Well Stimulation and Sand Production Management
(PGE 489)

Hydraulic Fracturing (1/3)

By
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Well Stimulation

- Main Purpose
  - Increase well productivity
  - Increase ultimate well recovery

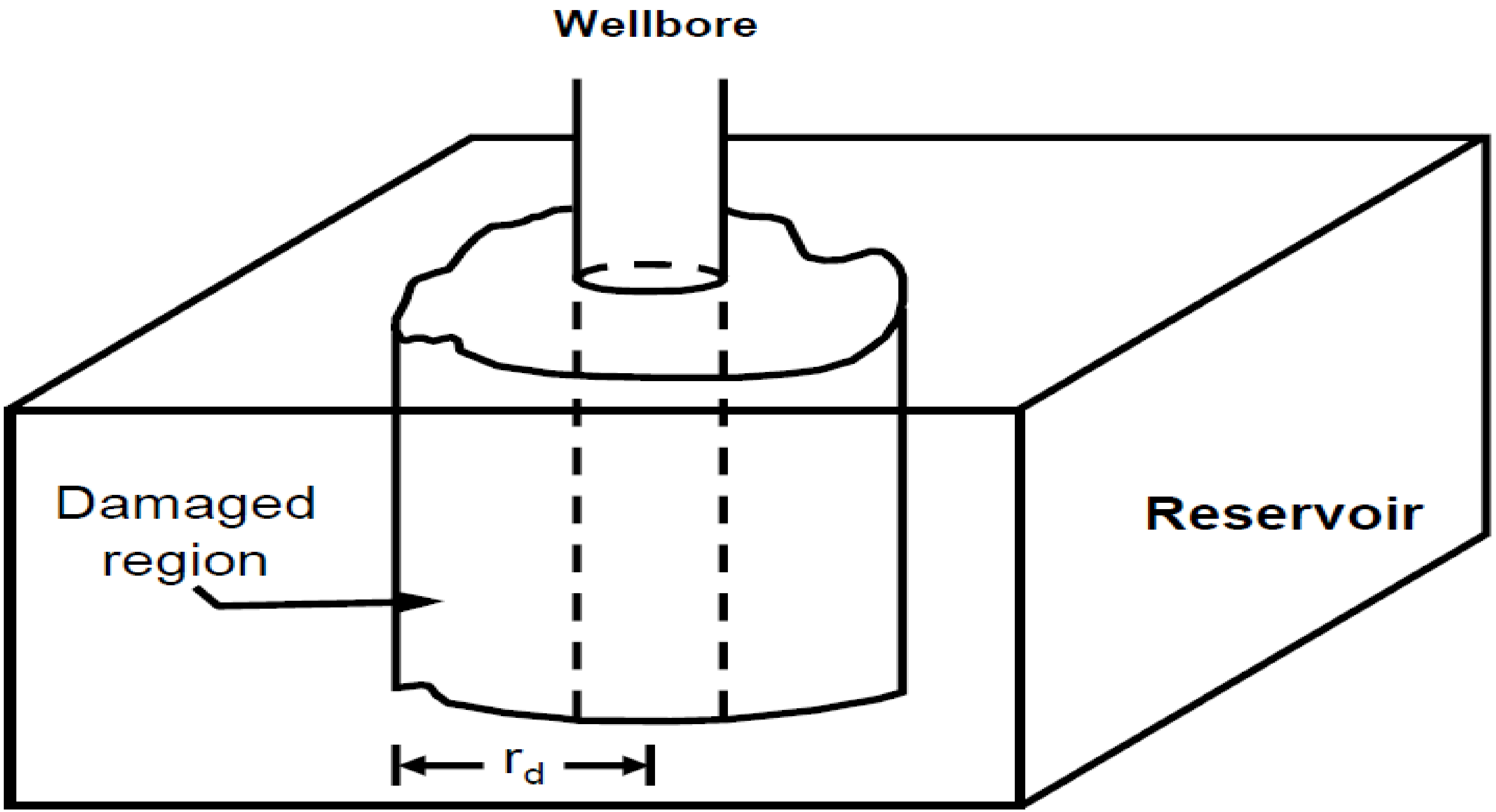
- Approach
  - Remove drilling or completion damage from around the well bore
  - Change reservoir flow pattern

Stimulation Treatments

- Matrix treatment
    - Removes damage from around the wellbore
    - Acids and other chemicals such as surfactants are used

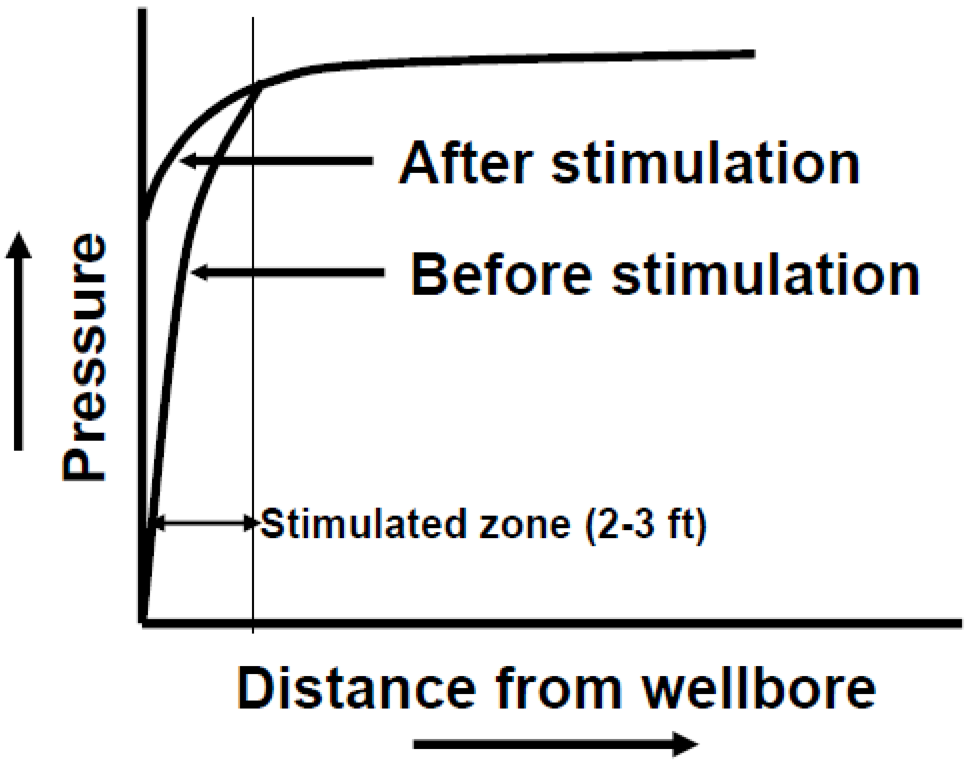
- Hydraulic fracturing
    - Changes flow pattern in the reservoir
    - Acid or proppant fracturing are used

Matrix Treatments

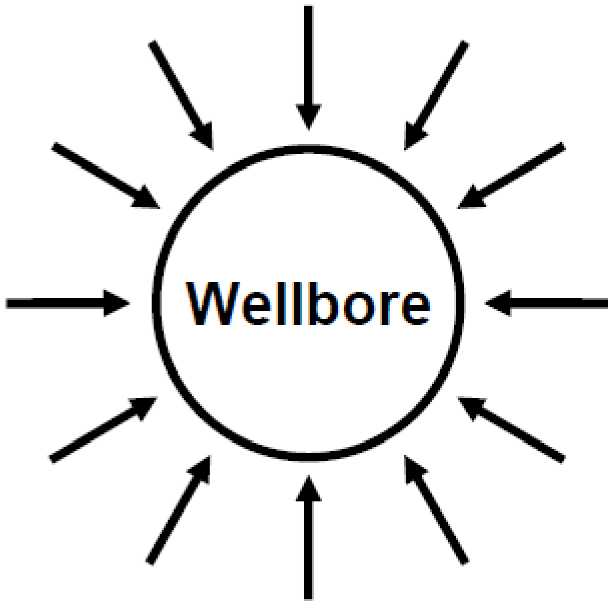


Matrix Treatments

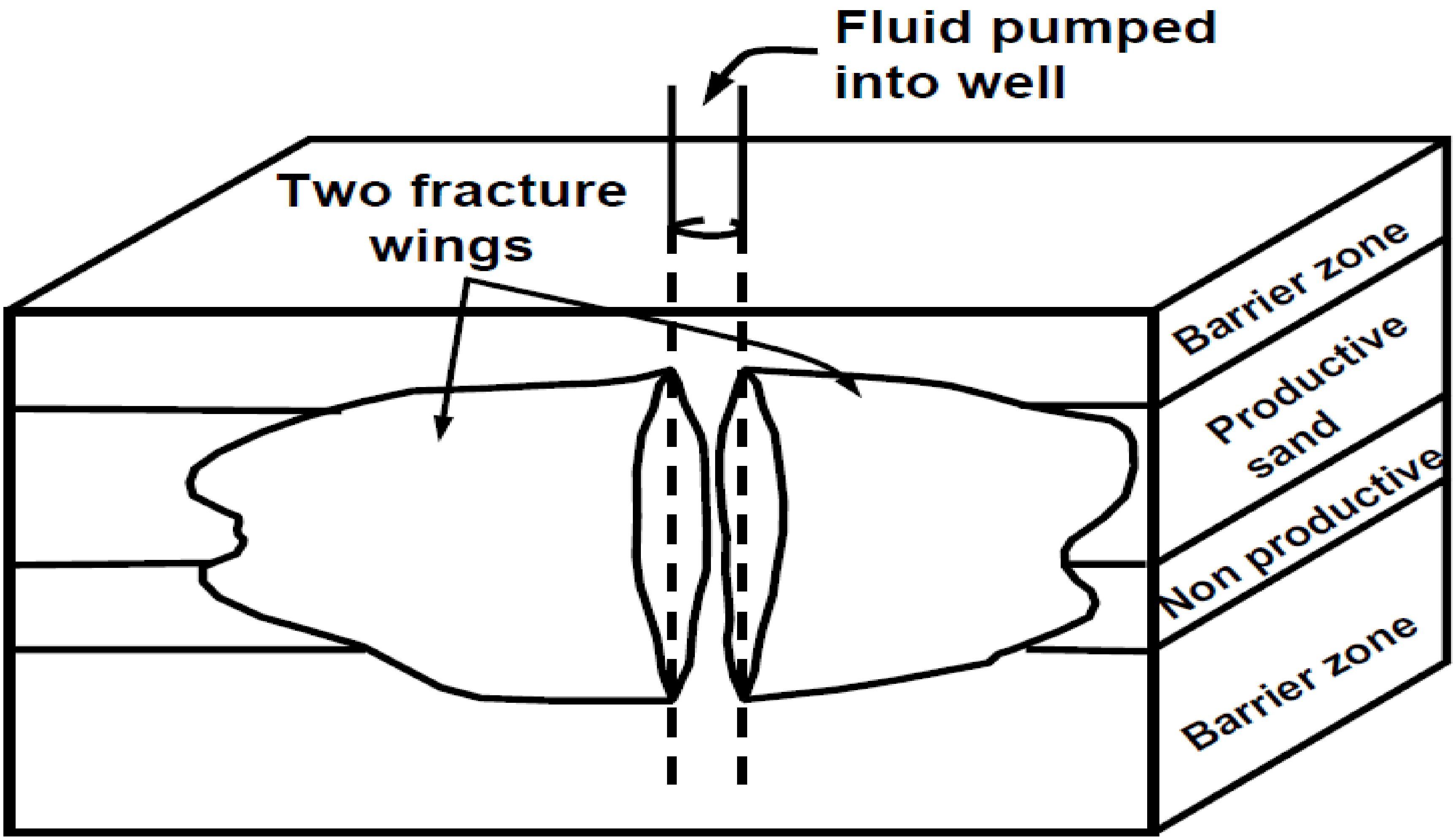
Pressure distribution for same production rate



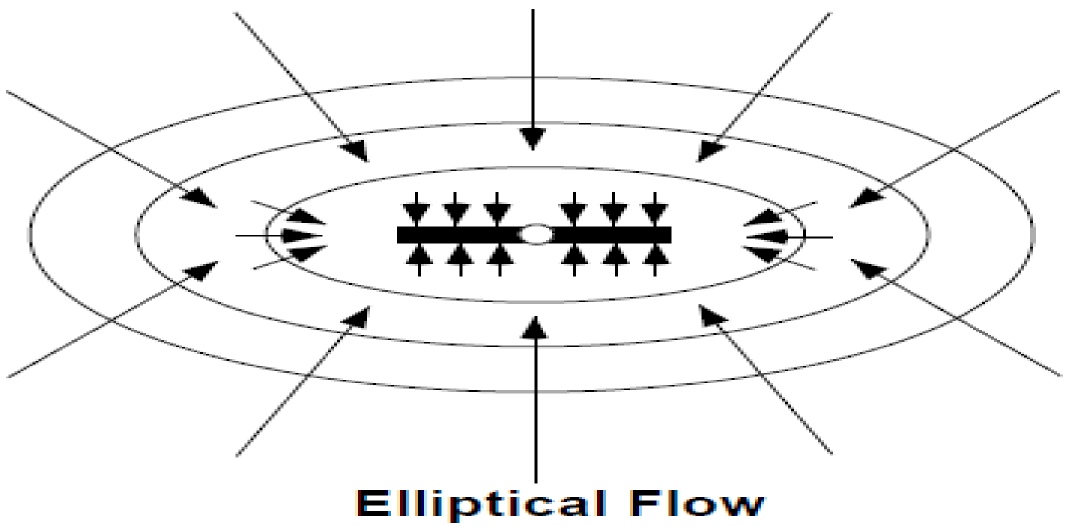
Radial flow

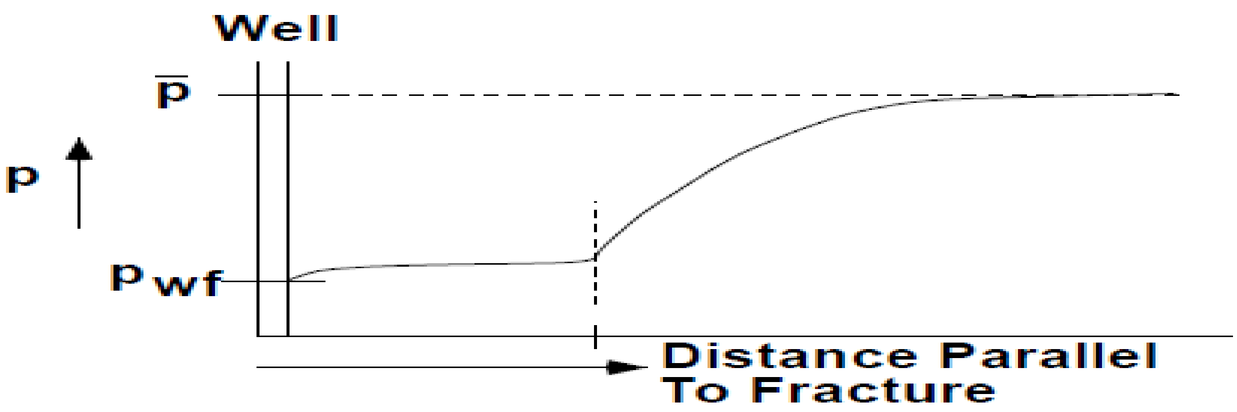


Hydraulic Fracturing



Hydraulic Fracturing





Reasons to Stimulate

- Increase oil and gas flow rates
- Overcome formation damage
- Enhance production from low permeability wells
- Connect with natural fracture system
- Increase effective drainage area
- Minimize drawdown around wellbore for Sand control
- Well bore stability
- Minimize paraffin and asphaltenes

Stimulation Candidates

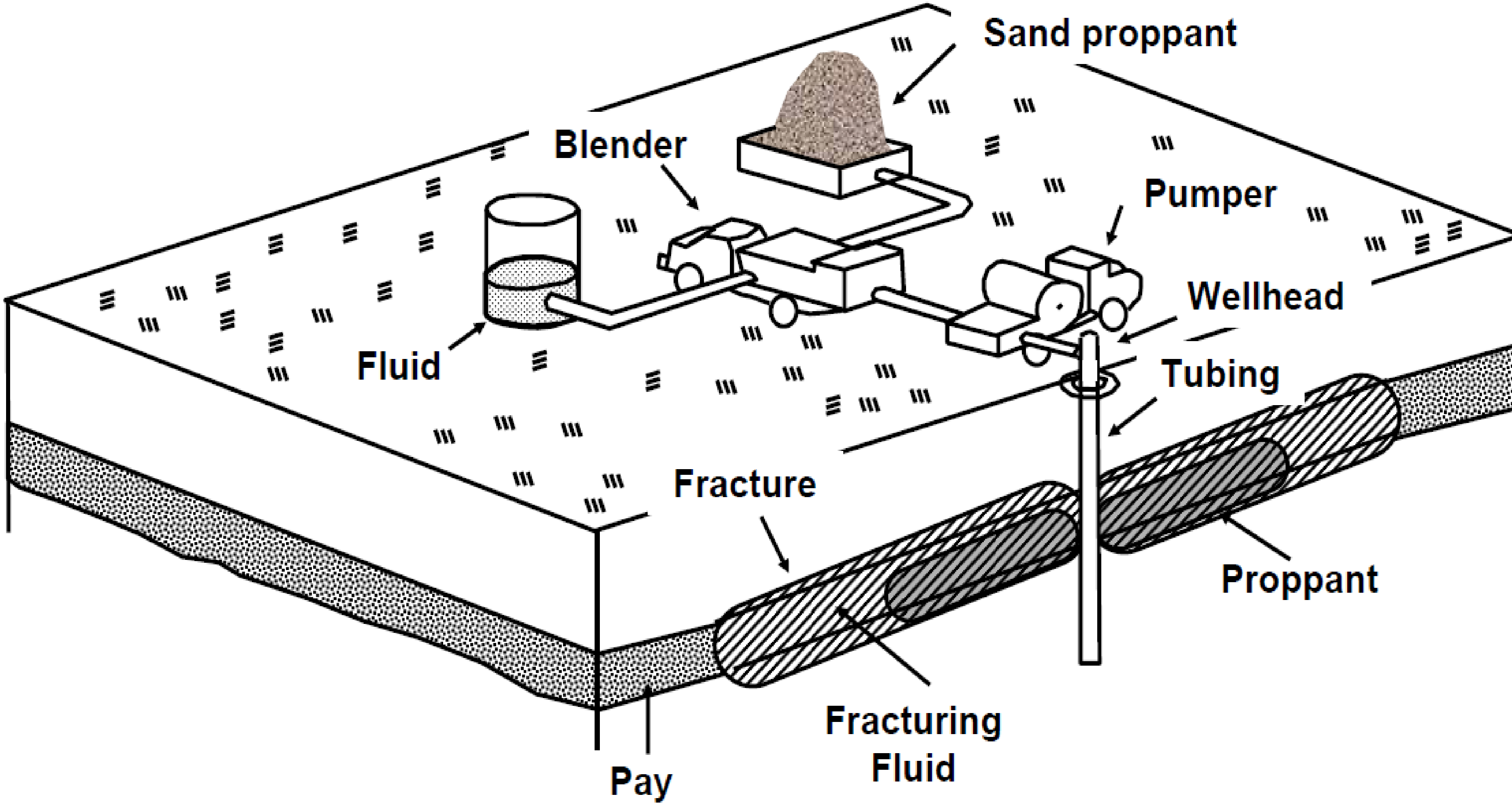
- Almost always good candidates:
  - Damaged wells
  - Low permeability reservoirs with sufficient oil or gas in place
- Sometimes good candidates:
  - Naturally fractured reservoirs
  - Unconsolidated, high permeability reservoirs, that have been damaged

Stimulation Candidates

Poor candidates:

- Reservoirs with limited reserves
- Thin reservoirs with poor barriers
- Low pressure reservoirs where fracture fluid flowback for cleanup is difficult (in case of hydraulic fracturing)
- Reservoirs where stimulation (particularly fracturing) can penetrate water zones and cause excess water production

Hydraulic Fracturing



Hydraulic Fracturing

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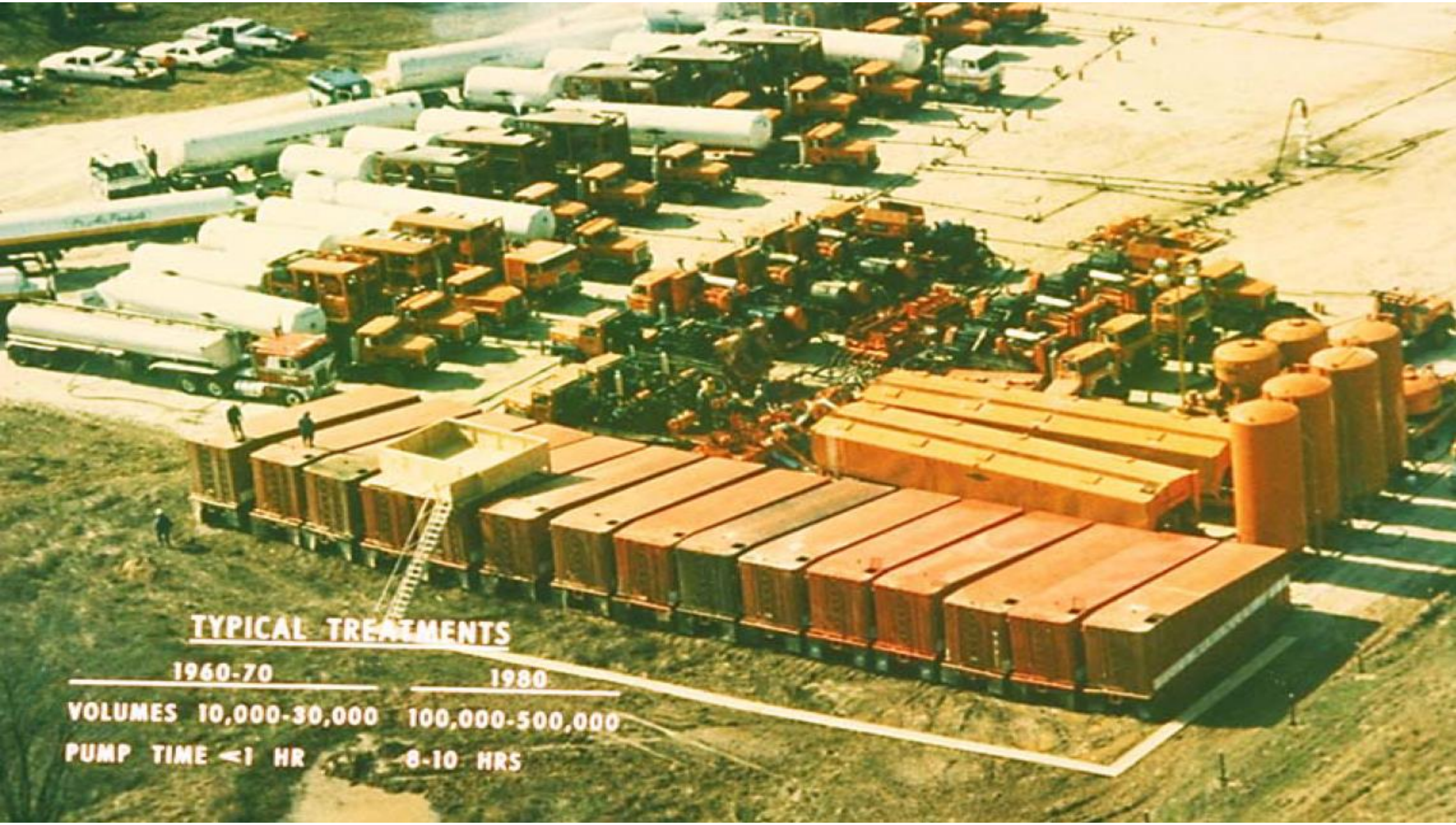

Hydraulic Fracturing

Hydraulic Fracturing

Proppants

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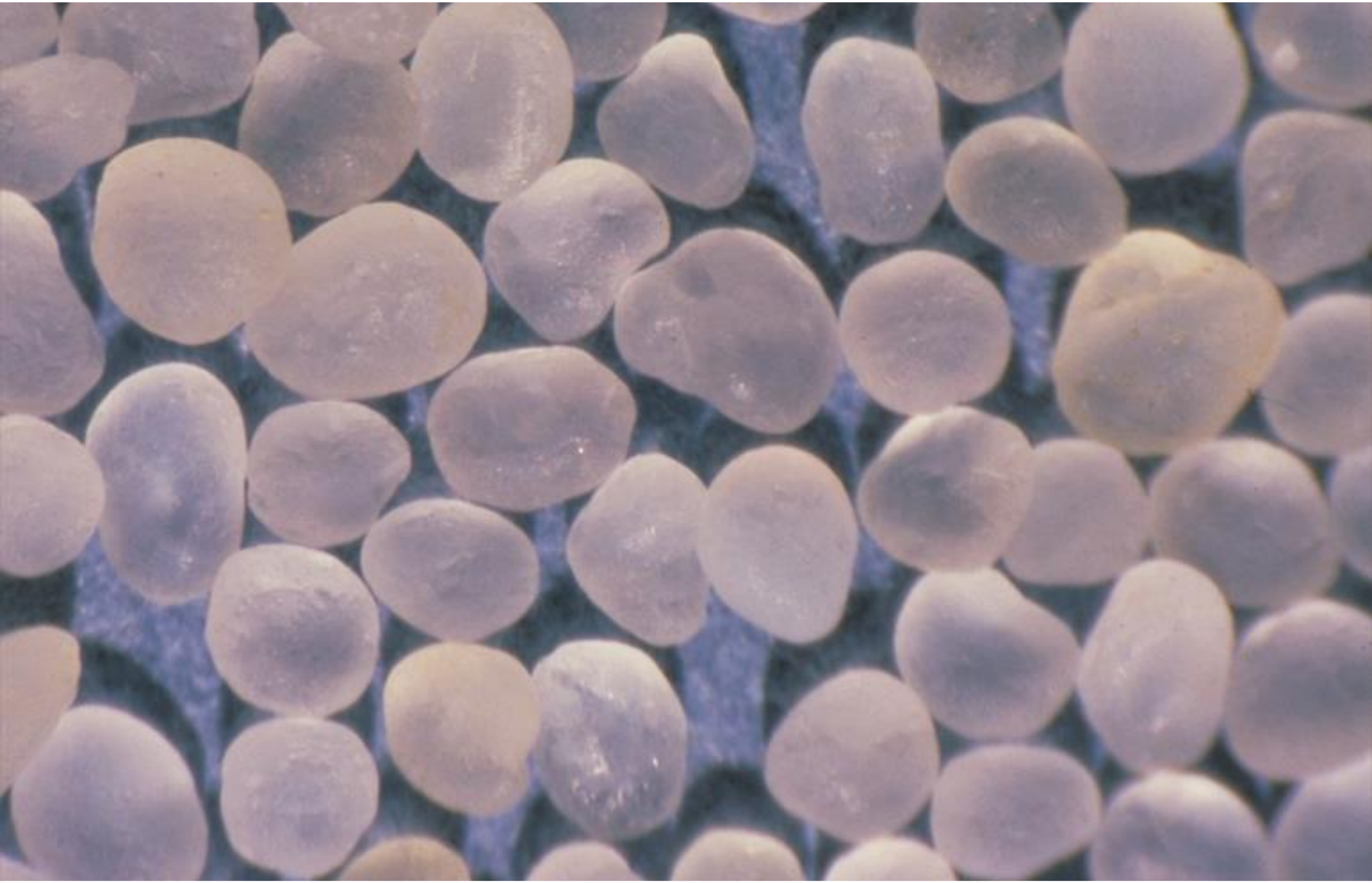

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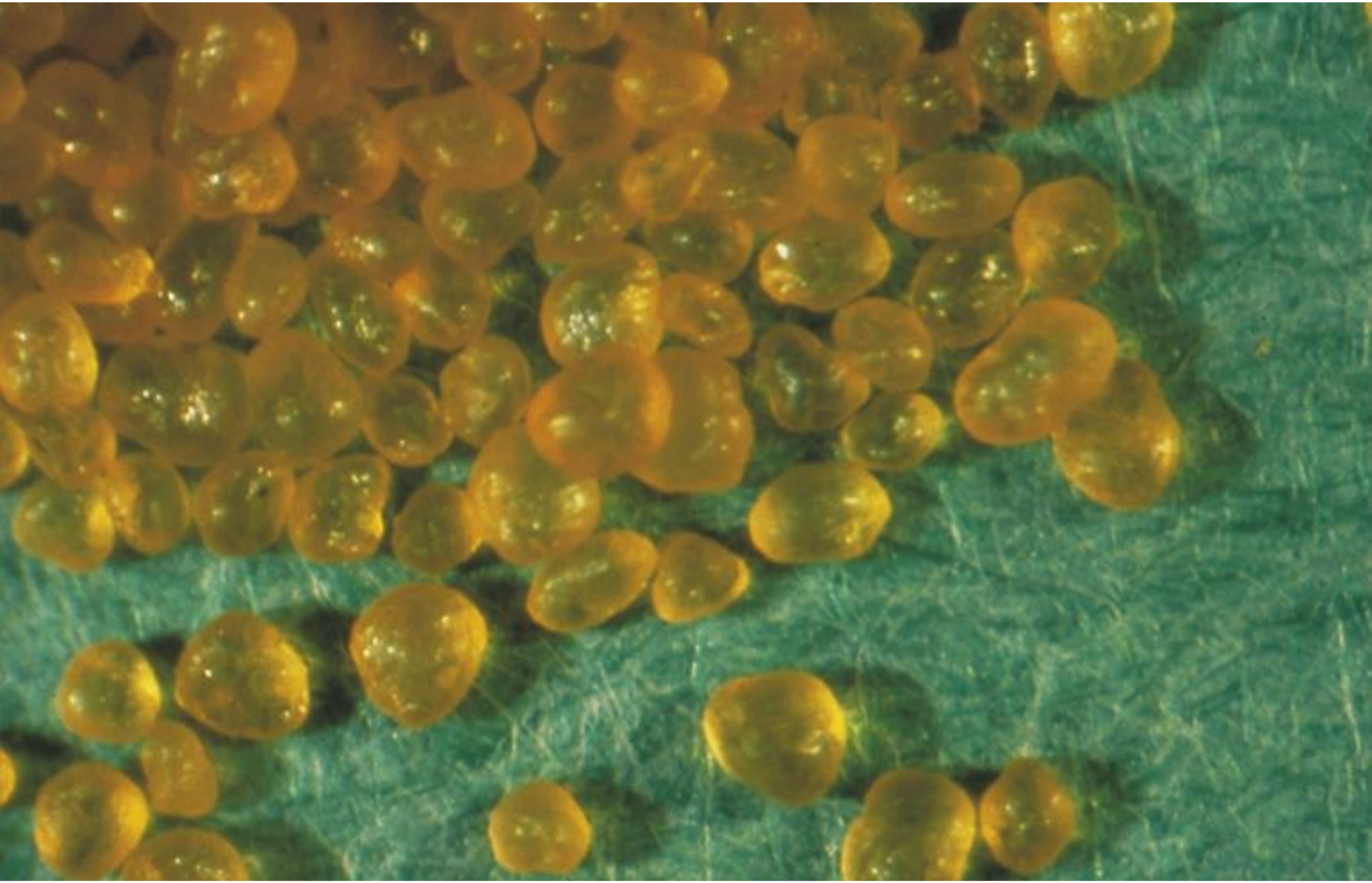

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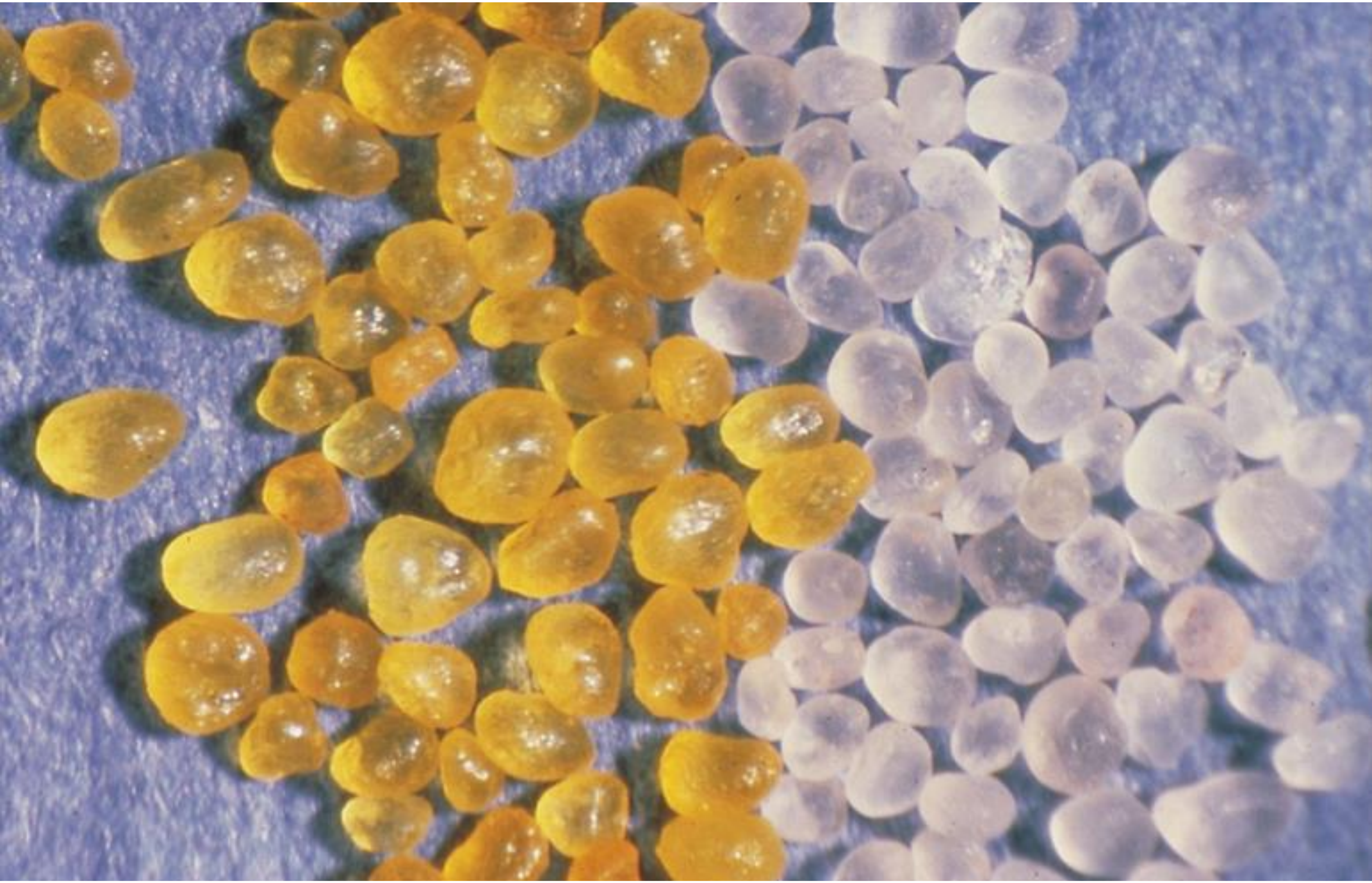

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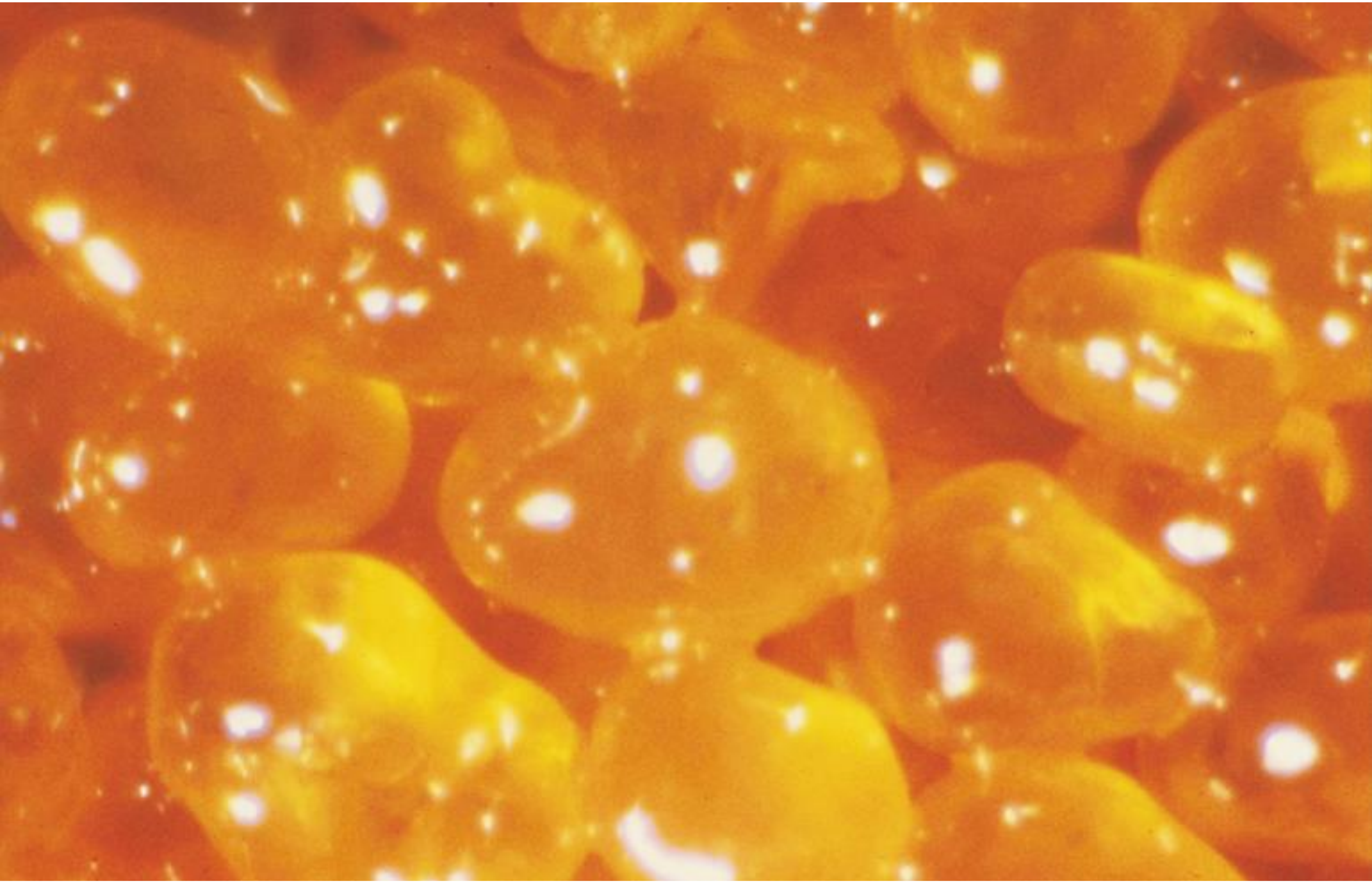

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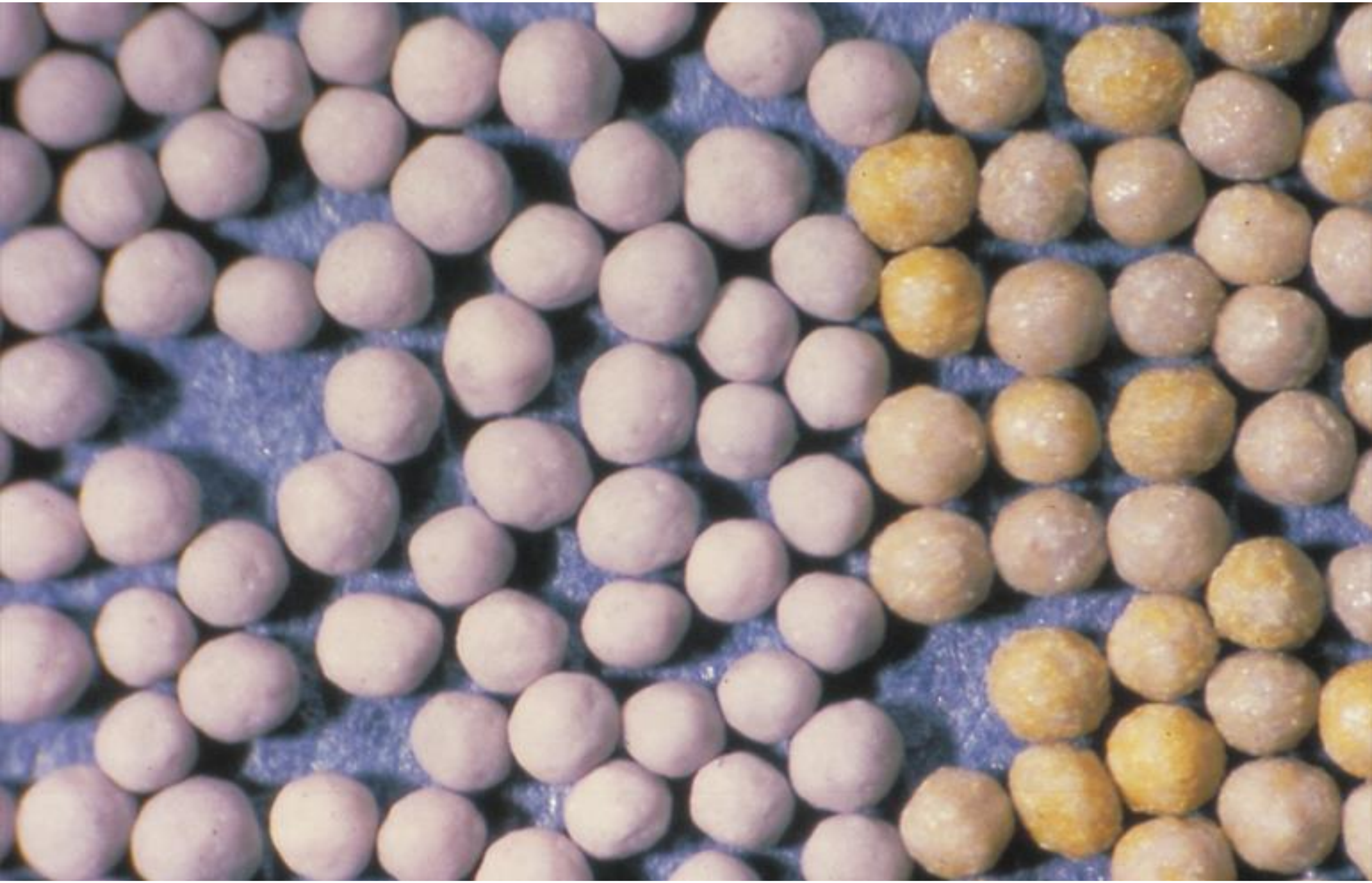

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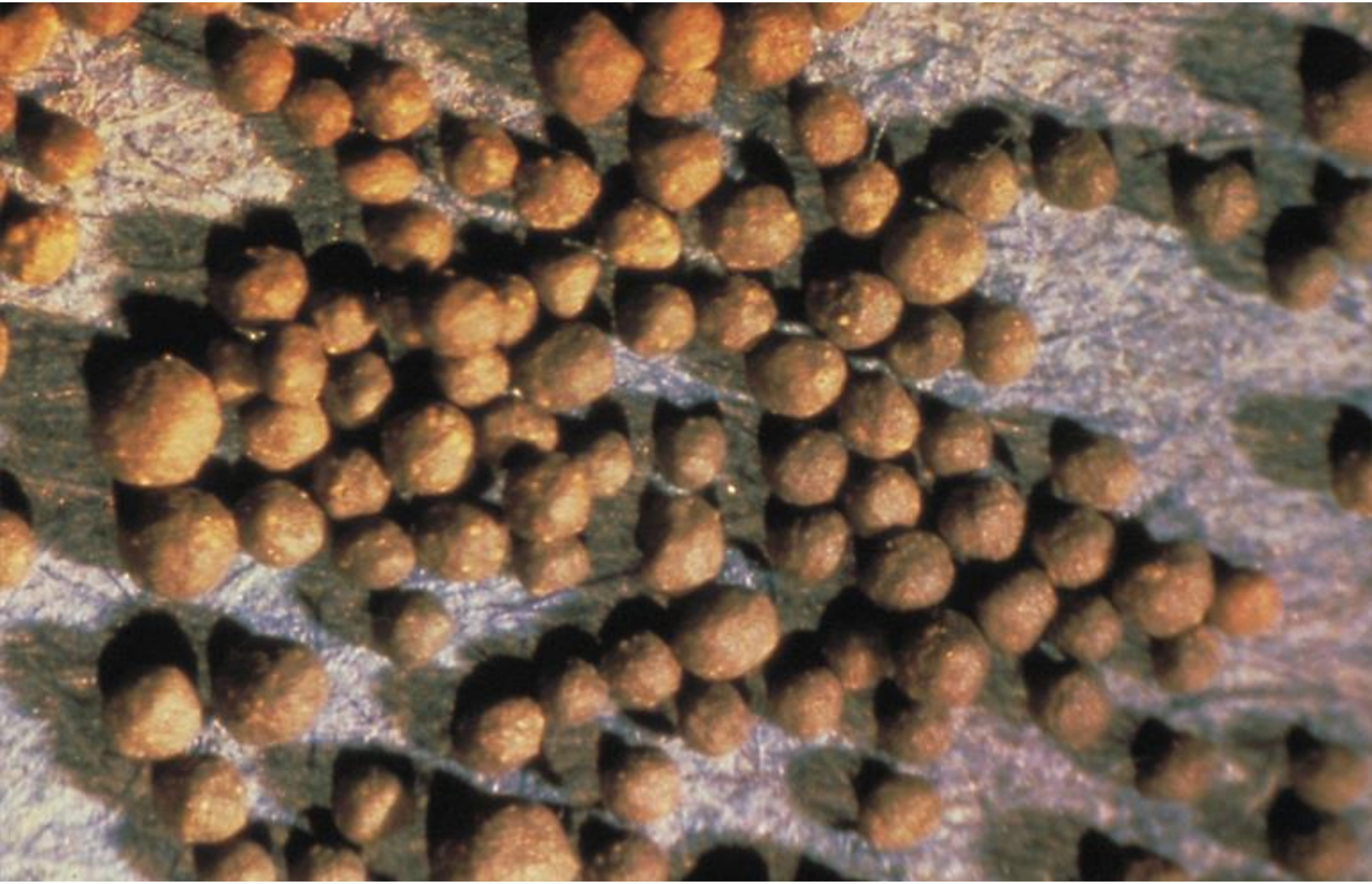

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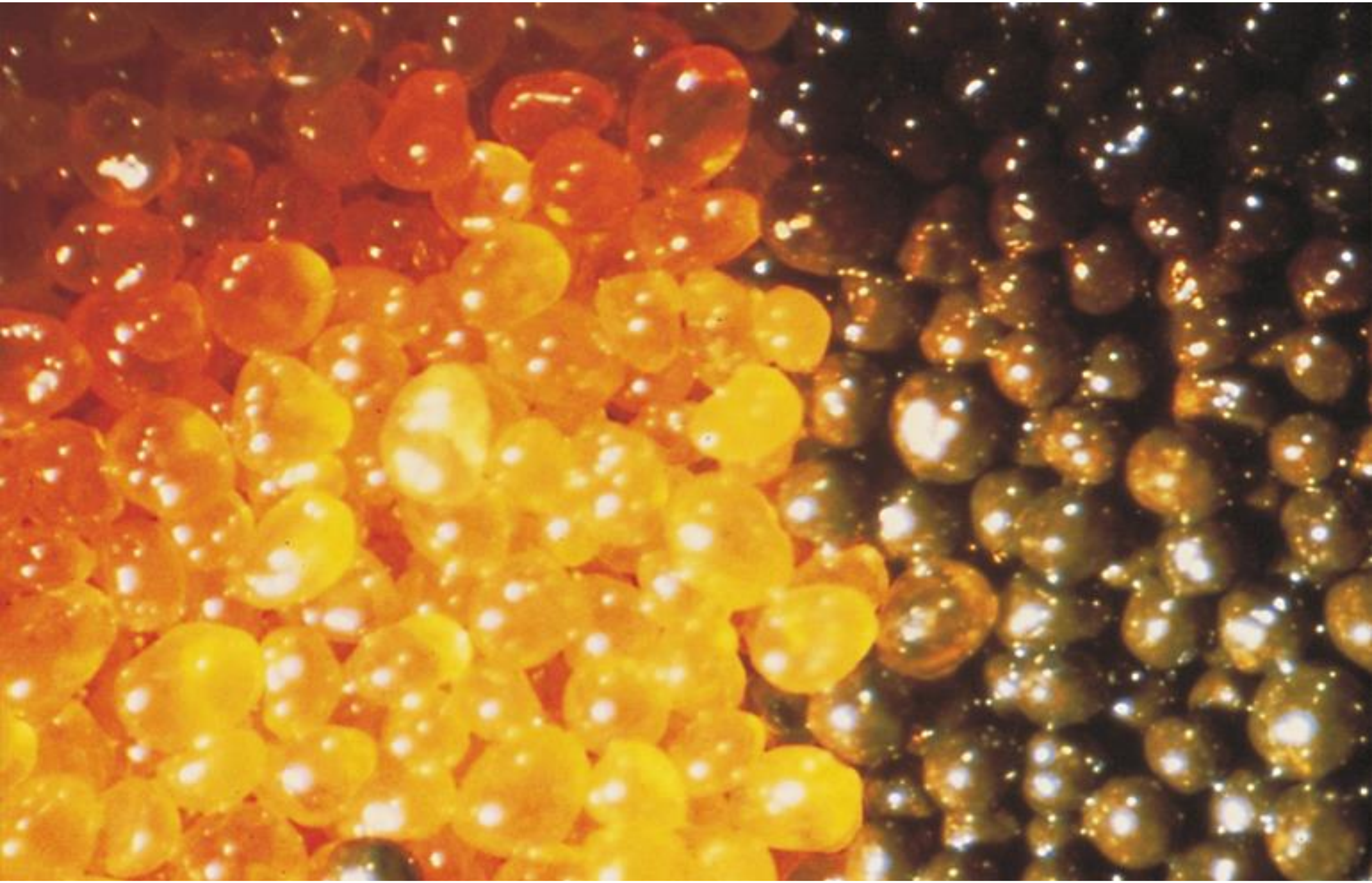


Typical Fracturing Fluid Additives

- Polymers
- Crosslinkers
- Breakers
- Buffers
- Foamers
- Temperature Stabilizers

Typical Fracturing Fluid Additives

- Biocides
- Surfactants
- Clay Stabilizers
- Friction Reducers
- Diverting Agents
- Fluid Loss Additives

https://fracfocus.org/chemical-use/what-chemicals-are-used

Additive Compatibility

- Use minimum number of additives required for each situation
- Check for compatibility of all additives
- Many additives are temperature and/or pH sensitive

Biocides

- All water contains bacteria
- Always use a biocide with water based fluids
- Biocides are required to control growth of both aerobic and anaerobic bacteria
- Bacteria will attack the organic polymers, destroying the bonds and reducing the viscosity

Breakers

- Breakers should be used through most or all of treatment below 250 F
- Breaker loading and type is a function of:
  - pH
  - Temperature
  - Polymer loading
- Encapsulated breaker used to delay reaction

Breakers

Conditions For Breakers

	pH Range	Temp Range
Conventional Enzyme	3-7.5	70-130°F
High Temperature Enzyme	3-7.5	100-250°F
pH Tolerant Enzyme	3-14	100-250°F
Oxidizer	3-14	130-260°F*
Catalyst Oxidizer	3-14	70-120°F
High Temp. Oxidizer	3-14	180-250°F
Encapsulated Oxidizer	3-14	100-300°F
Delay Oxidizer	3-14	100-300°F
Weak Acids	NA	200°F±**

* Very Rapid Breakdown and Sensitivity Above 180°F
** Not Applicable in Carbonate Reservoirs

Breakers

Oxidative And Enzyme Breakers

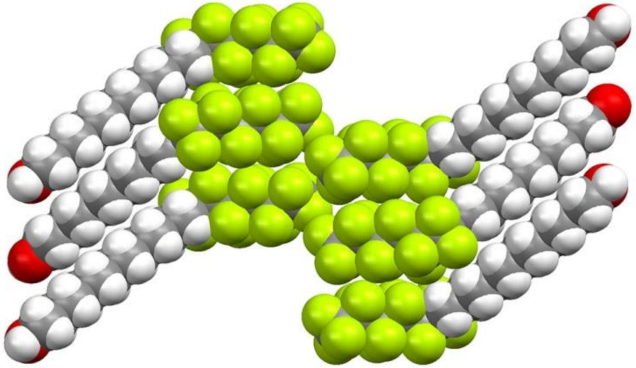
- Oxidative breakers (ammonium, $(NH_4)_2S_2O_8$ and sodium persulfate, $Na_2S_2O_8$)
  - Chemical reaction with metal ions
- Enzyme breakers (sugar)
  - Splits crosslink bonds
  - Each enzyme can react with multiple crosslink sites

Buffers

- Control the pH of fluids
- Crosslinking agents will be affected by pH
- Most fluids will break quicker when pH is lower
- Temperature stability of fluids are higher at higher pH values
- Engineer needs to be familiar with pH requirements for specific fluids being pumped

Surfactants

- Non-emulsifiers
- Water wetting
- Fluorocarbons
- Nonionics
  - Less adsorption
  - Compatible with clay control additives



- Mutual solvent
  - Mutual solvents are routinely used in a range of applications, such as removing heavy HC deposits, controlling the wettability of contact surfaces before, during or after a treatment, and preventing or breaking emulsions.

Clay Stabilizers

- Granular salts
  - Sodium chloride ($NaCl$)
  - Calcium chloride ($CaCl_2$)
  - Potassium chloride (KCl)
  - Ammonium chloride (NH_4Cl)
- Liquid KCl substitutes
- Cationic polymers
  - Type of chain growth polymerization in which a cationic initiator transfers charge to a monomer which then becomes reactive. This reactive monomer goes on to react similarly with other monomers to form a polymer.

Fluid Loss Additives

- Control leak off into matrix or natural fractures
  - Bridging materials
    - Solids, such as silica flour, 100 mesh
      - http://www.showmegold.org/news/Mesh.htm
  - Plastering materials
    - Soft material - resins, starch,
  - Multi-phase
    - Hydrocarbon emulsion

Diverting Agents

- Divert flow by physical means
- Ball sealers
- Ball and baffle technique
- Sand plugs
- Selective treating with packers and bridge plugs

Diverting Agents

Divert flow by chemical means

- Rock salt
- Benzoic acid flakes (fine and coarse)
- Oil soluble resin (high and low temperature)
- Unibeads (wax beads)
- Cross-linked polymers
- Foams
- Mixture of and oil soluble resin

Summary of Chemical Additives

Type of additive	Function performed	Typical products
Biocide	Kills Bacteria	Gluteridehyde Carbonates
Breaker	Reduces Fluid Viscosity	Acid, Oxidizer, Enzyme Breaker
Buffer	Controls the pH	Sodium Bicarb., Fumaric Acid
Clay Stabilizer	Prevents Clay Swelling	KCl, NH Cl, KCl Substitutes
Diverting Agent	Diverts Flow of Fluid	Ball Sealers, Rock Salt, Flake Boric-Acid
Fluid Loss Additive	Improves Fluid Efficiently	Diesel, Particulates, Fine Sand
Friction Reducer	Reduces the Friction	Anionic Copolymer
Iron Controller	Keeps Iron in Solution	Acetic & Citric Acid. EDTA, NTA
Surfactant	Lowers Surface Tension	Fluorocarbon, Nonionic
Gel Stabilizer	Reduces Thermal Degradation	MEOH, Sodium Thiosulphate

Fracturing Fluids Summary

Base Fluid	Fluid Type	Main Composition	Used For
Water Based	Linear Fluids	Gelled Water, GUAR< HPG, HEC, CMHPG	Short Fractures, Low Temperatures
	Crosslinked Fluids	Crosslinker + GUAR, HPG, CMHPG, CMHEC	Long Fractures, High Temperatures
Foam Based	Water Based Foam	Water and Foamer + N2 or CO2	Low Pressure Formations
	Acid Based Foam	Acid and Foamer + N2	Low Pressures, Water Sensitive Formations
	Alcohol Based Foam	Methanol and Foamer + N2	Low Pressure Formations With Water Blocking Problems
Oil Based	Linear Fluids	Oil, Gelled Oil	Water Sensitive Formations, Short Fractures
	Crosslinked Fluids	Phosphate Ester Gels	Water Sensitive Formations, Long Fractures
	Water External Emulsions	Water + Oil + Emulsifier	Good For Fluid Loss Control

Types of Fractures

According to the way that keep the Fracture conductive, it can be classified into:

- Propped fracture
- Acid fracture
- Propped acid fracture (soft carbonate)
- Closed Fracture Acidizing (CFA)
- Widely Spaced Etched Ridges (WISPER)

Types of Fracture Wells

Matrix Acidizing $p_i < p_f$

Acid Fracturing $p_i > p_f$

Closed Fracture Acidizing:

First $p_i > p_f$;

Second $p_i < p_f$

Closed Fracture Acidizing (CFA)

- The injection of a low viscosity acid (28 wt% HCl) at a pressure just below the fracture closure pressure into: previously fracture, naturally fractured carbonate formation.

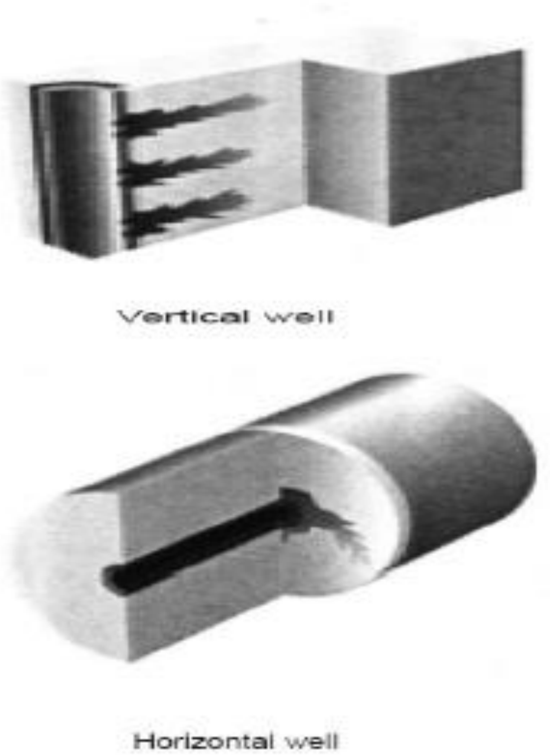
- Idea: only a small portion of the overall fracture face will be dissolved into relatively deep channels, the remaining un-etched fracture face can hold these channels open under very severe formation closure conditions

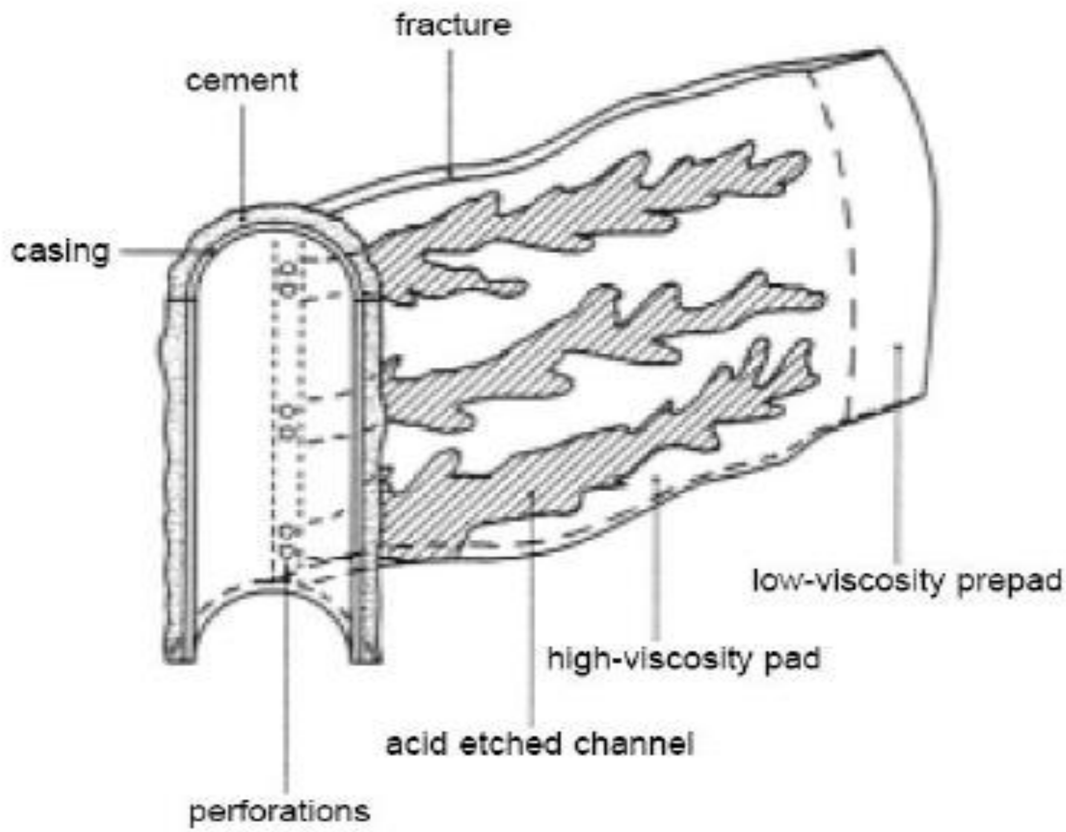
WISPER

- New technique developed by shell
- Used for homogeneous carbonates
- Procedures:
  - First pump a highly viscous pre-flush is required followed by the low viscous acid to displace the high viscous preflush in a finger-type pattern, thus creating high conductivity flow channels.
  - To prevent these fingers from merging, special perforation schemes should be applied, e.g. 2 ft of high-density perforations (4 spf or more) every 5 ft, a viscosity ratio between the pre-flush and acid of around 300 should be maintained

WISPER

WISPER





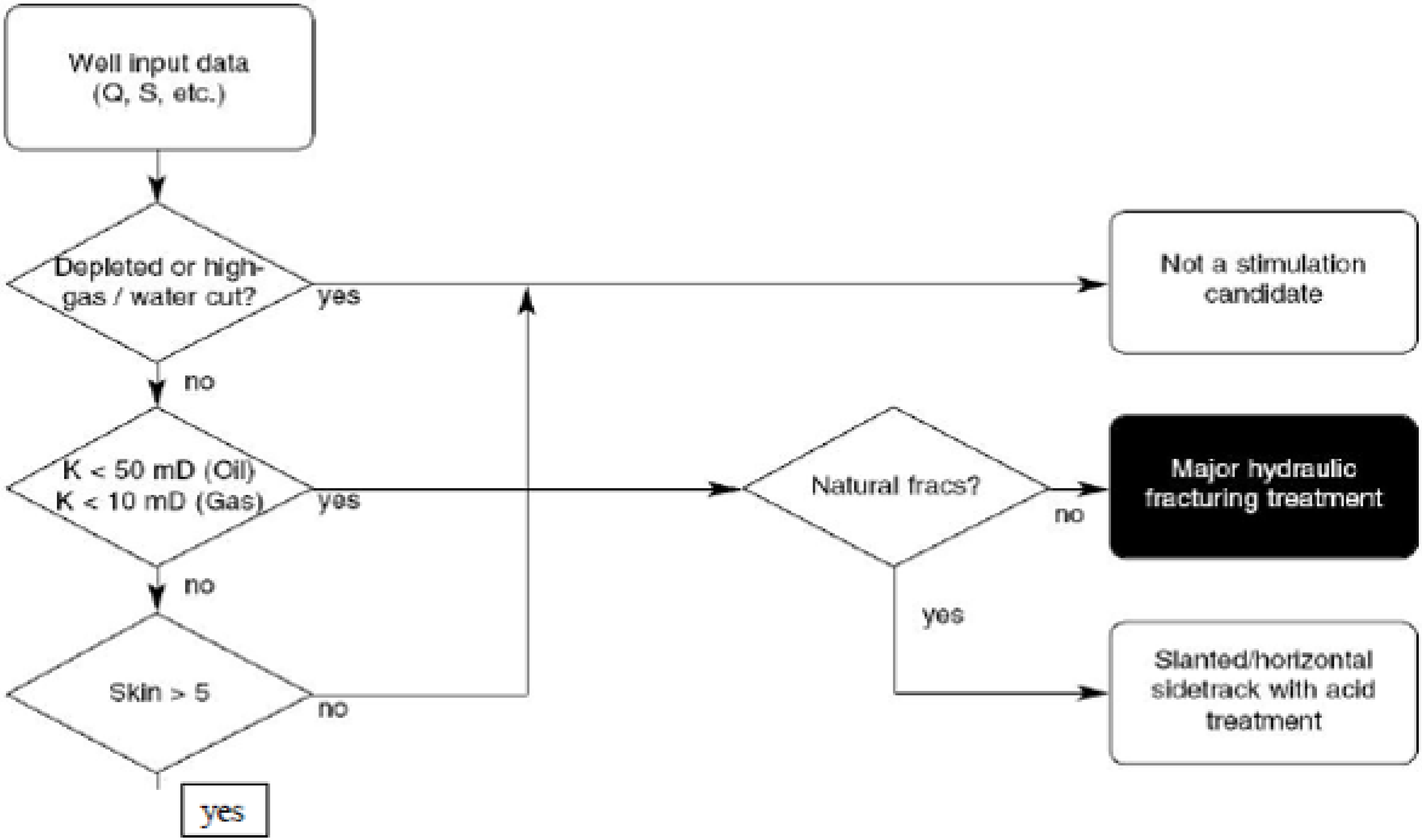
Basic Requirements

- The basic requirements for a successful stimulation treatment are simple:
  - The reservoir must contain adequate volumes of moveable hydrocarbons.
  - The reservoir pressure should be high enough to initiate and maintain hydrocarbon flow towards the well-bore.
  - The production system (tubing, flow lines, separators, etc.) can accommodate the extra production.
  - A professional treatment design, execution and supervision is important.

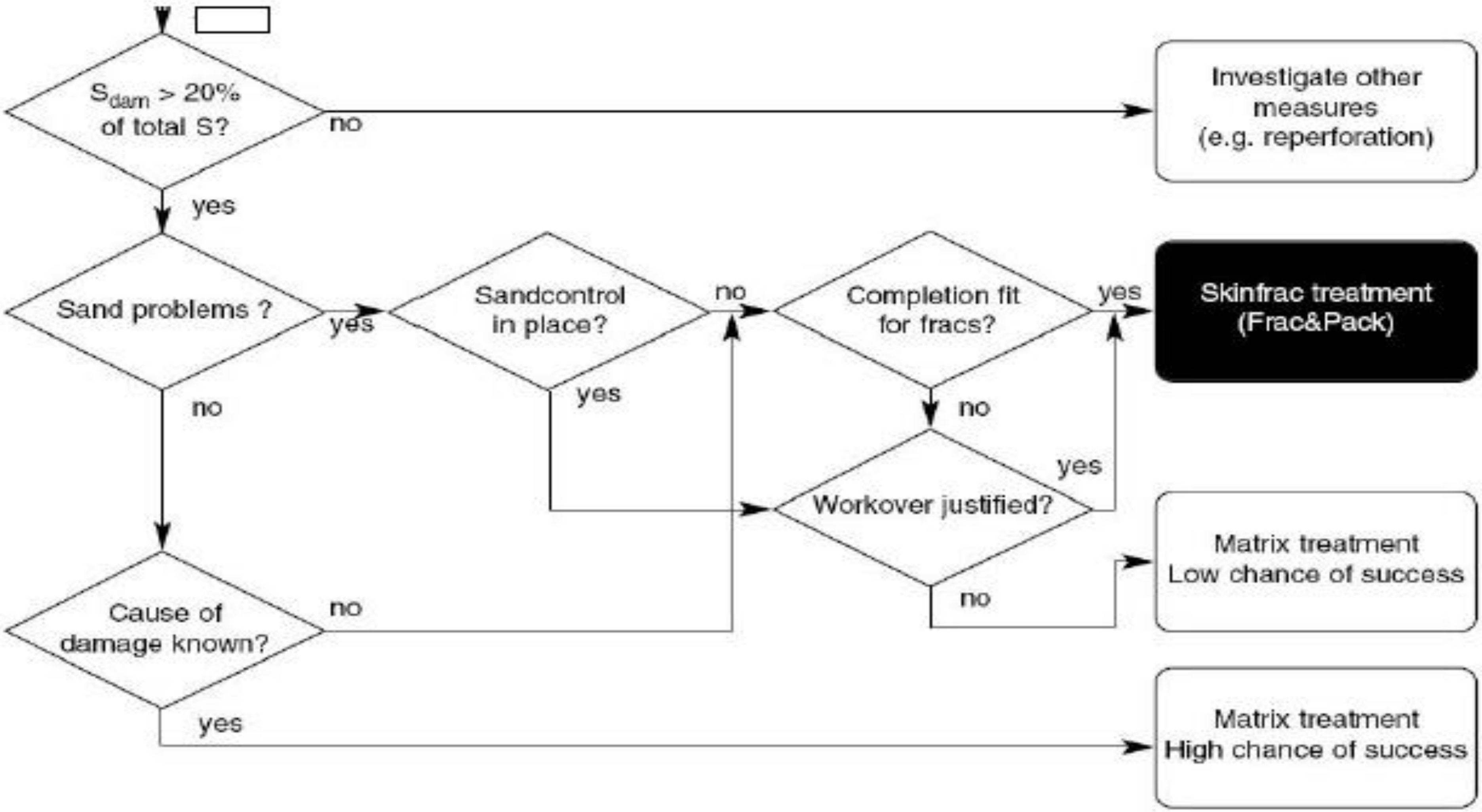
Requirements From Economical Point of View

- Hydrocarbon saturation 30% or more
- Water cut 50% or less
- Gross reservoir height : 10 m or more. In horizontal wells, where transverse fractures are expected, this requirement is not applicable
- Permeability : Gas: less than 10 md, Oil: less than 50 md
- Reservoir pressure :
  - Gas: at least two times the abandonment pressure
  - Oil: not more than 80% depletion
- Production system :
  - Production not more than 80% of maximum capacity of facilities

Stimulation Treatment Selection



Stimulation Treatment Selection



Fracture Treatment Selection

	Sand stone	Soft carbonate	Hard Carbonate	Fractured carbonate
Propped frac	+ +	+ +	+	-
Acid frac	-	-	+ +	+
WISPER	-	+ +	+ +	+
Propped acid frac	-	+	-	-
CFA	-	+ +	+ +	+ +

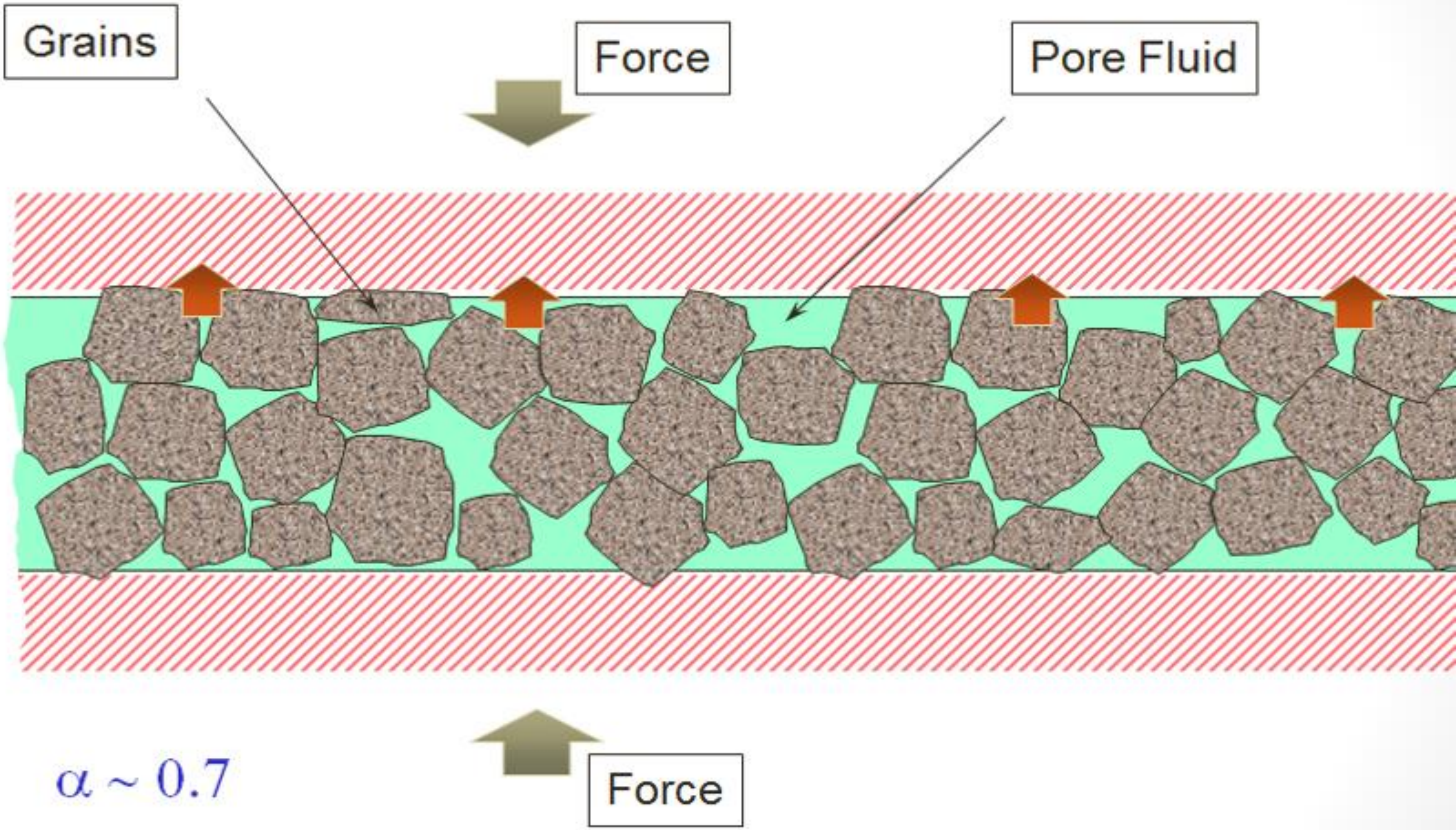
Legend: + + Preferred + Reasonable - Poor

Poroelasticity and Biot's constant

$$\sigma = \sigma' + \alpha p$$

Total Stress = Effective Stress + α [Pore Pressure]

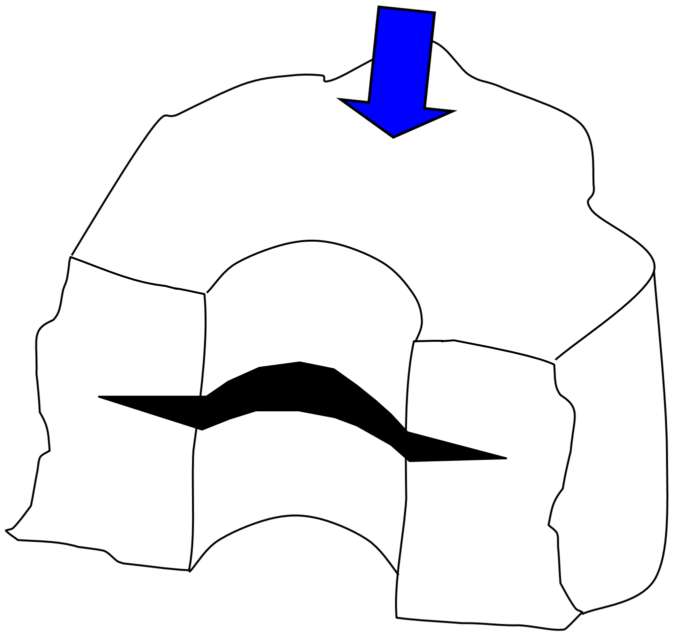
Who Carries the Load



$\alpha \sim 0.7$

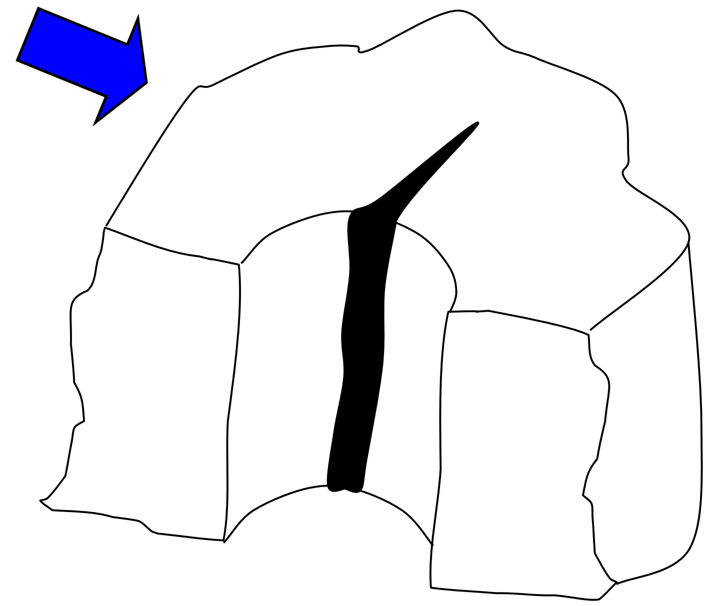
Principle of Least Resistance

Least Principal Stress



Horizontal fracture

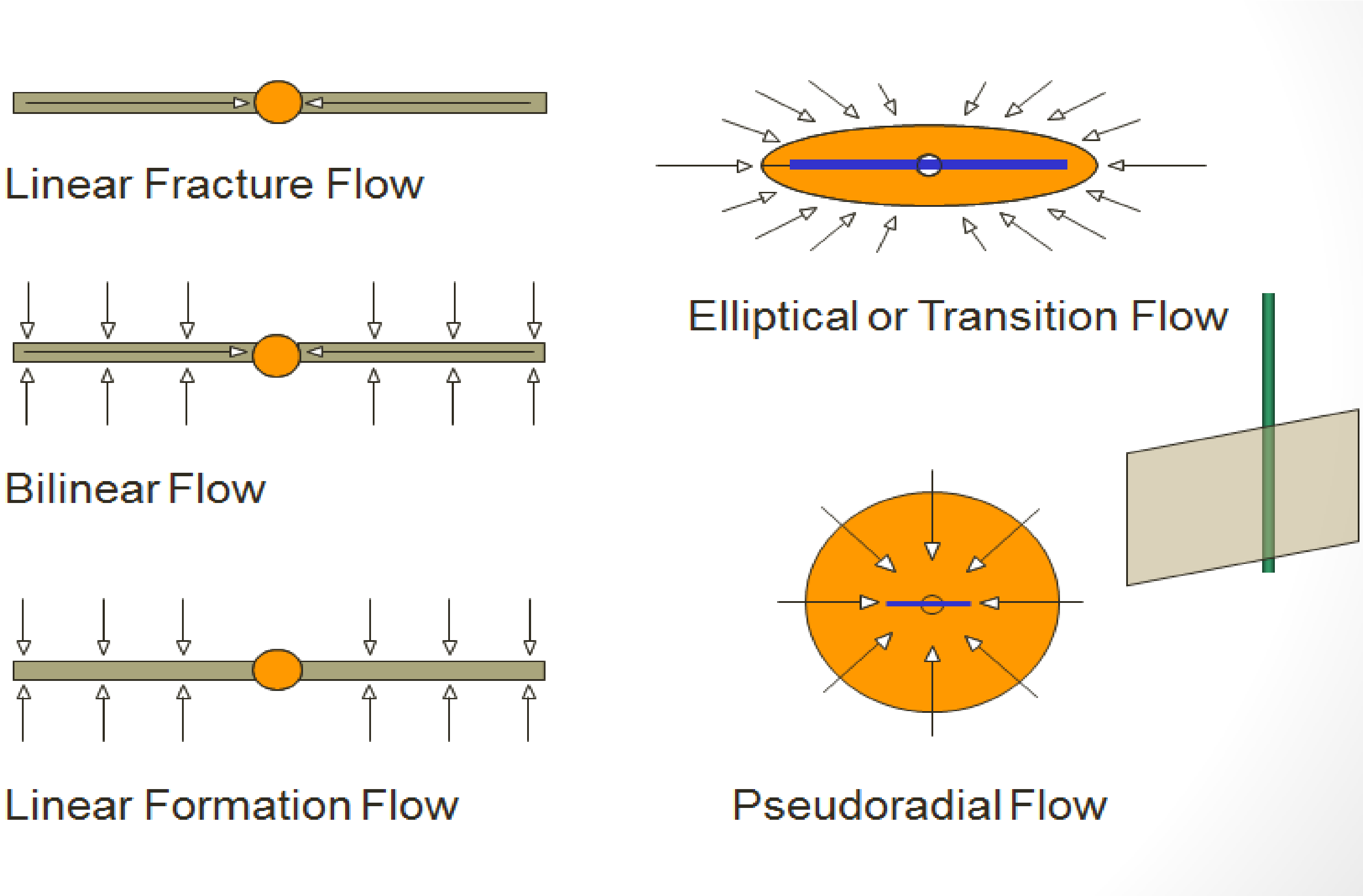
Least Principal Stress



Vertical fracture

Transient Flow Regimes

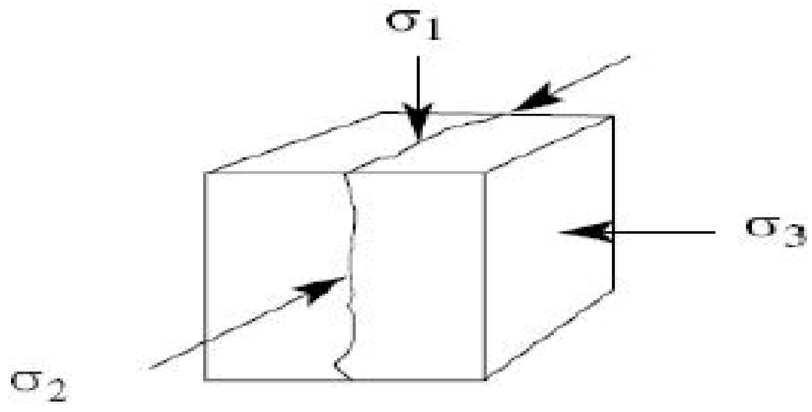
Vertical Fracture - Vertical well



Fracture Geometry

Fracture geometry and propagation

- In situ stresses:
  - Vertical stress ($\simeq$ 1:1.1 psi/ft).
  - Maximum horizontal stress.
  - Minimum horizontal stress ($\simeq$ 0.65: 0.7 psi/ft).

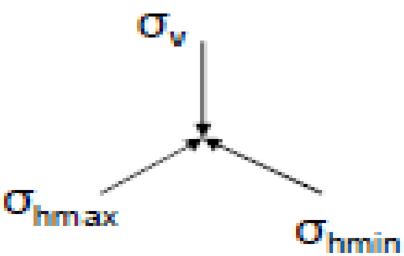


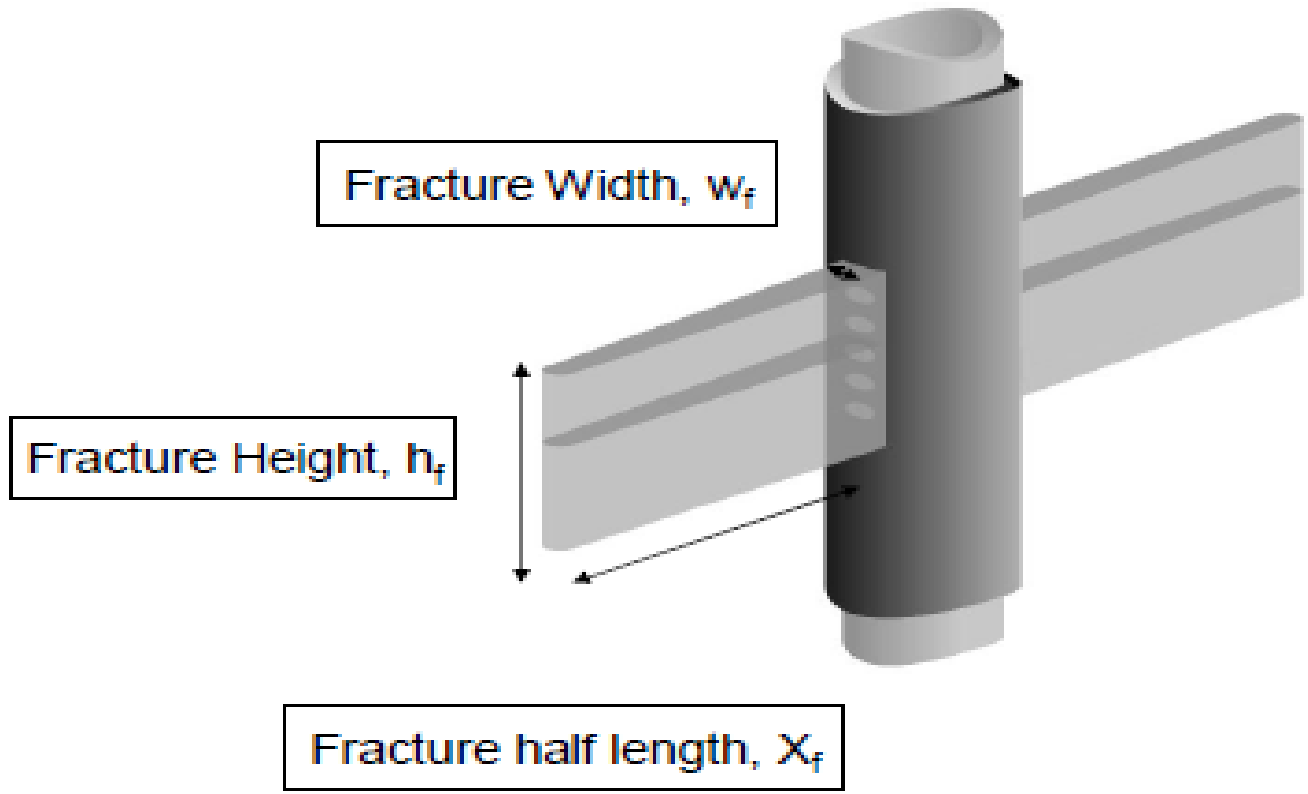
$\sigma_1 > \sigma_2 > \sigma_3$

Fracture Geometry

Fracture geometry and propagation

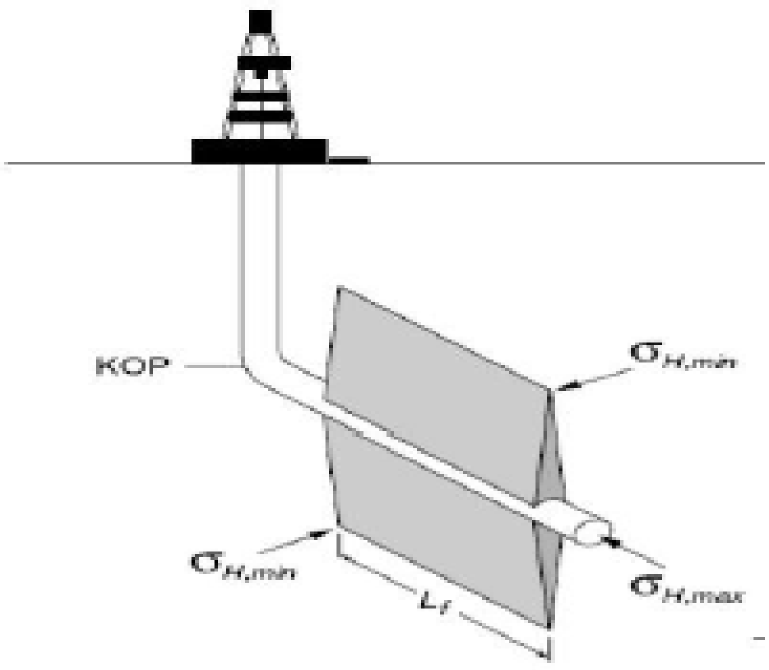
- Vertical Well



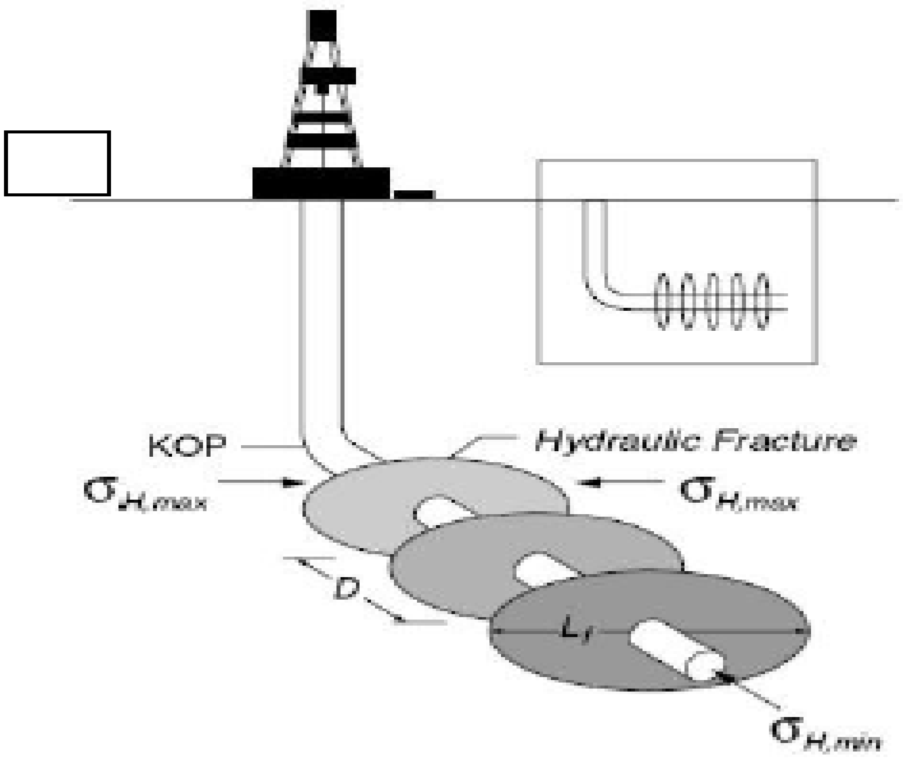


Fracture Geometry

Fracture geometry and propagation



Longitudinal vertical fracture



Transverse vertical fractures

Fracture Conductivity

- Defined as a multiply of fracture permeability by fracture width.
- Unit = md-in
- It is very difficult to separate between the permeability, and the width, therefore it combined in one parameter. also, it is still difficult to build a model than can predict fracture conductivity, because it depends on many parameter like:
  - Acid type - Temperature
  - Contact time - Leak-off rate
  - Rock type

Fracture Conductivity

Nirode and Kruk (1973) developed a correlation for acid fracture conductivity as follows:

$$wk_f = C_1 e^{(-C_2 S)}$$

$$C_1 = 0.265[DREC]^{0.822}$$

$$C_2\ (x10^3) = \begin{cases} 13.9 - 1.3\ln(RES), & 0 < RES < 20{,}000\ psi \\ 3.8 - 0.28\ln(RES), & 20{,}000 < RES < 50{,}000\ psi \end{cases}$$

Where;

S = fracture closure stress, psi

DREC = dissolved rock equivalent conductivity, md-in.

RES = rock embedment strength, psi

wk_f = fracture conductivity, md-in.

Special case: Closed fracture acidizing (CFA)

- Existing fractures in the formation. The fractures can be natural, previously created fractures, or fractures hydraulically induced just prior to the CFA treatment

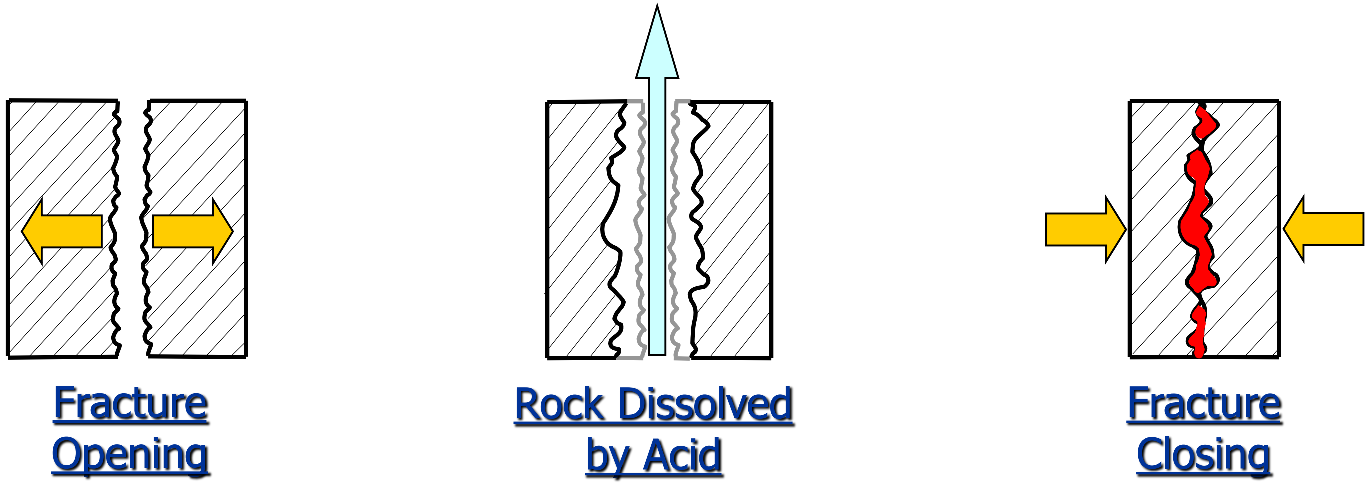
- Pumping acid at low rates below fracturing pressure into a fractured well. The acid preferentially flows into areas of higher conductivity (fractures) at low rates for extended contact times, resulting in enhanced flow capacity

Acid Fracturing

- Acid is injected at a rate high enough to generate the pressure required to fracture the formation.
- Differential etching occurs as the acid chemically reacts with the formation face.
- Areas where the rock has been removed are highly conductive to hydrocarbon flow after the fracture closes.
- In general no proppant

Acid Fracturing Process

- Acid dissolution along face of hydraulically induced fracture
- Success depends on long etched length with long lasting conductivity under closure



Acid Re-Fracturing Need

- Failure of primary process due to:
  - Uniform etching
  - Insufficient etching
  - Excessive formation softening

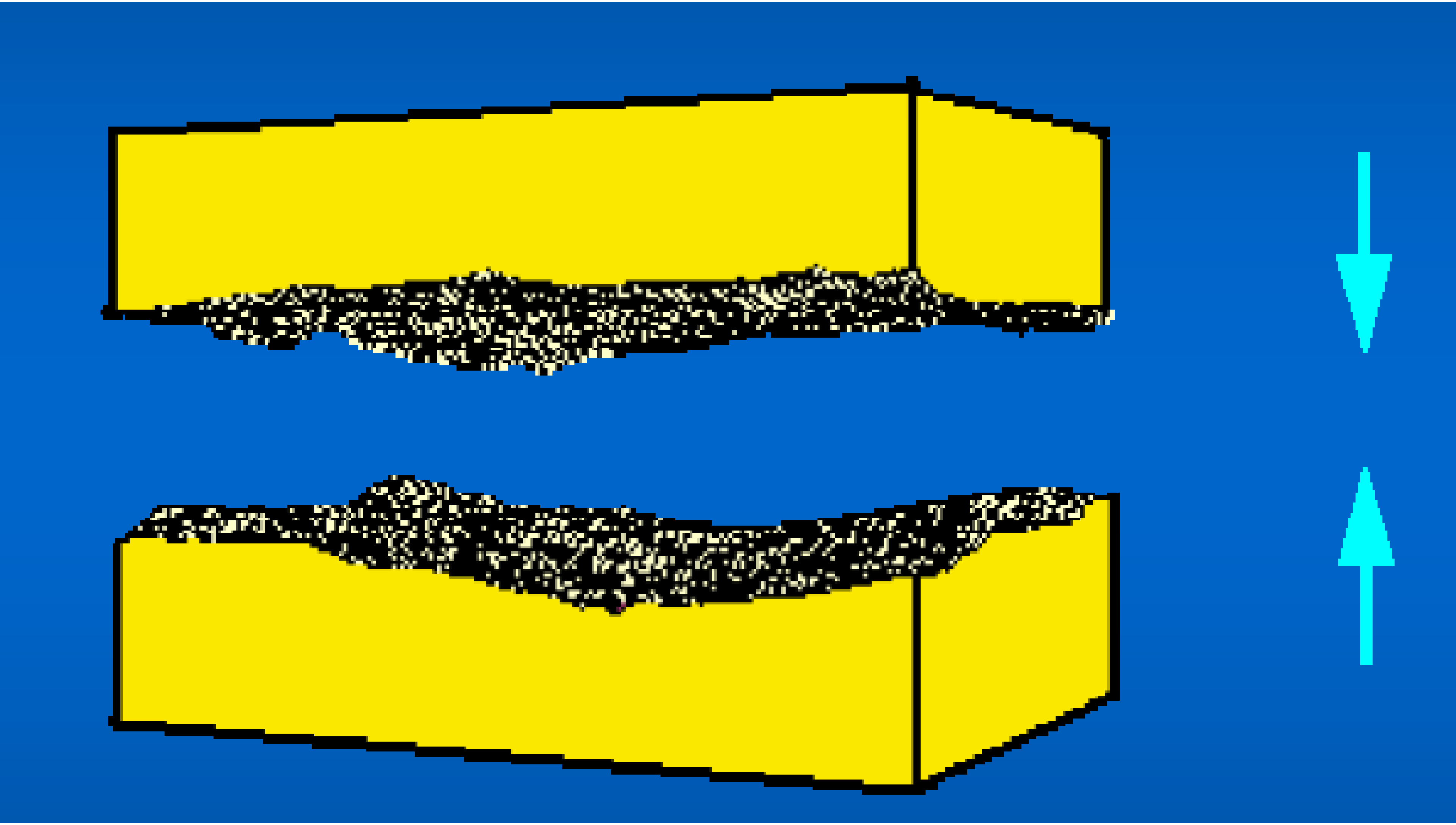
- Methods to overcome failure:
  - Closed fracture acidizing (CFA)
  - Equilibrium acid fracturing
  - Acid re-fracturing

Success of Re-Fracturing

- Mixed success results

- Success depends on:
  - Increase length for tight formations
  - Enhance conductivity for permeable reservoirs
  - Initial treatment size and reservoir capacity

Etching the Fracture Surface



Acid Leak off in Fracturing Process