TPJD Bülteni, Cilt 27, Sayı 1, Sayfa 7-30, 2015
TAPG Bulletin, Volume 27, No 1, Page 7-30, 2015

GEOMECHANICS APPLICATIONS IN RESERVOIR CHARACTERIZATION STUDIES

REZERVUAR KARAKTERİZASYON ÇALIŞMALARINDA JEOMEKANİK UYGULAMALAR

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ABSTRACT

In this study, a concise overview about the general aspects of geomechanics and recent developments in application of geomechanics in oil industry is compiled, in cases like wellbore stability, hydraulic fracturing, early water-breakthrough, surface subsidence, reservoir compaction, fault-reactivation or water-gas flooding. Finally, in light of recent studies, we conclude the study with future perspectives and foreseen applications of geomechanics in reservoir characterization.

Keywords: Geomechanical Modeling, Reservoir Characterization

ÖZ

Bu çalışmada, jeomekaniğin genel kavramlarının kısa bir özeti ile petrol endüstrisindeki uygulama alanları derlenmiştir. Bu uygulama alanlarının başlıcaları; kuyu stabilitesi, hidrolik çatlatma, kuyuya erken su gelişi, yüzey oturması, rezervuar kompaksiyonu, fay yeniden hareketlenmesi veya su-gaz ötelemesi uygulamalarıdır. Son olarak çalışma, güncel çalışmaların ışığında, jeomekanik alanında rezervuar karakterizasyonu amaçlı olarak geliştirilen geleceğe dönük perspektifler ve öngörülen uygulamalar ile sonuçlandırılmıştır.

Anahtar Kelimeler: *Jeomekanik Modelleme, Rezervuar Karakterizasyonu*

INTRODUCTION

Despite the fact that it is typically ignored, geomechanics has a considerable impact on both well and overall field performance during the life-cycle of a hydrocarbon reservoir. As our understanding of the subsurface system becomes increasingly more sophisticated at the level of the behavior of its components (solid, liquid and gas); implementation of coupled models (e.g. mechanical-hydraulic, mechanical-thermal and hydraulic-thermal) gets essential for the understanding of an increasing number of phenomena and in predicting human impact on these, such as depletion/injection activities (Zhang and Sanderson, 2002). Over the last years, there is an increasing interest in geomechanics in most of the areas of petroleum industry beginning with unconventional reservoirs (Dusseault et al. 1998; Gutierrez and Lewis, 1998; Pattillo et al. 1998; Bruno 2002; Barkved et al. 2003).

In geomechanical studies, information about rock strength, pore pressure, in situ stress and elastic properties are generated. Also mechanical stratigraphy has to be involved. Mechanical stratigraphy is among the most important controls on timing, style, and extent of rock deformation, including fracturing (Weinberg 1979; Teufel and Clark 1984; Corbett et al.1987; Erickson 1996; Gross et al. 1997; Laubach et al. 2009; Couples and Lewis, 2000; Ferrill et al., 2004; Ferrill et al. 2011; Ferrill et al. 2012; Ferrill et al. 2014; Cooke et al. 2006; Smart et al. 2010; Smart et al. 2012; Gale et al. 2014). Finally, the potential effects of pre-existing geologic structures (i.e., sub-seismic faults, folded or tilting bedding) are considered because of the fact that most of the formations include sub-seismic and seismic-scale jointing, faulting, and/or folding (Smart et al. 2014).

Accurate estimation of all of the dynamic changes in stresses and rock properties requires coupled numerical modeling between reservoir simulation (thermal fluid flow) and geomechanical model (changes in stress, strain and dilation). Development of a comprehensive geomechanical model of a reservoir (and overlaying formations) provides a basis for addressing a wide range of problems that are encountered during the production of a hydrocarbon reservoir (Zoback 2007).

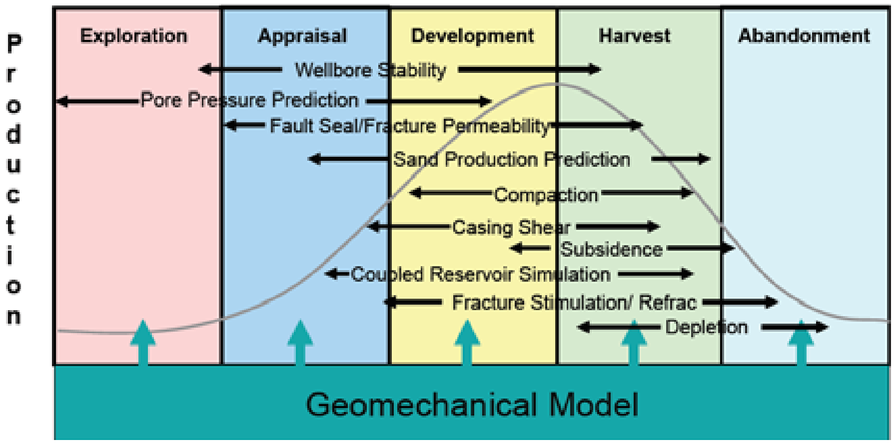


Figure 1. Use of geomechanical models during the life of a field (Zoback 2007).

GENERAL DEFINITIONS

Geomechanics is the theoretical and applied science of the mechanical behavior of geomaterials like rocks and soils in the stress fields of their physical environment. Geomechanical study or modeling of a field starts from the exploration stage with wellbore stability and pore pressure predictions (Figure 1). In appraisal and development stages plenty of problems could arise related to geomechanics like sealing capacity or transmissibility of faults/fractures, sand production, compaction, subsidence. This is the time that coupled reservoir simulations should be conducted as will be explained in the next chapters. As we come to the mature and abandonment stages, depletion and secondary recovery related problems will be probably more critical. So it is crucial to understand our field in geomechanical aspects in any period of production as well as other reservoir characteristics.

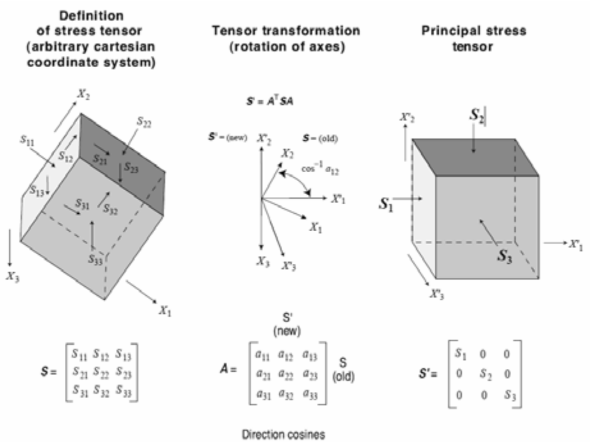


Figure 2. Stress Coordinate Transformation (Zoback 2007).

Stress

Stress is a tensor which describes the density of forces acting on all surfaces passing through a given point. Any given stress component represents a force acting in a specific direction on a unit area of given orientation. It is possible to evaluate stresses in any other coordinate system via tensor transformation. To accomplish this transformation, we need to specify the direction cosines a_{ij}, as illustrated in Figure 2 that describe the rotation of the coordinate axes between the old and new coordinate systems. By this transformation we can describe the state of stress at depth in terms of the principal stresses making the issue of describing the stress state *in situ* appreciably easier.

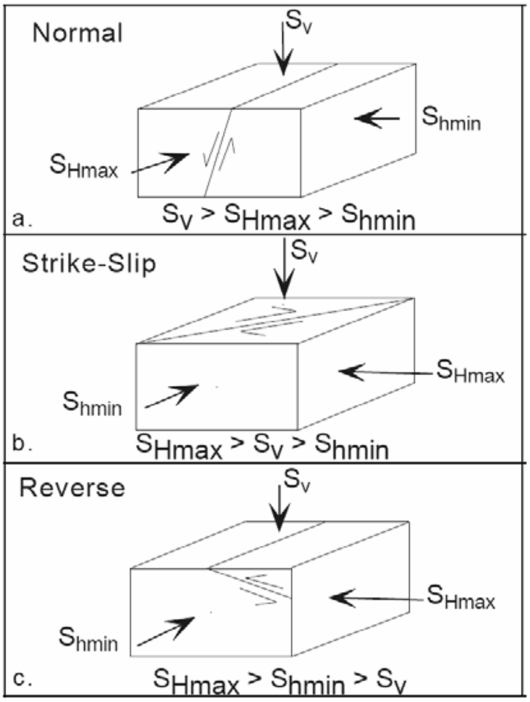
Assuming this is the case, we must define only four parameters to fully describe the state of stress at depth: three principal stress magnitudes, S_v, the vertical stress, corresponding to the weight of the overburden; SH_{max}, the maximum principal horizontal stress; and Sh_{min}.

Anderson Classification of Tectonic Regimes

By using the principal coordinates, (Anderson 1951) has proposed in 1951 that the tectonic regimes could be defined in terms of the relationship between the vertical stress (Sv) and two mutually perpendicular horizontal stresses; SH_{max} and Sh_{min} (Figure 3).

Constitutive Laws of Deformation

Fundamentally, a constitutive law describes the deformation of a rock in response to an applied stress or vice versa (Figure 4). Best known mechanical behavior is elasticity. If the material is elastic, the object will return to its initial shape and size



Regime/Stress	S_1	S_2	S_3
Normal	S_v	S_{Hmax}	S_{hmin}
Strike-Slip	S_{Hmax}	S_v	S_{hmin}
Reverse	S_{Hmax}	S_{hmin}	S_v

Figure 3. Anderson's tectonic regime classification

when the acting forces are removed like a spring. In poroelastic behavior the elastic modulus, the stiffness, depends on the rate at which it is being loaded. If you load a sample fast, it appears very stiff and strong. If you load it slowly, it appears very compliant. Or, if you are passing seismic waves through the rock, high frequency waves would see a very stiff rock, and very low frequency waves would see a very soft rock.

In an elastic plastic rock which can be conceptualized by a spring pulling a block, the relationship between displacement and force will go up linearly. The slope will be the spring constant. But at some point, that block will start to slide but when the force is taken back, the block does not slide backwards. So, big irreversible displacements at a constant force will be seen in the material. This behavior is commonly seen in softer rocks.

Viscoelastic rock is one in which the deformation in response to an applied stress or strain is rate dependent. The stress required to cause a certain amount of deformation in the rock depends on the apparent viscosity, η, of the rock. One can also consider the stress resulting from an instantaneously applied deformation which will decay at a rate depending on the rock's viscosity. The conceptual model shown in the Figure 4 corresponds to a specific type of viscoelastic material known as a *standard linear solid*. A viscous material that exhibits permanent deformation after application of a load is described as *viscoplastic*. Many oil and gas reservoirs in the world occur in such formations.

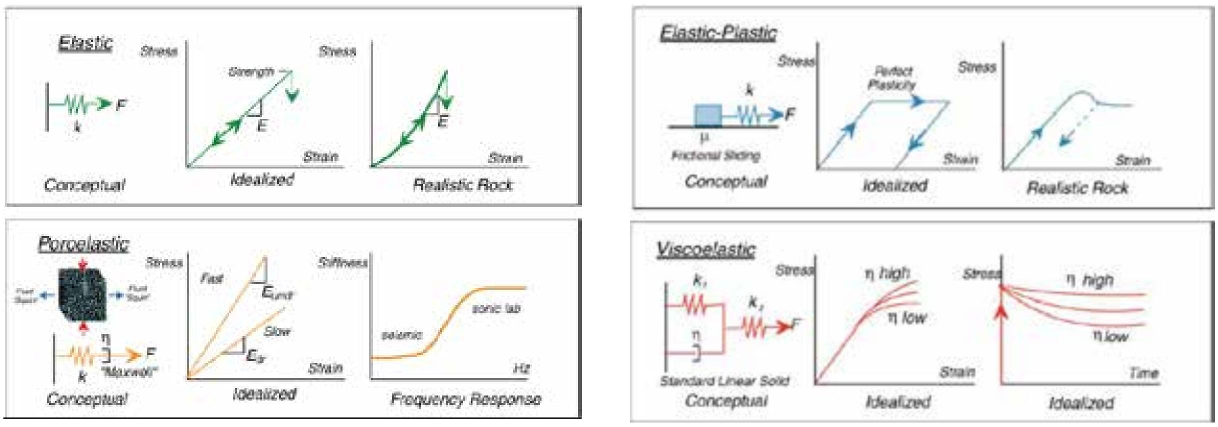


Figure 4. Common mechanical behaviors of the rocks (Zoback 2007).

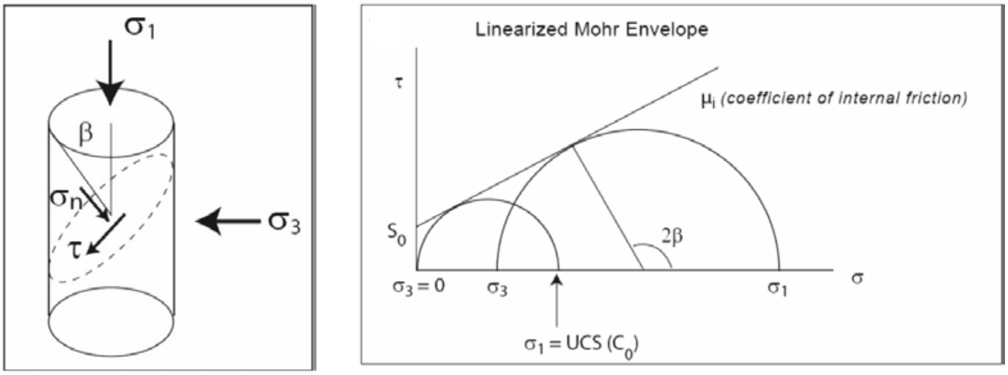


Figure 5. Uniaxial compressive test and Linearized Mohr-Coulomb Failure Envelope (Zoback 2007).

Thus, it is important to accurately predict: (i) how they will compact with depletion (especially as related to compaction drive); (ii) what the effects of compaction will be on reservoir properties (such as permeability); and (iii) what the effects will be on the surrounding formations (such as surface subsidence and induced faulting).

Failure Criteria

Failure theory is the science of predicting the conditions under which solid materials fail under the action of external loads. The failure of a material is usually classified into brittle failure (fracture) or ductile failure (yield). Depending on the conditions (such as temperature, state of stress, loading rate) most materials can fail in a brittle or ductile manner or both. However, for most practical situations, a material may be classified as either brittle or ductile.

Rocks either fail in tension when they are pulled apart or they fail in shear when they are crushed. The most likely failure mechanism could be estimated with the stress analysis.

In mathematical terms, failure theory is expressed in the form of various failure criteria which are valid for specific materials. Failure criteria are functions in stress or strain space which separate “failed” states from “unfailed” states. A precise physical definition of a “failed” state is not easily quantified and several working definitions are in use in the engineering community. In petroleum industry, it is common to use Mohr circles and Mohr failure envelopes.

In a uniaxial compressive test, a circular cylinder of rock is compressed parallel to its longitudinal axis, and axial and radial displacements are measured (Figure 5). The elastic properties; Young Modulus, Poisson’s ratio and uniaxial compressive strength in particular; may then be computed. Triaxial tests make the same measurements at different confining pressures and give a more complete picture of the rock’s failure defining an empirical Mohr–Coulomb failure envelope that describes failure of the rock at different confining pressures.

Allowable stress states (as described by Mohr circles) are those that do not intersect the Mohr–Coulomb failure envelope. Stress states that describe a rock just at the failure point touch the failure envelope. Stress states corresponding to Mohr circles which exceed the failure line are not allowed because failure of the rock would have occurred prior to the rock having achieved such a stress state.

In the Figure 5, *μ*i, the slope of the failure line, termed the coefficient of internal friction. The failure line’s intercept when σ_3 = 0 is called S_0, the cohesive strength (or cohesion), as is common in soil mechanics. In this case, the linearized Mohr failure line can be written as shown in Eq.1.

$$\tau = S_0 + \sigma_n \mu_i \qquad \textit{Eq.1}$$

Effective Stress and Pore Pressure

Karl von Terzaghi first proposed the relationship for effective stress in 1925 (Terzaghi 1925). For him, the term “effective” meant the calculated stress that was effective in moving soil, or causing displacements. It represents the average stress carried by the soil skeleton. According to Eq.2, Effective stress (σ’) acting on a soil is calculated from two parameters, total stress (σ) and pore water pressure (u).

$$\sigma' = \sigma - u \qquad \textit{Eq.2}$$

Pore pressure is an important factor in geomechanics since it has a big impact on stress magnitudes in rocks. It can be inferred from Terzaghi’s effective stress relationship in Eq. 2 that stress magnitudes are dependent upon pore pressure. The more pore pressure exist in the rock, the less

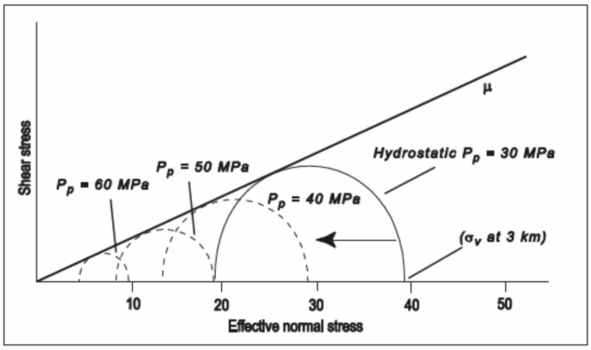


Figure 6. Dependency of stress magnitudes upon pore pressure (Zoback 2007).

effective pressure will be exerted on the skeleton, since most of the total stress is compensated by pore pressure (Figure 6).

Another important aspect is that, in terms of frictional faulting theory, as pore pressure increases (and effective stress decreases), the difference between the maximum and minimum effective principal stress (which defines the size of the Mohr circle) decreases with increasing pore pressure at the same depth.

Mechanical Stratigraphy

Accurately predicting how a reservoir rock will behave geomechanically requires detailed knowledge of the formation's mechanical strength and the way that rock will fail. Laboratory measurements on cores may be used to gather rock strength data as shown in the Figure 7. They provide valuable direct measurements but they are expensive to acquire and are only available at some of the depth zones of some of the wells.

Test Name	Evaluated Parameter
Uniaxial compressive test	Young Moduli
	Poisson ratio
	UCS
	Strains: Axial, Circumferencial, Volumetric
	Velocities: Compressive and Shear
Brazilian test	Tensile strength
Triaxial compressive test	Young Moduli
	Poisson ratio
	CCS
	Strains: Axial, Circumferencial, Volumetric
Multiple failure envelope	Cohesion, Internal friction coefficient

Figure 7. Mechanical properties gathered from core measurements (Jiménez 2007)

On the other hand, wire-line logs provide continuous profiles of data. But, no logging tool yields a direct measurement of rock strength or in-situ stress. This has given rise to interpretation techniques that combine direct measurements with sonic and density logs to derive the elastic properties of rock. Because there is no unifying theory that relates log measurements to rock strength, using the laboratory core data, empirical correlations are derived to obtain the desired rock strength parameters from log derived elastic properties (Eq. 3 & Eq. 4).

$$v = \frac{\left(\left(\frac{V_p}{V_s}\right)^2 - 2\right)}{2 \times \left(\left(\frac{V_p}{V_s}\right)^2 - 1\right)} \qquad \text{Eq. 3}$$

$$K = \rho \times \left(V_p^2 - \frac{4}{3} \times V_s^2\right) \qquad \text{Eq. 4}$$

Insitu Stress Determination

Utilizing observations of wellbore failures like drilling induced fractures and borehole breakouts, one can estimate orientations of horizontal stresses (Figure 8a). Although this phenomenon is discussed in the next chapters, it is always necessary to keep in mind that the breakouts occur in the direction of insitu minimum horizontal stress while drilling induced fractures are generated in the direction of insitu maximum horizontal stress.

Determination of the magnitude of least principal stress, Sh_{min} is possible from hydrofracs in reservoirs or extended leak-off tests at casing set points. A schematic mini-frac or extended leak-off

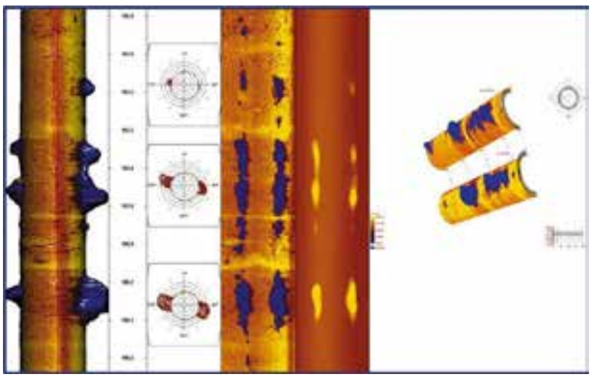


Figure 8a. Borehole breakouts as an indication of minimum horizontal stress (Rockware 2014)

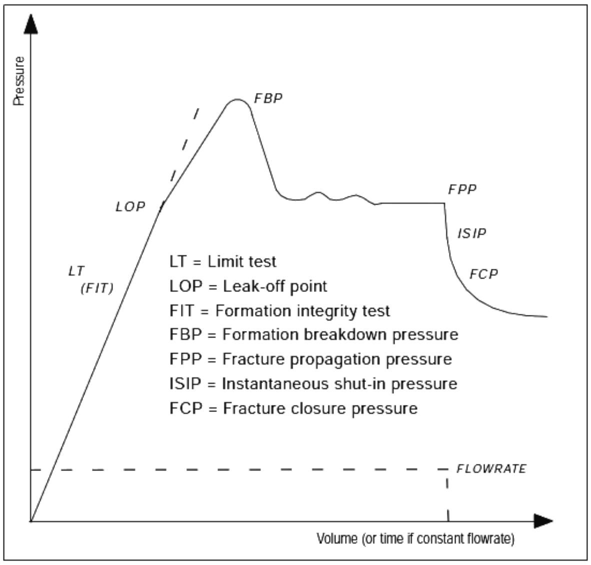


Figure 8b. Schematic extended leak-off test

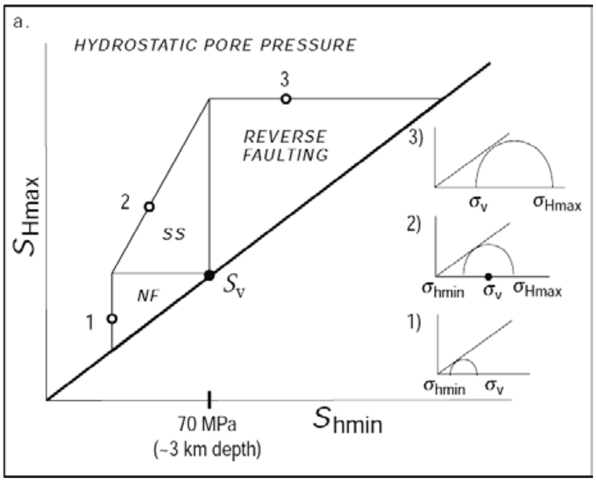


Figure 9. Stress polygon limiting possible stress magnitudes at a given depth for hydrostatic pore pressure in normal faulting (1), strike slip (2) and reverse faulting (3) stress regimes (Zoback 2007).

test showing pressure as a function of volume, or equivalently time (if the flow rate is constant) could be seen in the Figure 8b.

σ_v, vertical principal stress is obtained by integration of densities gathered from bulk density logs or correlations from sonic logs in the formula Eq.5.

$$\boldsymbol{\sigma_v = \int_0^b \rho_{sea} * d_z + \int_b^z \rho_b * d_z} \qquad \textit{Eq. 5}$$

Pore pressure, P_p, can be either directly measured or estimated using the correlations developed in the literature. Eaton's correlation in Eq. 6 is one of the best known and widely used method in the petroleum industry [27] (Eaton, 1969). Eaton's equation, published in 1969, is a classic method that relates changes in pore pressure to changes in P-wave velocity. The assumption in Eaton's method is the ratio of P-wave velocities obtained from regions of normal and abnormal pressures is related to the ratio of normal and abnormal pressures through an empirically determined exponent.

$$\frac{\rho}{D} = \frac{S}{D} - \left(\frac{S}{D} - \frac{P}{D_n}\right) \times \left(\frac{\Delta t_n}{\Delta t_0}\right)^E \qquad \textit{Eq. 6}$$

ρ/D is predicted formation pressure gradient
S/D is the overburden stress gradient
P/D_n is the normal pore pressure gradient
Δt_n is the normal hydrostatic shale travel time
Δt_o is the observed shale travel time
E is Eaton's empirically determined exponent

With the knowledge of the orientation of the horizontal principal stresses obtained from wellbore failures and with independently determined values of Sh_{min}, S_v, and P_p, determination of the complete stress tensor requires only the magnitude of SH_{max} to be determined. In order to quantify this stress, the stress polygons can be used. Stress polygons are convenient tools for simply estimating the range of possible stress states at any given depth and pore pressure provided that stress in the crust is limited by the frictional strength of faults (Figure 9).

Other parameters

Last but not least, we need to understand dominant failure mechanisms and tectonic elements which have a big impact on the local stress variations in the studied area.

- Dominant Failure Mechanisms
  – Brittle, ductile, creep, etc.
- Major tectonic elements (seismic or sub seismic faults, joints, fractures and folding) from image logs, seismic, cores, etc.

GEOMECHANICAL MODELING WORKFLOW

To carry out a complete geomechanical study, as a first step, Mechanical Earth Models (MEMs) should be built. MEM is a numerical representation of reservoir properties in 1D, 2D or even 3D style (Ostadhassan 2012). MEM contains data related to the rock failure mechanisms, in-situ stresses, stratigraphy and geologic structure of the reservoir (Sayers et al. 2009; Sayers et al. 2007; Plumb et al.

2000; Plumb et al. 2004). As aforementioned, MEM can and should be built any time in the production stage. It will be also upgraded with new information anytime when drilling is in progress and later during the production. Figure 10 depicts the flowchart for constructing a proper MEM.

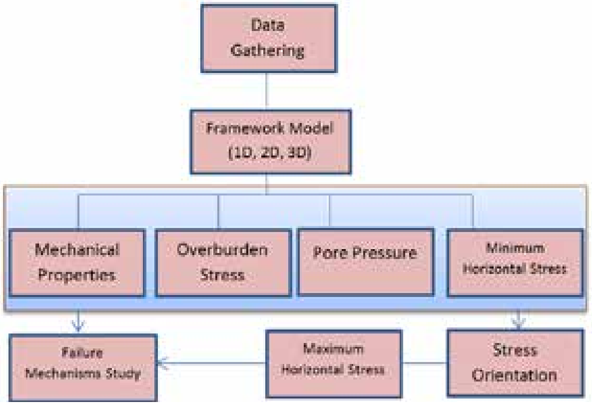


Figure 10. Mechanical Earth Model (MEM) flowchart (Ostadhassan 2012)

The workflow for construction of a MEM could be summarized as below:

1. To evaluate the acting forces on objective area (gravity and tectonic stresses)
2. To assess the rock strength
3. To calculate resulting stress field
4. To use the constitutive laws to relate stress field and strain
5. To state boundary conditions for stresses and strains
6. To identify the failure mode
7. To determine the mud weight window and calculate the best mud density
8. To define activities to control of instability

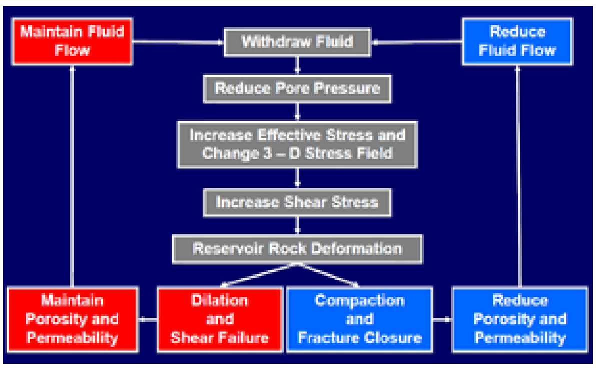


Figure 11. Effects of HC Production on Reservoir Rock Behavior

Figure 11 is a summary of the effects of HC production on reservoir rock behavior. As it can be seen there is a loop in the process.

Coupled Reservoir Simulations

Coupling the 3D MEMs to reservoir simulation incorporates time into the geomechanics modeling, transforming them to 4D (Bourgeois and Koutsabeloulis 2007; Dutta et al. 2011; Hossam et al. 2011; Masoudi et al. 2012). To simulate the dynamic behavior of a reservoir taking all these factors into consideration, it is necessary to perform two-way coupled reservoir geomechanical modeling that simulates the interaction between stress, pressure and permeability (Hossam et al. 2011). This is done by linking a reservoir simulator to a mechanical simulator (Figure 12). In two-way coupling, on one hand, pressure change affects the change in effective stress, which leads to strain changes. On the other hand, strain change modifies permeability or transmissibility, which leads to pressure redistribution.

Time-lapse seismic methods have proven successful in evaluating changes in reservoirs caused by production. Accurate modeling of compaction-related time shifts requires combining geomechanics with full-waveform simulation of seismic data (Smith and Tsvankin 2012).

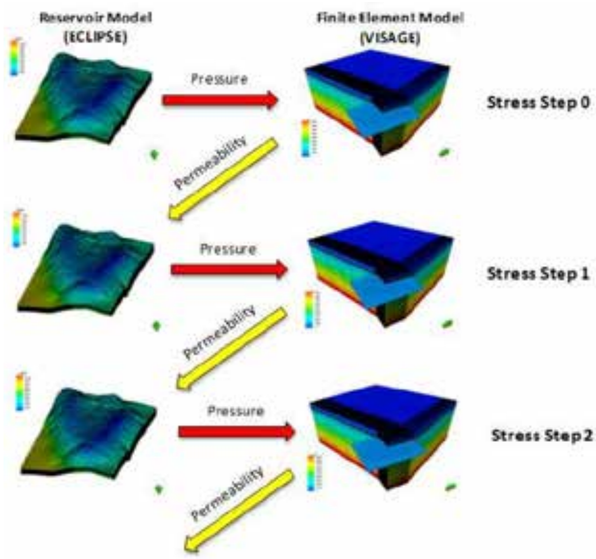


Figure 12. Reservoir simulation process linked to a geomechanical simulator (Hossam et al. 2011).

CASE STUDIES

In this section various application areas of geomechanics in different reservoir problems are considered.

Geomechanics in Unconsolidated Formations

In the unconsolidated formations, basic geomechanics related problems are sand production, wellbore stability, surface subsidence, reservoir compaction and decrease in reservoir permeability within time. All of these problems are highly related to geomechanical properties of the reservoir.

Sanding

Sanding or sand production is one of the challenging issues in the production engineering. Accurately predicting sand production potential requires detailed knowledge of the formation's mechanical properties and the in-situ earth stresses. Low inherent rock strength, high naturally existing earth stresses, additional stress due to drilling or production are the main reasons for sanding or sand production [38] (Carlson et al., 1992).

In totally unconsolidated formations, it may be triggered during the first flow of the formation fluid due to drag from the fluid or gas turbulence. In better cemented rocks, sanding may be induced by fluctuations in production rate, onset of water production, changes in gas/liquid ratio, reduced reservoir pressure or subsidence. In unconsolidated formations sanding can be triggered with the first flow. In better cemented rocks, factors like fluctuations in production rate or the other factors here could damage the perforation cavity stability by preventing the creation and maintenance of sand arches (Figure 13). An arch is a hemispherical cap of interlocking sand grains that is stable at constant drawdown and flow rate, preventing sand movement. Changes in flow rate or production shut-in may result in collapse of the arch causing sand to be produced until a new arch forms.

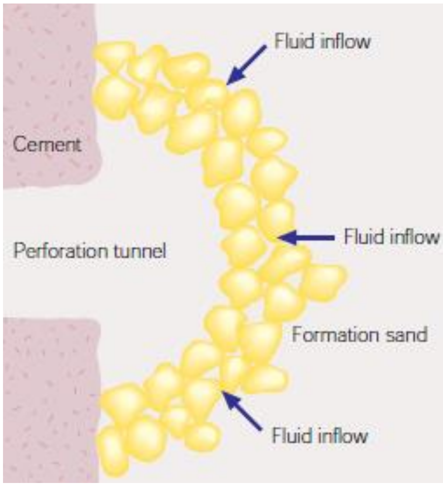


Figure 13. Arch formed during the production of unconsolidated formations (Carlson et al.1992)

Reservoir Compaction / Permeability Decrease

Prolonged or rapid production of oil, gas, and formation water causes subsurface formation pressures to decline. The lowered pore pressures increase the effective stress of the overburden, which causes compaction of the reservoir rocks. Mostly, this compaction has a decreasing effect on reservoir properties like porosity and permeability (Figure 14).

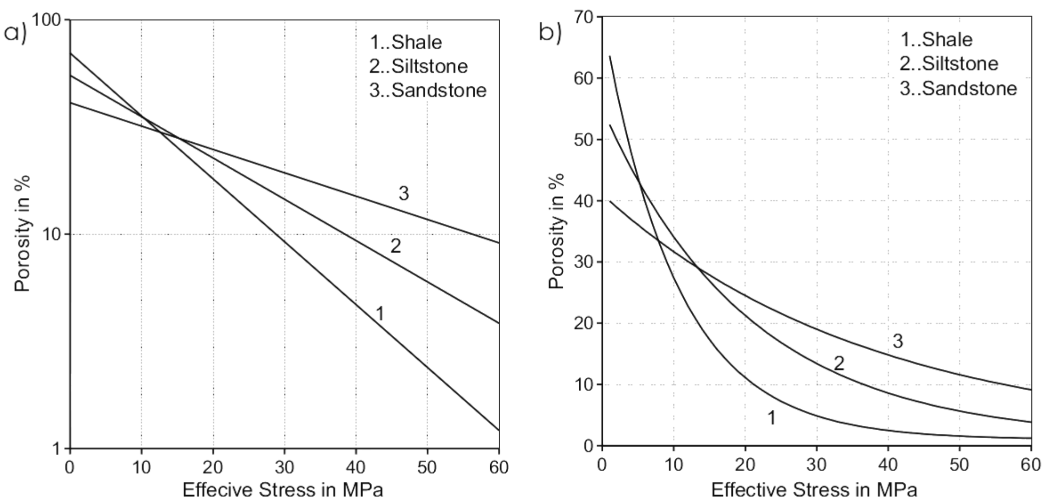


Figure 14. Decrease in reservoir porosity related to reservoir compaction (Goulty 2009)

Reservoir Compaction / Surface Subsidence

Where subsidence and fault reactivation occur in wetland areas, the wetlands typically are submerged and changed to open water causing the loss of these wetlands or stability risks on the surface structures (Figure 15).

Seabed and the platform subsidence on Ekofisk is the best known example of this phenomenon (Mathiesen and Gundersen 2008). It was first recognized in 1984, when the number of visible openings in the protective tank wall had been reduced from five-six to four. Figure 16 is from Norwegian Petroleum Museum.

The reservoir rock on Ekofisk consists largely of chalk, which is extremely porous in some zones up to 50 percent. Until the first production in 1971, oil under relatively high pressure has been bearing the weight of the overlying layers. As it was produced, a growing share of the burden had to be carried by the chalk – which failed to take the load.

In 1974, the 2/4-T concrete storage tank was installed on Ekofisk. It took a decade before people began to ask why the lowest openings in its shield wall were disappearing. This confirmed that subsidence was happening, although it was not the first time that such a phenomenon had been recorded in connection with oil, gas or coal production. The special feature of Ekofisk, however, was that its installations had subsided by three meters in 13 years.

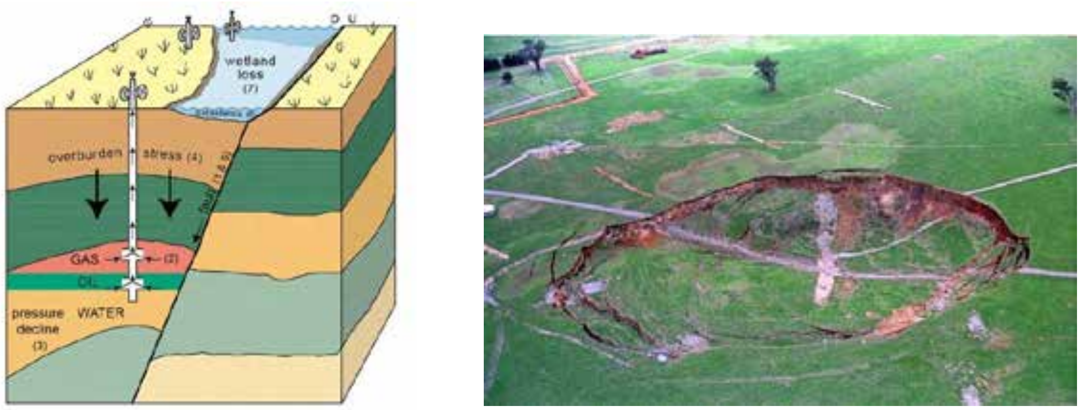


Figure 15. Schematic view (USGS. 2014) and surface photo (Underground mining (hard rock). 2015) of surface subsidence.

The joint chalk research program devoted tens of millions of krones to mechanical tests of the reservoir rocks. Modelling of rock properties and future production plans were then applied to predict the future course of the subsidence. Each forecast showed that the rate of sinking would decline in the near future. But it was finally recognized that the models were wrong – and the problem continued. More intensive research over the past decade into the interaction between pore filling and rock stability has improved theoretical understanding of the mechanism of chalk compression. Water injection is used today as the primary means of preventing such compression. The seabed on Ekofisk is still sinking, but at only 20 centimeters a year. Total subsidence so far has been measured at almost nine meters. Ekofisk is not the only Norwegian field to suffer from this phenomenon. It has been recorded on Eldfisk, Valhall and West Ekofisk. All these reservoirs comprise the same weak reservoir rocks and a similar geological structure between the hydrocarbon-bearing formations and the seabed.

Figure 16. The 2/4-T concrete storage tank which has sunk more than 3 meters in 13 years

Geomechanics in Naturally Fractured Reservoirs (NFRs)

In naturally fractured reservoirs geomechanics has found applications in many areas, such as fault-reactivation, early water breakthrough, breaching in cap-rock integrity and changes in reservoir permeability. Most work on fractures/faults and fluid flow treats the fracture/fault network as a static system having a fixed transmissibility. Recently, however, it has been recognized that flow is greatly enhanced in critically stressed fractures/faults, usually identified on the basis of their orientation with respect to the in-situ stress field (Barton et al. 1995; Zoback et al. 1996). In the fields with water/gas flooding applications, reservoir depletion/injection causes changes in effective stress that may trigger formation deformations, such as propagation of existing fractures/faults and initiation of new fractures/faults (Zhang and Sanderson 2002).

Understand and Characterize Fracture Systems

Natural fractures and faults are the primary pathways for hydrocarbon migration and production in many reservoirs. Unfortunately, they can also act as channels for water breakthrough and gas coning. Knowledge of these fractures and their conductivities in relation to rock stresses helps reservoir engineers and geoscientists to optimize reservoir and well performance.

Detailed knowledge of the extent, orientation, and permeability sensitivity of fracture systems in reservoirs are essential for well trajectory and completions planning. So as a first step we need to characterize fracture pattern whether it is a connected network or consist of mainly fracture corridors, unconnected fractures or nonconductive or close fractures (Figure 17). Fractured reservoirs, particularly fractured carbonate reservoirs, are very heterogeneous in terms of formation properties and fracture distribution. For example, fractures exist over a wide range of scales from micro fissures to kilometer-sized structures in the form of fracture corridors (Bush 2010).

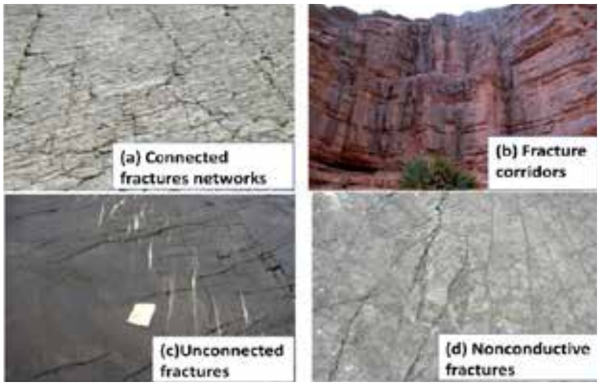


Figure 17. Common fracture patterns observed in outcrops (Bush 2010).

After describing this complex phenomenon in a simple conceptual or in a detailed DFN model like the one taken from a study by Golder Assoc. in Figure 18, what we will consider will be to define the flow and mechanical characteristics of these fractures.

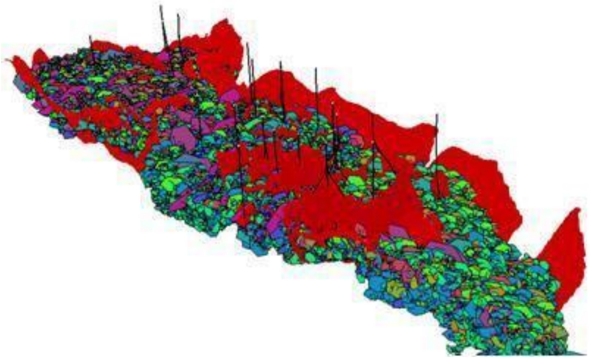


Figure 18. A Full Field Discrete Fracture Network Model

Development of Dual-permeability Models

Geostresses currently acting on natural fractures influence their permeabilities and their potential to slip. The recent stress regime acting in a reservoir and the orientations of any fracture set in relation to these stresses is a major control on the permeability anisotropy of the fractured reservoirs (Figure 19). Apart from describing rock stresses and rock mechanical properties as in any geomechanical job, in fractured reservoirs, data coming from image and acoustic logs are used to quantify properties like fracture aperture, permeability and conductivity sequentially.

Besides these undisturbed properties of reservoir condition, as production begins permeabilities will begin to change over the life of a field. Sometimes critically stressed fractures, as in this study, serve as highly efficient pathways for fluid flow if they are activated with changing stress state in the reservoir.

Unconnected natural fractures can become connected during production activities in consequence of depletion-induced reservoir compaction or injection-induced fracture propagation or both. In addi-

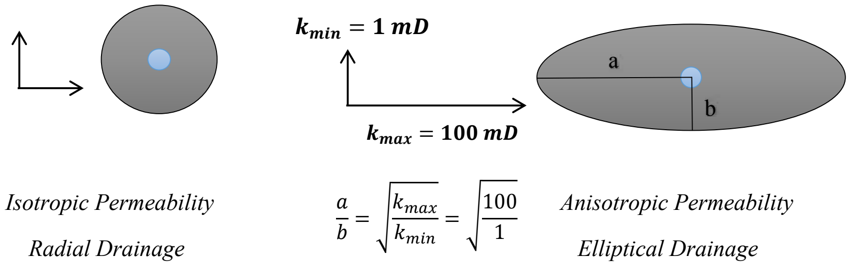


Figure 19. Description of anisotropic permeability (Teufel 2014).

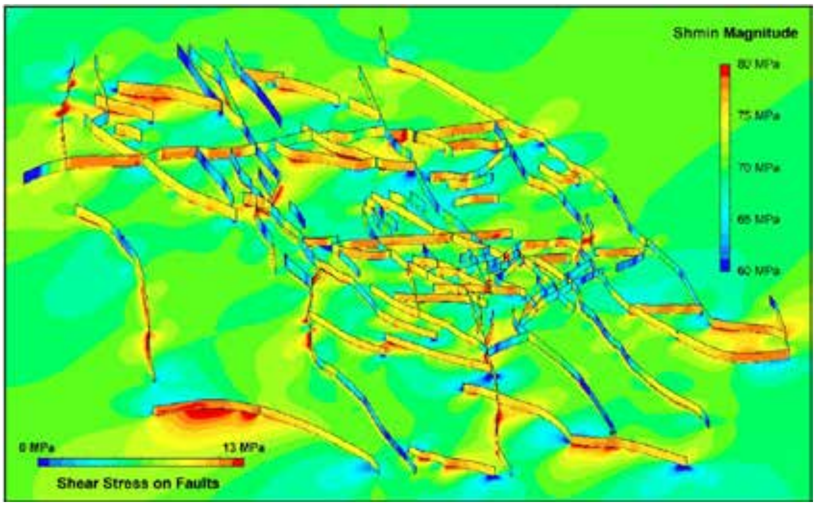


Figure 20. Critically stressed fractures identified after a stress modeling study (Fischer and Henk 2013).

tion, nonconductive natural fractures can become conductive as a result of reservoir deformation. Therefore, the dynamic behavior of fracture permeability plays a crucial role in reservoir performance and management (Fischer and Henk 2013).

When depletion or injection occurs, pressure changes can lead to stress changes that further modify the apertures, and hence, the permeabilities, of the fractures. Such changes can be dynamic over the life of a field, meaning that fracture permeabilities and preferred flow directions can change with depletion and injection. This type of dual-permeability reservoir models developed on the basis of the proposed fracture models improve reservoir simulations.

Challenges in Geomechanical Studies in NFRs

An important aspect in highly fractured and faulted fields is modified stress magnitudes and orientations. This is one of the biggest challenges in MEM generation in fault-controlled reservoirs, as local stress reorientations are seen up to 90 degrees relative to the regional trend. This means a huge deterioration of regional stress state near faults or near some big fracture swarms.

Cap rock integrity could be an issue for any kind of reservoir but in NFRs because that we already have faults and fractures this is a more likely situation and needs to be investigated.

When there are faults and fractures, the initial stresses within the reservoir and the surrounding formations won't be uniformly distributed. Where the stress exceeds the strength, plastic strains are expected. In this case, the stress state in such regions prior to production will be close to or at a critical stress state, at which a relatively small effective stress change due to depletion/injection might damage the formation and trigger fault reactivation if there are faults nearby.

In the study in Figure 21a, map view of initial porosity distribution prior to production in a reservoir layer is seen. Although there is an equilibrium

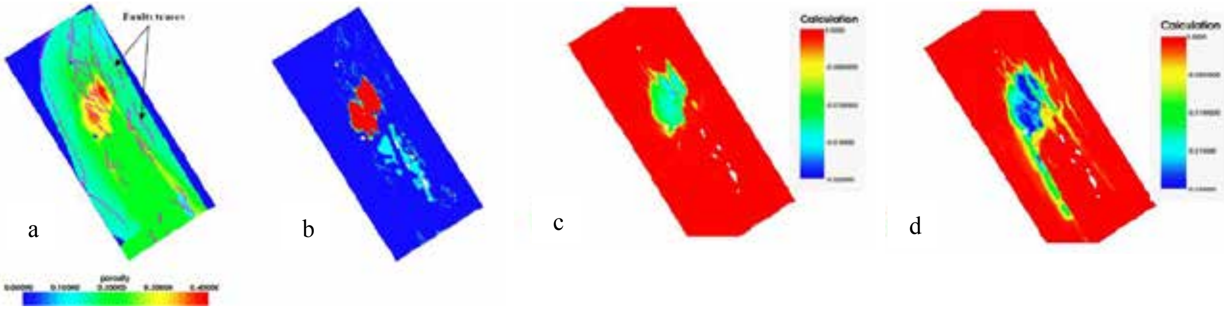


Figure 21. a) Initial porosity distribution – **b)** Initial computed plastic Strains – **c)** computed plastic strains after 313 days of production - **d)** Computed plastic strains after 2278 days of production (Koutsabeloulis and Zhang 2009)

state in stress and pore pressure prior to production, a relatively small change in effective stress due to depletion and/or injection exist in the formation in those regions with developed plastic strains that were associated with relatively higher porosity. A critical stress state in such areas might exist prior to production.

Wellbore Geomechanics

In wellbore stability assessments, prior objective is to estimate formation elastic properties which will lead to an accurate stress analysis and can prevent future financial losses. Drilling through the formation will cause stress alteration around the borehole and even in a radius into the formation, consequently these changes should be simulated prior to drilling (Ostadhassan 2012).

Wellbore stability is maintained when the well diameter fits the bit sizes and it remains constant while drilling. In contrast to this, geomechanical instability refers to mechanical conditions such as wellbore collapse or failure. In general wellbore instability is related to drill pipe sticking, tight spots, caving production wellbore collapse and unscheduled sidetracks, these conditions are mostly caused by unknown rock mechanics and lead to increased costs during drilling and completion operations.

Stress Concentration Around a Vertical Well

As described by Kirsch in 1898 (Kirsch 1898), the creation of a cylindrical opening (like a wellbore) causes the stress trajectories to bend in such a way as to be parallel and perpendicular to the wellbore wall because it is a free surface which cannot sustain shear traction (Figure 22). Moreover, as the material removed is no longer available to support far-field stresses, there is a stress concentration around the well. This is illustrated by the bunching up of stress

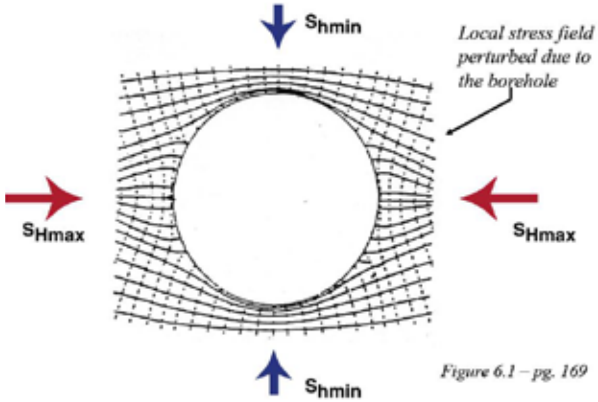


Figure 22. Stress perturbation around a wellbore (Kirsch 1898).

trajectories at the azimuth of Sh_{min}, which indicates strongly amplified compressive stress. In contrast, the spreading out of stress trajectories at the azimuth of SH_{max} indicates a decrease in compressive stress.

Stress concentration around the wellbore is totally independent of the elastic moduli of the rock. For this reason, the manner in which stresses are concentrated around wellbore does not vary from formation to formation. Moreover, it is independent of the wellbore radius. So only the in situ stress state and pore pressure controls this perturbation around the wellbore (Zoback 2007).

Mathematically, the effective stresses around a vertical wellbore of radius R are described in terms of a cylindrical coordinate system. $\sigma_{\theta\theta}$ and σ_{zz} are these transformed compressive stresses or so-called compressive hoop stresses.

In Figure 23, extremely large variations in $\sigma_{\theta\theta}$ is seen with position or azimuth around the well. σ_{zz} varies in a similar manner but the variations are much more low. Also, the stress concentration is symmetric with respect to the direction of the horizontal principal stresses.

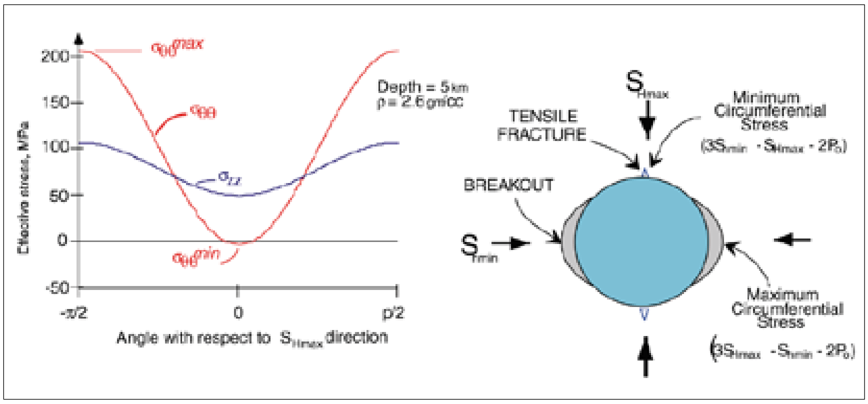


Figure 23. Variation of hook stresses with position around the well (Zoback 2007).

SH_{max} = 90 MPa

Orientation of SH_{max} = N90°E

S_v = 88.2 MPa (depth 3213m)

Sh_{min} = 51.5 MPa

$P_p = P_{mud}$ = 31.5 MPa

C_0 =45 MPa, μ_i =1.0

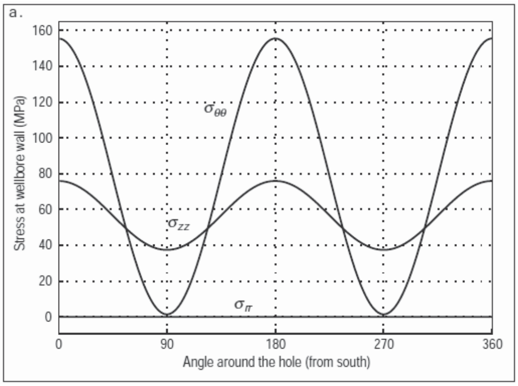


Figure 24. Calculated effective principal stresses, $\sigma_{\theta\theta}$, σ_{rr} and σ_{zz} around a vertical wellbore according to the given values on the left and representation of these stresses as a function of azimuth

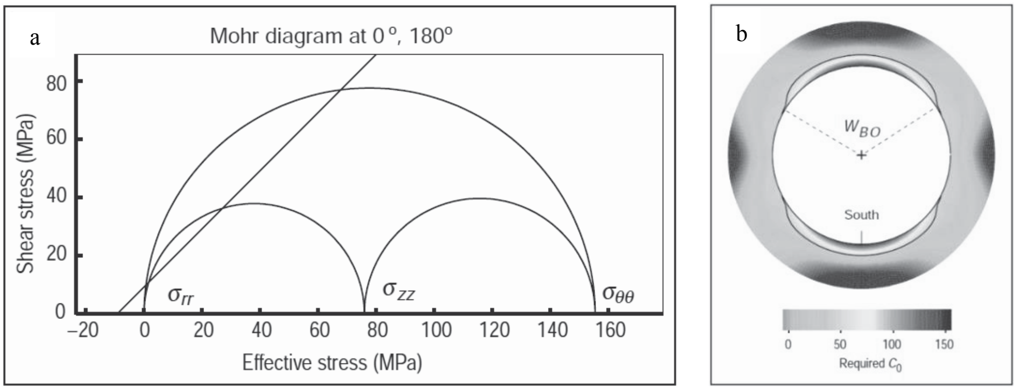


Figure 25. a) Mohr circle representation of three principal stresses at the wellbore wall at the point of maximum stress concentration (θ = 0, 180°) **b)** Required rock strength to inhibit failure

It is obvious that compressive failure of the wellbore wall is most likely to occur in the area of maximum compressive hoop stress (at the azimuth of Sh_{min}) or 90° from the direction of SH_{max}, if the stress concentration exceeds the rock strength (Bell and Gough 1979; Zoback et al.1985).

Effective principal stresses, $\sigma_{\theta\theta}$, σ_{rr} and σ_{zz} around the vertical wellbore are calculated according to the given values of pore pressure and rock strength parameters listed below and they are drawn as a function of azimuth in the Figure 24.

In the Figure 25a, the principal stresses at the point of maximum stress concentration (θ = 0, 180°) are drawn on the Mohr diagram. We see that the strength of the rock is exceeded with the given cohesion and internal friction angles. So the rock on the wellbore wall is expected to fail. In the Figure 25b, the required rock strength to inhibit failure is

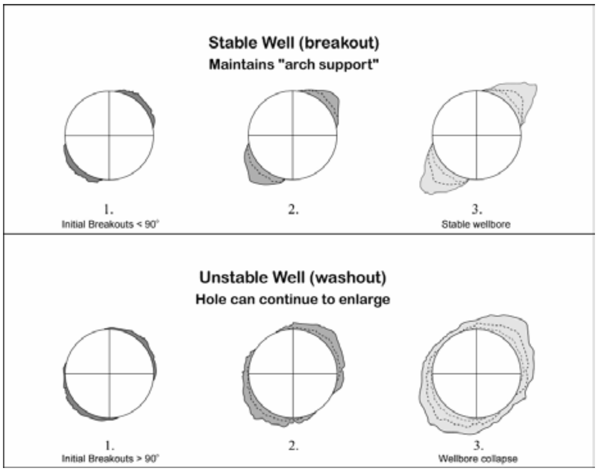


Figure 26. Breakout growth when the initial breakout size is relatively small (<60°, stable well or breakout) and when it is relatively large (~120°, unstable well or washout) (Zoback 2007).

drawn. Dark colors represents regions with high stress concentrations. The zone of failure around the wellbore wall for the assumed rock strength is signed by the contour line. This is the expected zone of initial breakout formation with a width given by W_{BO}. Between the contour line and the wellbore wall, failure of even stronger rocks would have been expected (the scale indicates the magnitude of rock strength required to inhibit failure). Lower rock strength would result in a larger failure zone.

So in order to maintain wellbore stability, we should control the width of breakouts by controlling drilling mud weight since it is the only parameter that we can change in the system. But of course we have to quantify other parameters properly to be able determine safe mud window for our well. As a rule of thumb, an angle of 90 degrees for the breakouts is found to be the limit for wellbore stability by many operators.

From geomechanical point of view, stable mud window keeps borehole safe against drilling induced tensile fractures or stuck pipes which happen due to high mud weight as well as breakouts which result from low mud weight (Al-Ajmi and Zimmerman 2006). Safe and stable mud weight windows are shown in the Figure 27 (Abdideh and Fathabadi 2013).

The processes that control the initiation of tensile wall fractures are also very important for understanding the initiation of hydraulic fractures. Of course, if hydraulic fracturing occurs unintentionally during drilling due to excessively high mud weights, lost circulation can occur. This is another serious problem during drilling, especially in areas of severe overpressure.

In the Figure 28, we see the results of a study in which stress parameters are calculated through the well as a log (Gholami et al. 2014). Possible breakout and breakdown zones according to Hoek-Brown Failure criterion are determined. This could be done by using different failure criteria.

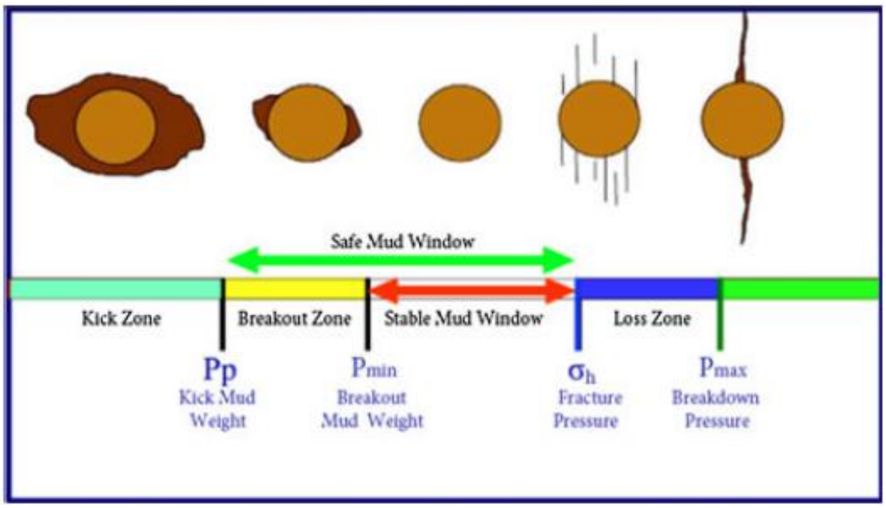


Figure 27. Safe and stable mud weight windows (Abdideh and Fathabadi 2013).

Also a calculated borehole caliper log can be created by the help of this stress analysis. Safe mud window can be defined all along the well by constructing this kind of logs.

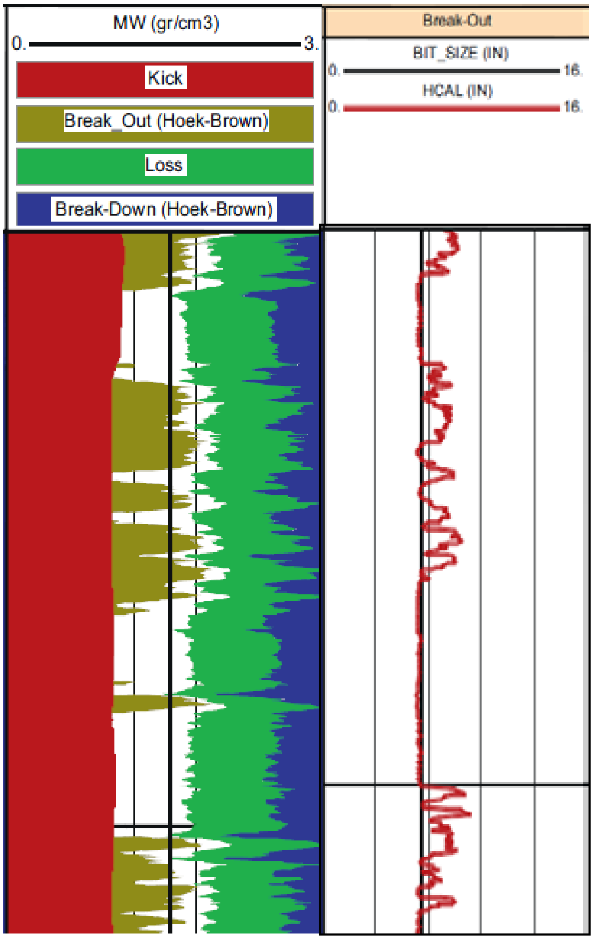


Figure 28. Determination of stable mud weight windows for a well using different failure criteria (Gholami et al. 2014).

Mud Weight Maps

Another study uses the fluid flow-geomechanical coupled simulation results to construct 3D mud weight cubes for a particular field (Hossam et al. 2012). The mud weight cubes can be used to establish the width of the stable mud weight window based on the difference between the breakout mud weight limit and the breakdown mud weight limit. The mud weight cube is helpful for making decisions with regard to new well trajectories and well placements. It provides general guidelines in regard to optimum wellbore direction for different formations and locations of the field (Figure 29).

Geomechanics in Unconventional Reservoirs

In unconventional or self-sourced reservoirs, there is an immense necessity for geomechanics for understanding the effectiveness of multistage hydraulic fracturing programs and estimating the size and orientation of fractures induced by fluid injection. Although the traditional approaches offer the advantage of rapid analysis, neglect of key features of the natural system (e.g., realistic mechanical stratigraphy, pre-existing natural faults and fractures, and heterogeneity of in situ stresses) may render results unrealistic for planning, executing, and interpreting multimillion-dollar hydraulic stimulation programs.

Numerical geomechanical modeling provides a means of including key aspects of natural complexity in simulations of hydraulic fracturing. A combination of long, horizontal wells (laterals) and aggressive stimulation (hydraulic fracturing to create new fractures and connect to existing fractures) are necessary for economic fluid recovery (Gale et al. 2014; Bodziak et al. 2014; Busetti, Jiao and Reches 2014; Busetti and Reches 2014; Imber et al. 2014). By some accounts, more than half of the cost of a typical Eagle Ford well in south Texas goes toward the post-drilling (stimulation) activities (Cowan 2011). Improvements in the planning and prestimulation prediction of hydraulic fracturing are an ever-increasing factor in the overall economics of most unconventional plays.

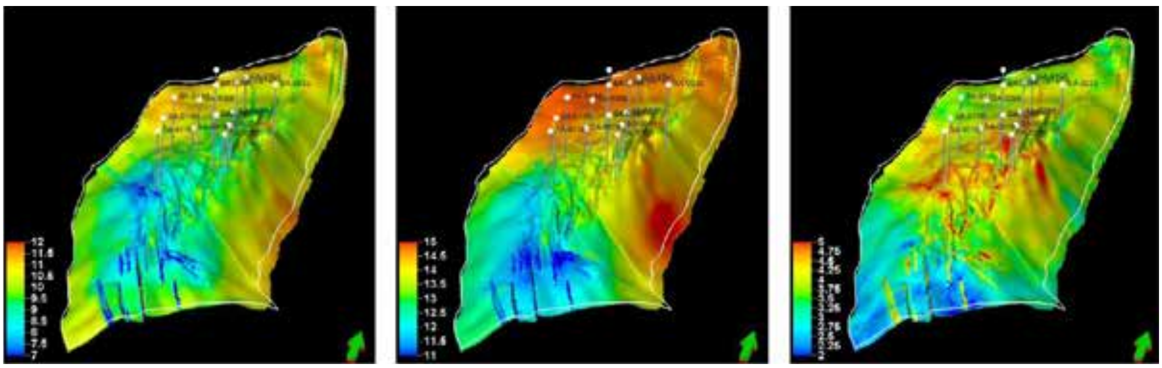


Figure 29. Breakout mud weight distribution (left), Break down mud weight distribution (middle), Stable mud weight window distribution (right) (Hossam et al.2012).

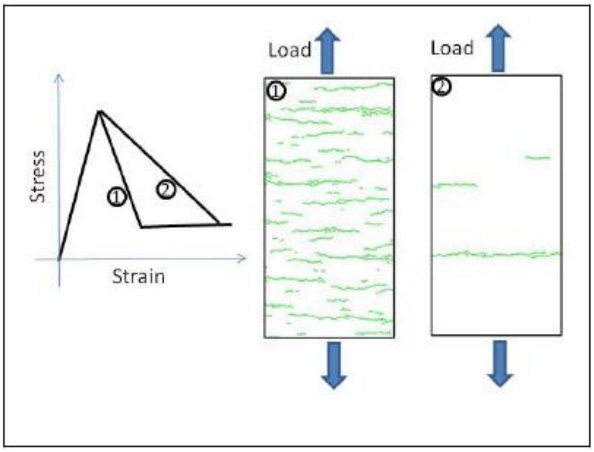


Figure 30. Comparison of two rock samples according to their fracturing behavior: more brittle sample (1) shows more fractures than the soft one (2) (Tayseer et al. 2011).

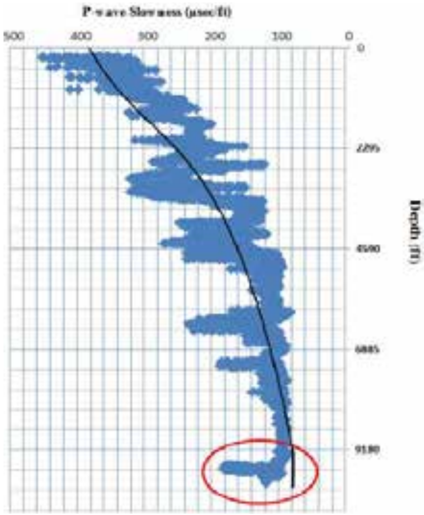


Figure 31. Deflection from the normal velocity-compaction trend line in the Bakken shale interval

Boom in the development of unconventional reservoirs is one of the most important reasons for increasing interest in geomechanics. Because the production of self-sourced reservoirs are very sensitive to geomechanical variations. Mostly, the unconventional reservoirs contain clay and organic material which lowers the stiffness of the rock. A study on the effect of brittleness on fracture development with a numerical modeling code has shown that the more brittle sample shows more fractures than the soft one (Figure 30) (Tayseer et al. 2011).

A study from Bakken Shale in North Dakota shows a deflection from the normal velocity-compaction trend line in the Bakken shale interval (red oval in Figure 31) (Ostadhassan et al. 2012). This represents the overpressure nature of this layer. This overpressure behavior is explained by the conversion of kerogen to hydrocarbon in Bakken Formation.

In the same study, anisotropic geomechanical parameters have been measured in the shales (Figure 32). Young's modulus and Poisson's Ratio values measured in the horizontal direction are greater than those in the vertical direction for both upper and lower shales. This phenomenon reflects their vertical transverse isotropy (VTI) behavior. These are the evidences demonstrating the anisotropic behavior of shales and the presence of horizontal

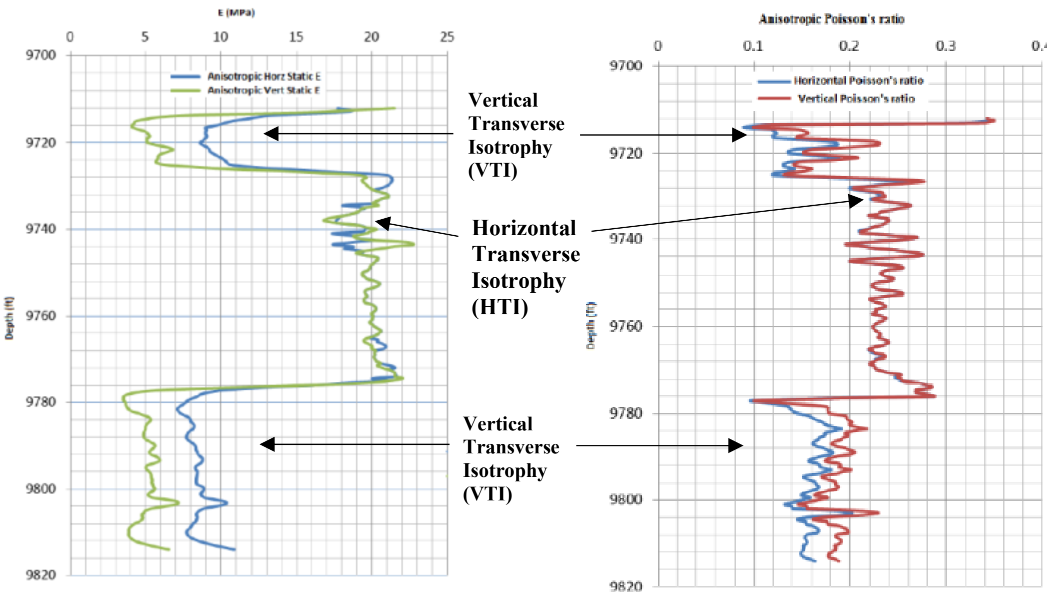


Figure 32. Anisotropic geomechanical parameters in Bakken shale (Ostadhassan et al. 2012)

planes of weakness. Relatively less shaly parts don't show a clear anisotropy effect. But if closely looked, there is also some anisotropy in this section but in the opposite direction. This type of anisotropy which is known as horizontal transverse isotropy (HTI) makes the vertical Young's modulus greater than the horizontal Young's modulus. It was interpreted as the existence of the vertical fractures in this specific zone. The cores from this zone were analyzed and the existence of vertical fractures was confirmed.

Hydraulic Fracturing

When it comes to hydraulic fracturing, mechanical stratigraphy, stress state and pre-existing structures are the most important factors affecting the success of the operation.

We are all familiar with the micro seismic measurements during the fracturing stages. They are the signs of very small micro seismic events. As an example, in the Figure 33, a well drilled in the direction of minimum horizontal stress and micro seismic events related to the multiple hydraulic fracturing from the toe to the heel of the well are shown (Moos et al. 2011).

What is not very well known about the seismicity of hydro fracturing is we could also have some aseismic faults which don't show these dots. A study from Standford University (Das and Zoback 2013a,b) showed that about 40 micro earthquakes are recorded in each hydrofrack stage in a typical well (Figure 34).

If we consider that in every stage, stimulated rock volume is about 200 m^3, they hardly fill the volume and basically they are hardly touching each other (Figure 34). So this number of micro earthquakes

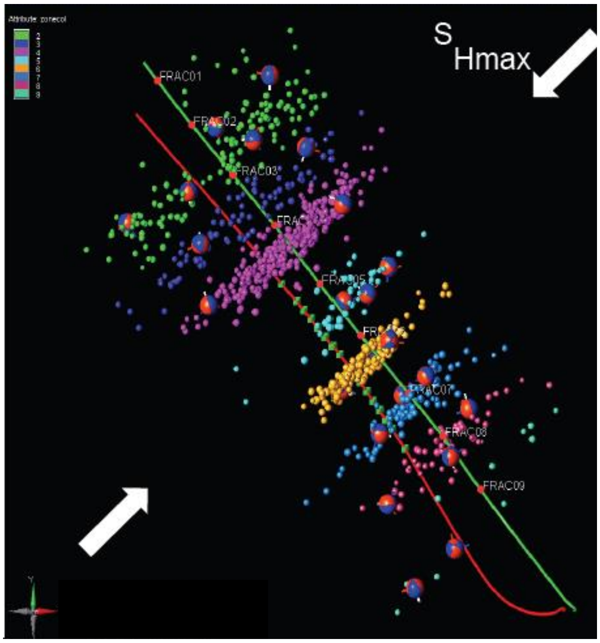


Figure 33. Dots showing micro seismic events related to multiple hydraulic fracturing (Moos et al. 2011)

does not explain the amount of gas produced. So some researchers think that in addition to these micro seismic events, there are slowly slipping faults which don't have a seismic response but that are also stimulating production.

Figure 35 shows the data collected on Barnett, Hainsville and Eagleford shales. They are separated into light and dark for low clay and high clay, respectively. The coefficient of friction is plotted in black as a function of clay and organic content. For a relatively low clay, the coefficient of friction starts at about 0.8, ends at about 0.4 meaning the more clay we have in the rock, the weaker it becomes.

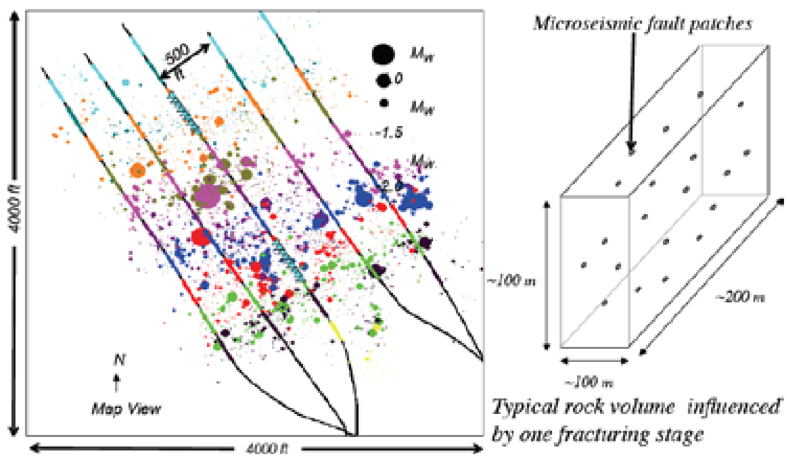


Figure 34. Micro seismic measurements recorded in a typical fracturing stage (Das and Zoback 2013a,b)

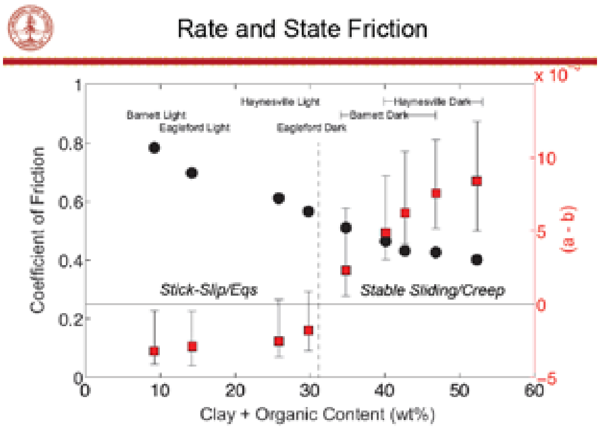


Figure 35. Coefficient of Friction and (a-b) parameters for different shale types and clay contents (Das and Zoback 2013a, b)

On the other axis is the a-b parameter which is a measure of whether the rock will show a slipping or creeping behavior. If it is negative it is in slipping mode, if positive in creeping mode. When there is more than 30% clay, a minus b is positive. In other words, the faults show creep behavior. So what we expect is that in low clay Barnett shale or Barnett light, we get micro-earthquakes, high clay Barnett shale or Barnett dark we get creeping faults which don't show any seismic activity.

Geomechanics in EOR Applications

Steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are successful thermal recovery processes in oil sands. But in these applications it is likely that because of continuous steam injection, increased pore pressure triggers complex coupled thermal and hydraulic processes, which can dramatically change the state of in-situ stresses, reduce rock strength, induce new fractures or reactivate existing fractures posing continued risk of containment breach of cap rock.

Cap Rock Integrity

Ensuring cap-rock integrity is critical in any subsurface injection process such as SAGD and CSS. Continuous steam injection triggers complex coupled thermal and hydraulic processes which alter the formation pressure and temperature leading to various changes within the reservoir as well as surrounding rock (e.g. change in in-situ stresses, rock properties, porosity and permeability). High temperature and injection pressures can reduce rock strength, induce new fractures or activate existing fractures posing continued risk of containment breach of cap-rock or fault reactivation. This can ultimately lead to breach in well or reservoir integrity and providing pathways for bitumen or steam to flow to aquifers or surface, both of which pose significant risk to safety and the environment (Khan et al. 2011).

In Figure 36 possible cap rock failure mechanisms could be seen (Khan et al. 2010). Rock can fail in tension, compression, shear or combination of these modes as shown in the figure. Predicting tensile failure is relatively easy because fracture pressure can be measured using mini-frac test which can be used as upper limit for injection to avoid hydraulic fracturing. However, prediction of

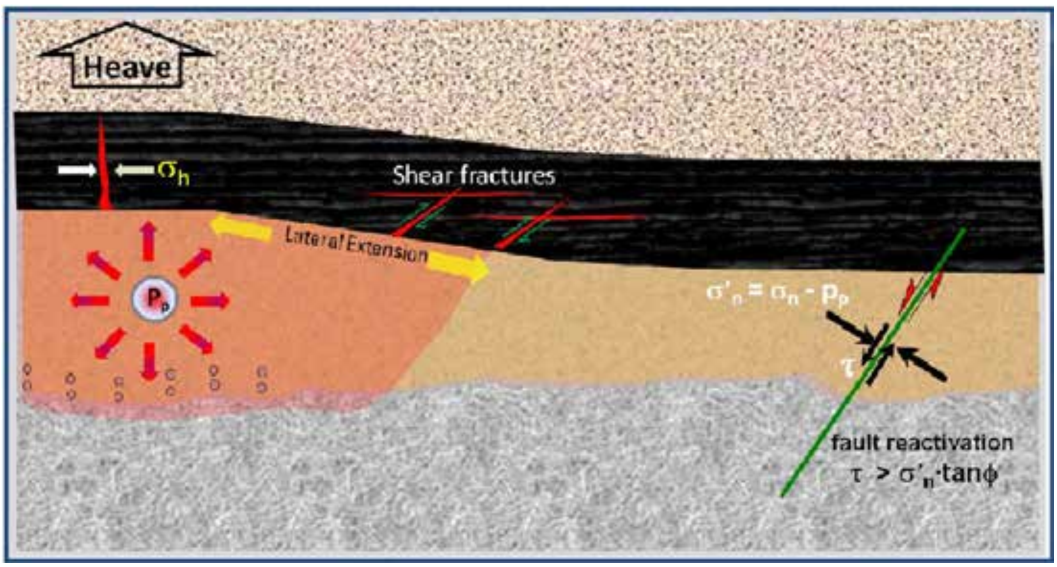


Figure 36. Possible cap rock failure mechanisms

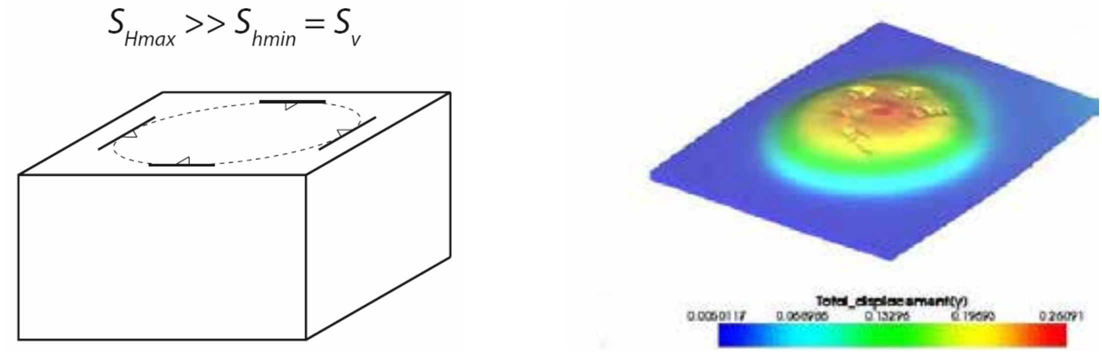


Figure 37. Vertical movement (m) of the top surface at the ground level (Hussein et al. 2010).

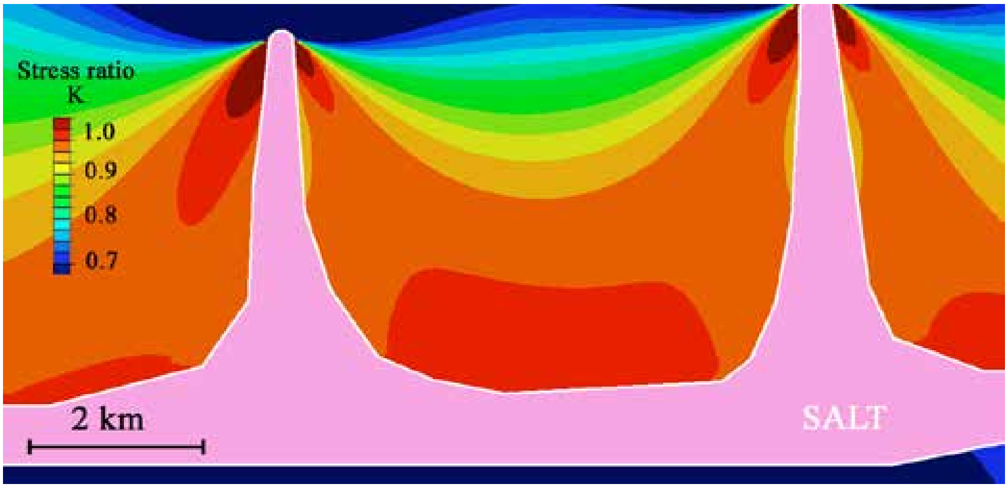


Figure 38. Stress ratio in a salt body's surrounding area (Moos et al. 2011).

shear failure or combination of other modes is not so easy; it involves a number of parameters and requires sophisticated numerical modeling of the reservoir and the surrounding rock. This requires coupling between changes in pressure and temperature, and changes in stresses, strain, rock properties, porosity permeability, dilation etc.

Reservoir expansion/ Surface Uplift

In the study illustrated in Figure 37, steam injection into a shallow fractured and faulted reservoir has been simulated with a coupled simulation technique (Hussein et al. 2010). There is a vertical up movement at the ground level related to the steam injection representing an extreme case of principal stresses SH_{max} >> Shmin = S_v (Figure 37, left).

The 3D mechanical earth model (MEM) of this thermal gas/oil gravity recovery process illustrates the potential for steam to facilitate drainage by reducing viscosity of the heated matrix oil, leading to upward movement of the surface in response to high steam temperatures. High levels of vertical deformation are increasingly likely where faults extend to the surface. Understanding these processes is important for ensuring the safety of the facilities during extended production period.

Geomechanics in Salt Structures

Salt is a viscous material and it cannot sustain deviatoric stresses. It has a really distinct constitutive behavior [68] (Nikolinakou et al., 2013). Under differential loading it flows, changes shape, and eventually relaxes to an isostatic stress state (Figure 38). Therefore, emplacement of a salt body and the viscous relaxation process may cause significant deformation of the surrounding sediments, perturb their state of stress and create local overpressures. This is the explanation for the high leak-off test values often measured close to salt. Viscous relaxation process of the salt may cause significant deformation of the surrounding sediments.

FUTURE PERSPECTIVES

Today we are in the age of simplifications. We never have chance to represent all the complexity of the real system in our models. In the future together

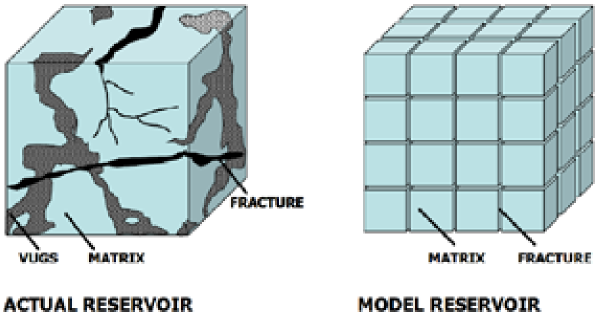


Figure 39. Comparison of the real complexity of a reservoir and the modeled reservoir (Das and Zoback 2013a).

with the acceleration in the computer technologies and with better simulators, we will be less compelled to this simplification processes like upscaling or sugar cube models for fractured reservoirs (Figure 39).

A Discontinuous Future in Geomechanics

This is one of the topics that are being discussed. Discontinuous methods will take the place of continuum methods or not. In continuum methods like finite-element or finite-difference methods, variables such as strain and stress are assumed to vary continuously in space.

But, there are two drawbacks with continuum methods: Firstly, an appropriate stress-strain law or constitutive law for the material may not exist. Secondly, the natural development of cracks and rupture surfaces is not well-handled by continuum approaches (Cundall 2011).

It is suggested that the future trend for numerical modelling in soil and rock may be the replacement of continuum methods by particle methods. These new techniques use assemblies of discrete particles bonded together to represent rock, and unboned to represent soil. This is difficult or even impossible today because of high computational demands. But such applications should be feasible within ten years, and certainly within 20 years.

Developments are expected to be seen in the near future in the areas below;

Data Gathering: (i) Seismic (microseismic, 1D to 4D) (ii) Logging tools (iii) Downhole Measurements

Data Interpretation: (i) Powerful computers to solve for coupled complex simulation (ii) Integration of all data sources in one unique model (iii) Quantitative Seismic Interpretation Techniques (AVO)

Better Understanding: (i) Geomechanical specialists (ii) Geoscientists (iii) Reservoir Engineers (iv) Drilling and completions engineers

CONCLUSION

Up to here, we tried to summarize the state of art with the recent studies and some accepted workflows from the industry. But it is for sure that we still have many things to enhance. We are discovering that geomechanics is at its early age in petroleum engineering, despite the main activity of petroleum industry since decades is creating boreholes and changing stresses. For unconventionals it is particularly evident because of multiple complexities like fracturing, strain localization, mechanical anisotropy, etc. Our vision should be to bring together multi-disciplinary insights from geomechanical specialists, geoscientists, reservoir engineers, drilling and completions engineers to address the challenges we are all facing, to help more effectively recognize, predict and avoid costly events throughout our projects.

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