MicroSeismic
Passive Monitoring, Active Listening

Geomechanical Principles for Unconventional Reservoirs

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About MicroSeismic, Inc.

Since 2003, MicroSeismic, Inc. has quickly grown to become the technology leader in surface microseismic monitoring across the world. Our services help customers optimize well completions, plan field development through well spacing and orientation, as well as improve estimates of reserves and ultimate recovery. With more than 15,000 stages monitored, 800 square miles of permanently deployed BuriedArray™ microseismic data acquisition arrays, and work spanning 12 countries, MicroSeismic, Inc. has both pioneered and proven the successful application of surface microseismic monitoring across the world. From hydraulic fracture mapping to seismicity and reservoir monitoring, our passive monitoring services and advanced analysis products are unmatched in the marketplace.

Introduction

This document is intended to give the reader a basic knowledge of the principles behind the generation of detectable microseismic energy during hydraulic fracturing and its relationship to reservoir properties. Appendix A provides a suggested reading list for further investigation into any of the topics addressed.

The paper is divided into five main sections. The first introduces important concepts in rock mechanics, including topics such as stress, strain, and rock strength. Taking these principles and applying them to the real earth results in an area of study called geomechanics, which is the focus of the second section. The basic principles of earthquakes and faulting are included in that section. In the third section we look at applying geomechanics to understand the processes occurring in the earth during hydraulic fracture stimulation. The fourth section discusses microseismicity, particularly microseismic event generation. The fifth, and final, section discusses the potential correlation of reservoir properties to microseismic events. The appendices provide references and suggested reading, a list of symbols and nomenclature used in the paper, and an overview of shale properties.

While going through this document and reading about theories, constitutive laws, fracture mechanics, models and so forth, the reader should always keep in mind that these are all tools that we as geoscientists and engineers use to try to describe the behavior of the earth. Inherent in every single one of them is a host of assumptions that rarely hold true in actual rock. Rocks are notoriously non-uniform (*heterogeneous*), and real data will always deviate from what we expect based on our theories and models. That said, the current state of knowledge provides the best chance we have for quantifying and predicting real-world geology. These concepts give us immense insight, so it is important to be familiar with them.

1. Principles of Rock Mechanics – Rock as a Material

Stress, Strain and Moduli

Stress (usually denoted as S or σ; τ for shear stress components) is a tensor that describes the forces acting on all possible surfaces passing through a given point, as illustrated in Figure 1. In the hydrocarbon industry, units for stress are usually pounds per square inch (psi) or some variation of Pascals (megaPascals [MPa], gigaPascals [GPa], etc.). The nine components of the stress tensor can be resolved into three orthogonal, principal stresses where $S_1 \geq S_2 \geq S_3$, and there are no resolved shear stresses.

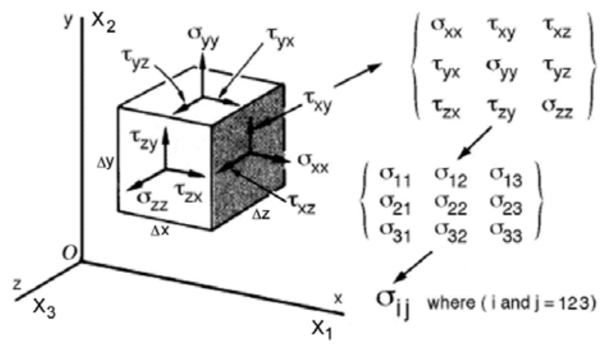

Figure 1. Representation of the components of the stress tensor. The top matrix represents stress in Cartesian coordinate system. The bottom matrix is a mathematical representation. The "point" represented by the block has zero shear stresses (σ_{ij} where $i \neq j$) when oriented along the three principal stresses (σ_{ij} where i = j). (http://www2.esm.vt.edu/~rkriz/classes/ESM5344/ESM5344_NoteBook/crcd/lectures/images/fig7.gif)

Strain is a material's deformation (not failure) in response to stress (Figure 2). That deformation is described through the use of an appropriate *constitutive law*, which is an equation that quantifies the exact relationship between stress and strain using parameters called *moduli*. For example, in a linear elastic material, strain is linearly related to stress and is totally recoverable once the stress is no longer applied. The constitutive equation for linear elasticity can be expressed as:

$$S_{ij} = \lambda\delta_{ij}\varepsilon_{00} + 2G\varepsilon_{ij},$$

where ε is strain, λ is called the *Lamé constant* (or *Lamé parameter*, singular; *Lambda* or *incompressibility* in the seismic world), and G is called the *shear modulus* (*modulus of rigidity*, or just *rigidity*; S, μ or *Mu*), and δ_{ij} is the Kronecker delta, which equals 0 if $i \neq j$ and 1 if i=j. The Lamé constant and shear modulus are together often referred to as "Lamé parameters," plural. The *bulk modulus* (or *incompressibility* in rock mechanics), K (or sometimes B), is used to relate volumetric strain to mean stress and is equal to:

$$\lambda+2/3G$$

The reciprocal of the bulk modulus, 1/K, is called *bulk compressibility* (β). Other important elastic moduli are *Young's modulus* (or *modulus of elasticity*, also referred to as *stiffness*, usually denoted as E), which is the ratio of applied stress to resulting strain in the same direction, and *Poisson's ratio* (usually ν, or *Nu*), which is the ratio of lateral expansion to axial strain. Shear modulus, Young's modulus and bulk modulus all have units of pressure (or stress). Elastic moduli are all related to each other as shown in Table 1, and thus the constitutive equations can be constructed using various combinations of them.

A note on terms and notation: At this point you may have noticed a certain lack of consistency in symbols and terminology. For instance, above we mentioned that S is sometimes used to denote the shear modulus, but we also use S for stress (usually with subscripts denoting directionality or relative magnitude). As you will see later μ is also used for the coefficient of friction. Unfortunately, nomenclature and notation tends to be unique to individual fields like rock mechanics versus seismic.

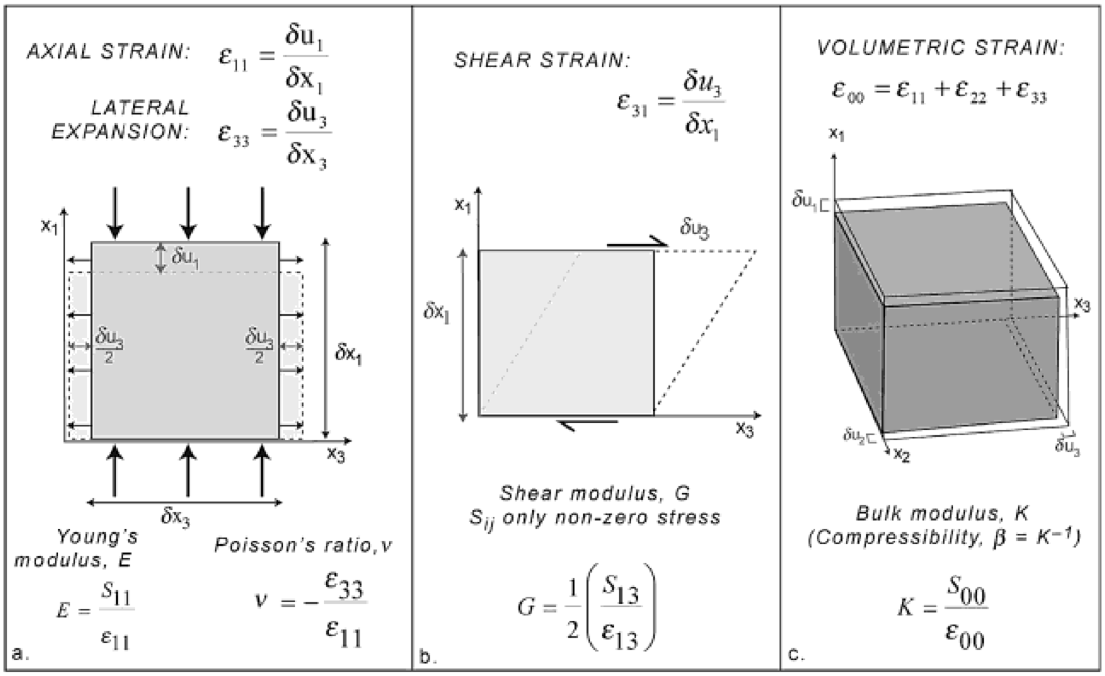

Figure 2. Schematic illustration of the relationships between stress, strain and the physical meaning of elastic moduli in different types of idealized deformation measurements. *Source: Zoback, 2010*

bulk modulus K	Young's modulus E	Lamé parameter λ	Poisson's ratio ν	Shear modulus G	"M" modulus M
$\lambda + \frac{2G}{3}$	$G\frac{3\lambda + 2G}{\lambda + G}$	–	$\frac{\lambda}{2(\lambda + G)}$	–	$\lambda + 2G$
–	$9K\frac{K - \lambda}{3K - \lambda}$	–	$\frac{\lambda}{3K - \lambda}$	$3\frac{K - \lambda}{2}$	$3K - 2\lambda$
–	$\frac{9K - G}{3K - G}$	$K - \frac{2G}{3}$	$\frac{3K - 2G}{2(3K + G)}$	–	$K + 4\frac{G}{3}$
$\frac{\varepsilon G}{3(3G - E)}$	–	$G\frac{E - 2G}{3G - E}$	$\frac{E}{2G} - 1$	–	$G\frac{4G - E}{3G - E}$
–	–	$3K\frac{3K - E}{9K - E}$	$\frac{3K - E}{6K}$	$\frac{3KE}{9K - E}$	$3K\frac{3K + E}{9K - E}$
$\lambda\frac{1 + \nu}{3\nu}$	$\lambda\frac{(1 + \nu)(1 - \nu)}{\nu}$	–	–	$\lambda\frac{1 - 2\nu}{2\nu}$	$\lambda\frac{1 - \nu}{\nu}$
$G\frac{2(1 + \nu)}{3(1 - 2\nu)}$	$2G(1 + \nu)$	$G\frac{2\nu}{1 - 2\nu}$	–	–	$G\frac{2 - 2\nu}{1 - 2\nu}$
–	$3K(1 - 2\nu)$	$3K\frac{\nu}{1 + \nu}$	–	$3K\frac{1 - 2\nu}{2 + 2\nu}$	$3K\frac{1 - \nu}{1 + \nu}$
$\frac{E}{3(1 - 2\nu)}$	–	$\frac{E\nu}{(1 + \nu)(1 - 2\nu)}$	–	$\frac{E}{2 + 2\nu}$	$\frac{E(1 - \nu)}{(1 + \nu)(1 - 2\nu)}$

Table 1. Relationships between elastic moduli in an isotropic material. (The M modulus is a mathematical convenience for considering relative rock stiffness derived directly from seismic velocities) *Source: Zoback, 2010*

There are many other constitutive laws that account for such things as time-dependence (viscoelasticity), pore fluids (poroelasticity), temperature-dependence (thermo-elasticity), material damage (plasticity) and various combinations of these. The key is to remember the basic concept and, when working with stress and strain, make sure to use the right equations with the right parameters for the application.

Rock Strength and Failure

At some point a rock is stressed, either in *compression* or *tension*, beyond its limits (strength) and breaks. We can learn a lot from rocks when stressing them until they break, including their strength and moduli, and thus people have spent entire careers breaking samples (usually cores) of rocks in labs. Various *failure criteria* have been developed using the results of these tests and can be applied to predicting rock failure.

There are a variety of procedures for conducting so-called "destructive" core tests, and the type of test can depend on the relative magnitudes of the stresses applied to the sample (see Figure 3), the number of time the same sample is tested or other operational parameters. For example, in a uniaxial compressive test a core is stressed axially only, with the other two stresses equal to zero. This test yields the *unconfined compressive strength* (UCS or C_o) of the rock. However, as this easily allows for possible

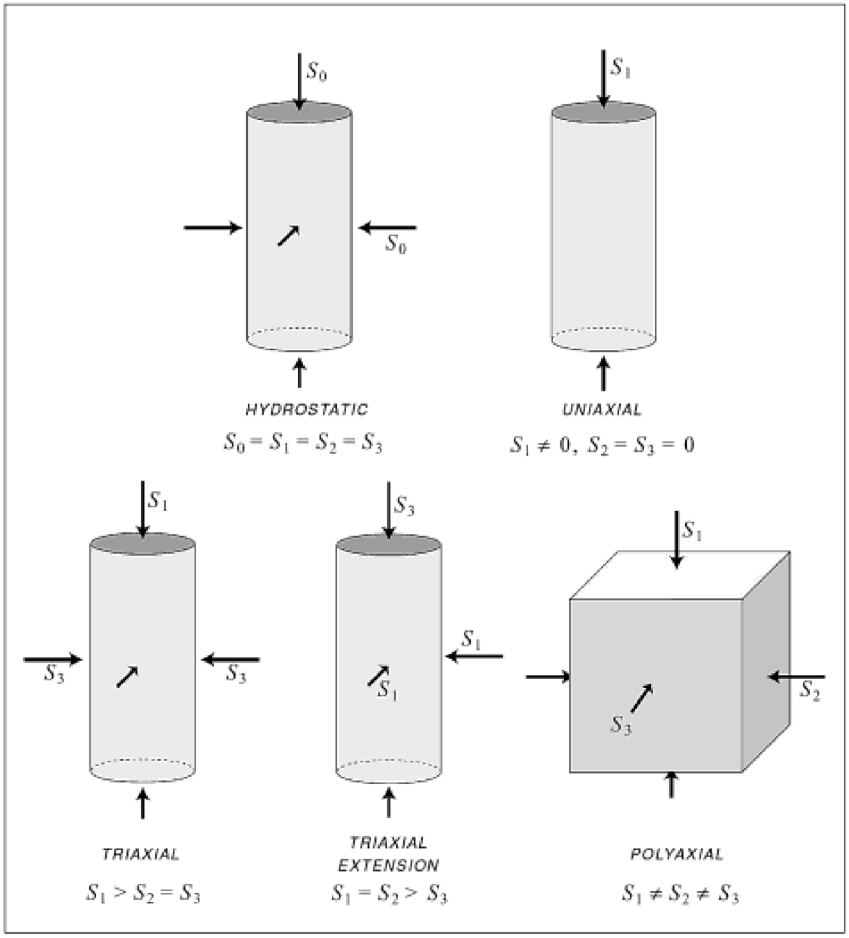

Figure 3. The most common types of rock mechanics tests and relative values of the stresses applied. *Source: Zoback, 2010*

sample splitting or slip on weak planes, the more preferred test for UCS is the (inappropriately named) triaxial compression test where the radial stress (which is uniform) is made to simulate in situ conditions (that is, *confining stress* is applied) and the core is loaded axially until it fails. Since strength is defined as the *differential stress* (axial minus confining) at which failure occurs, units of strength are the same as for stress (psi, MPa, etc.). There are also true triaxial tests, referred to as *polyaxial*, that can be performed on cube-shaped samples where all three stresses can be controlled, but these are rarely done.

During a test, axial strain is recorded as a function of axial stress, as illustrated in Figure 4. More *brittle* rock shows little strain until it breaks and is closer to being linearly elastic. *More ductile* (or inelastic, or *plastic*) behavior, however, means that the sample is deforming in a non-elastic, non-recoverable way before breaking. We will discuss brittleness and ductility in more detail in Section 3.

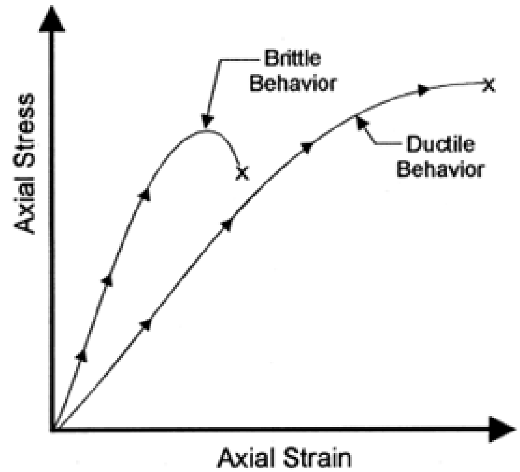

Figure 4. Schematic of brittle versus ductile rock behavior.

Data from a series of core tests are often presented using a *Mohr diagram*. The axes on a Mohr diagram are normal stress (σ_n, on the x axis) and shear stress (τ, on the y axis). After performing a series of tests on samples of the same rock under different confining pressures, the stresses on the sample at the time of failure are used as endpoints for semi-circles on the Mohr diagram. A curve called the *failure envelope* (or *strength envelope*, or *Mohr envelope*) is then drawn such that it is tangent to all of the circles as shown in Figure 5b. Drawing a circle with a minimum normal stress of zero and tangent to the failure envelope gives us the unconfined compressive strength, *cohesion* (or *cohesive strength*, S_o or C, the y intercept) and the tensile strength (negative x intercept) of the rock. Frequently the failure envelope is approximated as a straight line (*linearized Mohr envelope*, or *Mohr-Coulomb failure*), as shown in Figure 5c. The slope of the linearized envelope gives us the *coefficient of internal friction* (μ_i). ϕ (or β) is the angle of internal friction and is the inverse tangent of μ_i.

There are dozens of specialized tests for acquiring static properties such as rock tensile strength and Young's modulus (e.g. Brazilian test, bending test) or shear modulus (torsion test). There are also a few non-destructive core tests that can yield insight into rock properties such as the Brinell hardness test or the scratch test, each of which measures hardness along a core and then correlates it to rock strength.

Values obtained from core tests are only valid if the sample meets the correct size and condition parameters, the proper test was done for the property of interest, and the sample behaved in the way expected.

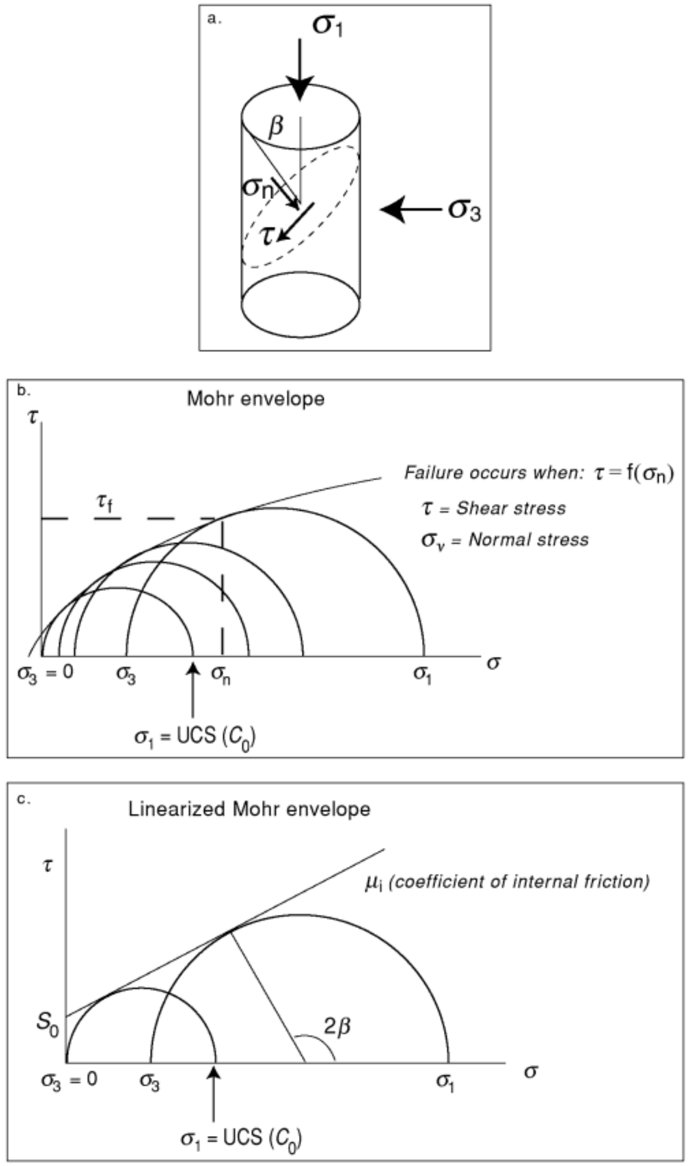

Figure 5. a) Diagram of a sample after a triaxial strength test. b) The Mohr envelope determined from several tests performed at different confining pressures. c) The linearized Mohr envelop.
Source: Zoback, 2010

Rock Properties

We mentioned rock properties several times already, introducing terms such as strength, moduli, hardness, etc. We also explained, in general, why they are important and how to measure them in the lab. There remains, however, some needed discussion about the properties themselves and how they can vary not only with rock type, but also with measurement method, the scale at which they are measured and even the direction in which they are measured.

Rock moduli have both static and dynamic values. Deformational tests give us the *static moduli*, whereas *dynamic moduli* are calculated from sonic wave velocity and rock density. The two values, both of which can be measured in the lab, may be significantly different, so it is important to specify which one is being reported and to know which one to use for various applications. Static Young's modulus, e.g., is usually lower than dynamic Young's modulus, and to further complicate things the ratio of static to dynamic Young's modulus is stress-dependent. As fluid saturation is often the primary contributor to the difference between static and dynamic moduli, static moduli are sometimes referred to as "drained" and dynamic as "undrained"; however, this nomenclature is not recommended.

Since moduli can be calculated from sonic wave velocity and rock density (two of the most commonly recorded properties in well logs), it is common practice to calculate moduli from logs. Dozens of empirical relations have also been developed to determine rock strength, internal friction coefficient and *Biot's constant* (both vertical and horizontal) from logs. Most of these, however, were developed for a specific geographical location. Best practice is to calibrate log-based calculations to lab tests on core taken from the logged interval of the same well. Great caution should be applied when using uncalibrated log-based values, as it has been shown that the same equation used in two closely spaced wells can work great in one well and not at all in the other. Some rock properties can also be determined from seismic data.

Rock properties may vary with the direction in which they are measured. This phenomenon is called *anisotropy*. Anisotropy may be the result of mineralogy and inherent rock fabric such as banding, layering or bedding. It can also result from aligned fractures, anisotropic stresses or, as is usually the case, a combination of these factors.

Since any measurement of a rock property is essentially averaged over the volume sampled, one can imagine how the resulting measurement can vary with scale. Testing a core that is just a few centimeters in length is never going to accurately represent a several hundred meter thick formation that is sampled when we measure in the field using seismic data, for example. On a very large scale, even tectonic structures such as fractures and faults can affect measurements of rock properties.

Rock Fractures

When intact rock breaks, the individual failure surfaces are called *fractures*. Fracture mechanics in material science is an entire discipline in its own right, and given that rocks are imperfect materials, rock fracture mechanics gets even more complicated. Here we will provide just a brief overview of some of its main concepts. Readers are encouraged to explore the topic further using the references provided in Appendix A.

As mentioned earlier, rocks break in either tension, resulting in *tensile fractures*, or compression, resulting in *shear fractures*. Common nomenclature for describing fracture type uses modes, which are illustrated in Figure 6. In the fracturing of materials, there are three main modes of failure. Mode I fractures, also sometimes called *open* or opening mode* fractures, occur where a fracture opens against the least principal stress acting on the material, meaning the tensile stress in the fracture must exceed the least principle stress (also referred to as *closure stress*). Because rocks have almost zero tensile strength, not a lot of tension is required for a tensile fracture to form in rocks. In fact, in theory the tension needed to create a fracture is about one tenth of a material's Young's modulus. Classic hydraulic fractures, whether natural or induced, are Mode I fractures, as are natural joints and veins. Mode II and III fractures both result from relative movement in shear but differ in the direction of fracture *propagation*, or growth, relative to the applied stress. In Mode II, also called *sliding mode*, the fracture propagates parallel to the maximum stress. In Mode III, also called *tearing mode*, the fracture propagates perpendicular to the maximum stress. All faults are Mode II or Mode III fractures, as will be discussed in the next section. In accordance with the heterogeneity of nature, mixed Mode II/Mode III fractures can be found frequently in the earth. In earth materials we can add two more modes to the picture. Mode IV, or *closing mode*, fractures, form from dissolution of rock material under very high compressive stress. Mode V fractures, or *deformation bands*, form from the displacement of material during shear. Modes IV and V are not universally considered rigorous fracture types but are good way of classifying particular geologic features.

*The term “open fractures” can be confusing because it is frequently used to describe things other than Mode I fractures. In analysis of an electrical image log, for example, an open fracture usually means one that appears to have a large aperture in the wellbore image and/or because of its electrical signature is interpreted to mean it is not filled. In regard to fluid flow through fractures, hydraulically conductive fractures are often referred to as “open,” because they are open to flow.

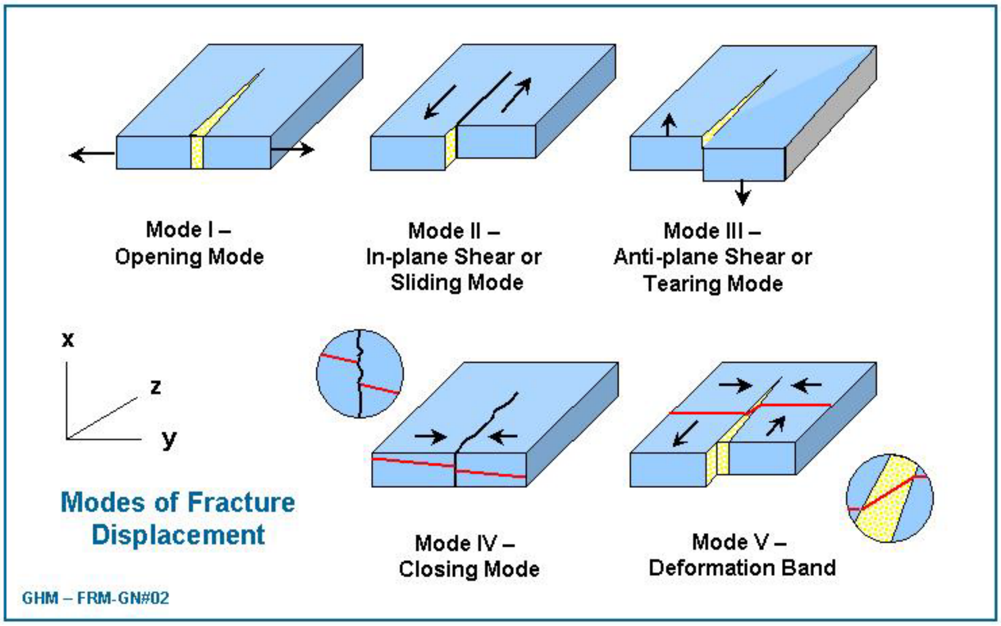

Figure 6. Fracture displacement modes. *Source: www.makel.org*

Fracture geometry is usually described by fracture height, length and width (or *aperture*). Fracture propagation is an increase in fracture length and height. An increase in fracture aperture due to increased fluid pressure (natural or as part of operations such as hydraulic fracturing) is called *dilation*. The mechanics of fracture initiation and growth are too complex to address in this paper, but it is important to know that our general understanding of rock fractures tells us that fractures initiate due to the stress concentration that forms at inhomogeneities or pre-existing micro-cracks in the rock (often referred to as *Griffith cracks* after A. A. Griffith, who laid some of the fundamental principles of fracture mechanics in the early 1900s), and fracture propagation is a function of the stress concentration that forms at the fracture tip.

In addition to fracture type and geometry we might also be concerned with fracture spacing, spatial frequency (or density), surface morphology, fill, permeability and connectivity.

2. Geomechanics and Faulting – Bringing Geology Back into the Picture

In Situ Stress, Pore Pressure and Faulting

In the earth we commonly think of the three principal stresses as being a vertical stress (or overburden), S_V, and two orthogonal horizontal stresses – the minimum horizontal stress, S_{hmin}, and the maximum horizontal stress, S_{Hmax}. While commonly the case, the vertical stress is not always a principal stress, and it is important to remember that. In an area very close to a large mountain range, for example, the stress field is likely to be inclined towards that significant topographic feature. Isostatic rebound from, e.g., deglaciation, is another cause of stress field inclination.

Below a few tens of meters depth, all three principal earth stresses (also called *in situ stresses*) are compressive and generally increase in magnitude with depth. Opposing these stresses in all directions is the fluid pressure, or *pore pressure* (or *formation pressure*, P_p or P_o, or *reservoir pressure*, P_R), in fluid-saturated rock. Earth stresses are often expressed as *effective stresses*, which equal the total stresses minus pore pressure and are important in many geomechanics calculations. The *effective stress ratio* is the ratio of one of the horizontal stresses to the effective vertical stress and is a useful way of looking at stress as a function of depth.

In situ stress states are usually divided into three types based on the relative magnitudes of the three principal stresses. These stress states, illustrated in Figure 7, are called *faulting regimes* and are based on *Anderson faulting theory*. If the vertical stress is the maximum stress, the regime is *normal faulting*. If the vertical stress is the intermediate stress, the regime is *strike-slip faulting*. If the vertical stress is the least stress, then the regime is *reverse faulting*.

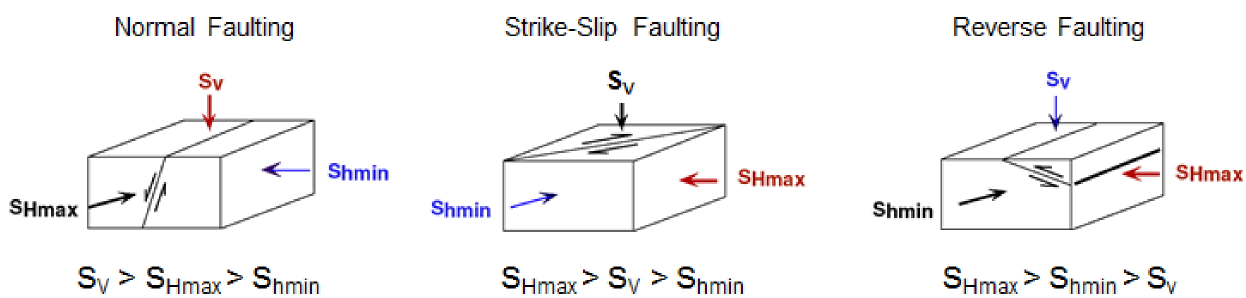

Figure 7. The three faulting regimes and relative stress magnitudes for them.

An excellent place to look at stress regimes as a function of geography is the World Stress Map (see Appendix A). It also illustrates how in some parts of the world, stress varies significantly over short distances. We call this *stress heterogeneity*, and we see it at all scales from continents to a single wellbore. This is because stresses can be affected by geologic features at all scales, from plate boundaries to grain boundaries.

Quantifying Pore Pressure and Stress

Downhole tests can be performed to determine pore pressure and least principal stress. Older-style *pressure tests* such as repeat formation tests (RFTs) and drill-stem tests (DSTs) test purely for pore pressure. Later tools actually collect a fluid sample as well as measuring pore pressure. Both methods involve letting formation fluid pressure up the measuring device. In contrast, *minifracs/Diagnostic Fracture Injectivity Tests (DFIT's)* (also called pre-frac, injection fall-off, data-frac, microfrac) are basically short, small volume hydraulic fracture jobs in which a fracture is initiated, injection stops and pressure is monitored for several hours to days during and after the fracture closes. The pressure data from pumping is interpreted for least principal stress, and the post-injection data are interpreted for pore pressure and flow regime. Because traditional methods like DSTs do not work well in low permeability formations, the minifrac has become the test of choice in most tight sand and shale plays and is usually performed immediately prior to a real hydraulic fracture job in the toe stage of a well. This has brought on a flurry of research into how the data from these tests should be interpreted. The difficulty is that they can be affected by induced fracture complexity and near-wellbore tortuosity as well as interaction with pre-existing natural fractures.

From Wellbore Failure

When a well is drilled into the earth, a stress concentration develops around it. This stress concentration is described by the *Kirsch equations*, which give us the three principal stresses in a cylindrical coordinate system: the *radial stress*, *tangential stress* (or *hoop stress*) and *axial stress*. These stresses are a function of not only the in situ stress magnitudes, but also the difference between the pore pressure in the rock and the fluid pressure in the well, the angle around the well with respect to the in situ stress directions, the radius of the well, radial distance from the center of the well and the difference in temperature between the well fluid and the rock. The stress concentration diminishes fairly rapidly as you move away from the wellbore and is usually insignificant by a distance of about two borehole radii. By setting distance equal to the radius of the well, the equations give us the stress concentration right at the wellbore wall. If the hoop stress exceeds the strength of the rock, features called *breakouts* form at the angles of maximum hoop stress. If the well goes into tension at the angle of minimum hoop stress, *tensile cracks* form along the wellbore wall (these do not propagate into the formation). Breakouts and tensile cracks are collectively called *wellbore failure*. The angles at which failure occurs depend on the orientation of the wellbore with respect to the in situ stresses. A vertical well drilled in a location where the overburden in a principal stress will have maximum compressive hoop stress in the direction of S_{hmin} and minimum hoop stress in the direction of S_{Hmax}. In deviated wells, these angles will rotate around the well and the directions of the horizontal stresses need to be determined through coordinate transformation.

By using the Kirsch equations to calculate borehole wall stresses, and knowing something about rock properties and applying the right failure criterion, we can predict if breakouts or tensile fractures will occur. Alternatively, if we know that we do or do not have breakouts and/or tensile fractures in a given well, and we know the well's geometry and orientation, the properties of the fluid that was in the well when the failure occurred, rock properties and pore pressure then we can we back out the borehole wall stresses and thus the in situ stresses.

The key to a good geomechanical analysis is having the right data. To assess wellbore failure, image logs are by far the best option. Caliper comes in at a far second, and drilling experience (hole cleaning issues, cavings coming over the shakers, etc.) third. Rock mechanical properties, as we have discussed, are usually calculated from logs but are best calibrated with lab tests, which are unfortunately not often done, particularly for mechanical properties; porosity, permeability, oil saturation and other properties related to fluid flow in the reservoir are more common. Tests can be performed downhole for both pore pressure and least principal stress, and overburden can be calculated from density logs, so often the only unconstrained parameter, the one that needs to be modeled, is maximum horizontal stress magnitude.

From Logs or Cores

Various methods have been derived over the years to calculate pore pressure and horizontal stresses from overburden and Poisson's ratio, with the application being to determine these from log or seismic data. The original method for predicting pore pressure in the way (*Eaton's method*), was developed for thick, relatively low stress sedimentary basins, such as the Gulf of Mexico, where compaction is really the only pressure generating mechanism. The original method for calculating stress in this way used the *bilateral constraint* (or *uniaxial strain condition/assumption*) and had no tectonic component – that is, it assumed all horizontal stress was due to the overburden, which is an invalid assumption in many parts of the world. Attempts have been made since to add additional terms that take into account tectonic forces and other factors, but to date there is no more reliable way to quantify stress than to look at what actually happened in a well in response to in situ conditions.

There are also methods that try to determine in situ stress from cores, but these are generally considered less reliable than other methods for determining stresses at depth. They may be more valid for shallow applications such as mining.

Natural Fractures and Faults

Natural fractures can be divided into two categories, tectonic and non-tectonic. Tectonic fractures, related to folding and faulting, tend to be variably oriented and regionally inconsistent and may be related to a past in situ stress environment, not the current day stress state. Non-tectonic fractures include fractures, joints or weak planes related to rock properties. They are often regionally consistent and unrelated to local structure. As fluid travels through these natural, high-permeability pathways after they are formed, mineralization often occurs leading to *cementation* of the fracture, commonly by calcite. Sometimes cemented fractures are called *healed*.

Regardless of how they originally formed, most existing natural fractures at any significant depth in the earth are shear fractures. Opening mode fractures are rare in the earth because of the high compressive stress that must be overcome for tensile conditions to exist. Fractures may form in tension induced by active tectonic deformation, but tensile stresses cannot be maintained for significant lengths of time because of the low tensile strength of rock.

The orientation of a plane of weakness with respect to the in situ stresses will determine the amount of shear and normal stress that acts on it. The orientation of approximately planar surfaces in the earth such as fractures, faults (fault segments anyway) and contacts between formations are described by their *strike* and *dip*. The strike is a geographic orientation given by the intersection of the planar surface with the horizontal plane. The dip is measured 90° to strike and is the angle downward to the planar surface from horizontal. So a fault with a strike of 45° (measured clockwise from North, which might also be expressed as N45°E) and a dip of 90° is a vertical fracture oriented to the northeast. If it were dipping 10°, then that would mean it is dipping shallowly towards the southeast. In order to be able to graphically illustrate strike and dip, we can represent planar surfaces on plots called stereonets. We can show either the plane itself or the pole to the plane, which is a line perpendicular to the plane. An example can be found in Figure 8.

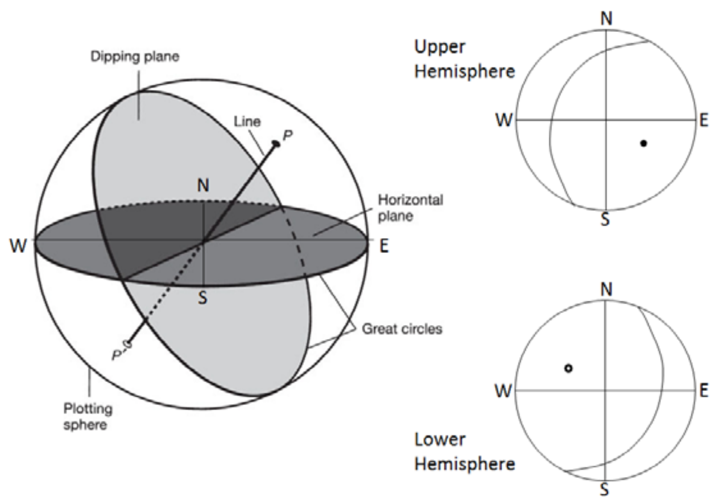

Figure 8. How planar features and their poles are represented on 2-D stereonet plots.

Slip on Fractures and Faults

If we know the orientation and magnitudes of the in situ stresses, we use the orientation of the fracture or fault plane to calculate the shear and normal stresses acting on it. We can then plot a point for that fracture or fault on a Mohr diagram, as shown in Figure 9. In this case, the bounds of the semi-circle are the actual maximum and minimum in situ stress. Intact rock cohesion, discussed earlier, is usually higher than fracture cohesion; in fact, fracture cohesion is often assumed to be 0, as shown in the figure. This means that it is easier to cause slip on a pre-existing plane of weakness (which can include bedding) than to break intact rock. The slope of the fracture failure envelope is known as the *coefficient of sliding friction* (μ) and describes the shear strength of a fracture under a non-zero normal stress. For most rocks rocks μ falls in the range of 0.6 to 1.

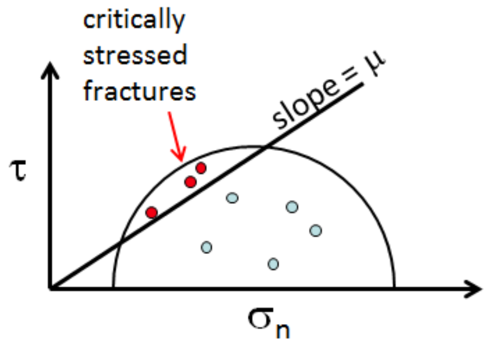

Figure 9. Mohr diagram showing the failure envelope for slip on pre-existing natural fractures.

If a fracture plots above the fracture failure envelope, then by definition, failure is occurring. Failure isn't constantly occurring, of course, but the fracture is barely stable and will slip given small changes in stress or pressure. We call these *critically stressed*, or optimally oriented for shear. In practice, it has been found that fractures that are critically stressed are most likely to be permeable and have fluid flowing through them. This is most likely because the plane has slipped recently in the geologic past and is not cemented (healed), allowing for fluid flow.

An important thing to note is that when we plot a point on a Mohr diagram we are plotting the effective normal stress, which as described earlier is the total normal stress minus the pore pressure. This means that if the fluid pressure is increased, effective stress will decrease, and the Mohr circle will slide to the left. This mechanism can serve to "turn on" fractures – that is, make critically stressed fractures out of fractures that under normal conditions were not critically stressed. This is also the mechanism behind most cases of human-induced seismicity.

Using the concept of critically stressed fractures, we can predict at what excess pressure a fracture at a given orientation will become critically stressed. We can also predict the orientations of the fractures that will become critically stressed first, under the lowest excess pressure.

Earthquakes and Seismicity

Earthquakes are shear slip along faults. Even in areas considered to be extensional – that is, a normal faulting environment – the slip on the fault is shear movement as one block of rock slides against the other. We describe earthquakes in terms of their location (*epicenter* and *focal depth, or hypocenter*), size (*magnitude* or *moment*) and their geometry including the relative motion of the bodies of rock on either side of the fault. Earthquake magnitude is often based on seismic wave amplitude and can be calculated in different ways from different types of waves making it a somewhat vague term. Earthquake moment is better related to the actual physics of the earthquake itself and is a more consistent value with which to quantify and compare events. For this reason, *moment magnitude*, Mw, is often used as a measure of size.

Since earthquakes do not always show displacement on the surface of the earth, we have to describe them from remote measurements of seismic waves. Earthquakes generate several types of waves that move through the earth. The two main waves are *compressional*, or *P-waves*, and move sort of like a slinky with forward and back "pushing" of material in the direction the wave travels (*propagates*). *Shear waves*, or *S-waves*, create particle movement at 90° to the direction the wave travels. Of great interest in many applications is the velocities at which these waves travel. P-wave velocity, V_P, is faster than shear wave velocity, V_S. In addition, P-waves can propagate through fluid, and S-waves cannot.

Source mechanisms

A *source mechanism* (a.k.a. *focal mechanism* or *fault plane solution*) is the characterization of the instantaneous deformation of the rock at the location of the event, considered as a point source of failure. In other words, it describes how the rock broke. We represent this using the *moment tensor*. The moment tensor can be divided into different components: Isotropic (ISO), *Double-Couple* and Compensated Linear Vector Dipole (CLVD), as shown in Figure 10. As mentioned above, movement along faults is primarily shear slip. These types of events can be described as double-couple sources; they have low or zero ISO and CLVD components. Double couple source mechanisms are represented graphically with so-called "beachball" diagrams. Beachball diagrams for different fault types are shown in Figure 11. A beachball diagram with a colored center shows reverse dip-slip, a white center shows normal dip-slip, and when the circle is divided into quadrants, it is strike-slip. Oblique-slip is a combination of strike-slip and dip-slip.

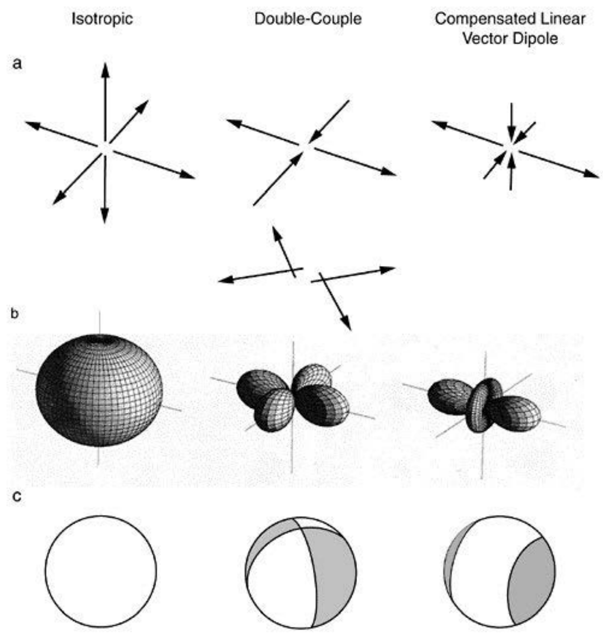

Figure 10. Source mechanisms for isotropic, double-couple and CLVD deformation. (Modified from Julian, Miller and Foulger, 1998)

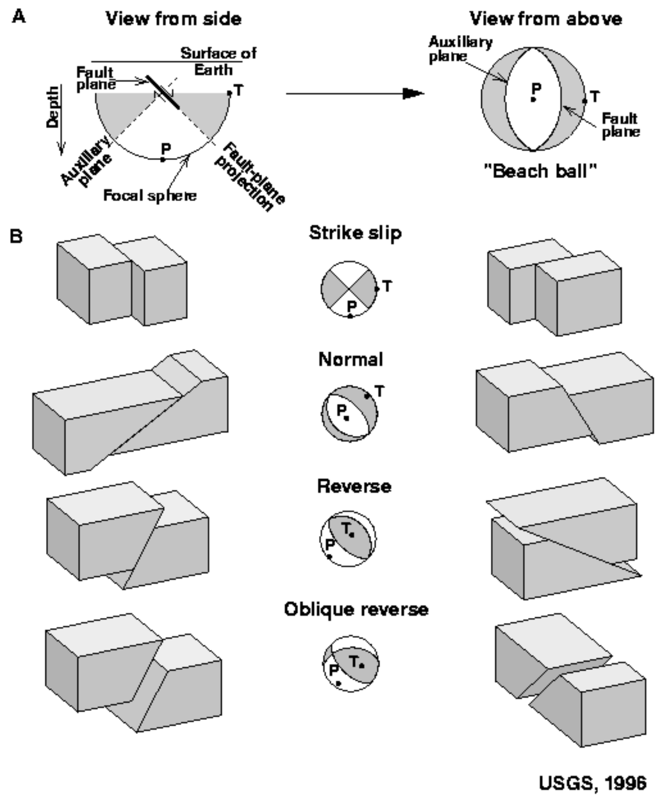

Figure 11. Schematic diagram of a focal mechanism for different fault types.
(http://serc.carleton.edu/files/NAGTWorkshops/structure04/Focal_mechanism_primer.pdf)

By measuring seismic waves either on the surface or using sensors in boreholes, we can create earthquake source mechanisms that allow us to better understand a given event. On the beachball diagram, the boundaries between the dark and light quadrants represent the fault plane and auxiliary plane. The solution to the earthquake is non-unique; we cannot tell which quadrant boundary represents the actual fault plane unless we have additional information such as a rupture surface or directional trends in seismic (or microseismic) hypocenters.

3. Hydraulic Fracturing – What's Really Going on Underground?

The Hydraulic Fracturing Process

In the hydraulic fracturing process, fluid is pumped into an isolated zone of a wellbore to break down the rock and form a tensile fracture. Pumping continues with the intent of extending the fracture. The idea is to create a) contact between the well and the formation, and b) a permeable pathway for fluids to flow into the well. Because the fracture will try to close as the pressure is decreased, material called *proppant* (natural sand or ceramic material) is often pumped into the fracture to hold it open against the compressive in situ stresses once the job is complete. The exact nature of the job, the geological setting, and the desired fracture parameters will dictate what type of fluids and proppants are used, what pressures the treatment will be pumped at as well as other operational considerations. Usually at the end of the job *flowback* is monitored to determine how much of the *frac fluid* has been recovered. Flowback data can sometimes provide information on reservoir or treatment quality. If flowback is low compared to the amount of fluid pumped, this may imply formation damage during the fracturing or loss into a complex fracture network.

Hydraulic Fracture Growth

In order to plan a hydraulic fracture job, modeling is usually performed to determine the expected fracture and the operating parameters needed to achieve it. Most, but not all, conventional hydraulic fracture models assume linear-elastic rock behavior, Mode I tensile failure as the only failure mechanism, a single, planar fracture (multiple fracs are modeled individually) and constant stresses, pore pressure and permeability. One of the key inputs into these models is log-based stresses and rock properties. Alternatively or in addition, post-treatment analysis can be conducted although the same models and assumptions are generally applied.

There are a several important factors that are not considered in conventional hydraulic fracture models. First, the borehole stress concentration is often ignored. The fracture will want to propagate in the direction perpendicular to the least principal stress. If the least principal stress is vertical, the fracture is likely to be horizontal. If the least principal stress is horizontal, then the fracture is likely to be vertical. But close to the wellbore the stress concentration creates a different stress state than the far-field stresses, so near the wellbore in an open hole the fracture will initiate and propagate according to the borehole stresses, then it may have to reorient as it propagates away from the well. This is called fracture *tortuosity*. The situation becomes even more complex when the completion is a perforated, cased hole, because perforation orientation needs to be considered as well. These factors may affect the initial *breakdown pressure*, the pressures needed to grow the fracture, and the ability to place proppant. These concepts are illustrated in Figure 12.

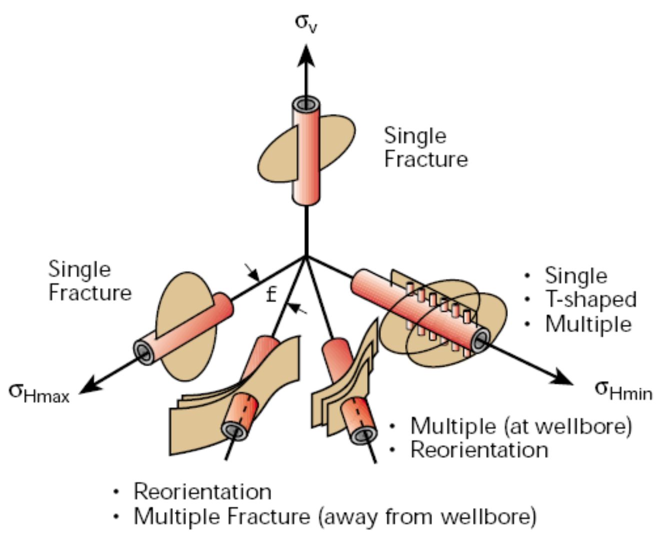

Figure 12. Illustration of various possible (simplified) hydraulic fracture geometries and their dependence on the orientation of the borehole with respect to the principal stresses. *Source: Barree & Associates*

Other complicating factors include inelastic rock deformation, possible shear failure (discussed more below) fracture branching and inhomogeneous stresses, pressures and rock properties. Finally, in multistage fracs, each stage will have an effect on the local stress environment. This stress *interference*, sometimes referred to as *stress shadowing*, can affect later frac stages.

What Makes a Rock "Fracable?"

Despite all the unknowns, experience has shown us that some rocks are easier to fracture than others. Stress contrasts between formations are a critical factor in fracture *containment*. It is, of course, undesirable to propagate a fracture into a non-hydrocarbon-bearing formation because the result is likely formation water (brine) production. Lithologic stress contrasts are not well understood and hard to both quantify and verify. Usually they are assumed to be due to contrasts in stiffness – so a rock with a higher Young's modulus is stiffer, while a rock with a lower Young's modulus is more compliant. In theory, it is harder for a compliant rock to maintain higher differential stresses.

Fracture-ability, or fracability, of a rock is usually described in terms of brittleness (vs. ductility). In discussing brittleness with regard to hydraulic fracturing it is a relative term, and rocks that are both stiff and weak are said to be brittle (Figure 13). Seismic amplitude interpretation for rock properties (*Quantitative Interpretation*, or QI) is being applied to find changes is reservoir properties like Poisson's ratio and Young's modulus to target zones for well completion and hydraulic fracturing. In this application brittleness increases with increasing Young's modulus and decreasing Poisson's ratio.

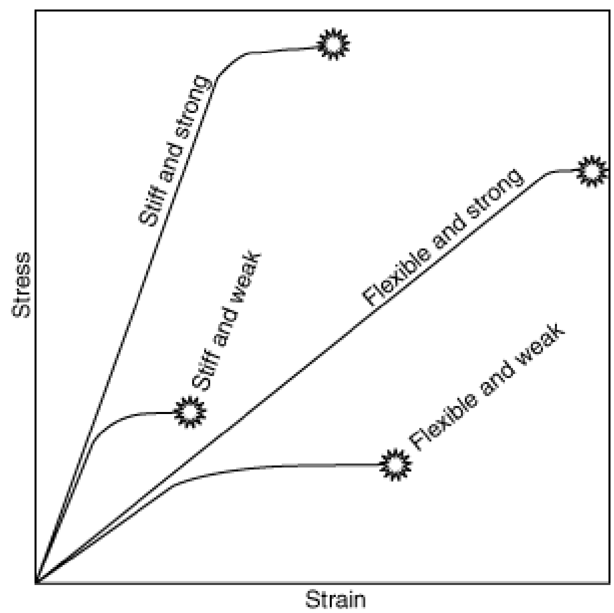

Figure 13. Idealized stress-strain behavior of materials with varying relative properties. *Source: http://www.geol.umd.edu/~jmerck/geol100/lectures/21.html*

Another aspect to how easy or difficult it is to frac are of course the in situ stresses. While there are methods to calculate closure stress (least principal stress) from seismic data using QI by applying the uniaxial strain assumption, as discussed in the Quantifying Stress section this does not accurately account for tectonic stress, unequal horizontal stresses, or the borehole stress concentration.

Hardness is also a consideration in successful hydraulic fracturing because it is related to proppant embedment, and, therefore, loss of conductivity in the fracture.

Hydraulic Fracture Propagation

From a geomechanics perspective, geological reality tells us fracture propagation is incredibly complicated. One can get into the details of grain boundaries, fracture toughness, different models, etc. etc., but the basic fact is we simply don't know exactly how hydrofracs propagate. There isn't even a theory or two that we're trying to decide between. It is an area of much active research.

Models of planar, bi-wing hydraulic fractures determine fracture propagation in opening mode by numerically satisfying conditions of mass conservation, continuity, momentum, elasticity and some pre-determine fracture propagation criteria (fracture toughness, or critical stress concentration at the fracture tip). Factors affecting fracture propagation in these solutions include fracture geometry, fluid rates, fracture characteristics (e.g. wall roughness), and others.

Micro-scale opening or micro-scale shear can occur at the crack tip in mixed mode loading of the fracture, which serves to propagate the fracture, as in Figure 14. Depending on the actual in situ stress magnitudes and orientations, one or the other could dominate.

Field experience, however, including microseismic monitoring, and research over the past 15 years or so suggests that in most cases we do not create a single, planar bi-wing fracture during hydraulic fracturing. Complex induced fracture networks can and do form, sometimes in part through interaction with pre-existing natural fractures in both shearing and opening mode failure. Fracturing of shales can be especially challenging, because the abundance of clay minerals in shales can cause them to fail ductiley, causing distributed deformation rather than individual fractures.

The fracture tip stress concentration, and thus fracture propagation, is highly affected by discontinuities, changes in material properties, and other deviations from a perfectly homogeneous, isotropic material. Considering how heterogeneous actual rock is, from grain boundaries and microcracks to large-scale lithologic contacts and faults, these material science-based models probably don't represent reality very well. In different rocks and geological settings, different assumptions will hold and different physical mechanisms will dominate, and failure is probably mixed-mode in most cases. Figure 14 illustrates some possible mixed mode mechanisms for fracture propagation.

The best understanding we have of complex hydraulic fracture growth comes from computer simulations and lab experiments. Some of the phenomena that have been attributed to the creation of these fracture networks include pressure-induced slip on frictionally weak natural shear fractures, diversion of the hydraulic fracture by natural fractures, stress-induced opening of previously healed natural fractures and the creation of new fractures that connect the hydraulic fracture to natural fractures. Unfortunately nobody currently knows to what extent any of these, or other, processes are involved. The answer is likely to be complicated and dependent on lithology, in situ differential stress, natural fracture frequency and geometry, and more.

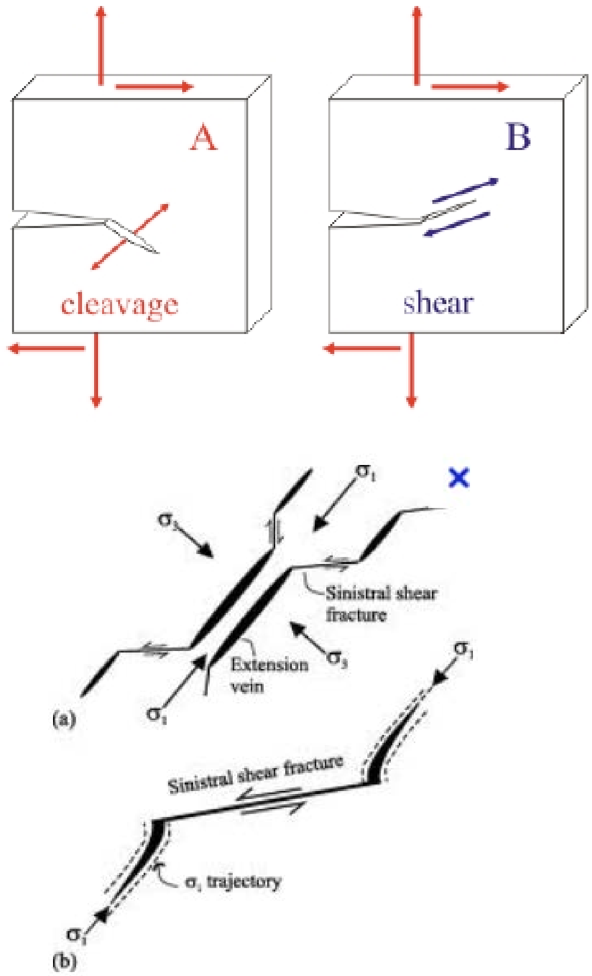

Figure 14. Potential mechanisms for mixed mode fracture propagation. (top - http://www.kokch.kts.ru/me/t2/SIA_2_Fracture_Mechanics.pdf; bottom - http://emg.geoscienceworld.org/content/13/1-4/129/F9.expansion.html)

4. Generation of Detectable Microseismic Events

Earthquakes (events that are ML 0 and greater) are almost exclusively large shear events, which generate P and S waves that can be detected at great distances. Earthquake detection networks typically use large, low frequency geophones, individually spaced 10's to 100's of miles apart to detect the emitted energy, which has been attenuated of all but the low frequencies. Microseismic events (smaller than Magnitude 0) recorded during hydraulic fracturing are essentially micro-earthquakes, often generated by the shear movement of fracture planes. As with larger events, the seismic energy generated is broadband but of much lower amplitude. The rapid attenuation of the higher frequencies requires the geophones to be close to the source of the event when using P/S wave first break picking techniques, or a large aperture, high geophone count (high fold) surface/near surface array when using PSET-type beam forming applications.

It remains unclear whether detectable microseismic events are initiated in newly failing rock or induced slip on pre-existing fractures due to pore pressure increases or changes in the surrounding stress field. It is generally accepted that pure tensile opening during hydraulic stimulation does not produce acoustic energy of sufficient amplitude and frequency content to be detectable, implying the actual hydraulically induced fracture is not being monitored if Mode I is its only failure and propagation mechanism.

How a hydraulic fracture initiates and propagates is not actually known. Is there a very low volume crack that moves in shear first when the mechanical strength of the rock is exceeded and then dilates in direction of minimum horizontal stress as fluid is pumped in? Or is the first motion a volume producing dilation with little shear movement? Are we monitoring crack tip propagation, and/or the reactivation of existing fractures, and/or the reactivation of conjugate natural fractures due to leak-off? We currently do not have concrete answers to these questions.

Recent laboratory research suggests that some of the shear failure in shale reservoirs happens too slowly to generate a seismic signature. Long-period-long-duration (LPLD) events appear to occur on pre-existing natural fractures that are not critically stressed in the current in-situ stress state because slip cannot occur faster than the excess fluid pressure from the frac job can move through the fracture. If correct, this implies that conventional microseismic processing might largely miss these events and thus provides only a partial picture of the deformation occurring in the rock.

Most events mapped by microseismic monitoring are either dip-slip or strike-slip events. Empirically it seems that dip-slip events are tied more closely to the propagating hydraulic fracture while strike-slip events seem to be associated with natural fracture or fault reactivation. This could be due to the modification of the stresses from the hydraulic fracturing process.

5. Correlating Reservoir Properties Against Detectable Microseismic Events

With the sudden increase in the importance of unconventional resources such as shale, our industry is in a race to understand the relationship between hydraulic fracturing, production and mapable reservoir properties. The ultimate goal is to know ahead of time how optimize the completion – well placement, frac stages, pumping pressures, etc. – and ensure the best production. At present we are far from achieving this goal. Doing so is going to require the integration of everything we think we know about the well and the reservoir, and everything we can quantify or measure in order to know those things. Doing this in a single reservoir may reveal correlations between parameters that can provide reasonable ways of planning a well. Doing so in a variety of reservoirs might allow us to make some generalizations about best-practice workflows, including data collection, in different geologic settings.

In this context, regarding microseismic data in particular we need to look for correlations between the shear events detected by the microseismic and anything we believe might be related to the generation of that shear event, whether it is part of the hydraulic fracture propagation or induced by it. Based on the discussions in the previous four sections, it would be important to look at the data in the context of the local state of in situ stress, which can change because of e.g., proximity to a fault or stress perturbations from the hydraulic fracturing process.

Some of the types of data that should be examined include:

- Lithology/mineralogy
- Log data
- Core data
- Measured, log-derived and seismic rock properties
    - Lamé parameter
    - shear modulus
    - bulk modulus
    - Poisson's ratio
    - UCS

- tensile strength
- cohesion (of intact rock)
- Biot coefficient

- Faults and fractures
  - Proximity to fault
  - Fracture density/spacing
  - Fracture orientation
  - Critical pressures for fracture slip or dilation

For any parameter, uncertainty – either measurement uncertainty or uncertainty in the calculation of them – in these parameters will need to be considered when quantifying their variability.

Appendices

A. References and Reading List

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Microseismic Monitoring:
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Some Common Rock Properties:
http://www.stanford.edu/~tyzhu/Documents/Some%20Useful%20Numbers.pdf

B. Symbols and Nomenclature

Symbols	Nomenclature
S, σ	stress
τ	shear stress
ε	strain
u	displacement
E, Y	Young's modulus, modulus of elasticity, stiffness
ν, Nu	Poisson's ratio
G, S, μ, Mu	shear modulus, modulus of rigidity, rigidity
K, B	bulk modulus, incompressibility (rock mechanics)
β	bulk compressibility, compressibility
λ, Lambda	Lamé constant, Lamé parameter, (with shear modulus) Lamé parameters, incompressibility (seismic)
μ	coefficient of (sliding) friction [also fluid viscosity in petroleum enginieering]
μ_i	coefficient of internal friction
UCS, C_0	unconfined (or uniaxial) compressive strength
C, S_0	cohesion, cohesive strength
ϕ, β	angle of internal friction
α	Biot's constant
P_P, P_0, P_R	pore pressure, formation pressure, reservoir pressure
V_S	shear wave velocity, S-wave velocity
V_P	compressional wave velocity, P-wave velocity, sonic velocity
M	earthquake magnitude
Mw	moment magnitude
k, K	permeability [and friction coefficient in minifrac analysis]
ϕ	porosity
ρ, Rho	density

C. Shale

Shale is a sedimentary rock made up of very fine grains of silt and clay (basically it is lithified mud). Despite often having significant porosity, its extremely low permeability (nano to microdarcies) compared to other sedimentary rocks (millidarcies to darcies) means that hydrocarbons cannot migrate significant distances through it in less than geological time scales, making it an excellent caprock for more traditional reservoirs. Additionally, shale is often a hydrocarbon source rock, and if the permeability is low enough the hydrocarbons generated in it cannot get out. With the onset of hydraulic fracturing, producing from these shales has become economical and drastically increased in recent years.

Natural fractures are also very important in most shales, as they provide a permeable pathway for fluid flow. Most important is probably the interaction between hydraulic fractures and pre-existing natural fractures. That said, completion type, fractures and near-wellbore permeability primarily affect early production. Later production is controlled by pressure support, drive mechanism, drainage volume of the reservoir and far field permeability, none of which are affected by a hydraulic fracture.

As mentioned previously, pressure tests that depend on fluid flowing from the formation often do not work in shale because of its low permeability.

In logs shales are easily identified by a high gamma ray response because of its clay mineralogy.

Some Average* Rock Properties for Shale (note that some of these have a very wide range)

Density	~2500 kg/m3
Porosity	up to 30%
Permeability	nanodarcies to microdarcies
Bulk modulus	~10 GPa
Young's modulus	1-70 GPa
Poisson's ratio	0.2-0.4
Shear modulus	~1.6 GPa
UCS	5-100 MPa
Shear strength	3-30 MPa
Tensile strength	2-10 MPa
P-wave velocity	1400-3000 m/s
S-wave velocity	~2600 m/s

*Shale can be massive but is usually highly laminated and/or fissile along weak bedding planes. Properties like sonic velocities, permeability and rock strength are therefore frequently anisotropic, different in the vertical and horizontal directions. The implication on drilling shales is that drilling parameters and well stability are heavily dependent on well orientation.