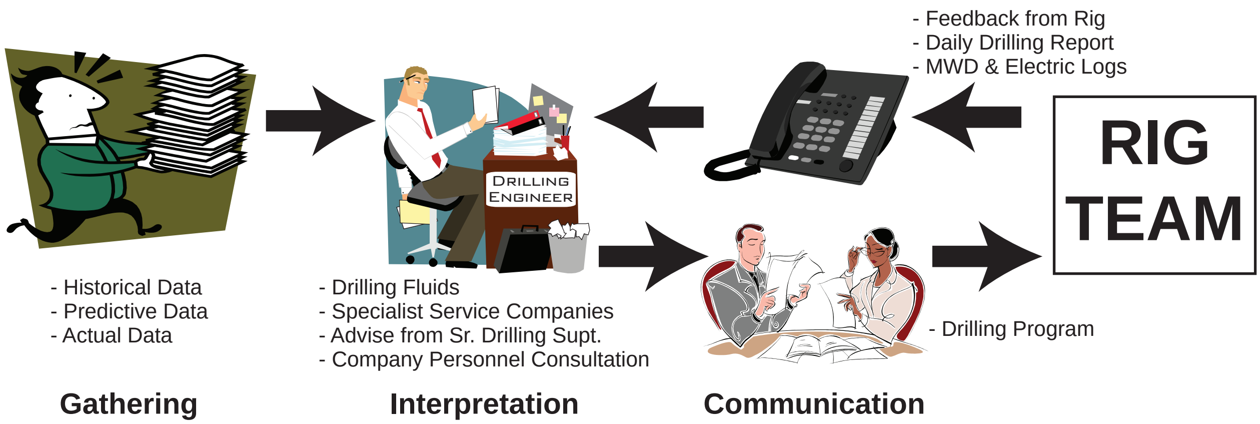
Drilling Manager/Engineer

A drilling operation only begins after an overall well plan has been developed. The operating company usually assigns a manager working at the company office, to head up the project. The manager receives constant reports and updates from the field. As drilling progresses, the manager, conferring with engineers and geologists, offers guidance as needed throughout the entire project.



Drilling Supervisor

The *drilling supervisor*, usually called the *company man*, is employed by the operator to oversee the daily operations on the rig and reports to manager(s) at the home office. The drilling supervisor manages the entire field operation. With regard to a stuck pipe prevention plan, the drilling supervisor is the team leader. As leader, all pertinent drilling data is relayed up the established reporting chain to him/her. The drilling supervisor consults with, and advises the toolpusher and service personnel throughout the drilling operation.



Toolpusher

The *toolpusher,* employed by the drilling contractor, is responsible for the rig and all the contractor's equipment on location. All contractor employees (drillers and crews) report to the toolpusher. The toolpusher works closely with the drilling supervisor in order to carry out the operator's well program. With regard to a stuck pipe prevention plan, the toolpusher is responsible for seeing that drillers understand their role in the plan and that all members of the drill crews are trained to their level of responsibility.

Driller

Since a drilling operation goes on around the clock, there is always a *driller* and his crew on shift (tour). It is the driller who actually operates the drilling equipment and therefore he is the person who is in a position to detect symptoms of a potential stuck pipe problem first. The driller is directly responsible for the safety and performance of his crew. Rig floor housekeeping, efficient pipe handling practices, and good record keeping are all part of the driller's job. Experienced drillers learn to "feel the hole" or "listen to the hole". In other words, drillers monitor a host of data which, when properly analyzed, can help to estimate changing downhole conditions.

Shift change is a critical time on the rig floor. Communication between drillers at shift change is crucial. It requires more than passing hard data. Good drillers chat about all they have experienced during their shift before leaving the floor at the end of their shift. Some companies require drillers to use a standardized "handover note". This is a good idea because a lot can happen in a long, hard shift. It's asking a lot of a tired driller to remember everything that went on during the past 8 or even 12 hours.

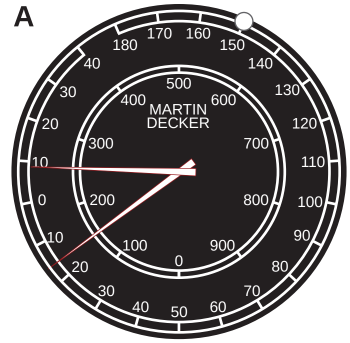
Rigs may use a conventional rotary table and kelly system in which drilling progresses by drilling one joint of pipe at a time, but some rigs are fitted out with complex top drive systems. Top drives are similar to rotating swivels but they are much larger and stronger. Using a top drive, the driller picks up and drills with an entire stand, often three joints of drill pipe.

Top drive systems offer many advantages over conventional kelly systems, but they do cause a driller to think differently with regard to stuck pipe. For example, circulating and back reaming tight spots on trips can be done with a top drive but care must be taken so that back reaming does not mask a developing problem. The bit is much closer to bottom on connections when using a top drive and that may limit the use of jars. A top drive creates greater drillstring vibrations that can result in accelerated drillpipe fatigue. Lastly, special care must be taken when cutting long, 90-foot cores.


LISTEN FOR
WHAT THE HOLE
IS TELLING YOU!

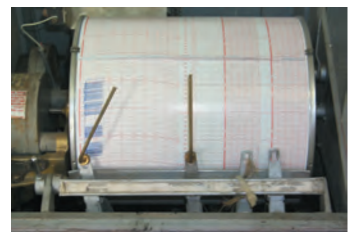

97062

Rigfloor instruments and gauges available to the driller include:

A.


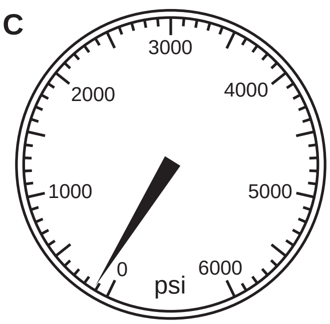
A. Weight Indicator

Measures suspended weight of the drill string. It is the indicator of overpull (drag) when making connections or tripping as well as detecting cuttings or “fill” falling to bottom.

B.


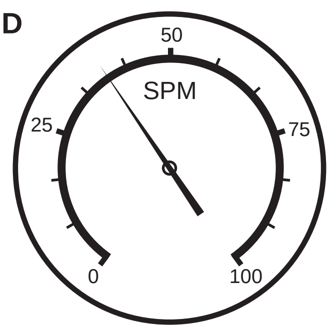
B. Geolograph Recorder:

Records various drilling parameters, most importantly, ROP, hookload, rotary torque, and pumping rate. Charts from a geolograph are included as part of the permanent record of the well.

C.


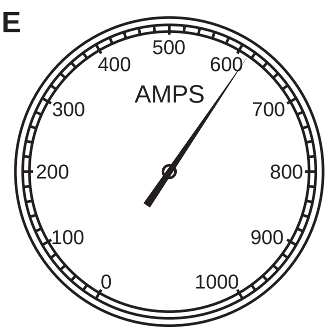
C. Mud Pump Pressure Gauge or Standpipe Gauge:

Measures pump pressure on the drill pipe. Also referred to as “Pump Pressure” or “Standpipe Pressure”. Pump pressure is a primary indicator in determining the potential for stuck pipe and defining which stuck pipe mechanism is likely.

D.


D. Mud Pump Stroke Indicator:

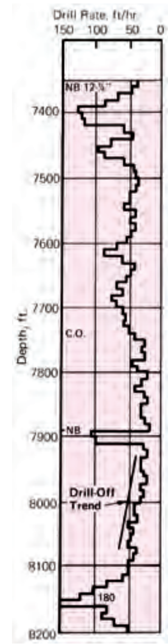
Counts the number of strokes or cycles (SPM) being produced by the mud pumps each minute. When analyzed in conjunction with pump pressure, the stroke counter can be used to detect changes that occur downhole.

E.


E. Rotary Torque Indicator:

Measures relative torque developed by the rotary table or top drive to rotate the drill string. Rotary torque may be in foot/pounds or amperes (amps) depending on rig equipment. Increasing or erratic torque is a definite indication of changing hole conditions.

Nowadays many drilling operations use measurement while drilling (MWD) or logging while drilling (LWD) tools in the drill string. These sensitive tools relay data to the driller and other locations on the site via computer screens. They present accurate, real time data. These sophisticated tools can also be used to transmit directional information and changes in formation pressure as well as monitoring and reporting common rigfloor data.



Assistant Driller

The *assistant driller* (A/D) is often a driller-in-training. The assistant driller's primary task is to aid and assist the driller during rig operations. The A/D relieves the driller from time to time and also keeps records, handles technical details, and, in general, keeps track of all phases of the operation. The A/D serves as the driller's "eyes and ears" as he/she moves about the location checking on various tasks delegated to the drill crew by the driller.

Derrickman

The *derrickman* handles the upper end of the drill string from a platform up in the derrick (monkey board) as it is being hoisted out of or lowered into the hole. The derrickman is also responsible for maintaining the mud pumps and associated circulating equipment. On most land rigs he/she is also responsible for maintaining the drilling fluid, a vital component of any stuck pipe prevention program. Larger rigs may have a special crewmember assigned to the mud system but that person usually reports directly to the derrickman.

Shakerman

Some rigs assign one member of the driller's crew to maintain the shale shakers and any mud separation equipment that might be located in the shaker area. The *shakerman* man usually also monitors a trip tank during trips. Observing and analyzing returns at the shakers can play a vital role in stuck pipe prevention. The crew member assigned to watch the shakers has the responsibility of keeping the driller and service personnel informed of returns at the flowline.

Floorman

Reporting directly to the driller, the *floormen*, or *roughnecks* do the heavy work on the drillfloor. A good stuck pipe prevention program stresses cross training of floormen. For example, working in the shale shaker or mixing mud material. It is the floormen who learn and perform good rigfloor housekeeping practices to the company standards.

Mud Logger

Mud loggers are usually graduate geologists who contract out to the operator. Working in an enclosed unit fitted with various instruments and testing equipment, they monitor all drilling trends and create a log, which is essentially a picture of technical data that presents essential information as a well is drilled. Mud loggers also collect and analyze drilled cuttings from the shale shakers. It is the mud logger who identifies changes in formation as drilling continues. Oftentimes the data gathered by a mud logger is used to predict the potential for stuck pipe incidents.

DRILLER HANDOVER NOTES

Date: ______ Driller: ______ A/D: ______

Well: ______ Rig: ______

CSG OD: ______ Shoe Depth: ______ Shoe Test: ______ PPG: ______

Initial Max Overpull: ______

Jar Type & Size: ______

Mech. Jar Trip Load Up: ______ DN: ______

Air Weight Below Jar: ______ Ten/Comp: ______

Jar Max Overpull: ______ Depth of SPR: ______

#1 SPR		#2 SPR	
SPM	Press	SPM	Press

Tour Start Time: ______ To: ______ Operation: ______

Hole ID: ______ Depth: FM: ______ To: ______ Last Trip Depth: ______

Hole Angle @ TD: ______ KOP Depth: FM: ______ To: ______ Deg/100:: ______

Mud Wt. ______ Funnel VIS: ______ PV: ______ YP: ______ GELS: / /

Pump Press ______ #1 SPM: ______ #2 SPM: ______ GPM: ______

ROT Wt: ______ P/U Wt: ______ S/O Wt: ______

RPM: ______ Off/B TQ: ______ WOB: ______ On/B TQ: ______

Press Trend: ______ Drag Trend: ______ TQ Trend: ______

Shaker Evidence: ______

Notes: ______

Time: FM: ______ To: ______ Operation: ______

Hole ID: ______ Depth: FM: ______ To: ______ Last Trip Depth: ______

Hole Angle @ TD: ______ KOP Depth: FM: ______ To: ______ Deg/100:: ______

Mud Wt. ______ Funnel VIS: ______ PV: ______ YP: ______ GELS: / /

Pump Press ______ #1 SPM: ______ #2 SPM: ______ GPM: ______

ROT Wt: ______ P/U Wt: ______ S/O Wt: ______

RPM: ______ Off/B TQ: ______ WOB: ______ On/B TQ: ______

Press Trend: ______ Drag Trend: ______ TQ Trend: ______

Shaker Evidence: ______

Notes: ______

Time: FM: ____________ To: ____________ Operation: ____________

Hole ID: ____________ Depth: FM: ____________ To: ____________ Last Trip Depth: ____________

Hole Angle @ TD: ____________ KOP Depth: FM: ____________ To: ____________ Deg/100:: ____________

Mud Wt. ____________ Funnel VIS: ____________ PV: ____________ YP: ____________ GELS: / /

Pump Press ____________ #1 SPM: ____________ #2 SPM: ____________ GPM: ____________

ROT Wt: ____________ P/U Wt: ____________ S/O Wt: ____________

RPM: ____________ Off/B TQ: ____________ WOB: ____________ On/B TQ: ____________

Press Trend: ____________ Drag Trend: ____________ TQ Trend: ____________

Shaker Evidence: ____________

Notes: ____________

#1 SPR		#2 SPR	
SPM	Press	SPM	Press

Depth of SPR: ____________

Time: FM: ____________ Tour End Time: ____________ Operation: ____________

Hole ID: ____________ Depth: FM: ____________ To: ____________ Last Trip Depth: ____________

Hole Angle @ TD: ____________ KOP Depth: FM: ____________ To: ____________ Deg/100:: ____________

Mud Wt. ____________ Funnel VIS: ____________ PV: ____________ YP: ____________ GELS: / /

Pump Press ____________ #1 SPM: ____________ #2 SPM: ____________ GPM: ____________

ROT Wt: ____________ P/U Wt: ____________ S/O Wt: ____________

RPM: ____________ Off/B TQ: ____________ WOB: ____________ On/B TQ: ____________

Press Trend: ____________ Drag Trend: ____________ TQ Trend: ____________

Shaker Evidence: ____________

Problem Form(s) Drilled: ____________

Problem Form(s) Prognosed: ____________

Notes: ____________

STUCK PIPE / TIGHT HOLE INCIDENT REPORT FORM

Well: ______ Rig: ______ Rpt Date: ______ Stuck Date: ______ Time: ______

LAST CREW CHANGE DAY: Drlg Crew ______ Drlg Supv ______ Tour Change Hour: ______

Well Data:

Csg ID: ______ Shoe MD: ______ TVD: ______ Shoe Test: ______

Hole ID: ______ MD: ______ TVD: ______ Last Trip MD: ______

#1 KOP MD: ______ Deg/100': ______ #2 KOP MD: ______ Deg/100': ______

Hole Angle @ Shoe: ______ Hole Angle @ TD: ______

Problem Form(s): ______

______

String Data:

☐ Top Drive ☐ Kelly

Bit #: ______ Bit Type: ______ Jets: ______ BHA Design: ______

DC Size: ______ Length: ______ DC Size: ______ Length: ______

Jar Type: ______ Size: ______ Jar Trip Load:UP: ______ DN: ______

Other BHA Equip: ______

______ HWDP Size: ______ Length: ______

DP OD/Grade: ______ FT: ______ DP OD/Grade: ______ FT: ______

Mud Data:

Mud Type: ______ Wt: ______ Fun Vis: ______ API Sand: ______

PV: ______ YP: ______ Gels: __/__/__ pH: ______ Inhibitor: ______

Shaker Evidence: ______

Notes: ______

Operational Data:

ROT WT: ______ P/U WT: ______ S/O WT: ______

Drag Trend: ______

RPM: ______ OFF/B TQ: ______ ON/B TQ: ______ TQ Trend: ______

Pump Press: ______ GPM: ______ Press Trend: ______

Stuck Pipe Symptoms:

Operation Prior to Sticking: ______

Up or Down Pipe Movement Possible? ______

(No) (Limited Up) (Limited Down) (Down Possible) (Erratic/Smooth Drag)

Rotation Possible? ______

(No) (High) (Erratic Torque) (Smooth Torque)

Circulation Possible? ______

(No) (Restricted) (Unrestricted) note: Report SPM versus pressure.

Will the Jar Trip? ______

Suspected Mechanism:

☐ Differential	☐ Settled Solids	☐ Reactive Form.	☐ Soft Cmt.	☐ Junk
☐ Tophole Coll.	☐ Geo-pressured	☐ U/Gauge Hole	☐ Ledges	☐ Salt
☐ Stiff Assembly	☐ Frac/Faulted	☐ Cmt. Blocks	☐ Key Seat	

Freeing Technique:

☐ Successful ☐ Unsuccessful

______

______

______

Note: Draw a detailed picture of the drillstring at the stuck depth on the back of the report form. Include all well and formation depths, lithology, and drillstring dimensions

Toolpusher: ______

Co. Rep: ______

Mud Engineer

Like mud loggers, *mud engineers* (drilling fluid technicians) are contracted to the operator. Mud engineers may work for a company that also supplies mud material, but many are private consultants that have no economic interest in the materials themselves. The drilling fluid is one of the primary communicators directly from the bottom of the well. The test results and guidance offered by the mud engineer often reveals a great deal about the conditions downhole. He or she occupies a unique position on a drilling location. Mud engineers act on behalf of the operator but must rely on contractor personnel to actually perform recommended mud treatments.

As can be seen, a good prevention program depends on the entire rig crew working together as a team. One common component of a successful program stands out. Without good communications the program will be less than the best. The team members, each on their own, have certain specific responsibilities. The degree to which they are able to carry out these tasks and communicate to supervisors contributes to the program as a whole. All information, both good and bad, should be reported to others, whether it is in reports or word of mouth. A good way to pass this information on is through the uses of a Stuck Pipe/Tight Hole Incident Report. One may be filled out and passed along to the toolpusher and the oncoming crew.

Stuck Pipe Prevention Program

The most important component of a stuck pipe prevention plan is communication. An effective prevention program includes service personnel as well as the rig crew and the operator's representative. Mud loggers, mud engineers, and directional hands have important roles in any stuck pipe prevention program. Although there are similarities between the various stuck pipe mechanisms, there are also differences. The following discussion keeps with the established pattern of discussing each mechanism separately even though there is some overlap in warnings and prevention activities. All drilling programs are made up of compromises. They are developed with the hopes of getting optimum results within an established budget. Stuck pipe prevention programs are no different. The perfect BHA or the perfect mud weight may not be practical, or even possible. Developing a stuck pipe prevention program is a matter of risk assessment and, like the overall well program, is the result of trade-offs and compromises. It goes without saying that good drilling and tripping practices and a properly maintained mud system are a key element in any stuck pipe prevention program.

Good Drilling Practices

- Always maintain circulation on connections for as long as possible.
- Always maximize pipe motion when in open hole.
- Always begin pipe motion in a downward direction once slips are pulled.
- If pump repairs are necessary stop drilling.
- Monitor and record the depths of higher torque.
- If hole conditions dictate invest in wiper trips. These may be to the casing shoe or only through newly drilled hole.
- Always monitor the shakers.
- Use top drives with care.
- Be prepared to limit penetration rate.
- On floaters use the motion compensator to minimize sudden pipe movements.
- Always leave sufficient room on the kelly to allow jars to operate.
- Never force the kelly bushings into the rotary if fill is encountered.
- Always wipe the hole before making a connection.

Good Tripping Practices

- Before tripping ensure that the shakers are clean.
- Acknowledge increasing hole drags.
- Monitor and record the depths and magnitude of overpulls.
- Never fight your way into or out of the hole – be patient.
- If possible, always use circulation to work the string through a tight spot.
- Initially limit overpulls to half the drill collar weight below the jars.
- Always insert slips when the pipe is moving in a downward direction.
- Swabbing indicates tight hole.
- In problem sections keep the string moving in the slips.
- Always ream at least the last three singles to bottom.
- Minimize time spent in open hole.
- Know how the jars work.

Prevention Techniques for Differentially Stuck Pipe (Wall Sticking)

Differential sticking occurs when the workstring, usually the BHA, is held imbedded into the wall cake that forms on a wellbore when a permeable formation is drilled. If the hydrostatic pressure of the working fluid in the well is greater than the formation pressure the string is held against the wellbore. If the difference between the hydrostatic pressure and the formation pressure were 100 psi, then every square inch of the imbedded portion of the BHA would have 100 pounds of force holding it against the wall of the hole. The lifting force required to pull wall-stuck pipe free can easily be greater than the tensile strength of the drillpipe. Since the cause of differentially stuck pipe is well known, it is a simple matter to make recommendations in order to avoid the problem. However, it is not always practical, or even possible to follow them.

The components of the BHA have a major influence on the potential for differential sticking. The assembly should be no longer than required to achieve the drilling objectives and spiral drill collars are always preferred over a slick assembly.

Fluid density recommendations are an important part of any drilling program. The mud weight must be carefully controlled as the bit penetrates permeable formations. The density (mud weight) must be great enough to protect against potential blowouts with a margin for safe tripping, and yet if the mud weight is too great, the drillstring might become differentially stuck. The most damaging contaminate of all drilling fluids is drilled solids. Experienced mud engineers use the shale shakers, desanders, desilters, and perhaps mud centrifuges whenever the fluid is being circulated. The goal is to keep the percentage of low gravity, undesirable solids at a practical minimum. The consistency of the wallcake deposited on the borehole is thought to be dependent on two primary factors, 1) the percentage of undesirable solids in the fluid and, 2) the "water loss" to the formation. When drilling fluid comes in contact with a permeable formation, some of the liquid phase of the fluid is forced into the formation, leaving solids on the wellbore. The liquid that enters the formation is called the *water loss*.

It is reasonable to assume that the lower the water loss is, the thinner the deposited wallcake will be. Considering stuck pipe, the most desirable filter cake would be thin and tough. Mud engineers use special chemicals in order to lower the water loss in tests at the surface. The tests in the mud lab do not necessarily reflect exactly what is happening downhole, but there is a great deal of empirical data that indicates that stuck pipe incidents are reduced when water loss is reduced. Drilling fluid programs often recommend reducing the water loss dramatically before entering a permeable formation in which differentially stuck pipe is considered likely. Even though the percentage of undesirable solids is low, it may take several circulations, or several days, in order for the mud engineer to achieve the recommended water loss. Chemical treatments must begin before the permeable zone is penetrated. Unfortunately, lower water loss often results in lower penetration rates. This is one of those trade-offs referred to earlier.

Guidelines for Good Mud Maintenance

Tight Hole Cause \ Preventative Measure	Increase Mud Weight	Increase Viscosity	Increase Gels	Decrease Fluid Loss
Differential Sticking				■
Reactive Formations	■	■	■	■
Fractured/ Faulted Formation	■	■	■	
Mobile Formations	■			
Unconsolidated Formations		■	■	■
Geo-pressured Formations	■		■	
Inadequate Hole Cleaning – High Deviation			■	
Inadequate Hole Cleaning – Low Deviation		■	■	

KEY

■ Improvement

Attempts to free differentially stuck pipe often call for spotting special chemicals in the annulus across the problem area. A thorough prevention program would specify that sufficient amounts of the spotting material be kept on location at all times. If possible, plans for mixing a stuck pipe spot should be worked out in advance. For example, the pit(s) to be used to mix the spot, the formulation of the spot, special mixing equipment if any, should all be considered.

Even if the bottomhole assembly is optimized and the mud program is executed perfectly, the string can become differentially stuck in a permeable zone if good drilling practices are ignored. Once the permeable formation is penetrated, the rate of penetration (ROP) must be controlled in order to allow time for the formation of a good wallcake and to make sure the annulus is cleaning up as it is drilled. It may be necessary to pause and circulate the well clean from time to time, especially before pulling out of the hole. Frequent wiper trips are often helpful. Connection time should be kept as short as possible because if conditions are ripe for wall sticking, the string will stick very quickly if it is not kept moving.

- Keep pipe moving whenever possible.
- Rotate string on connections.
- Make frequent wiper trips.
- Maintain careful control of mud weight.
- Use shortest practical BHA.
- Avoid surveying methods which result in pipe remaining static for long periods.
- If necessary, place the jars in the hevi-wate drill pipe.

Prevention Techniques for Formation-Related Stuck Pipe

When a driller experiences increasing fill on bottom after connections and the shale shakers begin to load up with large, misshapen cuttings, it is a good indication that the formation is overpressured. Usually the best way to ease the problem is by increasing the mud weight. The additional hydrostatic pressure will often help support the walls of the hole.

- Control ROP.
- Monitor cuttings carefully.
- Optimize hole cleaning techniques.
- Ream each single.
- Perform regular wiper trips.
- Minimize open hole time.
- Recognize increasing overpull trends and stop drilling until hole is clean.
- Ensure mud specifications are maintained.

Soft, reactive shales, like gumbo, may also be overpressured but in this case increased mud weight alone is usually not an effective solution. There may be large chucks of soft clay returning at the shale shakers followed by periods of virtually no cuttings at all. Sometimes chemicals are added to the drilling fluid in order to inhibit the hydration of the swelling formation. Bottomhole assemblies should be as short as practical. Frequent wiper trips often help, and if possible, the length of open hole sections should be as short as possible.

- Minimize the time in the hole.
- Plan regular wiper trips.
- Recognize the potential increase in swab/surge pressures.
- Wipe hole regularly while drilling.
- Use inhibitive mud.
- Limit BHA length.
- Keep open hole sections to a minimum.
- Avoid other open hole operations as far as possible.

Unconsolidated formations, such as pea gravel or loose sand are often drilled with a higher viscosity fluid than usual. Careful control of the annular velocity and fluid viscosity is one key to successfully preventing stuck pipe in these sections. Circulating at one depth for a long time will cause large washed out areas that not only increase the potential for stuck pipe, but will also cause problems when casing is run and cemented. Occasional high viscosity pills can be circulated carefully from time to time in order to lift or "sweep" the loose cuttings out of the annulus.

- Identify the formation.
- Monitor pump pressure carefully.
- Monitor shale shakers carefully.
- Use high viscosity mud.
- Control penetration rate.
- Avoid excessive periods of circulation opposite these formations.
- Pick up and circulate often.
- Wipe each connection.

Plastic formations, such as salt domes present unique drilling challenges. Drilling fluids must be designed to be nonreactive with the formation. Oil-based muds or saturated salt fluids are common. The drilling program usually recommends frequent reaming. Normal tripping practices are modified to accommodate conditions.

- Identify salt domes.
- Monitor chloride content of mud carefully.
- Monitor resistivity of mud carefully.
- Condition mud prior to penetrating the formation.
- Make round trips slowly with frequent reaming.
- Minimize open hole time.
- Consider the use of eccentric PDC bits.

Tripping speed should be reduced in highly fractured or faulted formations. Care must be taken not to knock large chunks of rock off the wall of the hole. Drill string vibration should be minimized as much as possible in these formations.

- Control ROP.
- Monitor the shale shakers carefully.
- Modify hole-cleaning techniques.
- Clean out annulus at a slow, controlled rate (remember – lost circulation potential).
- Minimize surge pressures – restrict tripping speeds.
- Run a jar in the upper assembly.
- Be prepared to wash/ream when tripping in.
- Design BHA to minimize risk of ledge formation.

Prevention Techniques for Mechanically Stuck Pipe

A keyseat is a groove worn into one side of a wellbore due to a sharp change in direction. If possible, changes in hole inclination and azimuth should be limited to no more that 3 degrees per 100 foot of hole length. Directional engineers must confer with drillers often, keeping them informed of the calculated keyseat severity. Potential keyseats should be recognized early and wiped (reamed) before the problem becomes severe.

- Avoid severe hole deviation.
- Run keyseat wipers in the BHA.
- Consider BHA design/configuration.

- Minimize length of rathole below casing.
- If problem recognized attempt to cure before drilling ahead.
- If problem is anticipated have a surface jar on location.

Weather keyseats develop or not, the potential for stuck pipe is always increased in high angle wells or when wellbore geometry changes for any reason. Drillers must look out for tight spots and ream or back-ream tight places before tripping out of the hole. This is especially true after changes are made in the bottomhole assembly. Great care should be taken when moving a changed BHA into the well for the first time.

- Avoid severe hole deviation.
- Minimize doglegs to programmed limits.
- Ream the hole often.
- Minimize changes to the BHA.
- Whenever possible simplify BHA configuration.
- Consider a hole opening trip.
- Do not run stabilizers above the jar.

Hard, abrasive formations may tend to wear away the gauge protection on the bit if the drilling assembly has been in the hole for a long period of time. Some of the newer polycrystalline diamond compact (PDC) bits are designed for long life in hard formations, but in time, the gauge protection on these bits will also wear. It goes without saying that all bits should be gauged when they are pulled out of a well. If a new bit is suddenly jammed into an undergauge section the result will likely be an expensive stuck pipe problem. To avoid this problem, trips should be made slowly, tight spots reamed, and care taken when running back into the well.

- Identify hard/abrasive formations.
- Make trips slowly.
- Ream frequently.
- Gauge bit and stabilizers accurately going in and coming out of the hole.
- Never attempt to force.
- Never attempt to force bit to bottom.
- Select bits with good gauge protection.
- Be careful when running PDC bits after TRI-cone bits.

Sometimes stuck pipe can result from inadequately cleaning the hole while drilling. Controlling the drilling rate is one way to help. Also, if hole cleaning is a problem, the well should be circulated until the shale shakers clean up before starting a trip out of the hole. Rotating the drillstem helps in cleaning drilled cuttings out of the annulus because as the pipe rotates, it causes some of the cuttings that are near the walls of the hole to move toward the center, where the annular velocity and the flow pattern is more efficient. Although downhole motors are remarkable tools and have greatly improved directional drilling, hole cleaning can become a problem when the string is not rotated. The string should be rotated while circulating before tripping out of a well if rotation will not affect the directional work.

- If a downhole motor is in string, rotate before trips.
- Circulate bottoms up frequently and before trips – ensure shakers are clean.
- Keep pumping whenever possible.
- Always reciprocate and rotate pipe while circulating.
- Maintain correct mud specifications.
- Maintain programmed annular velocities.

- Select the optimum (recommended) viscous sweeps (directional /straight holes).
- Control ROP.
- Recognize the significance of hole deviation.
- Plan regular wiper trips.

Junk is the general term used to describe anything that is left in a well accidentally. It might be part of the drillstring itself, components of a downhole tool, or even an item inadvertently dropped into the well from the rig floor. There is virtually no excuse for dropping hand tools or other small items into a well. This is one hundred percent avoidable. The hole should be covered at all times when the drillstem has been removed and no other tools are being run. There is no replacement for a properly trained crew and good rigfloor housekeeping. Careful inspection of all equipment before it is run into a well may alert supervisors to the potential of leaving junk in the hole. If the string is stuck on junk there are actually two problems, freeing the pipe and fishing out the junk.

- Good rigfloor housekeeping.
- Inspect all equipment before running it into a well.
- Leave hole covered as long as possible.
- Install drill pipe wiper on the hole whenever possible.

Sometimes chunks of cement can break off from around the casing seat and fall to the bottom of a well. Although drillable, these chunks may be quite large and if the BHA gets pinched between the junk and the casing or a hard formation, it may be impossible to pull it free. Limiting the rathole below casing as much as possible is a good practice since there is less chance of having long sections of cemented hole.

- Allow sufficient curing time for cement.
- Use good cementing practices.
- Minimize rathole below casing shoe.
- When drilling casing ratholes or cement plugs always ream section thoroughly before drilling ahead.
- Beware when tripping back through the casing shoe or past cement plugs.

Running the drillstring into green (unset) cement is another problem that has occurred. When the pump is started up, the additional pressure may cause the cement to set, effectively cementing the string in the well. Although it seems unlikely that this could happen, if sufficient time is not allowed for the cement to harden the driller may not be able to detect any unusual change on the weight indicator as the pipe is lowered into the well. The green cement is actually liquid and may take no significant weight off the hookload.

- Allow sufficient curing time for cement.
- Pretreat the mud if green cement is suspected.
- Do not rely on the weight indicator.
- Know the theoretical top of cement.
- Begin circulating 2 or more stands above the estimated top of cement.
- Check for cement returns at the shakers.
- Restrict ROP when cleaning out cement.
- Use good cementing practices.

More than one string of pipe has been stuck in collapsed casing. The well program should call for the casing to be callipered if it is subject to wear for a long time. The collapse rating should be downgraded with a safety margin as the wall thickness is worn away. Trips into a well in which the casing has been subject to wear should be made carefully so as not to jam the bit into a narrow, collapsed portion. Among other things, casing is a vitally important part of handling well control incidents and therefore it must be protected from severe damage.

- Avoid casing wear when possible.
- Use only smooth, polished hardbanding on tool joints.
- Use good cementing practices.
- Caliper casing after long periods of wear.
- Review inflow and production testing requirements. Modify if casing wear is evident while drilling.

It can be seen that an effective program for preventing stuck pipe must include all personnel from the engineers and geologists who design the well program, to a young floorhand who may be assigned to watch the shale shakers. A complete program includes good drilling practices and housekeeping, things that should be common on all rigs, plus technical information about the formations and how they will be drilled. The one, consistent component of an effective plan is free, open, and constant communication from top to bottom and bottom to top. The initials, C. A. R. E. can be used to sum up the main components of a good stuck pipe prevention plan.

- **C is for Communication**

  Constant two-way communication between rig supervisors and crewmembers is essential if a prevention program is to be successful.

- **A is for Awareness**

  All personnel involved in the operation must understand their individual responsibilities and be constantly on the lookout for potential warning signs of stuck pipe.

- **R is for Reporting**

  It goes without saying that written reports are important, but verbal reports should also receive high priority. It does little good if a worker notices some change at the shale shakers but does not report the change to his supervisor.

- **E is for Education**

  If a serious stuck pipe prevention plan is adopted, all personnel must be trained in their respective responsibilities. No one can be expected to know what to do and how to do it if they are not properly trained.

NOTES

NOTES

Freeing Stuck Pipe

4

It would be wonderful if there were a magic formula that would provide a standard guide for freeing all stuck pipe. Unfortunately, no such formula exists. However, the industry has gathered a tremendous amount of stuck pipe data over the years because stuck pipe has been a major problem since rotary drilling was first developed, more than 100 years ago.

Analysis of statistical data, specific field experience, and advances in equipment and engineering know-how, have enabled us to approach pipe sticking problems in a systematic manner. The first response is always for the driller to attempt to free the pipe mechanically. Freeing force should be applied in the opposite direction from the direction the pipe was moving immediately before it got stuck. If tripping into the well, try overpull and jar upwards. If the pipe becomes stuck while tripping out, slack off and jar downwards. If possible, circulation should be established with consideration given to the effect that circulation might have on jarring.

When working the pipe, downward, torque is applied (about 3/4 turns per thousand feet) to the stuck point, and then the pipe is slumped, allowing the jars to fire downward. When working the pipe upwards it must first be decided whether to apply maximum force from the start, or to increase the pull gradually. If gradual force application is thought to be best, the pipe is worked to about 40/50 thousand pounds over the force required to trip the jars. The force is increased gradually over an hour. Care must be taken to ensure the maximum overpull is not exceeded. If it is decided to work with maximum force initially, the pipe is worked allowing the jars to fire. The pipe is then worked to the limit with the jars uncocked.

As the driller works the pipe, an estimation of the stuck point should be made and the stuck mechanism should be identified. The stuck point may be estimated by running a wireline free point instrument or by pipe stretch calculations. Appendix I can be used to determine the stuck pipe mechanism. The next step usually involves making an estimate of how much time can be spent on freeing activities before the cost of the operation precludes continuing, and some sort of abandonment plan is adopted.

The time estimates are purely economic and do not take into consideration safety or local regulations. Obviously these concerns outweigh any rigsite operation. More than one mathematical model has been developed to determine the feasibility of freeing activities. The math, although elemental, requires information not readily available to contract employees. The oil company, or operator, tracks the various cost estimates associated with the drilling program. In this computer age, involved economic and engineering computations can be completed in the time it takes to enter the numbers.

The equation below has been used to determine the economical time limit to allot for freeing stuck pipe. It must be remembered that when using the formula, specific field experience might affect the actual decision to abandon or sidetrack a well. The equation is shown here only to provide an example.

$$\boxed{N_D = (V_F + C_{RD}) \div C_D}$$

Where:

N_D = Maximum number of fishing days

V_F = Total replacement value of fish in hole ($)

C_{RD} = Total estimated operational cost to re-drill interval (i.e. sidetrack), $

C_D = Daily operational cost plus additional daily cost of fishing tools and services, ($/day)

After the estimated optimum time has elapsed, an alternative plan to sidetrack or abandon the well is adopted.

Freeing Differentially Stuck Pipe

The differential mechanism is well understood and usually an experienced driller recognizes the tendency to stick when drilling ahead and making connections. If the pipe does become stuck the driller's first action should be to slump the pipe and try to rotate. Once the pipe becomes firmly stuck the only way to free it is to relieve or equalize the pressure differential that is holding the string, usually the bottomhole assembly, against the wall of the hole.

Sometimes the drillstring can be freed quickly by unbalancing the annulus/workstring configuration of a U-tube. Although this method is often effective, it should never be considered if there is any chance of inducing a well control incident. Consideration should be given the possibility of shocking unstable formations. U-tubing cannot be used if there is a float (check valve) in the drill string. The technique involves reversing a calculated volume of light fluid into the annulus through the choke line and then allowing the drill string to vent through the standpipe. The back-pressure trapped in the choke line is then bled off periodically while monitoring returns and working the drill string. If the pipe comes free or begins to move, every effort should be made to keep it moving and circulate the well with the original fluid.

There are a variety of stuck *pipe release agents* (PRAs) available from fluid service companies and their technicians usually make recommendations as to the best agent to use considering the specific problem as well as any environmental concerns. Unlike U-tubing, there are no hydrostatic pressure reduction concerns when using PRAs. Some general guidelines for spotting PRAs are listed on the following page, however a drilling fluid technician will make specific suggestions according to the spotting material and techniques tailored to the specific job.

- PRAs are usually weighted up to a density 1 to 2 pounds per gallon greater than the working fluid in the well.
- The volume of the spots should be about 1½ times the annular volume of the uppermost permeable zone in which the pipe is stuck.
- A low-viscosity spacer should be pumped ahead of the spotting pill. The spacer should be compatible with the working fluid as well as the PRA. Since the spacer is usually unweighted, well control issues must be considered.
- The spacer and the pill should be spotted at the maximum rate possible in order to try to get the spot behind the stuck pipe.
- Once the pill is in place, the pipe is worked by slacking off, applying right hand torque. The torque is then released and the string pulled upward. The goal is to work the stuck point down the hole a little at a time until it pulls free.
- The pipe is soaked until the pipe is free or until some other decision has been made. Circulating the pill out and then spotting another pill is not considered effective.

Data indicates that best results are obtained if the pill is spotted within 4 hours of the pipe having become stuck. There is not much likelihood of a PRA pill being effective after about 16 hours. Usually the stuck string is soaked for a minimum of 20 hours and a maximum of about 40 hours. The chart below can be used as a guide as to the probability of success and estimating the maximum soaking time before giving up and backing off the string.

Freeing Mechanically Stuck Pipe

Since there are various causes for mechanically stuck pipe, freeing techniques vary depending on the identified mechanism. Many of the mechanisms are related, therefore there is overlap in freeing techniques. However, once the mechanisms are identified there are some general established guidelines. These guidelines are discussed on the following pages.

Keyseating

Work the string downward increasing the weight gradually while rotating.

Undergauge Hole

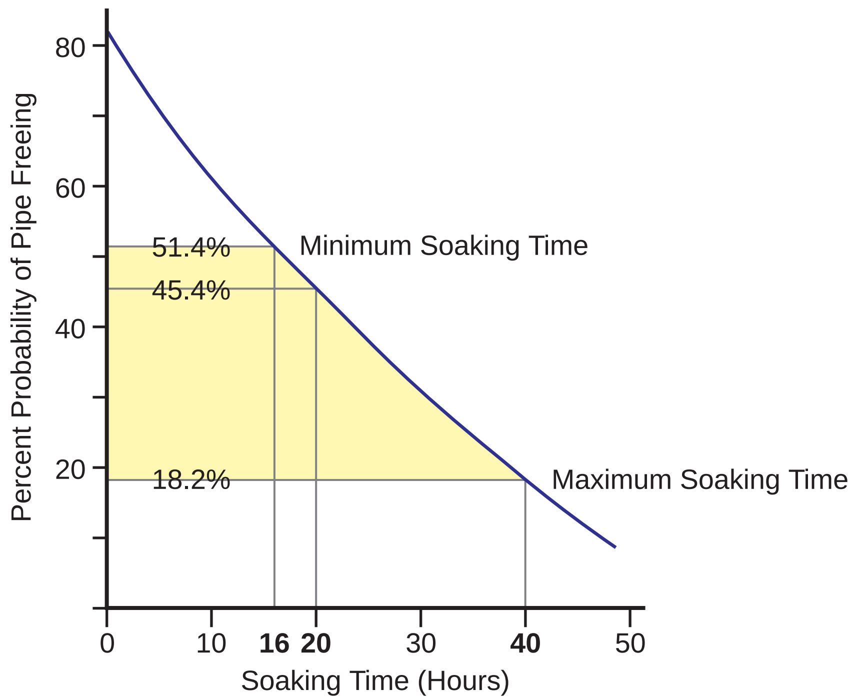
Work the string upward using maximum force from the start.

Wellbore Geometry

Work the pipe in the opposite direction from when the sticking occurred while increasing the force gradually.

Salt

Work the pipe with maximum force immediately. Consider pumping a fresh water pill.



These four mechanisms are often formation related, i.e., salt, clay, or limestone formations. In these cases, fresh water or acid pills are sometimes spotted around the pipe.

Fresh water pills are used when the pipe is stuck in a salt formation. Some important concerns when considering a fresh water pill are:

- Be certain that the pill will not induce a well control incident.
- The pill volume should cover the entire stuck zone and leave about 20 barrels inside the string.
- Consider adding a drilling detergent to the pill in order to help clean the walls of the hole.
- In the case of oil base mud, pump a viscous, weighted spacer ahead of the pill.
- Work the pipe while the pill (and spacer) is being prepared and pumped.
- Maintain maximum pull on the string while the pill is soaking.
- If the pipe does not come free after about two hours, pump it out and repeat the procedure.

Inhibited hydrochloric acid (HCL) pills are sometimes used in limestone and chalk formations and when the pipe is stuck in cement. Important points to consider are:

- Be certain that the pill will not induce a well control incident.
- The pill volume should be sufficient to cover the entire stuck zone. A fluid service company should be consulted on the exact pill formulation (often 7.5 to 10% HCL).
- Pump the pill quickly in order to minimize contamination of the drilling fluid.
- Work the pipe as the pill soaks. The pipe should come free in a few minutes; the acid works quickly. Pump the pill out after about 5 minutes.
- HCL can weaken tool joints and high strength pipe.

Unconsolidated Formations

Work the pipe up and down increasing the force gradually while circulating at the maximum rate.

Hole Cleaning

Work the string down while increasing circulation to prevent the hole from packing off.

Geopressured Formations

Work the pipe up and down increasing the force gradually while circulating at the maximum rate.

Reactive Formations

Work the pipe up and down increasing the force gradually while circulating at the maximum rate.

The four stuck pipe mechanisms listed above result when the borehole is partially or completely packed off, therefore the freeing practices are similar. Below is a suggested procedure for re-establishing circulation.

- Hang the string at the free point weight.
- Apply right hand torque.
- Apply low pump pressure.
- Work the string up and down with low pull/slack-off forces.
- If there is some movement or circulation, increase the pull and pressure until full circulation is established.
- If there is no initial progress, increase the torque gradually while working the pipe with the same forces.
- If circulation still cannot be established, continue to increase torque, pull/set down weight, and pump pressure gradually to the agreed maximum limit.

If the string is stuck in cement (either green or hardened) and the pipe cannot be worked free, consideration should be given to pumping an HCL pill as discussed earlier.

Green Cement

Pull upward with maximum force while jarring.

Cement Blocks

Work the string up and down.

When the pipe becomes stuck in plastic clay formations, spotting a pill will usually not free the pipe.

Plastic Clay

Work the string up and down, increasing the force gradually.

Junk in the hole and collapsed casing are special cases and often require the assistance of trained service personnel.

Junk

Work the string up and down, increasing the force gradually. Run in to an over-gauge section of the wellbore if possible, in hopes of losing the junk.

Collapsed Casing

Collapsed casing is a specialized problem and will likely require offsite decisions. Work the string downward, applying force gradually.

Summary

Since there are many causes of stuck pipe, there can be no one tried-and-true method for freeing a drillstring once it becomes stuck. It is obvious that the best thing is to avoid becoming stuck in the first place. There is no substitution for a well-designed stuck pipe prevention program and a properly trained crew. Although it is unlikely that this problem will be completely eliminated so long as wells are drilled, there is ample evidence that when the symptoms of stuck pipe are recognized early by a trained, alert driller and freeing activities begin immediately, stuck pipe incidents can be kept to a minimum.

Instructions

1. Answer the questions in each row by circling all the numbers in the row that apply to the situation.
2. Add the columns, the column with the highest totals indicates the type of sticking mechanism.
3. See the charts below or the quick reference pages for suggestions on freeing stuck pipe.

Calculator

Stuck Pipe Mechanism

Pipe Motion When Sticking Is The Worst:			
Moving Up	2	0	2
Rotation Up	0	0	2
Moving Down	1	0	2
Rotating Down	0	0	2
Static	2	2	0
Can You Move Down?			
Down Freely	0	0	2
Down Restricted	1	0	2
Restricted on Connection	2	2	0
Can You Rotate?			
Rotate Free	0	0	2
Rotate Restricted	2	0	2
Restricted on Connection	2	2	0
Can You Circulate?			
Circulation Free	0	2	2
Circulation Restricted	0	0	0
Circulation Impossible	2	0	0
TOTALS:			
Probable Cause	Pack-Off/ Bridge	Differential	Wellbore Geometry

Freeing Hole Pack-Off/Bridging		Freeing Wellbore Geometry	Freeing Differential
Stuck while ***MOVING UP*** or with String ***STATIC*** **Action to Establish Circulation:** Apply low pump pressure 300 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 jars to trip. If the string does not come free, **DO NOT JAR UP!** **JAR DOWN!** Continue this until string becomes free or an alternative decision is made. **When Circulation is Established:** Slowly increase pump speed to maximum rate, ***DO NOT SHUT DOWN!*** Work pipe and circulate hole clean. Ream the section until the hole is clean. If **POH** to log and/or run casing, return to bottom and circulate the hole clean.	Stuck while ***MOVING DOWN*** **Action to Establish Circulation:** Apply low pump pressure 300 to 400 psi. Maintain pressure if restricted circulation is possible. **DO NOT JAR DOWN! APPLY TORQUE!** **Apply *MAXIMUM* overpull to jar and jar up.** If the string does not come free, **DO NOT JAR DOWN! JAR UP!** Continue this until string becomes free or an alternative decision is made. **When Circulation is Established:** Slowly increase pump speed to maximum rate, ***DO NOT SHUT DOWN!*** *Work pipe and circulate hole clean.* Ream the section until the hole is clean. Continue RIH until excessive set down weight is observed, circulate hole clean.	If sticking occurred while moving up, apply torque and **JAR DOWN** with maximum jar action. If sticking occurred while moving down, do not apply torque and **JAR UP** with maximum jar action. Stop or reduce circulation when cocking the jar and when jarring down. **NOTE:** Pump pressure will **INCREASE** the jar up-blow and **DECREASE** the down-blow. Continue jarring until the string is free or an alternative decision is made. **Secondary Action:** Spot acid is stuck in limestone or chalk. Spot fresh water with mobile salt. **When the String Comes Free:** Increase circulation to maximize rate, rotate and work the string. Ream/backream the hole section thoroughly. Circulate the hole clean.	**Initial Action:** Circulate at maximum allowable rate. Work ***MAXIMUM*** limit torque down to the stuck depth and hold the torque in the string. Stop or reduce pump speed to minimum. Slack off to ***MAXIMUM*** set-down limit. Allow sufficient time for the jars to trip. If the string does not come free, hold torque in the string and continue jarring down with maximum jarring action. **Secondary Action:** If the string does not come free after 5 to 10 blows, continue jarring while preparing a pipe releasing pill. **When String is Free:** Rotate and work the string. Circulate at maximum rate to clean the hole. Check the proper mud specifications.

APPENDIX I

Stuck Pipe Identifier

APPENDIX II

Overpull Calculations

The initial overpull should be either ½ of the BHA weight below the jars in air or 85% of the tensile strength of the weakest component in the string.

To estimate the maximum allowable overpull:

1. Estimate the weakest point in the string. This is usually, but not always, the drillpipe at the surface (e.g. a tapered string). The maximum overpull at the weak point is 85% of the tensile strength at the weak point. (T_m)
2. Calculate the weight of the string in air above the weak point. (W_{sw}) Note that if the weak point is at the surface $W_{sw} = 0$.
3. Calculate the maximum overpull on the weight indicator (Wim).
   Block weight = W_b therefore $W_{im} = W_b + T_m + W_{sw}$
4. Calculate the overpull at the stuck point.

$$\boxed{T_o = W_i - W_b - W_s}$$

Where:

W_b = block weight

W_i = weight indicator reading

W_s = weight of the string in air above the stuck point.

Note: W_i must never exceed W_{im}

APPENDIX III

Jarring Calculations

Let:

L_s = surface load to operate the jars (lb)

W_i = weight indicator reading (lb)

L_j = desired jar load (lb)

D_h = hole drag (lb)

W_j = weight of BHA in air below the jars (lb)

P_f = pump open force (lb)

Load required to trip the jars upwards

$$\boxed{L_s = W_i - W_j + L_j + D_h - P_f}$$

Load required to trip the jars downward

$$\boxed{L_s = W_i - W_j - L_j - D_h - P_f}$$

Note:

- Ensure that the jars are uncocked before working the pipe to the limit.
- Tripping out – jar down
- Tripping up – jar up
- Pump open force only applies when circulating.

Effects of Circulation on Jars

When jarring up, hydraulic jars are more difficult to cock but deliver greater impact and impulse forces. When jarring down, they are easier to cock but deliver less impact and impulse forces.

Mechanical jars are more difficult to cock when jarring upwards but easier to trip. The forces are unaffected. When jarring down they are easier to cock, but more difficult to trip.

APPENDIX IV

Backoff Shots

The time between the free-point survey and running the back-off charge should be held to a minimum because the free point can move up the hole with time or in an unstable wellbore. Back-offs are almost always successful if the pipe torque and stretch are 80 - 85% free. In deviated wells back-offs should not be attempted unless there is at least 50% free torque. A backoff is possible with less than 25% free stretch.

Work left hand torque down to the back-off point as recommended in the table below. Limit the torque to 80% of the drill pipe makeup torque.

DEPTH (ft)	TURNS/1,000 ft
Below 4,000	0.25 – 0.50
4,000 – 9,000	0.50 – 0.75
9,000 +	0.75 – 1.00

Calculate the string weight in air to the backoff point and pull on the string to ensure neutral weight at the back-off point when firing. Incorrect weight is a common cause of back-off failure. If the back-off is successful, pull up and work the pipe while the wireline is removed. Circulate bottoms up before tripping the pipe out of the well.

NOTES