Baker Hughes

Chapter Five

Reservoir Geomechanics Applications

Overview of Geomechanics
RTS Geomechanics Services

Copyright 2022 Baker Hughes Company LLC. All rights reserved. The information contained in this document is company confidential and proprietary property of Baker Hughes and its affiliates. It is to be used only for the benefit of Baker Hughes and may not be distributed, transmitted, reproduced, altered, or used for any purpose without the express written consent of Baker Hughes.

Copyright

By accepting these materials you agree that all materials provided by Baker Hughes (Contractor) shall be the sole and exclusive property of Contractor, without limitation or exception. This provision shall extend to any and all training materials, documents, reports, files or computers used by Contractor in conjunction with the rendition of its training course. The copyrighted materials provided by Contractor for training may not be used for course training without the express written permission of Contractor. It is expressly forbidden to make analog and/or digital copies for individuals not involved in the training without the written permission of Contractor.

Warranty Disclaimer

THE TRAINING PROGRAM AND ANY TRAINING MATERIALS ARE PROVIDED TO CUSTOMER "AS IS", WITHOUT WARRANTY OF ANY KIND. CONTRACTOR EXPRESSLY DISCLAIMS TO THE FULLEST EXTENT PERMISSIBLE BY LAW ALL WARRANTIES, WHETHER EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY IMPLIED WARRANTIES FOR ACCURACY, COMPLETENES, PERFORMANCE, MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR NON-INFRINGEMENT, REGARDING ANY SERVICES PERFORMED BY CONTRACTOR HEREUNDER.

ACCORDINGLY, CONTRACTOR DOES NOT WARRANT THAT CUSTOMER'S RELIANCE OR USE AND/OR ANY THIRD PARTY'S RELIANCE OR USE OF THE TRAINING MATERIALS OR INFORMATION LEARNED THROUGH THE TRAINING PROGRAM WILL ACCOMPLISH ANY PARTICULAR RESULT, AND CUSTOMER ASSUMES ALL RESPONSIBILITY FOR ANY SUCH USE OR RELIANCE AND CUSTOMER HEREBY RELEASES, INDEMNIFIES AND HOLDS HARMLESS CONTRACTOR, ITS PARENT, SUBSIDIARY AND AFFILIATED OR RELATED COMPANIES, AND THE OFFICERS, DIRECTORS, EMPLOYEES, CONSULTANTS AND AGENTS OF ALL OF THE FOREGOING FROM AND AGAINST ANY AND ALL CLAIMS, DAMAGES, COSTS, LOSSES AND LIABILITIES ARISING OUT OF SUCH USE OR RELIANCE, REGARDLESS OF THE CAUSE, INCLUDING BUT NOT LIMITED TO, THE SOLE, JOINT, OR CONCURRENT NEGLIGENCE, STRICT LIABILITY, OR OTHER FAULT OR RESPONSIBILITY OF EITHER PARTY.

Baker Hughes

Hydraulic Fracturing

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Hydraulic Fracture

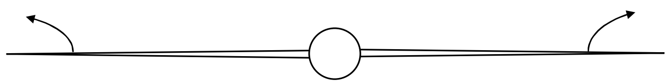
- Hydraulic Fracture Growth and Containment
- Sweep Efficiency in Water Floods
- Mapping Fracture Growth
- Hydraulic Fracturing and Depletion
- Minimizing Hydrofrac Net Pressures

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Baker Hughes

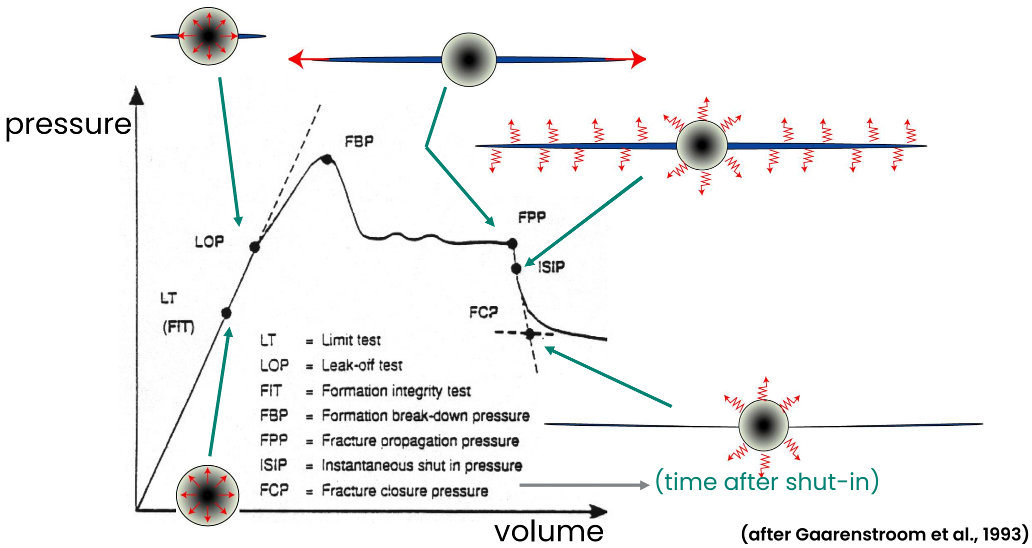
Hydraulic Fracturing Uses

- **To enhance well productivity/injectivity**
  - –Increase drainage efficiency, access naturally fractured zones, inject/produce fluids in geothermal wells, acidizing, frac packing
- **To introduce thermal energy (steam fractures)**
- **To measure stress (Minifrac™, LOT, XLOT)**
- **For drill cuttings annular reinjection and massive waste injection**



Baker Hughes

Least Principal Stress (S_{hmin}) from XLOT



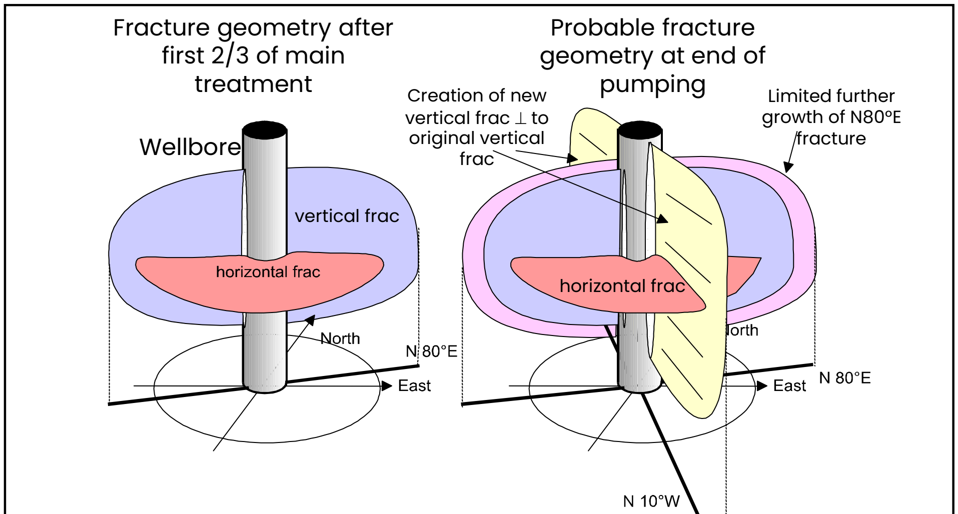
(after Gaarenstroom et al., 1993)

Baker Hughes

An idealized extended leak-off test is shown. The pumps are turned on and the pressure down hole increases linearly with increasing volume of fluid pumped. If the test is stopped before there is a deviation in the linear trend it is called a Formation Integrity Test (FIT) or Limit Test (LT). An FIT or LT does not provide any information about the least principal stress. The FIT or LT can be either above or below the least principal stress because of the stress concentration around the wellbore. If the test is continued then at some point volume will be created down hole as a result of either a pre-existing fracture opening, or a new fracture being created. At this point there is a deviation from the linear trend and the beginning of the deviation is called the Leak-Off Point (LOP). If the test is stopped at this point, the LOP can be a reasonable estimate of the least principal stress. If the test is continued beyond this point, then the formation will break down at the Formation Breakdown Pressure (FBP) and the fracture will propagate away from the wellbore at the Fracture Propagation Pressure (FPP). The FBP is an unpredictable number that depends on the tensile strength of the rock, the stress concentration around the wellbore, the complexity of the fracture being created, and the frictional losses of the fluids moving from the wellbore into the fracture. The FPP is a combination of the fracture toughness, the fluid invasion to the tip of the fracture, the tensile strength of the fracture, and the frictional losses of the fluid moving through the fracture. If the well is shut in and the pressure decline is monitored, then the two most accurate measures of the least principal stress can be obtained. The Instantaneous Shut-In Pressure (ISIP) is measured immediately after the well is shut in and there is still fluid propping open the fracture. The Fracture Closure Pressure (FCP) is measured after the fracture closes by extrapolating the steady-state pore pressure back to the intersection with the ISIP line. The ISIP is typically taken as the upper bound of the least principal stress and the FCP is the lower bound of the least principal stress. The idea is to measure the far field stress away from the local wellbore effects.

Fracture Orientation Changes

Tiltmeter data during fracturing confirms multiple orientations and flipping of growth plane (California)

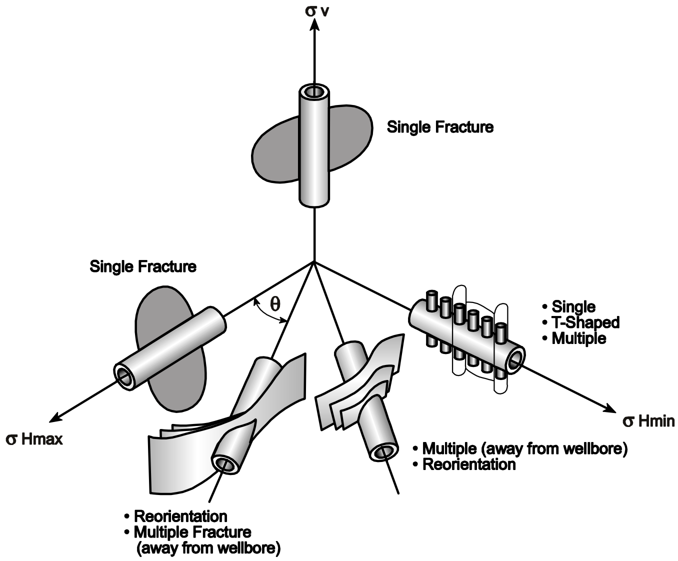


Courtesy Pinnacle Technologies

Baker Hughes

Induced changes in the stress field from hydraulic fracturing will cause fracture reorientation.

Wellbore Orientation Effects on Fracture Geometry



Baker Hughes

Benefits of orienting the well in the preferred fracture plane:

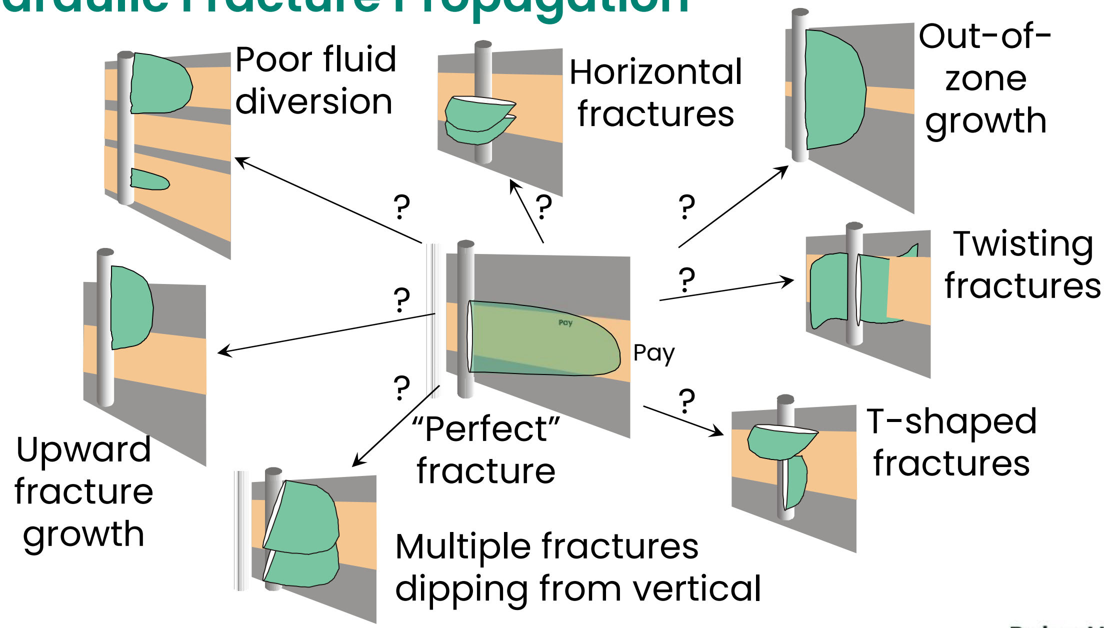
•Maximize the connection between the created fracture and the wellbore. A fully connected fracture will provide improved clean up and flow potential.
•Reduced risk of pre-mature screen outs.
•A single fracture is capable of developing more width providing higher conductivity in the near wellbore region. (as opposed to multiple fractures competing for width)
•The contact or inflow area can be increased by deviating the wellbore through the pay. The concept is to maximize the contact area with the reservoir.

What if the well path is not oriented with the preferred fracture plane?

•When the wells are more than 15 degrees out of phase with the preferred fracture direction, there is a significant risk of creating more complex fracture geometries with both multiple fractures and fracture re-orientation away from the wellbore.
•Multiple competing fractures will not develop as much fracture width in the near wellbore region, also the connection to the wellbore will be more radial rather than longitudinal limiting the connection to the reservoir.
•Premature screen outs are a problem.

•Focus should shift away from conventional FracPac completions and more toward unconventional FracPac (Extension Pack).
  - •Maximize perforation inflow at the wellbore.
  - •Perforate under balanced or extreme over balanced to minimize perforation damage.
  - •Practice sound pre-packing practices above fracturing rates to effectively pack each perforation and by-pass formation damage.

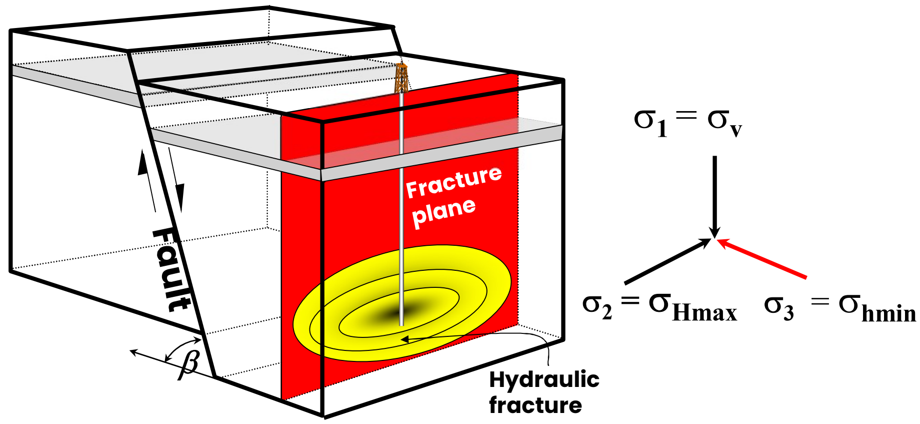
Hydraulic Fracture Propagation



Courtesy, Pinnacle Tech. Ltd.

Baker Hughes

Fracture Orientation – Normal Regime

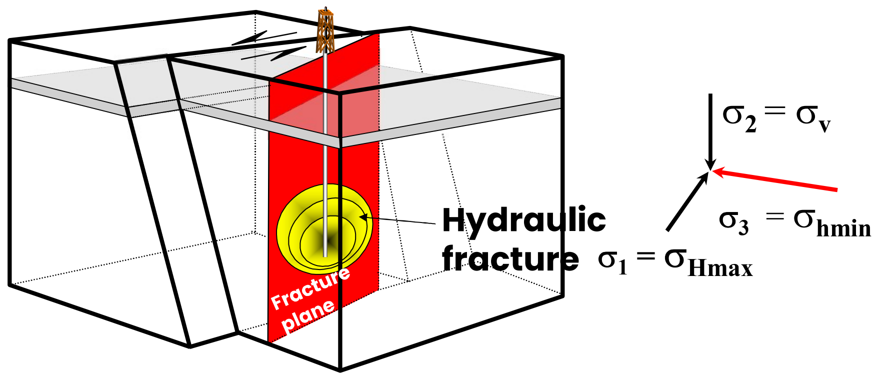


Normal regime → $\sigma_v > \sigma_{Hmax} > \sigma_{hmin}$
The hydraulically-induced fracture is vertical and parallel to the fault plane

Baker Hughes

After Hubbert and Rubey.

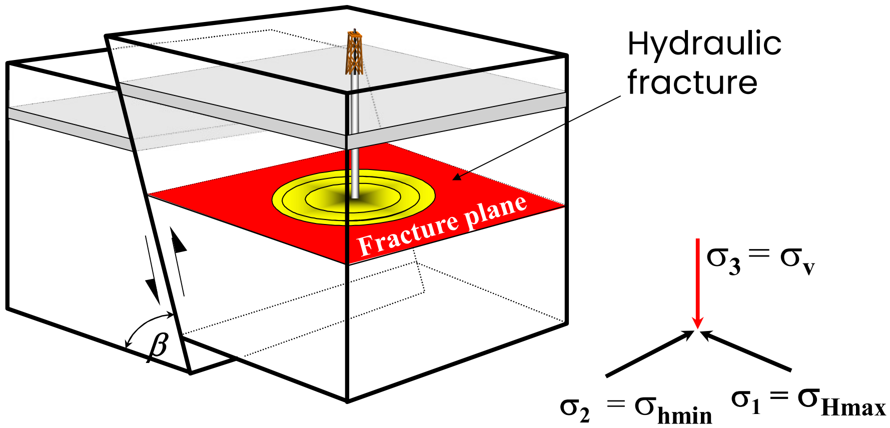
Fracture Orientation – Strike Slip Regime



Strike-slip regime → $\sigma_{Hmax} > \sigma_v > \sigma_{hmin}$
The hydraulically-induced fracture is vertical and 20°-35° from the strike of the fault

After Hubbert and Rubey.

Fracture Orientation – Thrust Regime

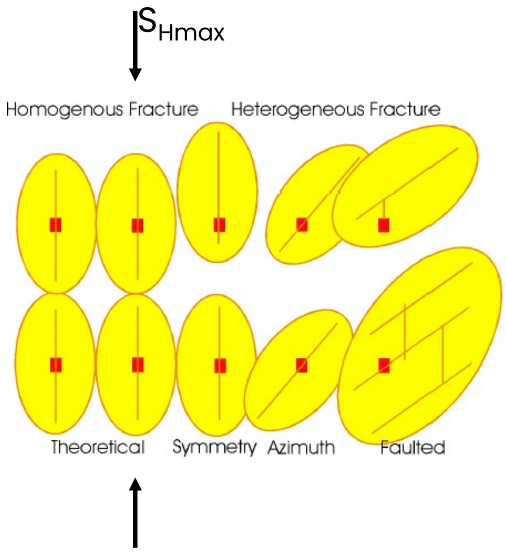


Thrust regime → $\sigma_{Hmax} > \sigma_{hmin} > \sigma_v$
The hydraulically-induced fracture is horizontal and the fault dips ~20° -35°

Baker Hughes

After Hubbert and Rubey.

Orientation of Fracture Propagation

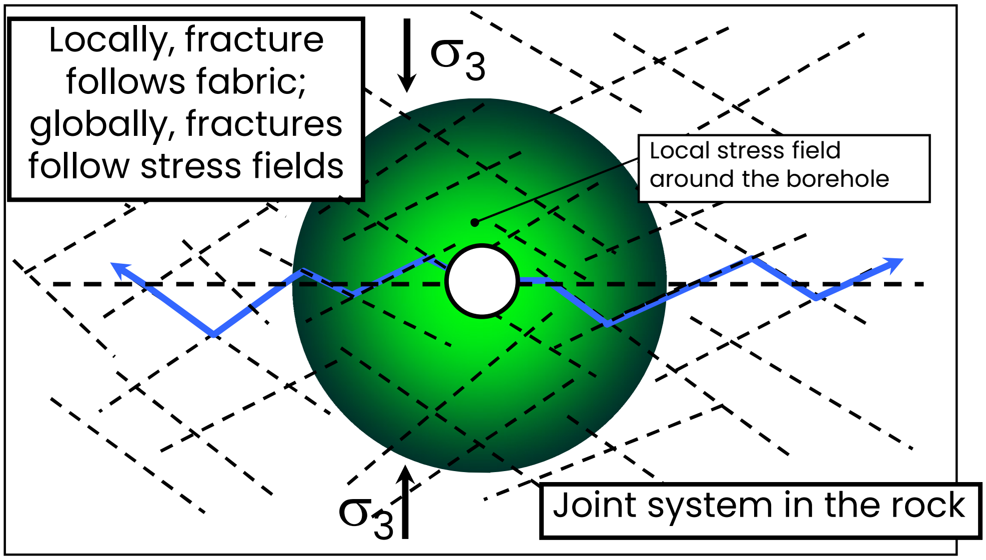


If permeable natural fractures intersect the wellbore or hydraulic fracture, the propagation direction can be affected by these pre-existing pathways through the rock.

Baker Hughes

Theoretically fractures propagate equally in both directions away from the wellbore. In reality, the fracture may propagate in only one direction and may be interfered with by preexisting natural fractures and faults. Cartoon from Dusseault.

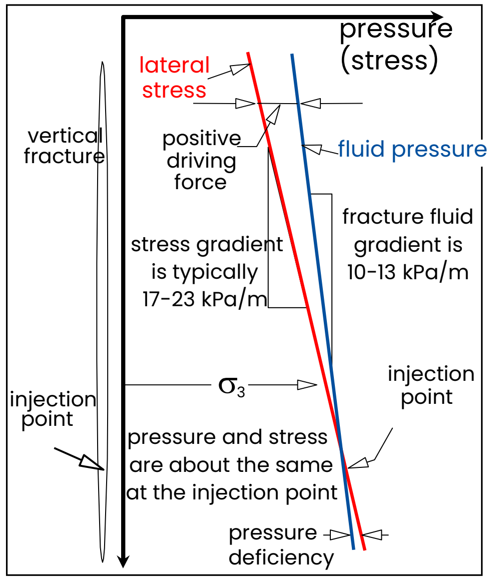
Local Fabric and Fracturing



Cartoon from Dusseault.

Why Fractures Rise

- Fracture fluid has a density of < ~1.2SG
- The gradient of lateral stress ($\delta S_h/dz$) is much more than this value
- Thus, there is an extra driving pressure at top
- Deficiency in driving pressure at bottom
- Fracture tends to rise



Baker Hughes

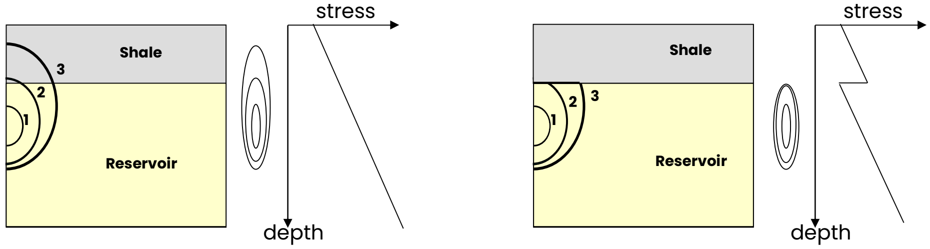
Cartoon from Dusseault.

Hydraulic Fracture Containment

Hydraulic Fracture Containment through Stress Contrast

- Hydraulic fractures propagate perpendicular to the least principal stress (S_3)
- Propagating fractures will avoid zones with the highest stresses
- A stress contrast can effectively stop fracture growth

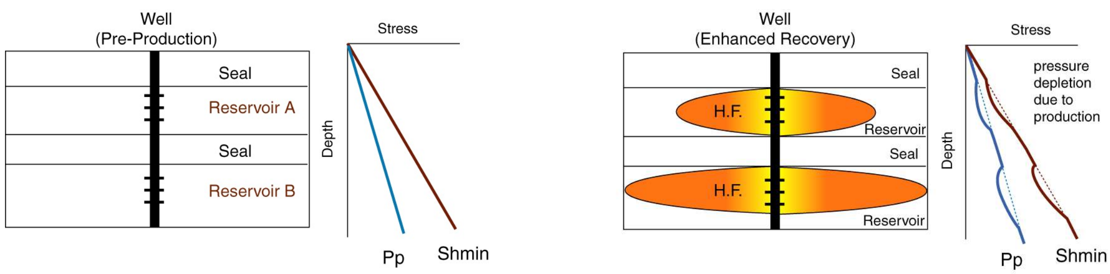
No stress contrast | Stress contrast



Baker Hughes

The existence of a least principal stress contrast between the reservoir and overlying shale can help to contain hydraulic fracture growth within the reservoir.

Creating Stress Contrast



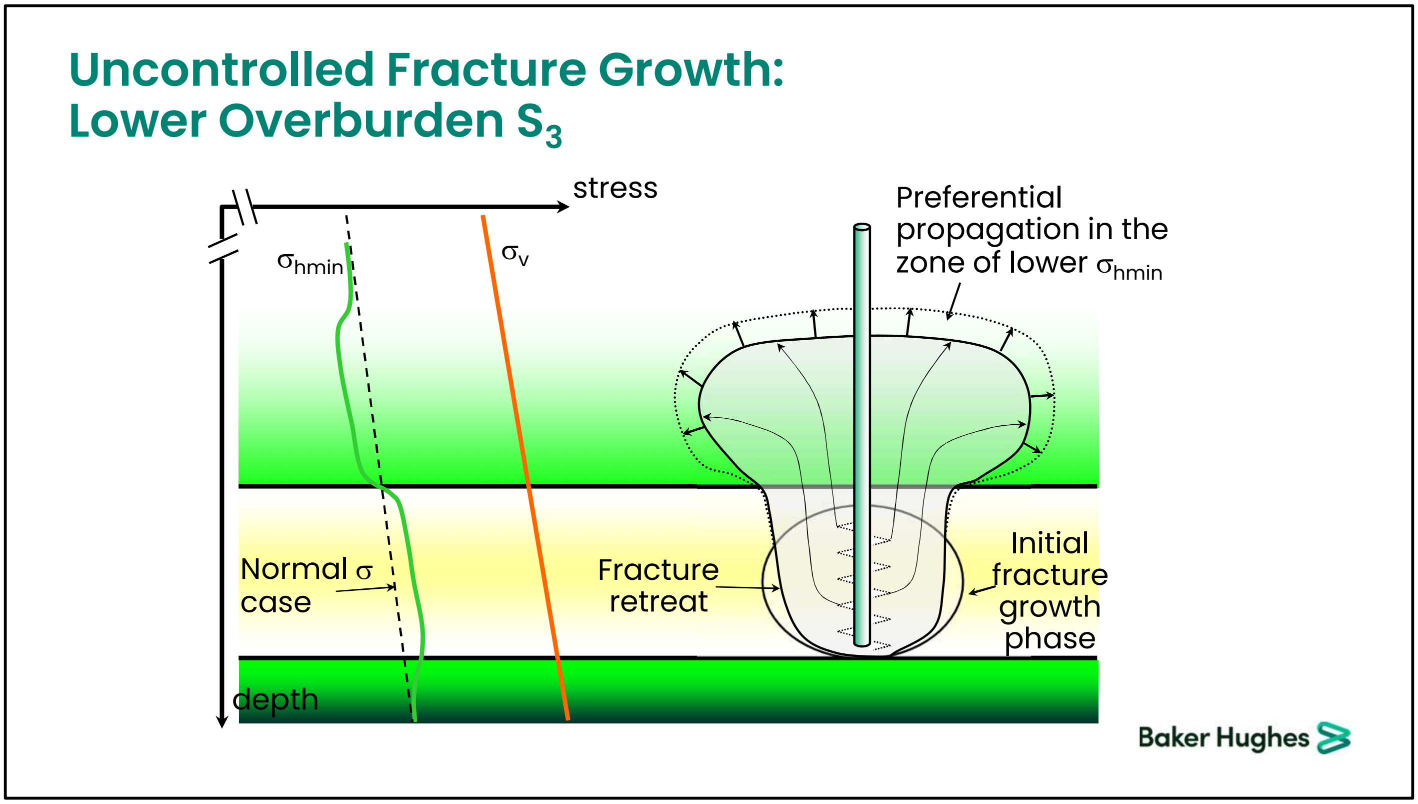
HYDRAULIC FRACTURE CONTAINMENT

S_{hmin} (reservoir) < < S_{hmin} (seal)

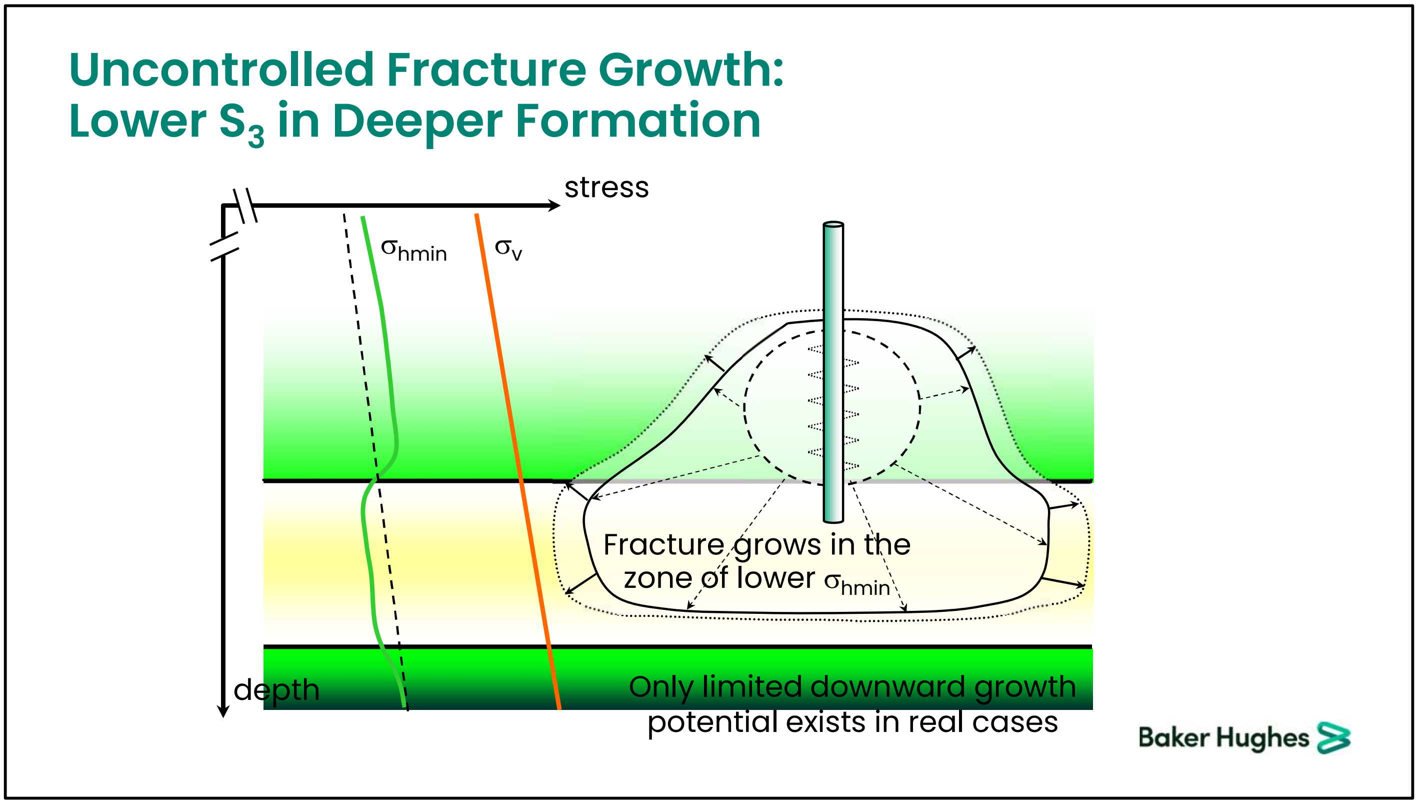
Propagation Pressure (Reservoir) < < Propagation Pressure (Seal)

Baker Hughes

Reducing the pore pressure in the reservoir reduces the stress and can contribute significantly to hydraulic fracture containment.



Fractures will tend to grow in the direction that is easiest. If the least principal stress in the overburden is less than in the reservoir then the fracture will preferentially grow into the overburden. Cartoon from Dusseault.



Fractures will tend to grow in the direction that is easiest. If the least principal stress in a deeper layer is less than in the overburden then the fracture will preferentially grow into the deeper layer. Cartoon from Dusseault.

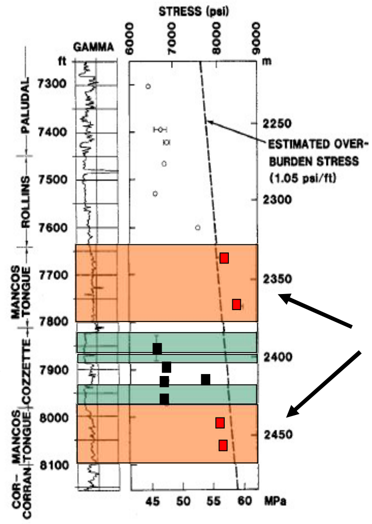
Effect of Stress Contrast on Fracture Containment

Stress profile, Mesaverde Group, Rifle, Colorado (after Warpinski et al., 1985)

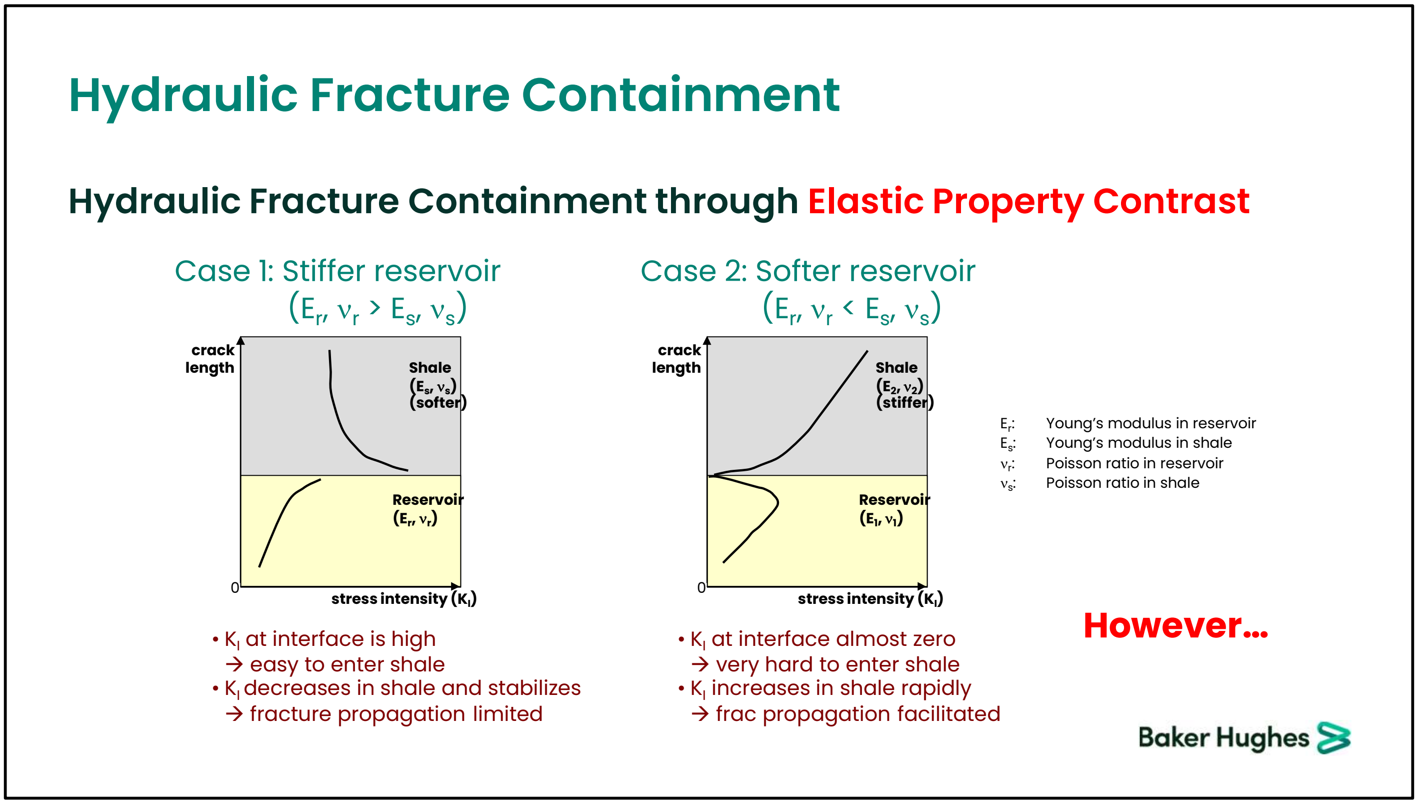
Usually,

$\sigma_{sand} < \sigma_{shale}$

Stress measurements in sand



Stress measurements in shale



If the reservoir is stiffer than the overlying shale (the most common case), the stress intensity at the fracture tip will increase toward the shale-reservoir interface. This means it becomes easier for the fracture to cross the interface as the fracture approaches the interface. Once the interface is crossed, the stress intensity drops so that fracture propagation further into the shale is limited. If the reservoir is softer than the overlying shale then it becomes very difficult to cross the interface, but once the interface is crossed then it becomes increasingly easy to propagate the fracture upward into the cap rock. However, the ability of the fluid to move along the fracture and deliver pressure to the tip of the fracture becomes more difficult in thin fractures, so Case 2 represents the conditions under which fractures are less likely to grow upward into the cap rock.

Hydraulic Fracture Containment

Hydraulic Fracture Containment through Elastic Property Contrast

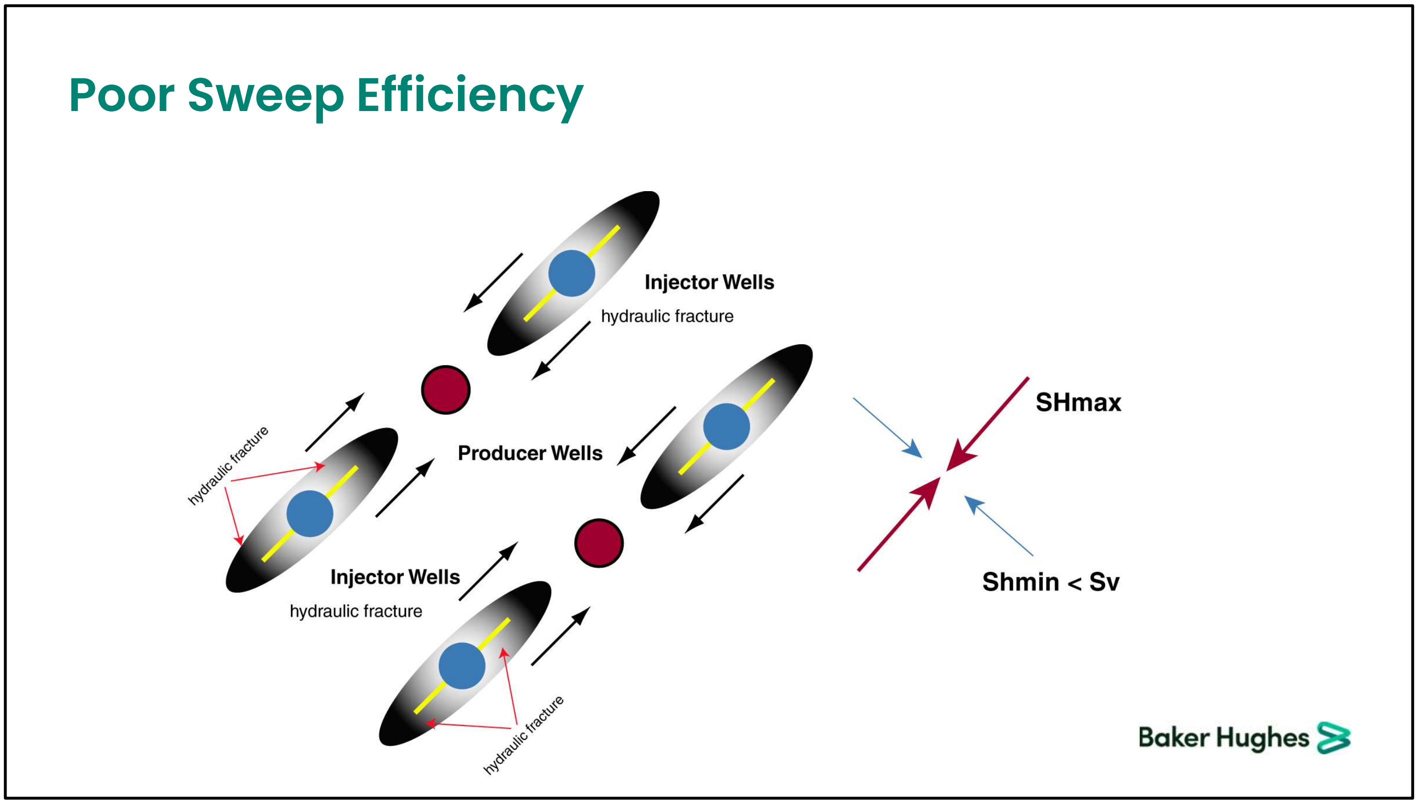
- Extremely complex fracture mechanics problem typically impacted by Young's Modulus (E), Poisson's Ratio (ν)
- Soft shale (Low E, high ν): large aperture, short fracture
- Stiff shale (High E, low ν): small aperture, long fracture
- Aperture affects hydraulic pressure distribution in the fracture (low aperture = higher pressure losses)
- E contrast may slow fracture height propagation but does NOT "STOP" fracture height propagation

➢ High E hinders fracture growth in the stratum and low E enhances propagation

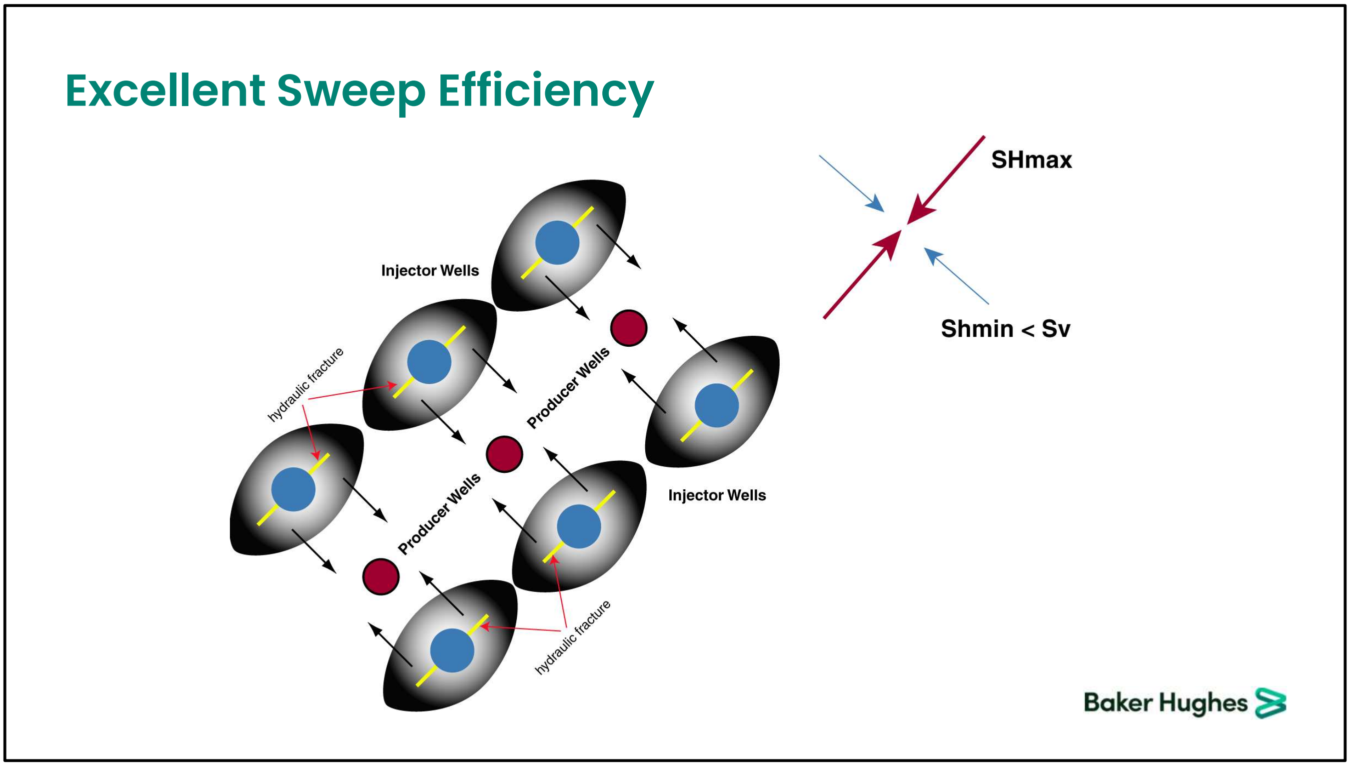
Normally, $E_{sh} < E_{ss}$ so the fracture would more easily propagate in shale. This behavior is contrary to the effect created by stress contrast

➢ **STRESS CONTRAST IS MORE IMPORTANT**

Baker Hughes



The orientation of injector and producer patterns with respect to the stress field can have a profound impact on the sweep efficiency and the time before water is produced. By aligning the injectors and producers in line with the maximum horizontal stress, the hydraulic fractures created by the injectors will propagate in the direction of the producer wells. This geometry will leave the oil between the injector/producer lines in place.



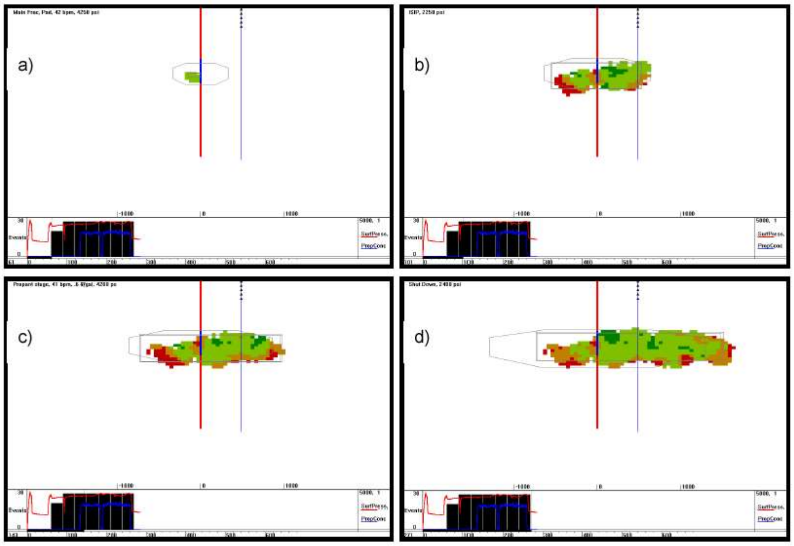
The orientation of injector and producer patterns with respect to the stress field can have a profound impact on the sweep efficiency and the time before water is produced. By aligning the injectors and producers in parallel lines with the maximum horizontal stress (one row all injectors, one row all producers, etc.), the hydraulic fractures created by the injectors will propagate in the direction of the other injector wells wells. This geometry will sweep oil from the line of injectors toward the line of producers.

Mapping Fracture Growth

- **Available techniques for mapping fracture propagation:**
  – Microseismicity
  – Tiltmeter surveys (at the surface and downhole)

Baker Hughes

Mapping Fracture Growth With Microseismicity



(Urbancic, Maxwell, Demerling, and Prince, 2002)

- Red well is injector
- Blue well is equipped with geophones

Color corresponds to stress release (red = high stress release)

Microseismicity can be used to map fracture growth over time and in space.

Mapping Fracture Growth With Microseismicity

The non-planar and irregular growth pattern of the seismic cloud indicated critically stressed, pre-existing fractures were being opened and invaded by the injection fluids.

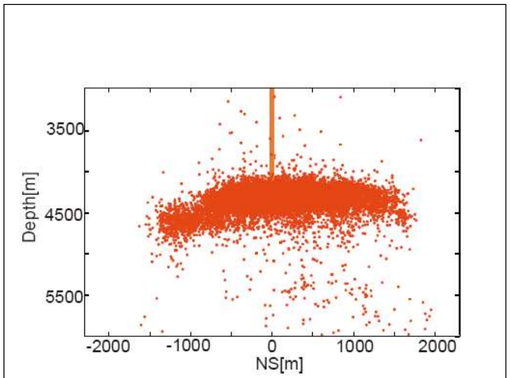


Figure-3: Vertical view of the seismic cloud at the Cooper Basin site.

Asanuma et al., 2005

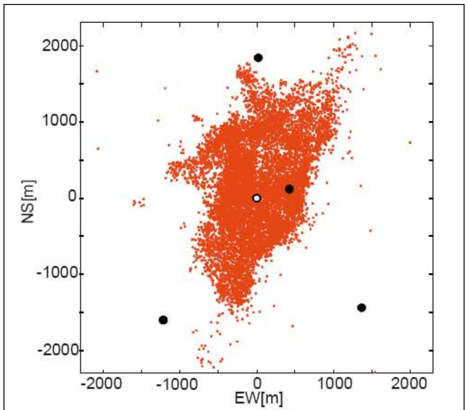
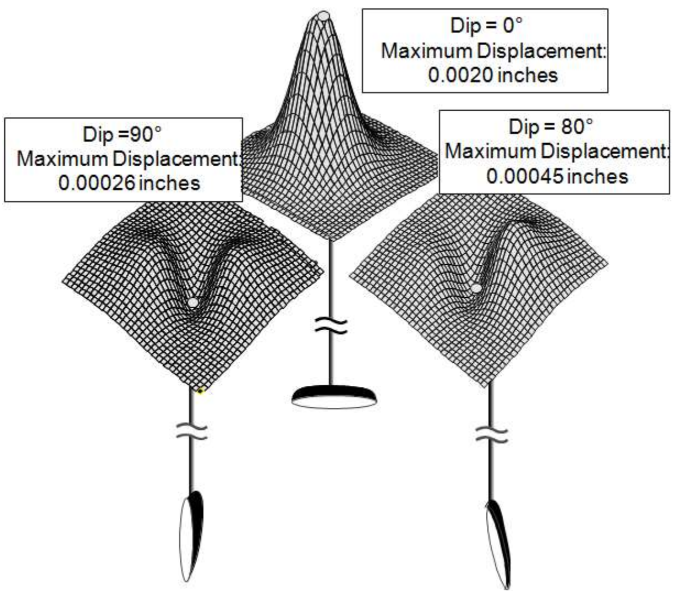


Figure-4: Plan view of seismic cloud at the Cooper Basin site.

Baker Hughes

Hydraulic Fracture Mapping



Characteristic deformation pattern makes it easy to distinguish fracture dip, horizontal and vertical fractures

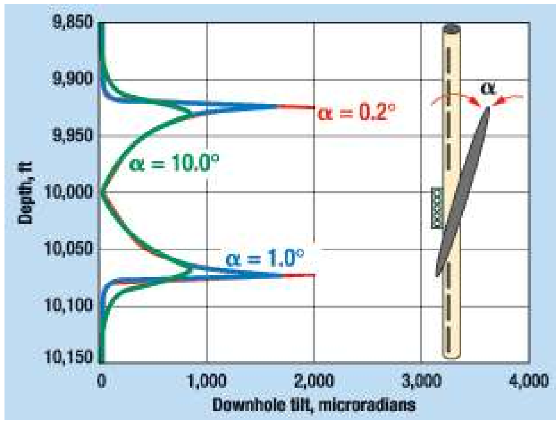
– Gradual "bulging" of earth's surface for horizontal fractures
– Trough along fracture azimuth for vertical fractures
– Dipping fracture yields very asymmetrical bulges

Baker Hughes

The shape of the deformation at the surface will define the orientation of the fracture being inflated. Tiltmeters can very accurately map the deformation at the surface during hydraulic fracturing.

Downhole Tiltmeter

Measurements from a borehole tiltmeter as the hydraulic fracture inclination (α) is changed



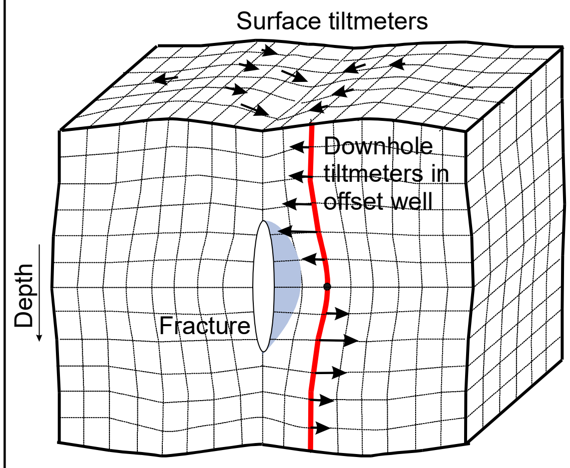
Wolhart et al. (2001)

Baker Hughes

It's easier to detect purely vertical fractures.

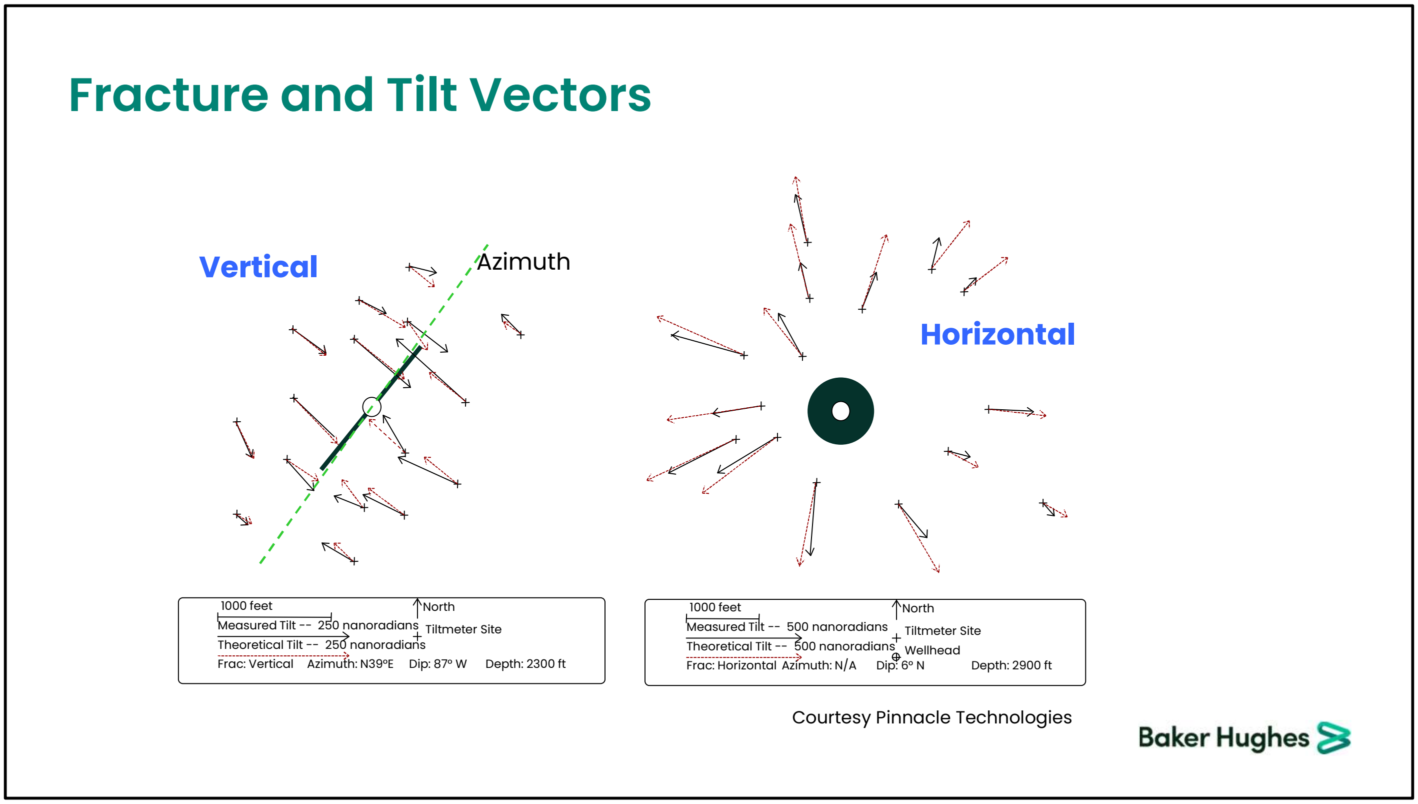
Tiltmeter Fracture Mapping

- Tilts measured
- Mathematical solution
- If depth > ~3 km, tilt measurements are quite difficult
- One solution is use of borehole tiltmeters



Courtesy Pinnacle Technologies

Baker Hughes



Actual tiltmeter data showing inflation of vertical and horizontal hydraulic fractures.

Critically Stressed Natural Fractures

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

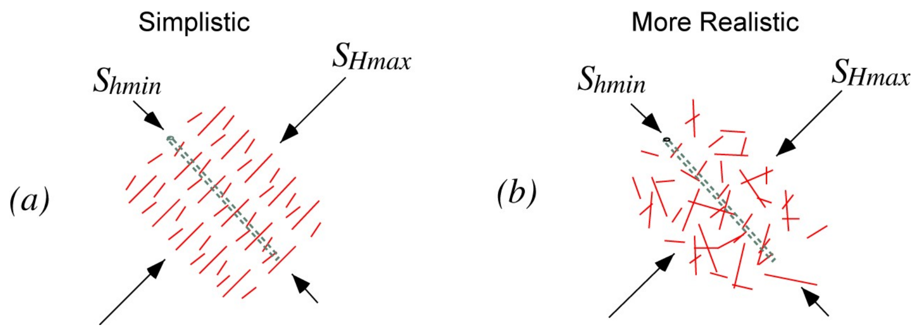
Baker Hughes

Critically Stressed Faults and Fractures

- Determining Critical Stresses on Fractures and Faults
- Importance of Critically Stressed Fractures in Reservoirs
- Fracture Stimulation
- Identification of Critically Stressed Faults
- Other Fracture Permeability Methods

Copyright 2022 Baker Hughes Company LLC. All rights reserved.

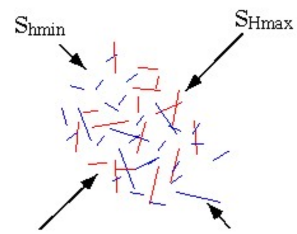
Characterizing Natural Fractures

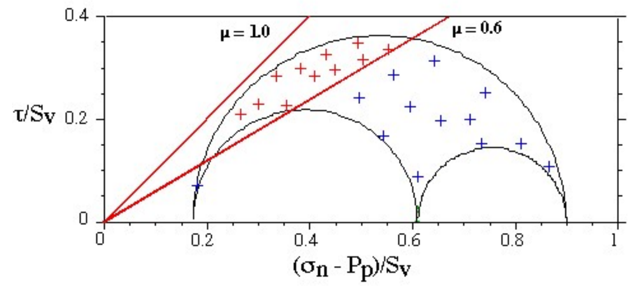


Baker Hughes

Models of fracture orientation often simplistically assume that the majority of fractures will open perpendicular to the least principal stress. A more realistic conception of a fracture population in the earth assumes that fractures exist in nearly all possible orientations.

Permeable Fractures and Faults are Critically Stressed

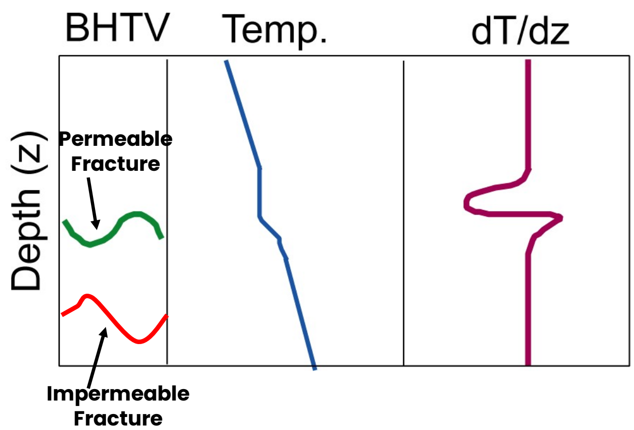




Baker Hughes

In general, a subset of the total population of fractures will be critically stressed. Those fractures that are well-oriented to be open in shear (red fractures) will tend to maintain their permeability over time due to constant breaking of any seal that might form within the fracture, while those fractures that are less likely to shear (blue fractures) will tend to remain sealed once a seal forms. Critically-stress fractures plot in the upper left portion of the Mohr Circle, where the ratio of the shear stress to effective normal stress is highest.

Relationship Between Critically Stressed Fractures and Fluid Flow



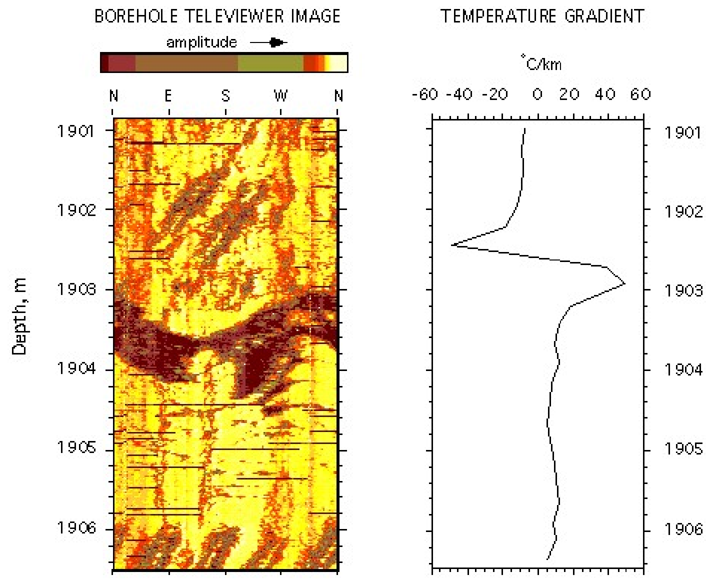
Permeable fractures cause an anomaly in borehole temperature.

If available, permeable fractures can also be identified with spinner-flowmeter logs (e.g. PLT log)

Baker Hughes

Fractures mapped from observations in a BHTV log sometimes showed temperature anomalies, while some fractures were not associated with temperature anomalies. Those fractures that showed temperature anomalies were assumed to be permeable while those without temperature anomalies were assumed to be sealing. The temperature anomalies were easier to identify when the gradient of the temperature curve was taken.

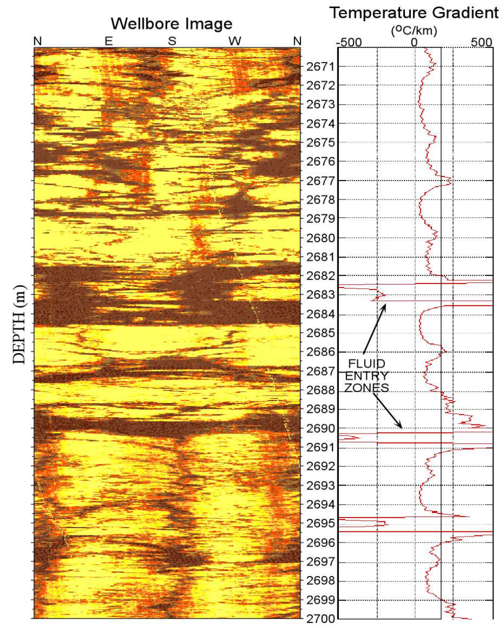
BHTV and Temperature Gradient in Dixie Valley Field



Baker Hughes

Example of a permeable fracture identified through an anomaly in the temperature gradient.

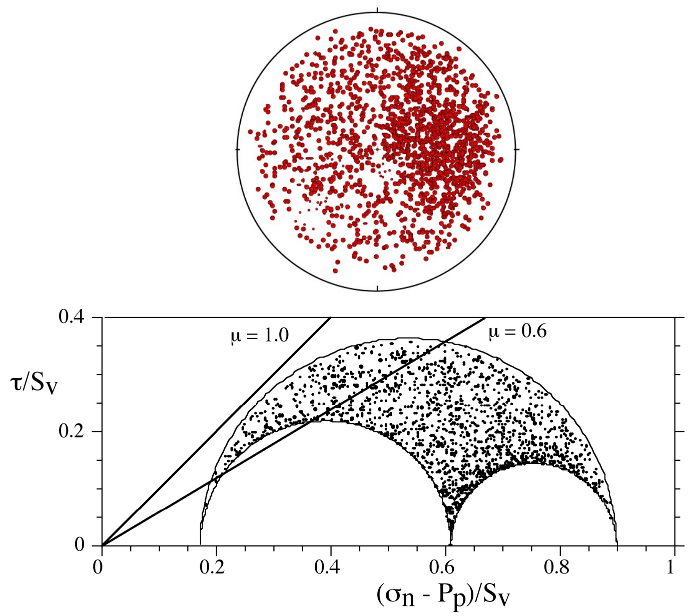
Correlation Between Natural Fractures and Reservoir Fluid Flow



In fractured reservoirs a single set of fractures can control fluid flow. These are the set of fractures that are optimally oriented to the current stress field to fail in shear. This shear failure props the fracture open thereby providing an open conduit for fluid flow.

Cajon Pass Well

Poles to Fracture Planes 1800–3500 m

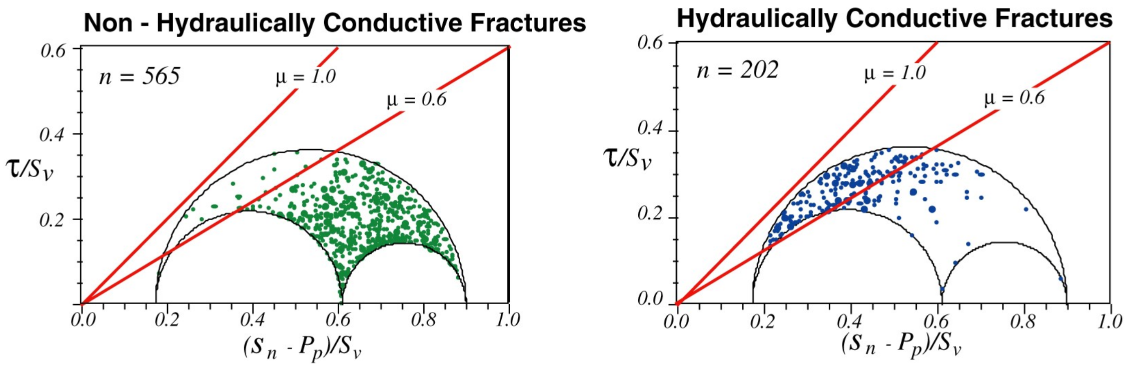


Baker Hughes

Poles to fracture planes represented in a stereonet (top) and a Mohr diagram (bottom).

Fracture Discrimination Based on Thermal Perturbations in the Borehole

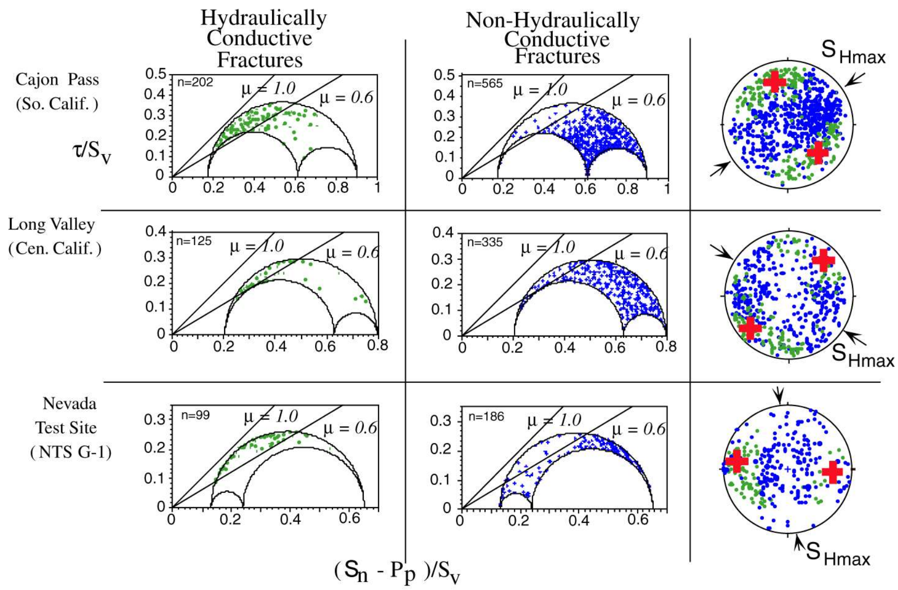
Statistically, the hydraulically conductive fractures displaying an enhancement in permeability are also critically stressed



Baker Hughes

After determining whether fractures were permeable or not based on thermal perturbations associated with fluid flow into the wellbore, the stresses on the fractures were determined. The fractures with high ratios of shear stress to normal stress tended to be hydraulically conductive, while the fractures with lower ratios of shear stress to normal stress tended not to be hydraulically conductive. Statistically, the hydraulically conductive fractures were more likely to be critically stressed.

Critically Stressed Fractures Can Occur in All Stress Regimes

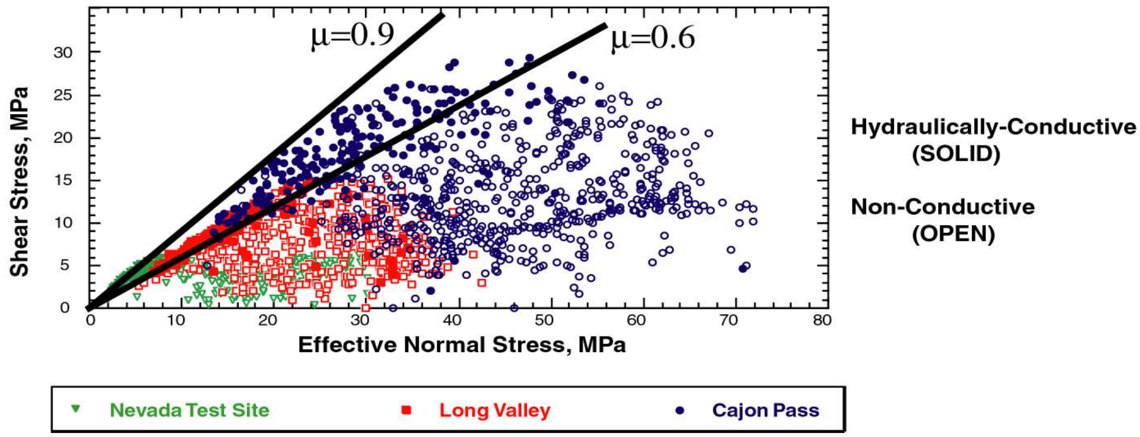


Baker Hughes

Coulomb failure bounds for 1 and 0.6 and 70-80% of the hydraulically conductive faults are critically stressed. No flow in faults that are not critically stressed. Plotted in the right column are both populations in lower hemisphere showing the distinct diff. In orientation between the 2 pops.

Red crosses represent the best drilling trajectory to intersect most permeable fractures. If a well is drilled in the direction to hit the most fractures, it wouldn't necessarily hit the most permeable ones (i.e. the trajectory for permeable vs. most fracs are different.

Composite of Fractures From Three Different Stress States



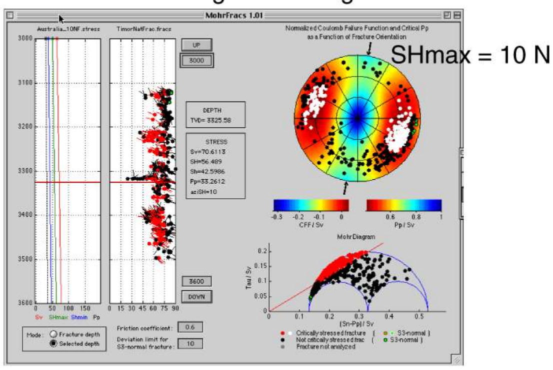
Baker Hughes

These are the same data as in the previous slide, but the stresses are not normalized by the vertical stress. Therefore, one can think of increasing depth from the green to the red to the blue points. The plot illustrates that the critically-stressed permeability concept holds up at very shallow depth (Nevada Test Site, a mining project), to very great depth (Cajon Pass, a deep scientific borehole).

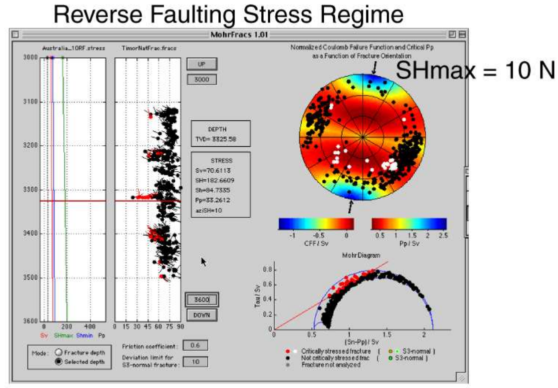
Comparison Between Normal and Reverse Stress Regimes - Same Fracture Pattern

A different set of fractures will be critically stressed depending on the stress regime

Normal Faulting Stress Regime



Reverse Faulting Stress Regime



Baker Hughes

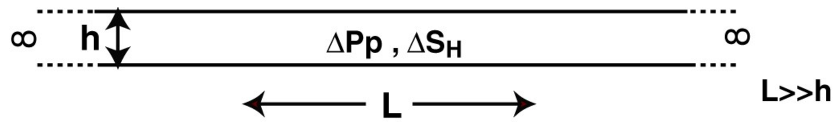
The same fracture population is shown in both plots. The relative stress magnitudes are changed in order to show that the stress regime can be a strong determinant in controlling the fractures that are likely to be permeable. Each plot shows the input stress field (left track), tadpoles of the fracture planes with critically stressed fractures plotted in red (right track), poles to fracture planes with critically stressed fractures plotted in white (top right), and fractures plotted in a Mohr Diagram with critically stressed fractures plotted in red (bottom right). In this example, the critically stressed fractures are more numerous in the normal faulting stress regime and strike ~20 degrees from north and dip ~70 degrees to both the east and west. In the reverse faulting case the critically stressed fractures are fewer, and the only significant cluster of fractures strikes ~NE and dips ~60 degrees to the NW.

Drilling Into Depleted Reservoirs

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Baker Hughes

Poroelastic Effect of a Pore Pressure Change



Using instantaneous application of force and pressure with no lateral strain:

$$\Delta S_H - \alpha \Delta P_p = \alpha \left(\frac{\nu}{1-\nu} \right) \left(\cancelto{0}{\Delta S_v} - \Delta P_p \right)$$

$$\Delta S_H = \alpha \frac{(1-2\nu)}{(1-\nu)} \Delta P_p$$

$$\text{if} \quad \nu = 0.25, \alpha = 1$$

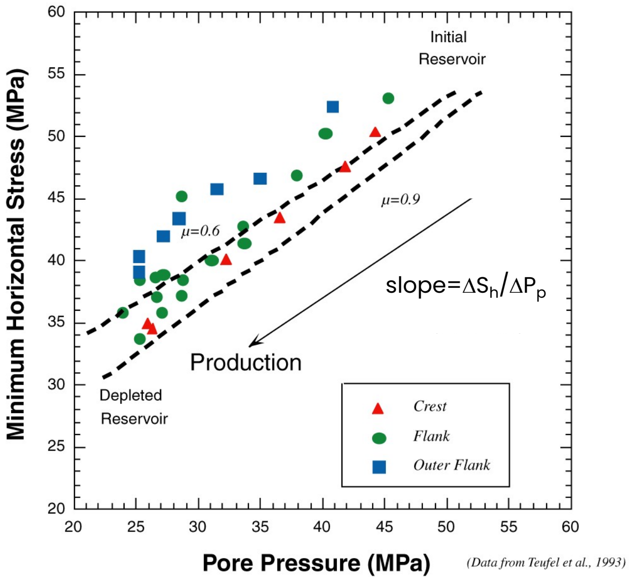
$$\Delta S_H = \frac{2}{3} \Delta P_P$$

L: Length (lateral extent) of reservoir
H: Height (thickness) of reservoir
ΔP_P: Change in pore pressure
ΔS_H: Change in horizontal stresses
$S_H \equiv S_{hmin} \equiv S_{Hmax}$
ν: Poisson's ratio
α: Biot's coefficient

Baker Hughes

The effect of an instantaneous reduction of the pore pressure is a related reduction in the horizontal stresses. If a Poisson's ratio of 0.25 and a Biot's Coefficient of 1 are used, then the expected decrease in horizontal stresses is equal to two-thirds of the reduction in the pore pressure.

Stress Path: Ekofisk Field

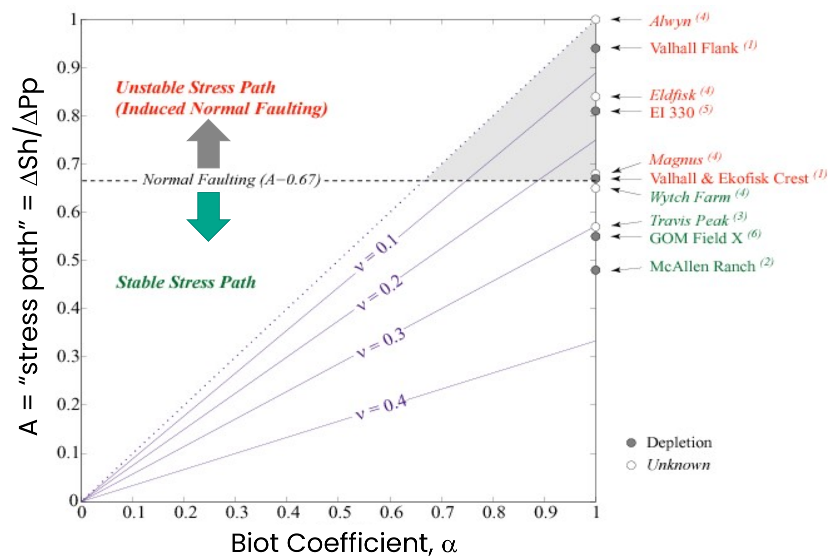


- Production results in minimum horizontal stress reduction
- $A = \Delta Sh/\Delta Pp$ is the "stress path"
- $A = \alpha(1-2\nu)/(1-\nu)$ is defined as the "stress path" using the poroelastic model in the previous slide

Baker Hughes

This result means that production will cause a reduction in the fracture gradient through depleted reservoirs.

Fault Reactivation Due to Poroelasticity



Baker Hughes

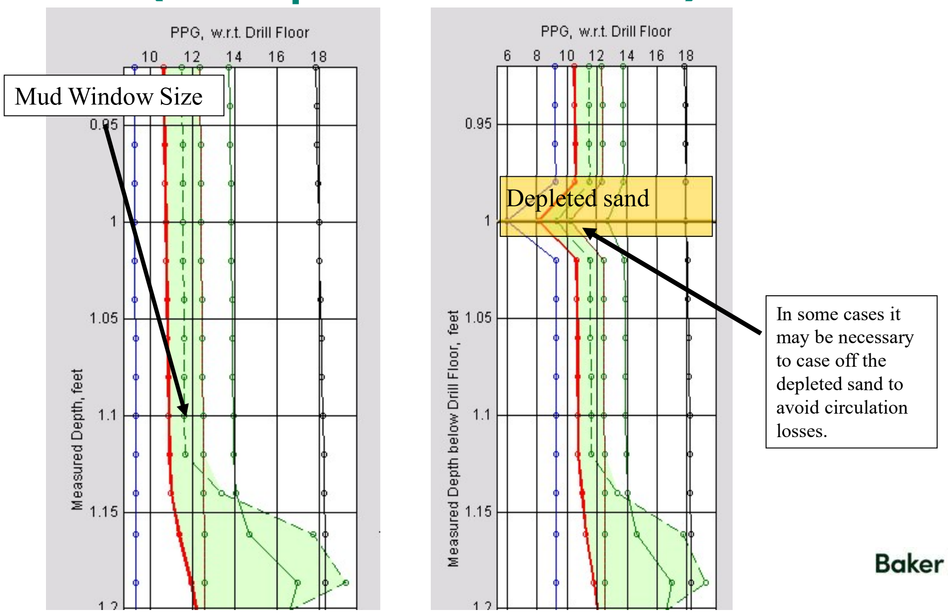
The poroelastic response of a reservoir to depletion or injection will determine whether faults intersecting the field will move. Reservoirs with Poisson's ratios less than ~0.25 and with Biot's Coefficient of ~1 are expected to induce normal faulting if the depletion is sufficient. (Figure after Chan & Zoback, 2002)

Some characteristics of the fields shown in the slide follow:

Alwyn - produces from the Brent and Statfjord formations which are sand reservoirs 440 kilometers northeast of Aberdeen in the North Sea.
Magnus - is a sand reservoir sourced from the Kimeridge clay in the Viking Graben 160 kilometers northeast of the Shetlands in the northern North Sea.
Wytch Farm - is a sand reservoir overlain by limestone and chalk in some areas and is onshore southern England.
Valhall, Ekofisk, and Eldfisk – chalk reservoirs in the Norwegian sector of the North Sea
GOM Field X and EI 330 – Gulf of Mexico fields of stacked sand/shale

sequences.
McAllen Ranch – sand reservoir with carbonate cement in south Texas
Travis Peak – East Texas, South Louisiana sand reservoir

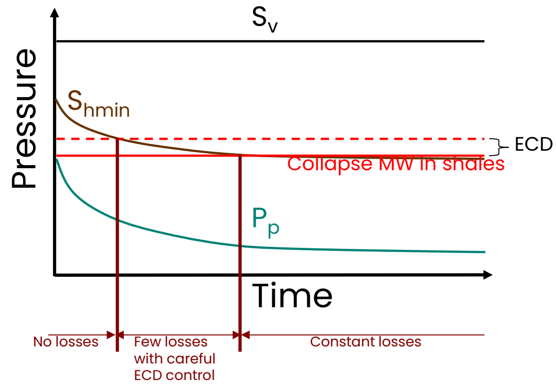
Does a Depleted Sand Increase the Risk for Lost Circulation? (Example from the GOM)



Baker Hughes

Pore pressure reduction in the sand causes a reduction in the fracture gradient and an increased likelihood of lost circulation when drilling through the sand.

Drilling Depleted Reservoirs – Planning Ahead



ECD: Equivalent circulating density

Baker Hughes

Alberty and McLean
Pressure depletion over time results in a reduction in the minimum horizontal stress and therefore an increase in the chances of lost circulation.

Sand Production & Prediction

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Baker Hughes

Sand Production Prediction

- Problems caused by sand production
- Sand management strategies
- Physics of sand production
- Thick-wall cylinder tests and detecting the onset of failure
- Predicting sanding using finite-element modeling

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Baker Hughes

The 3 Stages of Sand Production

Different physical processes are active in each stage:

1. Mechanical failure of the reservoir formation
   - Stresses at the wellbore wall or around the perforation must overcome the compressive strength of the rock
2. Mobilization of the failed material
   - Capillary forces may still hold the failed rock in place, so sand production is not observed
   - Increased water production may reduce the capillary forces and therefore allow failed material to move into the wellbore
3. Transport of the failed material through the well to the surface
   - Multiphase flow problem

Baker Hughes

Sand Production can be split in three stages in which different physical processes are active.

1. Mechanical failure of the reservoir formation. Our present technologies address the mechanical failure of the formation describing the rock as a porous elasto-plastic material. Failure is defined by the a critical value of plastic strain.

2. Mobilization of the failed material. Interaction between forces trying to hold the failed material in place (capillary force) and forces that try to move the failed material into the wellbore (drag force)

3. Transport of the failed material through the well to the surface. Multiphase flow (oil, gas, water, solids) in the wellbore determines if the failed material is moved to the surface

Comprehensive Sand Management Services

Geomechanical modeling
- 1D stress models
- 3D and 4D stress models (JewelSuite)
- Reservoir strength characterization rock testing and QC, LMP, JewelSuite

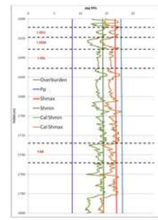
Sand production prediction
- Analytical (HeliSand3D)
- Numerical (GMI-FEST/SandCheck)

Sand volume quantification
- Open-hole
- Cased & perforated

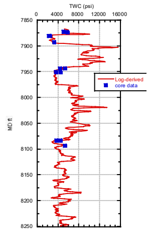
Training courses
- In-house
- Public

Ancillary modeling and services:
- Inflow & outflow
- Sand transport
- Flow-lines erosion
- Completion selection process
- Management & surveillance strategies

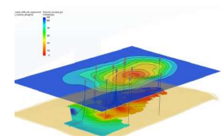
Detailed 1D Stress Profiles



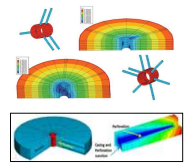
Calibrated Rock Strength Models



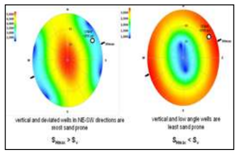
3D and 4D Reservoir Models



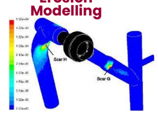
Finite- Element Models



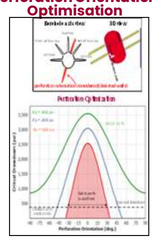
Effect of Well Trajectory on Critical Drawdown



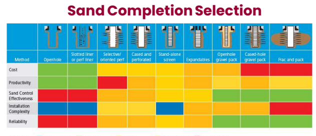
Erosion Modelling



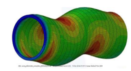
Perforation Orientation Optimisation



Sand Completion Selection



Assessing Casing and Screen Deformation



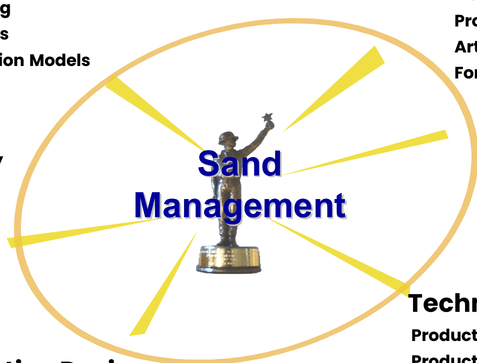
Baker Hughes

Multi-Discipline Nature of Sand Management

Geomechanics
- In Situ Stress Models
- Rock Strength Testing
- Rock Strength Models
- Sand Failure Evaluation Models

Well Deliverability
- Reservoir Inflow Performance
- Flow Assurance
- Production Optimisation
- Artificial Lift
- Formation Damage

Petrophysics/Geology
- Log QC, Log Interpretation, Lithofacies, Rock strength prediction, Moduli, RCA, SCAL, PSD, core-log correlation



Erosion/Transport
- Solids Transport Models
- Erosion Models
- Corrosion Models
- Metallurgy
- Fluid Properties

Technical Support
- Production Chemistry
- Production Engineering
- Economics
- Operational Decision and Risk Analysis
- Well Operations Management
- Well Test Analysis
- DIF Fluid Management
- Reservoir Management

Completion Design
- Completion Architecture
- Completion Functionality
- Completion Integrity
- Flow Optimisation
- Life Cycle Objectives

Baker Hughes

Erosion of Surface Equipment

(BP, Sand Management Forum, 2004)

(Eclipse, Sand Management Forum, 2004)

Baker Hughes

Erosion of Surface Equipment

(Courtesy of Statoil)

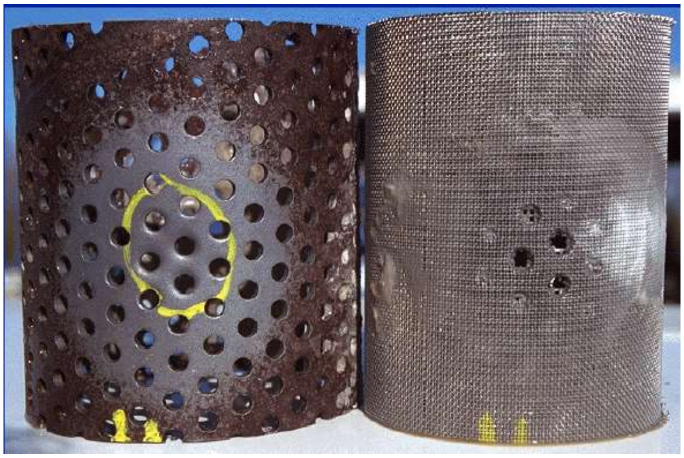
Baker Hughes

Separator Fill

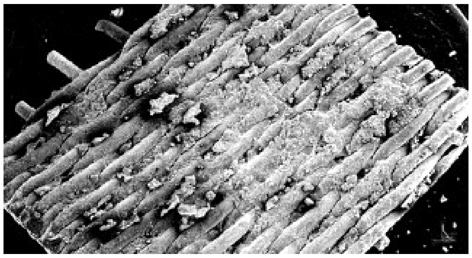
(Eclipse, Sand Management Forum, 2004)

Baker Hughes

Screen Erosion



Screen Plugging



(BP, Sand Management Forum, 2004)

(Courtesy of ResLink)

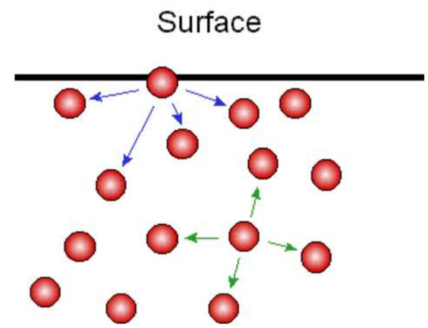
(Courtesy of ResLink)

Baker Hughes

Physics of Sand Production

Surface Tension (T)

- **Causes the surface layer of a liquid to behave as an elastic sheet**
- **Caused by intermolecular forces**
- **Increases as the intermolecular attraction increases and the molecular size decreases**
- **Surface tension is measured in [N/m] = [J/m^2], or [dynes/cm] = [10^{-3}N/m]**
- **For most oils, T~20 mN/m**
- **For water T~70 mN/m**
- **For liquid mercury, T~500 mN/m**



Baker Hughes

Surface tension is caused by the attraction between the molecules of the liquid, due to various intermolecular forces. In the bulk of the liquid each molecule is pulled equally in all directions by neighboring liquid molecules, resulting in a net force of zero.

At the surface of the liquid, the molecules are pulled inwards by other molecules deeper inside the liquid, but there are no liquid molecules on the outside to balance these forces, so the surface molecules are subject to an inward force of molecular attraction which is balanced by the resistance of the liquid to compression. There may also be a small outward attraction caused by air molecules, but as air is much less dense than the liquid, this force is negligible.

Polar liquids, such as water, have strong intermolecular interactions and thus high surface tensions. Any factor, which decreases the strength of this interaction will lower surface tension. Thus an increase in the temperature of this system will lower surface tension. Any contamination, especially by surfactants, will lower surface tension.

Interfacial Tension

- **Material property of a fluid-fluid interface**
- **Caused by attractive molecular forces that act in the two fluid phases**
- **<u>Miscible</u> fluid interfaces have no interfacial tension**
- **<u>Immiscible</u> fluid interfaces have an effective interfacial tension**
- **Generally the interfacial tension of two liquids is less than the highest individual surface tension**

Baker Hughes

Generally the interfacial tension of two liquids is less than the highest individual surface tension of one of the liquids because the mutual attraction is moderated by all the molecules involved.

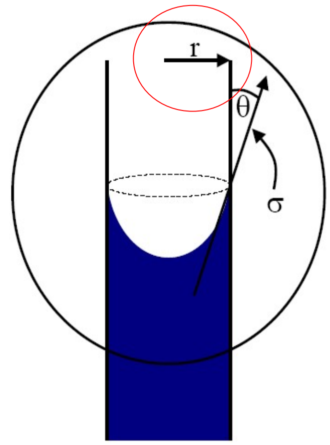
Capillary Pressure (P_c)

- **The difference in fluid pressure between the non-wetting fluid and the wetting fluid**
- **Related to the interfacial tension T, and the shape of the liquid bridge**

$$P_c = {}^{T}\!/_{r}$$

- **r is the principal radii of curvature of the liquid interface**

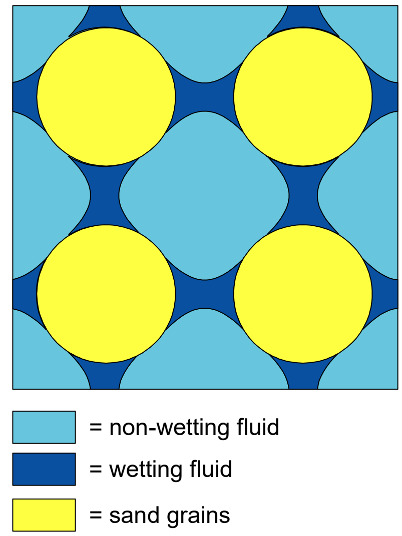
wrong



Baker Hughes

Capillary Force (F_c)

- **Attractive force oriented along lines connecting the centers of neighboring particles in a porous media containing two immiscible fluids**
- **Proportional to**
  - –the capillary pressure
  - –the shape of the liquid bridge
  - –the fluid system interfacial tension



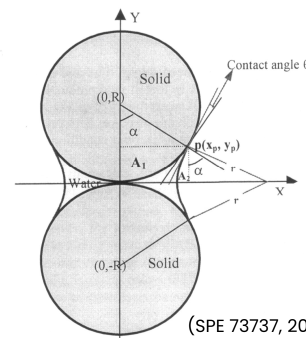
Baker Hughes

If two immiscible fluids are present in a porous media, the wetting fluid of the two will tend to spread along the grain surfaces, exluding the other, and forming an intergranular bridge bonding the particles together.
The capillary force, Fc, binding two grains together is proportional to capillary pressure, the shape of the liquid bridge profile formed between particles, and the fluid system interfacial tension.
The capillary forces are attractive forces and oriented along lines connecting the centers of neighboring particles.

Capillary Force Components

Two parts are contributing to the total capillary force:

1. **The force resulting from the pressure difference P_c between the two fluids**
2. **The tension T acting parallel to the interface of the two fluids**



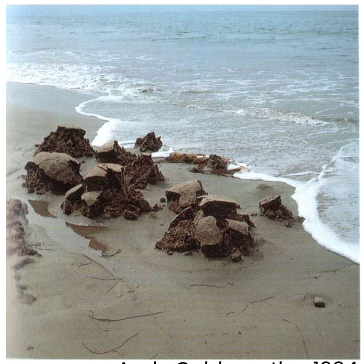
(SPE 73737, 2002)

$$F_c = \underbrace{\pi(R\sin\alpha)^2 P_c}_{1} + \underbrace{2\pi x_p \sin(\alpha+\theta)T}_{2}$$

Baker Hughes

Increasing Watercut

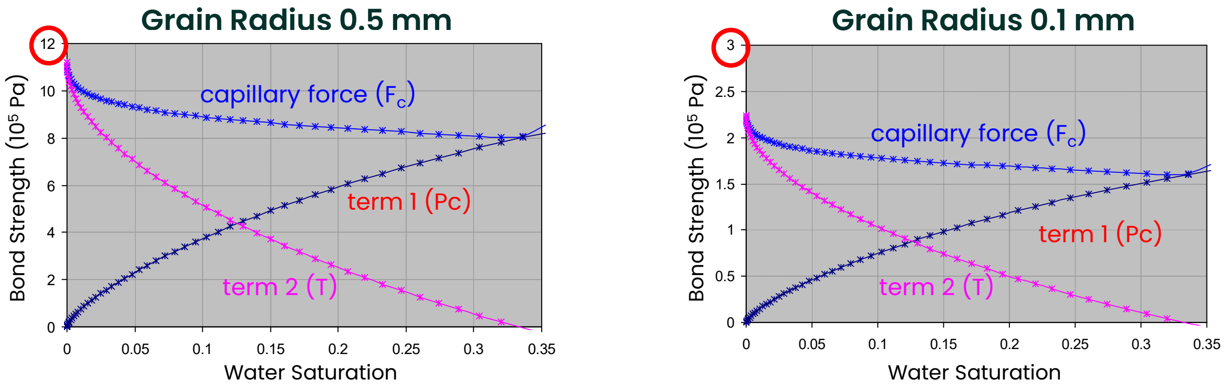
- Reduces capillary forces
- Allows drag forces to mobilize sand
- Often a reason for the onset of sand production



Andy Goldsworthy, 1994

Baker Hughes

Factors Affecting Capillary Forces

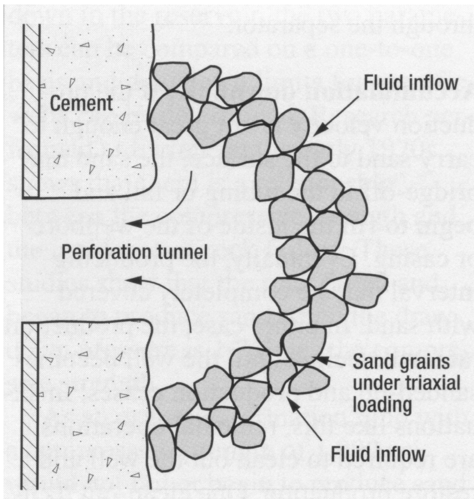


- **At zero water saturation, the capillary force is all surface tension**
- **Above 34% water saturation the capillary force is supplied entirely by the pressure difference between the two fluids**
- **Smaller grains have smaller capillary forces holding them together**

Baker Hughes

The total capillary force is made up of two separate forces, the force resulting from the pressure difference between the two fluids (Fs), and the tension acting parallel to the interface of both fluids (Fc0). At zero water saturation the capillary force is supplied entirely by the surface tension of the wetting fluid. With increasing water saturation up to ~34% the surface tension becomes less important, and the force resulting from the pressure difference between the two fluids begins to dominate. Beyond ~34% water saturation the capillary force is supplied entirely by the pressure difference between the two fluids. The radius of the grains being held together by the capillary forces also influences the capillary forces. Smaller grains will have smaller capillary forces holding them together than larger grains at the same water saturation.

Stable Arch from Well/Formation Pressure Difference



(WorldOil, 2003)

- **Zone of failed rock around the perforation can form a stable arch**
- **To get to this stable configuration at the start-up of the well, transient sand production may be experienced**

Baker Hughes

As well as capillary forces, the sand grains can be loaded due to pressure differences between the wellbore and formation during production, and can form a stable arch.

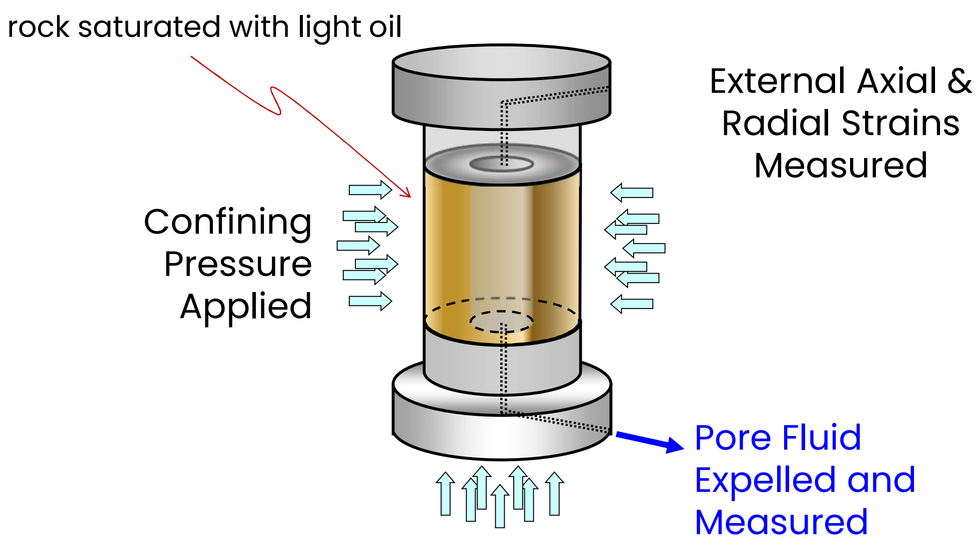
TWC (or Hollow Cylinder) Test Procedures

Used to simulate wellbore/perforation conditions in the lab, which can be scaled up using empirical relations:

- Sample: Hollow cylinder with 3:1 ratio of sample diameter (1.5”) to hole diameter (0.5”) and Length of 3”
- Load: Axial stress (increasing) and confining pressure on outer wall (increasing), with/without confining pressure on inner wall
- Measurements: Confining pressure versus strain, Expelled fluid, Hole deformation
- Result: Pressure at total failure (collapse strength)

Baker Hughes

Conventional TWC Test Configuration



Baker Hughes

Advanced Thick Wall Cylinder (ATWC) Tests

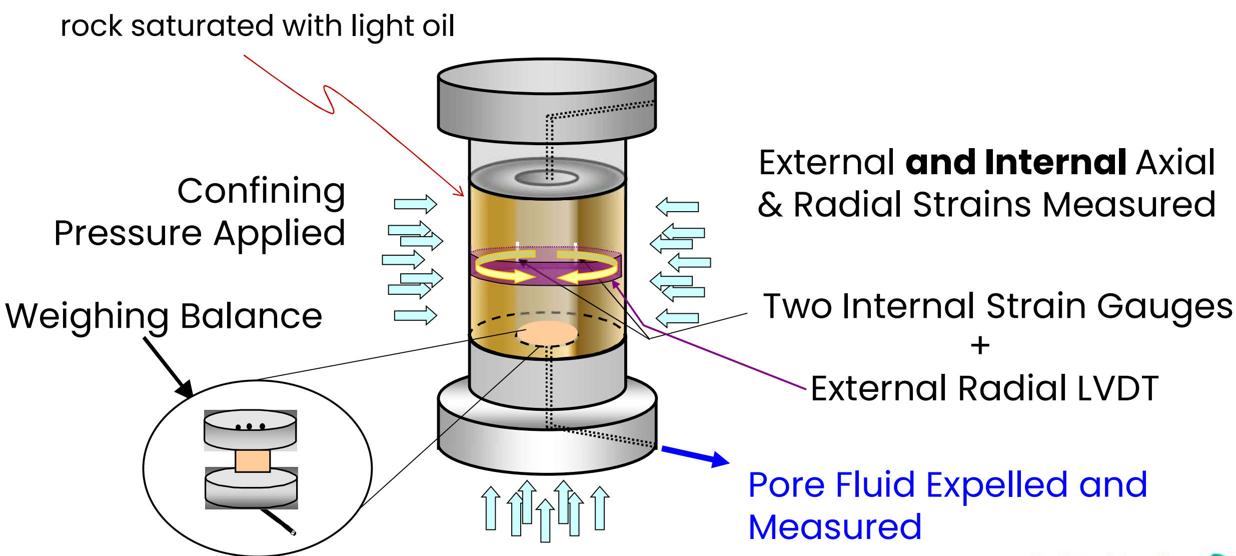
Variations on the TWC

- –With fluid flow through inner hole for erosion due to high-velocity sand grains
- –Fluid flow from outside of cylinder to inner hole for production simulation
- –Measure weight of failed material
- –Measure inner and outer wall deformation

Get both pressure at initial failure (onset of sand production) and total failure (collapse strength)

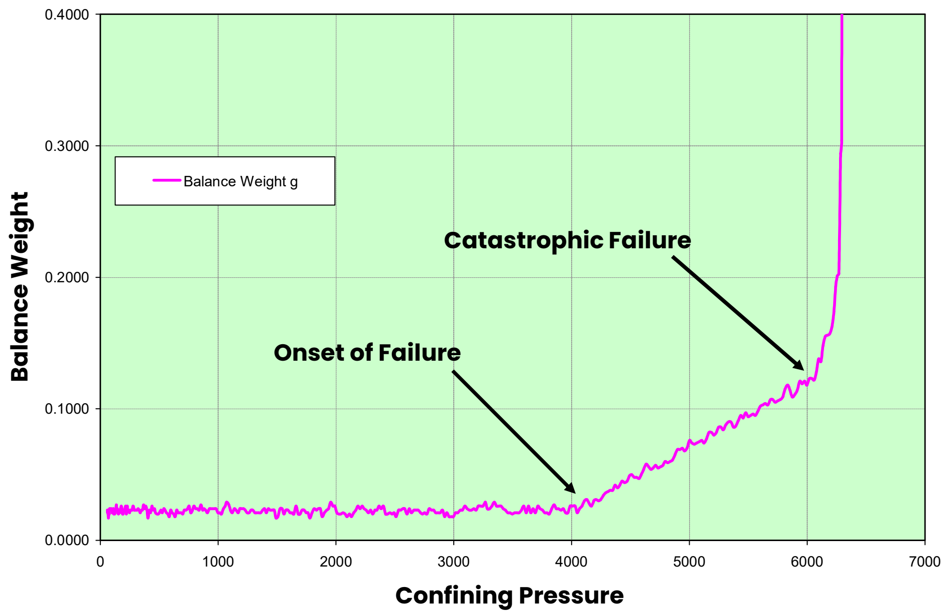
Baker Hughes

Advanced TWC Test Configuration



Baker Hughes

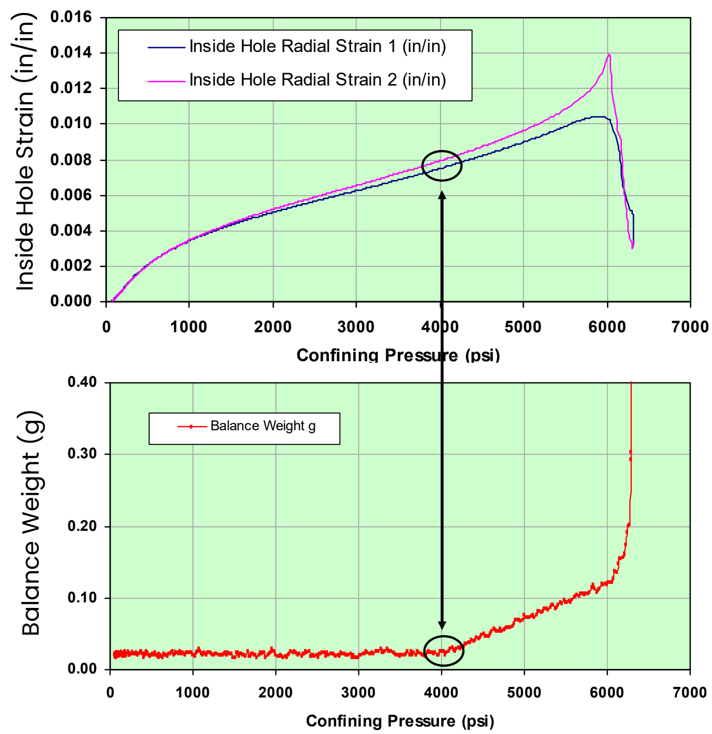
Onset of Failure



The balance at the base of the TWC detects an increase in weight as a result of failed material falling to the bottom of the simulated borehole. This measurement represents a much better criterion for failure than waiting for total failure of the sample.

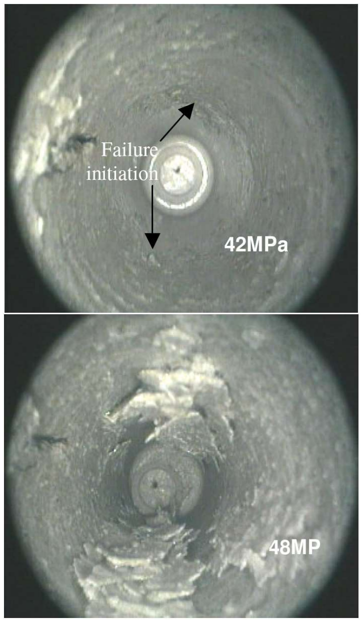
Plastic Strain

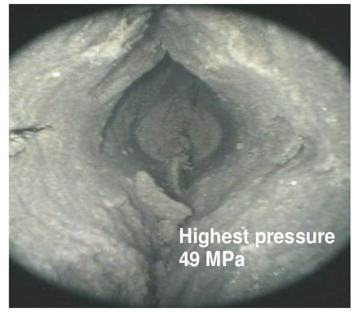
- **Waiting for large change in strain results in failure criterion that's too high**
- **Finite-element simulations allow us to define the critical value of plastic strain that relates to the onset of failure**



Relying on the strain would lead to a failure criterion that was too high. The strain does not change significantly until ~6000psi. This is 2000psi higher than the actual onset of failure detected by the balance at the base of the TWC.

Sample During Test

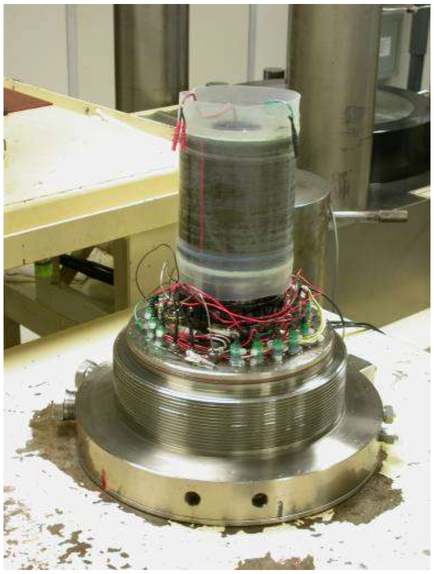




(Lei-Ming Yeow, Zurita Johar, Bailin Wu, Chee Tan & Mohd Azriyuddin Yaakub, SPE 87004)

from Sand Production Prediction Study Using Empirical and Laboratory Approach for a Multi-Field Gas Development, Lei-Ming Yeow, Zurita Johar, Bailin Wu, Chee Tan & Mohd Azriyuddin Yaakub, SPE 87004

Sample After Test



Baker Hughes

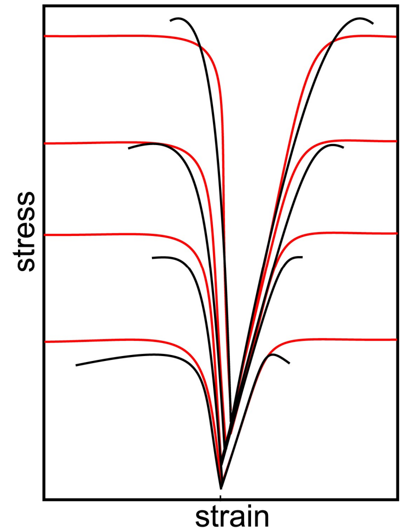
Current Sand Production Prediction Capabilities

- **Predict the onset of rock failure relative to:**
  - Amount of depletion and drawdown
  - Wellbore orientation
  - Perforation orientation
  - Changes in stress and pressure
  - Full well history from drilling, to placing casing, creating perforations, beginning production, and abandoning field
- **An empirical failure criterion is required – the critical value of the plastic strain**
- **Amount of sand is NOT predicted**

Baker Hughes

Modeling Material Deformation

- **Porous rock**
- **Fully coupled stress/strain relationship including pore pressure diffusion**
- **Use plastic material models**
  - –Drucker-Prager
  - –Mohr-Coulomb
  - –Cam-Clay
  - –Morita-type material model
- **Fit to lab data or use material library**

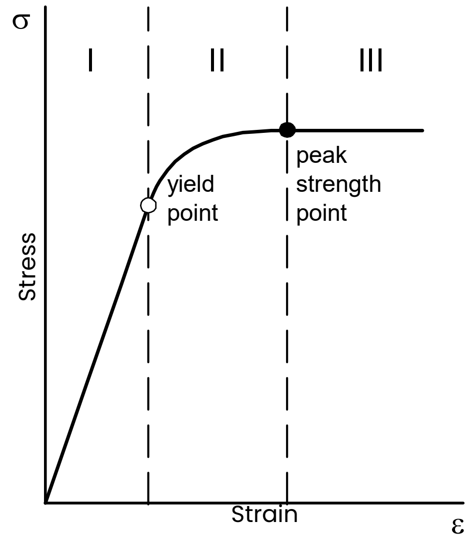


Baker Hughes

The deformation of the material needs to be modeled. The finite element models used for the sanding analysis use a fully coupled stress-strain relationship including pore pressure diffusion. The deformation of the material can be described with a number of plastic models and fit to the laboratory data. If no laboratory data is available, the program has a material library that can be referenced to choose a rock type most likely to be similar to the rock being examined.

Elasto-Plastic Material Deformation

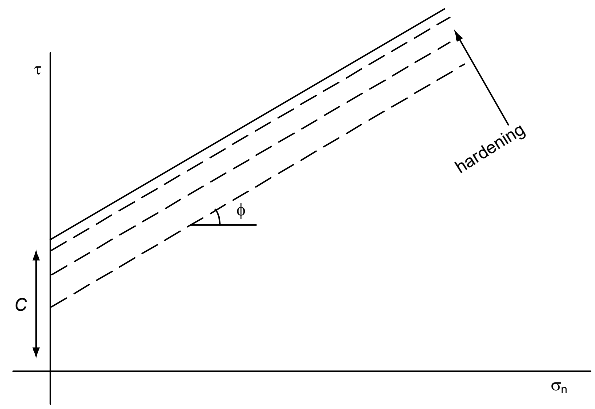
I. **Elastic**
II. **Strain Hardening**
III. **Plastic**



Baker Hughes

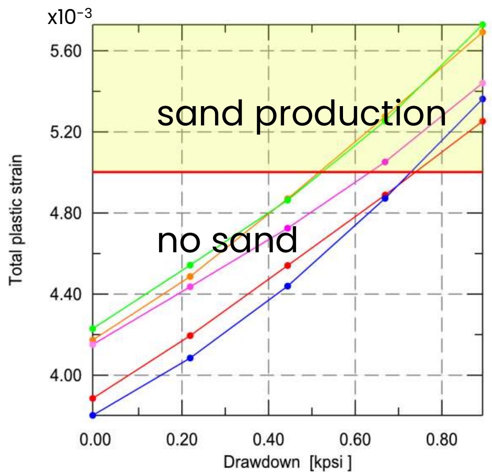
Mohr-Coulomb Model

- In ABAQUS FE Code
- Cohesion Hardening
- Constant Friction Coefficient

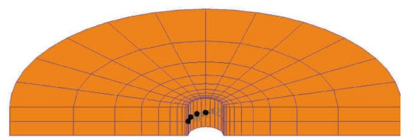


Baker Hughes

Modeling the Onset of Sanding



- Use empirical failure criterion – the critical value of total plastic strain
- Calibrate using TWC tests or material library
- Validate with field experience

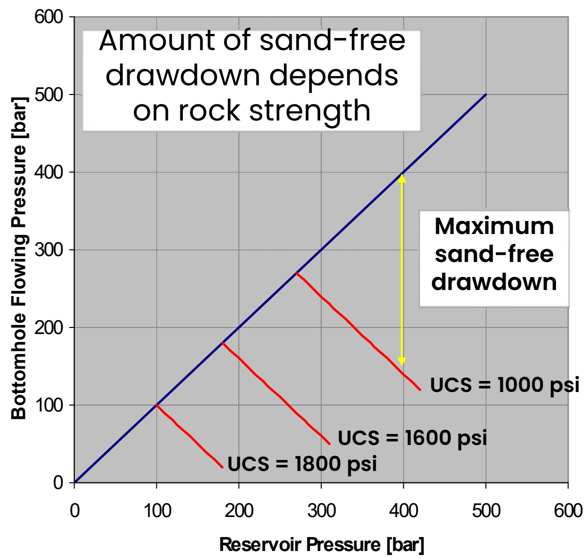


Baker Hughes

Onset of Sand Production

BHFP = RP – DD

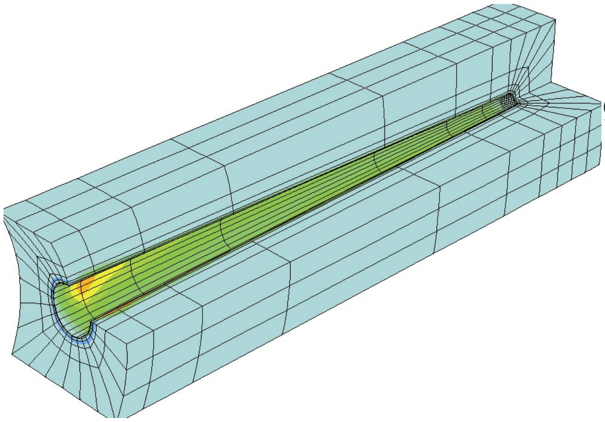
Where:
RP = Reservoir Pressure
DD = Drawdown



Baker Hughes

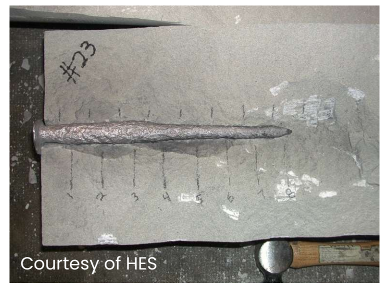
The critical drawdown and depletion for causing sanding can be calculated for different strength rocks. For example, a reservoir with 400 bar initial pressure may be able to draw the pressure down to ~150 bar before rocks with 1000psi strength will begin to fail, but if the reservoir is depleted to 300 bar then the bottom hole flowing pressure may only be able to reach 250 bar before sanding would be expected.

Modeling Sanding in Perforations



FEM approach allows for modeling complex geometries

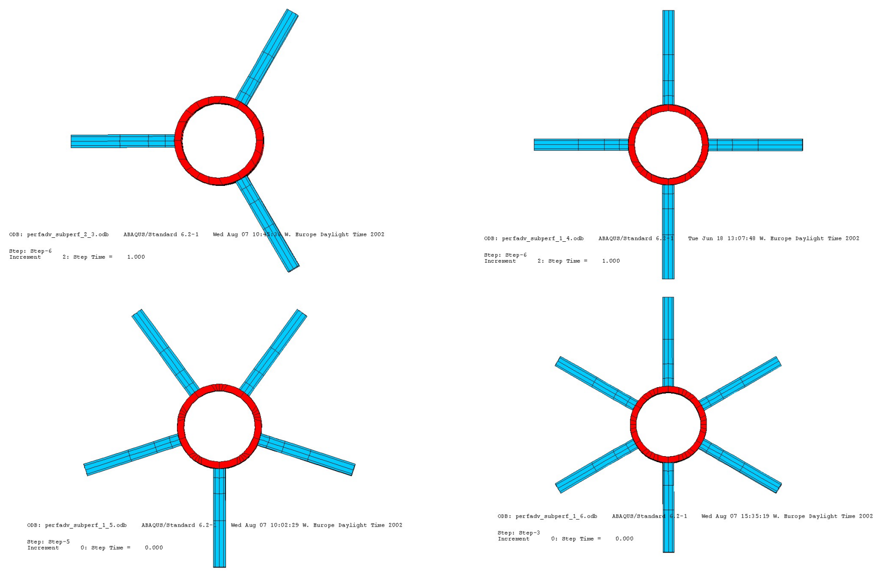
Mold of a perforation



Baker Hughes

Perforation tunnels can be quickly and easily modeled using the FE code.

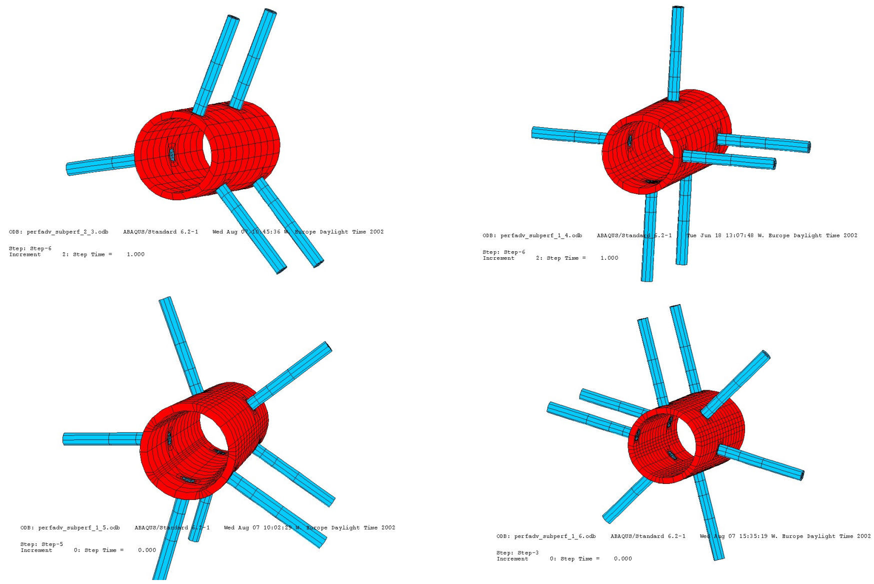
Modeling of Perf Phasing and Density



Baker Hughes

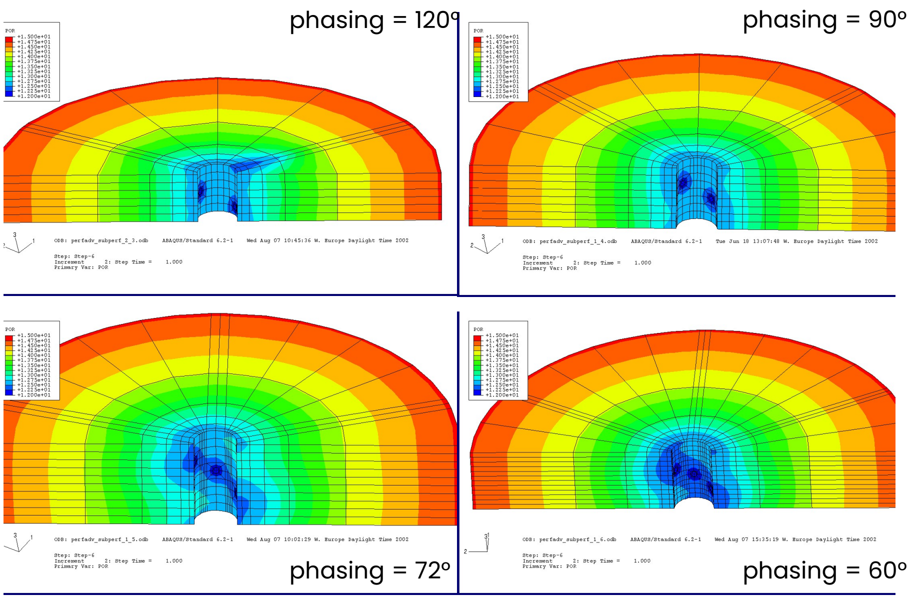
Modeling of shot phasing through the casing (red)

Modeling of Perf Phasing and Density



Modeling of shot phasing and density (shots/ft).

Modeling of Perf Phasing and Density



With 4 shots per foot and phasing of 120° phasing there is no perforation interference, however, with 6 shots per foot and 60° phasing there will be perforation interference and subsequent damage from sanding.

Other FEM Applications

- **Backflow simulations**
  –Drawdown in perforations
- **Injection simulations**
  –Tensile stresses close to the perforations
- **Waterhammer simulations**
  –Pressure pulse in perforation channels after shut-in

Baker Hughes

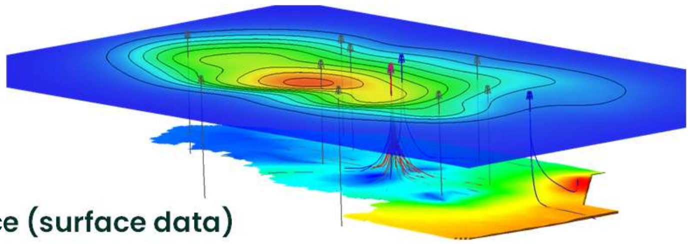
1. Backflow Simulations: to clean up perforation channels after long injection periods and to improve injectivity, injector wells are back-flowed. This means a small drawdown is applied to the perforations.
2. Injection Simulations: these calculations are run for well conditions during injection. The main purpose is to understand eventual tensile stresses close to the perforation that could lead to fracture initiation and propagation.
3. Waterhammer Simulations: as a water injector is shut-in, a pressure pulse is created that travels along the well while it is attenuated. We calculate the maximum magnitude of this pressure pulse and runs finite element simulations for the conditions in the perforation channel if this pressure pulse either creates a pressure reduction or a pressure increase.

Compaction & Subsidence

 Copyright 2022 Baker Hughes Company LLC. All rights reserved.

Baker Hughes

Compaction and Subsidence



From USGS Professional Paper 1401-A, "Ground water in the Central Valley, California- A summary report" Photo by Dick Ireland, USGS, 1977

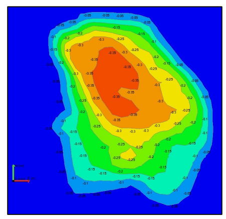
Subsidence (surface data)

Onshore, subsidence can be calibrated with surface data

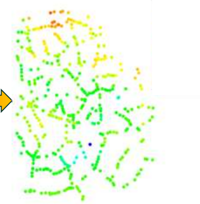
Offshore, regular bathymetric surveys or platform positioning are required

Compaction (downhole measurements)

Compaction calibration requires downhole measurements



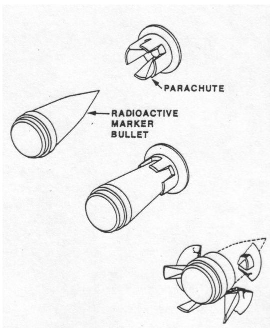
Modelled subsidence



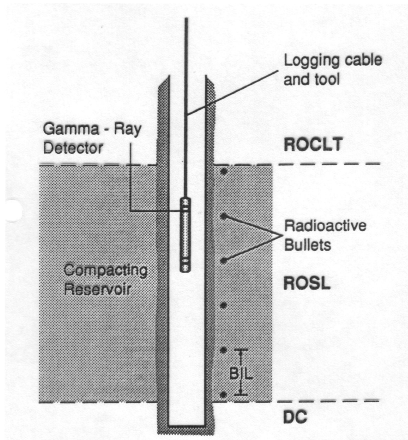
Comparison with surface data

Baker Hughes

Compaction Measurement



Cs137
Sphere of 2.3 mm diameter
Approx. spacing between bullets 10.5 m
Accuracy 1.5 mm/10.5 m



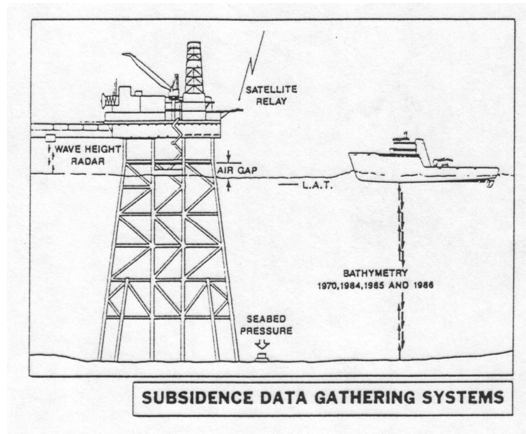
- **Measure spacing of radioactive markers over time**
- **Determine compaction as a function of depth**

Baker Hughes

Subsidence Measurements

Onshore
- GPS

Offshore
- Platform based
  - –GPS positioning
  - –Tiltmeter
  - –Wave height radar
- Field-wide measurements
  - –Hydrostatic pressure at seafloor
  - –Gravimetric measurements
  - –Bathymetry
  - –Side-scan sonar



Baker Hughes

Subsidence at the sea floor can be measured using a variety of techniques. Platform based measurements depend on the platform being supported by the sea floor rather than being a floating platform. If the platform is floating, then the other measurements may be the only options for detecting subsidence.

Baker Hughes