Tishk International University
Engineering Faculty
Petroleum and Mining Department

Petroleum Production Engineering II

Lecture 8 : Hydraulic Fracturing I

4th-Grade- Fall Semester 2022-2023

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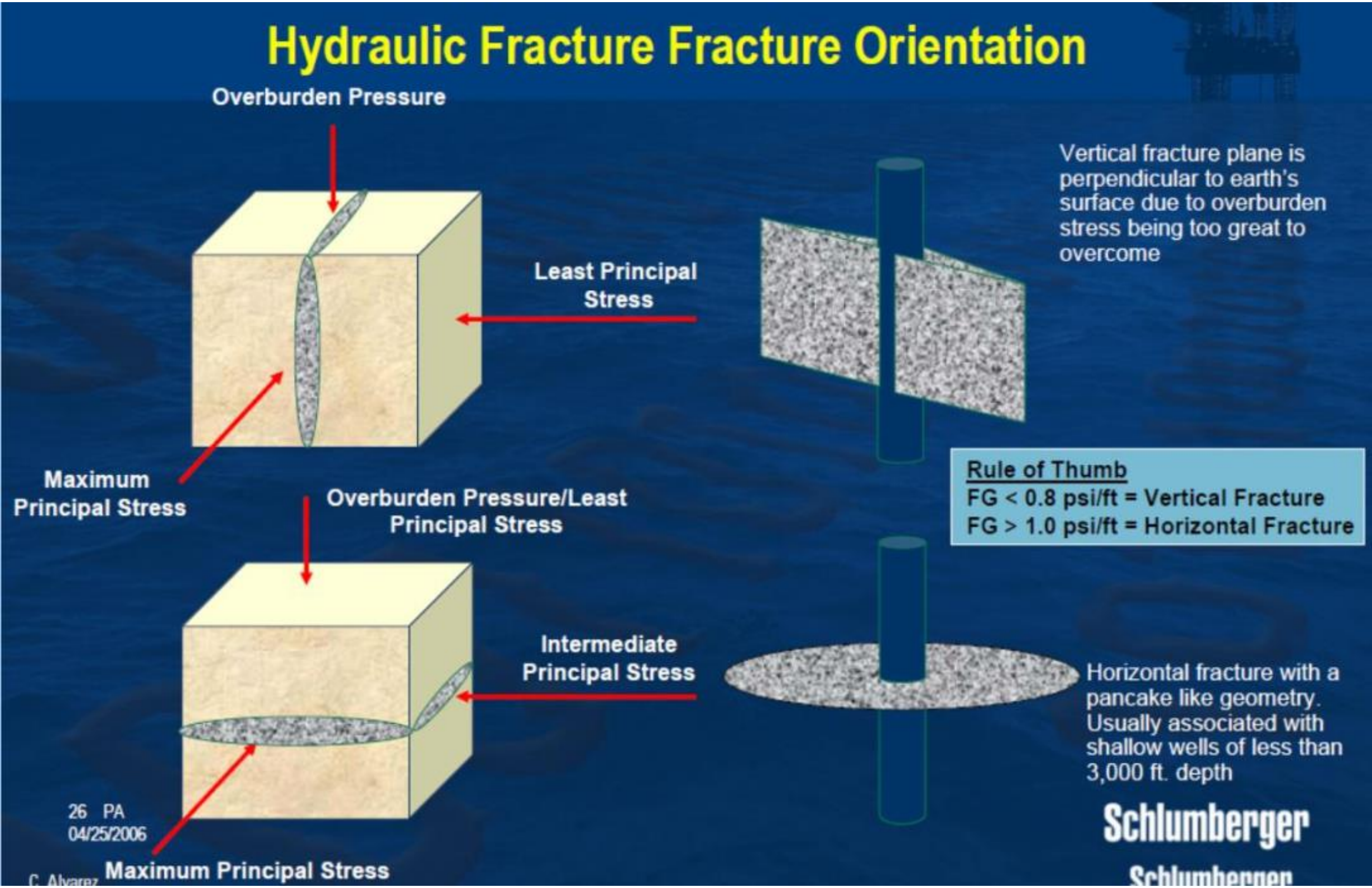
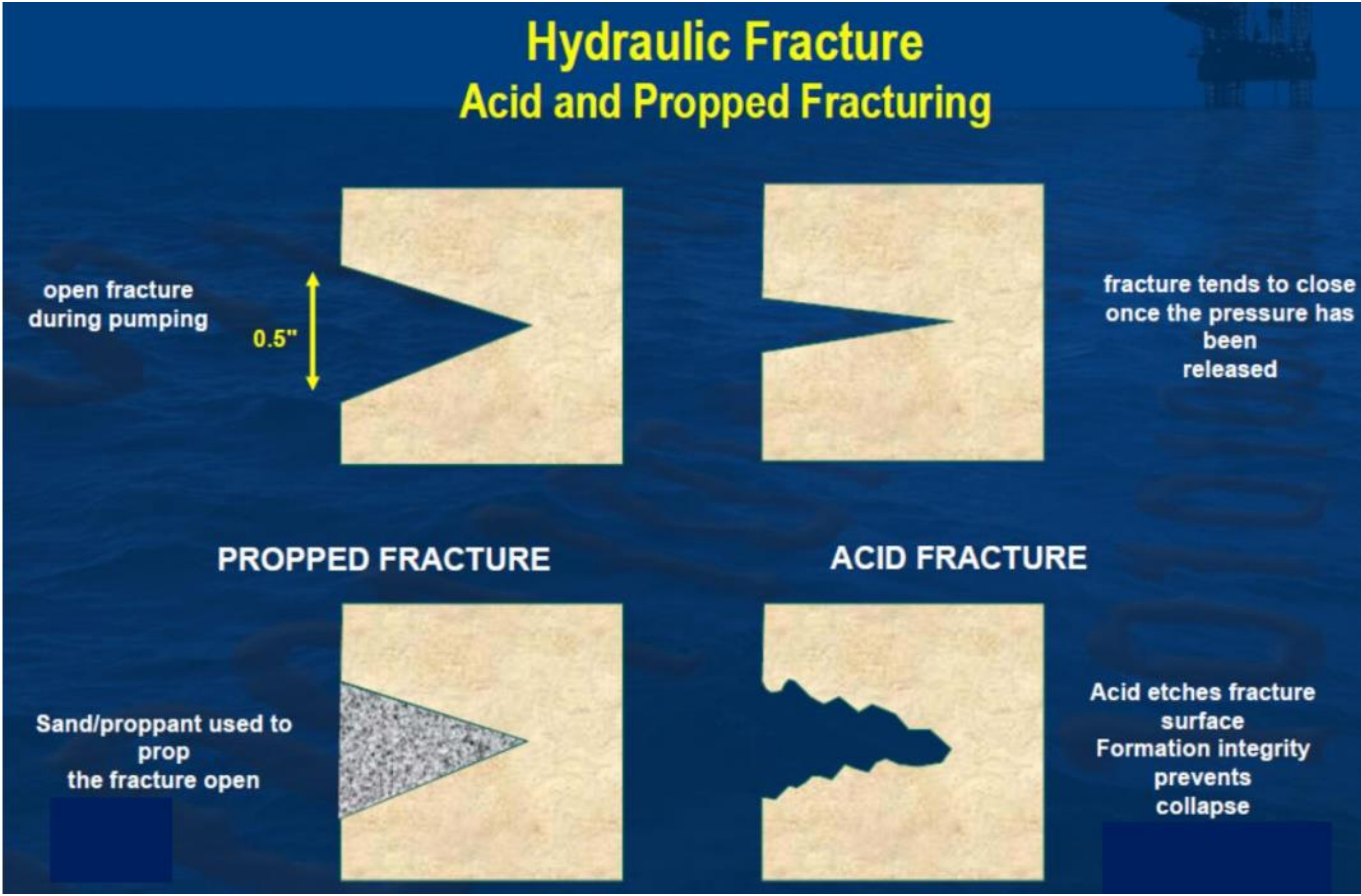
Hydraulic Fracturing

- Hydraulic fracturing is a well-stimulation technique that is most suitable to wells in low- and moderate-permeability reservoirs that do not provide commercial production rates even though formation damages are removed by acidizing treatments.
- Conductive path is maintained by propping agents (sand) to hold the fracture faces apart

Objectives of Hydraulic Fracturing

- Increase the flow rate of oil and/or gas from low permeability reservoir.
- Increase the flow rare of oil and/or gas from wells that have been damaged.
- Connect the natural fractures in a formation to the wellbore.
- Decrease the pressure drop around the wellbore.
- Increase the area of drainage or the amount of formation in contact with the wellbore.
- Connect the full vertical extent of the formation to the wellbore.


Hydraulic Fracture Fracture Orientation
Overburden Pressure
Least Principal Stress
Maximum Principal Stress
Vertical fracture plane is perpendicular to earth's surface due to overburden stress being too great to overcome
Rule of Thumb
FG < 0.8 psi/ft = Vertical Fracture
FG > 1.0 psi/ft = Horizontal Fracture
Overburden Pressure/Least Principal Stress
Intermediate Principal Stress
Horizontal fracture with a pancake like geometry. Usually associated with shallow wells of less than 3,000 ft. depth
26 PA
04/25/2006
C. Alvarez
Maximum Principal Stress
Schlumberger


Hydraulic Fracture
Acid and Propped Fracturing
open fracture
during pumping
0.5"
fracture tends to close
once the pressure has
been
released
PROPPED FRACTURE
ACID FRACTURE
Sand/proppant used to
prop
the fracture open
Acid etches fracture
surface
Formation integrity
prevents
collapse

Hydraulic Fracturing Mechanism

- Hydraulic fracturing jobs are carried out at well sites using heavy equipment including truck-mounted pumps, blenders, fluid tanks, and proppant tanks. Figure 8.1 illustrates a simplified equipment layout in hydraulic fracturing treatments of oil and gas wells. A hydraulic fracturing job is divided into two stages: the pad stage and the slurry stage (Fig. 8.2). In the pad stage, fracturing fluid only is injected into the well to break down the formation and create a pad. The pad is created because the fracturing fluid injection rate is higher than the flow rate at which the fluid can escape into the formation. After the pad grows to a desirable size, the slurry stage is started.

Hydraulic Fracturing Mechanism

- During the slurry stage, the fracturing fluid is mixed with sand/proppant in a blender and the mixture is injected into the pad/fracture. After filling the fracture with sand/proppant, the fracturing job is over, and the pump is shut down.

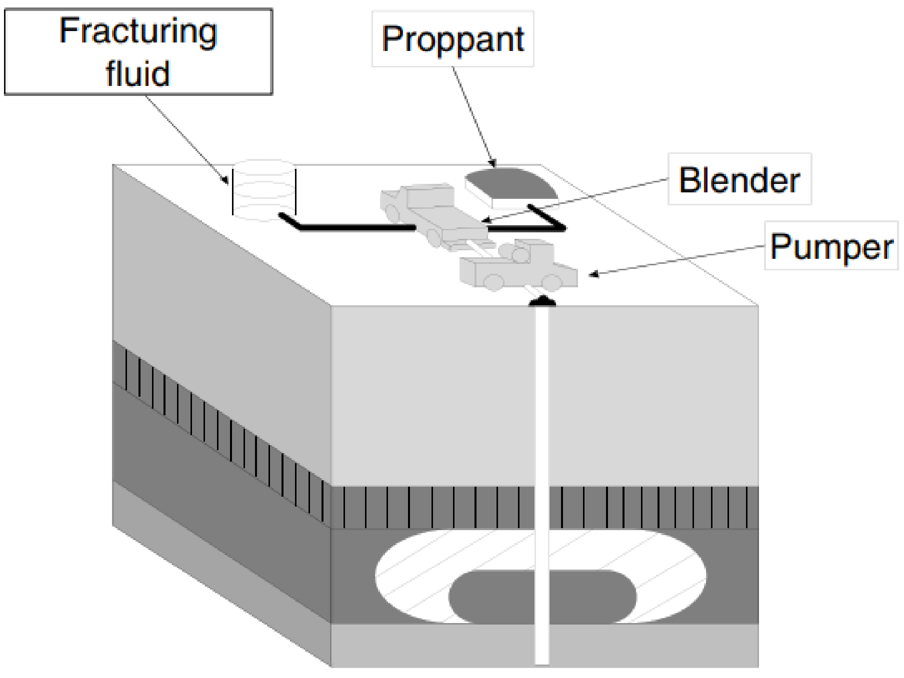


Figure 8.1 *Schematic to show the equipment layout in hydraulic fracturing treatments of oil and gas wells.*

Hydraulic Fracturing Mechanism

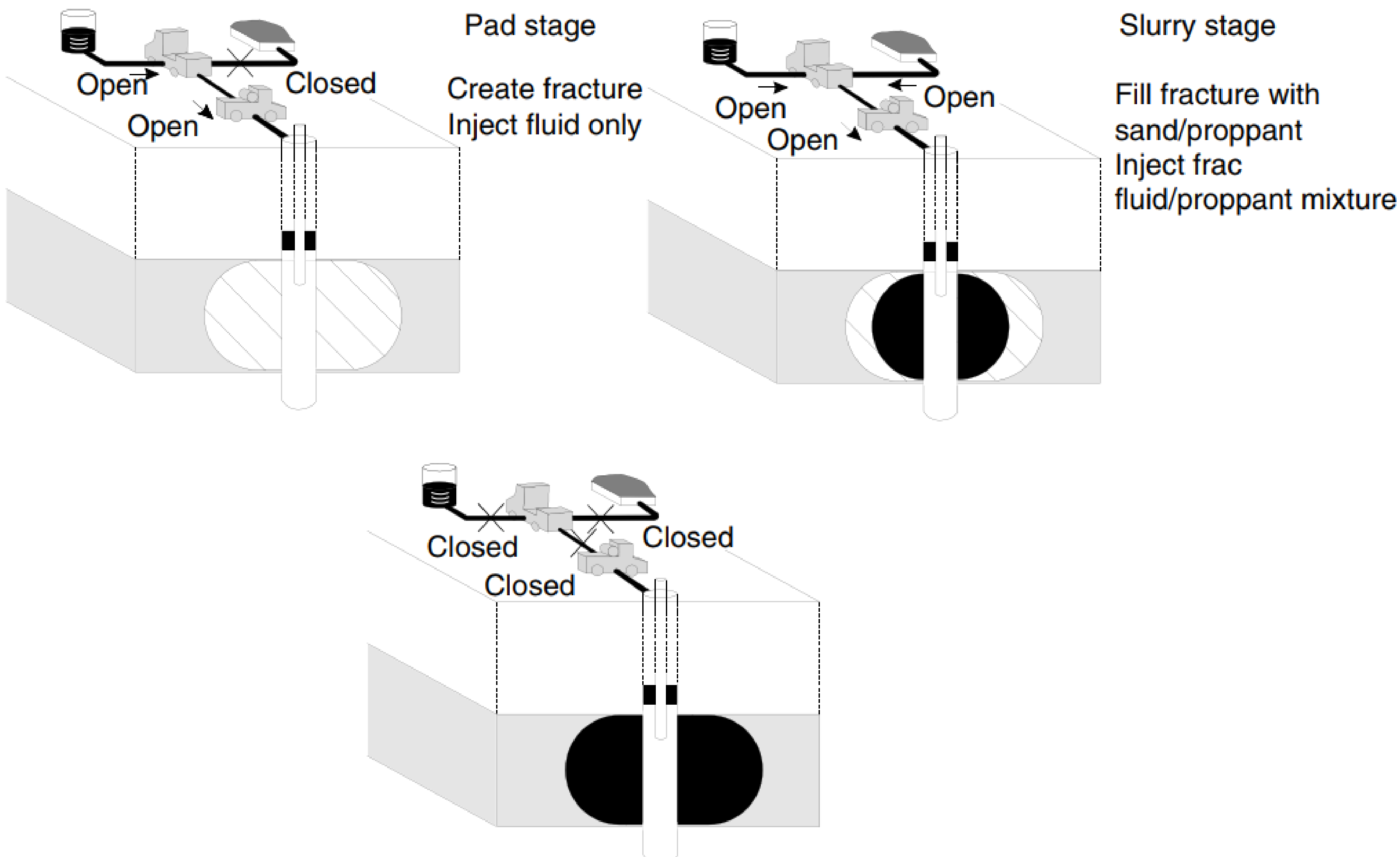


Figure 8.2 *A schematic to show the procedure of hydraulic fracturing treatments of oil and gas wells.*

Formation Fracturing Pressure

- Formation fracturing pressure is also called *breakdown pressure*. It is one of the key parameters used in hydraulic fracturing design. The magnitude of the parameter **depends on formation depth and properties**. Estimation of the parameter value begins with **in situ stress analysis**.
- Consider a reservoir rock at depth ***H*** as shown in Fig. 8.3. The *in-situ* stress caused by the weight of the overburden formation in the vertical direction is expressed as

$$\sigma_v = \frac{\rho H}{144}, \qquad (8.1)$$

where

σ_v = overburden stress, psi
ρ = the average density of overburden formation, lb/ft^3
H = depth, ft.

Formation Fracturing Pressure

- The overburden stress is carried by both the rock grains and the fluid within the pore space between the grains. The contact stress between grains is called *effective stress* (Fig. 8.3):

$$\sigma'_v = \sigma_v - \alpha p_p, \qquad (8.2)$$

where

σ'_v = effective vertical stress, psi
α = Biot's poro-elastic constant, approximately 0.7
p_p = pore pressure, psi.

The effective horizontal stress is expressed as

$$\sigma'_h = \frac{\nu}{1-\nu}\sigma'_v, \qquad (8.3)$$

where ν is Poison's ratio. The total horizontal stress is expressed as

$$\sigma_h = \sigma'_h + \alpha p_p. \qquad (8.4)$$

Formation Fracturing Pressure

Because of the tectonic effect, the magnitude of the horizontal stress may vary with direction. The maximum horizontal stress may be $\sigma_{h,\max} = \sigma_{h,\min} + \sigma_{tect}$, where σ_{tect} is called *tectonic stress*.

Based on a failure criterion, Terzaghi presented the following expression for the breakdown pressure:

$$p_{bd} = 3\sigma_{h,\min} - \sigma_{h,\max} + T_0 - p_p, \qquad (8.5)$$

where T_0 is the tensile strength of the rock.

Formation Fracturing Pressure

Effective stress

$$\sigma_v' = \sigma_v - \alpha p_p$$

Biot constant $\alpha \approx 0.7$

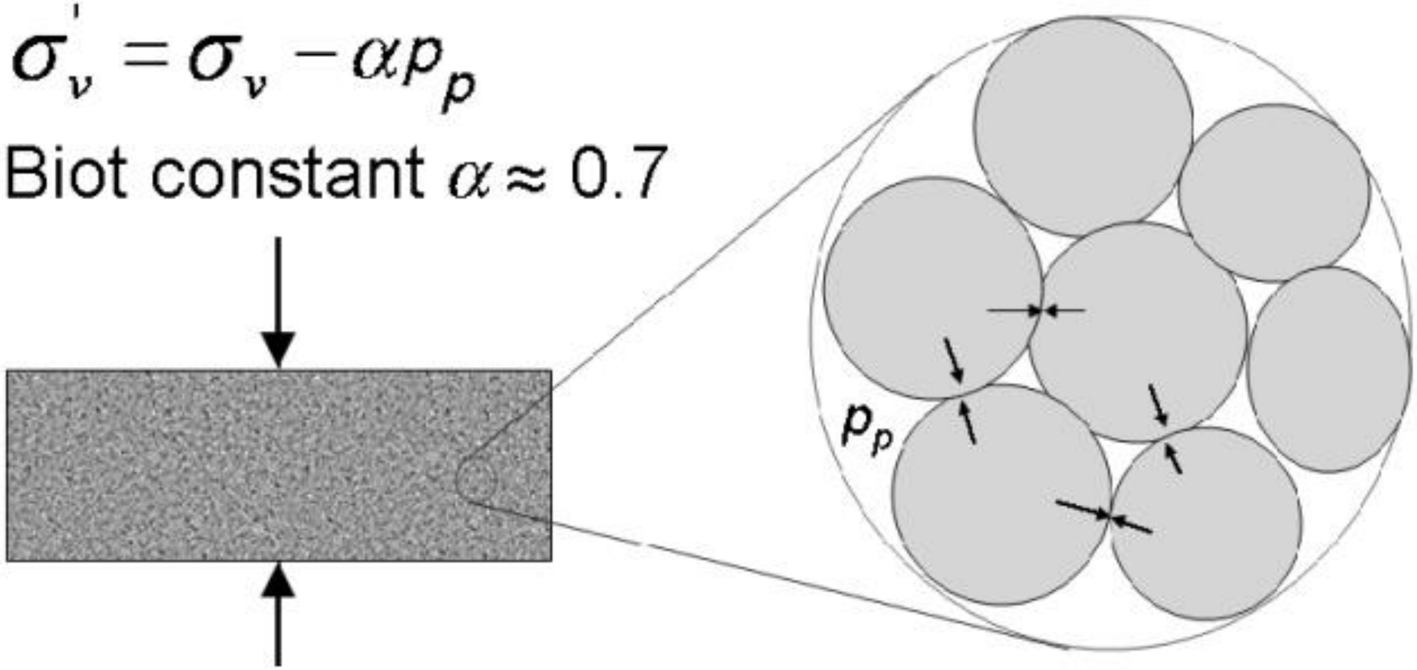
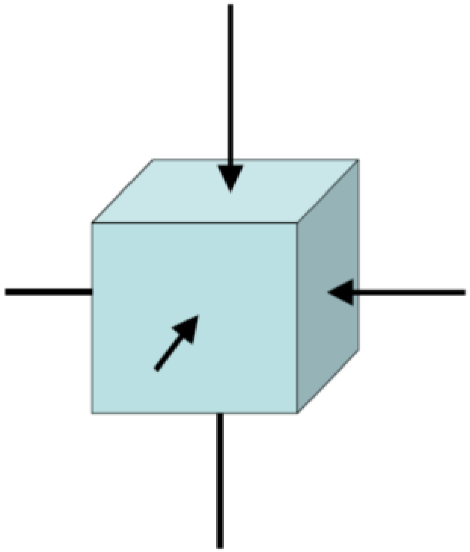


Figure 8.3 *Concept of effective stress between grains.*

Formation Fracturing Pressure

Max. and Min. Horizontal Stresses

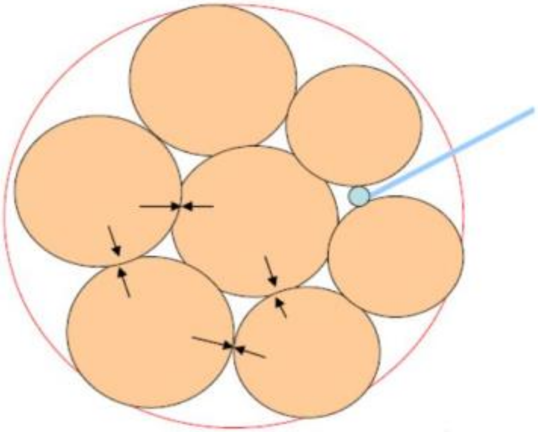
$$\sigma_{h,\max} = \sigma_{h,\min} + \sigma_{tech}$$



Breakdown Pressure

$$p_{bd} = 3\sigma_{h,\min} - \sigma_{h,\max} + T_0 - p_p$$

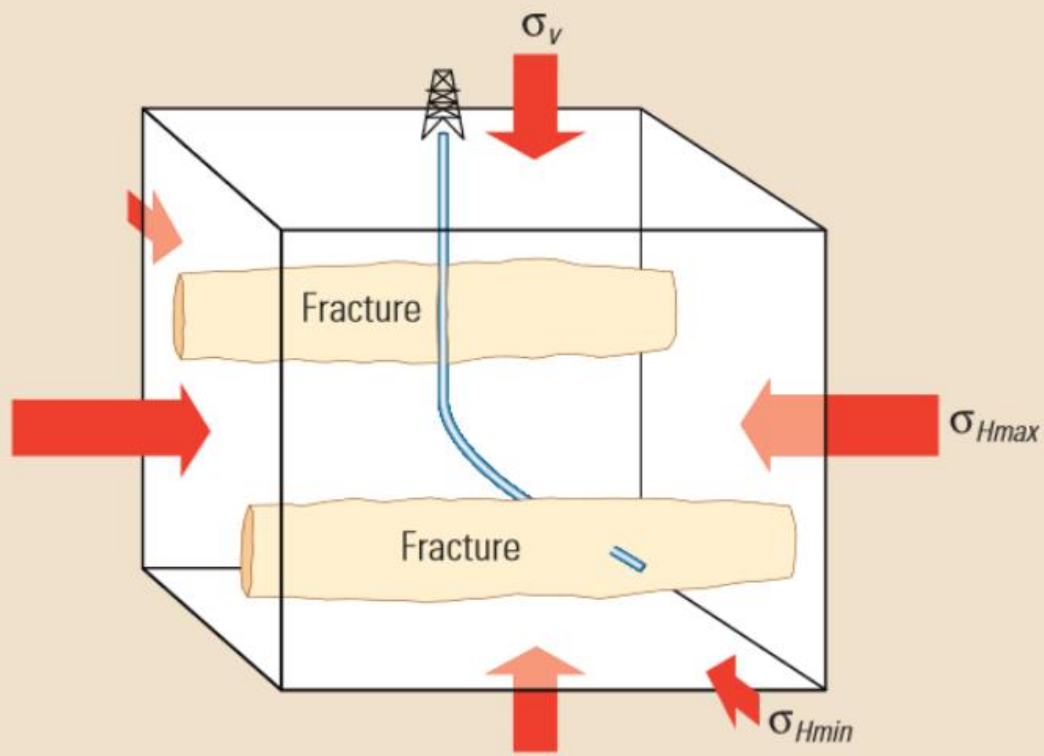
T_0 = tensile strength



Fracture orientation

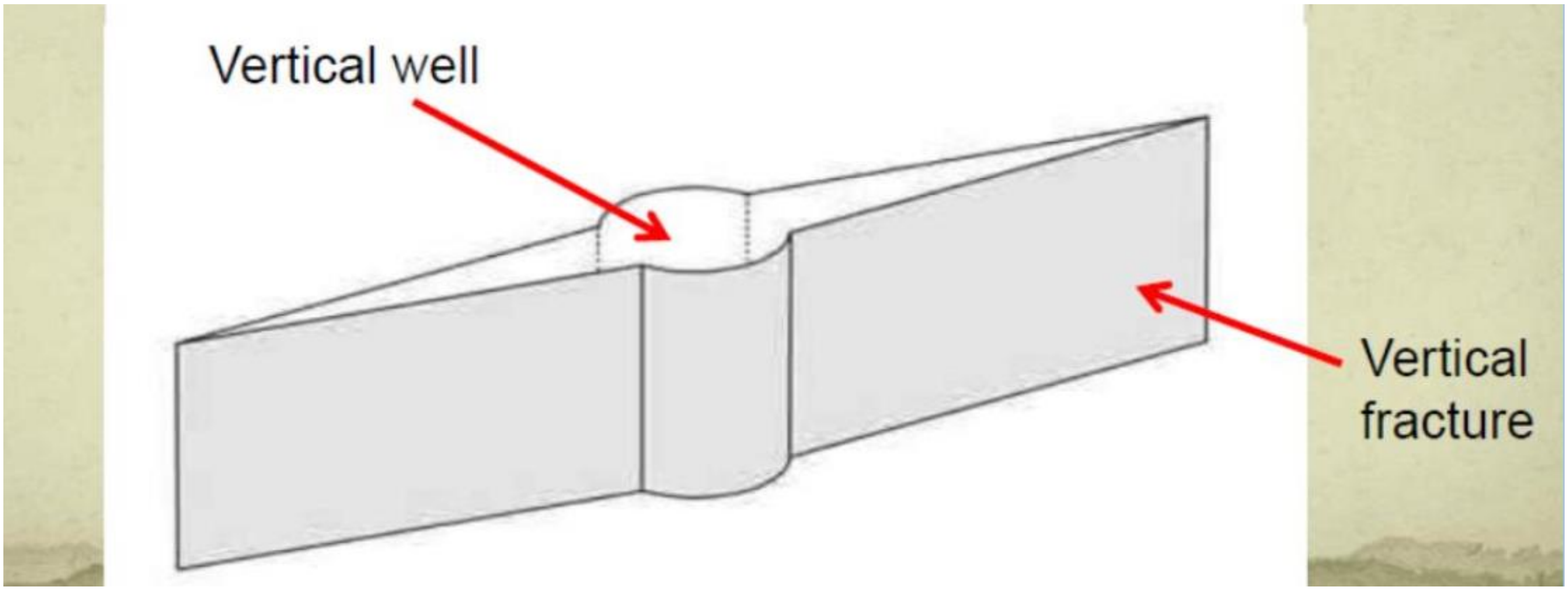
- The Hydraulic fractures are formed in the direction perpendicular to the least stress. Based on experience, horizontal fractures will occur at depths less than approximately 2000 ft. because the Earth's overburden at these depths provides the least principal stress. In general, therefore, these fractures are parallel to the bedding plane of the formation.
- As depth increases beyond approximately 2000 ft., overburden stress increases by approximately 1 psi/ft., making the overburden stress the dominant stress This means the horizontal confining stress is now the least principal stress. Since hydraulically induced fractures are formed in the direction perpendicular to the least stress, the resulting fracture at depths greater than approximately 2000 ft. will be oriented in the vertical direction.

Fracture orientation



^ In situ stresses and hydraulic fracture propagation. The three principal compressive stresses (red arrows) are a vertical stress (σ_V) and a maximum and minimum horizontal stress (σ_{Hmax} and σ_{Hmin}). Hydraulic fractures open in the direction of the least principal stress and propagate in the plane of the greatest and intermediate stresses.

Fracture orientation



Formation Fracturing Pressure

Example 8.1: A sandstone at a depth of 10,000 ft has a Poison's ratio of 0.25 and a poro-elastic constant of 0.72. The average density of the overburden formation is 165 lb/ft^3. The pore pressure gradient in the sandstone is 0.38 psi/ft. Assuming a tectonic stress of 2,000 psi and a tensile strength of the sandstone of 1,000 psi, predict the breakdown pressure for the sandstone.

Formation Fracturing Pressure

Solution

Overburden stress:

$$\sigma_v = \frac{\rho H}{144} = \frac{(165)(10{,}000)}{144} = 11{,}500\,\text{psi}$$

Pore pressure:

$$p_p = (0.38)(10{,}000) = 3{,}800\,\text{psi}$$

The effective vertical stress:

$$\sigma'_v = \sigma_v - \alpha p_p = 11{,}500 - (0.72)(3{,}800) = 8{,}800\,\text{psi}$$

The effective horizontal stress:

$$\sigma'_h = \frac{\nu}{1-\nu}\sigma'_v = \frac{0.25}{1-0.25}(8{,}800) = 2{,}900\,\text{psi}$$

Formation Fracturing Pressure

Solution

The minimum horizontal stress:

$$\sigma_{h,\min} = \sigma'_h + \alpha p_p = 2{,}900 + (0.72)(3{,}800) = 5{,}700\,\text{psi}$$

The maximum horizontal stress:

$$\sigma_{h,\max} = \sigma_{h,\min} + \sigma_{tect} = 5{,}700 + 2{,}000 = 7{,}700\,\text{psi}$$

Breakdown pressure:

$$\begin{aligned} p_{bd} &= 3\sigma_{h,\min} - \sigma_{h,\max} + T_0 - p_p \\ &= 3(5{,}700) - 7{,}700 + 1{,}000 - 3{,}800 = 6{,}600\,\text{psi} \end{aligned}$$

Productivity of Fractured Wells

- Hydraulically created fractures gather fluids from reservoir matrix and provide channels for the fluid to flow into wellbores. Apparently, the productivity of fractured wells depends on two steps: (1) receiving fluids from formation and (2) transporting the received fluid to the wellbore. The efficiency of the first step depends on fracture dimension (length and height), and the efficiency of the second step depends on fracture permeability.

Productivity of Fractured Wells

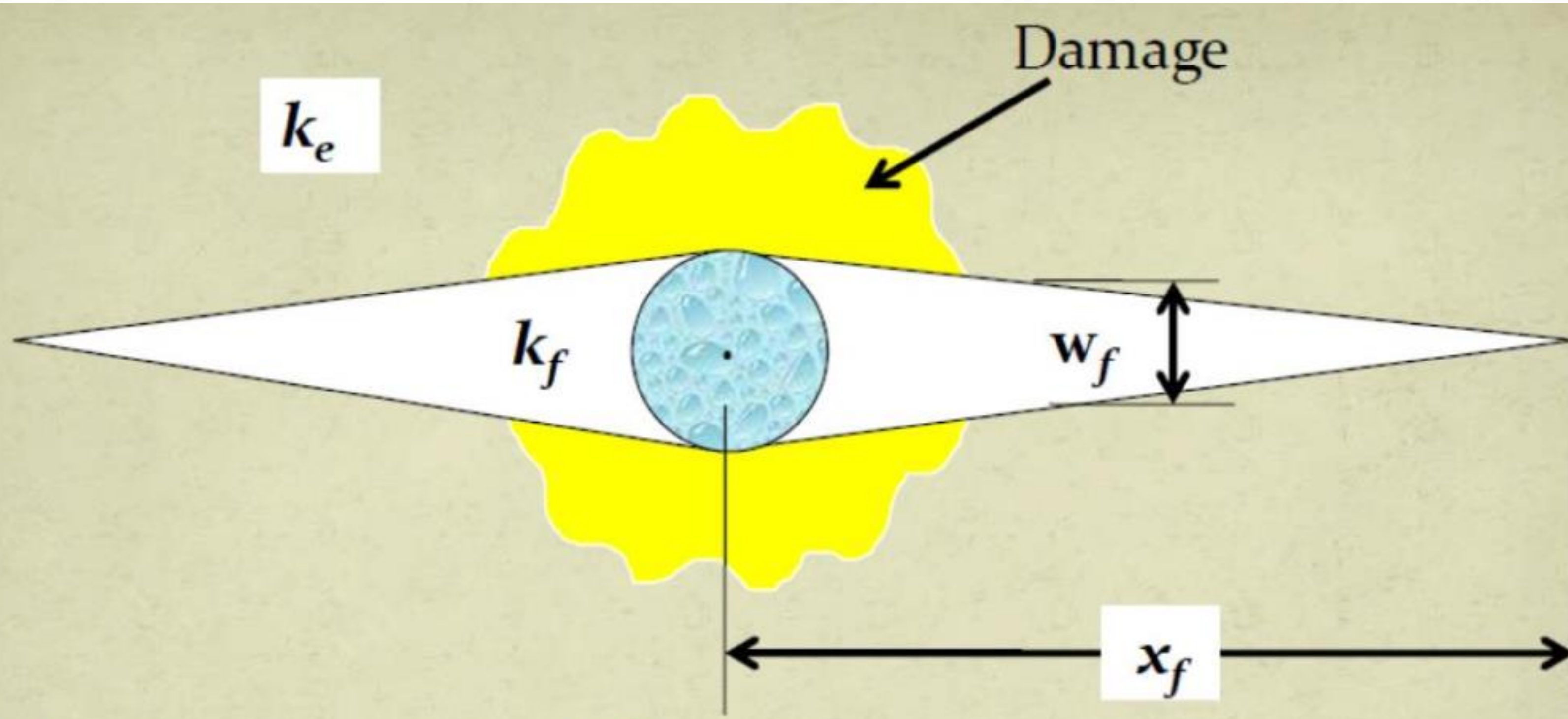
- The relative importance of each of the steps can be analyzed using the concept of fracture conductivity defined as (Argawal et al., 1979; Cinco-Ley and Samaniego, 1981):

$$F_{CD} = \frac{k_f w}{k x_f}, \qquad (8.6)$$

where

F_{CD} = fracture conductivity, dimensionless
k_f = fracture permeability, md
w = fracture width, ft
x_f = fracture half-length, ft.

Productivity of Fractured Wells



- k_f = Fracture permeability
- k_e = Formation permeability
- x_f = Fracture half-length
- w_f = Fracture width

- In hydraulic fracturing, damage is not an issue.

Productivity of Fractured Wells

- In the situations in which the fracture dimension is much less than the drainage area of the well, the long-term productivity of the fractured well can be estimated assuming pseudo-radial flow in the reservoir. Then the inflow equation can be written as

$$q = \frac{kh\left(p_e - p_{wf}\right)}{141.2B\mu\left(\ln\frac{r_e}{r_w} + S_f\right)}, \qquad (8.7)$$

where S_f is the equivalent skin factor.

Productivity of Fractured Wells

- The fold of increase can be expressed as

$$\frac{J}{J_o} = \frac{\ln \frac{r_e}{r_w}}{\ln \frac{r_e}{r_w} + S_f}, \qquad (8.8)$$

where

J = productivity of fractured well, stb/day-psi

J_o = productivity of nonfractured well, stb/day-psi.

The effective skin factor S_f can be determined based on fracture conductivity and Fig. 7.

It is seen from Fig. 7 that the parameter $S_f + \ln(x_f/r_w)$ approaches a constant value in the range of $F_{CD} > 100$, that is,
which gives

$$S_f \approx 0.7 - \ln(x_f/r_w), \qquad (8.9)$$

Productivity of Fractured Wells

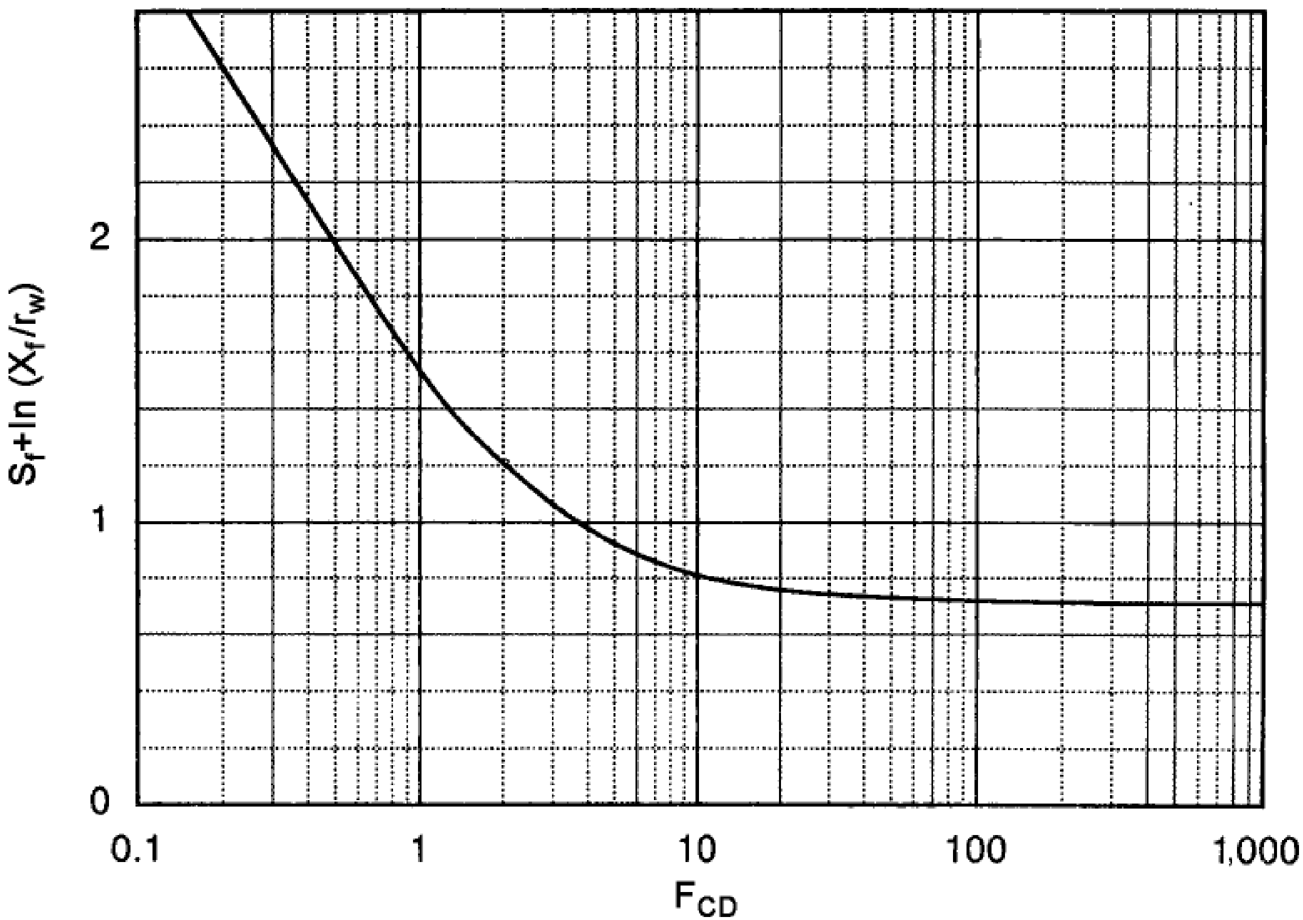


***Figure* 7** *Relationship between fracture conductivity and equivalent skin factor (Cinco-Ley and Samaniego, 1981).*

Productivity of Fractured Wells

Example 8.2: A gas reservoir has a permeability of 1 md. A vertical well of 0.328-ft radius draws the reservoir from the center of an area of 160 acres. If the well is hydraulically fractured to create a 2,000-ft long, 0.12-in. wide fracture of 200,000 md permeability around the center of the drainage area, what would be the fold of increase in well productivity?

Productivity of Fractured Wells

Solution Radius of the drainage area:

$$r_e = \sqrt{\frac{A}{\pi}} = \sqrt{\frac{(43{,}560)(160)}{\pi}} = 1{,}490\,\text{ft}$$

Fracture conductivity:

$$F_{CD} = \frac{k_f w}{k x_f} = \frac{(200{,}000)(0.12/12)}{(1)(2{,}000/2)} = 2$$

Figure 7 reads

$$S_f + \ln(x_f/r_w) \approx 1.2,$$

which gives

$$S_f \approx 1.2 - \ln(x_f/r_w) = 1.2 - \ln(1{,}000/0.328) = -6.82.$$

Productivity of Fractured Wells

- The fold of increase is

$$\frac{J}{J_o} = \frac{\ln \frac{r_e}{r_w}}{\ln \frac{r_e}{r_w} + S_f} = \frac{\ln \frac{1,490}{0.328}}{\ln \frac{1,490}{0.328} - 6.82} = 5.27.$$

Hydraulic Fracturing Design

- Hydraulic fracturing designs are performed based on parametric studies to maximize net present values (NPVs) of the fractured wells. A hydraulic fracturing design should follow the following procedure:

1. Select a fracturing fluid
2. Select a proppant
3. Determine the maximum allowable treatment pressure
4. Select a fracture propagation model
5. Select treatment size (fracture length and proppant concentration)
6. Perform production forecast analyses
7. Perform NPV analysis

Hydraulic Fracturing Design

- A complete design must include the following components to direct field operations:

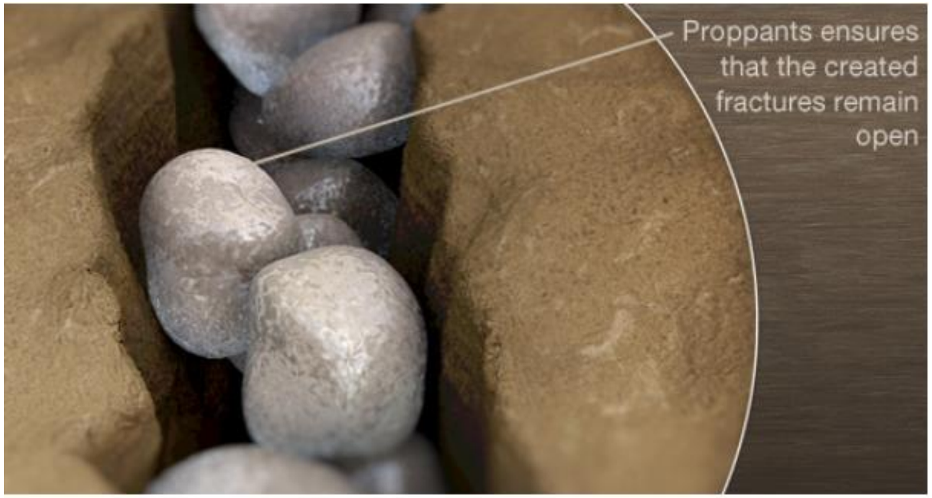
1. Specifications of fracturing fluid and proppant
2. Fluid volume and proppant weight requirements
3. Fluid injection schedule and proppant mixing schedule
4. Predicted injection pressure profile

Hydraulic Fracturing Design

- **Selection of Proppant**
- Proppant must be selected based on in situ stress conditions. Major concerns are compressive strength and the effect of stress on proppant permeability. For a vertical fracture, the compressive strength of the proppant should be greater than the effective horizontal stress. In general, bigger proppant yields better permeability, but proppant size must be checked against proppant admittance criteria through the perforations and inside the fracture. Figure 9 shows permeabilities of various types of proppants under fracture closure stress.

Hydraulic Fracturing Design

- **Selection of Proppant**



Hydraulic Fracturing Design

- **Selection of Proppant**

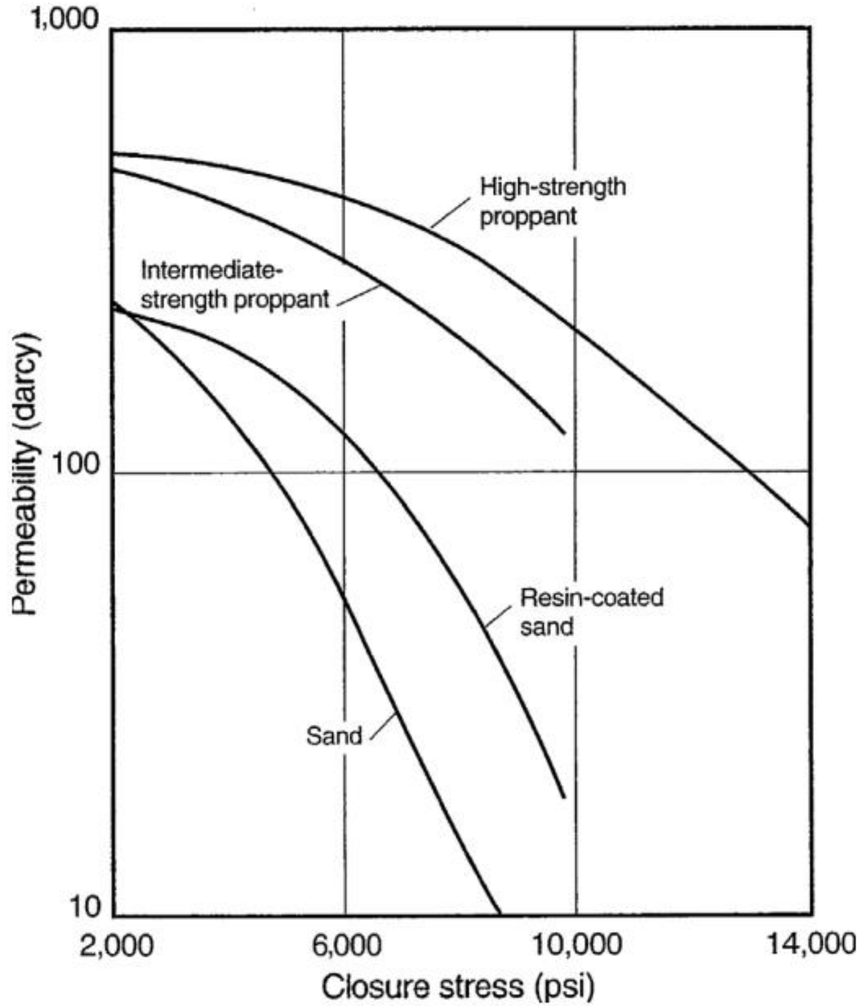


Figure 9 *Effect of fracture closure stress on proppant pack permeability (Economides and Nolte, 2000).*

Hydraulic Fracturing Design

- **Selection of Proppant**

Example 8.3: For the following situation, estimate the minimum required compressive strength of 20/40 proppant. If intermediate-strength proppant is used, estimate the permeability of the proppant pack:

Formation depth:	10,000 ft
Overburden density:	$165\,lb_m/ft^3$
Poison's ratio:	0.25
Biot constant:	0.7
Reservoir pressure:	6,500 psi
Production drawdown:	2,000 and 4,000 psi

Hydraulic Fracturing Design

- **Selection of Proppant**

Solution

The initial effective horizontal stress:

$$\sigma'_h = \frac{\nu}{1-\nu}\left(\frac{\rho H}{144} - \alpha p_p\right)$$

$$= \frac{0.25}{1-0.25}\left[\frac{(165)(10{,}000)}{144} - (0.7)(6500)\right] = 2{,}303 \text{ psi}$$

The effective horizontal stress under 2,000-psi pressure drawdown:

$$\sigma'_h = \frac{\nu}{1-\nu}\left(\frac{\rho H}{144} - \alpha p_p\right)$$

$$= \frac{0.25}{1-0.25}\left[\frac{(165)(10{,}000)}{144} - (0.7)(4500)\right] = 2{,}770 \text{ psi}$$

Hydraulic Fracturing Design

- **Selection of Proppant**

Solution

- The effective horizontal stress under 4,000-psi pressure drawdown:

$$\sigma'_h = \frac{\nu}{1-\nu}\left(\frac{\rho H}{144} - \alpha p_p\right)$$

$$= \frac{0.25}{1-0.25}\left[\frac{(165)(10{,}000)}{144} - (0.7)(2500)\right] = 3{,}236 \text{ psi}$$

Therefore, the minimum required proppant compressive strength is 3,236 psi. Figure 9 indicates that the pack of the intermediate-strength proppants will have a permeability of about $k_f = 500$ darcies.