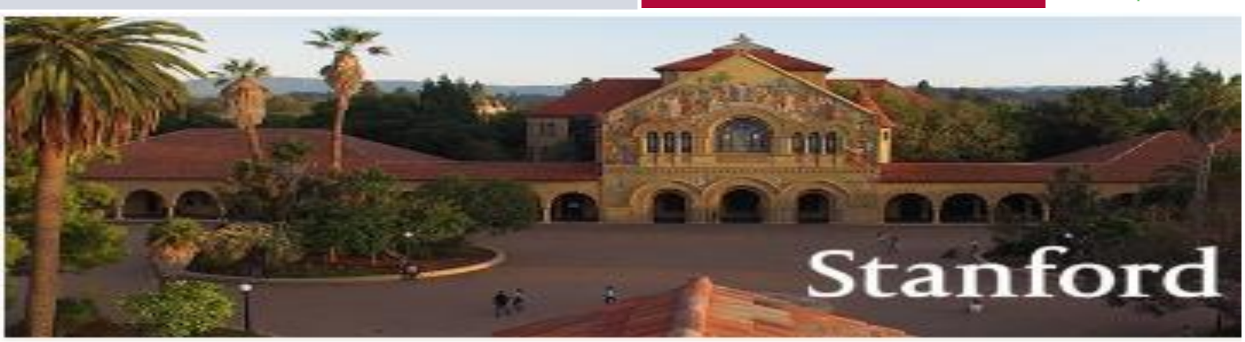
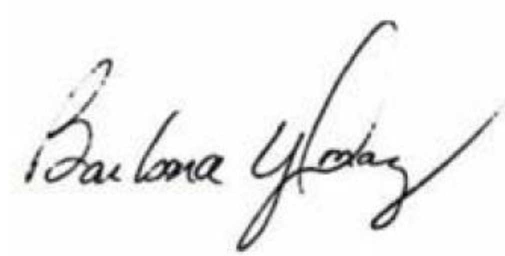
RESERVOIR GEOMECHANICS, GEOMECHANICAL EVALUATION AND WELLBORE STABILITY HANDBOOK/MANUAL FOR STUDENTS

Professor Dr. Sc., PhD **Elnur Amirov** at the Departments of Petroleum Engineering (Baku Higher Oil School, Khazar University and Heriot Watt University). M/LWD Log Analyst (Sr. Tech Prof Petrophysicist) at SS Drilling Services by the permission of BP Colleagues **Stephen Willson , Jianguo Zhang and Barbara Yilmaz** compiled this Handbook/Manual specially for students in order to help them to improve skills, accumulate knowledge and get the better understanding of the Reservoir Geomechanics, Geomechanical Evaluation and Wellbore Stability **(BP Colleagues compiled all data and updated the original Amoco handbook)**. Special thanks go to Jose Fernandez who communicated with authors (**Stephen, Jianguo and Barbara**) of the BP Wellbore Stability Handbook and got permission to share knowledge about wellbore stability and geomechanics with students).
e-mails: e.amirov@hw.ac.uk; eamirov@khazar.org; amire3@bp.com; elnuramirov@outlook.com; elnuramirov@hotmail.com; amirovelnur@gmail.com



Barbara Yilmaz

TVP, Drilling and Completions



Barbara Yilmaz (The BP Wellbore Stability Handbook is an update of the earlier Amoco Handbook, and incorporates much new learning and experience in wellbore stability assessment. It has been compiled by **Stephen Willson** and **Jianguo Zhang** in BP's Exploration and Production Technology Drilling Group. Hopefully knowledge which students will acquire from this Handbook will be very useful in their study and career path development in the future).

Elnur Amirov (I passed Reservoir Geomechanics course and got statement of accomplishment/certificate from the Stanford University and decided to prepare quick look handbook/manual for students as some of them kindly asked me to help them to better understand this subject which is very popular, important and useful in Oil and Gas industry nowadays. Some useful information and photos were taken from Stanford University website and some useful information and photos were taken from the BP Wellbore Stability Handbook. So this quick look handbook/manual specially was compiled and prepared for students in order to help them to get into the swing of things in regards of reservoir geomechanics, geomechanical evaluation and wellbore stability. So we all hope that students will study hard and become well educated/experienced specialists in the future).

Stanford
STATEMENT OF ACCOMPLISHMENT

June 10, 2016

Elnur Amirov

has successfully completed

Reservoir Geomechanics

and has demonstrated understanding of practical issues in energy production combining knowledge of the stresses in the Earth with the principles of rock mechanics, structural geology, petroleum engineering, and earthquake seismology.

Fatemeh S. Rassouli

Fatemeh S. Rassouli
PhD Candidate
Department of Geophysics
Stanford University

Noha Farghal

Noha Farghal
PhD Candidate
Department of Geophysics
Stanford University

Mark D. Zoback
Benjamin M. Page Professor of Geophysics
School of Earth, Energy & Environmental Sciences
Stanford University

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AND IS AWARDED THIS

CERTIFICATE OF COMPLETION

ROBERTO PEVERARO
Instructor

J. FORD BRETT
Managing Director

bp

Elnur Amirov

HAS SATISFACTORILY COMPLETED THE COURSE

STRUCTURAL GEOLOGY

BAKU, AZERBAIJAN / SEPTEMBER 5 - 9, 2005

AND IS AWARDED THIS

CERTIFICATE OF COMPLETION

Dr. RICHARD DAVIES, *Geologist*	*Dr. ELMIRA ALIYEVA,* *Geologist*	*STEWART SIMON,* *BP Geophysicist*

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Issued on:

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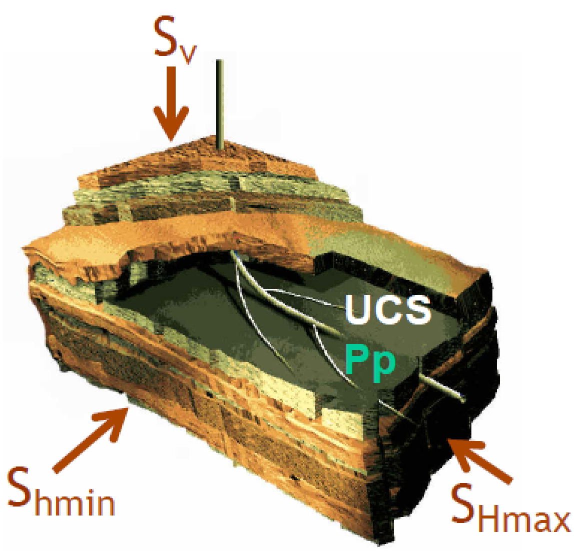
David A.T. Donohue, Ph.D., J.D

RESERVOIR GEOMECHANICS, GEOMECHANICAL EVALUATION AND WELLBORE STABILITY HANDBOOK/MANUAL FOR STUDENTS

Geomechanics (from the Greek prefix **geo-** meaning "**earth**"; and "**mechanics**") involves the geologic study of the behavior of soil and rock**.** Many aspects of geomechanics overlap with parts of geotechnical engineering, engineering geology and geological engineering. Modern developments relate to seismology, continuum mechanics, discontinuum mechanics and transport phenomena.

In the Petroleum Engineering Industry, geomechanics is used to predict important parameters, such as in-situ rock stresses, modulus of elasticity, leak-off coefficient and Poisson's ratio. Reservoir parameters that include: formation porosity, permeability and bottom hole pressure can be derived from **Geomechanical Evaluation**. The geotechnical engineer or geophysicist relies on various techniques to obtain reliable geomechanical models. These techniques that have evolved over the years, are: coring, log analysis; well testing methods like hydraulic fracturing, and geophysical sonar methods such as acoustic emission.



Principal Stresses at Depth

S_v - Overburden
S_{Hmax} - Maximum horizontal principal stress
S_{hmin} - Minimum horizontal principal stress

Additional Components of a Geomechanical Model

P_p - Pore Pressure
UCS - Rock Strength (from logs)
Fractures and Faults (from Image Logs, Seismic, etc.)

The ultimate objective of the Reservoir Geomechanics, Geomechanical Evaluation and Wellbore Stability in the petroleum industry is a guide to assure a stable wellbore. The Drilling and Completions Strategy is to be the industry leader in the delivery of wells to maximize recovery of resource (through safe, reliable and efficient operations). Well complexity continues to increase as we push the limits of the drilling envelope both in depth and extended reach. Not all of these wells are as trouble-free as we would wish them to be. Drilling Non-Productive Time (NPT) costs bunch of funds for many companies in the world. Formation-related problems account for over one-third of the NPT total. Many of these problems can be aggregated into the overall causes of wellbore instability and stuck-pipe.

This manual is designed to provide students with knowledge and better understanding of the Reservoir Geomechanics, as most of students will work in the future in Oil and Gas industry as drilling engineers, well-site leaders, well-site geologists and operations geologists involved with well planning and delivery the basic understanding of factors influencing the wellbore stability. It is hoped that through a better understanding of the causes of instability, formation related NPT can be reduced. The causes of wellbore instability can be many and various. The geology, state of stress and pore fluid pressure of the formations being drilled are important, as is the trajectory of the well through these formations. The density and chemical formulation of the drilling fluid play a key role in the prevention of wellbore instability. But the drilling fluid can also be a cause of problems too, if not properly designed. Drilling practices can also make the well become unstable, even if everything else is adequate. This manual for students provides awareness information on all these potential causes. Anticipating a wellbore instability problem in the planning stage, diagnosing a problem as it begins to develop, and intervening appropriately to limit its severity if a problem does develop, offers great opportunities to make a step-change in drilling performance.

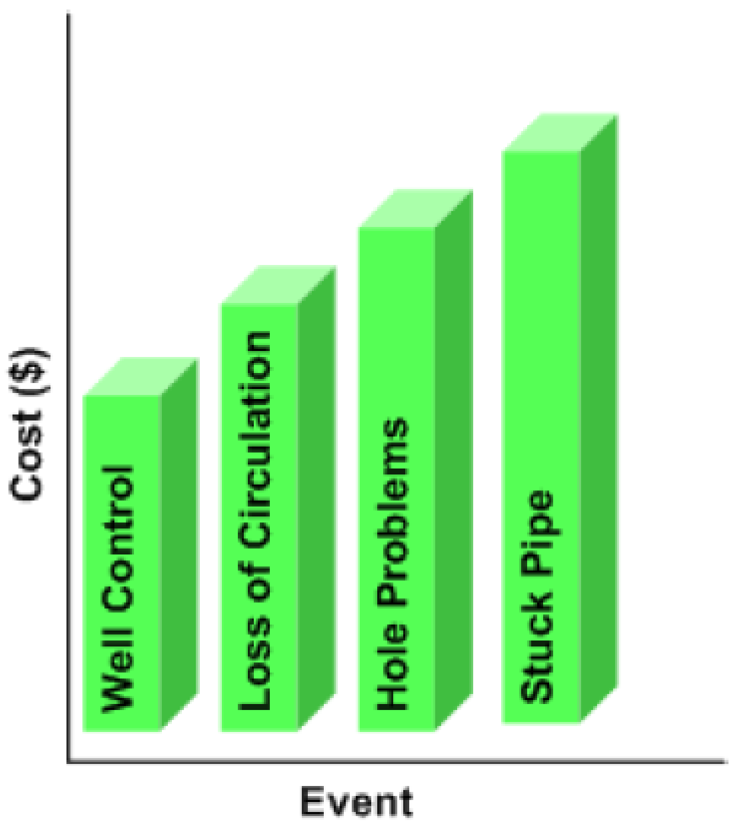
Hopefully this Handbook/Manual for students will be very useful in your study, projects, work in the future, summer internship and etc, as we strive to drill safe, reliable and efficient wells (if not take into the account all abovementioned valuable information and comments, then eventually uncontrolled release of crude oil or gas from a well can happen as shown below).

INTRODUCTION AND BASIC CONCEPTS

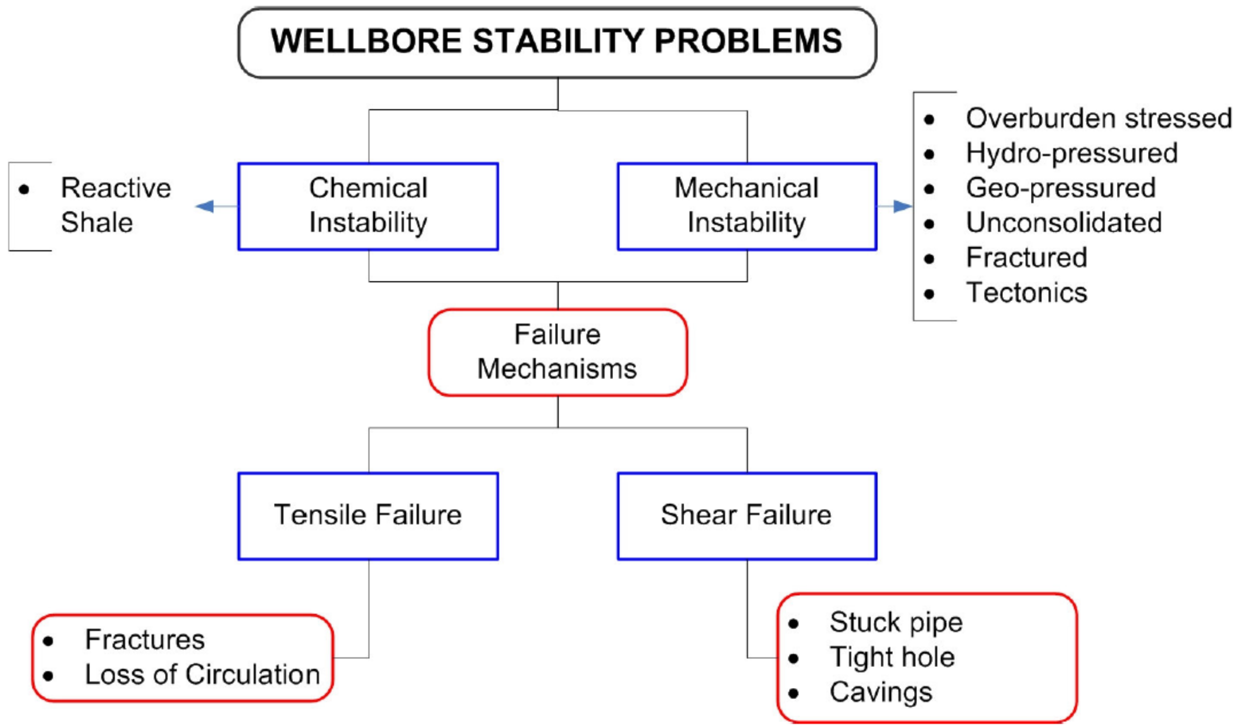
Wellbore stability management is the prevention of unwelcome failure or deformation of the rock surrounding the wellbore due to mechanical stress or chemical imbalance. Prior to drilling, the mechanical stresses in the formation are less than the strength of the rock. The rock is also in a state of chemical equilibrium, or changing slowly at a rate relative to geologic time (millions of years). Rocks under this equilibrium or near-equilibrium state are stable.

After drilling, the rock surrounding the wellbore undergoes changes in stress as the rock forming the core of the hole is removed. Chemical reactions also occur with exposure to the drilling fluid. Under these conditions of altered stresses, the rock surrounding the wellbore will begin to deform. Depending on the magnitude of the stress changes occurring, the rock surrounding the wellbore may become unstable. It may fracture, resulting in losses of borehole fluid to the formation. It may break into pieces, and these may fall into the wellbore so producing rock cavings along with rock cuttings at the rig shakers. If the drilling fluid chemistry is not formulated properly, the rock may crumble and disperse into the drilling fluid.

High rock stresses relative to the hydrostatic pressure exerted by the wellbore drilling fluid can collapse the hole, so resulting in a stuck pipe problem. In deformable, mobile formations this can also produce tight hole problems. Cavings from a failing formation result in sections of the borehole being larger than the original as-drilled bit diameter. This makes hole cleaning more difficult and increases mud and cementing costs.



Related Cost of Unscheduled Events Caused by Wellbore Stability Problems



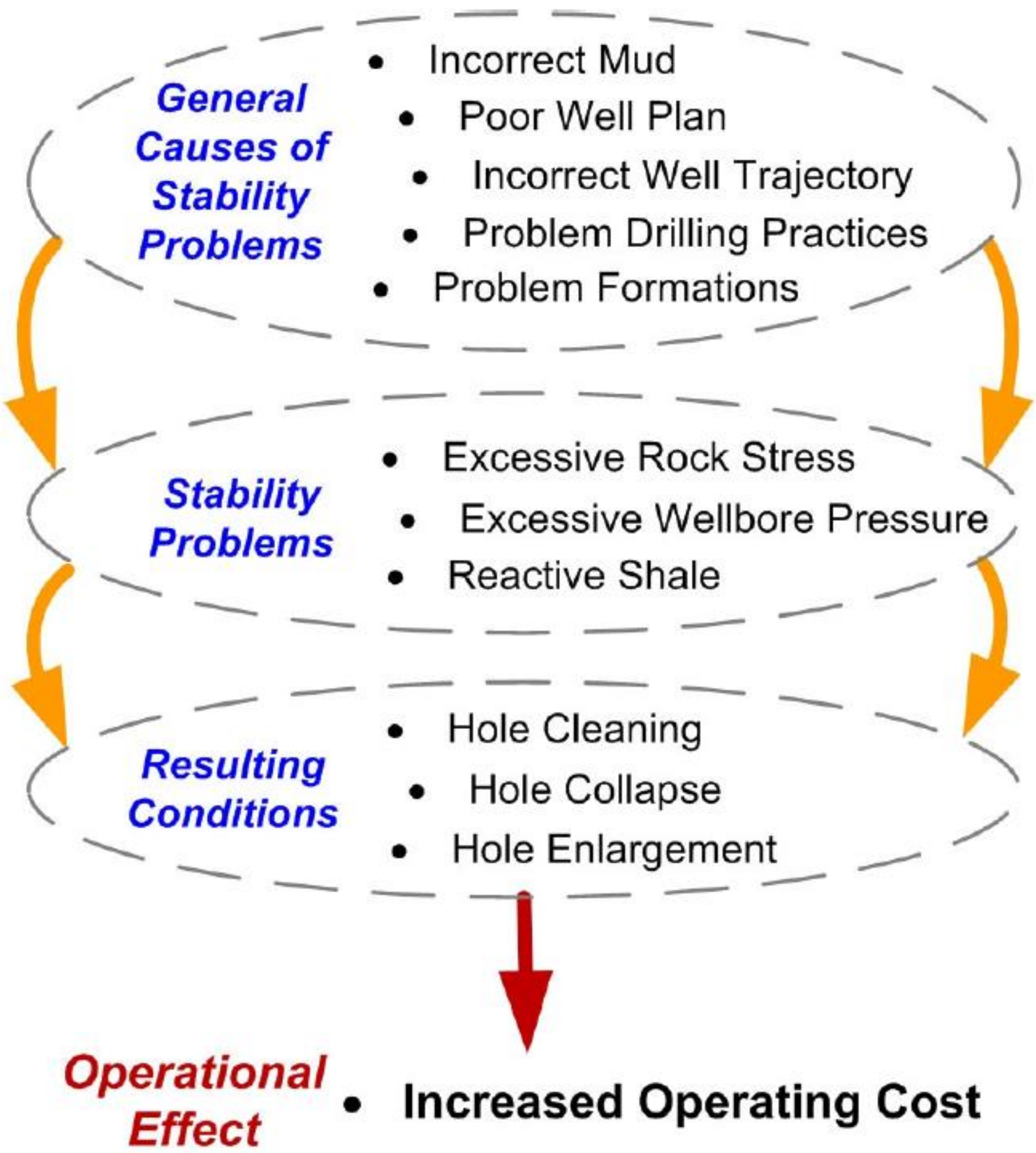
OBJECTIVES

Generally objectives related with identification of wellbore instability problems:

- Suggest consistent terminology.
- Associate warning signs with specific instability problems.
- Suggest corrective actions.
- Provide the background for preventative planning.

Understanding the conditions that cause stability problems provides for:

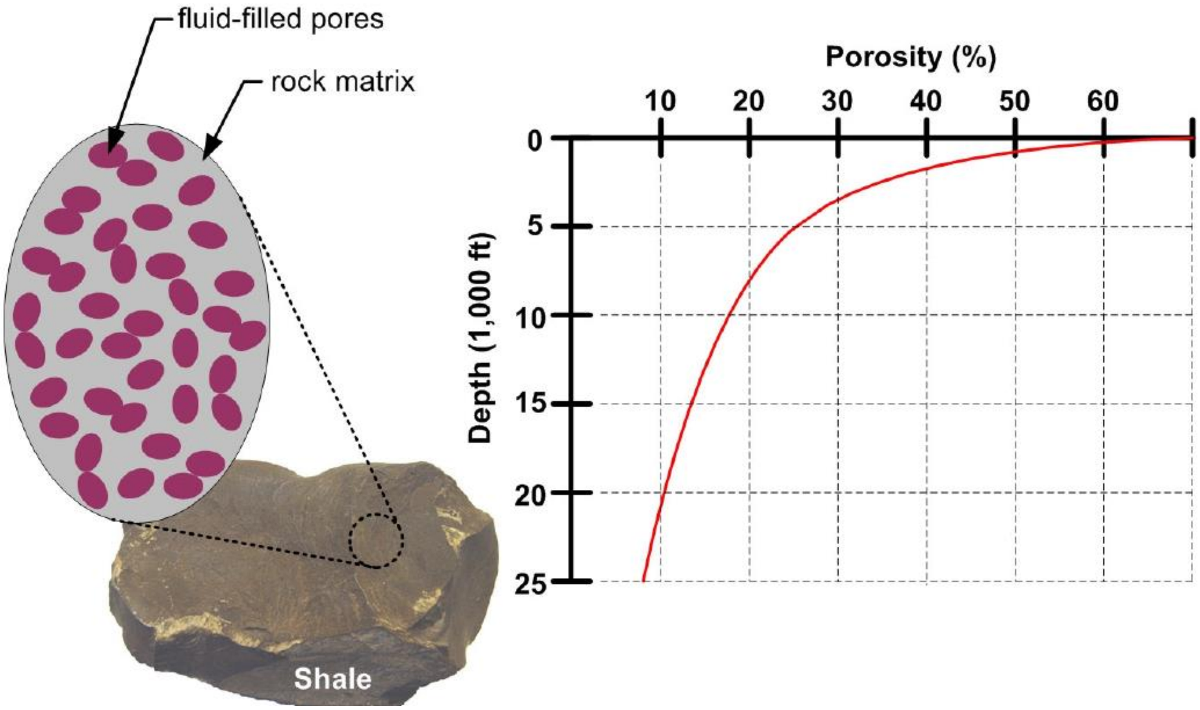
- More effective planning.
- Earlier and easier detection of warning signs.
- Contingency plans to prevent the progression of the problem.



IN-SITU WELLBORE CONDITION (POROSITY, PERMEABILITY AND FORMATION PORE PRESSURE)

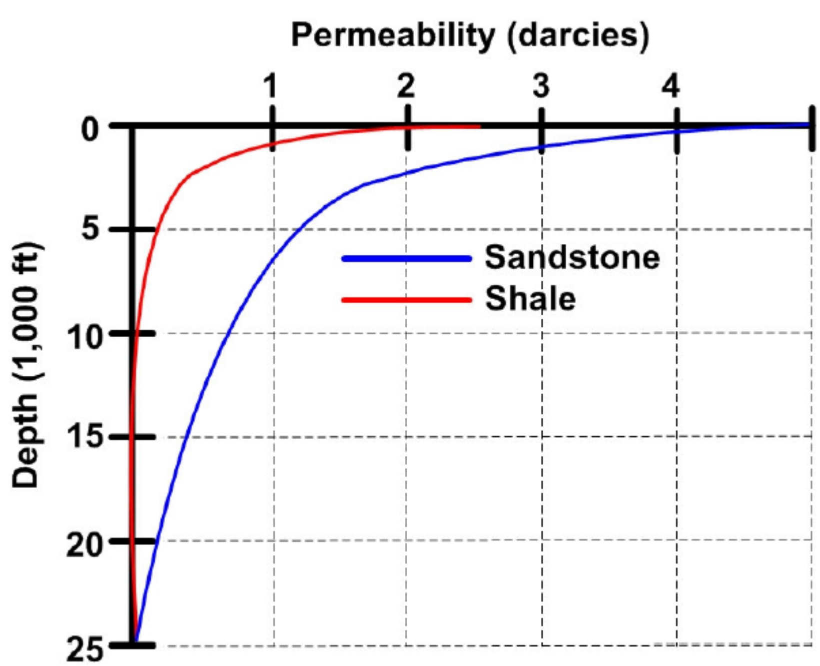
Porosity

Porosity is the percent of void space within the rock. The rocks of sedimentary basins always exhibit some porosity. Recently deposited sand and mud at very shallow depth have very high porosities – sometimes as much as 65%. As these sediments become buried over geologic time, the porosity decreases as the water gets squeezed from the pore space. As porosity decreases, the percent of fluid volume decreases while the rock matrix volume proportion increases. The figure below shows typical porosity change with depth due to compaction and cementation. Decreasing porosity strengthens the rock. Porosity loss during burial is not recovered if the rock formation becomes uplifted (exhumed) over geologic time. Upon exhumation, very little porosity may be regained by the unloading process.



Permeability

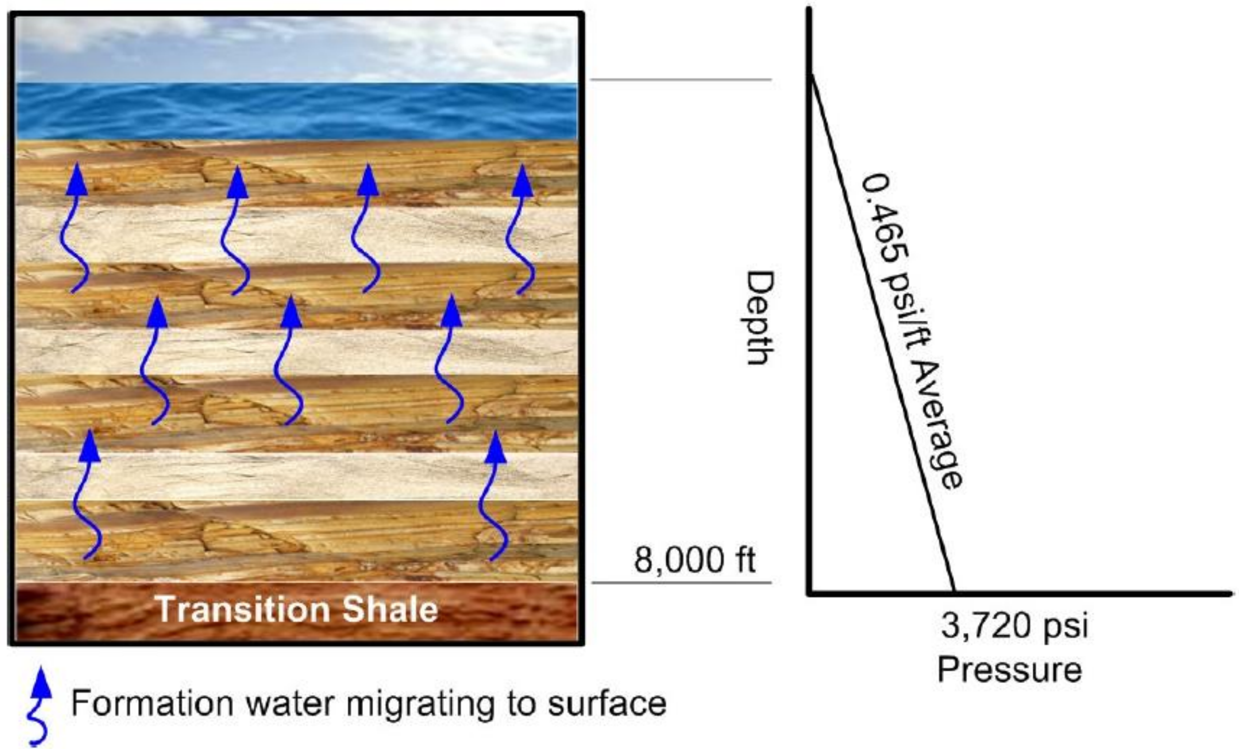
Permeability is the ability of a rock to allow the flow of fluids through it. Permeability is conventionally measured in units of Darcies. The figure below shows typical permeability changes relative to depth for shale and sandstone. Shales may have high porosity, but have very little permeability.



Formation pore pressure - p

Formation pore pressure is the pressure of the naturally occurring fluid(s) in the pores of the rock. As long as the increase in overburden load from the rate of deposition does not exceed the rate at which fluid can escape from the pore, a fluid connection exists from surface to the depth of interest. Pore pressure is then equal to the hydrostatic pressure of formation water (normal pressure).

Normal formation pressure is equal to the hydrostatic pressure of formation water at a vertical depth of interest.

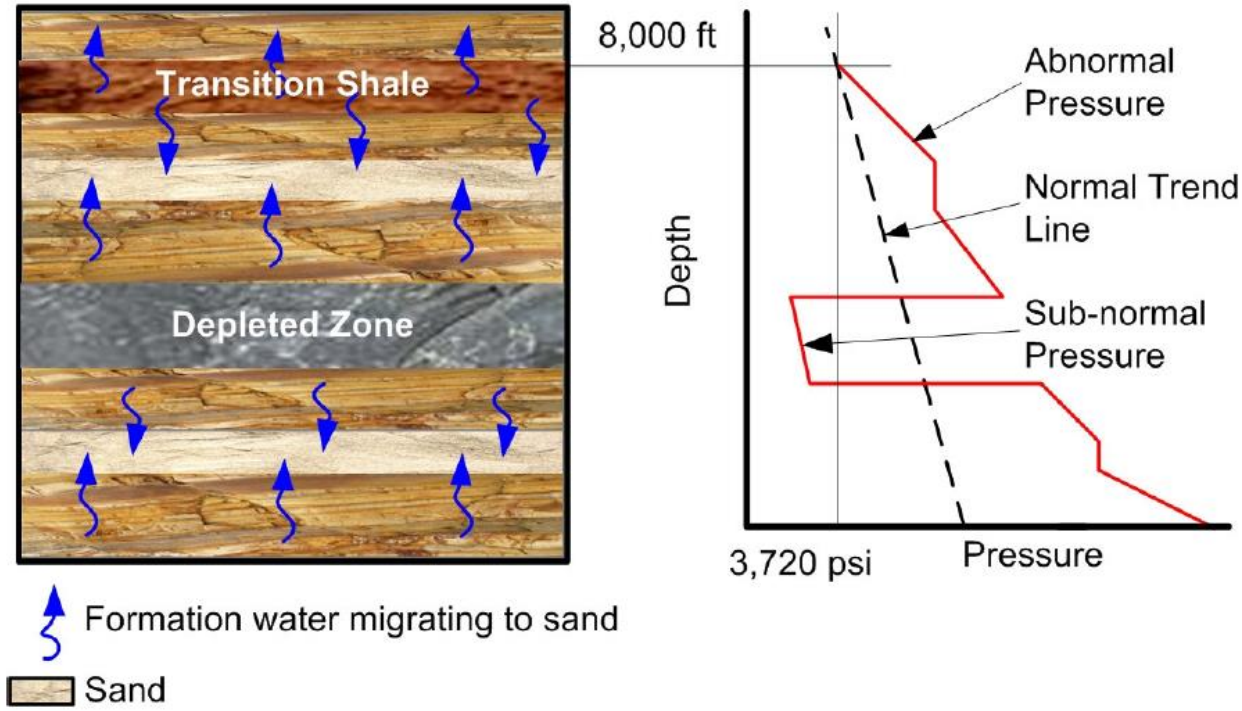


If the fluid cannot escape the pore, pore pressure begins to increase at a faster than-normal rate (abnormal pressure).

Abnormal formation pressure is greater than normal for the vertical depth of interest. Such formations are sometimes referred to as being **geopressured**.

Pore pressure of a permeable formation can be depleted below normal by production operations (subnormal pressure).

Subnormal formation pressure is less than normal for the vertical depth of interest.



Estimating formation pore pressure
Formation pore pressure prediction is a specialized process. Methods used to predict pressure can be grouped into one of three general categories:
1) Analog Methods, 2) Petrophysical Methods, or 3) Basin Modeling Methods

Analog methods use offset well data to estimate pressure at a planned well location. The source of pressure at the analog location may be actual measurements of pressure from formation pressure testers, drill stem tests, or production pressure data, or it may be inferred pressures from log measurements, drilling indicators, kicks, and mud weights. These pressures are then projected to the proposed well locations. Methods of projection will vary depending upon the complexity of the problem.

Petrophysical methods use seismic velocities to estimate pore pressure at a proposed well location. This method would normally involve carefully extracting velocities at a calibration reference point to determine key parameters and then applying those parameters to velocities carefully extracted at several control points surrounding the proposed location. The quality of results will usually relate to the validity of the calibration and the relationship of that calibration point to the proposed location.

Basin modeling methods use complex techniques to predict pressures in a two or three dimensional model of the basin where a well is planned. The model primarily considers compaction disequilibrium (sedimentation driven) and lateral pressure transfer mechanisms to arrive at a distribution of pressure throughout the basin. It can often also accommodate other pressure generating mechanisms (clay diagenesis, aquathermal expansion, osmosis, etc.) to a limited degree. Calibration to measured pore pressures in other wells in the basin is usually essential to predict reliable pore pressure estimates at the new well location.

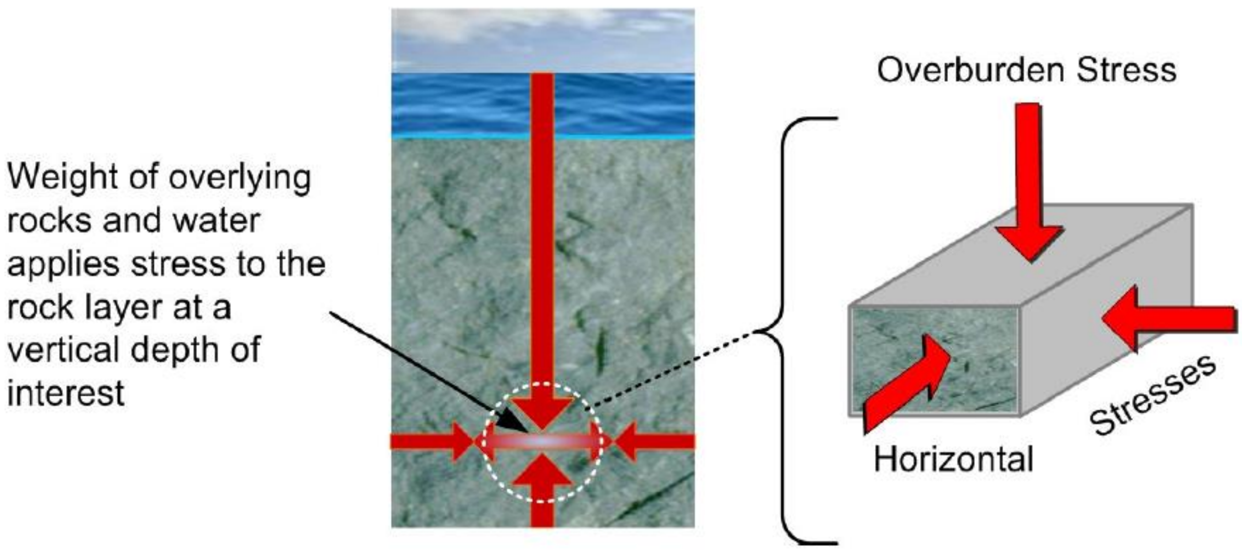
Each of these three methods have relative strengths and weaknesses. These strengths and weaknesses will vary with the complexity of the basin, the nature of the origin of pressures, the quality of the calibration data, the relationship of calibration points to target locations, etc. Determining which method is preferred can be complex. The cost of each method must also be considered. In many cases it may be advantageous to use more than one method.

In-Situ Earth Stress (Total Stress)

Prior to drilling, subsurface rocks are exposed to an equilibrium or near equilibrium (balanced or near balanced) stress environment. The naturally occurring stress in place is called in-situ total stress. In-situ total stress is compressive due to the weight of the overburden. For this reason, in rock mechanics terminology, compressive stress is defined to be positive. There are three components of in-situ total stress acting at depth: the overburden stress, which acts vertically, and two horizontal stresses.

Overburden stress - Sv

Overburden stress is the pressure exerted on a formation at a given depth due to the total weight of the rocks and fluids above that depth.



Most formations are formed from a sedimentation and compaction geologic history. Formations may vary significantly from the earth’s surface to any depth of interest both in their mineralogical composition and degree of compaction.

Shallow shales will be more porous and less dense than shales at great depth. Thus the density of the rocks making up the overburden increases with depth.

Estimating overburden stress – Sv

Ideally, overburden is determined through integrating the density of sediments vertically above a point of interest. Thus, Sv = $\rho \times g \times h$, where ρ is the average density over interval h, and g is gravitational acceleration. This relationship is usually calculated by subdividing the overburden into short intervals of measured density and then integrating the density over those intervals back to the surface.

Density log data should be used to determine the density of the overburden sediments. Unless measurements have been made from shallow depth, there is usually some near-surface interval where densities have to be estimated by extrapolating back to a seawater density at seabed (in marine environments).
The overburden gradient (the overburden stress divided by depth) is usually assigned a value of between 0.9 psi/ft to 1.0 psi/ft to approximate the changing density with depth. But at shallow depths in marine environments values may be much less than this. At greater depths, particularly onshore, the local overburden gradient may be slightly higher than 1.0 psi/ft. In deepwater settings, the seawater gradient of approximately 0.45 psi/ft can significantly affect the calculation of the overburden stress. The presence of considerable thicknesses of salt in certain deepwater environments also needs to be factored into the estimation of the overburden stress. As this stress profile is typically used as an input to pore pressure estimation, and the estimation of horizontal stresses, it is very important that the overburden estimation is undertaken with great care.

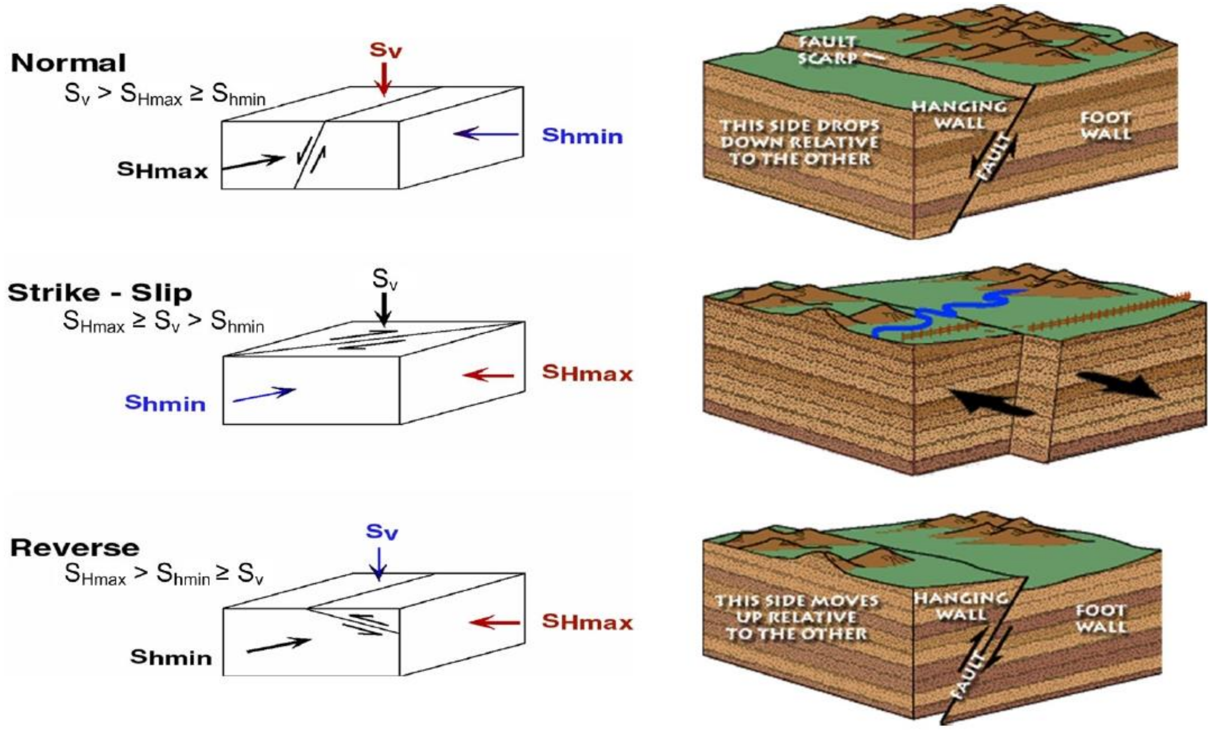
Horizontal stress – Shmin, SHmax
As the overburden squeezes the rock vertically, it pushes horizontally too. Constraint by the surrounding rock creates horizontal stress. In many drilling areas, the horizontal stresses are roughly equal. However, when drilling near significant geologic structures such as salt domes or in tectonic areas (e.g., mountainous regions onshore), the horizontal stresses will differ and will have minimum (**Shmin**) and maximum (**SHmax**) values.

Estimating horizontal stress

The minimum horizontal stress (Shmin) is usually determined from leak-off tests conducted in prior wells. In normally-pressured areas without much geological structural relief, the minimum horizontal stress will have a gradient of about 0.7 psi/ft – i.e., roughly half-way between the pore pressure gradient of 0.44 psi/ft and the overburden gradient of 1.0 psi/ft.
It is difficult to determine the maximum horizontal stress directly from field measurements. Its value can be constrained from estimates of the frictional strength of rocks at depth when the other stresses and pore pressure are known. Observations of borehole failures – either breakouts or drilling-induced tensile fractures – seen in image logs allow better estimates of **SHmax** to be made using rock mechanics equations.

Relative magnitudes of total stresses
The vertical overburden stress is not always the most compressive of the three components of in-situ total stress. Different geologic environments can sometimes give rise to large horizontal stresses which might exceed the magnitude of the vertical stress. Three regimes of stress can exist in the subsurface, depending on the relative magnitudes of the horizontal stresses relative to the vertical stress:

1) **normal stress regime**, where Sv > SHmax ≥ Shmin, typically found in extensional geologic environments or passive basins.
2) **strike-slip stress regime**, where SHmax ≥ Sv > Shmin, typically found in regions of moderate compression or uplift; and
3) **thrust fault stress regime**, where SHmax > Shmin ≥ Sv, typically found in highly compressional regions (this stress state is sometimes referred to as reverse faulting by geologists).



Effective Stress

The rock matrix (the grains forming the solid portion of the rock) does not support the full load of overburden and horizontal stress. Part of the load is supported by the pressure of the fluid in the pore space (the pore pressure), much like air pressure in a car tire supports the weight of the car. The effective stress is that part of the total external stress felt by the rock matrix. Effective stress is used in rock mechanics calculations to determine the stability of the wellbore.

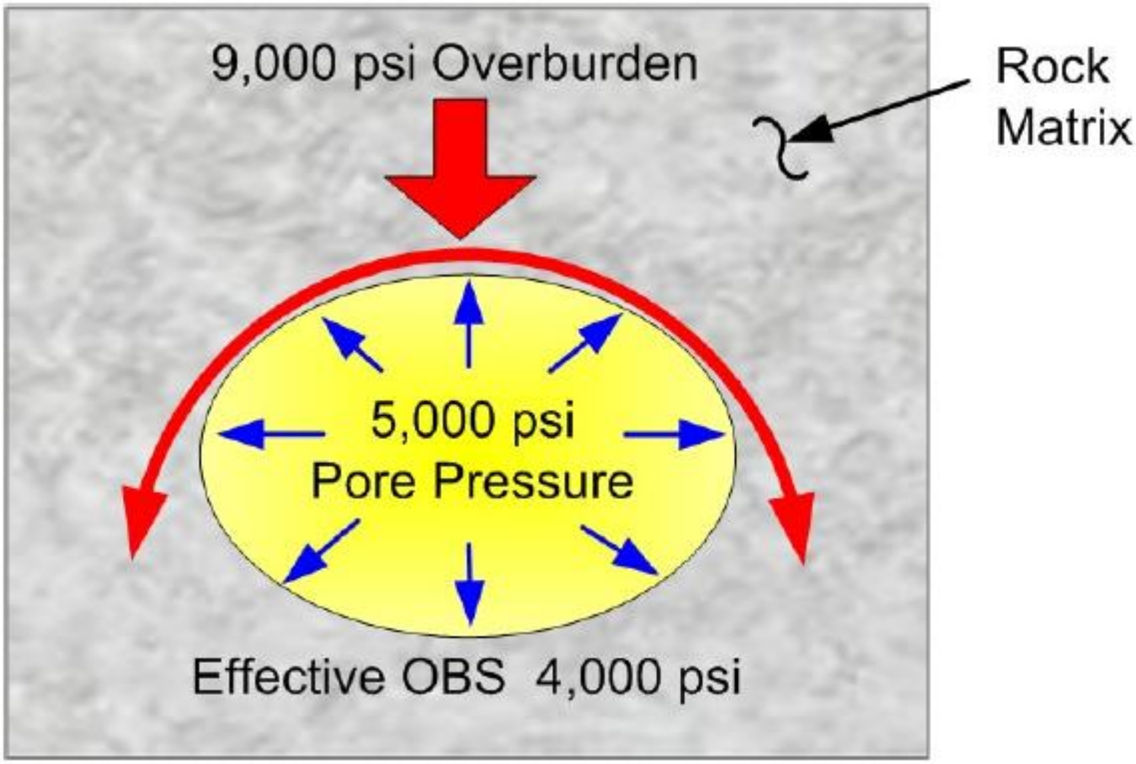
Effective overburden stress – $\boldsymbol{\sigma_v}$

Effective Overburden Stress is the proportion of the total overburden stress that effectively stresses the rock matrix.

Effective Overburden Stress = Total Overburden Stress – Biot's parameter × Pore Pressure

$$\boldsymbol{\sigma_v} = S_v - \alpha p$$

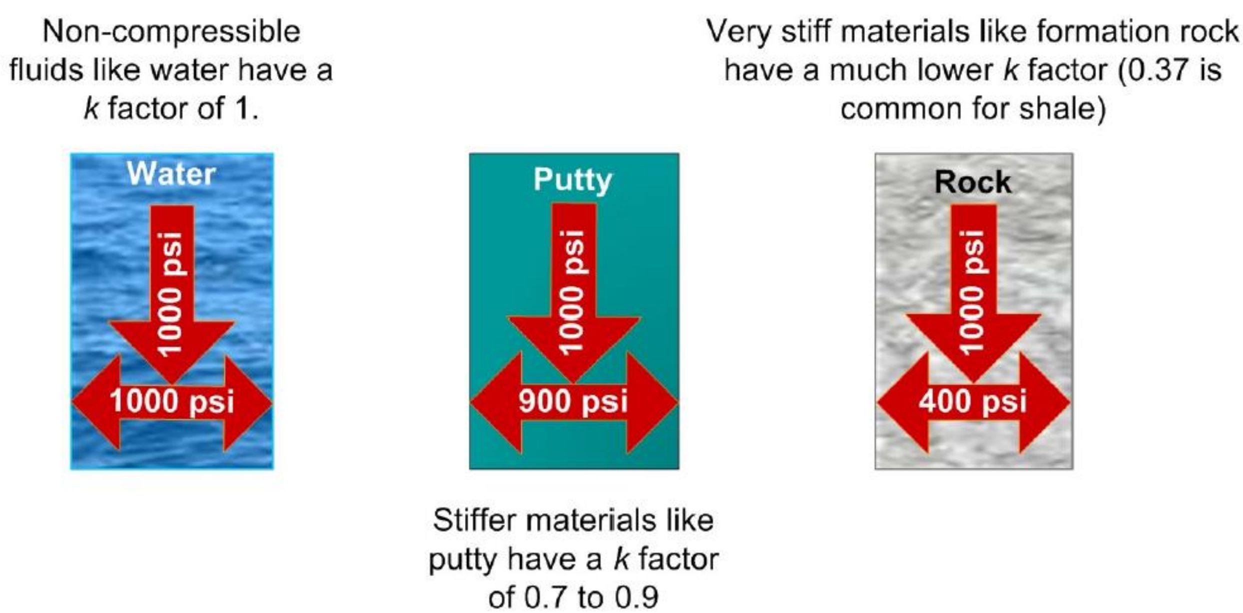
In the equation above, a is Biot's poroelastic parameter. For most practical applications, α is close to 1. In instances where pore pressure is very high (i.e., a large fraction of the total overburden stress) special rock mechanics tests may be performed to directly measure α.



Effective horizontal stress – σ_{hmin}, σ_{Hmax}

Similarly, the effective horizontal stresses can be determined. Often, in passive basin environments, the horizontal stresses are nearly equal, and the effective horizontal stress is equal to the effective overburden stress times a lithology factor, k. The lithology factor (k) is equal to 1 for salt (and also for fluids), but is less than 1 for most formation rocks.

$\sigma_{hmin} = \sigma_{Hmax} = k \times \sigma_v$



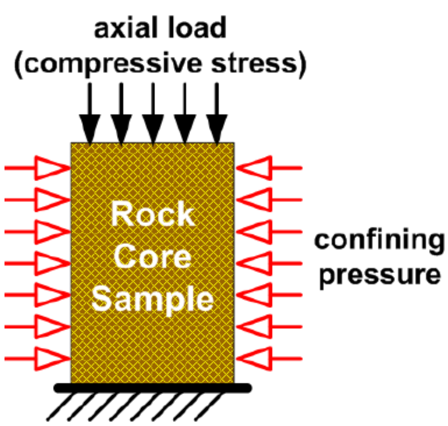
In tectonically active areas, the horizontal stresses are not equal. The maximum horizontal stresses will be higher, or lower depending on tectonic movements, by the additional tectonic stresses, thmin and tHmax. In these areas, the effective horizontal stresses are described by a maximum and minimum value.

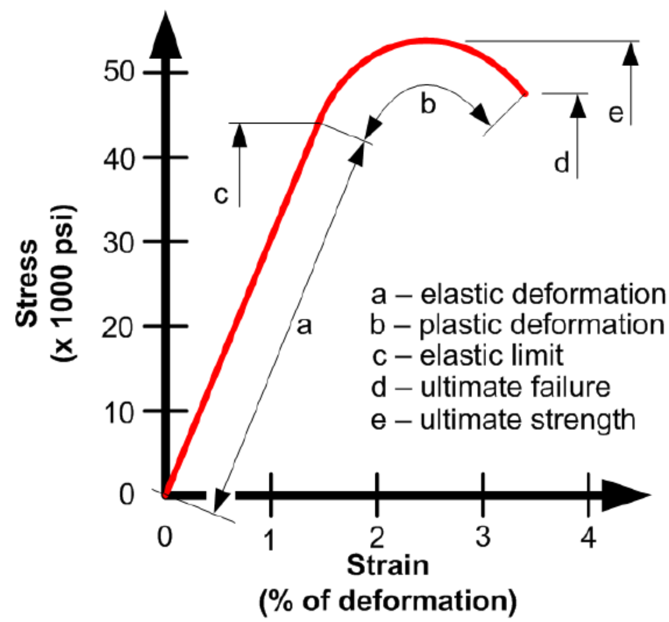
$\sigma_{hmin} = k \times \sigma_v + t_{hmin}$ and $\sigma_{Hmax} = k \times \sigma_v + t_{Hmax}$

As discussed above, in some tectonic environments, tHmax may be sufficient to make the maximum effective horizontal stress higher than the vertical stress. In extreme cases, thmin may also increase the minimum effective horizontal stress to a value that is just above the vertical stress.

Rock Strength

Rock mechanics is the study of the mechanical behavior of subsurface rocks. Core samples removed from in-situ conditions are usually tested in compression with specialized laboratory equipment. To better simulate subsurface conditions, core samples tested are also subjected to a confining pressure (stress). The rock responds to the stress by changing in volume or form (deformation) or both.
The proportional change in the rock volume or form due to the applied stress is called strain.
Rocks subjected to compressive (+) or tensile (-) stress can go through three stages of deformation. In elastic deformation, the rock deforms as stress is applied but returns to its original shape as stress is relieved. In **elastic deformation**, the strain is proportional to the stress (Hooke's Law).

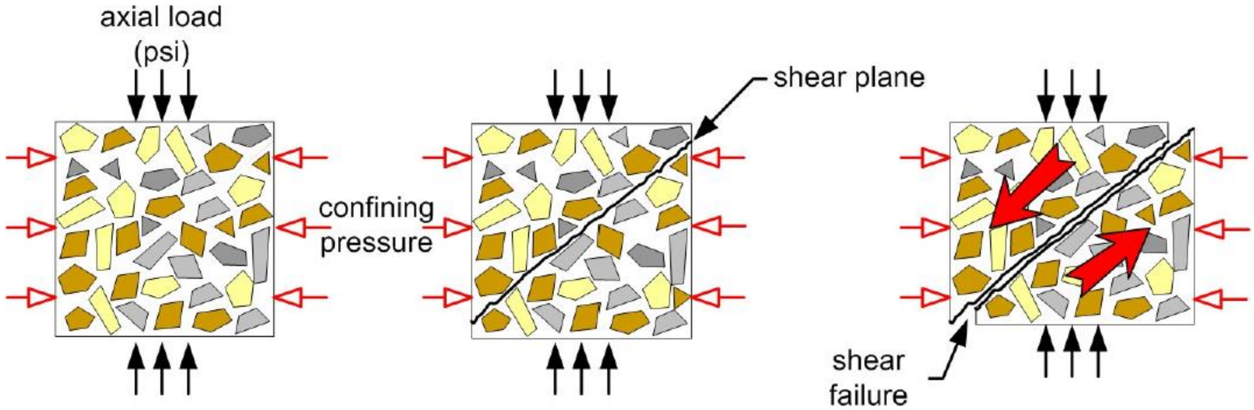




When applied stress reaches the elastic limit, the rock begins to exhibit irrecoverable **plastic deformation**. After experiencing **plastic deformation**, the rock only partially returns to its original shape as stress is relieved. If continued stress is applied, fractures develop and the rock fails (**ultimate failure**).
Rocks can fail in a brittle manner, usually under low confining stress, or in a ductile manner under higher confining stress.

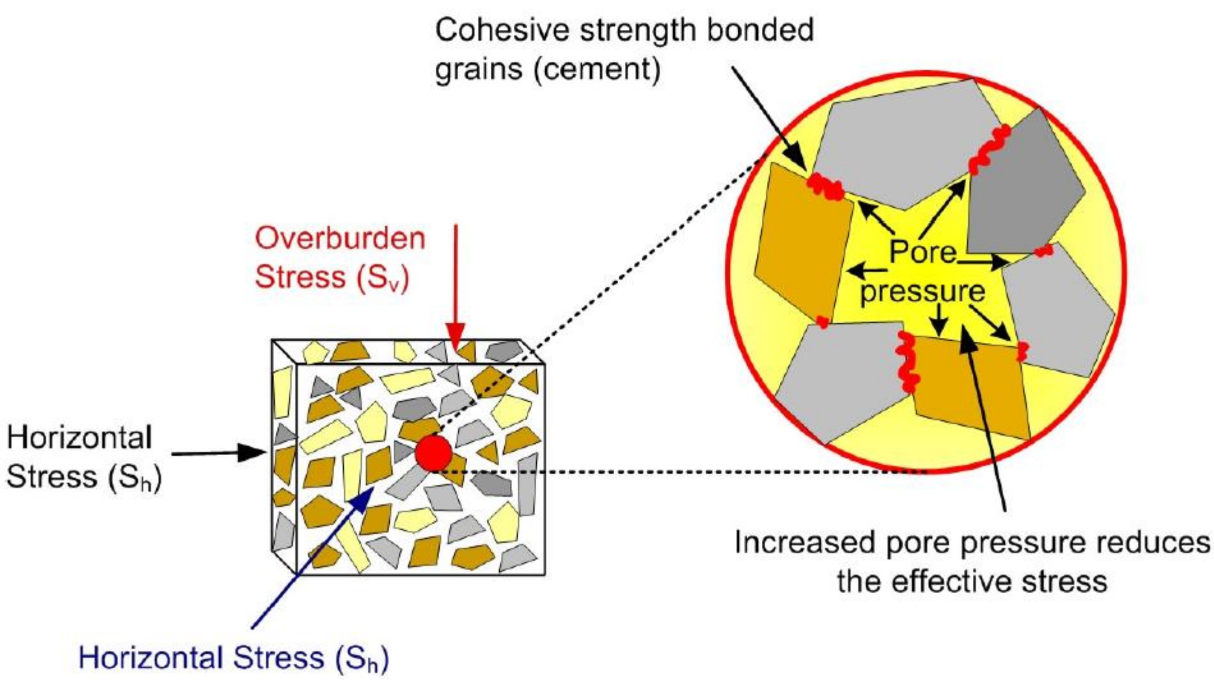
Shear strength and shear failure

Under compression rocks actually fail in shear – it is easier to slide rock grains past each other than to crush them.

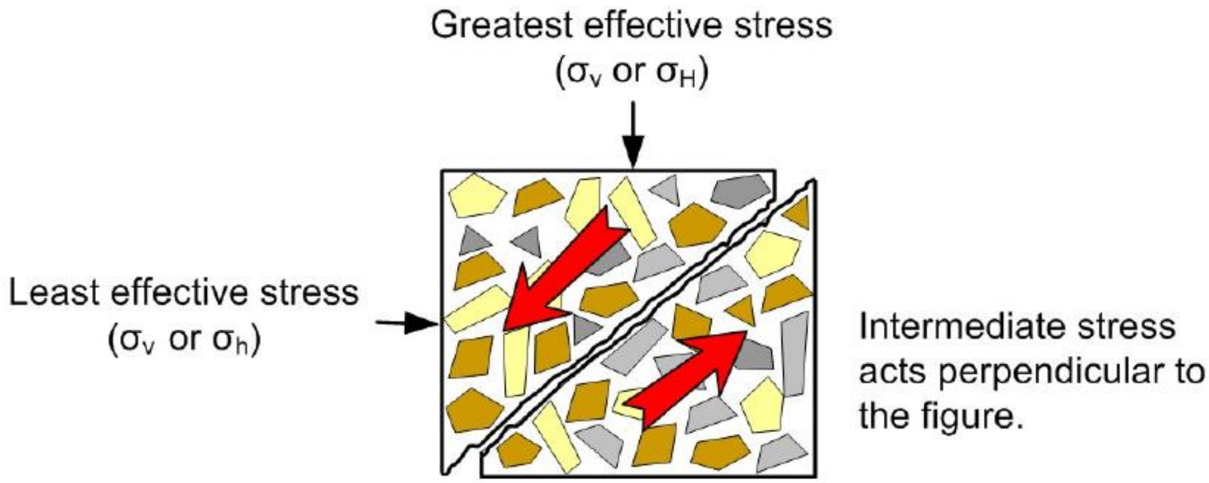


High confining pressure resists sliding on the shear plane and the rock appears stronger. If the confining pressure and axial load were equal, there would be no shear stress on the rock and no shear failure.

Equal stresses promote stability and unequal stresses promote shear stress and possible shear failure.



Rock mechanics uses failure models to predict wellbore stability. Several models exist of differing complexity. The Mohr-Coulomb failure model, used in the illustrations here, considers only the *greatest* and *least* effective stress acting on the rock. These could be any of the three effective stresses, depending on insitu environment and well conditions.



The shear stress that fails the rock must overcome the cohesive strength, So (equivalent to the cement and other forces that bond together the grains of the rock), and the frictional resistance between the grains. The frictional resistance between the grains is the product of the coefficient of friction (μ) and the effective compressive stress (σ).

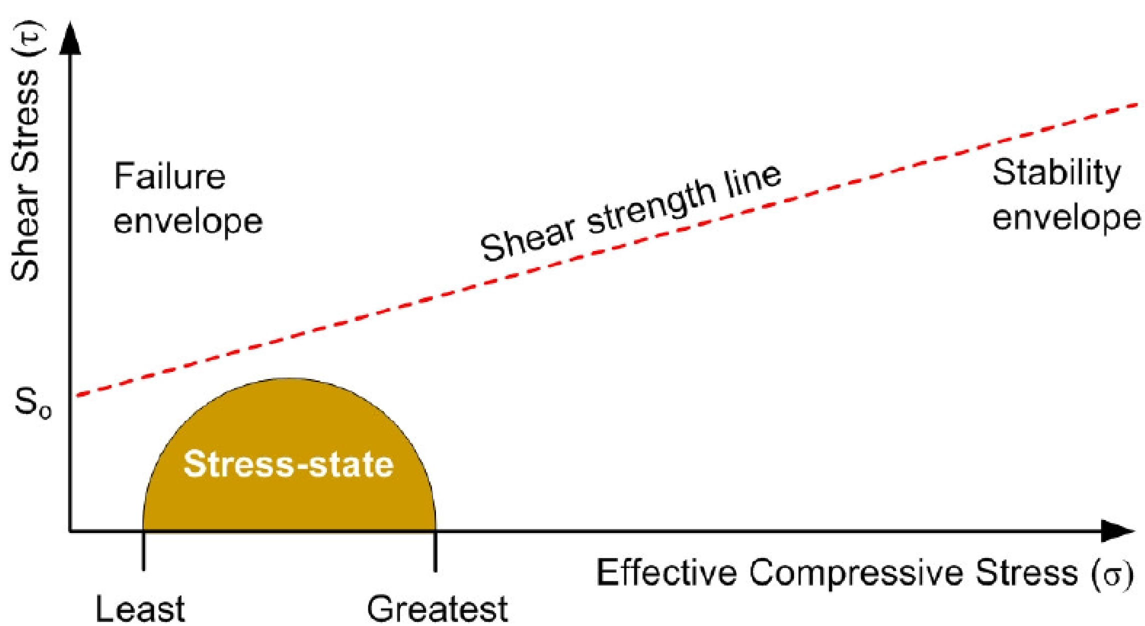
Shear Stress = Cohesive Strength + $\mu\sigma$

$$\tau = So + \mu\sigma$$

The shear strength is defined as the shear stress that fails the rock. The coefficient of friction is also expressed in terms of an angle of internal friction (φ).

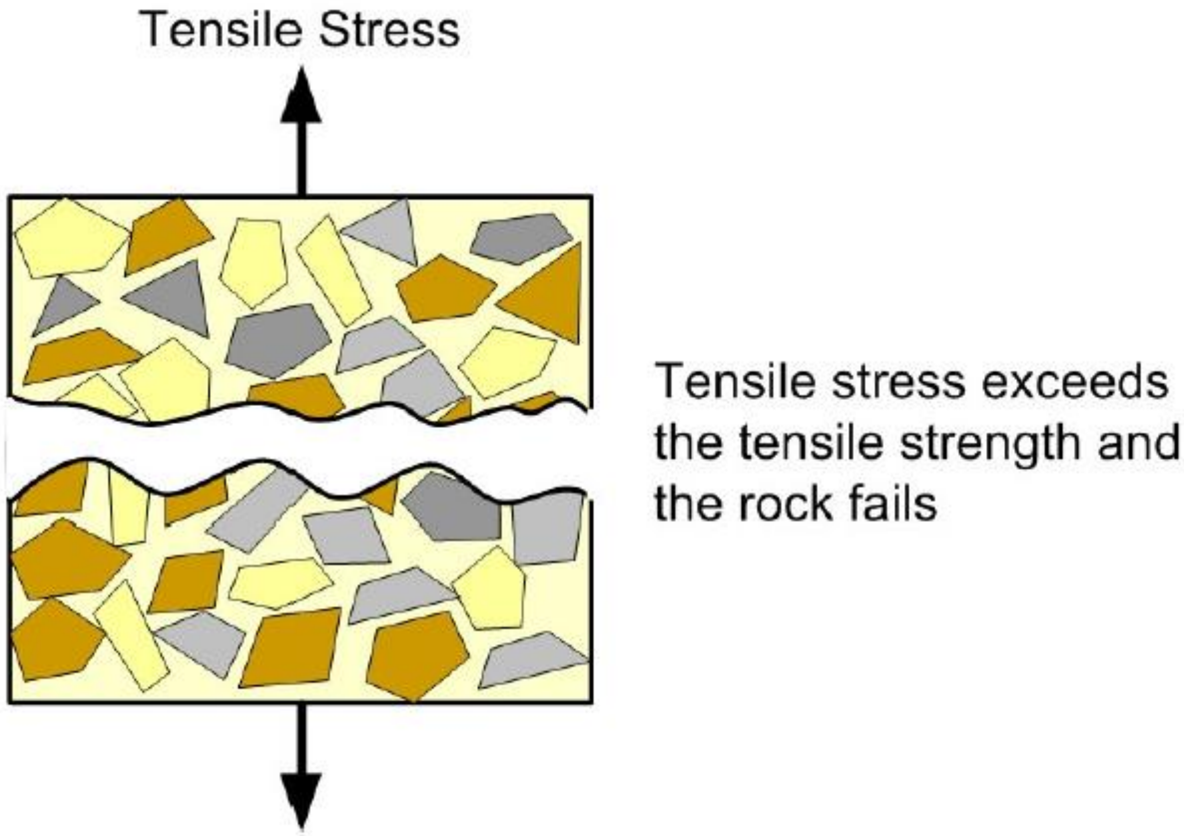
$$\mu = \tan\varphi$$

A shear strength line or failure envelope shown below is produced from such core. The greatest and least effective stress on the wellbore are also calculated using in-situ stress, pore pressure, hole inclination, etc., and indicated on the chart. If the stress-state produces a shear stress that falls beneath the shear strength line, the wellbore is stable. If the shear stress falls outside the stability envelope, the wellbore is unstable and formation failure will occur.



Tensile failure

Tensile failure results from stresses that tend to pull the rock apart (tensile stress). Rocks exhibit very low tensile strength.

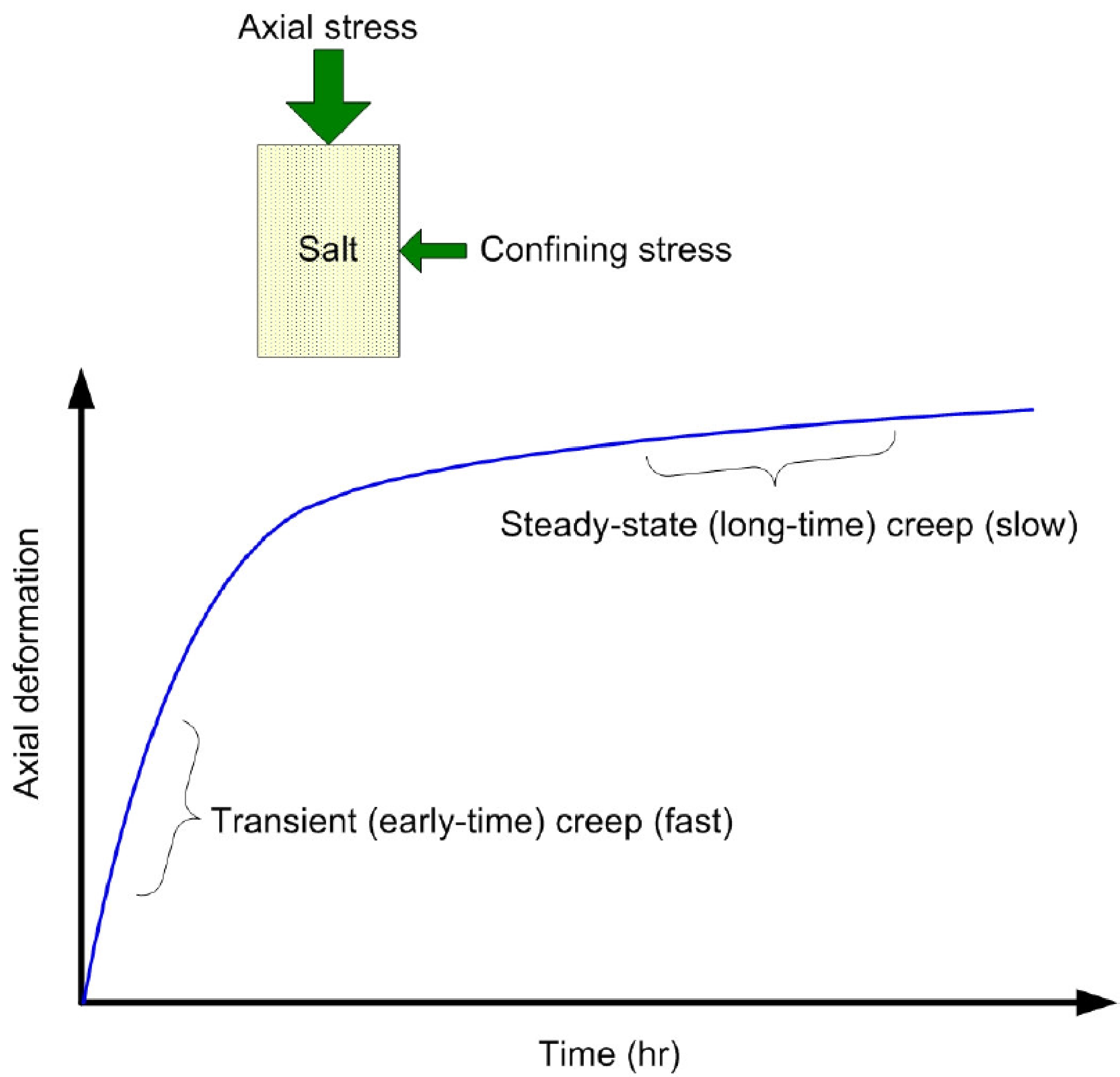


Time

Geological processes have great lengths of time in which to operate. Although geologic time is impossible to duplicate in a laboratory, it is possible from experiments to make some deductions concerning the influence of time.

One analysis of special interest to drilling operations is that of creep. Creep is the slow continuous deformation of rock with the passage of time under conditions of constant applied stress. Salt is especially noted for this behavior, though shales and sandstones both exhibit this behavior to a lesser degree.

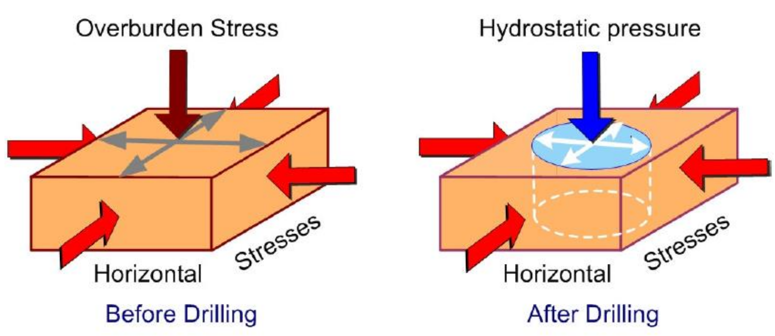
The creep behavior of salt is shown schematically below. Upon altering the conditions of the sample (e.g., by increasing the temperature or the stress difference) salt begins to deform at a relatively fast rate (transient creep), which then slows to a lower steady-state creep rate. Transient creep can cause tighthole conditions when drilling, while steady-state creep can cause casing collapse over longer timescales.



AFTER THE WELLBORE

Near Wellbore Stress-State

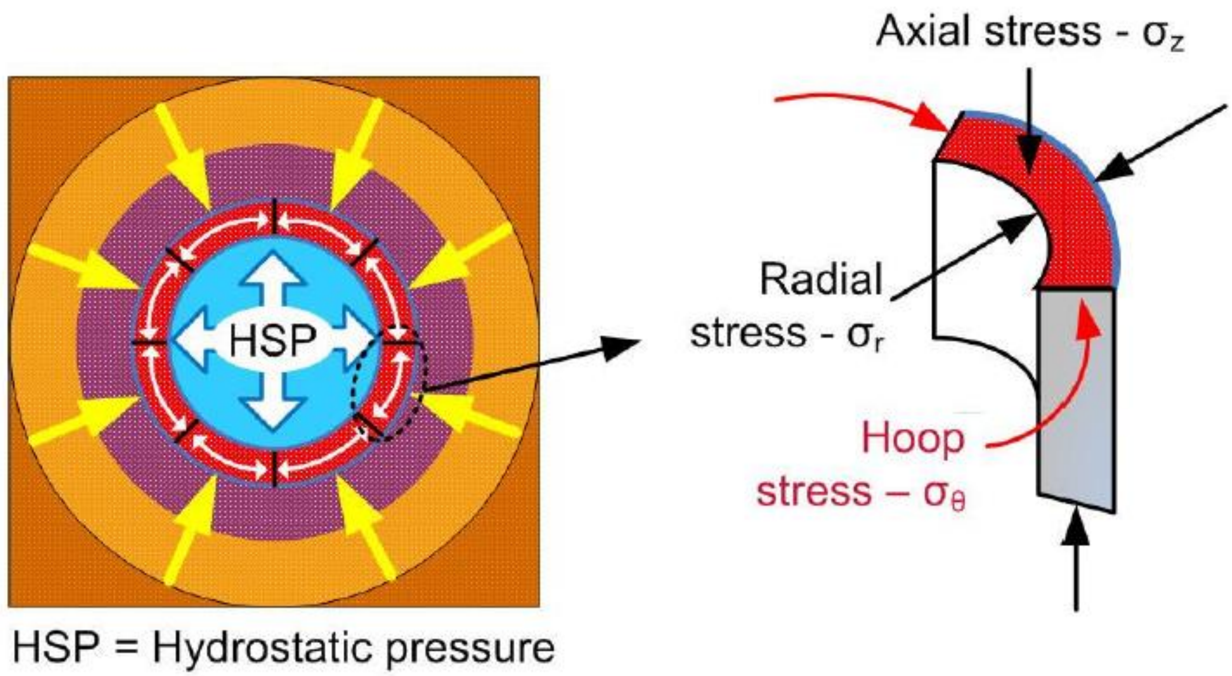
Before drilling, rock stress is described by the in-situ stresses: effective overburden stress, effective minimum horizontal stress, and the effective maximum horizontal stress. These stresses are designated by (σv, σhmin, σHmax).



As the circular borehole is drilled, the support provided by the rock is removed and replaced by the hydrostatic pressure of the drilling fluid. This change alters the stresses locally around the wellbore. The stresses that were once carried by the rock become concentrated in the near-wellbore region. The stress at any point on or near the wellbore can be described in terms of a:

- ✓ radial stress acting along the radius of the wellbore (normal to the borehole surface);
- ✓ hoop stress acting around the circumference of the wellbore (tangential);
- ✓ axial stress acting parallel to the well path.

These stresses are designated by (σr, $\sigma \theta$, σz) and the additional shear stress components designated by ($\tau r\theta$, τrz, $\tau \theta z$).
These stresses are perpendicular to each other and for mathematical convenience, are used as a borehole coordinate system.

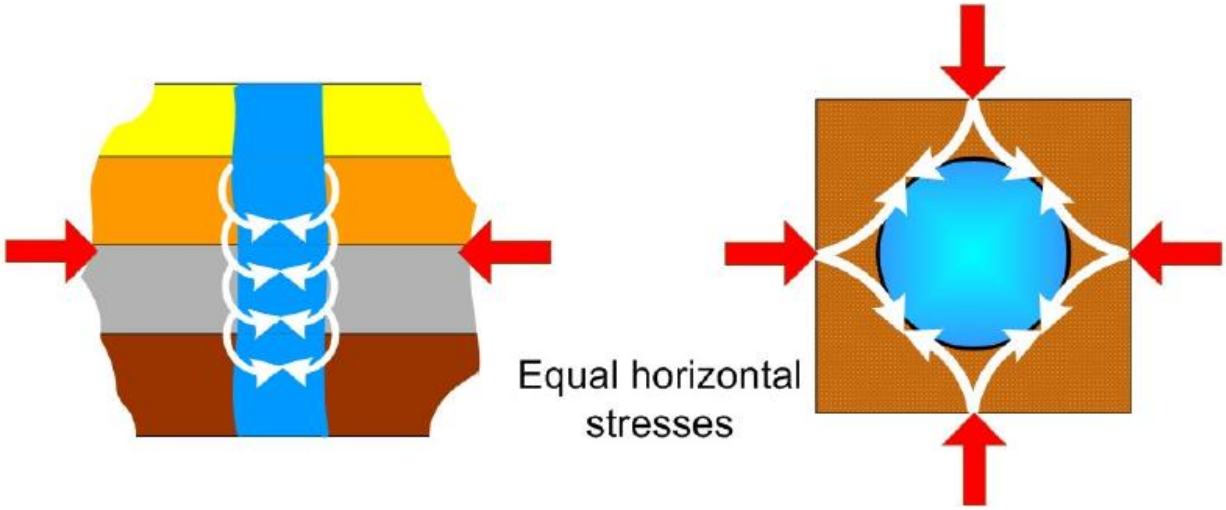


Hoop stress – σθ

Hoop stress is dependent upon wellbore pressure (pw), in-situ stress magnitudes and orientation, pore pressure, and hole inclination and direction.

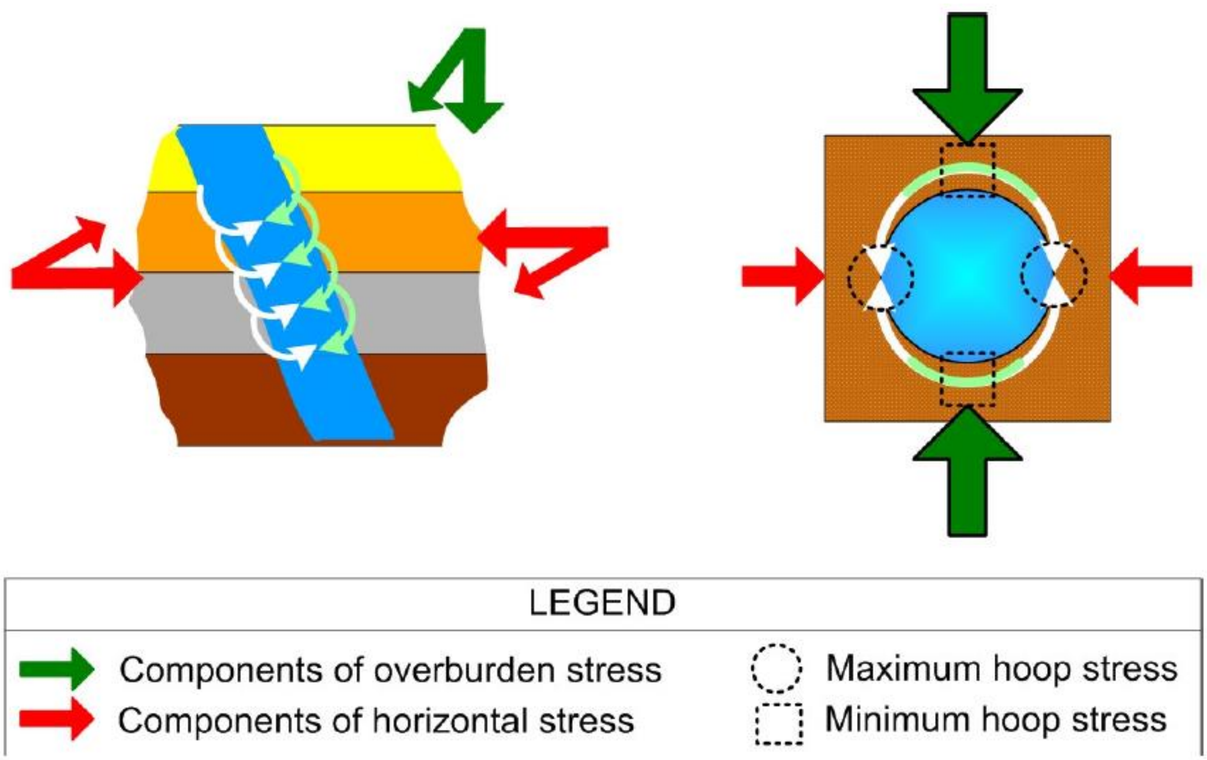
$$\boldsymbol{\sigma\theta = [\text{in-situ and well parameters}] - pw - p}$$

For a vertical wellbore with equal horizontal stresses, the hoop stress is dependent upon the mud weight and the magnitude of the horizontal stresses, and is equally distributed around the wellbore.



A deviated well creates unequal distribution of hoop stress around the wellbore due to the redistribution of the horizontal and vertical stresses. The hoop stress acting on a cross-section of the wellbore is maximum at the sides of the wellbore perpendicular to the maximum stress (i.e., opposite the direction of the maximum stress). It is also minimum at the sides of the wellbore parallel with the maximum stress.

The same is true when drilling a vertical well in an in-situ environment of unequal horizontal stresses. The hoop stress is maximum at the side of the wellbore perpendicular to the maximum horizontal stress, and minimum at the side parallel with the maximum stress.

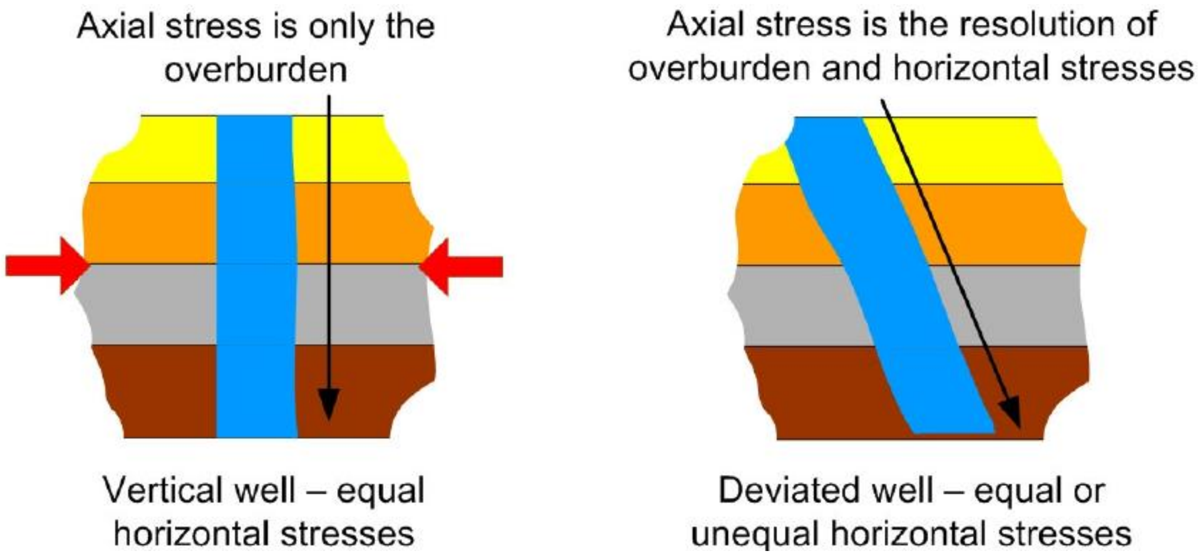


Axial stress – σ_z

Axial stress is oriented along the wellbore path and can be unequally distributed around the wellbore. Axial stress is dependent upon the in-situ stress magnitude and orientation, pore pressure, and hole inclination and direction. Axial stress is not directly affected by mud weight.

$$\sigma_z = [\textit{in-situ} \text{ and well parameters}] - p$$

For a vertical well with equal horizontal stress (Shmin = SHmax), axial and vertical stress are the same. Axial stress in a deviated well is the resolution of the overburden and horizontal stresses acting along the wellbore.



Axial stress – σ_r

Radial stress is the difference between the wellbore pressure and the pore pressure, and acts along the radius of the wellbore.

Since wellbore and pore pressures both stem from fluid pressure acting equally in all directions, this pressure difference acts perpendicular to the wellbore wall, along the hole radius.

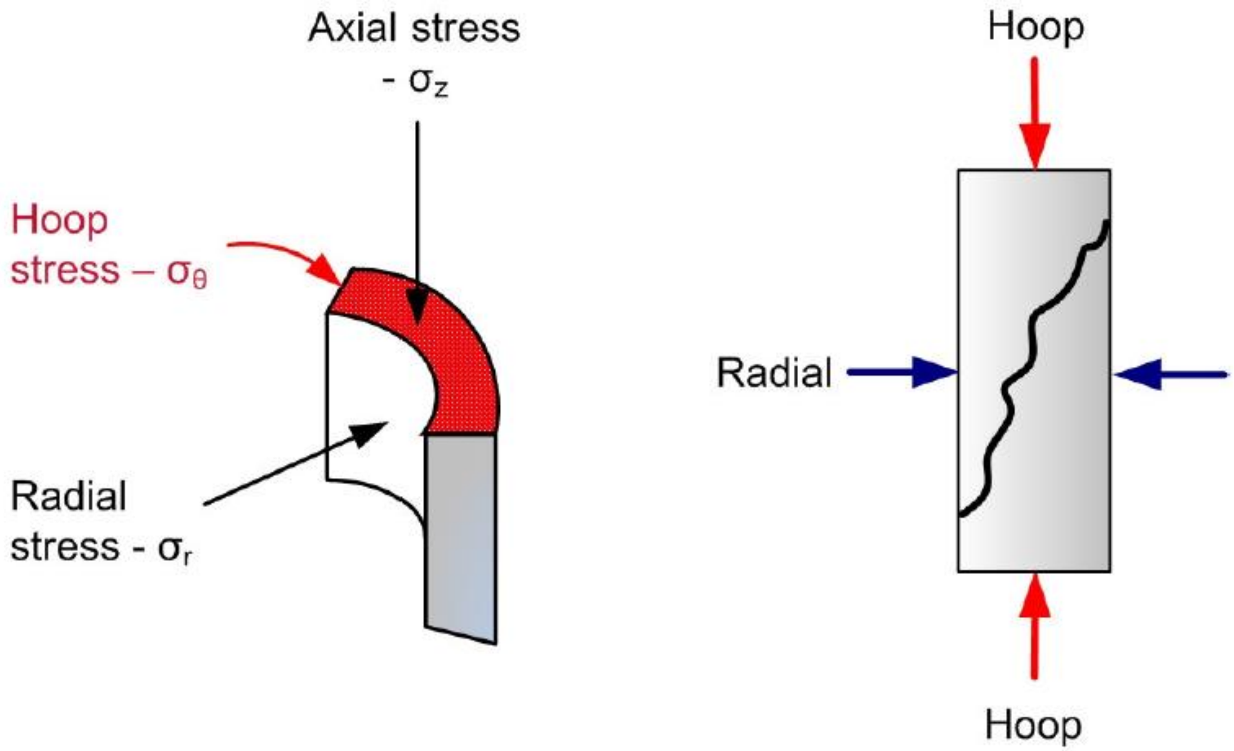
Radial Stress = Wellbore Pressure – Pore Pressure

$$\sigma_r = p_w - p$$

Mechanical Borehole Stability

Hoop (σ_θ), radial (σ_r), and axial (σ_z) stresses describe the near wellbore stressstate of the rock. Mechanical borehole stability is the management of these stresses in an effort to prevent shear or tensile rock failure. In the field, these translate into borehole breakouts and cavings caused by shear failure, and losses caused by tensile rock failure.

Normally the stresses are compressive and create shear stress within the rock. The more equal these stresses, the more stable the rock.

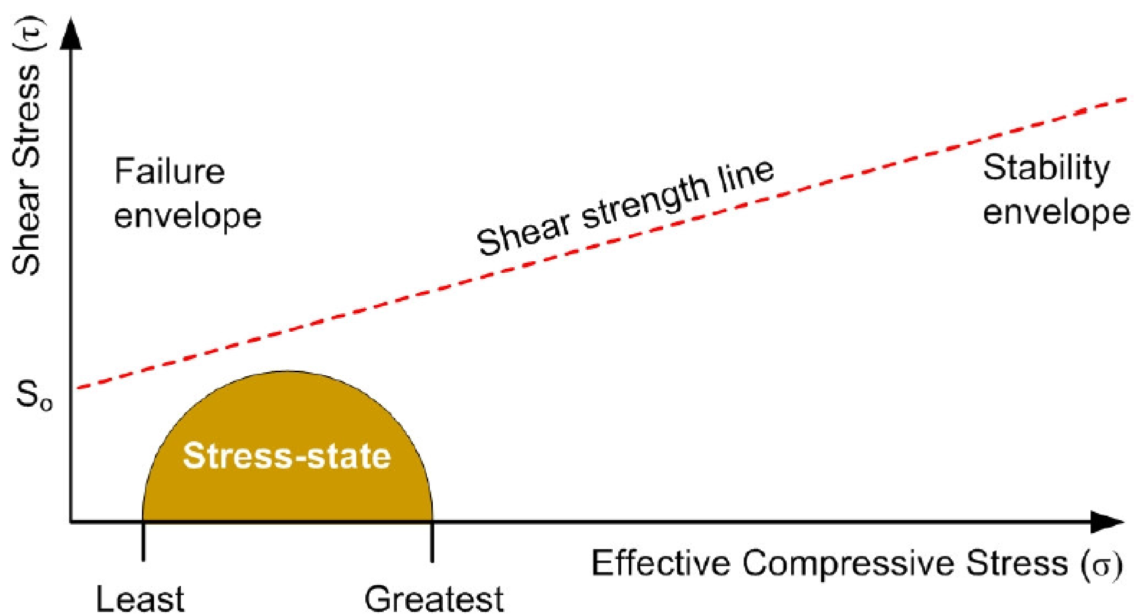


Shear Stress

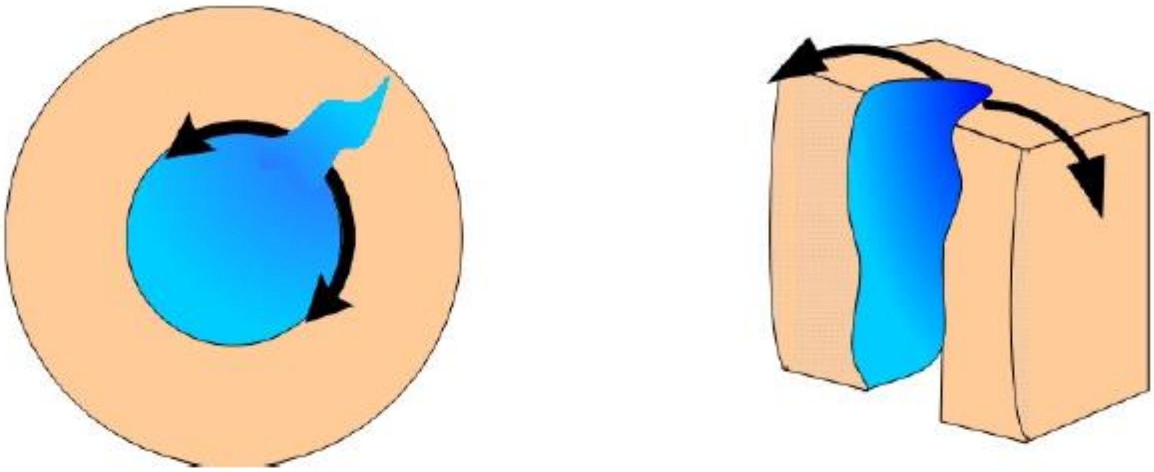
As shown by the right side drawing above, the radial stress is resisting shear caused by the hoop stress.

Hoop, axial, and radial stress can be calculated for any well trajectory in a known stress field, and the greatest and least of the three indicated by a stress-state semicircle on the stability chart.

Shear failure occurs if the stress-state falls outside of the stability envelope. Tensile failure occurs if the stress-state falls to the left of the shear stress axis and exceeds the tensile strength of the rock.



Whenever hoop or radial stress becomes tensile (negative), the rock is prone to fail in tension. Many unscheduled rig events are due to loss of circulation caused by tensile failure.



Tensile failure due to negative hoop stress

Mechanical stability is achieved by controlling the parameters that affect hoop, axial, and radial stress.

Controllable parameters:
· Mud weight (MW) and equivalent circulating density (ECD)
· Mud filter cake
· Inclination and azimuth of the well path
· Drilling and tripping practices

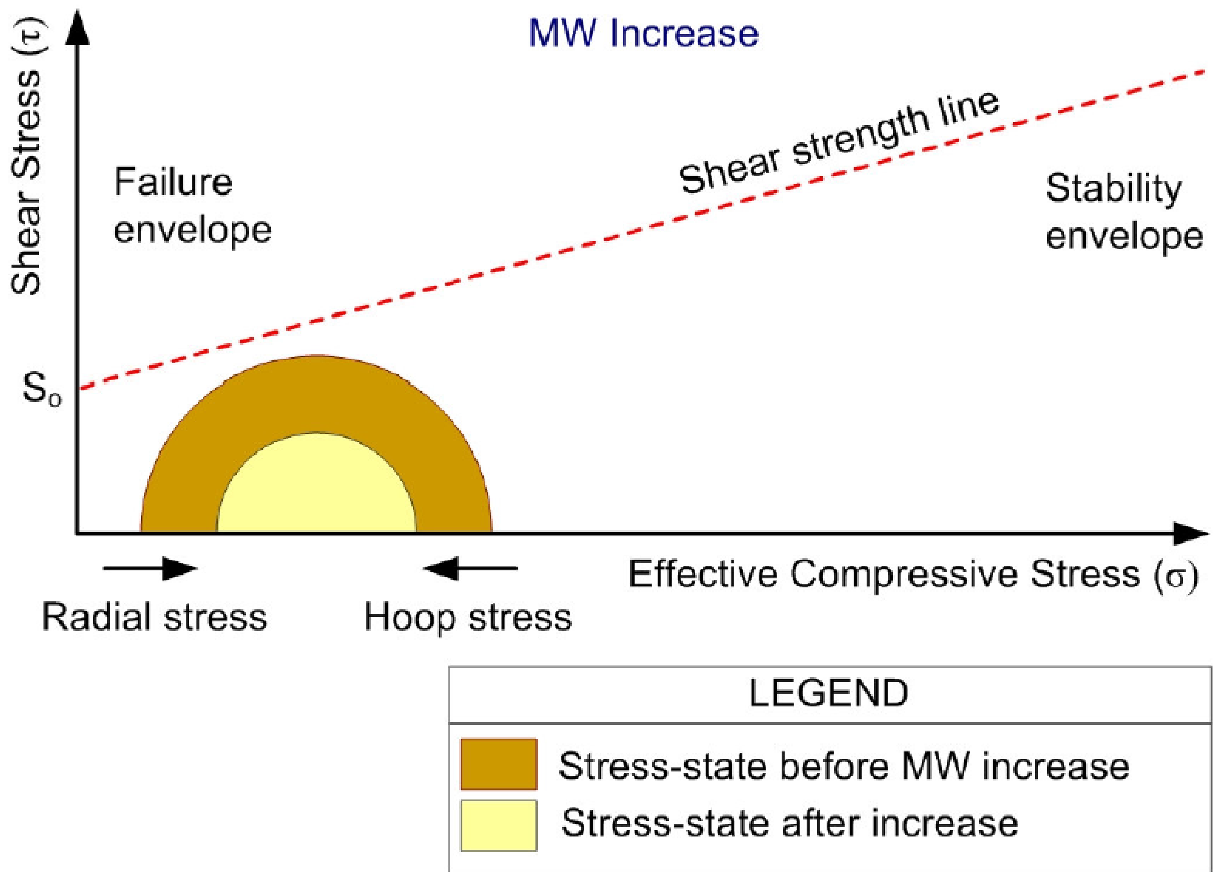
Uncontrollable parameters:
· Unfavorable in-situ conditions
· Adverse formations (e.g., weak, fractured, or chemically reactive)
· Constrained wellbore trajectory

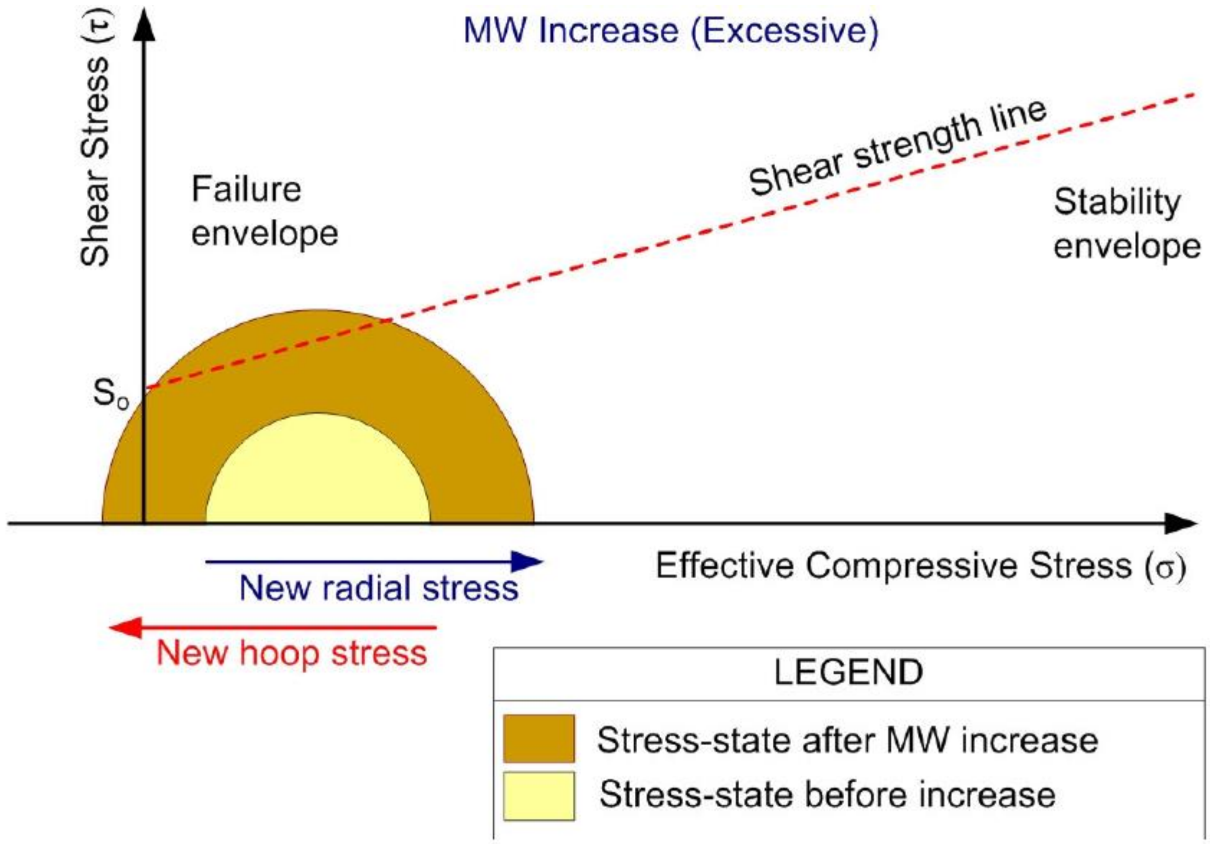
Mechanical stability of the well is also impacted by the interaction between the drilling fluid and the formation. Chemical instability eventually results in mechanical failure of the rock in shear or tension.

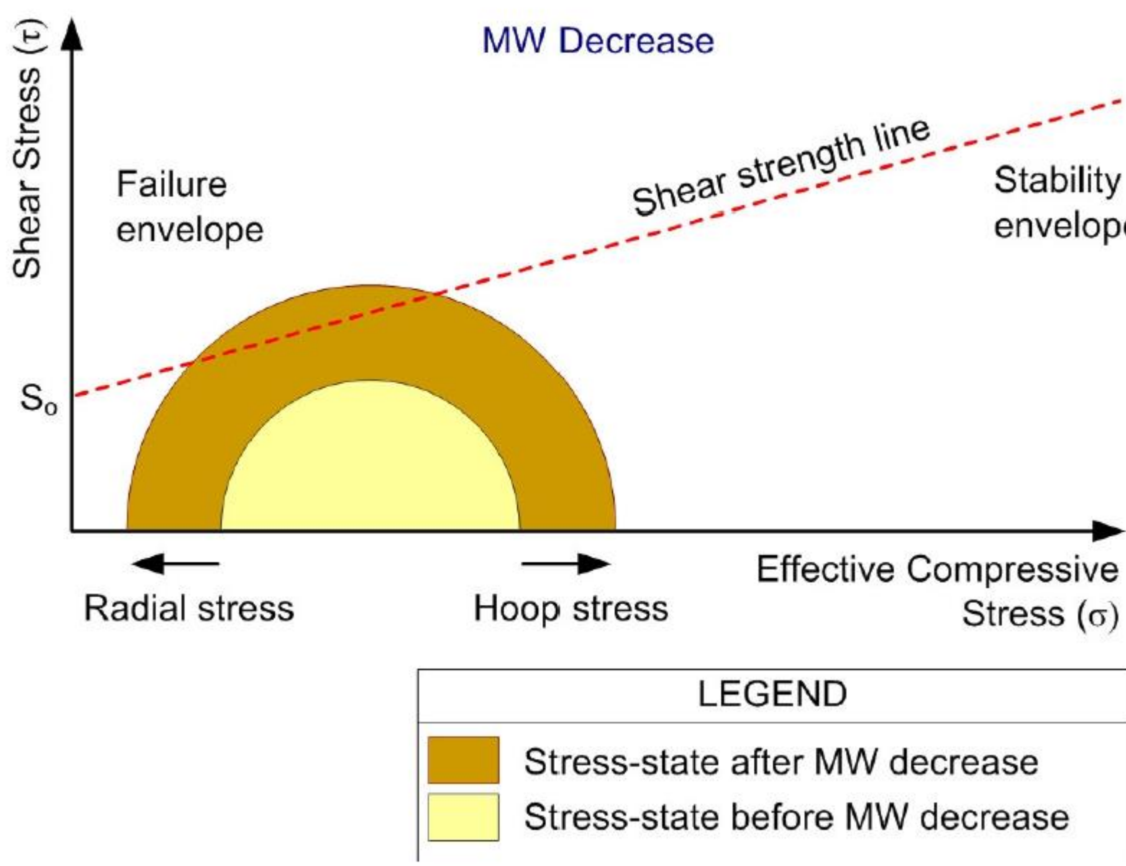
Time is also an important consideration. The longer the formation is exposed to the drilling fluid, the more the near-wellbore pore pressure increases to match the higher pressure exerted by the mud weight because of seepage through the filter cake. The rock thus loses the support provided by the mud weight over time.
This can lead to time-delayed shear failure of the rock surrounding the borehole.

Effect of mud weight / ECD

Mud weight, ECD, and pressure surges on the wellbore directly affect hoop and radial stress. An increase in mud weight decreases the hoop stress and increases the radial stress. Similarly, a decrease in mud weight increases the hoop stress and decreases the radial stress. The result on wellbore stability is dependent upon the magnitude of the mud weight increase / decrease.

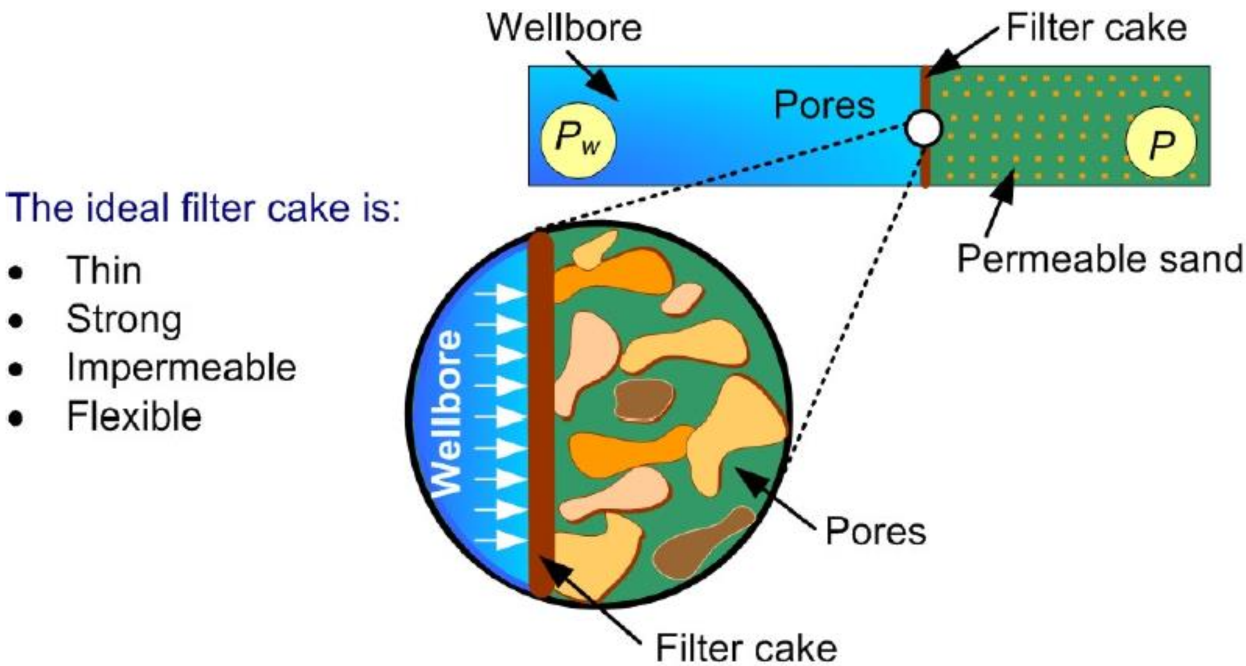



MW Increase (Excessive)
Shear Stress (τ)
Shear strength line
Failure
envelope
Stability
envelope
S_o
Effective Compressive Stress (σ)
New radial stress
New hoop stress
LEGEND
Stress-state after MW increase
Stress-state before increase

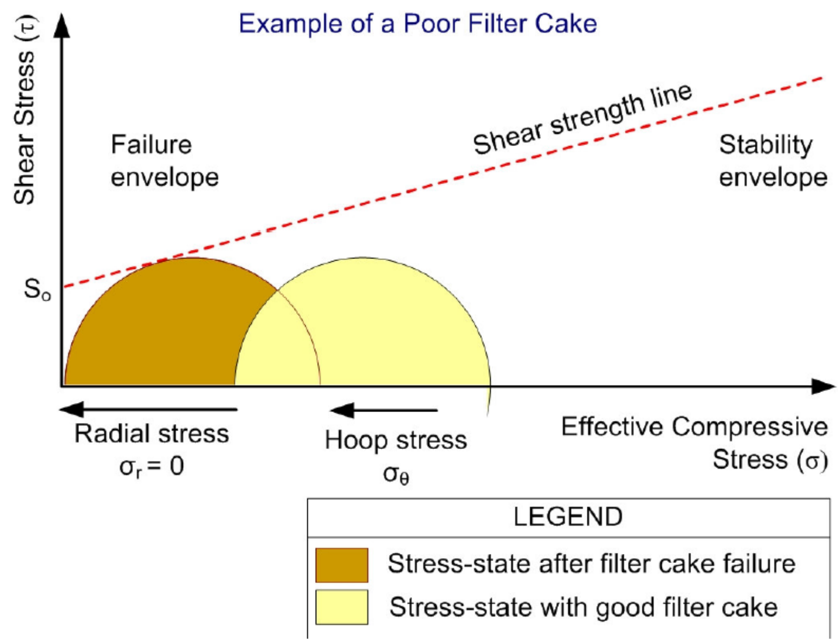

MW Decrease
Shear Stress (τ)
Shear strength line
Failure
envelope
Stability
envelope
S_o
Radial stress
Hoop stress
Effective Compressive
Stress (σ)
LEGEND
Stress-state after MW decrease
Stress-state before MW decrease

Mud filter cake and permeable formations

The filter cake plays an important role in stabilizing permeable formations. An ideal filter cake isolates the wellbore fluids from the pore fluids next to the wellbore. This is important for borehole stability and helps prevent differential sticking as well.



If there is no filter cake, the pore pressure near the wellbore increases to the mud hydrostatic pressure; the effective radial stress is zero. The simultaneous decrease in effective hoop stress causes the stress-state to move left in the stability envelope diagram, so decreasing the stability of the formation. An ideal filter cake helps provide for a stable wellbore by preventing the seepage of borehole fluids into the formation.



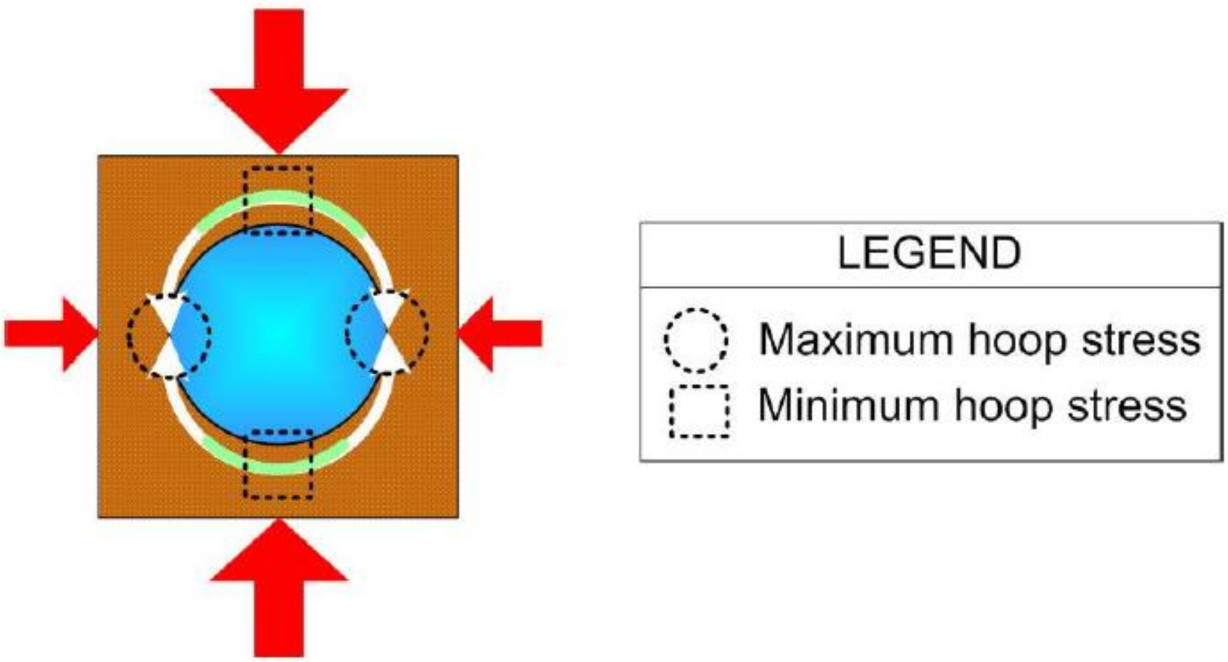
The chemical composition of the mud and permeability of the formation control the filter cake quality and the time it takes to form. Oil-based and synthetic oilbased drilling fluids generally create a thinner, better quality filter cake than do water-based drilling fluids.

Hole inclination and direction

The inclination and direction of the wellbore greatly impacts the stability of the well. An unequal distribution of hoop and axial stress around the circumference of the well tends to make the wellbore less stable.

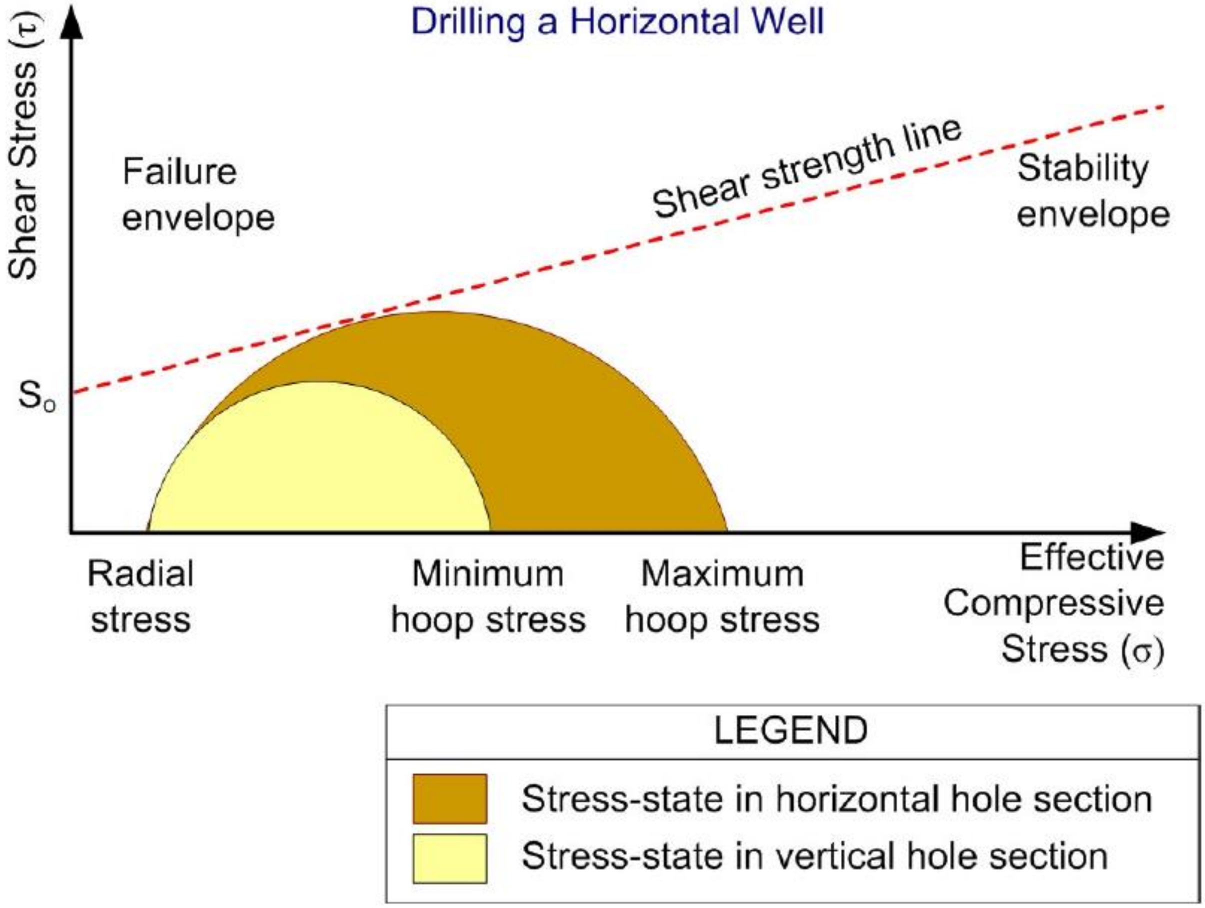
Drilling a horizontal well causes the hoop and axial stress distribution around the wellbore to change.

Before drilling from vertical, the hoop stress is equally distributed. As angle increases to horizontal, the hoop stress on the high and low side of the wellbore decreases, but the hoop increases greatly on the perpendicular sides.



The change in the stress-state at the wellbore wall for a vertical and horizontal well is shown below for a normal-faulting stress regime (i.e., one where the vertical stress is greatest). The radial stress remains fixed but the magnitude of the hoop stress increases with borehole deviation, so increasing the stress-state that the well is subjected to. In this stress regime, a horizontal well is subjected to higher stresses than a vertical well. This arises because the larger axial stress is aligned parallel to the wellbore in the vertical well and so plays no part in destabilizing the wellbore. In a horizontal well, the full effect of the vertical stress now acts on the borehole, so resulting in a more heavily loaded (and less stable) condition.

An interesting illation to this is that in a strike-slip stress regime – where the vertical stress is the intermediate stress, SHmax > Sv > Shmin – a vertical well is the least stable well trajectory from a mechanical borehole stability standpoint. Here increasing deviation would increase stability.



Bottom-hole temperature

High bottom-hole-temperature wells may experience stability problems as a consequence of hoop stress changes caused by temperature differences between the drilling fluid and the formation. In some well construction circumstances, the temperature of the drilling fluid may be manipulated (either heated or cooled) to overcome otherwise challenging conditions.

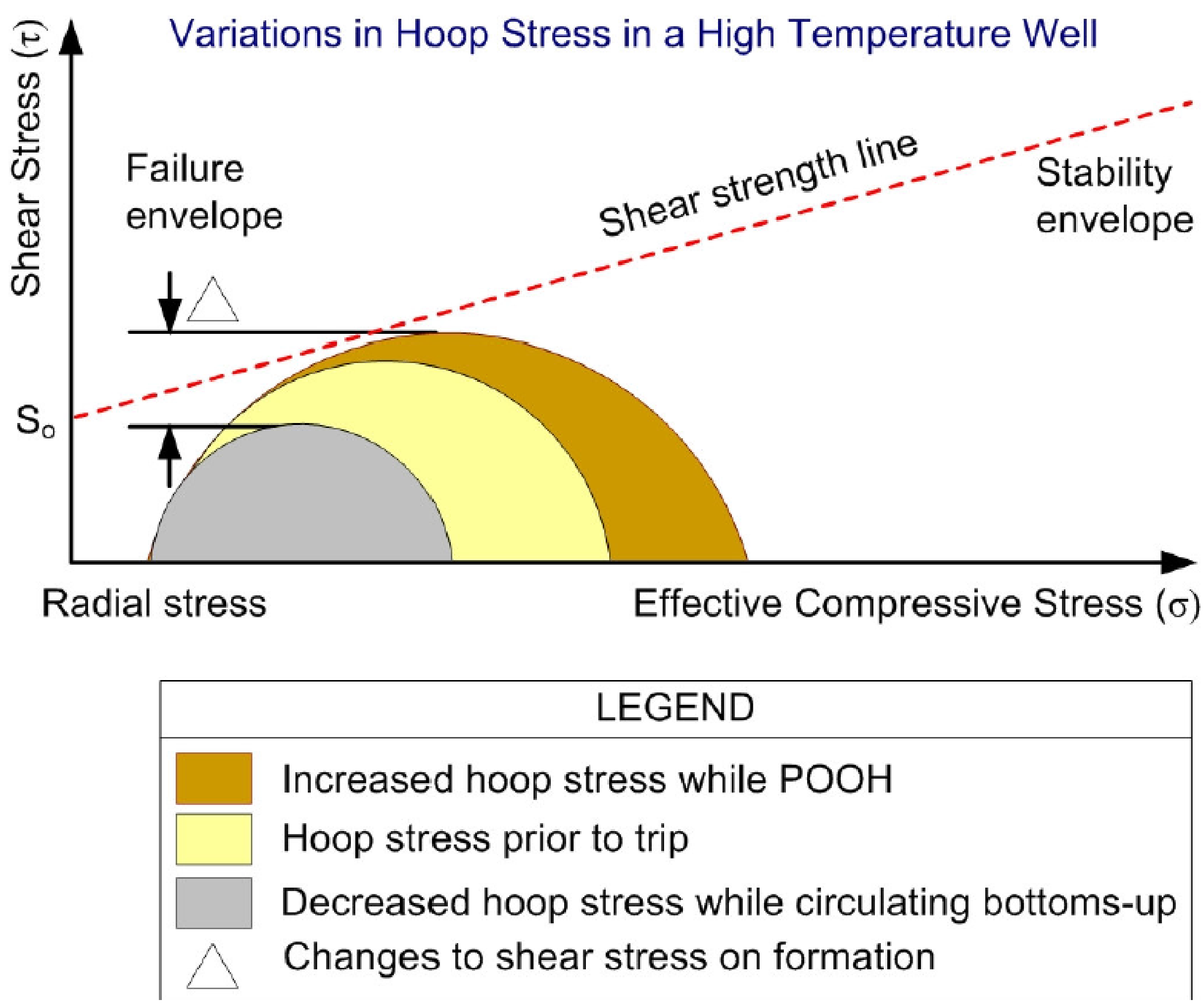
As a basic concept, heating induces expansion of the rock. When this expansion is resisted by the adjacent formation (which is being heated too), additional compressive stresses are generated in the rock. Conversely, cooling induces contraction of the rock. This contraction causes near wellbore stresses to become less compressive, and even tensile, if the amount of cooling is sufficient.

So, from a mechanical wellbore stability standpoint, if the drilling fluid is cooler than the formation, it reduces the hoop stress as the formation is cooled. This reduction in hoop stress can prevent shear failure and stabilize the hole from failing in shear. However, if the mud weight being used is relatively high and close to the fracture gradient (as might easily occur in an over pressured, high pressure, high-temperature (HPHT) well), excessive cooling can lower the stresses in the formation sufficiently to make some of them tensile. This could cause tensile failure or fracturing as it effectively lowers the fracture gradient.

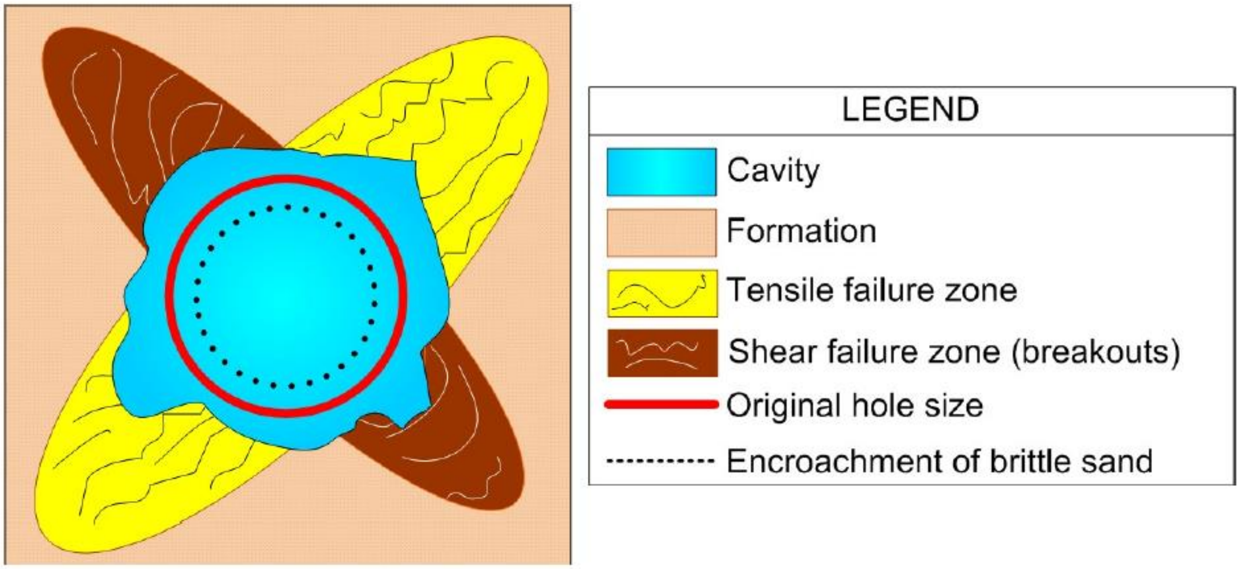
If the drilling fluid is hotter than the formation, exactly the opposite occurs as the hoop stress is increased. This could promote spalling or shear failure.

Drilling operations influence the bottom-hole temperature of the drilling fluid in a well. Consider what happens during a typical round-trip in a deep high temperature well. Prior to the trip, the

near-wellbore region will have become cooled somewhat by the circulation of drilling fluid. During the trip, the formation temperature warms back to its ambient value. This causes the hoop stress to increase. When back on bottom and circulation resumes, the cooler drilling fluid traveling down the drill string reduces the temperature of the nearby formation, causing hoop stress to decrease.
As the hot bottoms-up drilling fluid circulates past cooler formations at shallower depths, hoop stress increases as the drilling fluid heats up these formations.
These variations in hoop stress have the same effect as pressure surges associated with swabbing and surging, and can cause both tensile and shear failure downhole. In HPHT wells, where these effects are most pronounced, understanding – and managing – borehole temperature effects can become a significant part of the wellbore stability assessment.



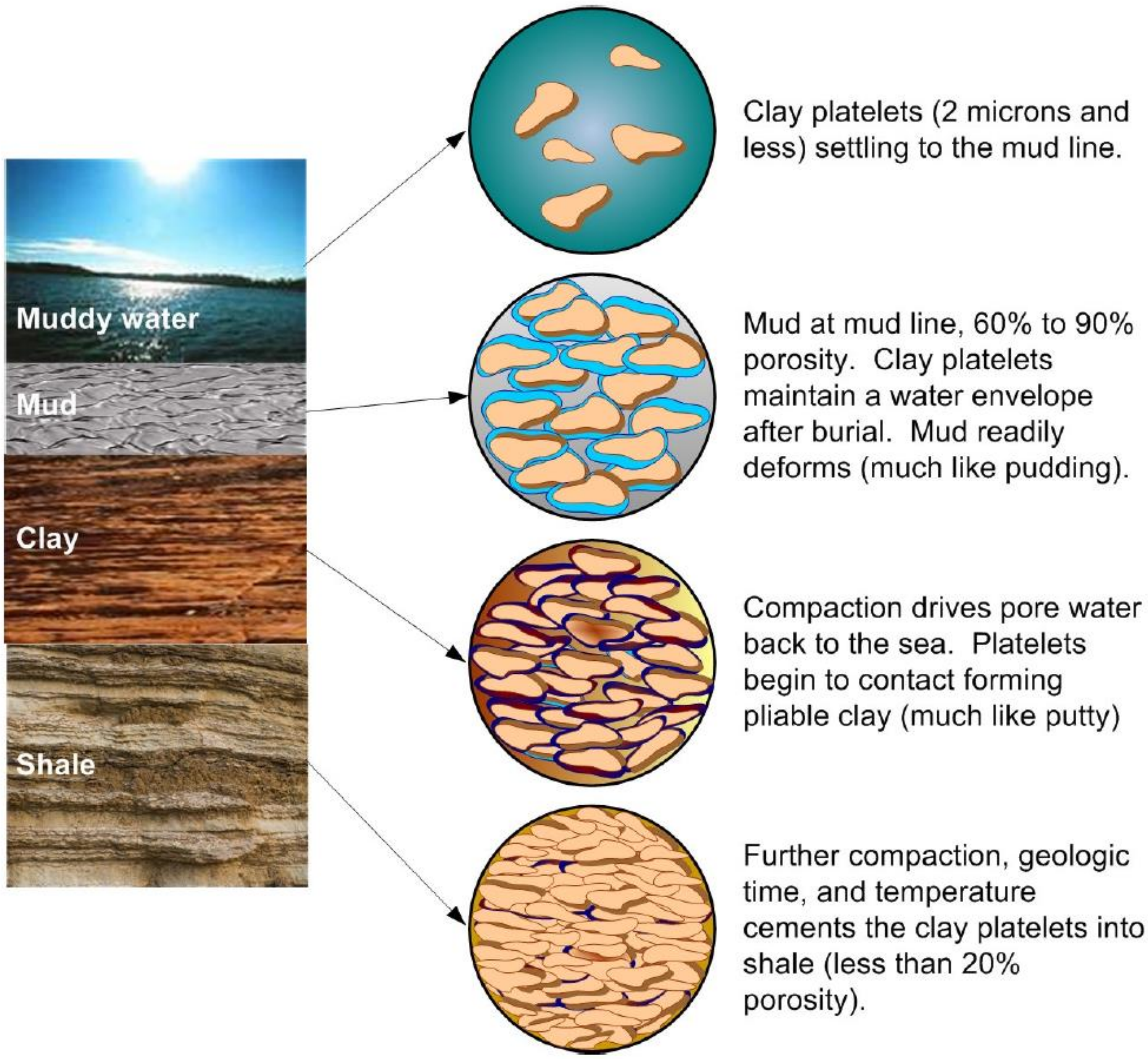
Impact of mechanical stability on the wellbore
Mechanical stability problems directly account for many unscheduled rig events. Stability problems also affect overall drilling efficiency by altering the shape of the hole being drilled.
Severe borehole deformation occurs when extreme in-situ stress environments are penetrated. The drawing below is indicative of such drilling. The drawing is only a slice of the actual wellbore. Consider the path of a typical well, and consider this deformation over several thousand feet of open hole; it is easy to see the impact of such a wellbore on operations.



Resulting operational failures include:

· Stuck pipe, casing, logging tools, etc.
· Ineffective hole cleaning.
· Ledges and breakouts.
· High torque and severe slip-stick.
· Drill string failures.

Chemical Stability
Chemical stability is the control of the drilling fluid / rock interaction. This is usually most problematic when drilling shales.
Shales are fine grain sedimentary rocks with very low permeability and composed primarily of clay minerals (gumbo to shaly siltstone).



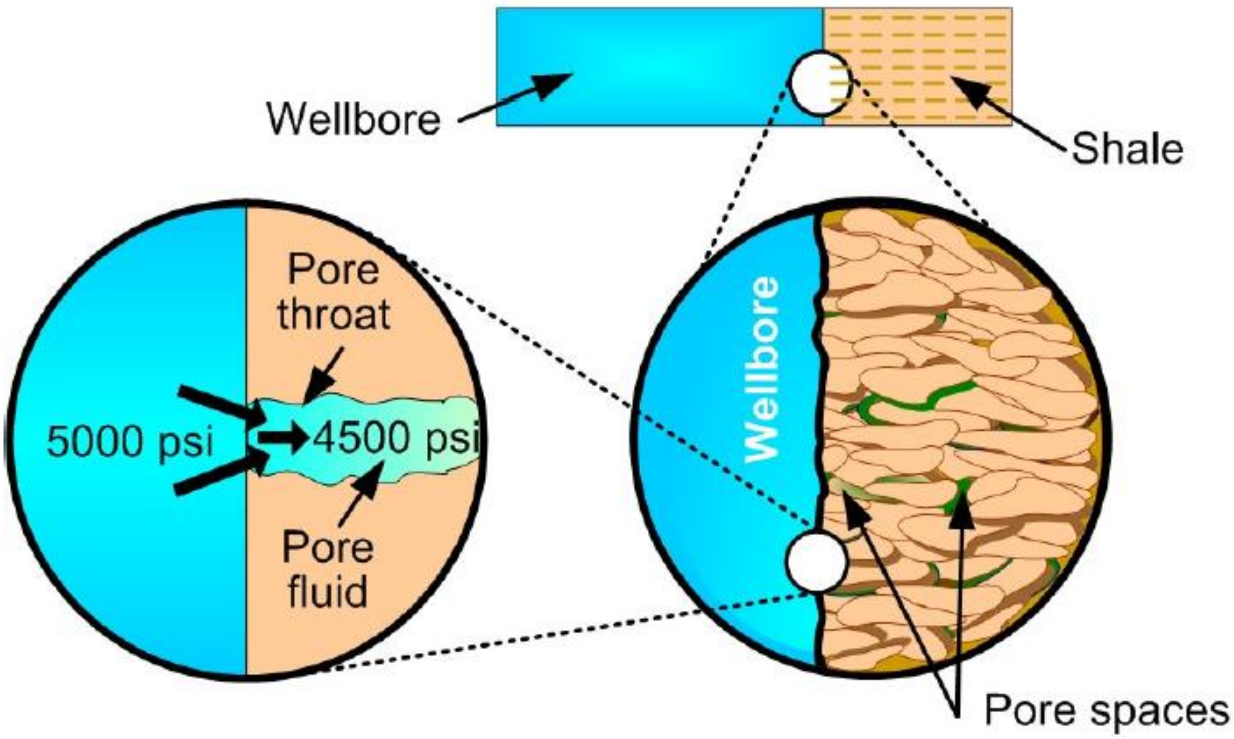
One factor that distinguishes shale from other rock is its sensitivity to the water component of the drilling fluid. With time, shale / water interaction will decrease the strength of the shale, so making it more prone to mechanical failure.

As shale is drilled, a sequence of events takes place that can lead to the stressing, weakening, and eventual failure of the shale. Several parameters, described below, contribute to the chemical stability of shale.

Advection

Advection is the transport of fluid through shale due to a pressure differential. Typically, the wellbore hydrostatic pressure from the drilling fluid is greater than formation fluid pressure. When exposed to a permeable formation, the liquid phase of the drilling fluid is pushed into the pore openings by the pressure differential.

In highly permeable sand, the rate of fluid loss is sufficient to form a filter cake that controls further fluid loss to the formation. However, with shales, the filter cake cannot develop, since the permeability of shale is typically much less than those of any filter cake. Also, the particle size of a typical filter cake is too large to plug the pore throats of shale (much like trying to plug a shaker screen with beach balls).



Capillary effects

Drilling fluid must overcome the capillary pressure of the formation pore fluid in order to enter the pore throats of shale. Capillary pressure, developed at the drilling fluid / pore fluid interface, is dependent on several factors. These include the pore throat radius, the fluid interfacial tension, and contact angle.

When drilling water-wet shales with a water-based drilling fluid, surface tension between the drilling fluid's water phase and the pore fluid is very low. Under favorable salinity conditions, the water phase enters the pore throat.

When drilling water-wet shales with an oil-based drilling fluid, the capillary pressure is very high (i.e., 8,000 psi to 10,000 psi) due to the large interfacial tension, and extremely small pore throat radius. The high capillary pressure prevents entry of the oil phase as overbalance pressures are very low in comparison. However, if the salinity of the drilling fluid's water phase is not balanced with the salinity of the shale pore fluid, water transfer through osmosis can still occur.

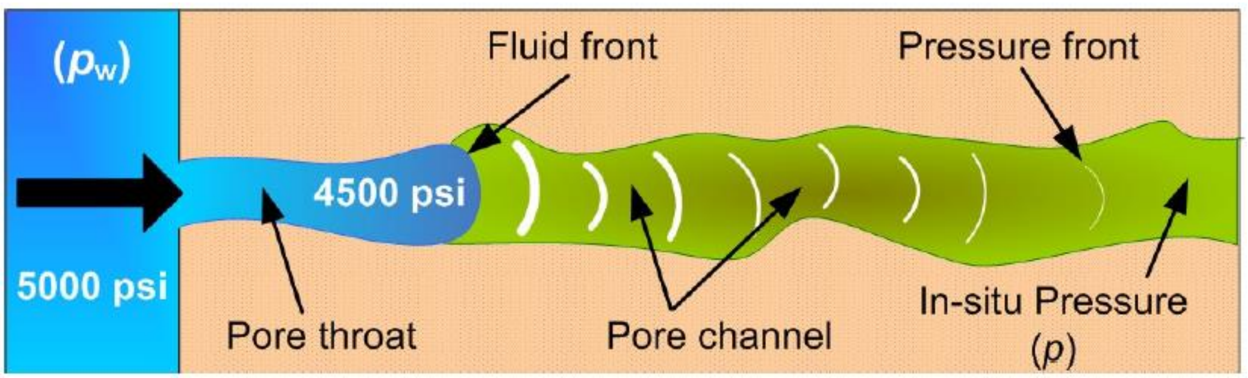
Osmosis

Osmosis is caused by the imbalance of chemical potential between the drilling fluid and the shale formation. The chemical imbalance is separated by shale which acts as a semi-permeable (i.e., leaky) membrane that allows the transport of water only. Water activity is used to describe chemical potential. Water moves from the system with high water activity to that with low water activity until the chemical potential difference is balanced.

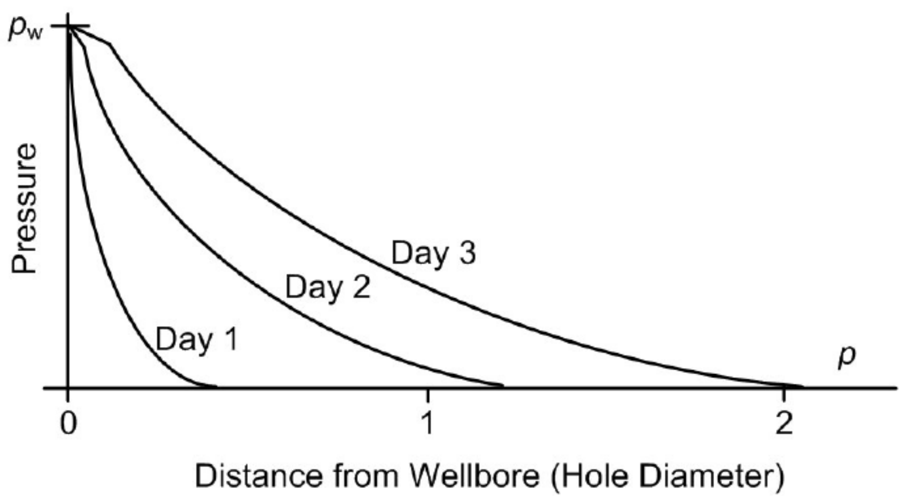
It is believed that a balanced activity between the drilling fluid and the shale formation can improve wellbore stability. The water activity of the drilling fluid can be adjusted by changing the salinity of the drilling fluid. The higher the salinity, the lower the water activity of the drilling fluid. If the drilling fluid salinity is too low (i.e., water activity is too high) relative to the

adjacent formation, water moves into the shale and increases the pore pressure locally in the near-wellbore region. As the pore pressure increases, it has an adverse effect on stability as the effective mud overbalance is reduced.
If the drilling fluid salinity is too high (i.e., water activity is too low), water flows from the shale formation into the drilling fluid system and dehydrates the shale.
As the near-wellbore pore pressure decreases as a result of this fluid removal, the effective hoop stress increases, promoting shear failure. It also locally reduces the fracture gradient, which may potentially cause lost circulation.
Optimization of the salinity of the water phase of the drilling fluid needs to take place for each hole section of the well, as the salinity of the formation pore fluids will vary with depth. The depositional environment and the current environment (e.g., onshore or marine) will influence this salinity variation. It is important that petrophysical and geologic considerations are included in the overall assessment of drilling fluid salinity in the design stages of the well.

Pressure diffusion
Pressure diffusion is the change in near-wellbore pore pressure occurring over time. This occurs as overbalance and osmotic pressures drive the pressure front through the pore throat, increasing the pore fluid pressure away from the wall of the hole. This pore pressure penetration leads, over time, to a less stable condition at the wellbore wall and progressively in the near-wellbore region.



The time required for the pressure front to penetrate a given depth depends primarily on the permeability of the shale (connectivity of the pores) and the pressure differential between the wellbore (pw) and in-situ pore pressure (p).

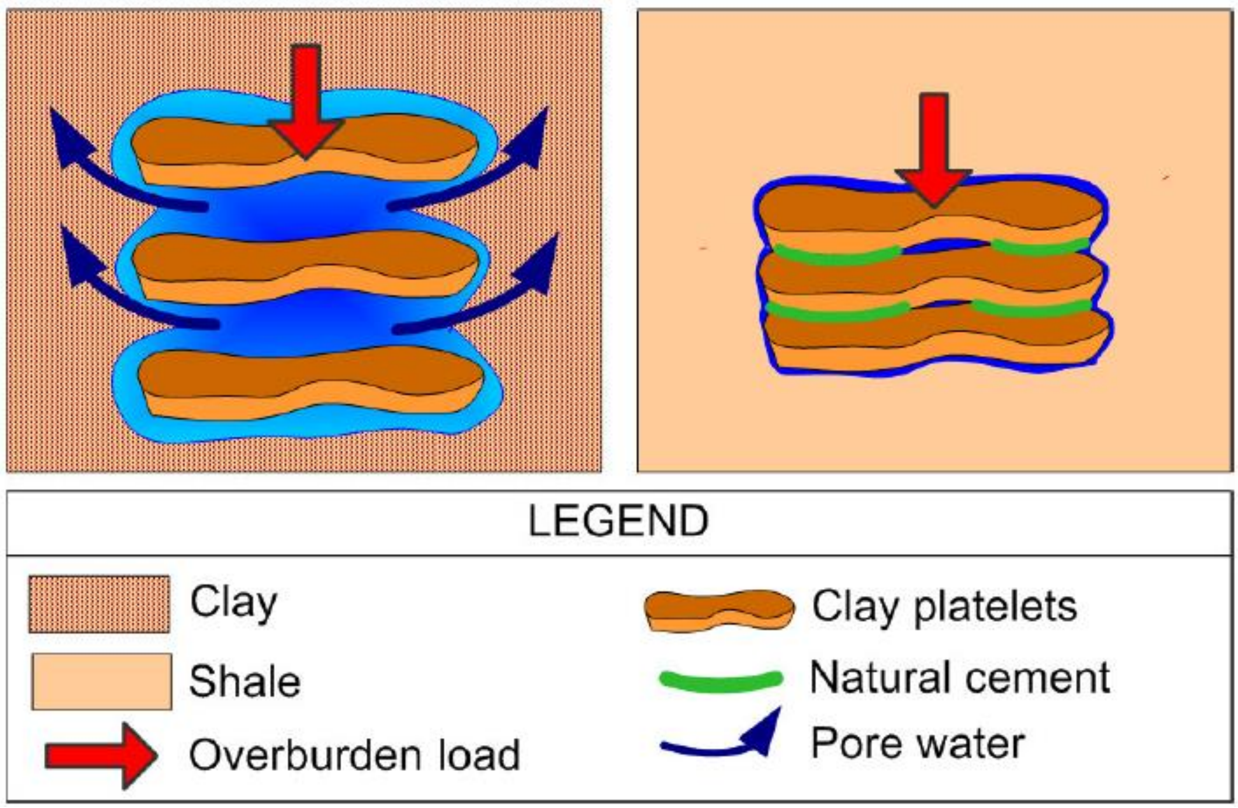


As pressure diffusion increases pore pressure near the wellbore, the shear strength of the rock is reduced. The time needed for pressure diffusion to affect shale stability may result in the time delayed failure of a shale section that has been exposed for several days.

Swelling / hydration

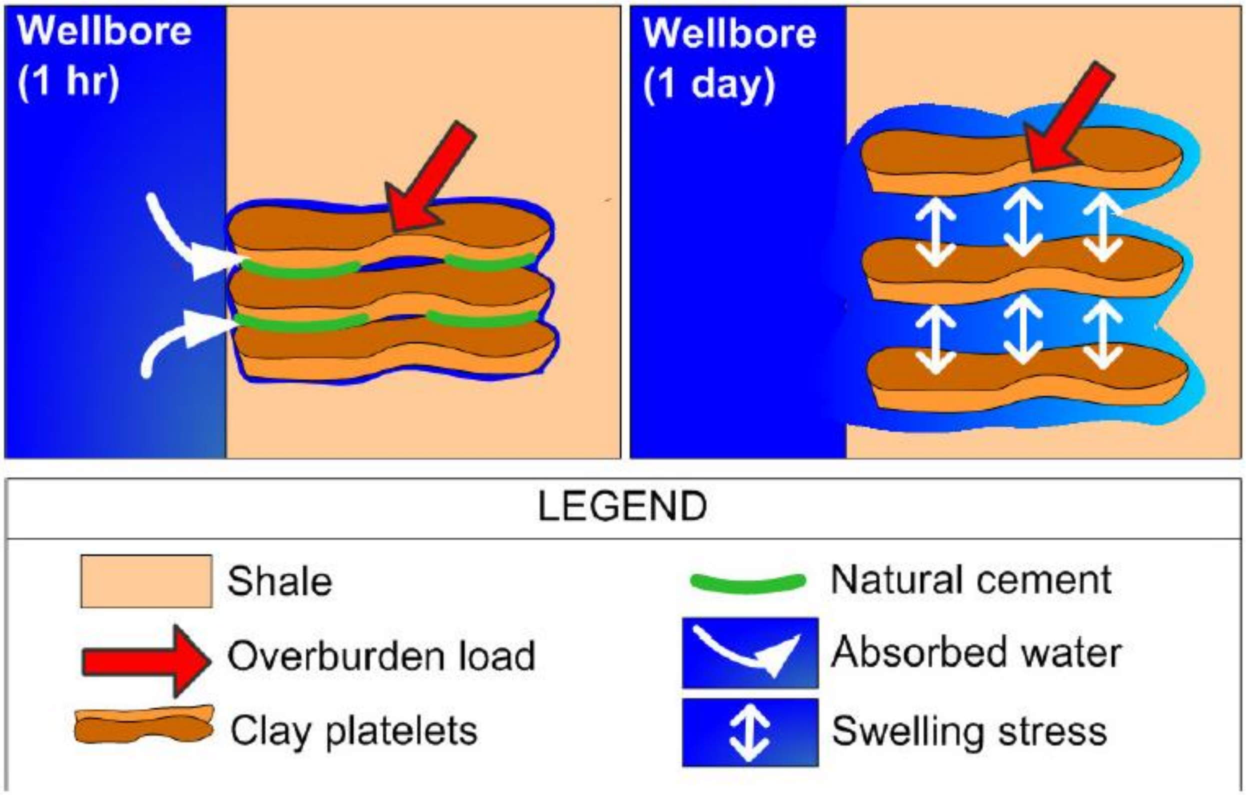
Over geologic time, mud / clay solidifies into shale as the increasing overburden stress drives off the water enveloping the clay platelets (a process known as dehydration) and cements the platelets with the minerals left behind after dehydration.

After drilling, water from the drilling fluid may enter the shale by advection and osmosis. Negatively charged clay ions attract and hold the polar water. The increasing volume of attached water produces a swelling stress that wedges the clay platelets apart.



The swelling pressure and behavior of shales are directly related to the type and amount of clay minerals contained in the shale. Shales with high concentrations of negatively charged ions can produce very high swelling pressure (50,000 psi plus) that act very locally on the microscopic clay platelet fabric.

Swelling pressures decreases the strength of the shale by destroying the natural cement bond between the clay platelets. Brittle shale becomes ductile and is pushed into the wellbore by the compressive hoop stress and the swelling stress.



Differential Sticking

This is typically caused by a thick filter cake build-up across permeable formations when the drilling mud solids are inappropriately sized. Sticking may also be an indicator of possible chemical incompatibility with some formation types if over-pulls or high friction factors are seen when running in the hole or when tripping. Attempts to free drill-pipe that has become differentially stuck (e.g., jarring) can result in large pressure fluctuations down-hole. These can destabilize the borehole or lead to losses.

Overpressure (or Geopressure)

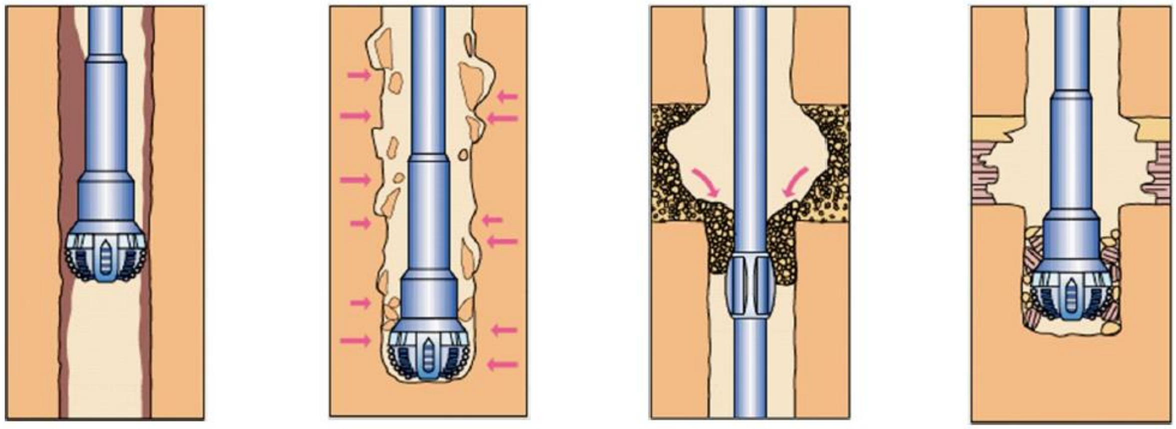
Geopressured formations are defined as those where the formation pore fluid pressure is greater than hydrostatic (ca. 0. 45 psi/ft or 10.2 MPa/km). Drilling these formations with a wellbore fluid pressure that is less than the pore pressure can result in fragments of shale popping off the borehole wall. This is the classic cause of splintery cavings when drilling underbalanced.

Unconsolidated Zones

If uncemented sands and gravels are drilled – particularly at relatively shallow depth in the borehole – a problem of running sands can occur, as an effective drilling fluid borehole filter cake cannot be built in these highly permeable formations. This can result in large amounts of running sands swamping the shakers or causing borehole pack-offs, particularly around stabilizers and larger bottomhole assembly (BHA) components.

Fractured or Faulted Zones

Rock surrounding a fault or fractured zone may be mechanically weakened making it more susceptible to instability relative to a borehole drilled in the undisturbed rock. Where the rock has a pronounced intrinsic fabric or layering, failure along these pre-existing planes of weakness often produces the classic blocky or tabular cavings. Chaotic, randomly-shaped cavings from a faulted region are also referred to as rubble zone cavings. Both can easily give rise to mechanical wellbore stability problems.



Differential sticking　　Geopressure　　Unconsolidated zones　　Fractured or faulted zones

Mobile Formations

Naturally-mobile formations, such as salt, deform over time when the drilling fluid hydrostatic pressure is less than the overburden stress in the salt. Under this underbalanced condition, salt begins to deform at a relatively fast rate (transient creep). This then slows after several days to attain a longer-term slower creep rate (steady-state creep). Halite (sodium chlorite, NaCl) and sylvite (potassium chlorite, KCl) are the two most common salts; they also posses the slowest creep rates relative to other, less common salts. Carnalite (KMgCl3.6H2O) and tachyhydrite (CaMg2Cl6•12(H2O)) are less common salts – rare in the deepwater Gulf of Mexico, but more common offshore Angola and Brazil – which exhibit faster creep rates. As a rule of thumb, it is recommended that salt is drilled with a mud weight that is at least 90% of overburden in order to minimize the severity of tight-hole conditions caused by the creeping salt.

Under-gauge Hole

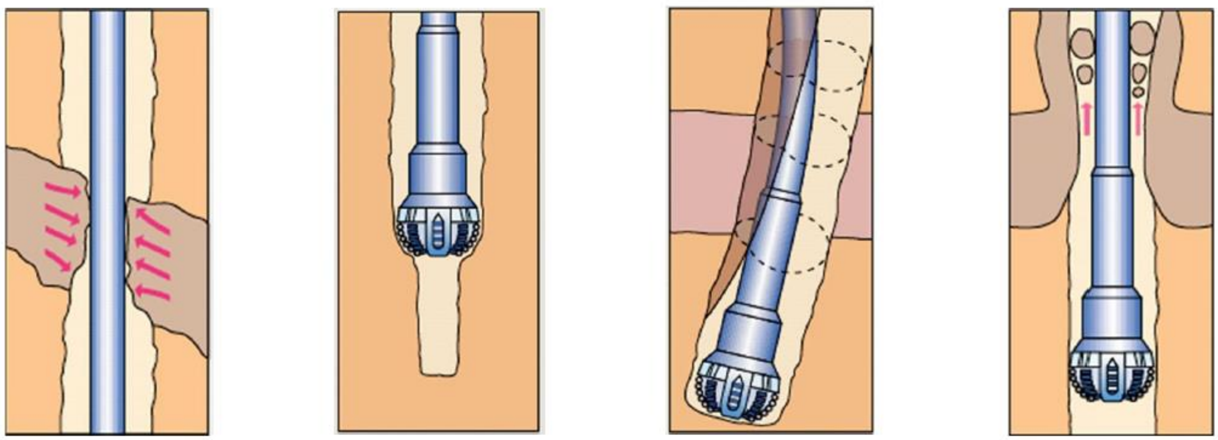
Tight-hole problems resulting from under-gauge boreholes typically are thought of as occurring in formations that are not usually considered as being mobile. Under-gauge boreholes in shale can occur as a consequence of improper drilling fluid chemistry which reacts with the formation. When the formation pore fluid has a salt concentration that is higher than that used in the drilling fluid, water can migrate from the drilling fluid into the formation as a consequence of osmosis. Under these conditions the formation shale can swell, so resulting in a borehole diameter that is under-gauge. In sandstones, undergauge boreholes can form when there exists a large difference between the magnitudes of the horizontal stresses. This is most likely to happen in tectonically-stressed regions. Frequent under-reaming may be necessary to prevent the borehole from closing over time. This problem is typically solved by increasing the mud weight.

Key Seating

When moving the drill-pipe, a slot can be worn on the high- or low-side of the borehole. This can be a cause of additional rock material removed from the borehole. The abrasion of the formation by the drill-pipe may produce small coffee grounds-sized cavings. The enlarged borehole area may also be a cause of poor hole cleaning due to reduced flow velocity which reduces the solids carrying capacity of the annular drilling fluid through this enlarged section.

Reactive Formations

Often called gumbo shales, these smectite-rich rocks tend to swell and disperse in the drilling mud when drilled with a fluid having inadequate inhibitive properties. This can be a problem with water-based and synthetic oil-based drilling fluids. This is a problem of mud chemistry, and not of mud weight.



Mobile formations   Under-gauge hole   Key seating   Reactive formations

Collapsed Casing

Where inadequate centralization or cementation exists in casings adjacent to a mobile formation, point-loading by the formation can result in deformed or collapsed casing. Deformed casing can also occur in HPHT wells due to annular pressure build-up (APB) during drilling. Both casing issues are characterized by tight-spots, particularly during the passage of drill collars and stabilizers, and by the risk of packing-off. In extreme cases, metal shavings may be observed in the returns crossing the shaker.

Junk

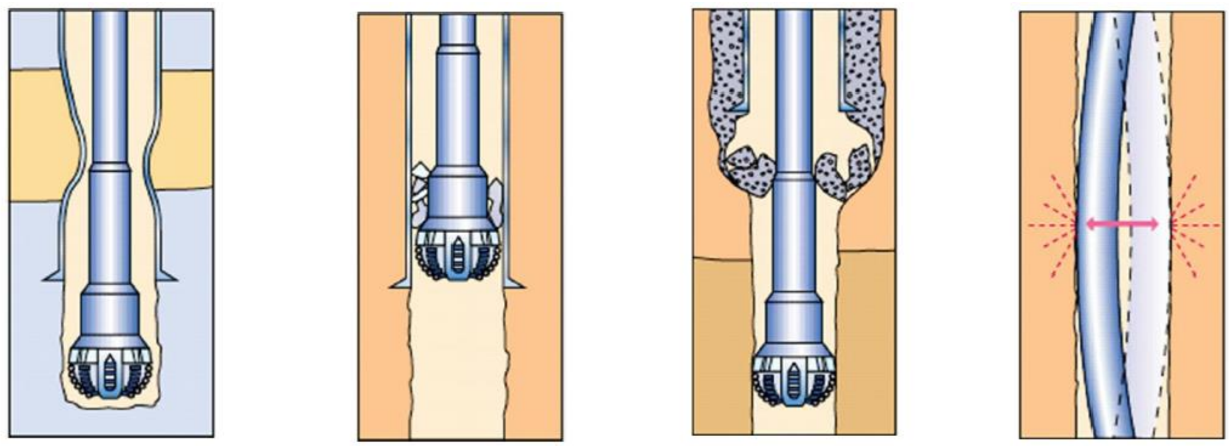
This is a term normally used to describe mechanical debris resulting from the failure of drilling or BHA components. The heavier metal debris may be difficult to remove by conventional drilling fluid circulation or by pumping sweeps. Junk remaining in the borehole may be a cause of stuck-pipe, particularly when pulling back into the casing.

Cement-related Problems

Cement cavings can be caused by cement remaining in the shoe-track of the previous hole section, or coating the borehole wall of the current hole when the prior casing failed to be run to bottom. Cement cavings are distinguished from rock cavings by their arbitrary shape and color difference. Where slabs of cement fall off the borehole wall – possibly by drill-string vibrations – this can lead to a hole cleaning and stuck-pipe problems.

Drill String Vibration

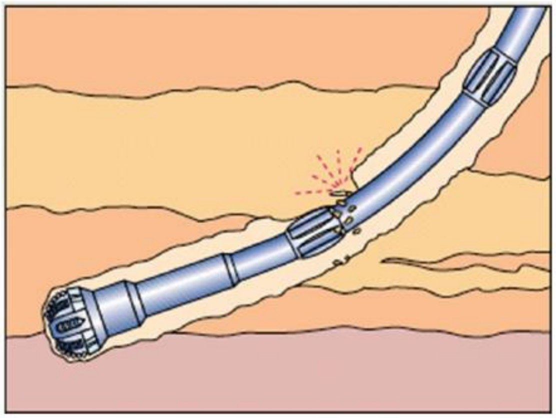
When drilling or reaming parameters (weight-on-bit, rate-of-penetration (ROP), etc.) are not optimized, drill-string vibrations may result. In these instances, the drill-pipe, collars or stabilizers may violently contact the borehole wall. Drill string vibration can cause borehole wall destabilization or a disturbance in built up cuttings beds. In fragile formations – such as those surrounding faults – unwanted drill string vibration can contribute to further cavings and instability.



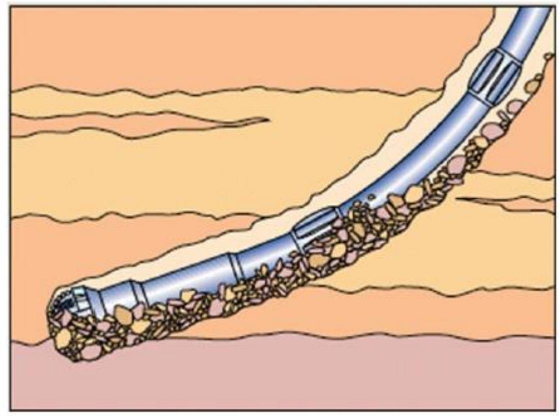
Collapsed casing | Junk | Cement-related problems | Drill string vibration

Wellbore Geometry
When drilling with a well trajectory deviated at more than 45° from vertical, or where harder rock layers are interbedded with weaker rock, wellbore geometry can result in ledging problems. With ledging, casing collars, BHAs, or stabilizers can become hung-up on irregularities on the borehole wall. Cavings and poor hole cleaning can result when these ledges are removed by the action of the drillpipe.
Another example of the well geometry affecting wellbore instability is when the well deviation is within 20° of the bedding-parallel direction. In certain layered shale formations, break-up of the layers can occur resulting in blocky, tabular cavings falling from the top and bottom of the borehole.

Poor Hole Cleaning
Poor hole cleaning can often be confused with problems of wellbore instability. Has the borehole packed-off because of excessive cavings caused by wellbore instability, or are the flow-rate and fluid pressures being used insufficient to clean (or remove) the cuttings produced while drilling? Distinguishing between cavings and cuttings coming over the shakers, particularly after pumping viscous sweeps, is an important diagnostic to identify hole cleaning problems and / or borehole instability. Enlarged sections of the wellbore will result in a hole cleaning problem across these intervals as the flow velocity is reduced. During reductions in flow velocity, response timing is important to minimize the instability occurring and mitigate a future hole cleaning problem.



Wellbore geometry



Poor hole cleaning

PLANNING A STABLE WELLBORE

The Need for a Wellbore Stability Analysis

Not all wells require a wellbore stability analysis to be performed prior to drilling the well. Much depends upon the complexity of the well, the complexity of the geology, and the amount of previous experience of drilling wells in the region. Using an integrated process, incorporating both Subsurface and Drilling staff, answer the questions can help to clarify, how complex your well is likely to be from a wellbore stability perspective!

Steps to Be Taken in a Wellbore Stability Analysis

Regional tectonics, structure and stress regime

What does the regional big picture tell about the well to be drilled? Information may be available from a variety of sources – e.g., from seismic sections, or from external sources such as the World Stress Map Project. The regional geology can tell you about likely stress directions and the stress regime (the ordering and relative magnitudes of the vertical and two horizontal stresses).

Determine magnitude of in-situ stresses and pressure

Overburden - Sv

This is typically obtained from the integration of density logs from offset wells. Where suitable offsets are few, the overburden stress can be estimated from correlations established in analogue depositional regimes.

Formation pore pressure - p

This is usually derived from interpretations of velocity data from seismic, supplemented by wireline sonic data from offset wells, where available. In new exploration areas, or in sub-salt areas where seismic velocity data may be poor, formation pore pressure may be predicted using basin models. This may be used in conjunction with seismic velocity interpretations where they exist. In sandstone intervals, direct measurement of pore pressure in offset wells – from using wireline sampling tools, or production data from nearby wells or fields - may be available. Note that there is no requirement for the pore pressure in sandstone intervals to be the same as that in adjacent shales.

Minimum horizontal stress - Shmin

This is usually derived from compilations of results from leak-off tests, extended leak-off tests or hydraulic fracture testing in offset wells. Approved regional correlations based on pore pressure and overburden stresses may also be used. As with pore pressure, there is no requirement that sandstones and shales possess the same equivalent horizontal stress gradient. In fact, it is very unlikely that they are similarly stressed. Shales often are more highly stressed than sandstones at equivalent depths in passive, extensional basins. In deep, tectonically stressed areas, however, it will be the stiffer rocks (either sandstone or shale) that will have the highest horizontal stresses. Care should be taken in assigning formation stress values using global or regional trends in these situations.

Maximum horizontal stress - SHmax

At an early stage in a wellbore stability assessment, the magnitude of the maximum horizontal stress is usually uncertain. In a normal faulting stress regime, where the magnitude of SHmax is constrained by the minimum horizontal stress (Shmin) and the overburden (Sv), it is often adequate to assess the influence of SHmax on the required mud weight by running analyses with SHmax varying between these two extremes. In more complex stress environments, where SHmax is greater than the overburden stress, the magnitude of SHmax may be determined at a later stage in the analysis if adequate additional information is available. The direction of SHmax is also usually uncertain, though this may be estimated from a review of the regional geology and available faulting patterns. When of significance, the magnitude of the horizontal stress and its direction is best determined by rock mechanics analyses of drilling-induced borehole failures identified in image logs ran in offset wells. The analyses consider whether breakouts or drilling-induced tensile fractures are evident in the images of the borehole wall. The analyses should also look at the orientation of breakouts obtained from caliper logs to establish stress directions in the field. With the additional information from image logs, together with knowing the mud weight used to drill the well, the wellbore instability indicators can be back-analyzed to provide an estimate of the maximum horizontal stress at particular depth intervals where these features occur. This is a relatively advanced analysis, the discussion of which is beyond the scope of this handbook.

Determine formation rock strength

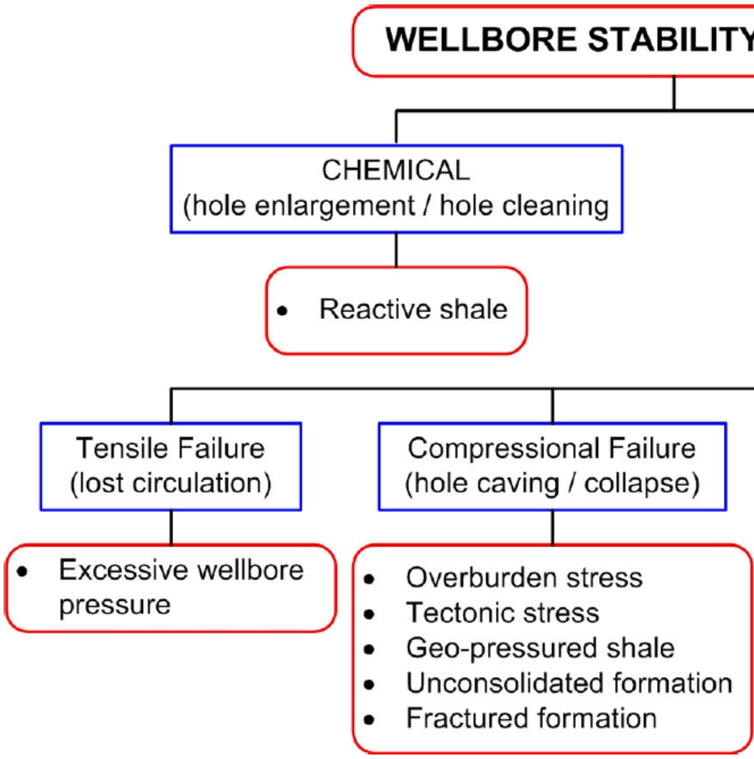
Rock strength is estimated through correlations with sonic data, since slow sonic velocity generally relates to high porosity and low rock strength. In exploration wells with no offsets, the seismic interval velocity may be used to assess rock strength. However, this represents an average velocity over an interval of several hundred feet and so does not give a high-resolution value for rock strength. Where available, it is preferable to use wireline or LWD sonic velocity data to establish a detailed description of rock strength variation.

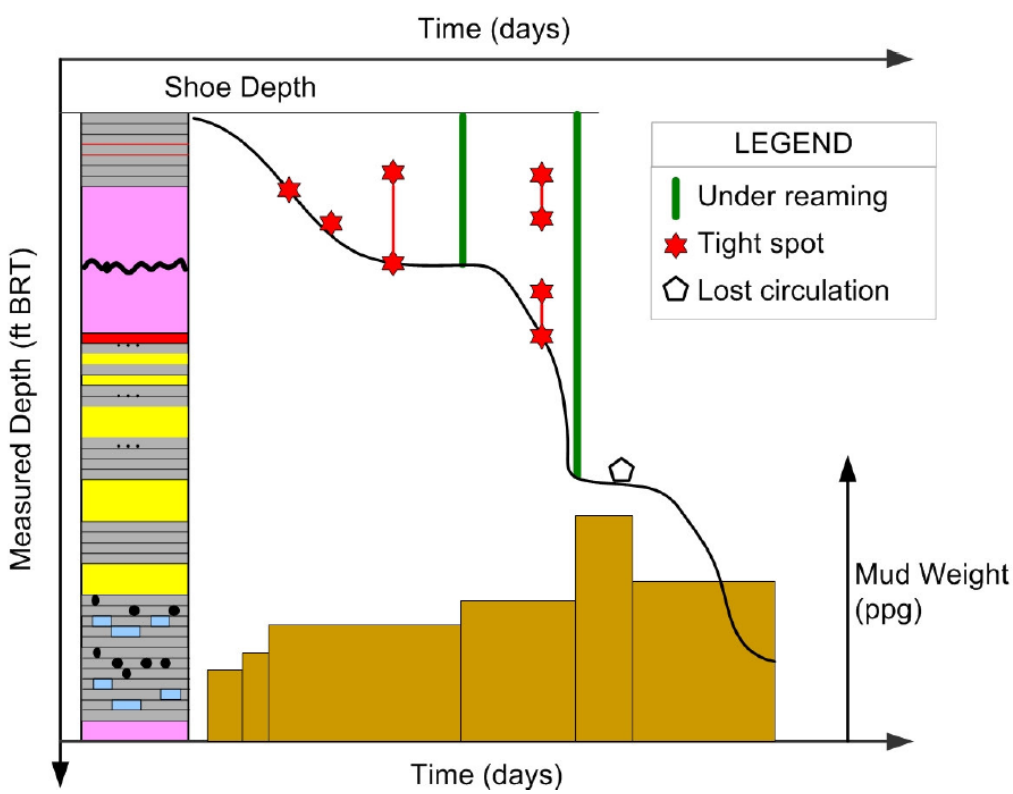
Review offset wells for indications of instability problems

Offset well experiences can provide invaluable information on previous wellbore instability problems. These need to be catalogued in any wellbore stability study in order to understand the root causes of the problems so that these can be prevented or adequately managed in new wells to be drilled. The following checklist is provided of issues to look for when reviewing offset well information:

- ✓ Identify hole sections with wellbore instability symptoms.
- ✓ List the conditions that caused the instability problem.
- ✓ Identify similar problems in offset wells occurring at the same vertical depth. Look for similarity in the conditions that caused the problem.

✓ List the drilling parameters affecting the problem (i.e., drilling fluid type, weight and salinity, hole angle and azimuth, adverse formations, unusual drilling practices).





Wellbore instability problems are not confined to just recently-drilled formations. Instability can develop over time in any section of the open borehole. It is often useful to annotate drilling problems on a time-line to assess the potential for time dependent instability problems. It is important to identify occurrences of drilling NPT events and indicators of deteriorating hole conditions (e.g., tight spots, fill on bottom when running back into the hole, intervals requiring reaming, etc.). The time-based data presentation enables exposure-time effects to be identified, as well as problems arising from poor hole cleaning when drilling with high rates of penetration.

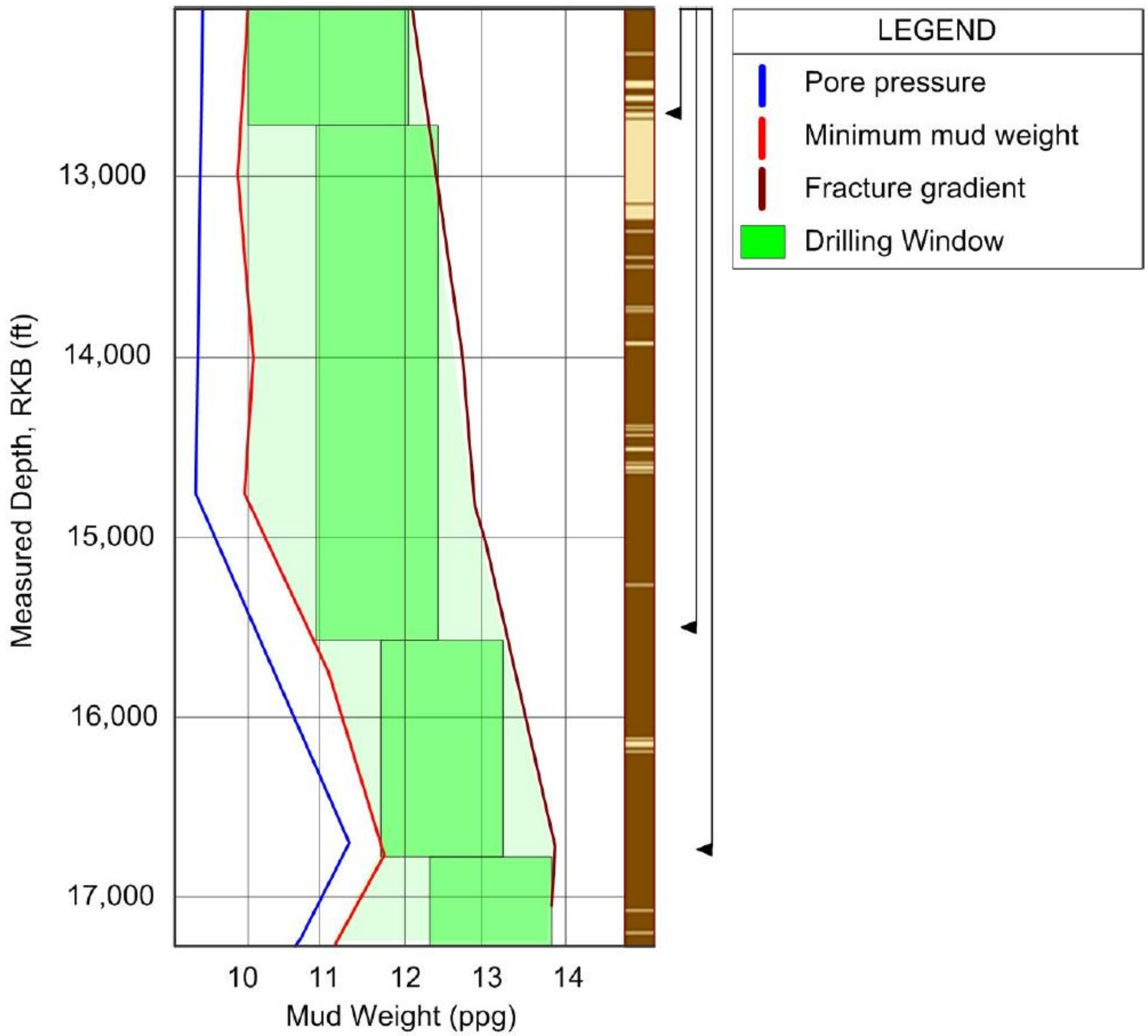
Select the drilling fluid system

Selection of an appropriately inhibitive drilling fluid can often form part of the overall wider wellbore stability assessment for the well. This can be especially important when designing challenging wells to be drilled with a water-based drilling fluid. While synthetic oil-based drilling fluids are reasonably inhibitive, care must still be taken to specify the appropriate water-phase salinity for the various hole sections in the well. While it is impossible to have balanced water activity (i.e., correct salinity) for every depth and hole section in the well, analyses should be performed to arrive at the most suitable compromise salinity for each hole section. Identifying the location of potential problematic formations from a mechanical wellbore stability standpoint is an important part in optimizing the drilling fluid chemistry for the well.

Predict the required mud weight for each hole section

With all the necessary parameters defined, wellbore stability analysis software can be used to predict the minimum mud weight required for stability through any particular hole section. The analysis determines the stresses acting on the borehole wall for a given well trajectory, and then predicts the required mud weight at that depth necessary to limit the borehole failure occurring around the borehole circumference to an acceptable amount.

It is important to realize that predictions are seldom made for mud weights that prevent all breakouts from occurring. There is an inherent conservatism in the analysis approach. It is also possible to successfully drill with a limited amount of borehole failure. A mud weight that provides a gun-barrel quality is higher than normally used in most off-set wells. The wellbore stability prediction methodology therefore predicts a static mud weight that produces an acceptable level of borehole failure. The higher ECD pressure existing when drilling ahead thus provides a quality borehole. In situations where this minimum level of acceptable breakout is underestimated (e.g., as a consequence of in-situ conditions differing from the pre-drill prediction) a wellbore instability problem can develop. When this happens it is important that the warning signs are recognized early, and corrective actions put in place, to prevent the problem developing into a major NPT event.



Typical result of a wellbore stability prediction for a section of a well

DRILLING DEPLETED SANDS

Introduction

When accessing deeper reserves, or when drilling to satellite oil accumulations, it is often necessary to drill through reservoir formations where the pore pressure has been reduced by off-set production to a value lower than that existing at discovery. This reduction in pore pressure is associated with a reduction in horizontal stress. This effect is well recognized from hydraulic fracture treatments in fields that have been on production for some time. The average stress path ($\Delta Shmin/\Delta P$) is approximately 0.75 with a standard deviation of 0.2. This means that, on average, the horizontal stress in a sandstone reservoir reduces by 750 psi for every 1,000 psi drop in reservoir pressure.

Techniques are available to mitigate these losses via augmentation of the fracture gradient by loss-reducing additives to the drilling fluid, or by the use of chemical consolidation of the depleted sand zone, together with the use of prescribed drilling practices. StressCage is one method utilized by many companies to increase the fracture resistance above the conventional minimum horizontal stress through the incorporation of a calculated blend of sized calcium carbonate particles in the mud system. When applied correctly, drilling with hydraulic pressures above the (far-field) fracture gradient can be accomplished without inducing mud losses. Although sized calcium carbonate has been employed for many years to prevent losses, the proprietary analysis and design techniques inherent in the StressCage methodology produces a recommended formulation that dramatically improves the chance of a successful application.

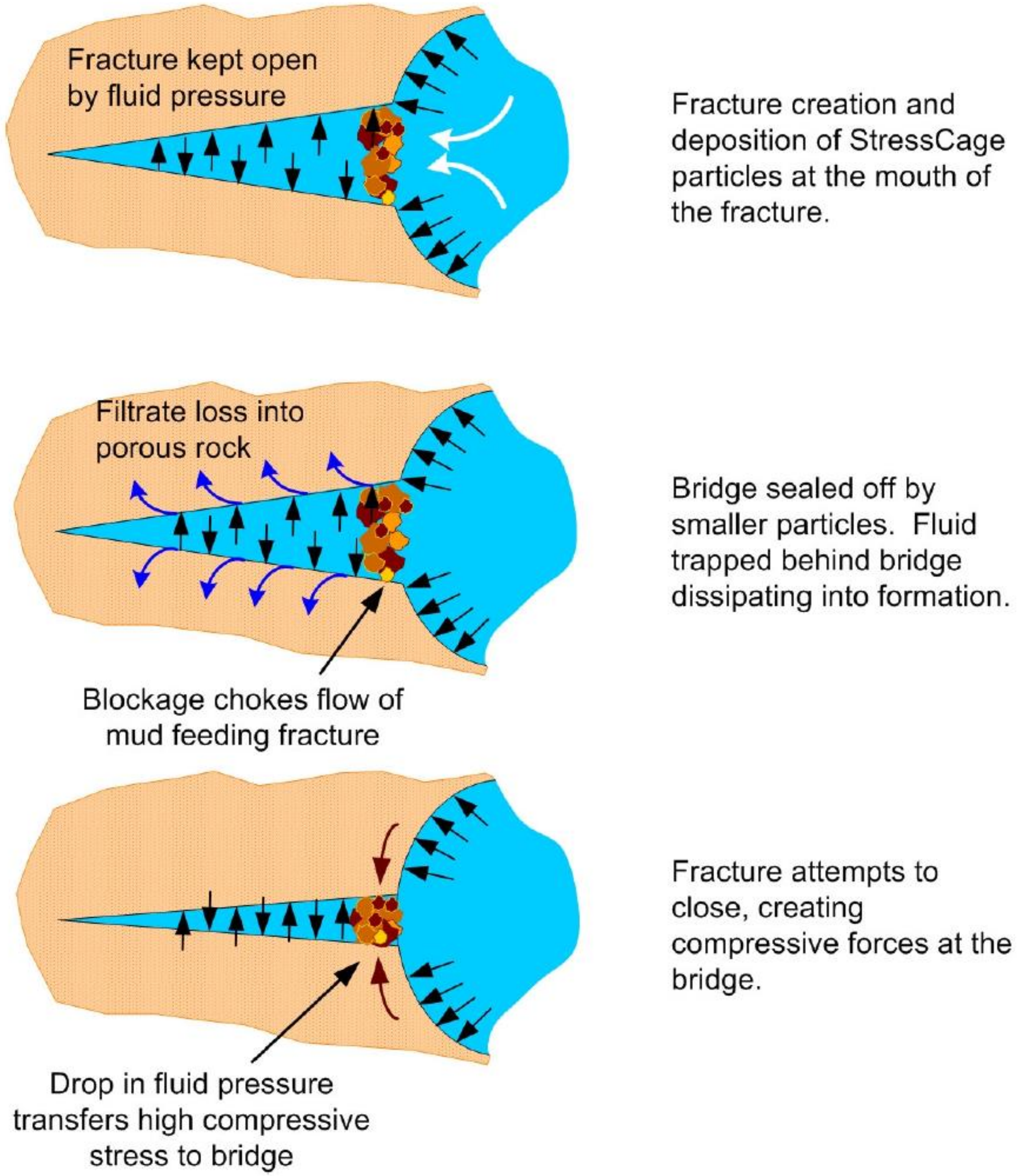
The benefits of a successful implementation of this technology mean that previously un-drillable prospects can now be drilled in a cost effective manner without any compromise to productivity or HSSE. The potential to eliminate casing strings and the enhanced potential to access reserves below depleted intervals are both major prizes here. Another beneficial application is in deep and ultra-deepwater drilling where the margin between pore pressure and fracture gradient often narrows as the well gets deeper.

Other benefits and the possible range of applications of StressCage technology include the following:

- ✓ Reducing (or eliminating) losses when running casing.
- ✓ Reducing (or eliminating) losses during cementing jobs.
- ✓ Improved well control.
- ✓ Extending casing shoe setting depths.
- ✓ Drilling over-pressured shale formations while avoiding losses in adjacent depleted zones.
- ✓ An alternative option to expandable casing.

StressCage – A Physical Model

StressCage is the method utilized by many companies to increase the fracture resistance above the minimum horizontal stress. When the mud hydrostatic pressure exceeds the minimum stress, fractures will begin to propagate away from the borehole in a direction that is normal to the minimum horizontal stress, Shmin. The principle of StressCage involves incorporating a calculated blend of sized calcium carbonate and graphitic particles in the mud system that is deposited in the mouth of the fracture as it is created and begins to propagate into the formation. The larger sized particles act as a proppant in the fracture mouth while the smaller particles seal off the fracture mouth, isolating the fluid trapped in the fracture from that in the wellbore. Hydraulic isolation also stops the induced fracture from propagating further and becoming wider. Depending on the permeability of the formation where the fracture was induced, the trapped fluid behind the bridge dissipates over time, and the fracture will close behind the bridge. The closure of the fracture onto the particles at the bridge causes compression to be created at this point, with a resultant increase in the near wellbore hoop stress. The figure below shows pictorially how the process occurs.



Schematic of the wellbore strengthening process achieved by a StressCage treatment

StressCage – Application in Impermeable Formations

In low permeability rocks, such as shale, the process of creating a StressCage is hampered by the low permeability of the formation. The initial rush of fluid into the fracture when it forms will deposit the bridging solids at the fracture mouth. However, pressure decay into the shale matrix behind the bridge will be minimal because of the relatively low permeability and the effects of interfacial tension.

While the fracture mouth is sealed; the inability of the filtrate to dissipate into the formation does not allow the fracture to close against the bridge. The fluid pressure in the fracture behind the bridge is maintained at the fracture closure pressure.

Since a positive pressure difference across the bridge is required to hold the bridge and seal in place, the particles composing the bridge can easily become dislodged by pressure fluctuations in the wellbore. These fluctuations can easily occur by circulating, tripping in and out of the well, or simply by setting the drill pipe into the slips. The initial propping open of the induced fracture will cause hoop stresses to increase, but the effect will be lost when the particles in the bridge become dislodged. Furthermore, the seal on the bridge is imperfect and additional fluid continues to seep through the bridge, growing the fracture in both length and width. Eventually the bridge will fail, even if a positive differential is maintained into the fracture. Current initiatives focus on using a carrier fluid that solidifies behind the bridge.

StressCage – Key to Success

The following factors are essential for a successful implementation of StressCage technology:

- ✓ The ability to form a bridge in the newly created fracture is dependent on the size of the fracture and the concentration and size of StressCage particles in the mud volume that enters the fracture.
- ✓ An appropriate concentration of smaller particles must also be present in the mud volume that enters the fracture to seal off and isolate the fluid behind the bridge to prevent further fracture propagation and associated increase in width. The desired result is that the flow through the bridge must be less than the dissipation rate of the filtrate into the formation from the faces of the fracture.
- ✓ It is important to accurately predict the width of the induced fracture so that particle sizes and concentrations are appropriate. This requires an accurate pore pressure / fracture gradient / overburden gradient model. The integration of leak-off test and mini-frac data into the model for calibration purposes enhances the chances of success and is highly recommended.
- ✓ Understanding the stiffness of the rock to be treated is a critical input to the model. Stiffness can be most accurately derived from acoustic and density logging data, but it may also be adequately estimated from suitable effective stress correlations.

Data Requirements for StressCage Design

The key to a successful application of a StressCage operation lies in accurately predicting the width of the induced fracture and determining the size and concentration of particles to incorporate into the drilling fluids system. The following data are required to plan a Stress Cage application strategy. Many of these inputs are required for wellbore stability prediction also, and the two approaches should be regarded as being complementary:

a. Pore pressure, sand fracture gradient, shale fracture gradient and overburden gradient curves.

b. Data that establishes the local stress regime the well path will drill through.

c. Borehole parameters (hole size, deviation and azimuth).

d. Data to derive Young’s modulus of the rock.

e. Drilling ECD simulations for each hole section.

f. Mud hydraulics surge calculations for each casing string run requiring StressCage treatment.

g. ECD simulations for circulating with the casing modeled to be on bottom and at different points in the well, as designated in the operations procedure.

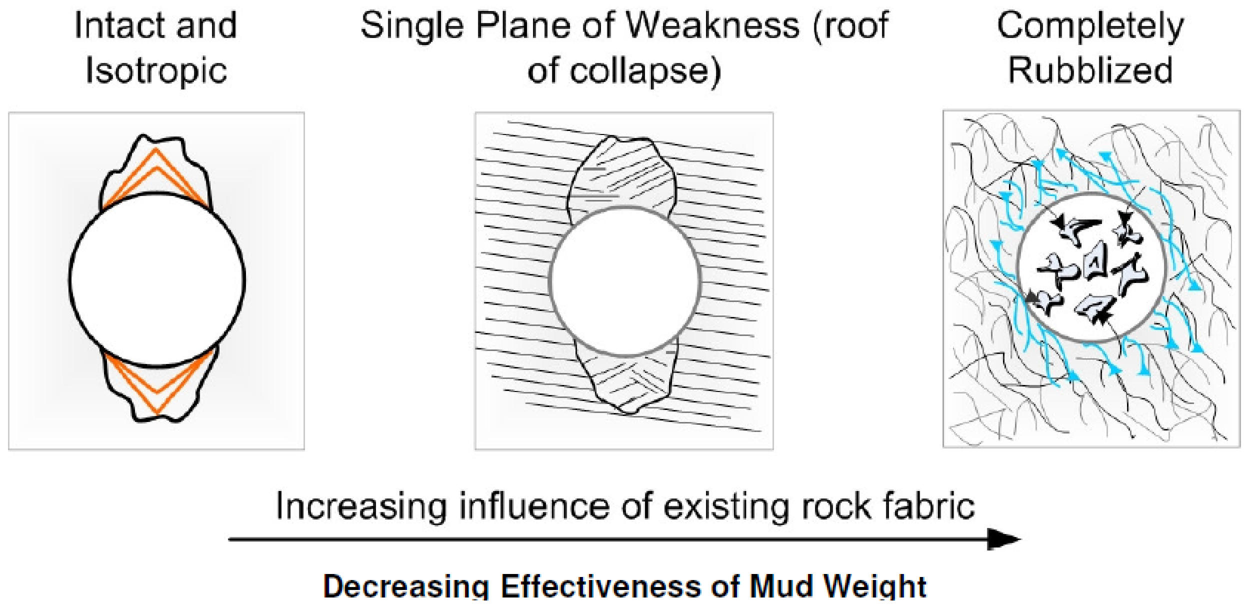
h. Cementing ECD simulations. The data sets listed below should also be reviewed (if available) to increase the chances of a successful implementation. This may also serve to identify cases where StressCage applications may have limited success – for example, in unstable fault zones or above rapidly depleted reservoir zones where the overburden stress may have been reduced as a consequence of stress arching.

a. Offset drilling data - mud weight curves, NPT data associated with hole problems and lost circulation events, directional profiles, drilling fluid systems, LOT / FIT data, flow-line temperature, hole size, measured / simulated ECD data, and lessons learned.
b. Offset mud recaps - LCM treatments, background LCM materials and concentrations, drilling fluid types (SOBM, WBM), drilling fluid product concentrations, hydraulics, mud mixing capabilities, mud product logistics, and mud properties.
c. Core data - permeability, porosity, pore-throat size, lithology, fracture permeability.
d. Reservoir data - pore pressure, permeability, porosity, horizontal stresses.
e. LWD / MWD / log data - ECD, porosity, permeability, formation temperature, pore pressure, formation dip, formation temperature and hole deviation.

DIAGNOSTIC TOOLS FOR WELLBORE INSTABILITY DETECTION

Introduction

Wellbore instability and its resulting problems, such as lost circulation, stuck pipe, difficulty with hole cleaning, tripping, logging and casing running, are extremely costly to many drilling and workover operations in terms of NPT and unit mud costs (especially whole synthetic or low toxicity mineral oil mud). Traditionally, increasing mud weight and / or salinity are normally used to address wellbore instability problems. However, the perception that high mud weight and high salinity are beneficial to wellbore stability in all situations needs to be revised.
Increasing mud weight is generally an effective remedy to conventional wellbore instability arising from shear-induced breakouts in intact and isotropic formations, as shown in the left of the following picture. There is, however, a spectrum of instability mechanisms dependent on formation type – shown schematically in the picture below – that require different approaches for remediation and prevention. The effect of mud weight on wellbore instability in laminated formations (as shown in the middle picture) depends on the potential for drilling fluid filtrate to penetrate into the formation - i.e., whether the wellbore surface is sealed or not. The wellbore wall may be sealed if either the bedding planes themselves have no enhanced permeability, or additives in the drilling fluid prevent fluid loss to the formation. In this instance, the pressure of the mud column will act to support the wellbore wall, as it does in the conventional case.



If the bedding is significantly weaker than the bulk rock then the magnitude of mud weight increase may be substantially more than that required in an otherwise identical conventional case. An example of this is shown in the following contour plots.

In anisotropic, laminated rock in order for the necessary increase in mud weight to be effective, the drilling fluid must be prevented from penetrating these planes of weakness. These weakness planes may be either intrinsically permeable, or generate additional permeability as a consequence of instability-induced slip on the planes. If mud penetration does occur, the mud pressure will not support the wellbore wall and the mud weight increase will not be effective at suppressing instability. In this case, the addition of fluid loss prevention additives, together with careful drilling and tripping practices, are needed to manage this form of instability. However, remedial measures tend to be short-lived in these formations, and re-drilling the hole section at a more stable angle to bedding may be the most appropriate remedial action for future wells.

Sometimes, around faults and near salt diapirs, the formation may be extensively fractured and broken before it is drilled. The fractures between rock fragments can be permeable, such that drilling fluid easily penetrates between the fragments and destabilizes the wellbore wall. Therefore, increasing the mud weight is likely to cause further mud penetration into the cracks between the rubble fragments and further destabilize the borehole within this rubble zone.

The salinity of the drilling fluid is also very important when drilling faulted or fractured shale formations. In these instances it is particularly important to control the movement of water (either from or into the formation) caused by osmotic pressure differences. Any disturbance of the formation by chemical or mechanical means could result in shale fragments breaking-off the wall and collapsing into the borehole. Once wellbore instability is initiated in these fragile rubble zones it can be very difficult to remediate the situation. For this reason, drilling faulted or fractured shale using the correct drilling fluid water-phase salinity will reduce wellbore instability problems and improve drilling performance.

From the foregoing discussion it is seen that it is important to understand the mechanism of wellbore instability that is occurring in the open borehole, as different mechanisms require different remedial actions. The cornerstone of realtime wellbore stability monitoring is the early diagnosis of the mechanism of instability that is occurring while drilling. This requires a combination of tools and observations, not just a wellbore stability model.

In this section a systematic way to diagnose wellbore instability into one or more potential root causes is described. Based upon the classification of instability mechanisms, it is then possible to identify treatments that are effective for the range of possible root causes.

Various sources of information may be available to predict and diagnose potential causes of wellbore instability. These can be compiled from offset well information, the pre-drill predictions for the particular well, and real-time data collected while drilling the well. Data sources include:

- ✓ Borehole images
- ✓ Caliper logs
- ✓ Resistivity logs
- ✓ Gamma ray logs
- ✓ Density logs
- ✓ Cuttings / cavings report
- ✓ PPFG and wellbore stability analysis
- ✓ XRD, CEC and water activity analysis
- ✓ PWD / ECD
- ✓ Rock mechanical tests

- ✓ Tectonic regime
- ✓ Bedding dip and azimuth
- ✓ Well trajectory
- ✓ Salinity of drilling fluid
- ✓ Temperature information
- ✓ Fault stability analysis tool
- ✓ Losses / gain behavior
- ✓ Torque and drag

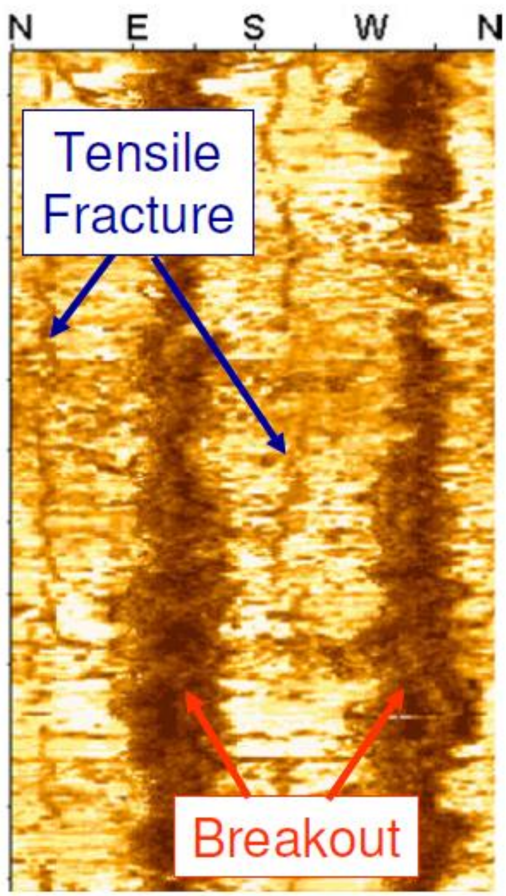
Diagnostic Tools

Borehole image

Borehole images are generated by measuring something sensitive to the difference between the rock and drilling fluid, such as density, acoustic velocity, resistivity, or Gamma ray. They are valuable sources of information for wellbore stability analysis. An obvious application of the image is to visualize the severity and nature of any borehole instability and take proper steps to resolve the problems. It can be used to describe failure mode (breakout or tensile failure), fracture types (induced or natural), fracture patterns, and sedimentary features.

The drilling-induced features seen in the borehole image can also be used to constrain in-situ stress magnitudes and their directions. Borehole breakouts (diametric elongation of the borehole in a preferred direction) are often observed.

In certain drilling situations, drilling-induced fractures can occur if the stress concentrations around the borehole become tensile and exceed the tensile strength of the formation.



Borehole image shows both natural and induced fractures simultaneously.

Caliper logs

The caliper tool measures the size and shape of a borehole. It is used to measure borehole diameter and rugosity, to locate fracture zones, to assess borehole quality and stability, and also to calculate the wellbore volume for cementing operations. Caliper log information can be used to identify borehole washout, ellipticity, breakout, and spiral hole conditions. It is a great piece of information for wellbore stability analysis. The simple observation of wellbore enlargement in a particular area combined with other observations, such as cavings shape, can be very useful.

Drilling engineers or rig site personnel use caliper measurement as a qualitative indication of both the condition of the wellbore and the degree to which the mud system has maintained wellbore stability.

There are two types of caliper logs: wireline (or mechanical) and logging while drilling (LWD) calipers. The mechanical caliper measures the variation in borehole diameter as it is withdrawn vertically from the bottom of the hole. Unlike wireline tools, LWD calipers do not make a physical measurement of the hole diameter. Rather, the hole diameter is inferred from indirect information such as ultrasonic measurement of two-way travel time between the tool and borehole wall, or from density or resistivity differences between the drilling fluid and the formation.

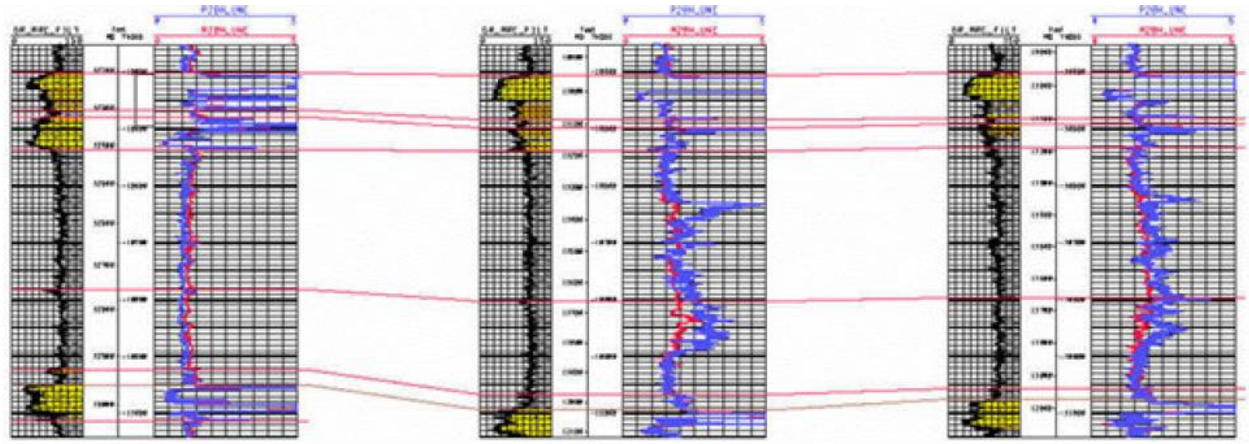
Resistivity logging

Resistivity logging is a method of characterizing the rock or sediment in a borehole by measuring its electrical resistivity. Resistivity is a fundamental material property which represents how strongly a material opposes the flow of electric current. Most rock materials are essentially insulators, while their enclosed fluids are conductors. Hydrocarbon fluids are an exception, because they are almost infinitely resistive. When a formation is porous and contains salty water, the overall resistivity will be low. When the formation contains hydrocarbon, its resistivity will be very high. High resistivity values may indicate a porous, hydrocarbon bearing formation.

Resistivity logs can provide very useful information on wellbore instability. LWD tools typically transmit two resistivity curves in real-time (usually a shallow and a deep resistivity curve). Under normal conditions these two measurements should read the same. However, it is not uncommon to see a curve separation (i.e., the shallow and the deep measurement have a different reading). This is most commonly seen when drilling with an oil-based mud – i.e., a mud system that has a much higher resistivity than the formation. In an oil-based mud, there are several possible causes for the shallow and deep resistivity to read differently:

1. Invasion - If mud filtrate penetrating the near wellbore region has a different resistivity to the formation fluid, the shallow reading will be at least partly reading the resistivity of the invaded zone. When using oil based mud, the shallow reading will have a higher resistivity than the deep reading. In high permeability sands, invasion can often occur during the time taken between first drilling and logging the formation. In shale, invasion cannot occur this rapidly because of the low matrix permeability.

When an invasion profile is seen in shale, it probably means that the shale is fractured or contains some permeable pre-existing weakness into which the mud has penetrated. The figure below shows an example of this, where the two right-hand resistivity logs show separation between the shallow (blue) and deep (red) resistivity readings. Note that hole enlargement was ruled out as a possible cause of curve separation because an azimuthal density tool with an ultra sonic caliper was run in the same BHA, directly behind the resistivity, and this confirmed that the hole was still in gauge.



Anomalous resistivity seen in two out of three wells associated with oil-based mud invading pre-existing fractures in fractured or fissile shale.

2. Hole enlargement - If the wellbore is sufficiently enlarged, the shallow resistivity measurement may be influenced by the resistivity of the mud in the (enlarged) annulus. Without a caliper measurement it can be difficult to differentiate between invasion and hole enlargement. However, either one of these causes is a good indication that the hole is either already unstable or could be becoming unstable.

3. Resistivity anisotropy - When the formation has an intrinsic anisotropy in its resistivity – e.g., due to dipping bedding – different depths of investigation of resistivity can be affected differently, causing curve separation. The physics of this is complicated, however and some reverse invasion profiles have been attributed to anisotropy. This is quite commonly seen in shales drilled at high angle (i.e., when the wellbore is within about 30° of being parallel to bedding). Because there are a number of different causes of resistivity curve separation, care has to be taken when interpreting it. However, it is often a sign that something unusual in the wellbore is taking place.

Gamma ray logging

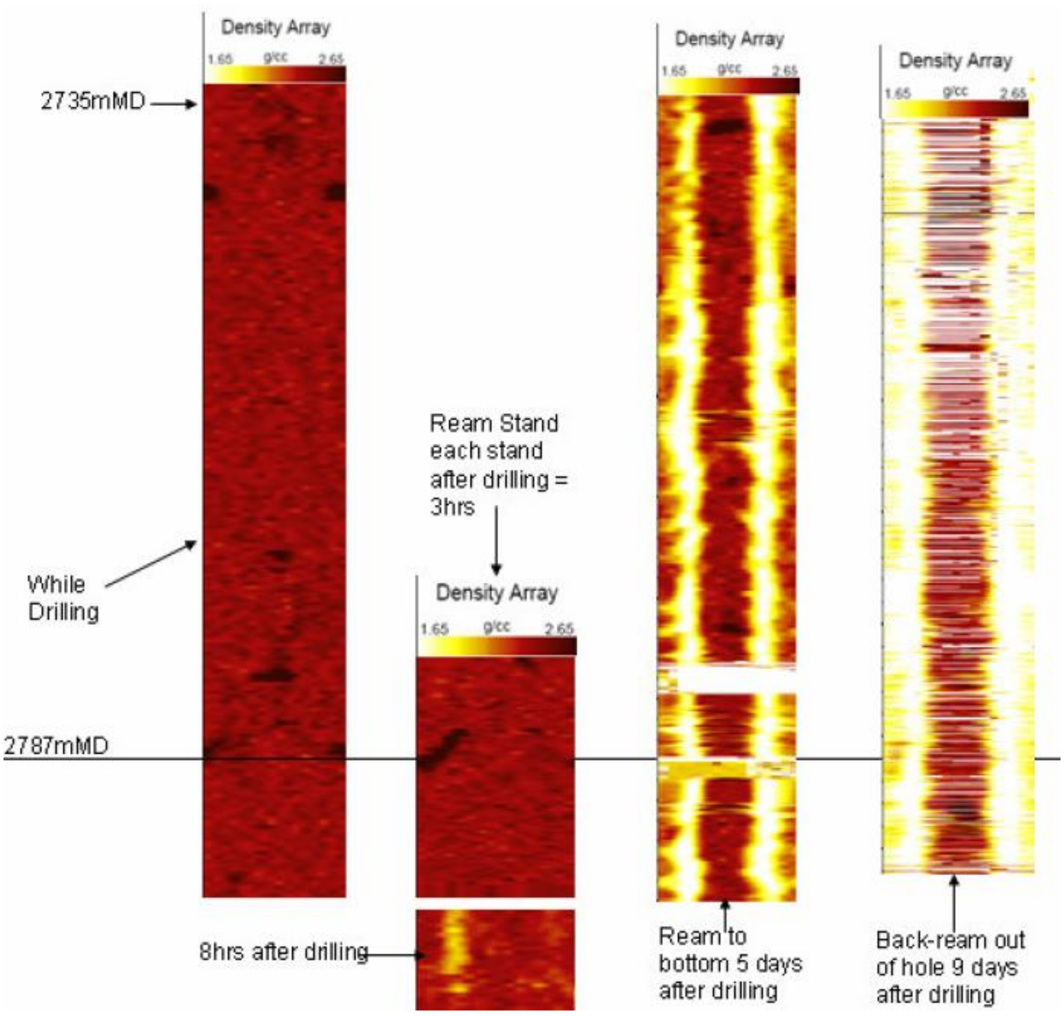
Gamma ray logging is a method using natural gamma radiation to characterize the rock or sediment in a borehole. Different types of rock emit different amounts and different types of natural gamma radiation. In particular, shales usually emit more gamma rays than other sedimentary rocks, such as sandstone, gypsum, salt, coal, dolomite and limestone. Therefore, gamma ray logs are used to detect shale content, clay type, the volume of shale or clay in many rock types. In conventional gamma ray logging, high counts are equivalent to high clay content. Combined with resistivity logging, gamma ray logging is used to locate whether a problematic zone is in a shale or sand formation.

Density logging

A density tool has a nuclear source which emits beams of electrons aimed at the formation. The density of the material determines how many of these electrons are absorbed and how many bounce back. Once calibrated, the tool can provide quite accurate density measurements. Density tool is most commonly used for LWD imaging.

The density tool can also measure a property called the photoelectric factor (PEF). The PEF is related to the way in which different materials preferentially absorb electrons of different energy levels. Barite has a very high PEF and rock a much lower PEF. If the mud is weighted with

barite, the PEF provides a very sensitive measure of where the well has failed and mud instead of rock exists.
The figure below shows a collage of density images from four separate passes referenced to a common depth datum. The wellbore in this example is 12¼" in diameter. The well is deviated at about 75°, drilling down dip where the bedding dip angle is about 5°. Thus, the angle between the wellbore and the bedding dip angle is about 10°. In the images, intact formations are a red / brown colour. Denser nodules or concretions are black. Regions of enlargement are yellow and particularly severe enlargements are shaded white.
As seen in the left-most figure, there is no sign of instability in the while-drilling image. As the section was reamed down after 3 hr, there is still no sign of instability. After some additional time spent circulating, the next section was reamed (below 2,787 m MD) about 8 hr after drilling. This is where the first sign of hole enlargement is seen (shown as orange / yellow zone in the image, indicating a lower density). It is most noticeable on one side of the hole although there are hints of instability on the other side also.



Time lapse LWD density images from high angle section with Sperry's ALD tool.

After five days, the interval was reamed again (in the intervening time, there had been rig repairs and the BHA had been sitting a short distance above this interval). The extent of the instability is clearly more advanced in this five-day image. Significant enlargement is seen during the final pass after nine days as the BHA is back-reamed out of the hole. Only the low side of the wellbore can be imaged, as this is where the tool sits. Elsewhere, significant enlargements have occurred.

Cuttings / cavings report

Cavings are pieces of rock from the wellbore wall that were not produced directly by the action of the drill bit. Variation in size, shape, and volume of shale fragments in the drilling fluids can provide indication of wellbore instability and abnormal formation pressure.

Cavings monitoring provides:

- ✓ A warning signal that the wellbore is falling
- ✓ An indication of which formation is unstable
- ✓ Evidence of the mode of wellbore failure
- ✓ Information to decide the appropriate remedial action – e.g., improve hole cleaning, increase mud weight, or change the mud chemistry formulation.

Angular

Splintered

Tabular

Cavings may be long and splintery, tabular or angular in shape. Angular cavings are produced from shear failure resulting in multifaceted fragments. Platy / tabular cavings are characterized by flat surfaces, two of which are parallel or sub-parallel to bedding. These typically result from failure along bedding planes or along cleavages in pre-existing fractures. Splintery cavings are produced from tensile failure due to ‘under-balanced’ conditions.

PPFG / wellbore stability analysis

Reliable predictions of pore pressure and fracture gradient (or minimum horizontal stress) are essential for the pre-drill prediction and real-time management of mud weights required to assure wellbore stability.

XRD, CEC and water activity analysis

The mineralogical composition and petrophysical properties of a shale formation are important inputs to wellbore stability prediction and the prevention of hole problems while drilling. Simple properties measurements, such as X-ray diffraction (XRD), cation exchange capacity (CEC), and water activity, can help identify any potential chemical incompatibility between the formation and the drilling fluid, so permitting an optimization of the drilling fluid formulation.

XRD is used to identify and determine the approximate amount of each mineral type in a particular formation. This information can be used to understand the mechanisms of wellbore instability and to properly formulate the drilling fluid. For example, smectite-rich shales tend to swell and disperse in water-based drilling fluids; therefore, appropriate additives to prevent clay dispersion need to be added to water-based drilling fluids, or consideration needs to be given to the use of synthetic oil-based drilling fluids.

CEC is the quantity of positively charged ions (cations) that a clay mineral or similar material can accommodate on its negatively charged surface. This is commonly expressed in units of milliequivalents (meq) per 100 g. CEC values are directly related to the reactivity of the shale. If shale has a high CEC, it might be easily altered by the contact to a drilling fluid.

The water activity of shale is a parameter used to describe the potential for water movement in or out of the shale when exposed to a drilling fluid. Activity is an inverse measure of salinity, measured on a scale of 1 to 0. A high activity corresponds to low salinity, fresh water having an activity of 1. Water always flows from the system with **high** water activity (**low salinity**) to the system with **low** water activity (**high salinity**). Therefore, if the water activity of shale (**aw**, shale) is greater than the water activity of the drilling fluid (**aw**, fluid), water flows from the shale formation into the drilling fluid causing dehydration of formation.

Conversely, if the water activity of the shale formation is less than the water activity of the drilling fluid, water flows from the drilling fluid into the shale formation. This results in hydration of shale formation which can cause swelling and dispersion of the shale, and a reduction in strength. Ideally, when the water activity of the shale formation equals the water activity of the drilling fluid there is no water movement between the formation and the drilling fluid. It is believed balanced water activity between drilling fluid and shale formation promotes wellbore stability. This is called balanced-activity theory. For more detailed information on this subject, we should refer to Osmosis.

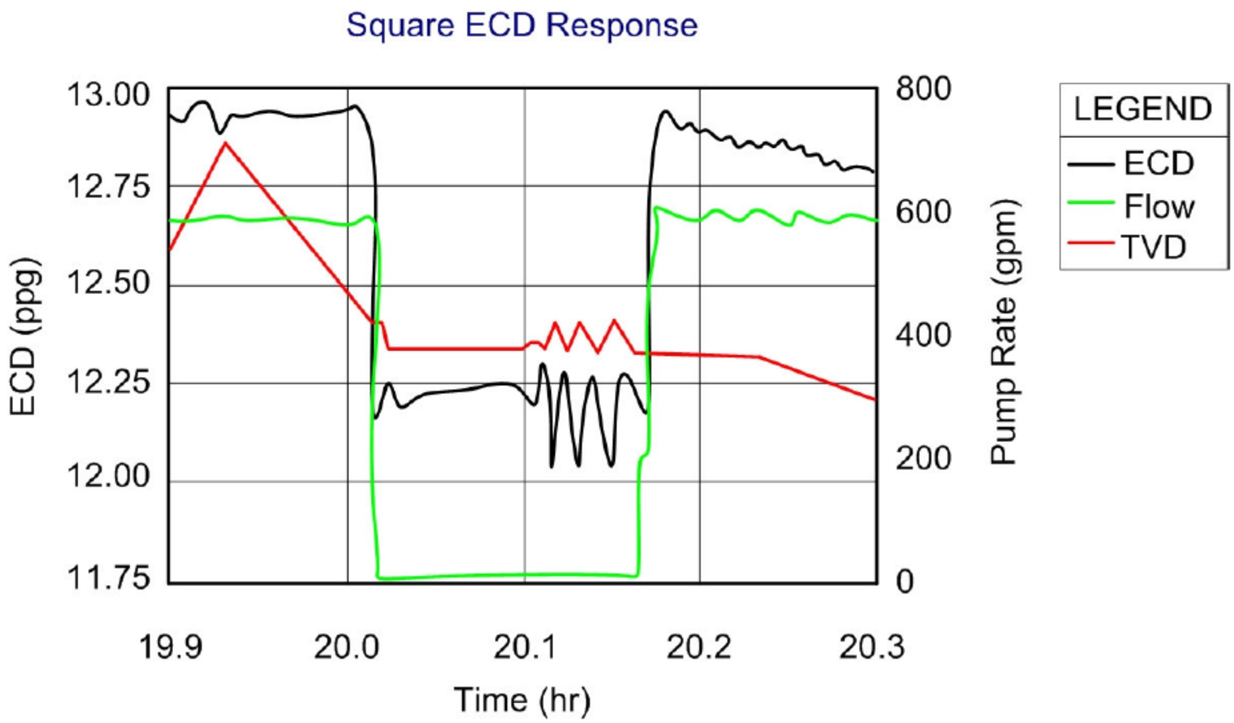
CEC and activity for different shales. Depends on a high clay content and high percentage of the reactive clays illite and smectite (which have higher CEC values and a lower water activity). Therefore, a greater likelihood of chemical related wellbore instability problems should be anticipated in shale. This would require an appropriately designed drilling fluid chemistry formulation to suppress any adverse chemical interactions between these formations and the drilling fluid.

PWD / ECD

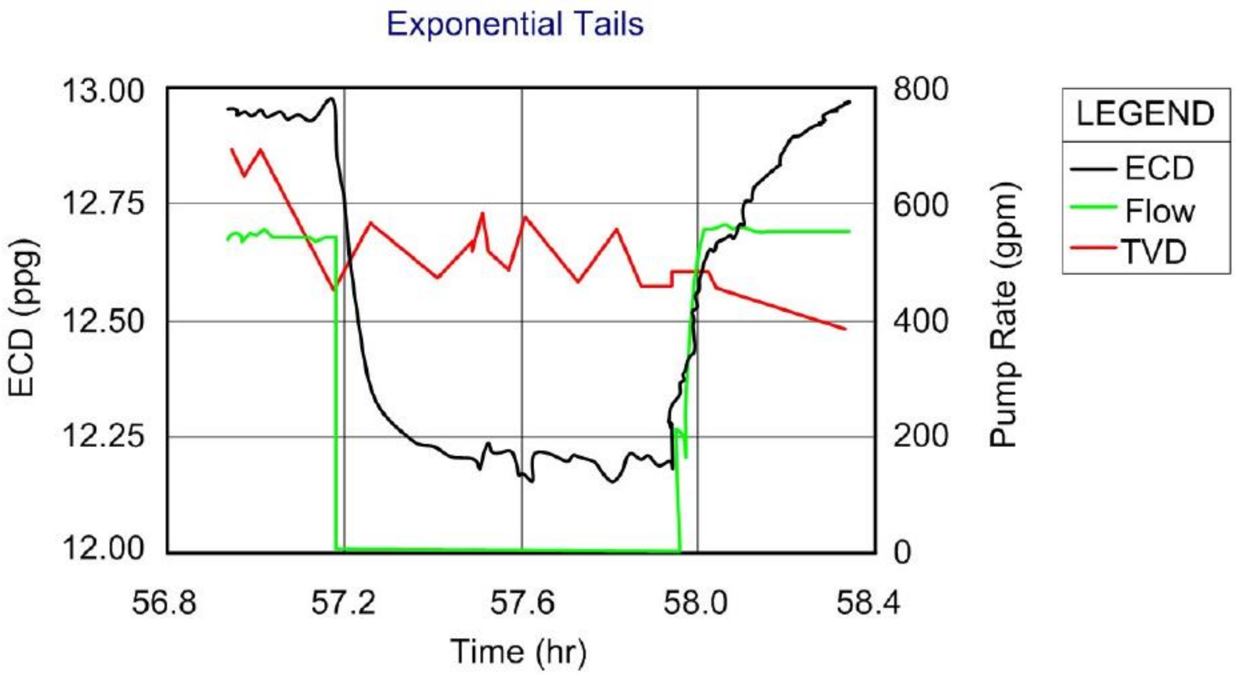
The measurement of downhole pressure while drilling (PWD), or annular pressure while drilling (APWD), is a useful tool in monitoring and managing wellbore instability while the well is being drilled. While pumping, the annular pressure will increase when there is some kind of annular restriction. Such annular restrictions can be due to either poor hole cleaning or wellbore instability.

Typically, once the wellbore becomes unstable, hole instability and poor hole cleaning go hand in hand and it is difficult to separate the effects.

Time-based PWD data during connections (either transmitted real-time or downloaded from memory upon retrieval of the PWD sub) can be used to diagnose wellbore breathing, a loss-and-gain phenomenon whereby near-wellbore fractures open, causing a small fluid loss while drilling ahead with the higher ECD, but return these fluids as a small gain when making a connection when the wellbore pressure returns to the static density. An example of this is shown in the following time-based PWD data plots:



A square response of ECD is observed during a connection in a non-fractured formation (from SPE 67742 by Bratton et al). The ECD immediately drops when the mud pumps are shut off and immediately increases when the mud pumps are turned back on.

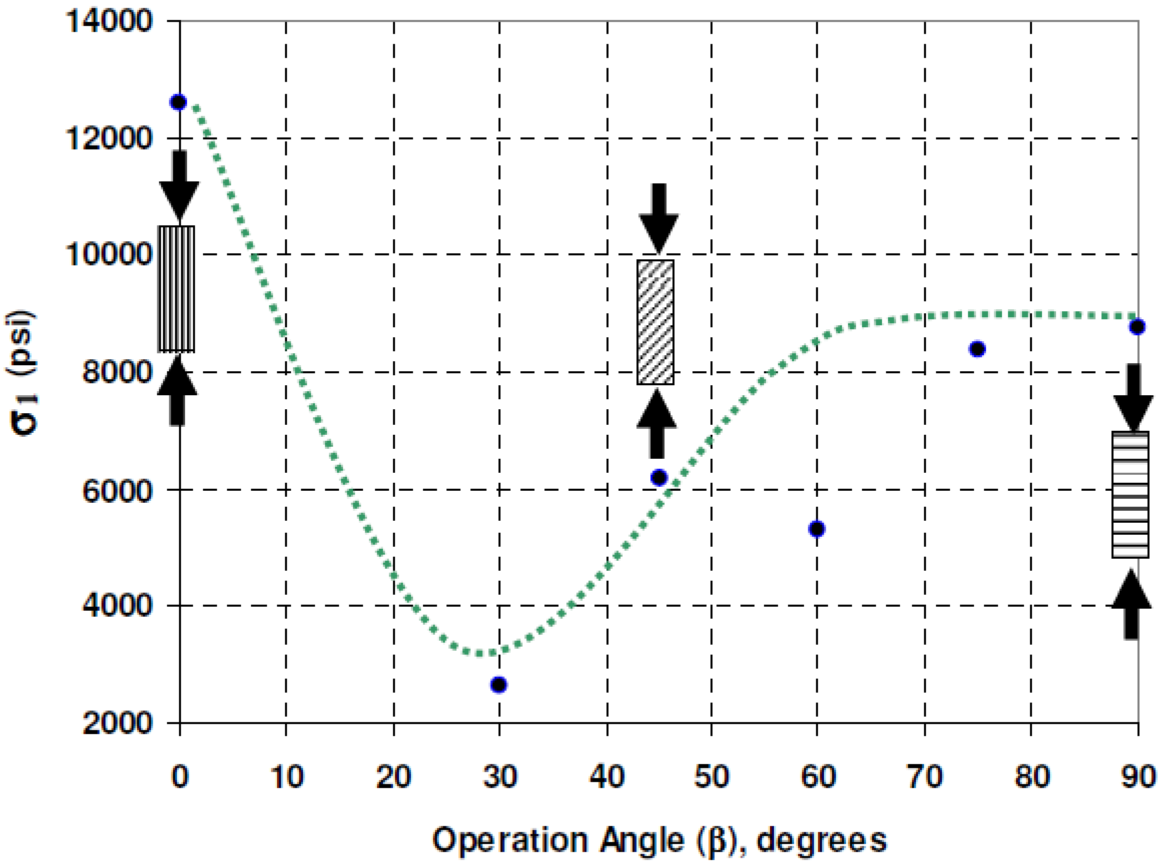


A softer ECD profile is observed in a fractured formation (from SPE 67742 by Bratton et al.). The back-flow of drilling fluid from the fracture delays the drop in ECD when the pumps are turned off. A more gradual increase in bottom-hole pressure is also seen when the mud pumps are turned back on as the fractures reopen and take some of the fluid.

Rock mechanical testing

Knowledge of the mechanical properties of the formation (particularly its strength) is critical when predicting the required mud weight for stability. It also helps understand the wellbore instability mechanisms that might occur should the well be drilled with an inappropriate mud weight. The direct laboratory measurement of rock properties also enables location-specific correlations to be established in order to predict rock properties from indirect well log data.

Numerous wellbore instability problems have been reported when drilling through laminated (or fissile) shale formations. This is because the bedding provides planes of weakness that are not present in more massive, uniform shale formations. The degree of strength anisotropy can be tested by measuring the unconfined compressive strength of the shale at different orientations to the bedding planes. An example is shown in the following graph below:



Strength anisotropy for laminated shales.

In the particular shale shown, the compressive strength was reduced from about 9,000 psi to 3,000 psi when the test specimen was oriented at 30° to the bedding plane. This strength anisotropy can be used to explain why more wellbore instability occurs in laminated shales.

Tectonic regime

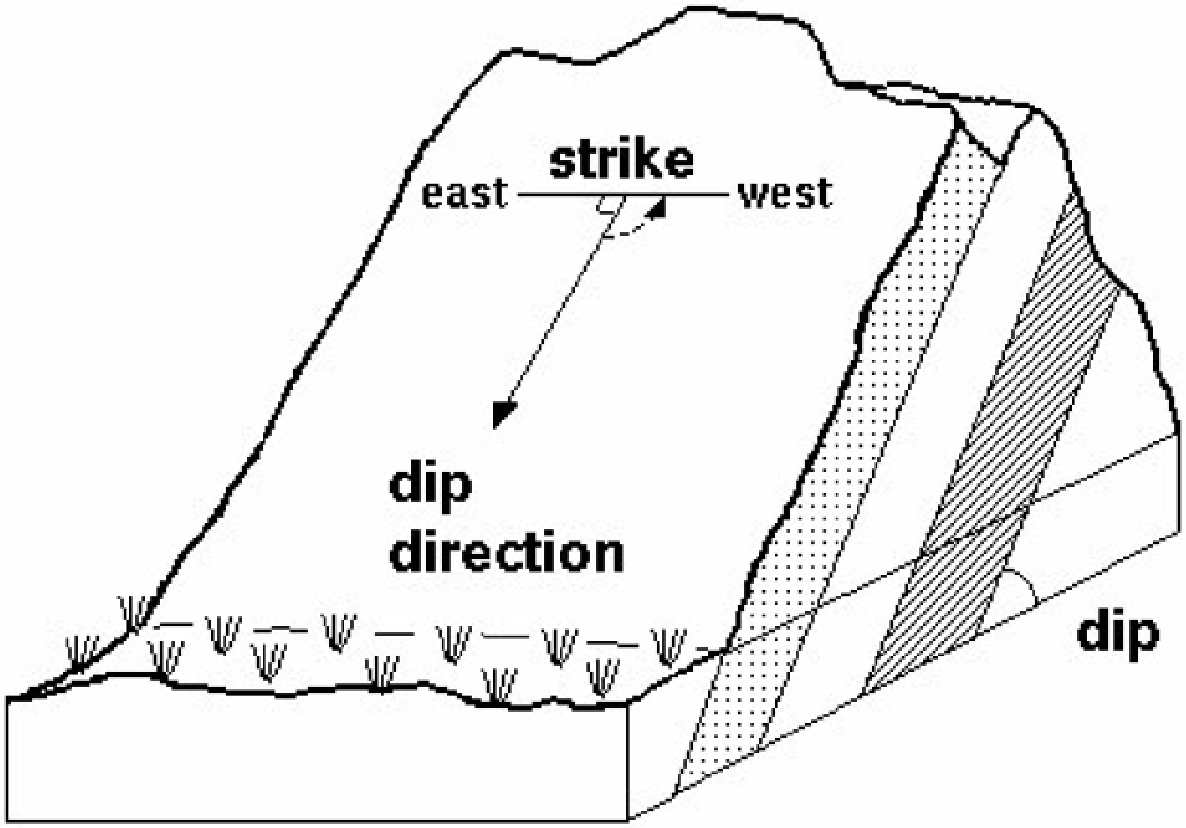
Formations are typically subjected to three total stresses; the overburden stress and two horizontal stresses. Based on relative magnitudes of these stresses, three regimes of stress can exist in the subsurface: normal, strike-slip, or thrust (or reverse) stress regimes.

Information on the ordering and relative magnitudes of the in-situ stresses is important in wellbore stability analysis, well trajectory optimization, and lost circulation identification. For example, a vertical well is more stable than a directional or a horizontal well in normal stress regime. However, under a strikeslip stress regime, such as is found in tectonically active and mountainous areas, directional and horizontal wells are more stable than vertical wells.

Bedding dip and azimuth

If shale is laminated, the bedding layers can serve as weak planes that result in strength anisotropy which needs to be taken into account in wellbore stability predictions. In the subsurface, formations may not be flat-lying and so the tilt and tilt direction of the formation needs to be defined. Bedding planes can be defined in space by their inclination (dip) and their strike, which is the bearing of the line of intersection of the plane and a horizontal surface, as shown below. Note that the bearing of the projection of the dip on a horizontal surface is in a direction at right angles to the strike. This is called dip direction or bedding azimuth. Bedding dip and azimuth can be interpreted from information obtained from image logs.

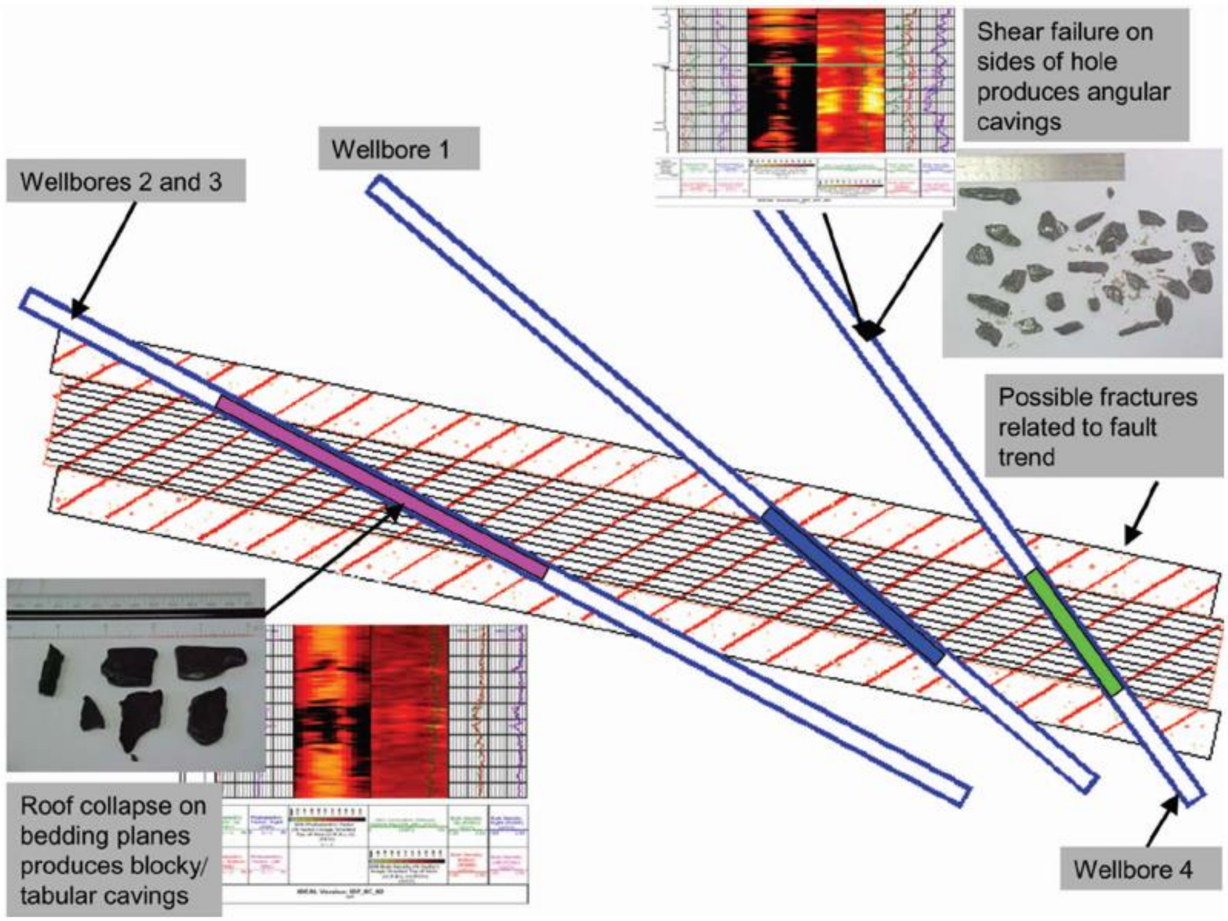
In fissile shale, when the wellbore trajectory is close to parallel with the bedding planes, wellbore instability is often dominated by failure along the weak bedding planes.



Definition of bed dip and strike.

Well trajectory

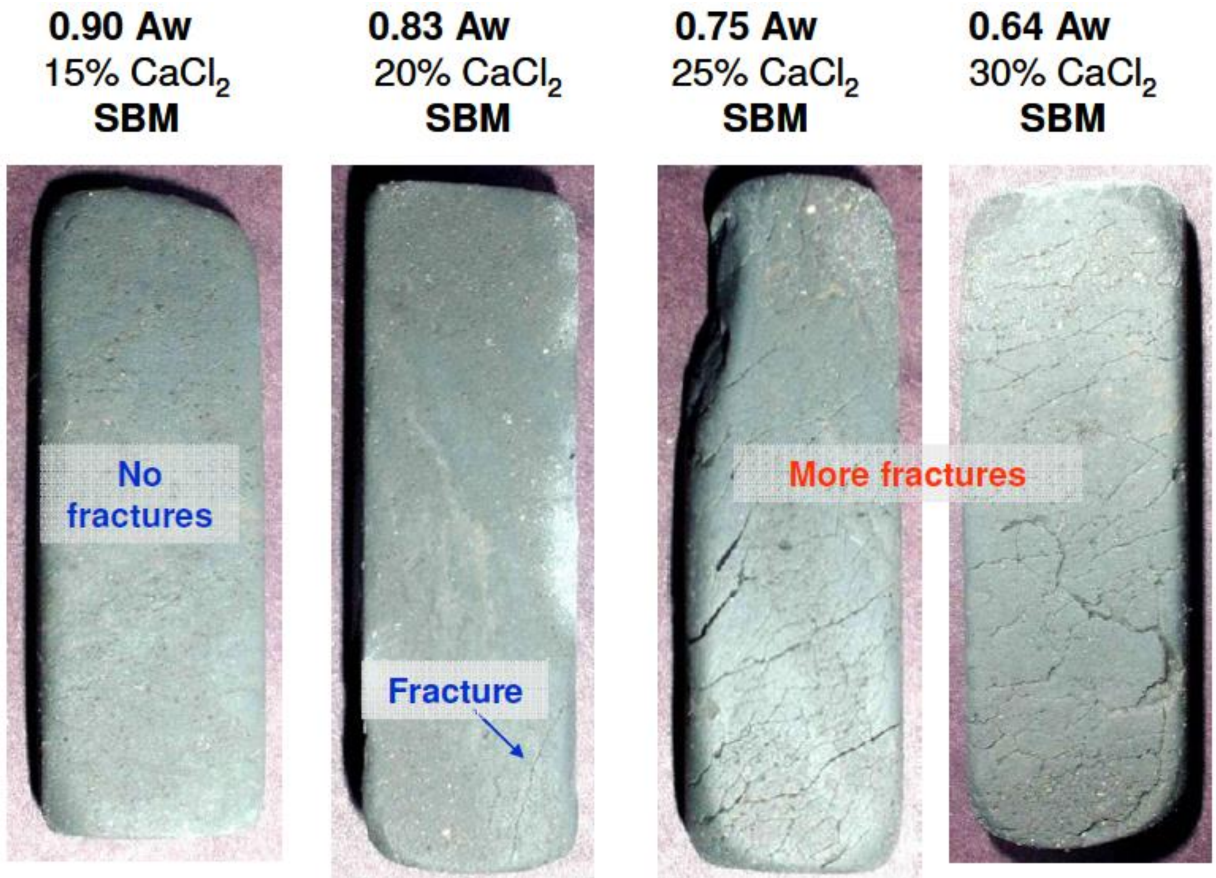
Well trajectory plays an important role in wellbore instability due to anisotropy in both in-situ stress and strength. More wellbore instability occurs when the well trajectory is in an adverse orientation with in-situ stresses and formation bedding planes.



A schematic of how well trajectory can impact borehole stability is shown in the figure above. In this example the bedding dip angle is 12°. Very different wellbore stability conditions were experienced in several near-by wells drilled through this formation. No wellbore instability was evident in Wellbore 1, which was drilled at an inclination of 50°. Wellbore 2 was sidetracked from Wellbore 1 at an inclination angle of 60° and oriented in a down dip direction. Significant instability occurred in this well and it had to be abandoned due to instability related problems. Wellbore 3 was drilled at the exactly the same azimuth and deviation as Wellbore 2, but with 1 ppg higher mud weight. However, worse wellbore instability was experienced, and no improvements were seen with further increases in mud weight. Wellbore 4 was drilled at an inclination of 36° and with a lower mud weight compared to the other wells, but with no severe wellbore instability problems (from SPE 78205 by Edwards). This is a clear example of where increasing mud weight was not the solution to wellbore instability; rather the well trajectory needed to be changed to achieve a more benign intersection with the fissile shale being penetrated.

Salinity of the drilling fluid

It is believed that a balanced water activity (i.e., same salinity) between the shale and drilling fluid is helpful in improving wellbore stability in reactive shale formations. The water activity of drilling fluids can be adjusted by changing the salinity of the internal phase of oil-based or synthetic-based drilling fluids. It is important to recognize that even in these emulsion systems, where the water is not the continuous phase, the salinity of the water still has an important effect on shale stability.



Effects of salinity on dehydration fracture

The effect of water-phase salinity on fracture generation has been studied by exposing shale samples to synthetic-based solutions with different salinity. In each case the proportion of water in the drilling fluid was kept constant, only the salinity of the water was changed. The results are shown in the pictures above.

The fractures began to occur when the shale was exposed to fluids with internal phase salinity above 15 wt%. Numerous cracks were generated after the salinity was increased to 25 wt% $CaCl_2$. Similar effects occur to the borehole wall when the formation is exposed to a very saline drilling fluid. These dehydration fractures can lead to instability of the wellbore over time.

Temperature information

Temperature information is important for both wellbore stability management and wellbore instability identification. Changes in temperature in the near-wellbore region occur at all times in the open hole. Formations near the bit may be cooled by the passage of cooler mud from the drill pipe. Further up on the open hole section, formations may become warmed by the passage for hotter mud from below. When circulation stops for a period of time – e.g., for a bit trip - nearwellbore temperatures will revert back to their in-situ values over time. All these time-varying changes in temperature cause an alteration in local stresses which can affects wellbore stability.

Critically-stressed faults and the potential for losses

All rocks are faulted or fractured to some extent and these can have a profound affect on wellbore stability and lost circulation. Stresses may be altered in the vicinity of faults and zones of mechanical damage to the formation may extend for several hundred feet away from the fault zone in some rock types. The orientation of the fault with respect to the regional stress state will influence the likelihood of incurring losses into the fault when it is intersected by the wellbore.

Additional wellbore stability analyses can be conducted to assess the mud weights that would cause additional losses into a fault.

Preventative drilling practices may be necessary when drilling through a fault zone. These include the recommended drilling fluid additives to suppress the leakage of drilling fluid into the fault plane.

Loss behavior analysis

Lost circulation is extremely costly to many drilling and workover operations in terms of unit mud costs (especially whole synthetic or low toxicity mineral oil mud) and NPT. It can be better understood through loss behavior analysis. The rate of fluid loss from the borehole and the rate of change of this fluid loss vary depending upon whether the fluid loss is occurring into an induced fracture or into a natural fracture. Fluid loss information may be obtained from time-based mud logging data. Proprietary analysis techniques are available to interpret the losses data to identify the nature of the fracture into which the losses occurred and the appropriate lost circulation material (LCM) is necessary to plug the fracture. In the case of hydraulically conductive natural fractures, treatments combining particulate additives with cement- or polymer-based fluids may be necessary to stem the losses.

Torque and drag

Wellbore instability can cause excessive torque and drag when the BHA passes through the unstable zone. When numerous trips are made, monitoring torque and drag as a function of depth can be a useful tool to help distinguish between hole instability and hole cleaning and to identify the extent of the problem zone.

A hole cleaning problem will not necessarily be seen at the same depth each time as cutting beds tend to move up and down the hole. Conversely, a tight spot at a specific depth could be caused by a problematic localized hole geometry irregularity (dog-leg) or by a hole instability problem. Trip sheets can be used to track torque and drag. These typically consist of some graphical representation of bit depth versus time.

ANALYSIS OF WELLBORE INSTABIITY: SELECTING THE RIGHT TREATMENT

Introduction

The main mechanisms of wellbore instability can be fingerprinted using the **diagnostic tools**. It is expected that several possible **diagnostic tools** will be available or can be applied in any hole section. Thus, the methodology described in this handbook is generic and can be applied in many different drilling environments. This is because, in the majority of cases, the origins of wellbore stability problems have common causes.

It is important that the appropriate root cause is identified for a particular drilling problem occurrence as this then directs the appropriate preventative or remedial solution to the problem. Sometimes more than one root cause may be suggested as the source of the drilling problem. In this case, the range of possible preventative or remedial solutions has to be considered, and those which are common to the identified root causes should be applied.

Common Mechanisms of Wellbore Instability
Over-pressured shale formations

DIAGNOSTICS

OBSERVATIONS		TOOLS
Splintered cavings	< >	Cuttings and cavings report
Enlarged wellbore	< >	Caliper log
Circular failure	< >	Image
High pore pressure	< >	PP-FG prediction
Occurs in shale formation	< >	Lithology
MW < PP	< >	MW / PWD / ECD
Kick detected	< >	Loss / Gain behavior

ROOT CAUSES

Over-pressured shale formations

TREATMENT

(P = Prevention, R = Remediation)

- Drilling fluid design - increase mud weight (P&R)
- ECD management - swab reduction (P)
- Drilling operations - control ROP (P&R)

Wellbore breakouts

DIAGNOSTICS

OBSERVATIONS		TOOLS
Angular cavings	< >	Cuttings and cavings report
Oriented, enlarged hole geometry	< >	Caliper log
Diametrically-opposed borehole failure	< >	Image log
Mostly in shale	< >	Lithology
MW < Minimum MW for stability	< >	MW / PWD / ECD
Separation on shallow and deep resistivity logs	< >	Resistivity
Unfavorable borehole orientation	< >	Well trajectory
Torque and drag increase	< >	Torque and drag

ROOT CAUSES

Wellbore breakout in intact formation

TREATMENT

(P = Prevention, R = Remediation)

- Drilling fluid design - increase mud weight (P&R)
- Mud cooling (P&R)
- Balance activity by adjusting water-phase salinity (P)
- ECD management - minimize swab and surge (R)
- Well design - optimize well trajectory in future wells / sidetracks (P)

Reactive shale

DIAGNOSTICS

OBSERVATIONS		TOOLS
Sticky / soft cavings	< >	Cuttings and cavings report
Wellbore under-gauge	< >	Caliper log
Increase in torque and drag	< >	Torque and drag
In shale formation	< >	Lithology
High smectite content in shale formations	< >	XRD analysis
MW adequate for the formation being drilled	< >	MW / PWD / ECD
Low salinity water-phase drilling fluid	< >	Salinity in mud

ROOT CAUSES

Reactive shale

TREATMENT

(P = Prevention, R = Remediation)

- Drilling fluid design - increase the water-phase salinity in the existing drilling fluid (P&R)
- Add other mud chemicals designed to improve inhibition (P&R)
- Consider switching to SOBM in the current hole section or in future wells (P&R)

Borehole instability in laminated / fissile shale

DIAGNOSTICS

OBSERVATIONS		TOOLS
Tabular cavings	< >	Cuttings and cavings report
Enlarged borehole	< >	Caliper log
High / low side failure	< >	Image log
Occurs in a shale formation	< >	Lithology
MW as required for intact formation strengths	< >	MW / PWD / ECD
Strength anisotropy	< >	Well trajectory
Strength anisotropy	< >	Torque and drag

ROOT CAUSES

Borehole failure in laminated or fissile shale

TREATMENT

(P = Prevention, R = Remediation)

- Drilling fluid design - increase mud weight (P&R)
- Increase fine crack-blocking additives (P&R)
- Balance activity by adjusting water-phase salinity (P)
- ECD management - minimize swab and surge (R)
- Well design - optimize well trajectory in future wells / sidetracks (P)

Rubble zone

DIAGNOSTICS

OBSERVATIONS		TOOLS
Irregularly shaped cavings	< >	Cuttings and cavings report
Enlarged hole geometry	< >	Caliper log
Torque and drag increase	< >	Torque and drag
Mostly in shale	< >	Lithology
Irregular hole geometry	< >	Image log
MW as required for intact formation strengths	< >	MW / PWD / ECD
Separation on shallow & deep resistivity	< >	Resistivity logs

ROOT CAUSES

Formation instability in a rubble zone

TREATMENT

(P = Prevention, R = Remediation)

- Drilling fluid design - increase mud weight (P&R)
- Increase fine crack-blocking additives (P&R)
- Balance activity by adjusting water-phase salinity (P)
- ECD management - minimize swab and surge (R)
- Well design - optimize well trajectory in future wells / sidetracks (P)

Formation breakdown due to excessive borehole pressure

DIAGNOSTICS

OBSERVATIONS		TOOLS
Significant loss of mud returns	< >	Mud logging
Rate of mud losses	< >	Mud losses analysis
Symmetric fracture axial to the wellbore	< >	Images
Often in sand	< >	Lithology
Temperature anomaly at loss location	< >	Temperature survey (wireline)
High deep resistivity	< >	Resistivity
Erratic borehole pressure	< >	PWD
Mud temperature significantly cooler than the formation	< >	Temperature measurements from LWD
ECD > fracture gradient	< >	PWD / ECD
Low fracture gradient	< >	PP-FG prediction

ROOT CAUSES

Formation breakout due to excessive borehole pressure

TREATMENT

(P = Prevention, R = Remediation)

- ECD management
- Reduce mud weight (P&R)
- Reduce ROP (P)
- Reduce flow rate (P)
- Drilling fluid design - add $CaCO_3$ sealing material (P&R)
- $CaCO_3$ and cement for sand and shale (P&R)
- High fluid loss cement (with LCM materials) that gains compressive strength in sands
- Balanced activity (P&R)
- Heating, or less cooling (if using mud chillers on location)

Losses into a pre-existing fault or fracture

DIAGNOSTICS

OBSERVATIONS		TOOLS
Significant loss of mud returns	< >	Mud logging
Rate of mud losses	< >	Mud losses analysis
Sinusoidal cross cutting fracture	< >	Images
Fault seen on seismic	< >	Seismic images
Can be sand or shale	< >	Lithology
Temperature anomaly at loss location	< >	Temperature survey
High deep resistivity	< >	Resistivity
ECD < expected fracture gradient in intact formation	< >	PWD / ECD
Anomalously low fracture gradient	< >	PP-FG prediction

ROOT CAUSES

Losses into a pre-existing fault or fracture

TREATMENT

(P = Prevention, R = Remediation)

- ECD management
- Reduce flow rate (P)
- Drilling fluid design
- $CaCO_3$ and cement for sand and shale (P & R)
- High fluid loss cement / LCM that gains compressive strength in sands
- X-link polymer / resin with bridging solids (R)
- Well design - optimize well trajectory in future wells / sidetracks (P)

CLASSIFICATION OF FORMATION-RELATED NPT

Introduction

Non-Productive Time (NPT) is defined as the total time lost making no progress towards a well objective as the result of an unplanned event. NPT is calculated as the time taken to return to the position in a well's program at which an unplanned event occurred. This includes the time involved in drilling a sidetrack or a new well as a result of the event.

NPT is tracked by many companies as a metric to assess drilling performance against set targets. The data historically has been recorded in the Management System of Drilling Information (MSDI). Not only is the total amount of NPT important, but the category, or categories, into which it falls are important as well. There are eleven general categories of NPT:

1. CEMT (Cementing) – The failure of any and all aspects of a cementing job including, inappropriate setting times, channeling, and equipment failures.
2. DFAL (Downhole Failures) – The failure of any downhole equipment (except cementing equipment), including BHA, tool strings, drill or running string, tubing, casing, etc.
3. DPRB (Downhole Problems) – The failure of the wellbore (excluding stuck pipe) including influx control problems.
4. FLUD (Fluids) – Problems relating to wellbore fluids (drilling muds, completions fluids, etc) and their properties and constituents.
5. HMAN (Human Error) – Problems caused by the way people work (lack of training, communication, etc).
6. RREP (Rig Repairs) – Time lost due to necessary work to the rig / primary unit working on the well.
7. SFAL (Surface Equipment Failure) – Problems relating to surface equipment (other than time lost repairing rig / primary), such as service company equipment (other than cement company equipment) and operator equipment.
8. STUC (Stuck Pipe) – All stuck pipe related problems (including stuck tool strings).
9. UFAL (Subsea Equipment Failure) – All failures of subsea equipment including ROV and Diver equipment problems and seabed wellhead equipment.
10. WAIT (All unplanned waiting) – Excludes waiting which was part of the well plan, such as waiting for production to shut in a well prior to work commencing.
11. MISC – Only to be used if no other category can be found to fit the situation.

Numerous subcategories are defined within each of the general overall categories listed above. Several of these are relevant to wellbore stability and the root cause analyses described before.

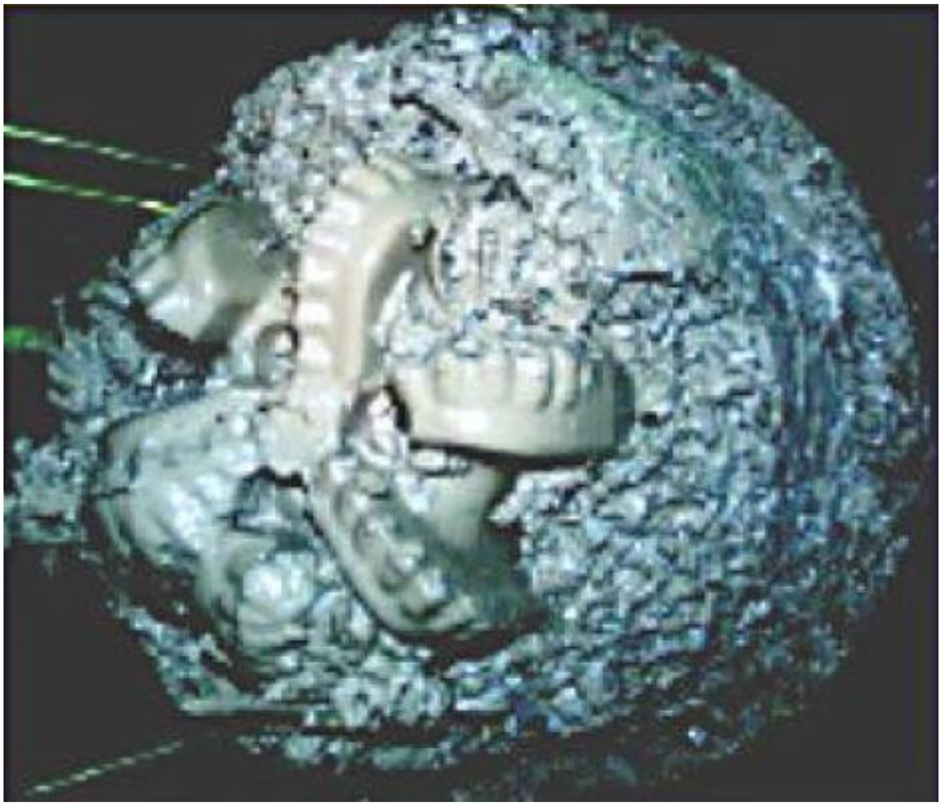
Downhole Problems

BALL- Bit balling

Bit balling is characterized in two ways – primary and secondary bit balling. Primary bit balling is defined as the adherence of water-wet clays to the cutters and face of the bit, while secondary bit balling occurs in the junk slots and areas above the cutting surface. The most noticeable effect of bit balling is the significant reduction in rates-of-penetration, particularly when using water-based drilling fluids with PDC bits.

Bit balling often occurs when using a hard-formation bit with short teeth on a reactive soft shale formation. It can also occur when drilling through soft formations without adequate drilling fluid circulation and / or using excessive bit weight.

Remediation of bit balling is by adding inhibitive material to the drilling fluid; changing from water-based to oil-based or synthetic-based drilling fluids; and optimizing bit design such as using lager cutters, extended nozzles, etc.



Bit balling

CIRC – Lost circulation

Lost circulation, or lost returns, is the partial or total loss of drilling fluid from the wellbore to the formation. It is extremely costly to many drilling and work-over operations in terms of unit mud costs (especially whole synthetic or low toxicity mineral oil mud) and NPT.

Losses can result from either natural or induced causes which range from a couple of barrels per hour to hundreds of barrels in minutes. Natural losses occur in formations with natural permeability, usually voids or fractures. Induced losses occur in an induced fracture, caused when hydraulic forces in the wellbore exceed the formation strength.

Lost circulation can be prevented through ECD management, proper formulation of the drilling fluid; and by suitable drilling operational practices.

FILL – Fill / debris (undefined)

Fill is a situation when the drill string cannot be tripped back to the bottomhole without encountering spalled or failed material from the borehole walls somewhere in the open hole. Fill on bottom can often be encountered when tripping back to bottom after a bit trip. This is a problem often related to hole cleaning (CLN - Hole cleaning) or wellbore instability (STAB – Wellbore instability).

STAB – Wellbore instability
For the purposes of NPT classification wellbore instability is defined as the failure of the rock around the wellbore. As described elsewhere in this handbook, wellbore instability can itself take many forms, including:

- ✓ Mechanical stress imbalance in brittle rock can result in the creation of breakouts. This is characterized by the production of angular cavings.
- ✓ Pore pressure imbalance due to a mud weight that is lower than the formation pore pressure (most commonly in shales). This is characterized by the production of splintery cavings.
- ✓ Formation lithology weaknesses in the form of rubble zones or laminated shales can result in wellbore instability even when the mud weight is otherwise adequate for intact rock. This is characterized by the production of erratic or chaotically cavings, or cavings that are characteristically tabular in shape.
- ✓ Chemical compatibility effects, caused by unsuitable drilling fluid waterphase salinity or additives which react with the exposed formation can compound the mechanical and pore pressure effects described above.

TGHT – Tight hole
A section of a wellbore, usually open hole, where larger diameter components of the drill string, such as drill pipe tool joints, drill collars, stabilizers, downhole motors, and the bit, may experience resistance when they are pulled through the section. Tight hole mainly results from swelling of reactive shale formations or when drilling through mobile formations such as salt.

Fluid – Related Problems
CLN – Hole cleaning
Cuttings or cavings not carried to surface in a timely manner result in circulating times off-bottom taking longer than planned. Precautionary hole cleaning – particularly in extended reach or high-angle wells – is typically built into the drilling plan. Hole cleaning NPT relates to extended periods of circulating that lie outside the plan. Hole cleaning is affected by the pump capacity, drilling parameters, fluid properties, and the wellbore condition. There may be circumstances where the original problem was one of wellbore instability (STAB) but which is now managed, the region of enlarged borehole then causes a hole cleaning problem later in the section.

Cementing Problems
LSTR – Lost returns
Lost circulation may occur during cementing because of the higher density and viscosity of the cement slurry, together with the smaller annular clearances between the casing and the borehole. Lost cement returns can produce poor cement jobs, poor zonal isolation and increased casing corrosion. Incomplete cement coverage (which can be caused by reasons other than lost returns) can also give rise to an annular pressure build-up problem when the well is placed into production. Remedial cementing operations are often time consuming and expensive.

STUC – Stuck pipe problems
Stuck pipe is a condition where the drill string cannot be moved (rotated or reciprocated) along the axis of the wellbore. The pipe can become stuck as a result of mechanical problems during

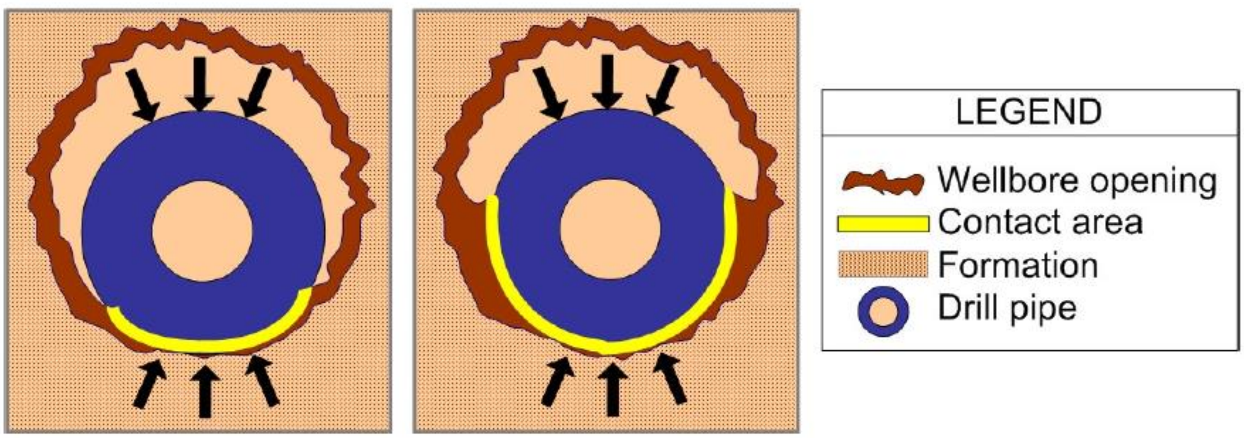
the drilling process itself or due to the physical and / or chemical properties of the formation being drilled. Each is classified differently, as discussed below:

DS – Differential sticking

Differential sticking typically occurs when high contact forces are exerted over a sufficiently large area of the drill string which results in the drill string being forced against the borehole well. It normally occurs in high permeable sand formations, particularly where a thick filter cake is built up. This may be a particular problem when using water-based drilling fluids. Particular scenarios that exacerbate the situation include low reservoir pressures and high mud overbalances, such as might occur when drilling depleted sands.

Differential sticking is, for some drilling organizations, the greatest drilling problem worldwide in terms of time and financial cost.

Preventions of differential sticking include: limiting the mud overbalance to prescribed (formation-dependent) limits; adding lubricants and sealing material to the mud system; continuous rotation and movement of the drillstring; and using centralizers or spiral drill collars to minimize contact area between string and formation.



Differential sticking

FORM – Formation / differential sticking

Some clay minerals may absorb water from drilling fluid. This causes the clays to swell and eventually reduce the wellbore size to the point where either the BHA or drill pipe becomes stuck. Prevention of formation sticking is by adding inhibitive material into the drilling fluid in order to prevent clay swelling.

GEOM - Wellbore geometry

When drilling with a well trajectory deviated at more than 35° from vertical, or where harder rock layers are interbedded with weaker rock, wellbore geometry can result in stuck pipe problems. This may be a particular problem when using bent-housing motors. An additional cause of drilling problems related to hole geometry can occur when small amounts of slip occurs on critically-stressed faults. This is usually associated with small volumes of losses into the fault. The abrupt offset in the hole profile – even if relatively small in absolute movement – can cause a ledging hold-up of larger BHA components as shown in the schematic below.

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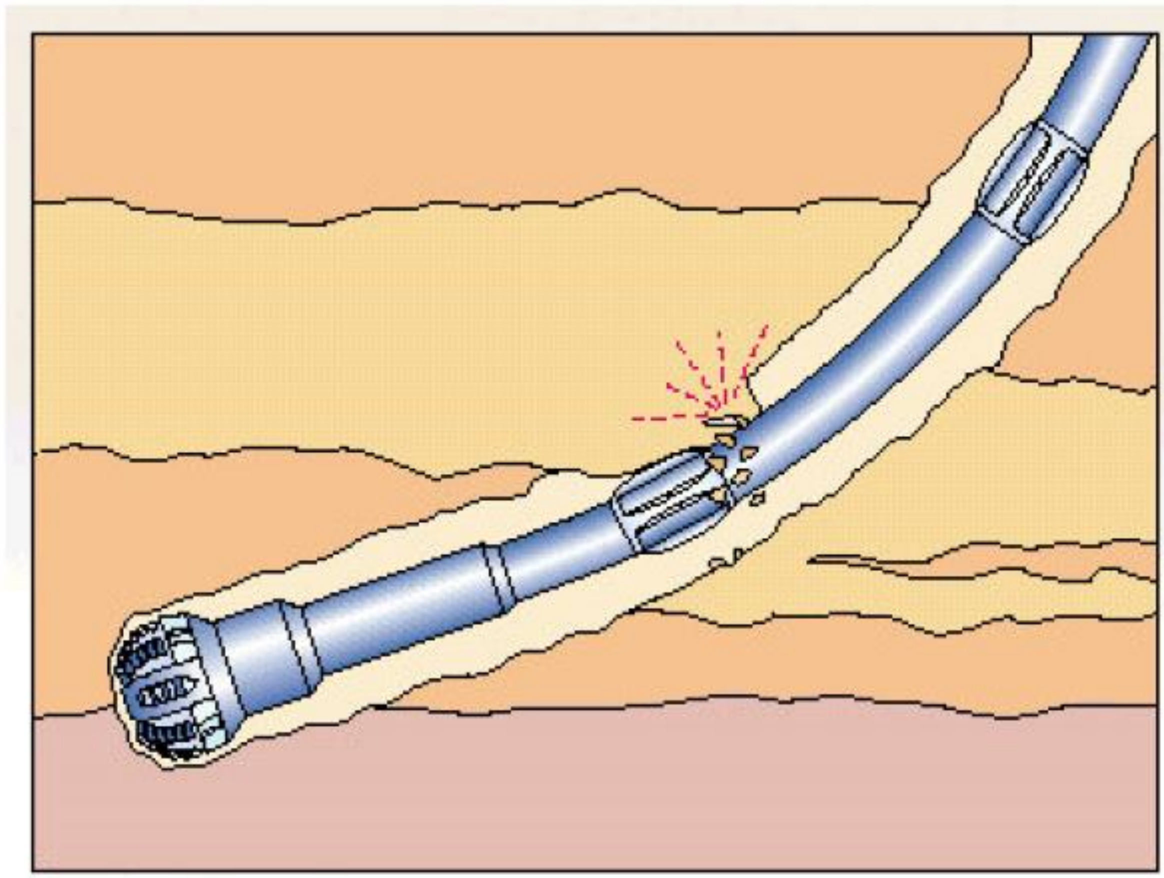
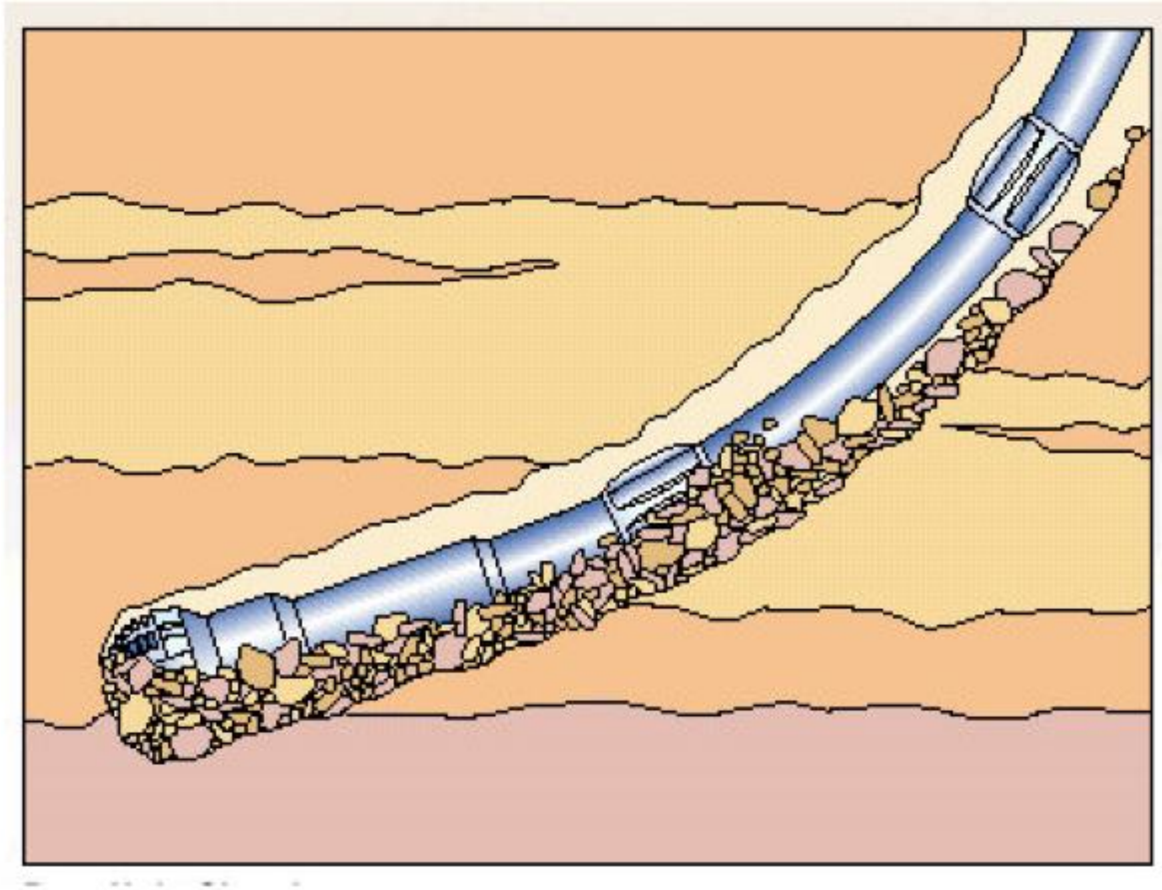


Wellbore geometry

HC – Poor hole cleaning

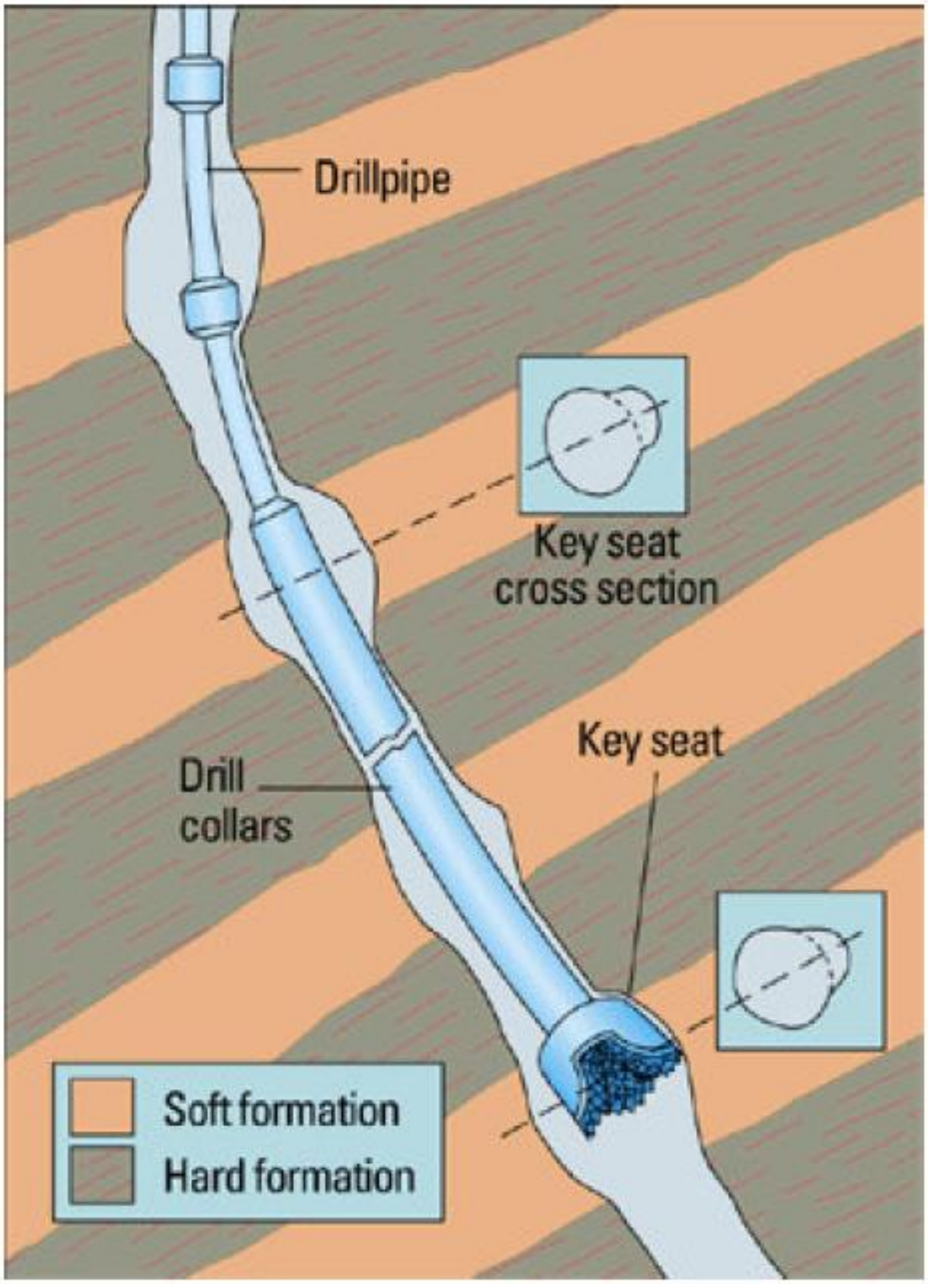
Cuttings, and especially cavings, that are not carried to surface can result in the build-up of cuttings beds on the bottom of the hole. This can lead to a stuck pipe problem – particularly when tripping the drill pipe – as the cuttings bed gets dragged back up the hole by the BHA and larger diameter components. In highangle wells pack-offs and stuck pipe can occur within the cased-hole section as the annular clearance between the casing and BHA / drill-pipe is smaller than in the open hole.



Poor hole cleaning

KEYS – Keyseating

A keyseat is a smaller-diameter channel that is worn into the high-side or lowside of a larger diameter wellbore by the action of the drill string. This high-side / low-side orientation of the enlargement, clearly seen in caliper logs, is diagnostic of a key seating problem. The diameter of the channel is typically similar to the diameter of the drill pipe. When larger diameter drilling tools such as tool joints, drill collars, stabilizers, BHA, and bits are pulled into the channel, these may become stuck. Preventive measures include keeping the wellbore rugosity to acceptable levels. Stabilizers with hard-banding on their upper surface – capable of some hole opening capability while back-reaming – may also be considered. The remedy to key seating involves enlarging the worn channel so that the larger diameter tools will fit through it.

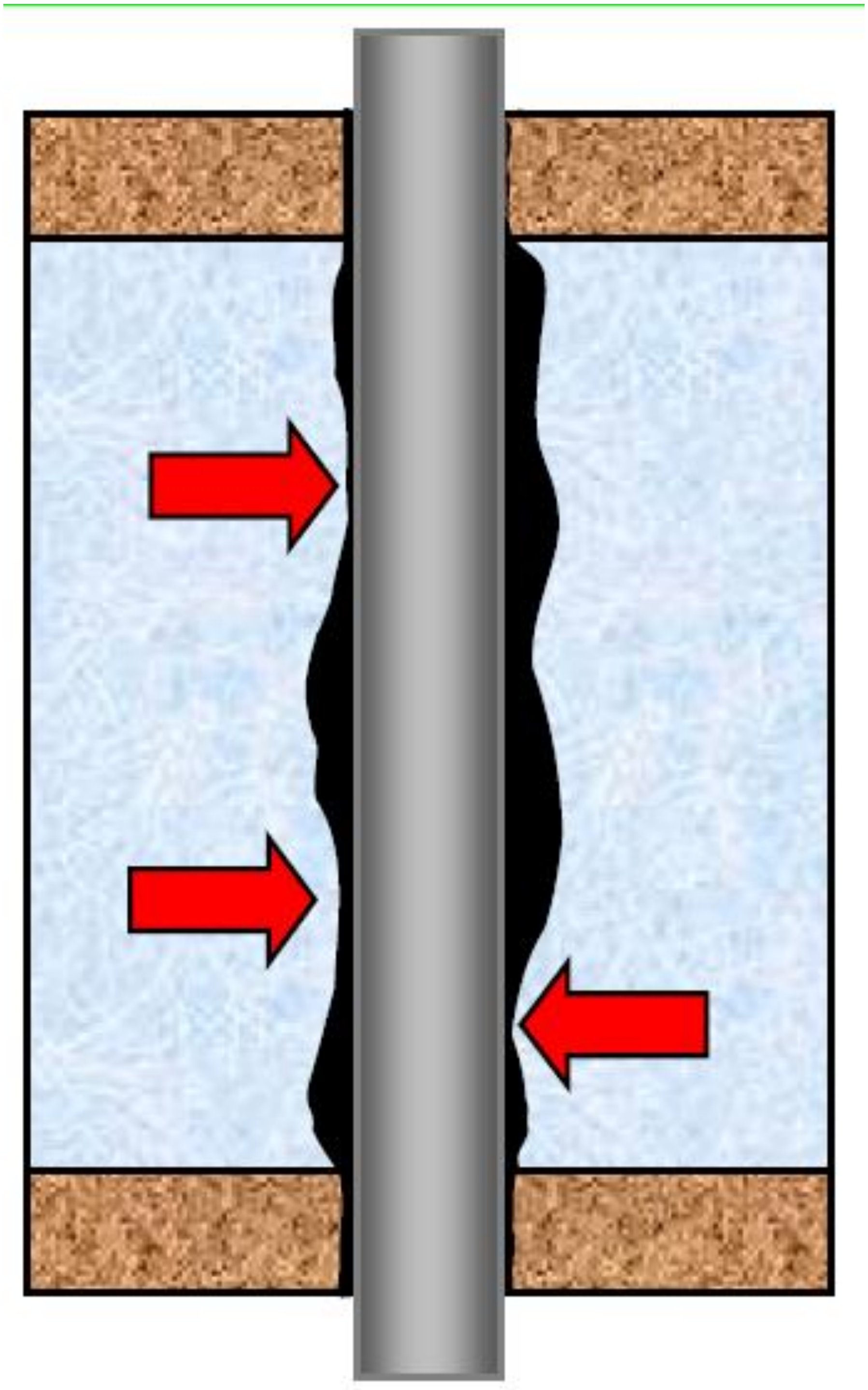


Keyseating

REAC – Reactive formations
Reactive shale often called gumbo shales. These smectite-rich rocks tend to swell when drilling with a fluid having inadequate inhibitive properties and results in stuck-pipe problem.

SALT – Mobile salts
Salt flows or deforms when subjected to a stress differential. The temperature of the formation also impacts the rate of salt movement – hotter salts move at a higher rate than cooler salts, when subjected to the same stress differential. While drilling, a stress differential is imposed equivalent to the difference in stress between the lithostatic (i.e., overburden) stress in the salt, and the mud hydrostatic pressure. Stuck pipe may result in under-gauge borehole conditions in mobile salt.

Prevention of stuck pipe in salt formations is achieved by using a mud weight through the salt section which is at least 90% of the overburden gradient at that depth – e.g., if the overburden is calculated to be 18 ppg, then a mud weight of at least 16.2 ppg is recommended. Specific mud weight requirements should be confirmed through wellbore stability analysis. Additional prevention and remediation measures include pumping, or spotting, of freshwater pills which dissolves the salt, and increases the hole diameter.

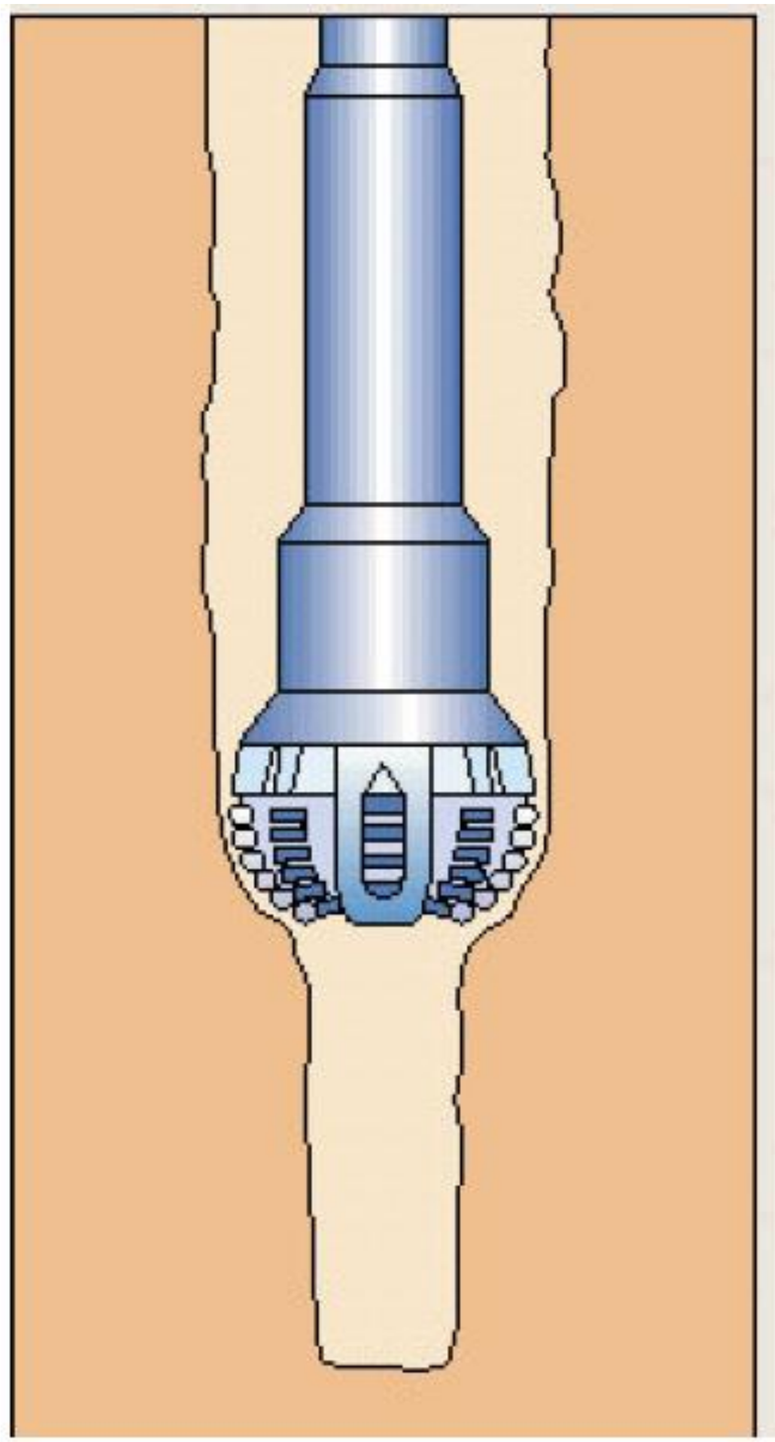


Mobile salt

UGAG – Under-gauge hole

Under-gauge hole is defined as the hole was not drilled as large as it should have been at the outset. This can occur when a bit has been worn down from its original size but might not be discovered until it is tripped out of the hole, resulting in an under-gauge hole.

Some plastic formations, such as reactive shale or salt, may slowly flow into the wellbore over time. This may also result in an under-gauge hole.



Under-gauge hole

In summary, we can say that reservoir geomechanics, geomechanical evaluation and wellbore stability is the science of evaluating the interplay between stress, pressure, mechanical properties and natural fractures in rocks (which plays a critical role in the reservoir characterization, description and development of oil and gas fields. In particular, geomechanics is becoming a critical design tool for the optimization of drilling, completion and stimulation programs. A fundamental knowledge of petroleum geomechanics is a key part of good field development planning, because geomechanics often underpins optimized engineering and has been proven to realize significant project cost savings.

This handbook/manual provides geomechanics insights for wellbore instability problems, subsidence and compaction, fault re-activation and etc (this handbook/manual can be pivotal for best field development success, which can reduce costs, risks and cycle times (efficiency), enhance well productivity and reservoir recovery (effectiveness) and ultimately maximize the assets' net present value).