

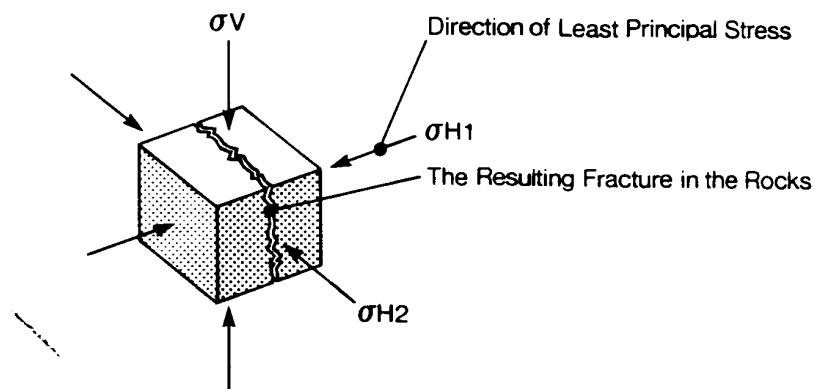
## Fracture pressure

### Fracture gradients

Knowledge of the magnitude of formation fracture gradients is vital, especially when drilling into an abnormally pressured zone. Formation fracture gradient determines the maximum allowable mud weight that can be *used (after incorporating an operational safety factor)*.

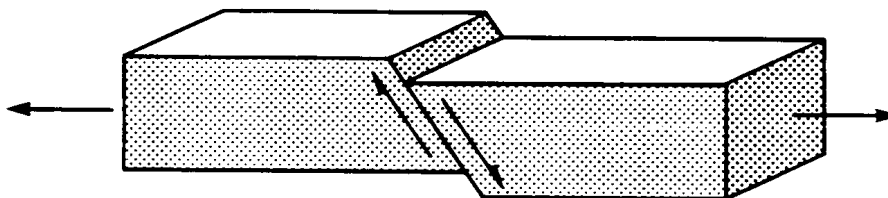
#### Mechanism of Formation Fracturing

A formation can be made to fracture by the application of fluid pressure to overcome the least line of resistance within the rock structure. Normally fractures will be propagated in a direction perpendicular to the least principal stress. Which of these three stresses is the least can be predicted by the fault activity in the area.



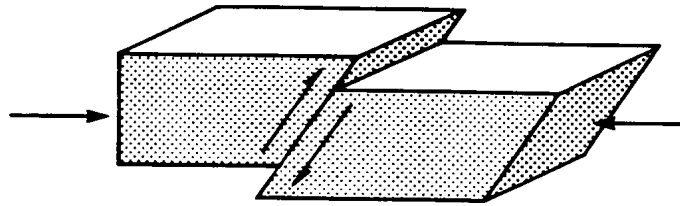
**Figure 1: Distribution of Stress Planes in Unit of Rock Formation**

**Normal faulting** indicates that the least principal stress is **horizontal** and probably about equal to the minimum horizontal stress required to avoid rock failure (figure 2).



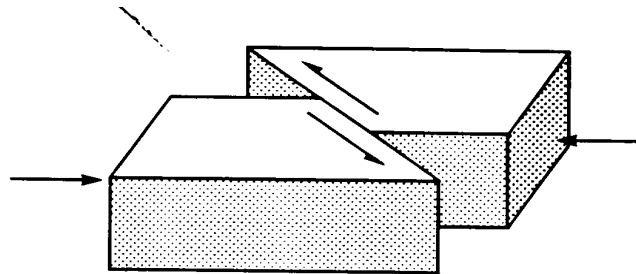
**Figure 2: Normal Fault**

**Thrust (reverse) faulting** indicates the least principal stress to be of a **vertical** nature. It must be at least equal to the weight of the overburden, or about 1 psi/ft (figure 3).



**Figure 3: Reverse Fault**

**Transcurrent** faulting indicates that the least principal stress is **horizontal but can be larger than the minimum required to avoid failure**. It cannot be larger than the vertical stress (figure 4).

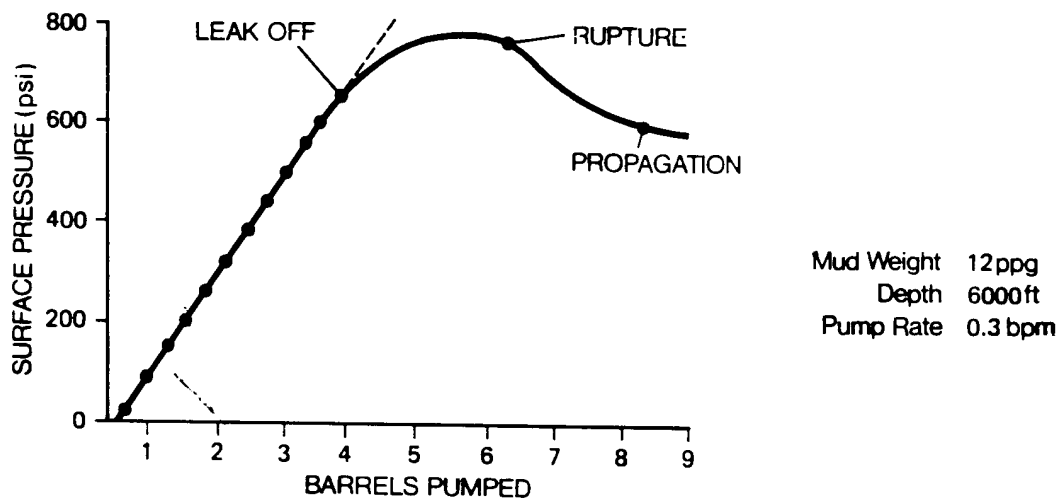


**Figure 4: Transcurrent Fault**

To initiate the fracture fluid pressure must be transmitted to the formation, and to propagate the fracture this pressure must be maintained at a level greater than the least principal stress. If mud is used, then the fluid pressure has to overcome the filter cake deposited on the borehole wall, plus the pressure at which the formation fractures. It is therefore preferable to use a clear, low viscosity fluid when making a determination of the formation breakdown gradient.

In practice, formation breakdown gradients are determined by performing a **Leak Off Test (LOT)**. This is normally done after drilling through a casing shoe in order to determine the maximum allowable mud gradient for the next section of open hole. The usual procedure is outlined below.

- a) Drill through the casing shoe and into new formation to a depth of 15 to 20 feet. Close the blowout preventers.
- b) Raise the surface pressure in increments until bleed off is indicated. Alternatively, pumping could be maintained at a slow rate until bleed off.



**Figure 7-5: Typical Leak Off Test**

During fracture testing it is generally **not** the coherent rock matrix that is sheared, rather the existing natural discontinuities (joints, parting, etc) which are normally held together by the compressive stresses in the formation. When the hydraulic stress in the borehole equals the formation compressive stress, it effectively reduces the latter to zero across the crack. If the borehole pressure is then raised slightly, fluid will enter the crack.

### **Leak off tests and fracture pressures**

Terzaghi and Peck (1948) states that

$$S = \mathbf{s} + P$$

where                      S = Overburden Stress  
                                    $\sigma$  = Matrix Stress  
                                   P = Pore Pressure

As previously stated, subsurface stress is characterised by three unequal, mutually perpendicular principal stresses.

The greatest stress is vertical ( $\sigma_v$ ) although the **least principal stress** ( $\mathbf{s}_h$ ) is of greatest interest as this indicates formation strength along the weakest plane.

Hubbert and Willis (1957)

Hubbert and Willis conducted laboratory experiments on core samples and derived the empirical relationships below.

To extend a fracture

$$\mathbf{s}_h = \frac{1}{3} \mathbf{s}_v$$

To induce a fracture

$$\mathbf{s}_h = \frac{1}{2} \mathbf{s}_v$$

Hence

$$\frac{1}{3} \mathbf{s}_v < \mathbf{s}_h < \frac{1}{2} \mathbf{s}_v$$

or

$$\frac{1}{3} (S - P) < \mathbf{s}_h < \frac{1}{2} (S - P)$$

Therefore, to extend

$$FP = P + \frac{1}{3} (S - P)$$

while to induce

$$FP = P + \frac{1}{2} (S - P)$$

Therefore to fracture a formation one must overcome both the pore pressure and the horizontal matrix stress of the rock.

This value (1/3 to 1/2) is only an estimate. The actual value will depend upon lithology and compaction of the sediments. To take account of this, the **Poisson's Ratio** was introduced.

Poisson's Ratio

From Young's Law

$$\frac{\mathbf{s}_h}{\mathbf{s}_v} = \left( \frac{\mathbf{m}}{1 - \mathbf{m}} \right)^n$$

where

$$n = 1$$

$\mu$  = Poisson's Ratio

Hubbert and Willis estimated Poisson's Ratio as between 0.33 and 0.25, ie

$$\frac{0.33}{1 - 0.33} = \frac{1}{2} \text{ while } \frac{0.25}{1 - 0.25} = \frac{1}{3}$$

Poisson's Ratio is a property which describes the behaviour of rock stresses in the least principal stress direction when pressure is applied in the direction of the principal stress. For elastic rocks, the ratio of the stresses is represented by

$$\frac{\mathbf{s}_L}{\mathbf{s}_P} = \frac{\mathbf{m}}{1 - \mathbf{m}}$$

Laboratory tests on unconsolidated rocks have shown that

$$\frac{L}{P} = \frac{1}{3} \text{ ie } \mathbf{m} = 0.25$$

Field tests have shown  $\mu$  to have values between 0.25 and 0.5, above which the rock becomes plastic, *ie the stresses are equal in all directions*. Poisson's Ratio varies with both rock type and the degree of compaction, and will never exceed 0.5. Every rock will have its own characteristic Poisson's Ratio.

Note should be made of unconsolidated clay formations, often found at shallow depths in North Sea wells, which may exhibit abnormally high fracture pressures. Wet clays will behave plastically and the Poisson's Ratio will approach 0.5. Due to the pore water and adsorbed water surrounding the individual clay platelets, these platelets will not be in contact with each other, and so these clay types will have very low shear strength. Thus the pore water would be supporting the weight of the overlying sediments and the pore pressure should almost be equal to the overburden pressure. As a result, hydraulic pressures greater than the overburden pressures would be necessary to fracture this formation. Under these circumstances, a horizontal fracture would form lifting the overburden.

With increased depth, compaction will squeeze out some of the pore water, bringing the clay platelets into contact. They are then able to support a superimposed horizontal stress, and Poisson's Ratio will become similar to that of a more compact clay.

To build up a complete fracture gradient picture for any well, the fracture pressure should be calculated every time a lithology or pore pressure change is noted. This is particularly important when drilling into sands or zones of decreasing pore pressure gradient, which may be less competent than the formation at the shoe.

In the case of changing lithology, evaluation is best carried out using experimentally derived Poisson's Ratio values for different lithologies, such as those of Weurker (1963) shown in table 1.

### Matthews and Kelly Method

For compacted shales, it has been shown that the overburden stress ( $S$ ) is supported by the formation fluid pressure ( $P$ ) and the grain-to-grain bearing strength ( $\sigma$ ) of the clay particles.

$$S = \sigma + P$$

In the above equation  $\sigma$  represents the matrix stress, and it is evident that its value will depend solely upon the degree of rock compaction. Hubbert and Rubey state that "a useful measure of the degree of compaction of a clay is its porosity". This is defined as the ratio of pore volume to the total volume. From this it may be inferred that, for any given clay, for each value of  $\Phi$ , there is some minimum value of matrix stress  $\sigma$  which the clay can support without further compaction. The porosity at a given burial depth ( $D$ ) is dependent on the fluid pressure ( $P$ ). Thus if the fluid pressure is abnormally high (greater than hydrostatic) the porosity will also be abnormally high, and so the matrix stress would be abnormally low. The converse is assumed to be true if the formation fluid pressure is abnormally low.

It has been assumed that whenever a formation is fractured horizontally the fracture pressure is about equal to the overburden stress. However, for the case of a vertical fracture, the stress required may be much less than the overburden load at the depth where the fracture is created. Nevertheless, in both the horizontal and vertical fracture cases, it may be safely assumed that the fracture will not begin until the applied pressure is at least equal to the formation fluid pressure. If this is the case, then any additional pressure required may be related to the matrix stress and hence will only vary with the degree of compaction. The relationship below has been developed for calculating the fracture gradient of sedimentary formations.

$$F = \frac{P}{D} + \chi \frac{\sigma}{D}$$

where

$P$  = the formation fluid pressure (psi) at depth of interest  $D$

$\sigma$  = the matrix stress (psi)

$\chi$ (chi) = the matrix stress coefficient for the depth at which the value of  $\sigma$  would be the normal matrix stress

$F$  = the fracture gradient in psi/ft

Matthews and Kelly (1967) assumed 1.0 psi/ft for overburden, but replaced the Poisson's Ratio by a **matrix stress coefficient (c)**.

$\chi$  was determined from empirical data, ie leak off tests.

$$\frac{FP}{D} = \frac{P}{D} + c(1 - \frac{P}{D})$$

This showed that

- a)  $\chi$  was depth dependent
- b)  $\chi$  was geographical area dependent

Eaton (1969)

Eaton established variable overburden gradients from bulk densities, and calculated a Poisson's Ratio from empirical data.

$$\frac{FP}{D} = (\frac{S}{D} - \frac{P}{D}) (\frac{\mathbf{m}}{1 - \mathbf{m}}) + \frac{P}{D}$$

where

S/D from density logs

P/D = actual pore fluid pressure

$\mu$  from empirical data, or by Anderson *et al* method for sands

Anderson et al (1973)

Anderson expands Biot's (1955) stress/strain relationship

$$\frac{FP}{D} = \left[ \frac{2}{1 - m} \frac{S}{D} \right] + \left[ a \left( \frac{1 - 3m}{1 - m} \right) \frac{P}{D} \right]$$

where

$$a = 1 - \frac{C_r}{C_b}$$

$C_r$  = intrinsic compressibility of solid rock material

$C_b$  = compressibility of solid rock skeleton

$C_r/C_b$  = function of shale estimated in cuttings

If cuttings contain 100% shale then  $a = 0$ , ie no porosity, hence pore pressure does not have an effect. The equation becomes

$$\frac{FP}{D} = \frac{2m}{1 - m} \frac{S}{D}$$

## Daines (1982)

Daines states that there are two unequal horizontal stresses which must be overcome before fracturing occurs.

- 1 That caused by the weight of overlying sediments ( $\sigma_h$ )
- 2 A superposed tectonic stress ( $\sigma_T$ )

Proof that this tectonic stress exists is evidenced by folding, faulting, etc, which rely on unequal stress states for their occurrence and maintenance.

The minimum horizontal stress occurs when the tectonic stress ( $\sigma_T$ ) is zero, ie

$$s_H = s_V \left( \frac{m}{1 - m} \right) \text{ where } s_V = (S - P)$$

The superposed horizontal tectonic stress will increase uniformly with depth such that the ratio  $\sigma_T:\sigma_V$  remains constant.

The value of  $\sigma_T$  is calculated from the first LOT by subtracting the Eaton calculated fracture pressure from the LOT result, ie

$$s_T = LOT - [s_V \left( \frac{m}{1 - m} \right) + P]$$

where  $\sigma_V = S - P$

The ratio of  $\sigma_T:\sigma_V$  is then calculated so that for subsequent points in the borehole the value of  $\sigma_T$  can be calculated from

$$s_T^i = s_V^i \left( \frac{s_T^l}{s_V^l} \right)$$

where  $i$  denotes depth of interest  
 $l$  denotes LOT depth

As a result, the fracture pressure can be calculated for any depth if the overburden gradient, pore pressure, and Poisson's Ratio for the lithology at that depth are known

$$FP = s_T + [s_v \left( \frac{m}{1 - m} \right) + P]$$

To simplify this calculation Daines paper provides a list of typical Poisson's Ratios for certain lithologies reproduced here in table 7-1 (from Weurker 1963).

Obviously if this data is to be accurate then strict lithological control is necessary. Problems arise when two types of lithology are intermixed eg sandy clay and shaly sand. In these cases the mineral forming the **matrix** must be determined and the Poisson's Ratio for that used.

Daines quotes a figure of 95% accuracy for use of his equations.

<b>Formation Type</b>	<b>Poisson's ratio</b>
clay, very wet	0.50
Clay	0.17
Conglomerate	0.20
Dolomite	0.21
greywacke: coarse	0.07
fine	0.23
medium	0.24
Limestone: fine, micritic	0.28
medium, calcarenitic	0.31
porous	0.20
stylolitic	0.27
fossiliferous	0.09
bedded fossils	0.17
shaly	0.17
sandstone: coarse	0.05
coarse, cemented	0.10
fine	0.03
very fine	0.04
medium	0.06
poorly sorted, shaly	0.24
fossiliferous	0.01
shale: calcareous (<50% CaCO <sub>3</sub> )	0.14
dolomitic	0.28
siliceous	0.12
silty (<70% silt)	0.17
sandy (<70% sand)	0.12
kerogenaceous	0.25
Siltstone	0.08
Slate	0.13
tuff (glass)	0.34

**Table 1: Suggested Values of Poisson's Ratio**

(From Weurker R.G. "Annotated Tables of Strength & Elastic Properties of rocks," Drilling Reprint Series SPE, Dallas (1963))

## Poisson's Ratio Calculations

This method was described by Tony Taylor (1978) and is based on an equation formulated by Tixier, Loveless and Anderson in 1973. The Poisson's Ratios calculated by this method can be applied to **sands**, particularly those with significant clay content.

Since the minimum value of  $\mu$  available is 0.27, this method cannot be used to define Poisson's Ratio in finer grained clastics. Also, since carbonates tend to have low values of gamma ray the Poisson's ratio would appear much higher than would be appropriate for such competent rocks.

$$m = 0.125 q + 0.27$$

where

- $\mu$  = Poisson's Ratio
- 0.125 = constant
- q = Shaliness Index
- 0.27 = theoretical minimum for Poisson's Ratio in a clean sand

To calculate shaliness index (q) use the gamma ray log. Average the readings over 50 ft intervals and insert into the formula

$$q = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}}$$

This value is substituted into the equation for  $\mu$  above, and in turn Poisson's ratio ( $\mu$ ) may be substituted into the desired fracture gradient equation discussed above.