COMPLETION AND STIMULATION OF HORIZONTAL WELLS IN SHALE RESERVOIRS

FROM THEORY TO PRACTICE

JORGE PONCE

jorge.ponce@apachecorp.com

JULY 12th ,2012

SHARING & LEARNING PHILOSOPHY

- "Give a man a fish and he won't starve for a day, teach him to fish and he will feed himself for his entire life"

  Chinese proverb

- "Success = knowledge + effort + strategy"

  … and a little bit of luck…

  from experience

- "At least get one practical application from every slide"

  My expectations

Apache

DISCLAIMER, COPYRIGHT AND LEGAL NOTICE

Apache

OUTLINE

- *Sharing & learning philosophy*
- *Disclaimer, copyright and legal notice*
- *Roadmap*
- *Unconventional reservoirs*
  - *Organic rich shale reservoirs*
- *Hydrocarbons storage and flow mechanisms*
  - *Storage in shale gas reservoirs*
  - *Storage in tight oil reservoirs*
- *The nano-world in perspective*
- *Mass transfer and flow regimes*
- *Flow from matrix to wellbore*
  - *Shale gas*
  - *Tight oil*
- *Reservoir rock permeability*
- *Why multi-fractured horizontal wells?*
  - *Advantages from reservoir perspective*
  - *Any else to consider?*
  - *Where does the flow come from in shales?*
- *Structural discontinuities*
  - *Natural fractures*
  - *Stress azimuth and natural fractures*
  - *Interaction between NF & HF*
  - *Fracture complexity*
  - *Stimulated reservoir volume*
- *Rock mechanics – anisotropy*
  - *Frac stress modeling*
  - *Natural and induced fractures in horizontal wells*
- *Shale completions in horizontal wells*
  - *Multi-stage completions in horizontal wells*
  - *Open hole vs cased and cemented*
  - *Best practices*
- *Hydraulic fracture initiation and propagation*
  - *Transverse fractures*
  - *Connecting wellbore to reservoir*
  - *Cluster perforating*
- *Multi-fractured horizontal well optimization*
  - *Lateral length*
  - *Fractures number and spacing*
  - *Stress shadowing*
- *Proppant related issues*
  - *Proppant transport in fractures*
  - *Proppant transport in slick water fracs*
  - *Proppant selection and conductivity*
- *Frac design approach*
  - *Fracture design guidelines*
  - *Frac design examples*
- *Where does the frac fluid go and stay?*
- *Q &A*

ROADMAP – BOTTOM-UP METHODOLOGY

Well & Field Evaluation

Reservoir
- Geology
- Seismic analysis
- Petrophysics
- Mineralogy
- Geochemistry
- Geomechanics
- Log analysis & interpretation
- Pore pressure
- Reservoir temp

Fluids & Production
- Fluid composition
- Water chemistry
- Rates, IP
- Production decline
- WHFP, choke management
- Actual P & T

Completion & Stimulation
- Completion method
- Frac design & water availability
- Frac mapping
- Execution & operation efficiency

Well Design
- Single or multiwell design
- Integration w/ surface facilities
- Wellhead
- Hole sizes
- Tubular diam, strength & connections
- Directional plan

Drilling
- Rig selection
- Surface location
- Mud selection. Close or open loop system
- Directional drilling & bits
- LWD
- Torque & drag
- SIMOPS

- Environmental issues
  - Contamination & remediation
  - Surface ground disturbance
  - Water sources & disposal
  - Cutting and mud disposal
- Cost related
  - Hydrocarbon prices
  - Taxes increment
  - Materials & services costs
  - Gas & oil transportation costs
- Community related
  - Land access
  - Impact on local economy
  - Safety concerns

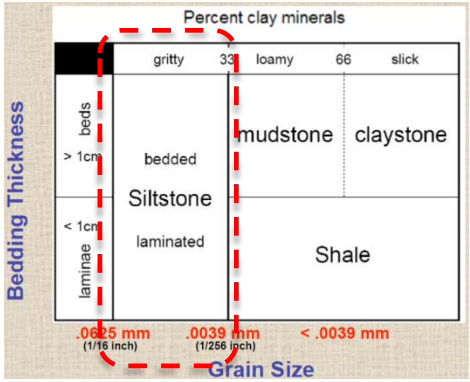
UNCONVENTIONAL RESERVOIRS

- Despite industry has defined long time ago that unconventional reservoirs are those that have permeability to gas lower than 0.1 mD, a better description is needed
  - Definition actually comes from government for tax reduction program purposes
- One common categorization (and very broad by the way) is:
  - Tight sandstones
  - Organic rich shale reservoirs
  - CBM
  - Hydrates
  - Tar sands and extra heavy oil sandstones
- In order to understand the reservoir, need to consider:
  - Hydrocarbon generation
  - Migration if any
  - Hydrocarbon storage
  - Flow mechanism
  - Structural discontinuities
- Then complete and stimulate the well…

Apache

ORGANIC RICH SHALE RESERVOIRS

- Hydrocarbons are generated, stored and trapped in the same rock
- Definition of shale based on grain size rather than mineralogy composition (grains size < 1/256 mm)
  - In our case focus of siltstones (high quartz content). Low clay content. Carbonates are welcome!
  - Preferably high pore pressure
  - Low porosity (<12 %) and extremely low permeability. $K_v = +/- 0.01\ K_h$
  - Free, adsorbed and dissolved gas. Ratio depends on rock type
- High lamination in some areas = prone to break easily
- Due to its extremely low permeability, hydrocarbons did not have enough time to migrate



Source: Jobe, 2011

  - As there is very low effective porosity there is also extremely low permeability
  - Presence of organic material not converted to hydrocarbon (kerogen)
  - Flow mechanisms: Darcy´s flow is the exception rather than the rule.
    There is life outside Darcy's world!
  - Storage: pore volume, natural fissures and adsorption in the organic & inorganic material
- Shale types:
  - Shale gas
  - ~~Shale oil~~
  - Tight oil

- Shale oil definition reserved for tar / bitumen reservoirs

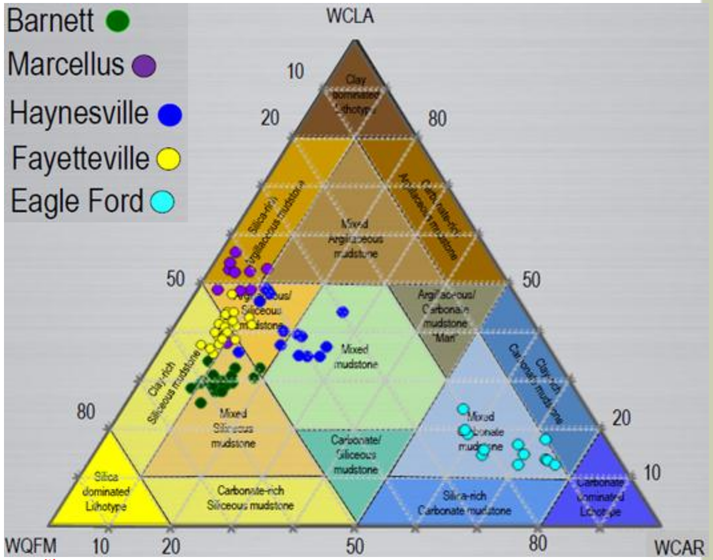
ORGANIC RICH SHALE RESERVOIRS

- Rock mineralogy = brittleness
  - Mainly composed of siliceous, carbonaceous and argillaceous compounds
  - For our purposes rock should have more than 30 % quartz content. Detrital quartz provides higher porosities. Quartz porosity directly related to free gas
  - If quartz is low, carbonates must be high in replacement
  - We do not want clays at all!
- Reservoir model
  - SGR: gas is produced from the shale itself
  - TOR: oil/condensate & gas is mainly produced from carbonate or sandy section in contact with organic shale

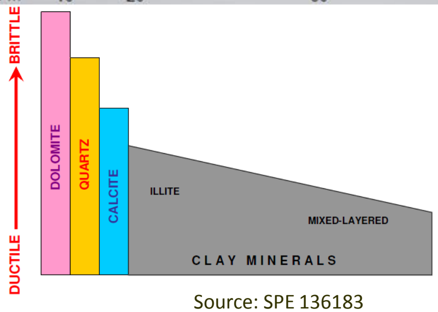
Formation	Fluid type	Reservoir rock description
Barnett	Dry / wet gas	Reservoir made of siliceous and calcareous mudstone with variable amounts of limestone, minor dolomite and clays
Marcellus	Dry / wet gas	Thinly bedded blackish shale with thin silt bands. Mainly quartzite with minor carbonates and clays
Bakken	Oil	Three layers, upper and lower are organic rich shale. Middle member is sandstone / limestone
Eagle ford	Oil, wet / dry gas	Composed of calcareous mudstone and chalk . Thinly interstratified siltstones, dolomites , shale and limestones
Woodford	Oil / gas	Horizontally bedded and highly laminated, quartzite and carbonate mudstone

- **siliciclastic mudrocks**
  - biogenic quartz + clay
  - detrital quartz + clay
  - diatomite, porcellanite, & chert
- **carbonate mudrocks**
  - micrite
  - dolomite
  - chalk
  - marl
- **hybrid reservoirs**
  - interlaminated mudstone-siltstone/sandstone
  - phosphorite

Source: Bridges, 2011



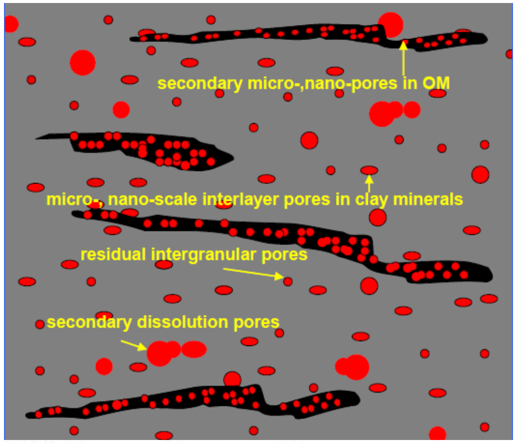
Source: Diaz, 2012



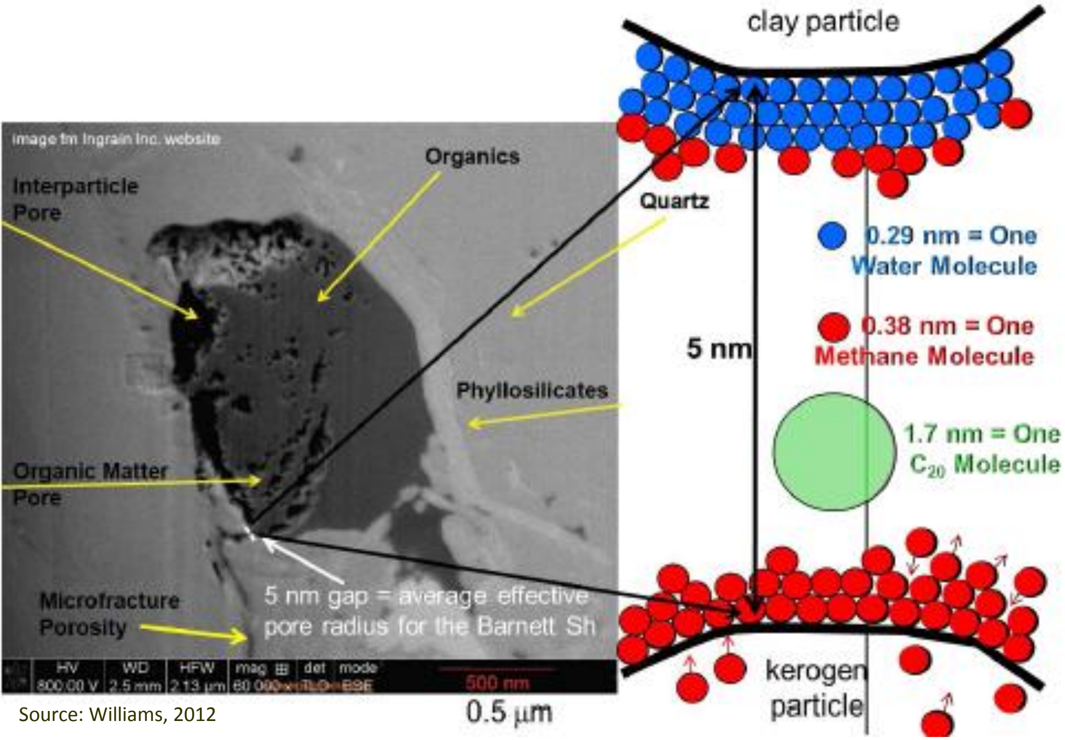
Source: SPE 136183

HYDROCARBONS STORAGE IN SHALE GAS

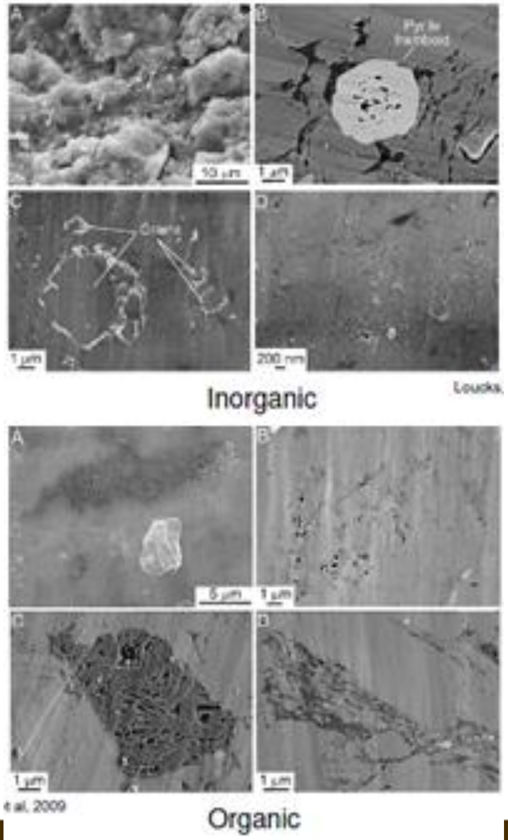
- In SGR, total gas composed of three sources
  - Free gas. Only small molecules can fit inside (methane, ethane)
    - Matrix gas = f(por, Sw, Sg, P, T). Organic and inorganic pores
    - Micro and nano fissures gas = f(por, Sw, Sg, P, T). Probable partly has migrated
  - Sorbed gas = f(kerogen, non swellable clays, P, T). Produced at later time as it requires low pressure. Some volume probably close to the wellbore as pressure drawdown is high



Source: Li, 2011



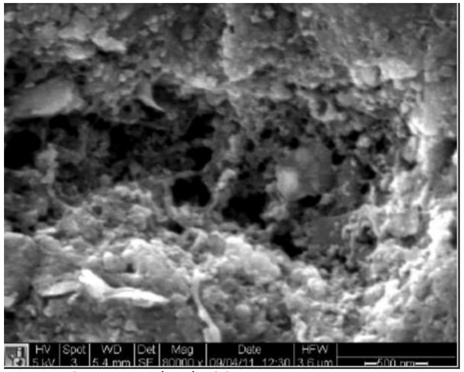
Source: Williams, 2012



Source: Loucks, 2009

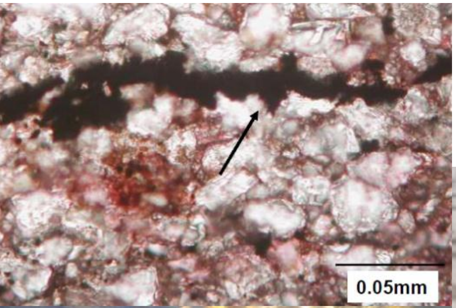
HYDROCARBONS STORAGE IN TIGHT OIL

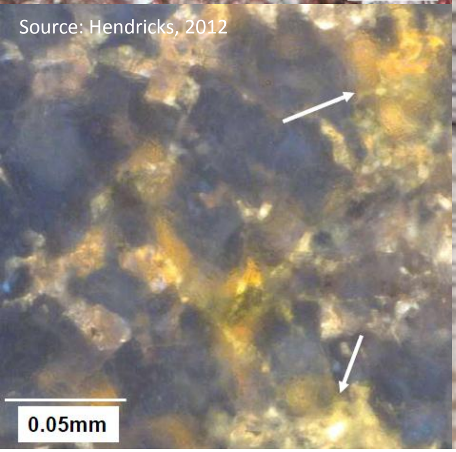
- In TOR, hydrocarbons are stored in void spaces which include pores and fissures. Larger molecules = bigger pore sizes
  - Can produce from dry gas to condensate (high API)
  - Matrix oil = f(por, Sg, Sw, So, P, T). Only those molecules with lower viscosity can flow thru the matrix
  - Micro and macro fissures oil = f(por, Sg, So, Sw, P, T). Oil production not only from natural fractures as volume is limited
  - Dissolved gas = f(por, Sw, So, GOR). Low in water but high in oil



Source: Zoback, 2011

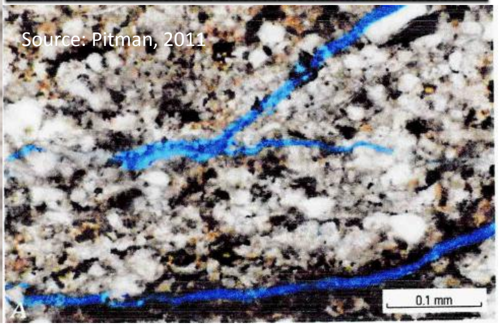
Source: Bustin, 2009



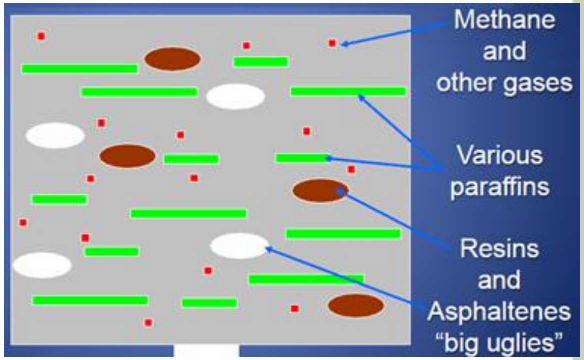


Source: Hendricks, 2012

Source: Slatt, 2011



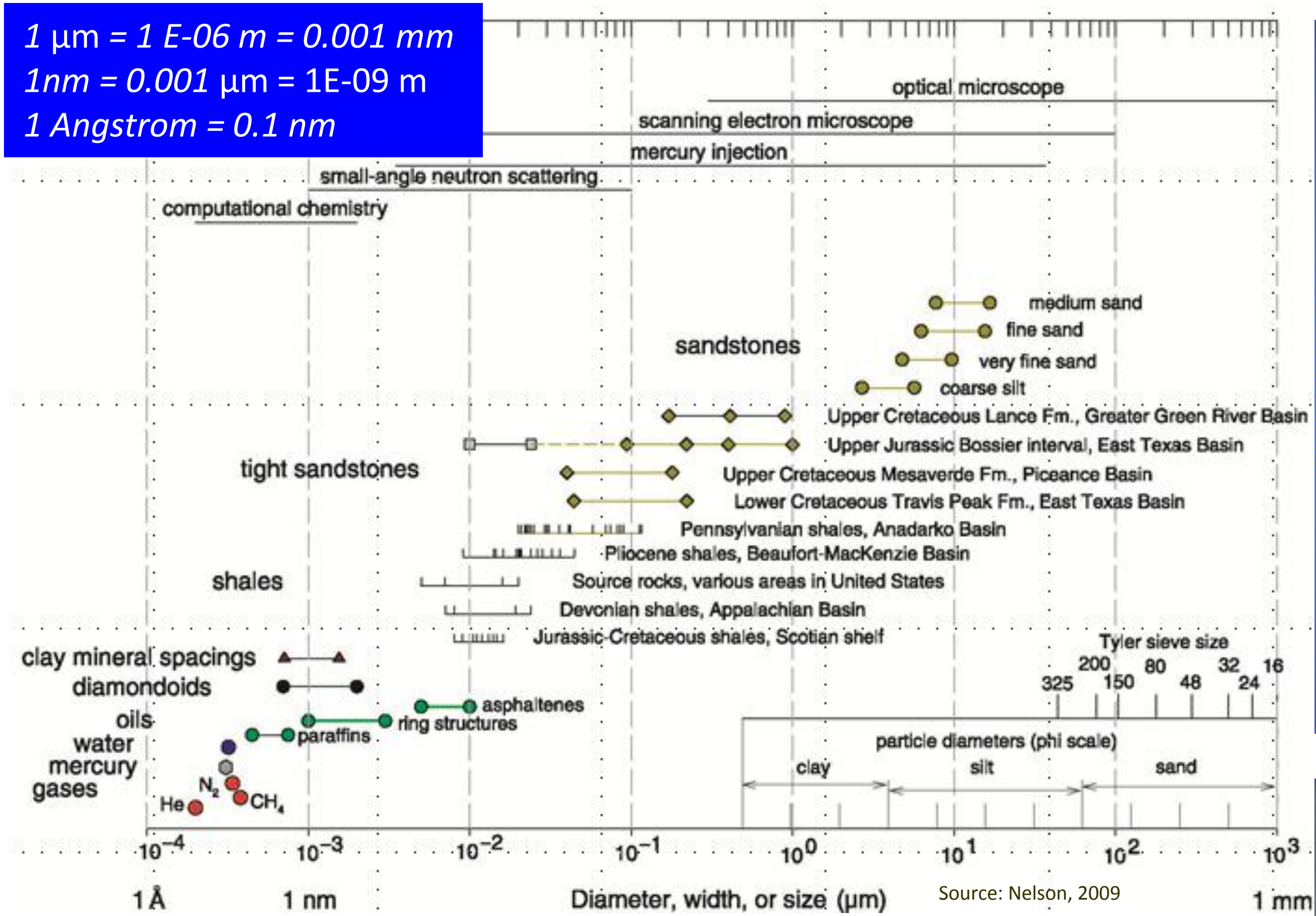
Source: Pitman, 2011



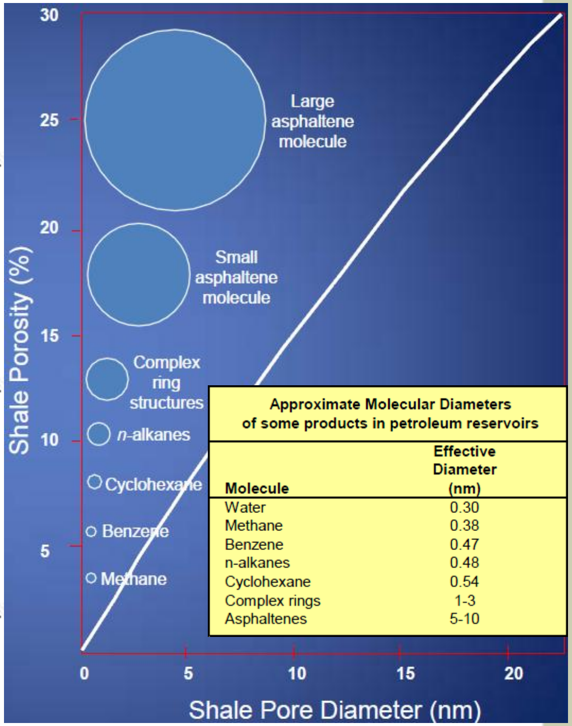
Source: Jarvie, 2008

THE NANO WORLD IN PERSPECTIVE

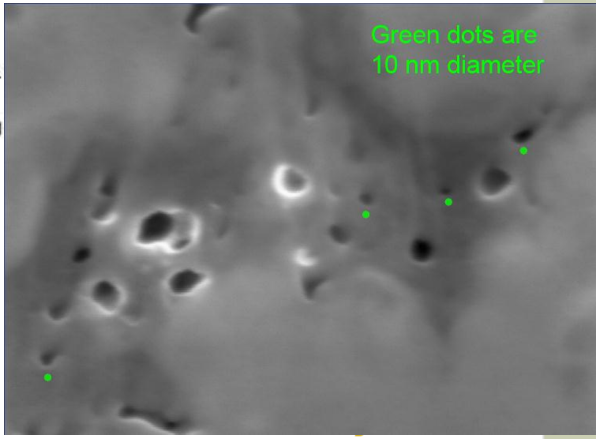
1 µm = 1 E-06 m = 0.001 mm
1nm = 0.001 µm = 1E-09 m
1 Angstrom = 0.1 nm



Source: Nelson, 2009



Source: Jarvie, 2008



Conventional oil & gas
$D_{pore} \geq 1$ µm
$K \geq 1$ mD

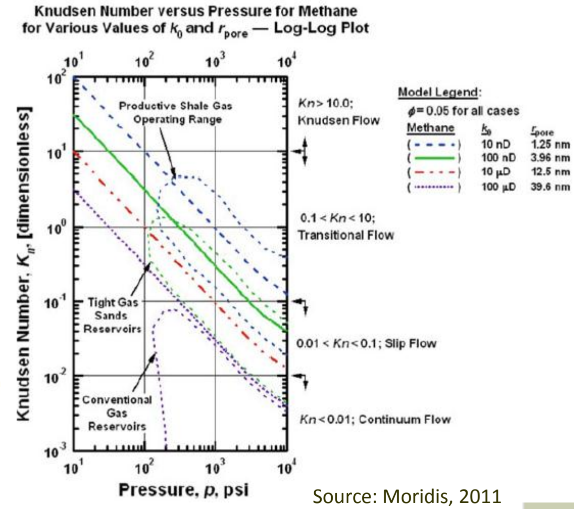
Tight gas
1 µm $\geq D_{pore} \geq 10^{-3}$ µm
1 mD $\geq K \geq$ 1 µD

Shale gas
1 µm $\geq D_{pore} \geq 10^{-3}$ µm
10^{-9} mD $\geq K \geq 10^{-3}$ mD

MASS TRANSFER AND FLOW REGIMES

- Complexity and heterogeneity of pore structure
- Pore throats and mean free path. Knudsen's number

$$K_n = \frac{\bar{\lambda}}{r_{pore}}, \quad \mathrm{Kn} = \sqrt{\frac{\pi \gamma}{2}}\frac{\mathrm{Ma}}{\mathrm{Re}} = \sqrt{\frac{\pi}{2RT}}\frac{\mu}{\rho D}$$

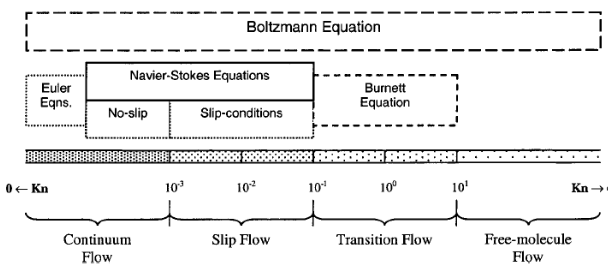


Source: Moridis, 2011

- Dry gas. Four main types of transport
  - Free molecule or Knudsen´s flow
    - Collision of molecules with pore walls matters
    - $0 < \mathrm{Kn} \leq 0.001$ = no slip flow
    - $0.001 < \mathrm{Kn} \leq 0.1$ = slip flow. Klinkenberg's effect on k
    - $0.1 < \mathrm{Kn} \leq 10$ = transition flow
    - $\mathrm{Kn} \geq 10$ = free molecular

$$k_g = k_\infty\left(1 + \frac{b}{p}\right)$$

  - Viscous flow (bulk/continuous flow)
    - Fluid driven by pressure gradient. Collisions between molecules dominate
    - Darcy's flow. $\mathrm{Re} < 1$. If $\mathrm{Re} \geq 1$ Darcy is no longer valid.
    - Inertial flow. Forchheimer's eq. $200 < \mathrm{Re} < 300$
    - Turbulent flow. $\mathrm{Re} > 350$



  - Ordinary (continuum) diffusion
    - Different species moves due to concentration, temperature and other external force gradients. Diffusion dominated by collisions between molecules

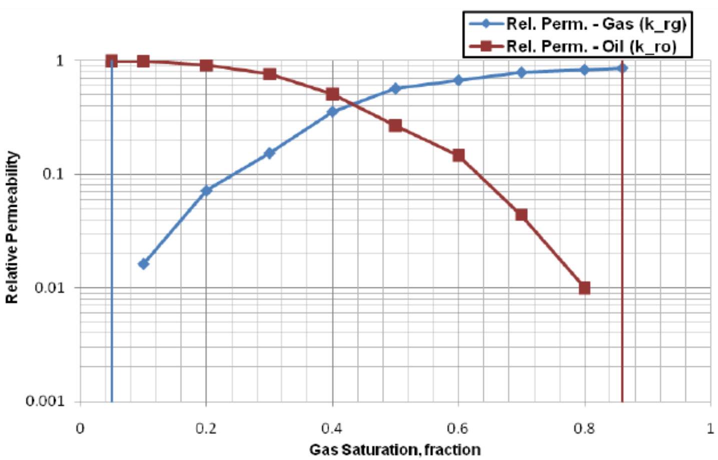
Source: Roy, 2003

  - Surface flow
    - Molecules move along a solid surface on a adsorbed layer

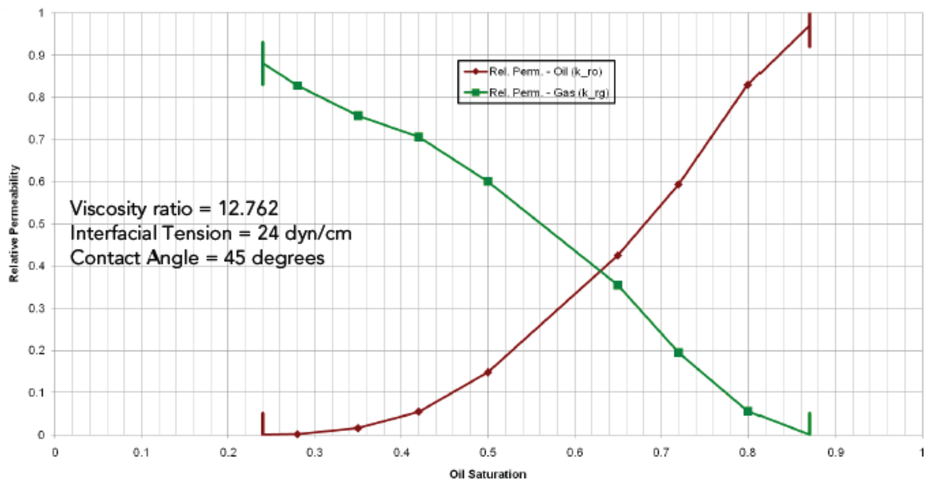
Apache

MASS TRANSFER AND FLOW REGIMES

- Wet gas and / or condensate. Multiphase flow
  - Free molecule or Knudsen´s flow
    - Bigger molecules in same pores makes this flow difficult. Only possible in bigger pores
  - Viscous flow (bulk/continuous flow)
    - Hydrocarbons viscosity is several orders of magnitude larger than gas one and permeability still is very low. Reason for only having high API condensate in production stream
    - Most of the hydrocarbon flow will be in this regime
    - Coexistence of phases (three after fracturing and two after frac water vanishes), relative permeability issues are important. Different relative permeability curves in matrix and fissures. Extremely difficult to measure in the lab. Best results from rock physics modeling
  - Diffusion and desorption have a minor role
    - PVT behavior in small cavities (pores) is different to conventional. Other forces need to be considered



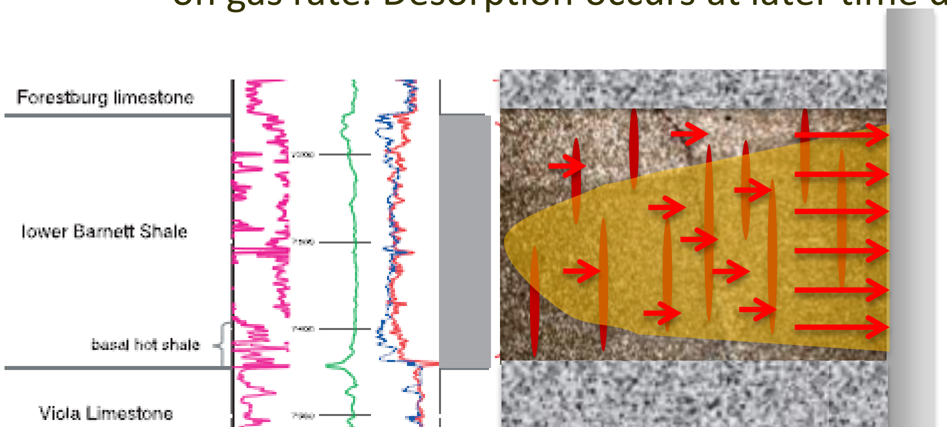
Source: Ingrain, 2011



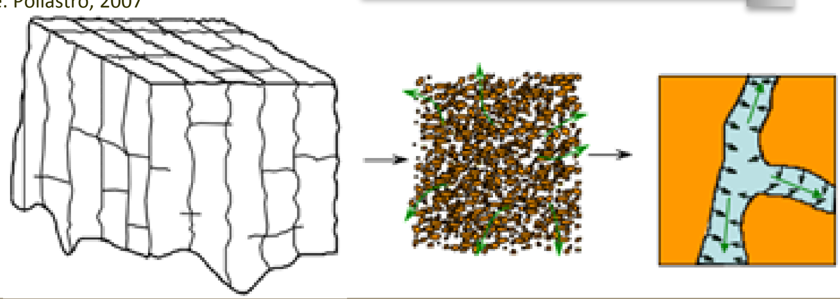
Source: Ingrain, 2010

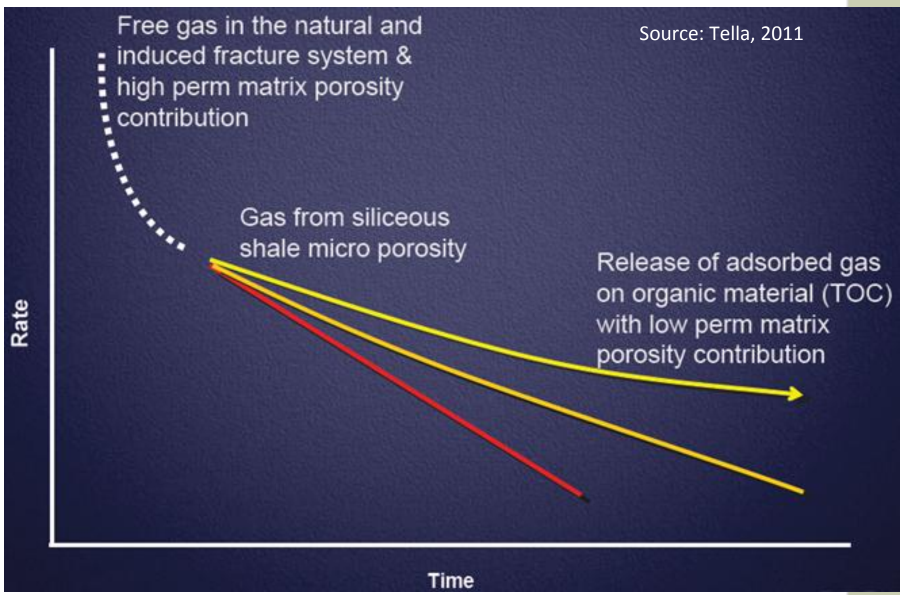
FLOW FROM MATRIX TO WELLBORE – SHALE GAS

- Shale gas mass transfer process
  - Matrix gas flows small distances under Knudsen's flow.
  - When gas reaches fissure walls, gas gets into them under diffusion and viscous flow. Still nano-fissures has extremely low width for accepting large gas flow. All fissures conform the network. The greater the SRV the smaller the matrix blocks and the larger the matrix surface exposed to fissures thus making significant gas flow
  - Large number of fissures feed into secondary and main hydraulic fracture. Basically viscous flow
  - At early time multiphase flow at wellbore (gas + water). Potentially some turbulence depending on gas rate. Desorption occurs at later time during well life when pressure drawdown is large



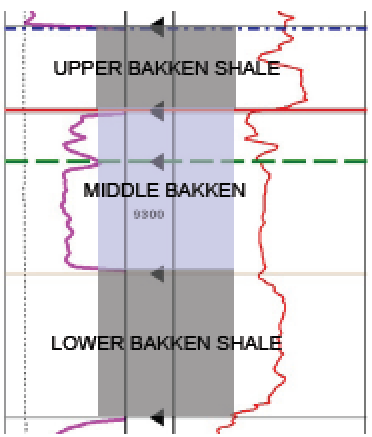
Source: Pollastro, 2007



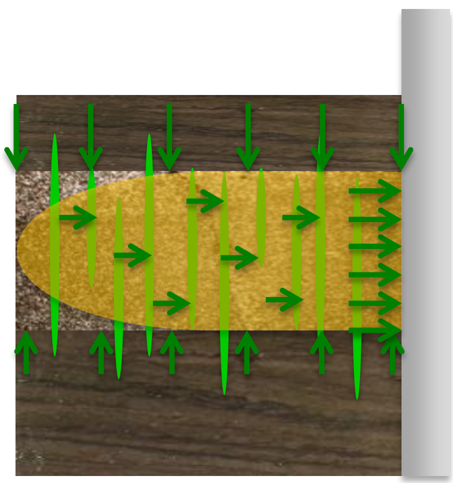


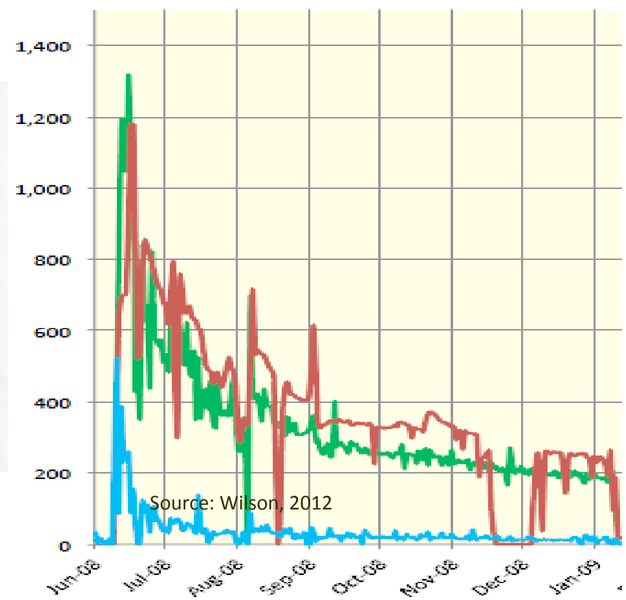
FLOW FROM MATRIX TO WELLBORE – TIGHT OIL

- Tight oil mass transfer process
  - Oreo cookie model. “Sweet” production comes from inbetween organic sections “cookie”
  - Liquid and gas molecules travel along interconnected bigger pores. Gas has advantage. Mostly viscous flow but also some Knudsen’s flow is possible for gas
  - When leaving matrix, oil mixes with oil already in open fissures and flows thru the existing and created network.
  - The network feeds oil into the secondary and into the main hydraulic fracture
  - Multiphase flow during well life. Water diminishes early on production, mainly frac water



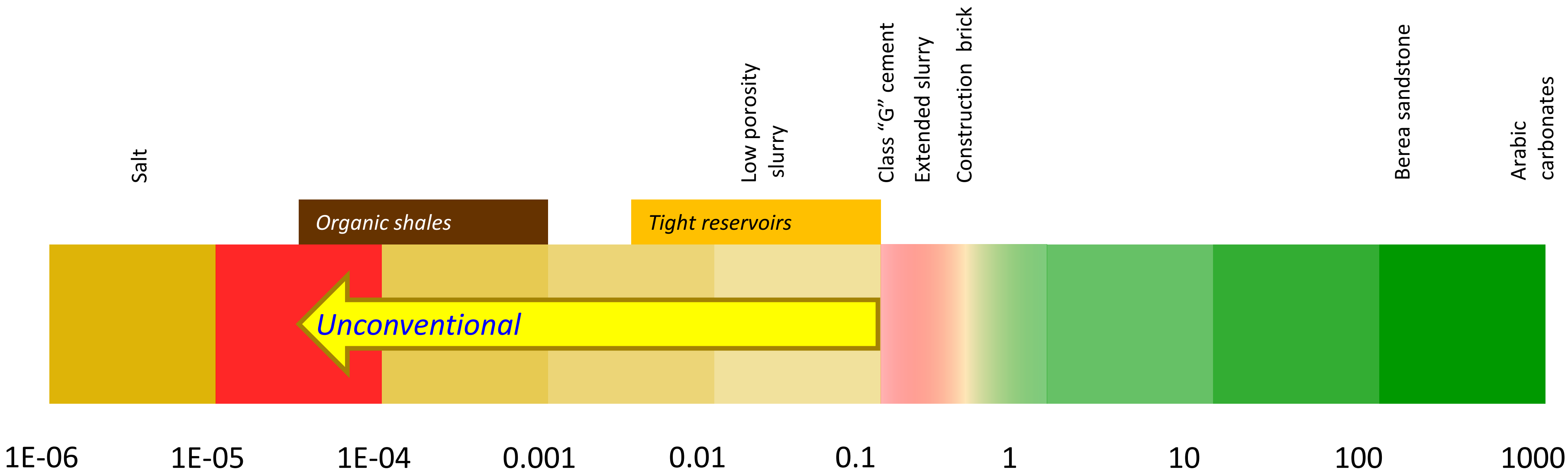
Source: Sterling, 2012





Source: Wilson, 2012

RESERVOIR ROCK PERMEABILITY & PRODUCTIVITY



Dry Gas	
P_res	5500 psi
BHFP	1500 psi
BHT	200 ºF
SG_gas	0.65
Thickness	5 m

Qg \ K_gas	10 mD	1 mD	0.1 mD	0.01 mD
m^3gpd	924,000	92,400	9,240	924

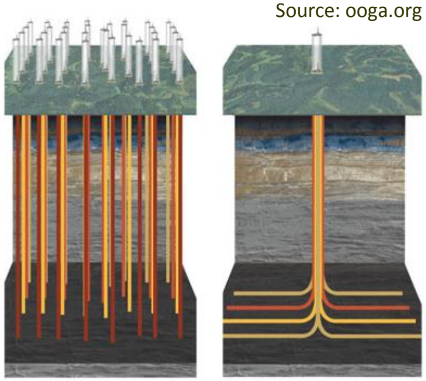
- For dry gas, no commercial rates below 0.1 mD unless well is hydraulically fractured
- Shales have less than 0.01 mD, so matrix flow is negligible
- If multiphase flow exists, gas production will be much lower
- Oil production must come from intervals with higher permeability (oil viscosity >> gas viscosity)

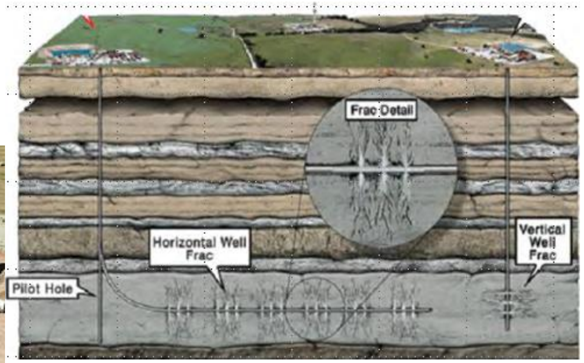
Apache

WHY MULTI-FRACTURED HORIZONTAL WELLS?

- Mandatory state regulations
  - Requirement of minimum ground disturbance
  - Access to reservoirs under populated cities, farming areas, preserved lands, water resources
- Cheapest way to put in the ground several wells at the same time!
  - Closer well spacing. Drainage area is much smaller
  - Pad drilling and completion. Offshore approach
    - Centralized facilities. Smaller foot print
- Vertical wells just for initial phase
  - Field trials, pilot hole
  - Frac mapping monitor wells
  - Disposal wells

Source: ooga.org





Source: www.srbc.com

Source: epmag.com

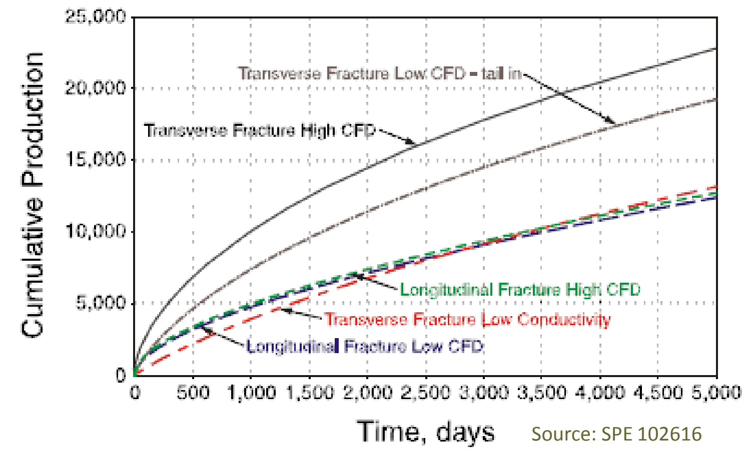
Source: Griffin, 2007

Jonah field, 40 acres well spacing

Marcellus, 40 acres well spacing in pads

ANY ADVANTAGE FROM RESERVOIR PERSPECTIVE?

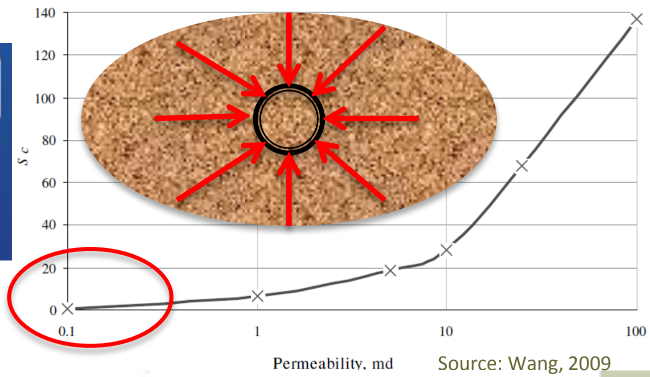
- Transverse HF is only attractive from productivity perspective as permeability decreases
  - Best option for k < 0.5 mD. The lower the K the better the option is
  - Basically choke flow at perfs is the limiting factor
- Multi-fractured horizontal wells provides highest productivity index
  - No other combination can surpass it
  - High number of fractures provides large IP and cumulative production
    - Incremental production diminishes with number of frac stages. Reservoir issues
    - Economical considerations



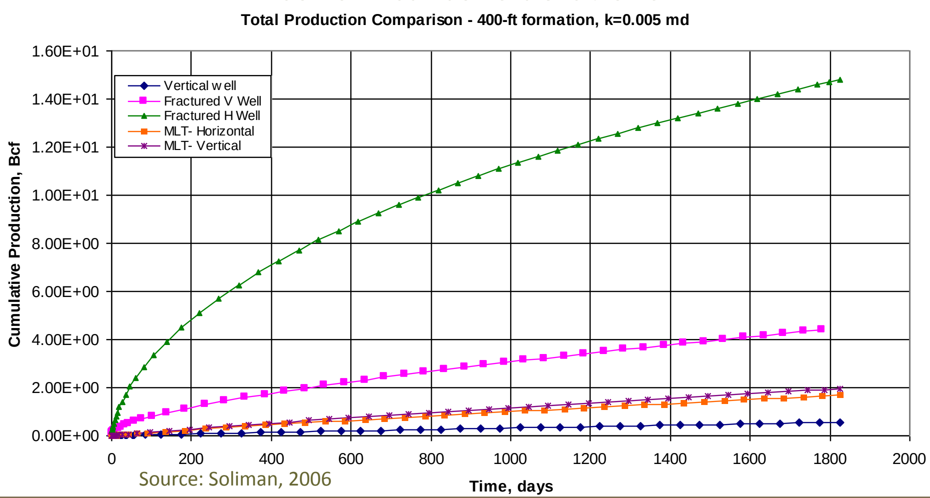
Source: SPE 102616

$$s_c = \frac{kh}{k_f w}\left[\ln\left(\frac{h}{2r_w}\right) - \frac{\pi}{2}\right]$$

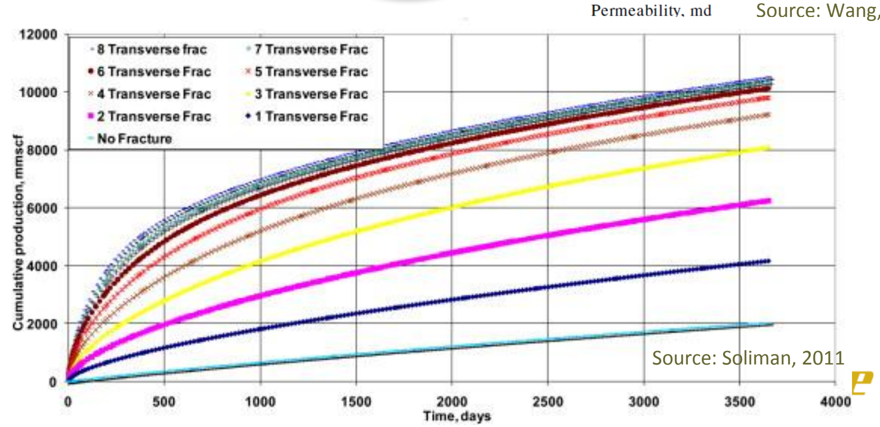
$$J_{DTH} = \frac{1}{(1/J_{DV}) + s_c}$$



Source: Wang, 2009



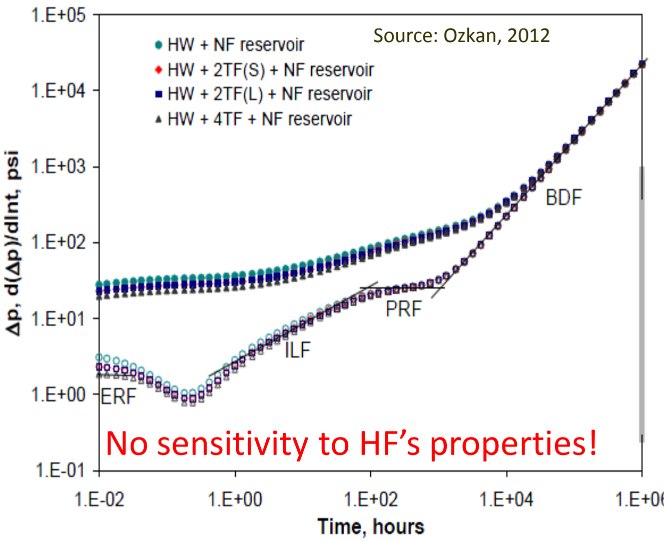
Source: Soliman, 2006

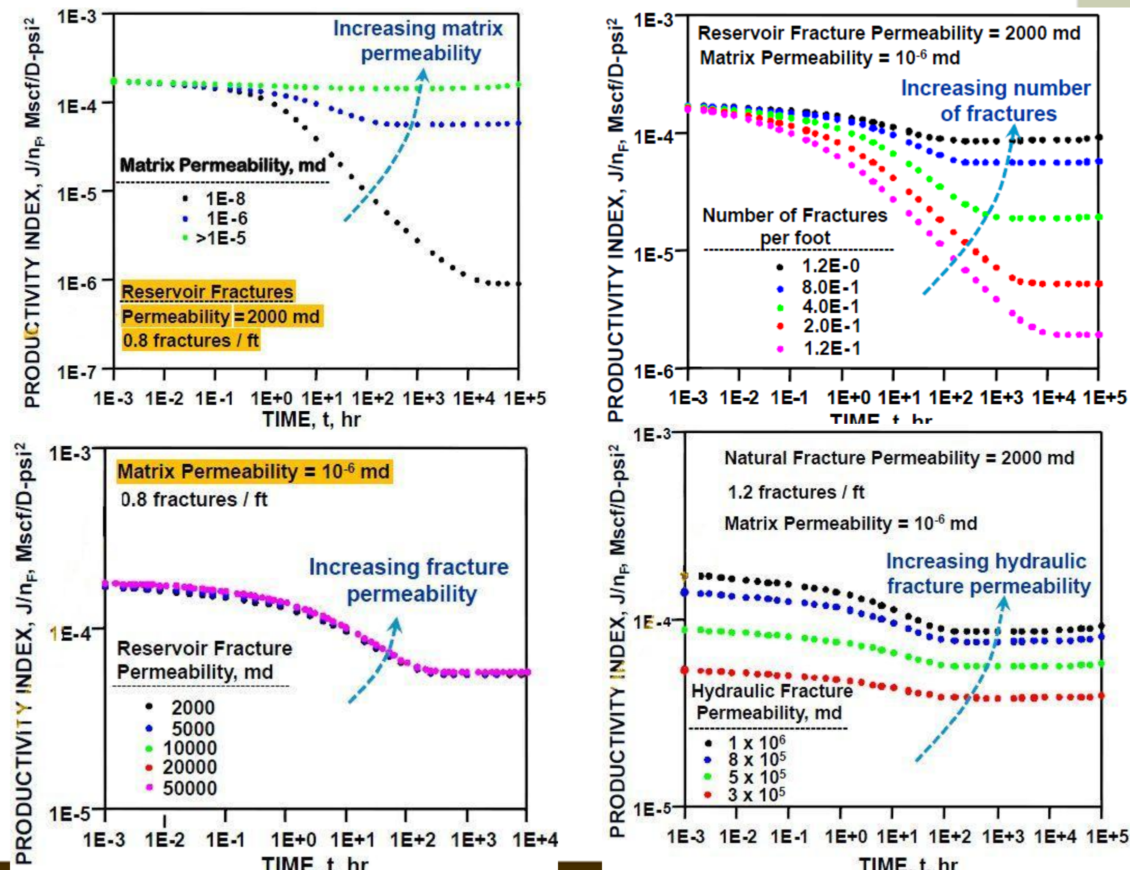


Source: Soliman, 2011

ANYTHING ELSE TO CONSIDER? – "THE REVELATION"

- YES! Presence of natural fissures in sufficient density
  - We do not create the network, we just activate it if present!
- **Hydraulic fractures are only used to activate and enhance the existing network of natural fissures and if we are lucky we can leave certain conductivity in those pathways**
  - Main and secondary fracture just bring collected gas to wellbore
  - **Matrix governs, so no need of expensive conductivity in the main fracture!**

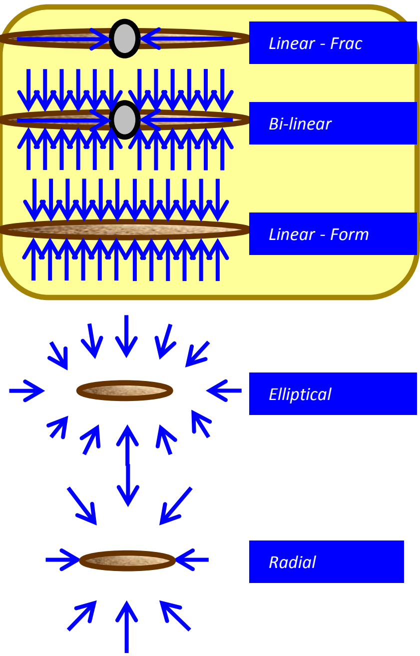


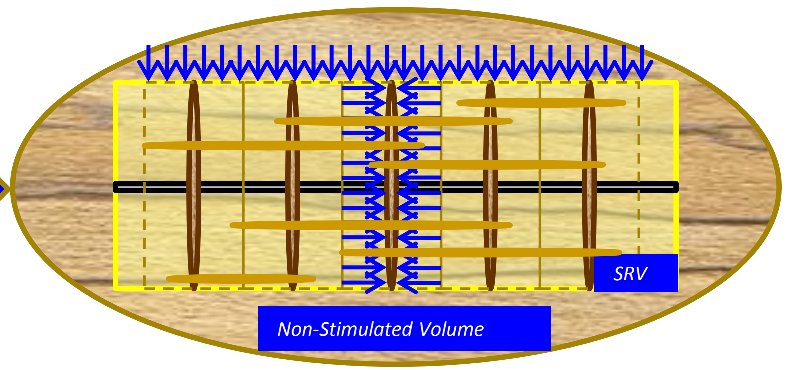


- ✓ **NF flow capacity is restricted, when reached no additional productivity is possible**
- ✓ **NF permeability is not important, matrix flow is the limiting factor**
- ✓ **Incremental HF permeability decreases as fracture permeability increases, volume available to move is limited**

WHERE DOES THE FLOW COME FROM IN SHALES?

- If permeability is less than 5E-5 mD gas only flows from SRV to fractures. No gas from outer boundary in 30 years (practical well life).
  - Distance between main fractures dictates interference. No flow boundaries.
  - SRV is a function or ability to create a fracture network. Natural fracture density and hydraulically created fractures are the key





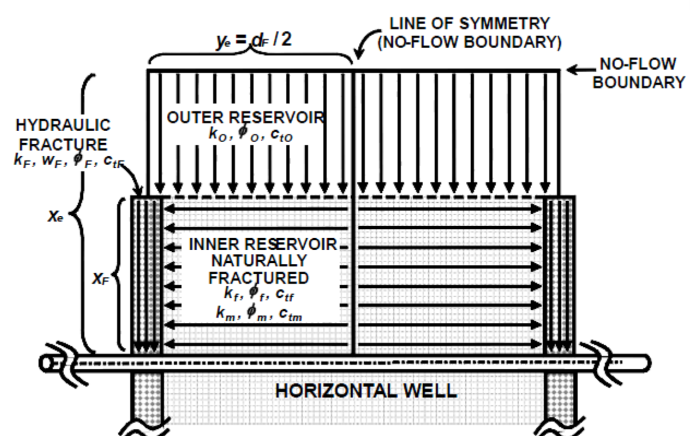
Source: adapted from SPE 144583

- ✓ *SRV as a consequence of HF*
- ✓ *Pressure reduction at wellbore creates a pressure gradient*
- ✓ *Sorbed, matrix and fracture gas moves thru connected pores, fissures and induced fractures. Sorbed gas produced at later time*
- ✓ *Gas stream flow from secondary created fractures to main HF*
- ✓ *Gas reaches wellbore*

k, mD	Xf, ft / m	t_int, hr	T_int, days	T_int, yrs
0.1	100 / 30.5	2.28	0.095	~
0.1	300 / 91.4	20.52	0.855	~
0.001	100 / 30.5	228	9.5	~
0.001	300 / 91.4	2052	85.5	0.2
0.00001	100 / 30.5	22800	950	2.6
0.00001	300 / 91.4	205200	8550	23.4

$$t \geq \frac{1.14 \times 10^4 \phi c_t \mu x_F^2}{k}$$

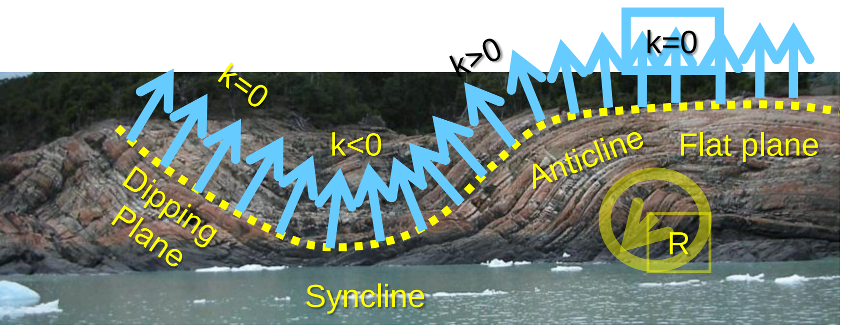
But Xf,eff= D/2 !



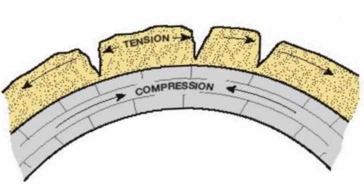
Source: Ozkan, 2011

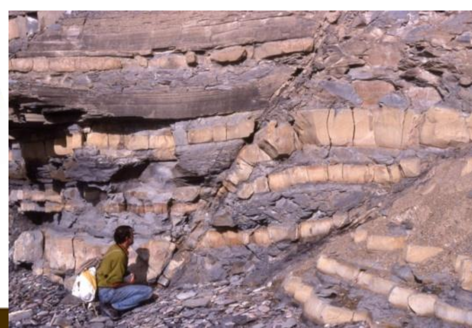
STRUCTURAL DISCONTINUITIES

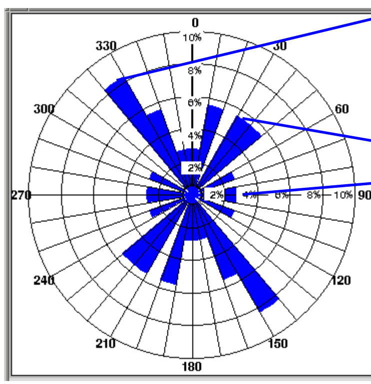
- Something else is required to assist the gas to flow acting also as storage volume for hydrocarbons = natural fractures. Great impact on stimulation
  - Origin. Uplifts. Faulted folds. Bed thickness in laminations
  - Density
  - Open or healed (filling material, generally calcite). Energy to open them
  - More than one set of natural fractures? Orientation
  - Seismic identification
- Other discontinuities include joints, planes of weakness, damage zones
  - Important for stimulation purposes



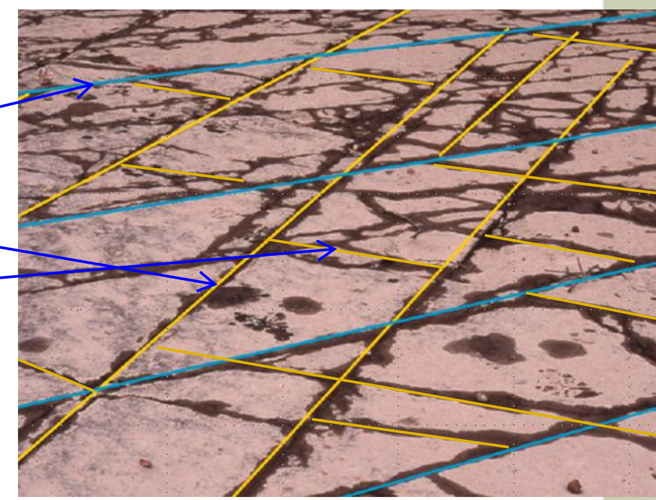
Source: K. Marfurt´s presentation







Source: Gale. 2009

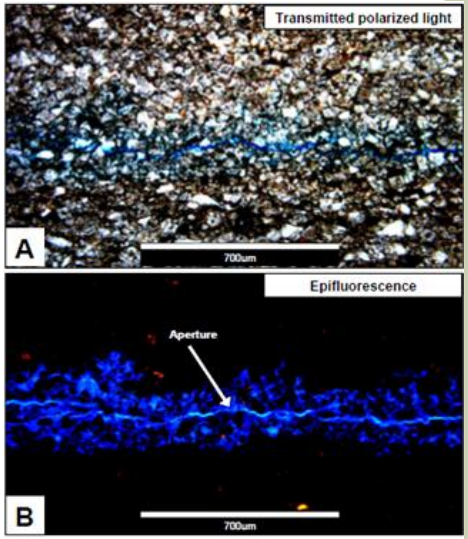


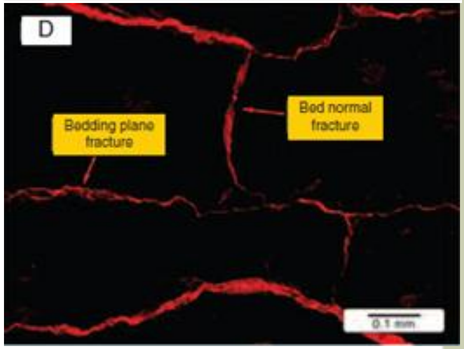
Source: Adapated from Marcellus shale. Gary Lash. SUNY

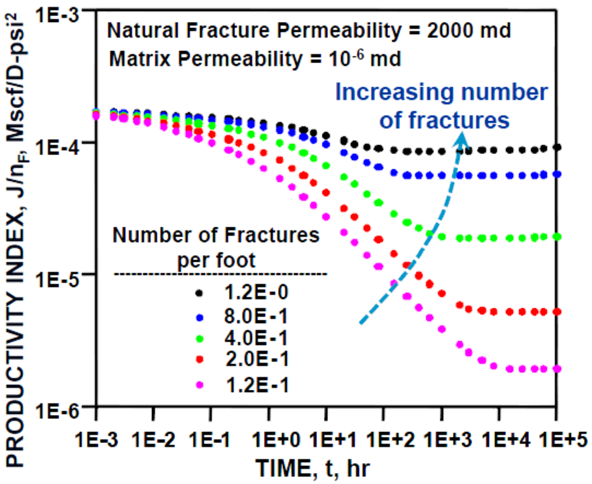
NATURAL FISSURES

- In SGR it looks like healed fissures are better than open ones
  - If they are open probably gas has migrated thru them
  - Healed fissures in high density are the key for stimulated volume generation
  - Nano and micro-fissures
- In SOR they are critical
  - Balance of open and healed fissures. Open for storage and healed for stimulation purposes
  - Density
  - Flow path to main HF
  - Nano and micro-fissures

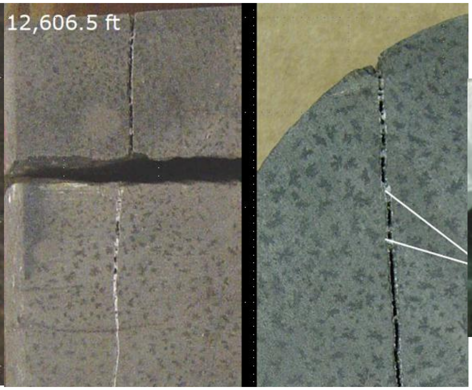
Source: Warner, 2011



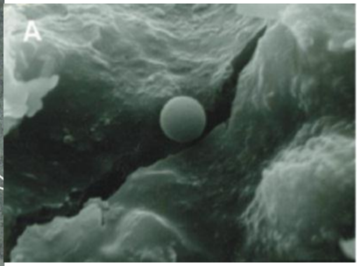


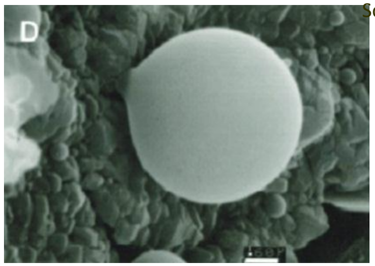


Source: Ozkan, 2011



Source: Slatt, 2011





Source: Stegent, 2011

Oil droplet in microfracture

Oil droplet oozing from matrix

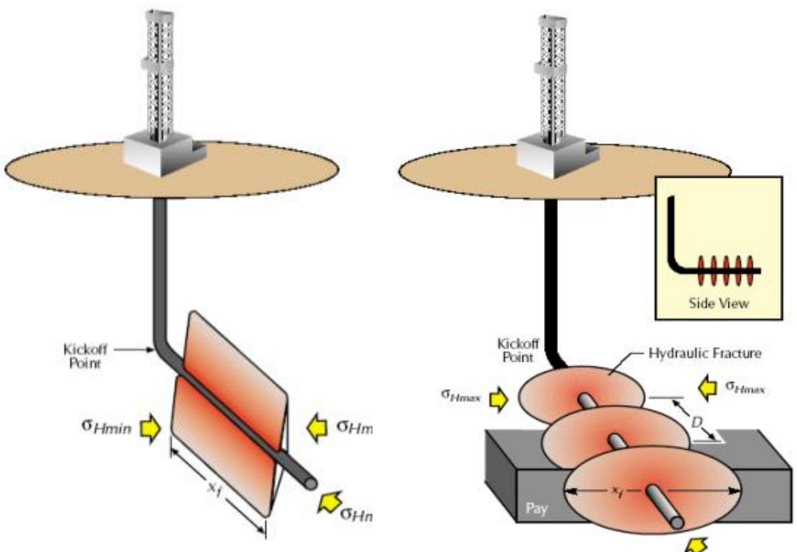
Source: Gale, 2008

Source: Barnett Shale. AAPG. Gale, 2009

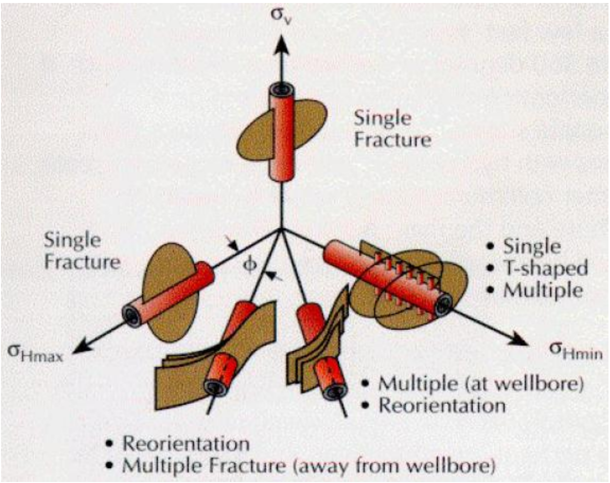
Apache

WELL ORIENTATION

- In vertical wells there are no issues as fracture can initiate anywhere around the wellbore. Unless deviation exists most of the HF will be connected to wellbore
- As HF grows in the same plane of the two principal stresses, the direction of the horizontal wellbore axis will dictate the orientation of the HF to the well
  - Longitudinal fractures: no impact on well productivity if permeability is less than 0.1 mD. In addition, no assurance entire fracture will be connected to wellbore
  - Transverse fractures: best option for reservoirs with permeability less than 0.5 mD. As contact point with wellbore is reduced, choked flow is observed
  - Fractures at any other angle: hard to initiate. Fracture tends to start growing parallel to wellbore axis, until it leaves local stress effects and turns to align to field stress. High breakdown and treatment pressures. High tortuosity. High probability of early screen outs



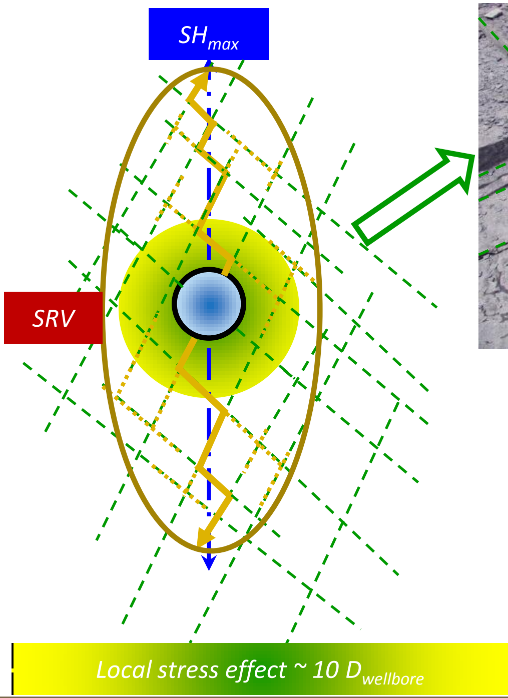
Source: Halliburton

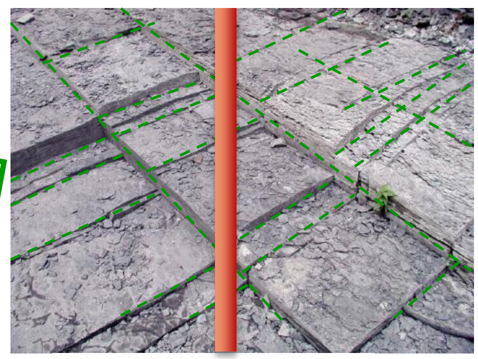


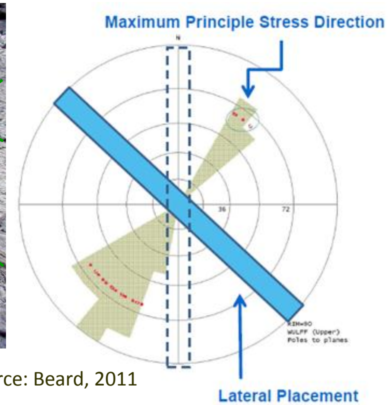
Source: Halliburton

STRESS AZIMUTH & NATURAL FRACTURES

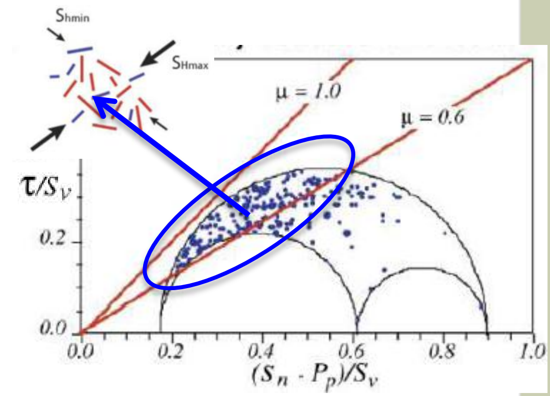
- Globally HF follows stress fields, locally HF follows fabric (fissures, planes of weakness)
  - NF can be oriented at different directions related to actual principal horizontal stress azimuth
    - In general with three principal orientations it is possible to define the whole set
- Only critically stressed NF's can be activated
  - Shear failure does not occur in the same plane of tensile failure
  - Critically stressed NF's in contact with perfs are the ones that will take fluid easily
  - If NF´s are aligned parallel to the principal horizontal stress, an option to study is to drill the well in a certain angle related to the least horizontal principal stress to make the rock failing in shear mode and increase the fracture network and still keeping transverse HF's

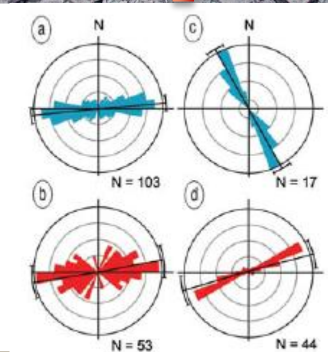






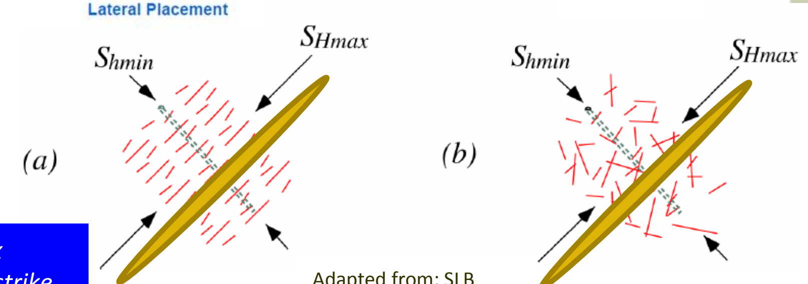
Source: Beard, 2011





Source: Olson, 2007

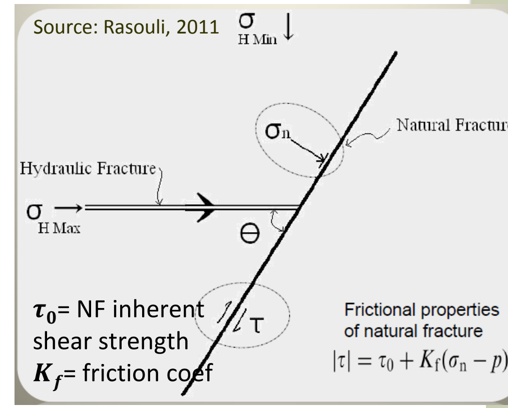
A / C) Shmax
B / D) open NF's strike

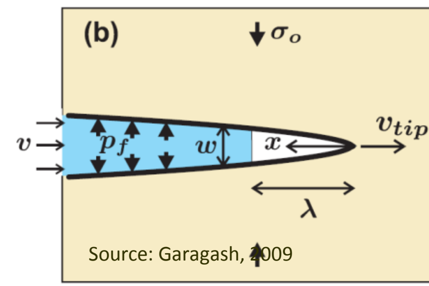


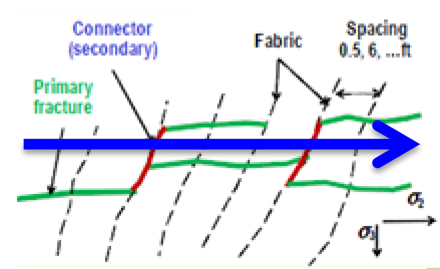
Adapted from: SLB

INTERACTION BETWEEN HF & NF'S (INTERFACES)

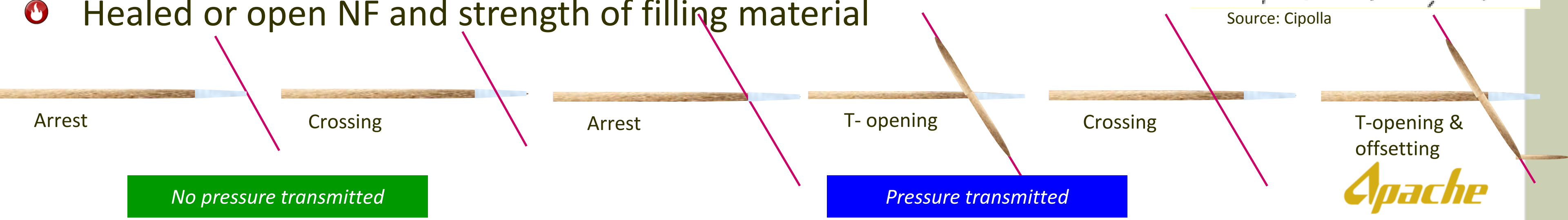
- When the HF tip reaches the NF, there is no pressure transmission as net pressure within the fluid lag zone is virtually zero. Still NF is under influence of stress field generated by HF. Two outcomes:
  - Arresting by slippage. Tip stops growing as area increases suddenly
  - Crossing
- Once the frac fluid reaches NF, depending on different factors the outcomes might be:
  - Arresting
  - Crossing
  - T-opening. It requires frac fluid gets into the NF. Dilation
  - T-opening and offsetting. It also implies fluid flows inside the NF. While extending the NF, weak planes (fabrics) or barriers that stop growing might reinitiate main HF into its original direction. Complex network
- Magnitude of the stress transferred to the other side of interface determines whether the fractures is able to cross the NF or not
- Viscosity and leak off rate governs fluid flow inside NF
- Healed or open NF and strength of filling material







Source: Cipolla



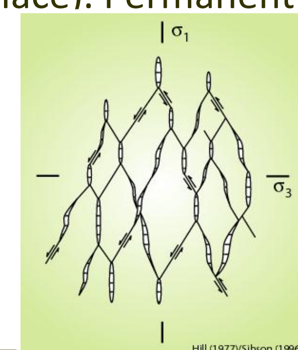
Apache

INTERACTION FACTORS BETWEEN HF & NF'S

- Friction of the natural interface
  - NF works a tensile stress barrier. HF crosses just by a small increase in friction
- Shear strength (cohesion of the natural interface)
  - In general NF has less shear strength that rock matrix itself. Directly related to filling material if any. Open to healed condition. Weak interfaces are always ready to accept fluid
  - HF crosses the interface with higher shear strength.
  - If fluid pressure is larger than normal compressive stress, NF will dilate and NF is part of HF
- Angle of approaching
  - Best condition for direct crossing given other conditions is 90°. Even at 60° the HF crosses the interface but it takes longer time. At 30° or less even if the friction coefficient of the interface is increased considerably there is no crossing
- Superposed effects of all parameters
  - Except for high shear strength, in zero friction coefficient, arresting is the dominant mechanism.
  - High angle and high friction coefficient promote crossing
  - If fluid pressure is larger than normal stress and shear stress is higher than shear strength of the interface, the NF will dilate first (inflate) and then will shear (displace). Permanent bond failure

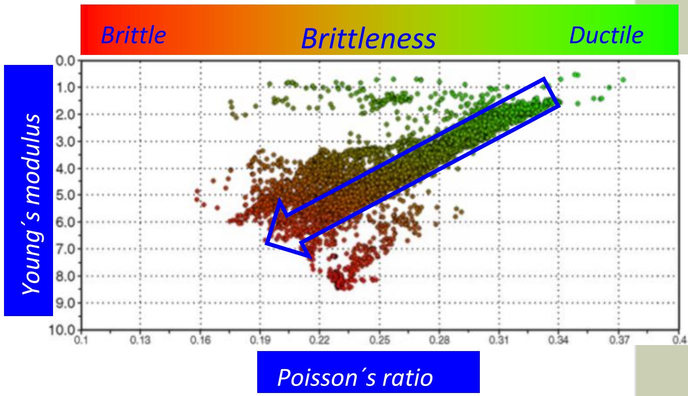
Closed fissure Dilated fissure Sheared fissure

Promote shearing ! = complex networks

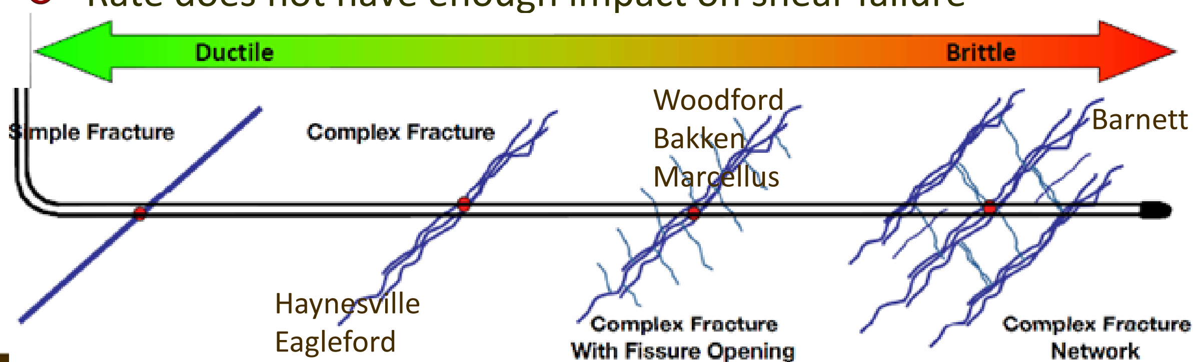


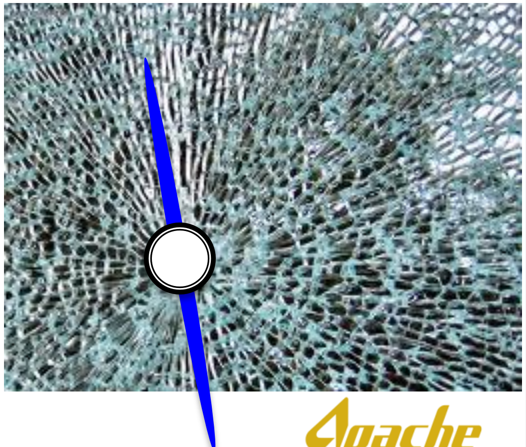
FRACTURE COMPLEXITY - SUMMARY

- Conditions to maximize fracture complexity
  - Brittle rock
  - Low horizontal stress differences (net pressure > σ_m)
  - Stress differences are high but predominant natural fissure sets are oblique to the stress field. Parallel are not preferred
  - Weak natural fractures. Low strength healing material
  - And of course proper density of natural fissures!
- Shearing promotes more complexity than tensile failure
- Viscosity
  - Low viscosity boosts shear failure
  - High viscosity slightly increases tensile failure area
- Rate
  - High rate favors tensile failure area
  - Rate does not have enough impact on shear failure



Adapted from: SPE 115258



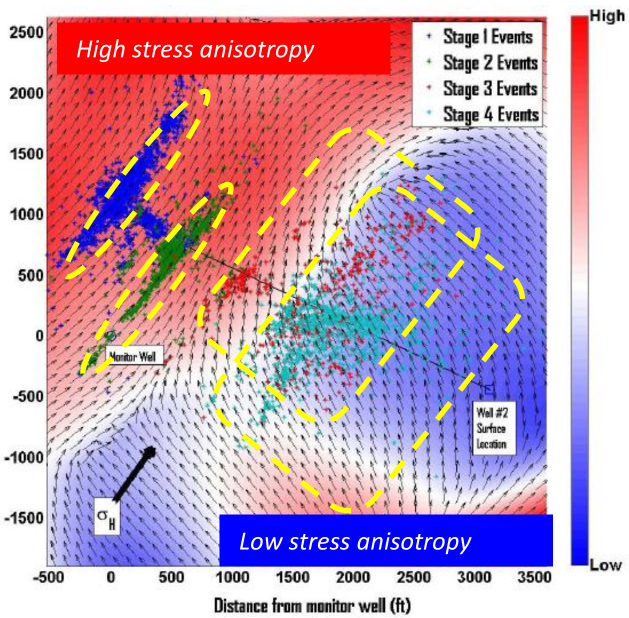


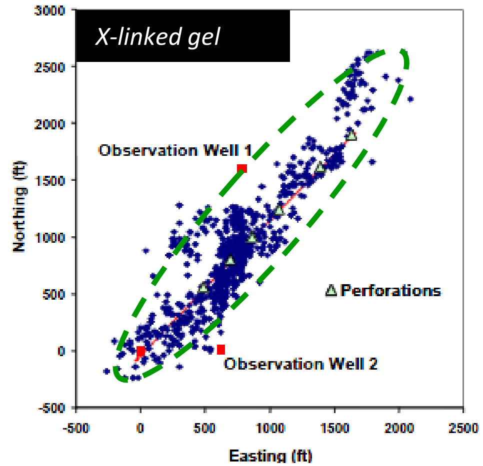
Source: McKeon, 2011

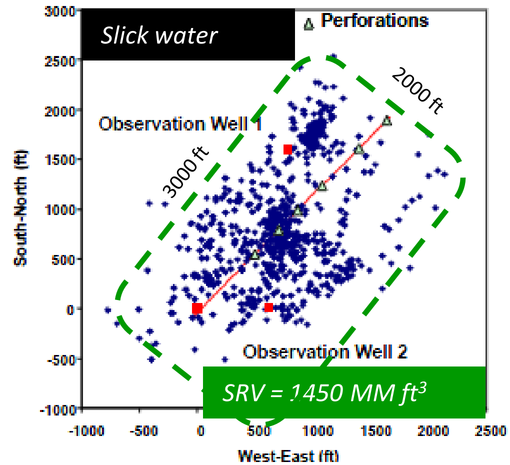
STIMULATED RESERVOIR VOLUME (SRV)

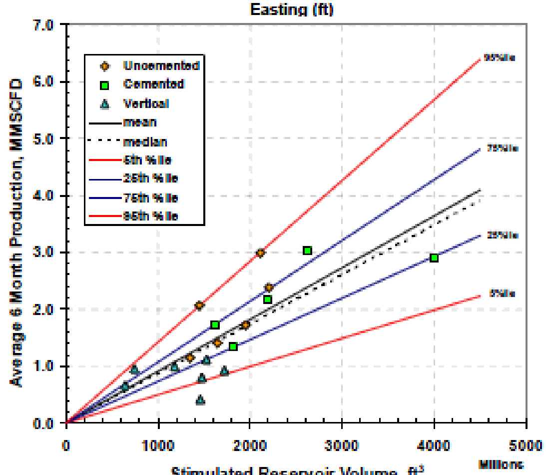
- In SR is critical to create a large stimulated volume (SRV) in order to contact large areas
- Ability to create such a large SRV depends on geological factors and also fracture design
  - Difference in magnitudes between both principal horizontal stresses
  - Presence, density and orientation of natural fissures and/or planes of weakness
  - Fluid pumped (x-linked vs slick water – SW) and volume (frac fluid & proppant)
  - Fracturing rate

Adapted from: SPE 131779









Stress anisotropy (SA) = SH - Sh

Low SA = fracture network = SRV

High SA = planar fractures

$$R_n = \frac{Pf - Sh}{SH - Sh}$$

from: SPE 95568

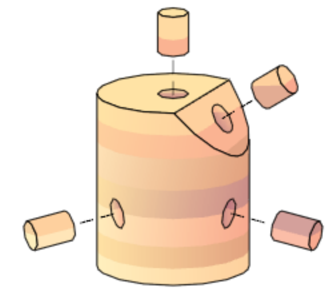
Rn = relative net pressure

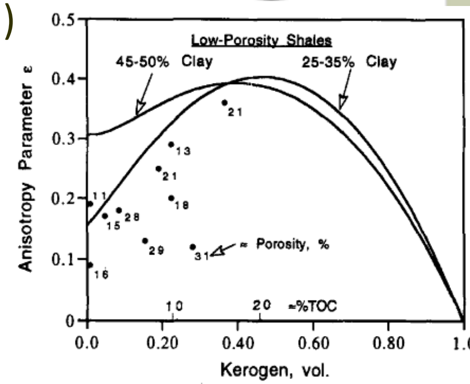
-Inversely proportional to local deviatoric stress in which the fracture propagates
-High Rn = fracture path complexity

Apache

ROCK MECHANICS - ANISOTROPY

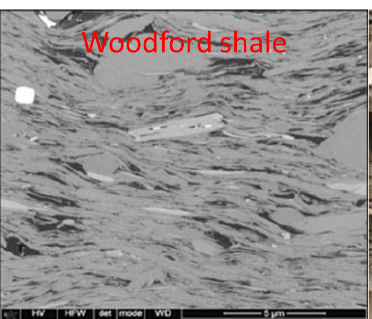
- Anisotropy = an attribute as a function of the direction of measurement
  - Conventional reservoirs are generally considered isotropic
- Shale itself is moderately to highly anisotropic
  - Layering microstructure, bedding cause vertical transverse isotropy (VTI)
  - Presence of NF, plane of weakness, faults create horizontal transverse isotropy (HTI)
  - As a consequence shale can be described in general as an orthotropic anisotropic medium. Some shales behave close to conventional rocks
  - Kerogen increases anisotropy. 15 – 20 % TOC provides maximum values



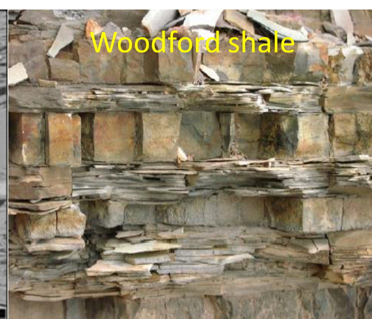


Source: Vernik, 1997

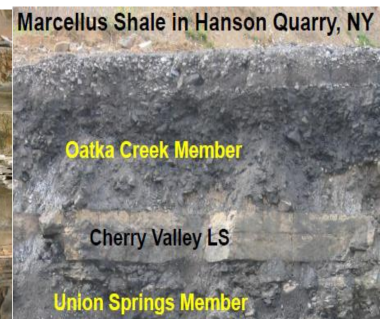
Source: Vernik, 2011

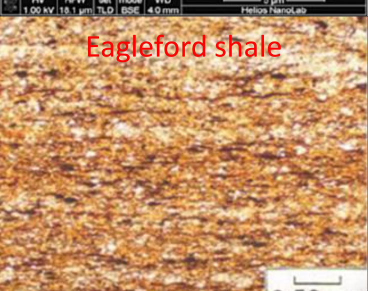


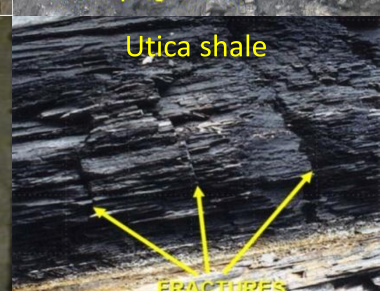
Source: Sondhi, 2011



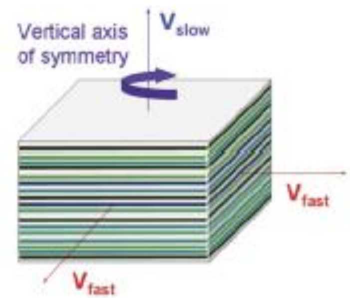
Source: Soeder, 2011

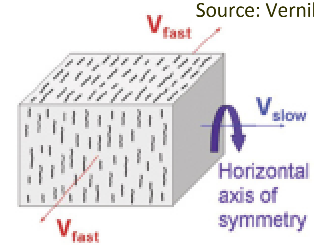




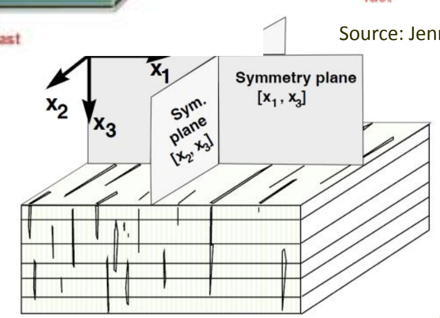


Source: RPSEA meeting, April6, 2010





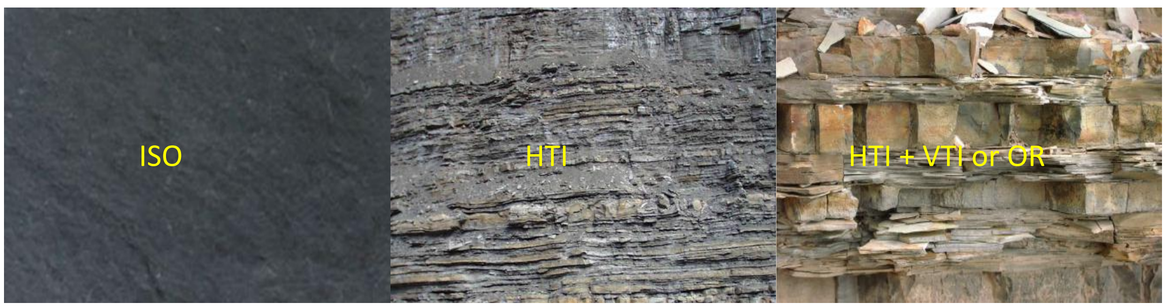
Source: Jenner, 2011



Source: Ticora Geosciences Inc

ANISOTROPY IMPACT ON FRAC STRESS MODELING

- In conventional reservoirs it is generally assumed rock behaves as an isotropic medium. Stress profiles for hydraulic fracturing purposes are generated using an isotropic model
- SR show clear anisotropy at different levels. Need to adjust stress calculations accordingly
- Fracture growth dominated basically by:
  - Stress contrast
  - Lamination
  - Rock's moduli (Young, Poisson, Biot)



ISO

$$\sigma_h - \alpha\sigma_{pp} = \frac{\nu}{1-\nu}(\sigma_v - \alpha\sigma_{pp}) + \frac{E}{1-\nu^2}\varepsilon_h + \frac{E\nu}{1-\nu^2}\varepsilon_H$$

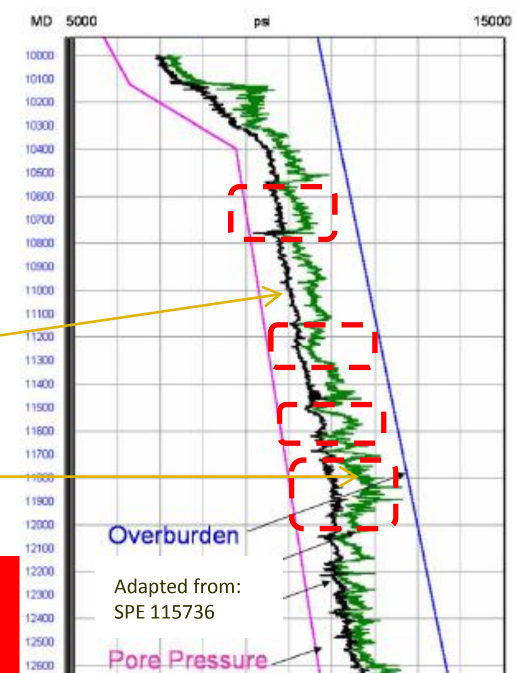
HTI

$$\sigma_h - \alpha\sigma_{pp} = \frac{E_{horz}}{E_{vert}}\frac{\nu_{vert}}{1-\nu_{horz}}(\sigma_v - \alpha(1-\xi)\sigma_{pp}) + \frac{E_{horz}}{1-\nu_{horz}^2}\varepsilon_h + \frac{E_{horz}\nu_{horz}}{1-\nu_{horz}^2}\varepsilon_H$$

Argillaceous shale bed	E_h= 6 E6 psi Ev= 3 E6 psi	ν_h= 0.26 ν_v= 0.25	ISO S_h= 0.66 psi/ft ANI S_h= 0.87 psi/ft
Siliceous shale bed	E_h= 8 E6 psi Ev= 6 E6 psi	ν_h= 0.16 ν_v= 0.13	ISO S_h= 0.53 psi/ft ANI S_h= 0.57 psi/ft

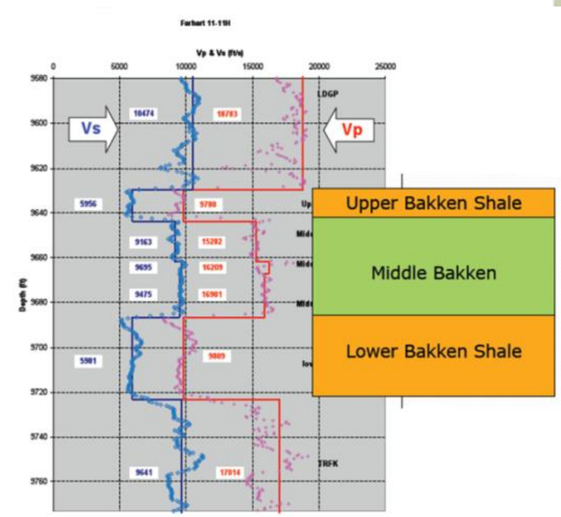
Adapted from: Lewis

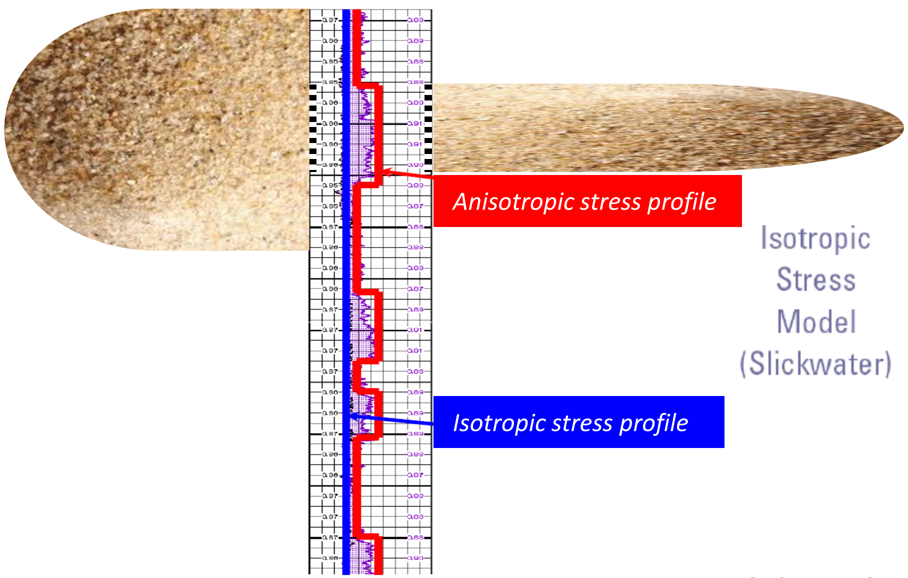
Large stress contrast = barrier



ANISOTROPY IMPACT ON FRAC STRESS MODELING

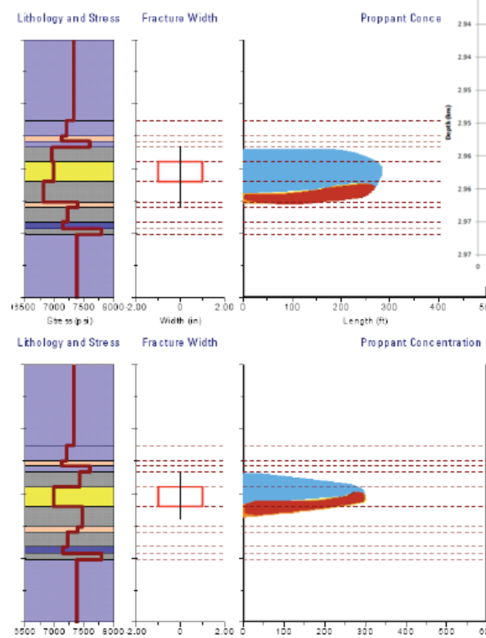
- If conventional modeling for estimating stress profile is used, fracture height calculation might be wrong
  - Important for shales unless they show isotropic behavior
  - In general HF's are more confined than model predictions. Longer Xf's
- Cross- dipolar sonic logs or quadri-polar sonic logs in HZ wells
  - Compliance tensor. Calibrate against core and actual frac data



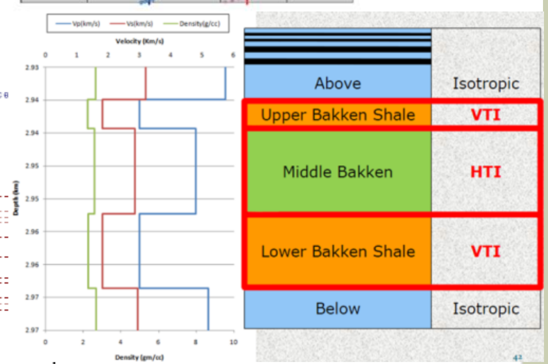


Adapted from: Geomechanics for Hydraulic Fracturing.SLB´s presentation

Isotropic Stress Model (Slickwater)



Anisotropic Stress Model (Slickwater)



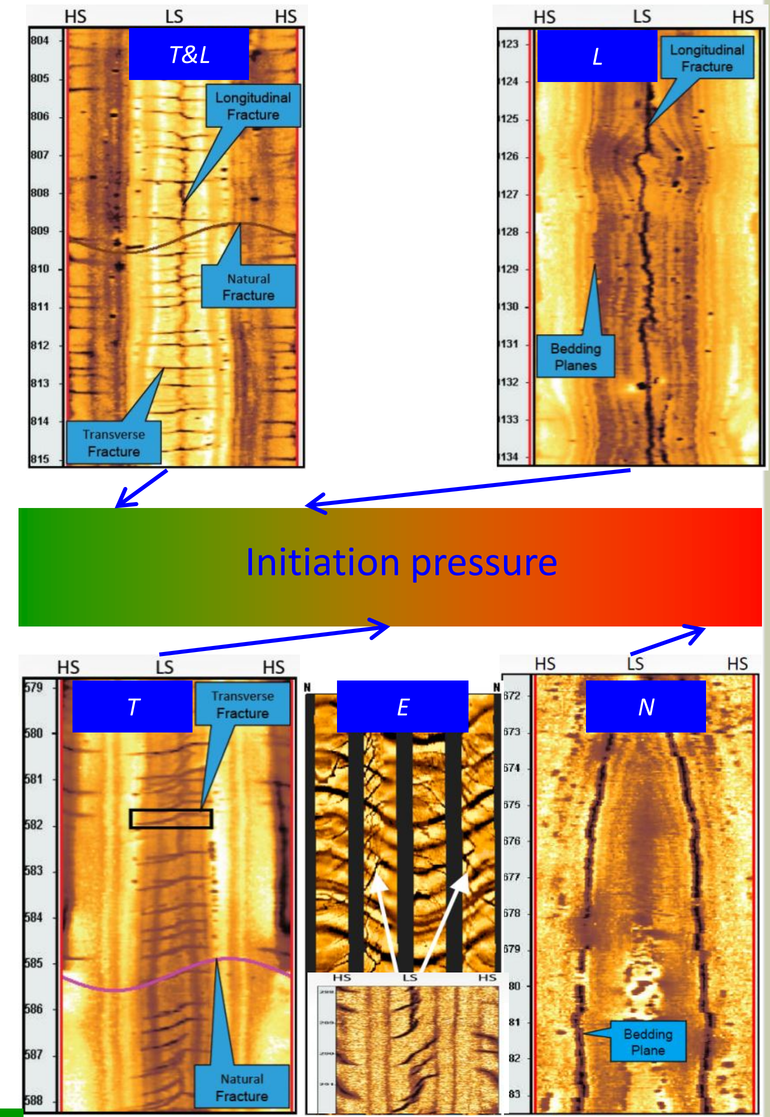
Source: Ye, 2010

$$C_{orthor} = \begin{pmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & 0 \\ c_{12} & c_{22} & c_{23} & 0 & 0 & 0 \\ c_{13} & c_{23} & c_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{66} \end{pmatrix}$$

$$C\ ij = V^2 \rho_{bulk}$$

NATURAL AND INDUCED FRACTURES IN HZ WELLS

- Stress field behavior along the horizontal wellbore thru image logs analysis. Worth having it?
  - Transverse and longitudinal (T&L)
    - Low stress anisotropy
    - Low initiation pressure
  - Longitudinal (L)
    - Higher stress anisotropy
    - Low maximum stress
    - High minimum stress
    - Intermediate initiation pressure
  - Transverse (T)
    - Highly stress anisotropy
    - Low minimum stress
    - Maximum stress much higher than minimum stress
    - Intermediate initiation pressure
  - No fractures (N)
    - High stress anisotropy
    - High initiation pressure
  - Echelon fractures (E)
    - Well is deviated from principal stress direction
    - Existence of stress anisotropy

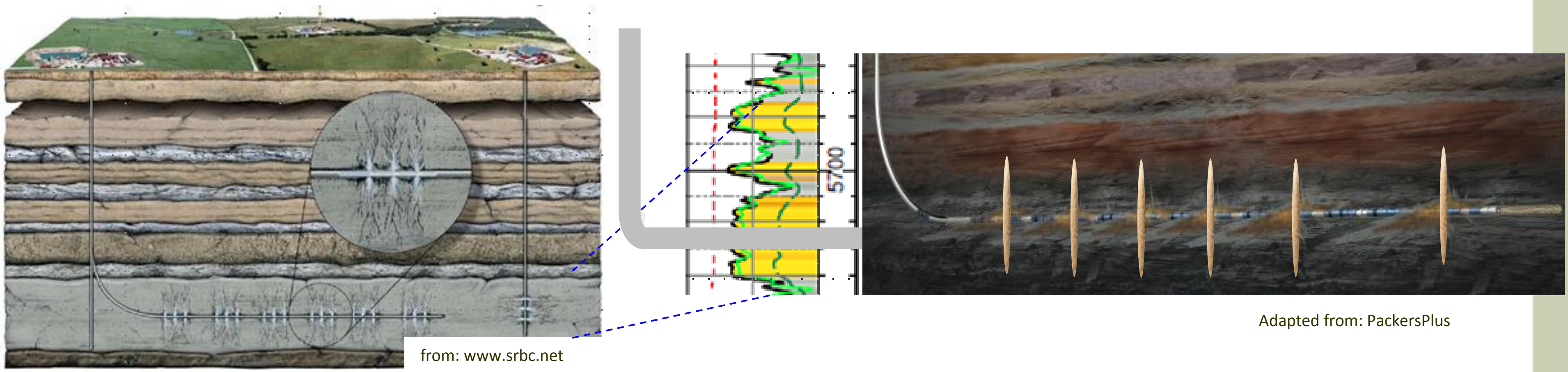


Source: Baker, 2011

- *Select perfs in intervals with low initiation pressure*
- *Perforation spacing can be increased as natural fracture spacing decreases*
- *Isolate intervals with significant differences in natural fracture spacing*

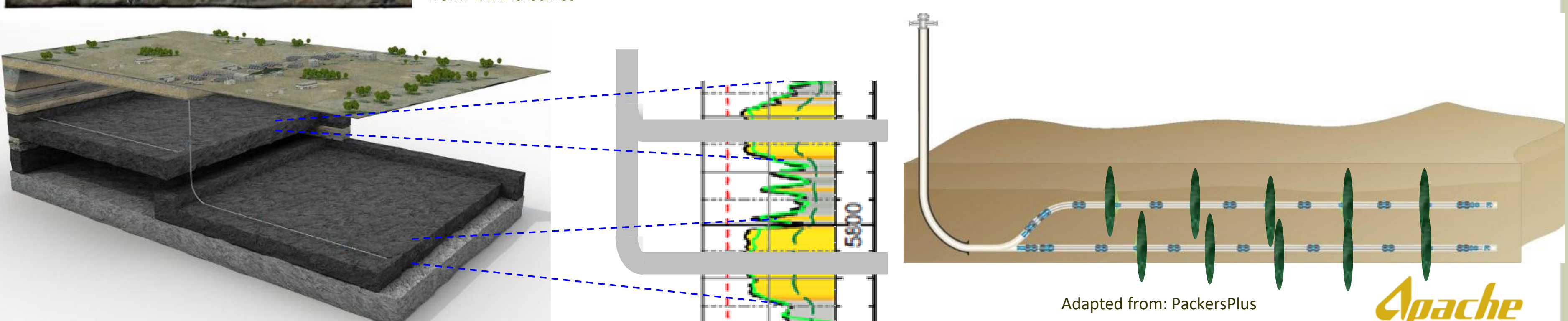
SHALE COMPLETIONS IN HZ WELLS

- Based on number of vertical individual reservoirs
  - Single reservoir: multi hydraulically fractured horizontal wells
  - Multiple individual reservoirs: dual horizontal wells with multiple hydraulic fractures
- Based on completion type designed for multiple frac stages
  - Cased and un-cemented completions. Packerless or with them for zonal or compartment isolation
  - Cased and cemented



from: www.srbc.net

Adapted from: PackersPlus



Adapted from: PackersPlus

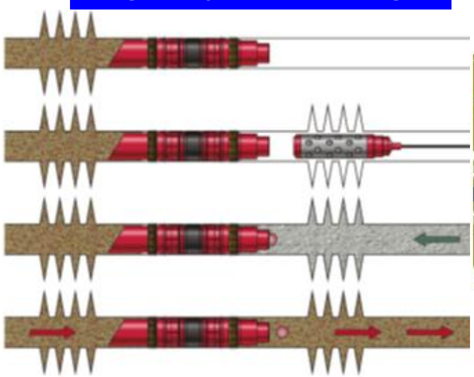
Source: PackersPlus

Adapted from: Martinez, 2011

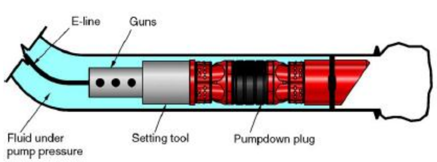
MULTI STAGE COMPLETIONS IN SHALE HZ WELLS

- Multiple technologies available but industry basically dominated by three methods:
  - Plug and perf. 70 – 75 % of the wells currently utilize this technology
  - Ball activated frac ports. 20 – 25 % of the wells use this method. Sometimes combined with P&P
  - CT based. Less than 5 % of total wells are fractured using these techniques
    - Abrasive jetting for cutting holes. Sand or composite plugs for isolation purposes
    - Pumping fracture thru annulus
    - Anchor and packer
    - CT activated frac sleeves (thru shifting tool)

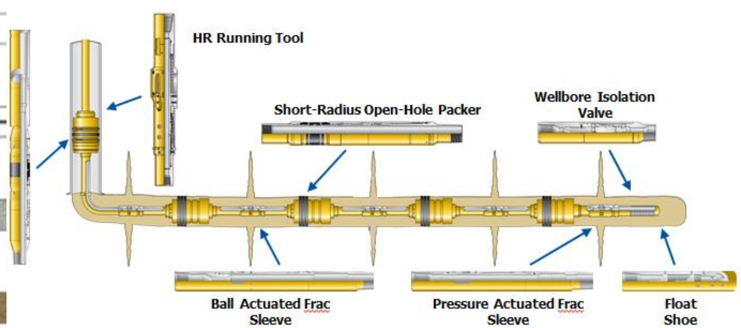
Plug & Perf – Unlimited stages

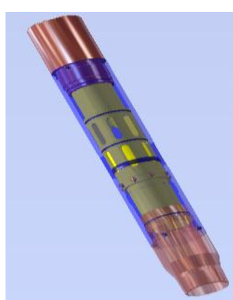


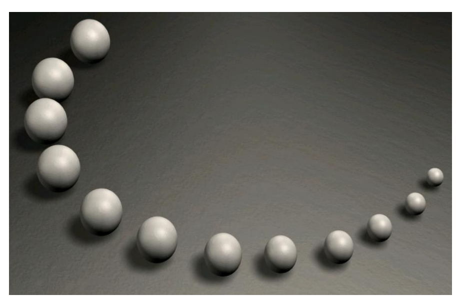
Source: Halliburton



Frac sleeves – 40 stages max

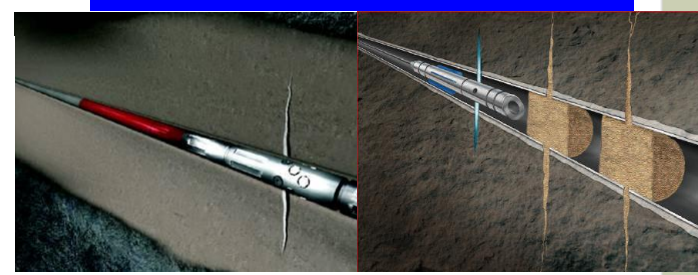




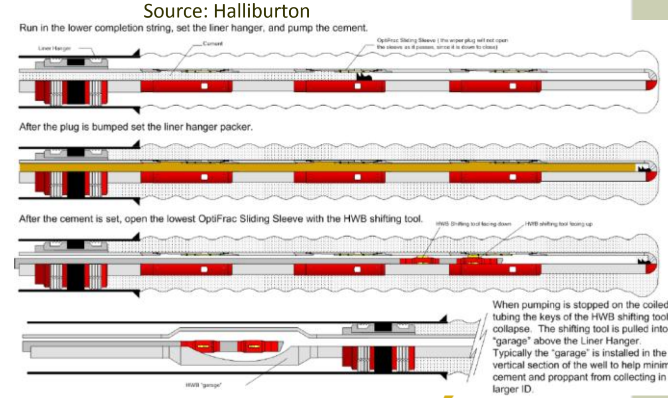


Source: Baker Oil Tools

CT based tech´s – Unlimited stages



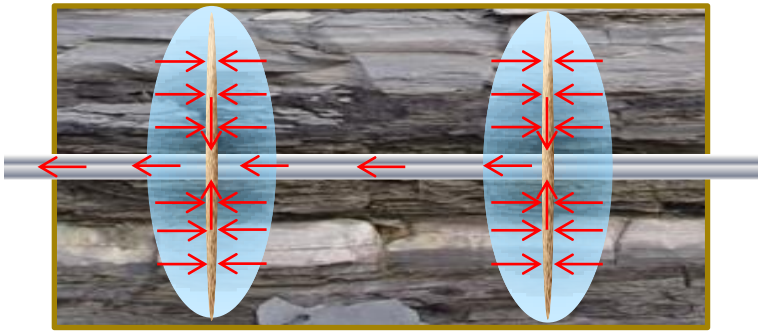
Source: Halliburton



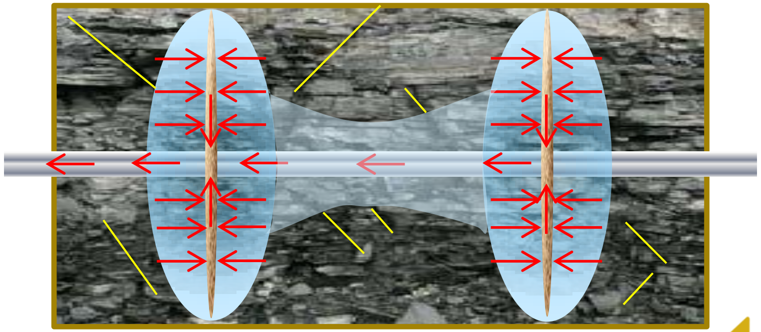
Source: Weatherford

OPEN HOLE vs CASED AND CEMENTED COMPLETIONS

- Big debate around this issue. Let´s separate commercialization from engineering !
- Open hole: cased without mechanical diversion or cased and isolated
  - Pre-perforated or slotted liners (some use in Bakken shale) and frac ports + isolation packers
  - If natural fissures per se produces to wellbore it is good idea to leave the well un-cemented
  - If cement damages natural fractures inhibiting fissures reactivation or production, it is recommended as well
  - Indications of higher impact in shale oil
  - No good idea if wellbore stability is an issue or precise pin-point stimulation is required
- Cased and cemented hole: always there is a pipe surrounded by cement that acts as isolation barrier.
  - Best option for unstable formations. Should not be a problem in high strength shales.
  - Preferred option if faults from deeper zones that produce water are reactivated with HF
  - Generally, it takes longer completion time but provides more options in case of problems



Minimum inflow from natural fractures



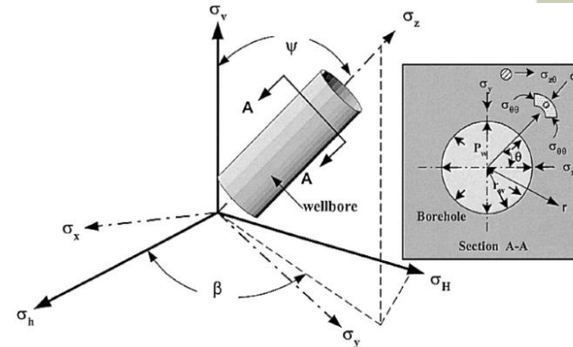
Fair to good inflow from natural fractures

MULTI STAGE COMPLETIONS – BEST PRACTICES

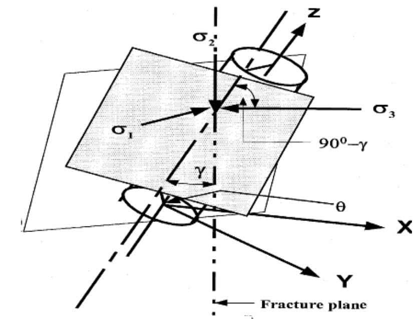
- Some recommendations and/or best practices:
  - Based on learning and experience. Own and thirty parties. Some of them learned the hard way!
  - Plug & Perf:
    - Best option to start with in new areas. Allows flexibility in selecting intervals to stimulate
    - Relatively easy to work with and in generally individual components well known by well personnel
    - Use tool that allow setting plug and perforating in a single run. Pump down plugs
    - At the beginning of flush pump a small pill of x-linked fluid to sweep proppant that remains in the hole. Avoid getting stuck and setting the plug at wrong depth
  - Ball activated frac sleeves
    - When you are confident you know your reservoir and how HF´s behave, it is an excellent technology
    - Evidence fractures grow by mechanical packers (higher stress imposed on rock-PKR's contact area)
    - Ball diameter in increasing steps limits the number of stages. High number of stages is possible (how many)
    - It requires some training from field staff to get efficient results. Coordination between parties
    - Swelling time for swellable packer to work properly is really long!
    - Mechanical packers are easy to set but well caliper must be in good condition otherwise switch to swellable option
  - CT based
    - Basically intended for pin-point frac jobs
    - Rate might be an issue in high rate treatments. Erosion of CT and potential fishing jobs
    - Need of CT for the entire operation. Availability and cost impact
    - Abrasive jetting works fine to cut holes and reduce breakdown pressure. Quick and efficient. Run plug and jetting tool in a single run. Reduce CT fatigue life and completion time

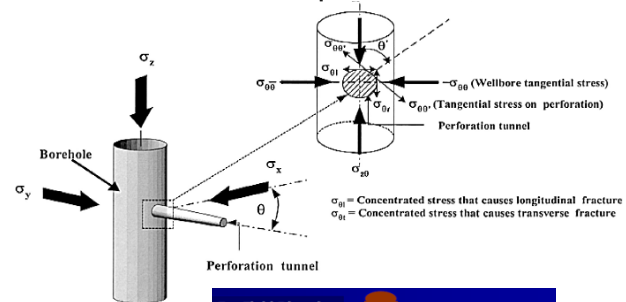
HYD FRACS INITIATION AND PROPAGATION

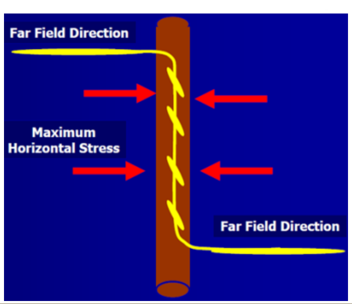
- Initiation
  - Rock fails when a principal tensile stress exceeds rock tensile strength
  - Stresses are a function of regional fault regimes and local stresses
  - In rocks with natural fissures, tensile strength is very low
  - HF will start at certain angle that satisfies first statement
  - At wellbore level, firstly fracture grows along the wellbore, then turns into the local stress orientation and possible to the regional stress direction if different from local stress
- Open hole
  - Horizontal well (ψ=90º). Wellbore axis deviation ranges from (β=0º - axis along σ_h) to (β=90º - axis along σ_H)
    - For normal and strike slip faulting regimes, fracture initiates at top and bottom of the horizontal well axis
- Cased hole
  - Orthogonal intersection of two holes. Superimposition of stress concentration
  - If perforations are aligned to the same direction of the fracture plane reservoir to wellbore connectivity is enhanced
    - For normal and strike slip faulting regime, fracture initiates at top and bottom of the horizontal well axis



Source: Hossain, 2000

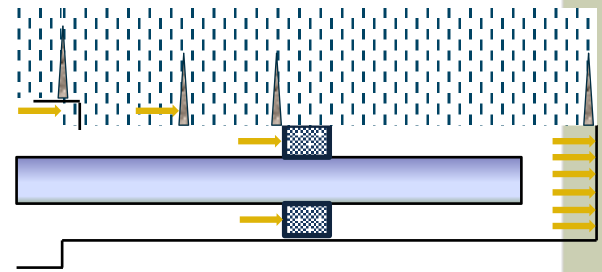


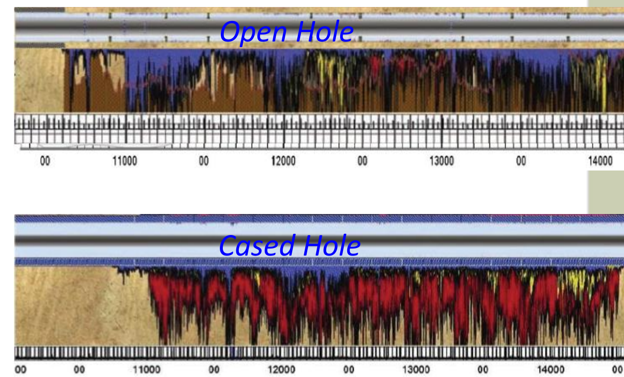


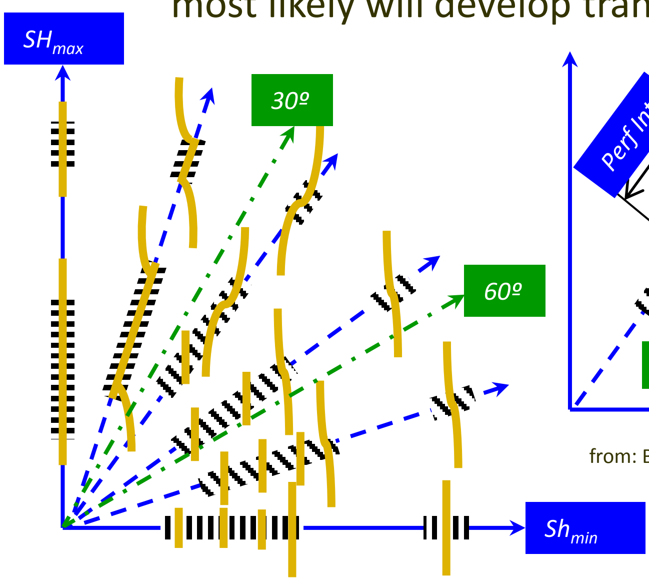


TRANSVERSE HYD FRACS INITIATION

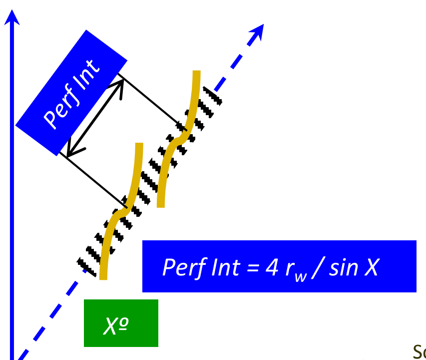
- Transverse fractures
  - Initiation requires axial forces and parallel stresses along the wellbore axis. These conditions exist at natural fractures, packers, bottom hole and rat hole.
  - Narrower fracture width, even smaller at fracture twists
  - To avoid multiple fractures a short perforated length is recommended (<= 4 * Wellbore diameter) in transverse HF's. Limited number of holes. Choked flow
  - Higher breakdown and extension pressures
  - Wellbore axis at angle (> 15°) to minimum horizontal stress most likely will develop transverse fractures





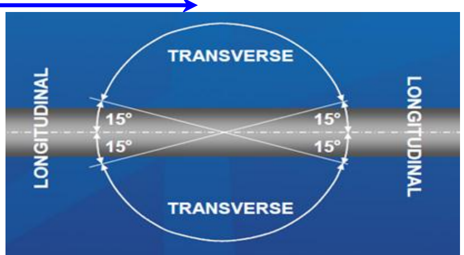


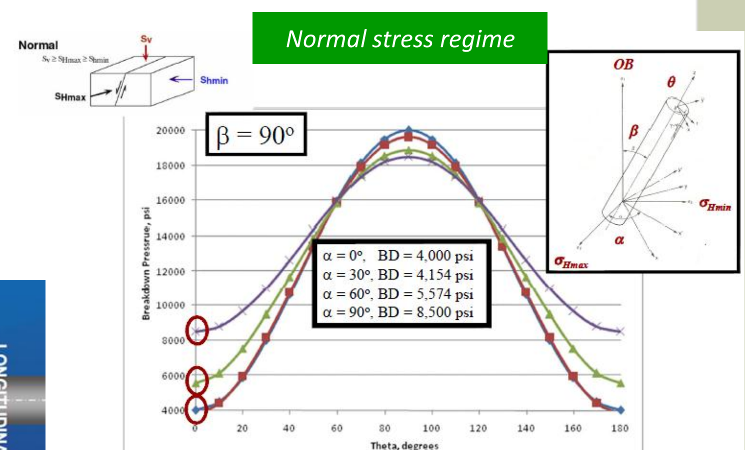
Interval perforated < 4 Wellbore Diameter



Source: Martin, 2011

from: Britt, 2007

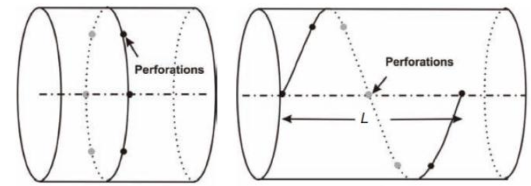




from: Britt, 2012

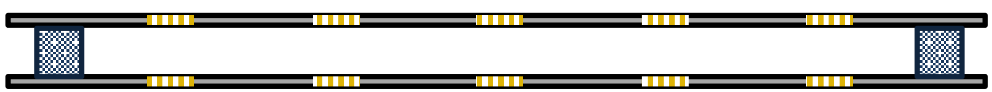
CONNECTING WELLBORE TO RESERVOIR

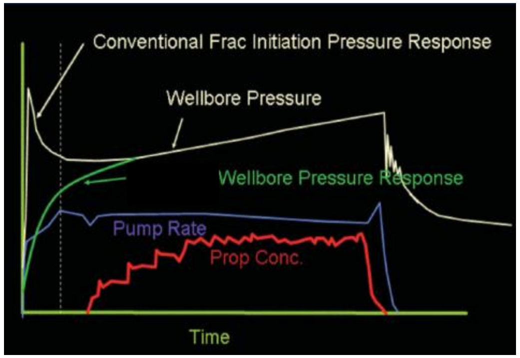
- Perforating: cased applications
  - Short intervals (cluster) to avoid multiple parallel fractures and high initiation pressures. 1 – 2 ft. 4 – 6 SPF. 60º and 90º
  - Phasing: perforations located in one plane or top and down
  - Perforation size more important than penetration
    - Perforation hole size between 0.35 and 0.5 in (most used about 0.45 in)
  - Number of perforations: dictated by friction pressure and diversion effectiveness. Later requires high rates (>50 bpm)
    - At least 1 bpm / perf. > 2 bpm/perf to ensure decent diversion
  - Clusters: set of perforations located at certain points along the well that are stimulated at the same time. Savings?
    - Good knowledge of fracture development, otherwise try pin-point stimulation
    - Cluster length: 1 – 4 ft/cluster
    - Quantity: up to eight. Average: no more that five
    - Spacing between offset clusters: 30 – 150 ft
    - Spacing between outermost clusters: 100 – 400 ft
- Jetting: open hole and cased hole applications
  - Holes are cut with abrasive jetting technology
    - Clean holes. Rocks fails in tension. Lower breakdown pressure
  - Technology has been optimized conveyed on CT
    - Possible to set plugs and cut holes in the same run



Source: Daneshy, 2009

Source: Halliburton, 2011

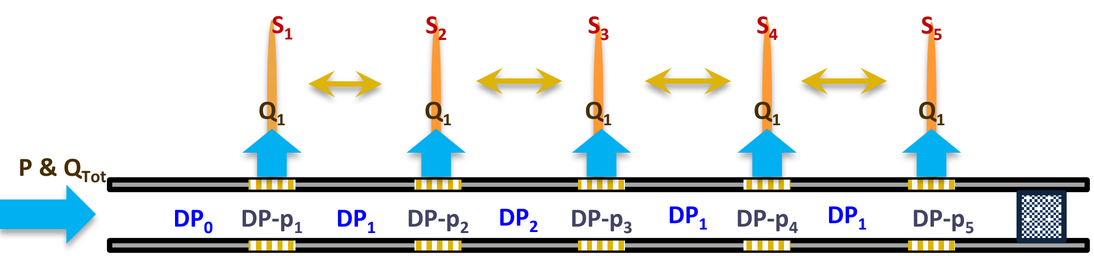




Source: Halliburton

CLUSTER PERFORATING

- Just a fancy name for limited entry perforating. Limited = inefficient
- An existing technology showed with lot of advantages but behind the scenes intended to reduce pumping costs
  - Based on choked flow. High pressure drop at perf > 400 – 500 psi. No more than 1500 psi
    - Once 100 mesh sand enters perfs at high rate, erosion destroys this condition
  - Not all clusters take fluid along the stage
    - Confirmed with PLT. In general 1 out of 3 produces back. Why do we continue doing this?
- Reduced number of holes
  - Not all holes are open.
    - Industry claims just ¾ to 2/3 of the holes are open and ready to accept fluid. New specifically designed charges might mitigate this issue
    - In theory attempt to balance injection rate in every cluster, dynamic problem, not all parameters are fixed while pumping. We can only govern few of them. Potential interaction between fractures

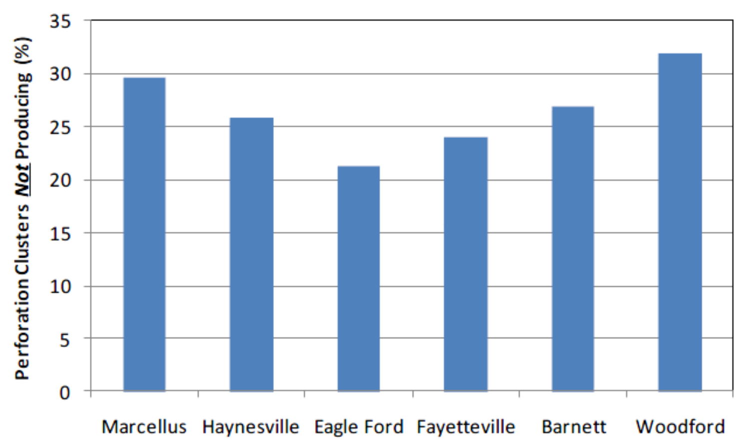


$Q_{tot} = Q_1 + Q_2 + Q_3 + Q_4 + Q_5$

$P = S_1 - \text{DP-p}_1 - \mathbf{DP_0}$

$\mathbf{DP_0 = f(Q_{Tot}, ID, L)}$

$\text{DP-p}_1 = f(N^o, Q_1, Cd)$

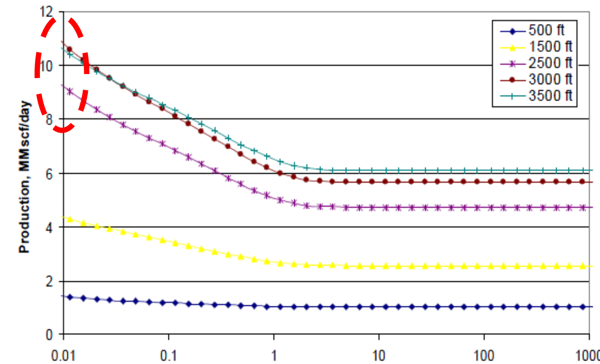


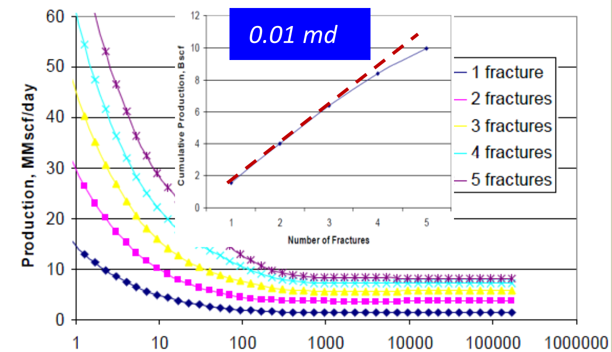
source: SPE 144326

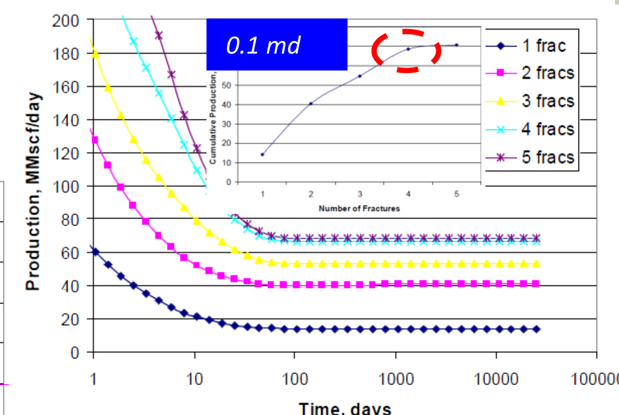
Apache

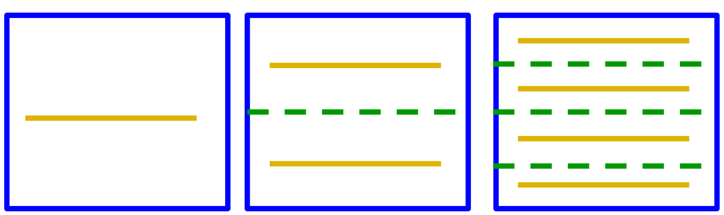
HORIZONTAL WELL LENGTH OPTIMIZATION

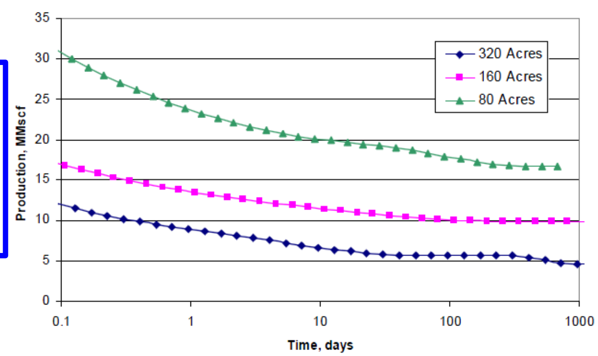
- First approach is directly related to reservoir engineering
  - Limited reservoir dimension. After certain well length there is no production increase
  - Pressure losses inside the well (not considered in several simulators), can have impact. Internal backpressure
- Number of fractures in the well
  - Each fracture drains an increasing volume until it reaches the drainage volume of its neighbor fractures, after that, it will drain a constant volume. Closer spacing just give higher IP's
- Well spacing
  - Similar approach as in the number of fractures
  - Ultimately it will depend on production gain vs the cost of placing the wells
- Operational issues, actually maybe the most important!
  - CT capacity to reach TD is major variable to define well length









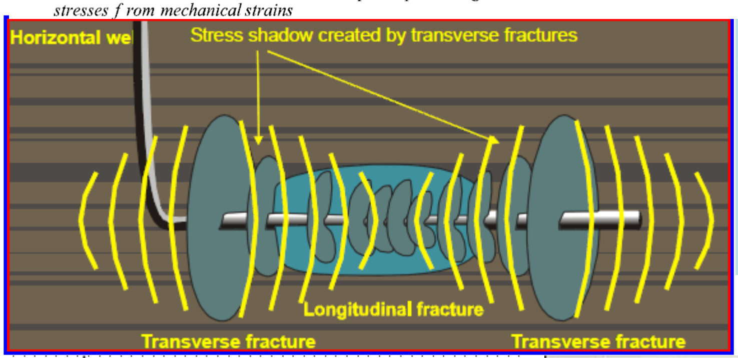


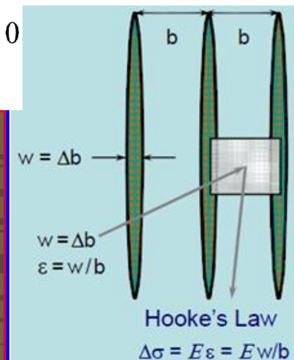
source: Magalhaes, 2007

FRACTURES NUMBER AND SPACING

- Basically governed by three factors:
  - Stress interference or shadowing: due to very low permeability, once the first HF is created, pressure within the fracture does not dissipate fast enough, causing an excess of stress. Next fracture will "suffer" it. If both horizontal principal stresses are close, most likely there will be changes of orientation, denoted by higher pressures and tortuosity. Additive effects
  - Consequence of mechanical strains, pore pressure gradients and volumetric stresses

$$\underbrace{2G\varepsilon_{ij,j} + \left(K - \frac{2}{3}G\right)\varepsilon_{kk,j}\delta_{ij}}_{stresses\ from\ mechanical\ strains} - \underbrace{\alpha\delta_{ij}p_{,j}}_{pore-\ pressure\ gradients} + \underbrace{\rho g_i}_{volumetric\ stresses} = 0$$

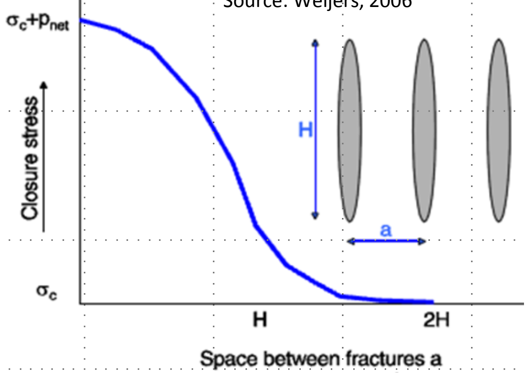




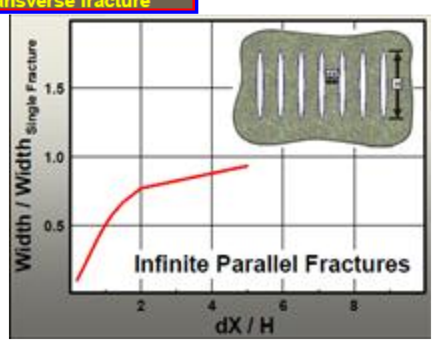
Modified from: Waters, 2009

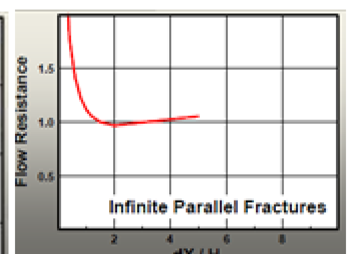
Frac Spac	YM	Wf_1	Wf_2	Wf_3	Ind Stress_1	Ind Stress_2	Ind Stress_3
ft	psi	in	in	in	psi	psi	psi
1	3E+06	0.1	0.05	0.025	25000	12500	6250
10	3E+06	0.1	0.05	0.025	2500	1250	625
30	3E+06	0.1	0.05	0.025	833	417	208
50	3E+06	0.1	0.05	0.025	500	250	125
100	3E+06	0.1	0.05	0.025	250	125	63
150	3E+06	0.1	0.05	0.025	167	83	42
200	3E+06	0.1	0.05	0.025	125	63	31
250	3E+06	0.1	0.05	0.025	100	50	25
300	3E+06	0.1	0.05	0.025	83	42	21

Source: Weijers, 2006

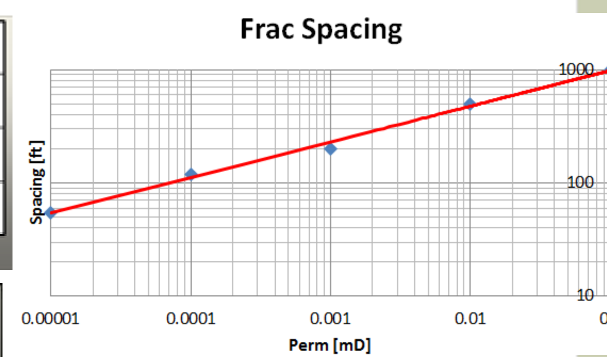


Min spacing between HF > 2 * Frac height





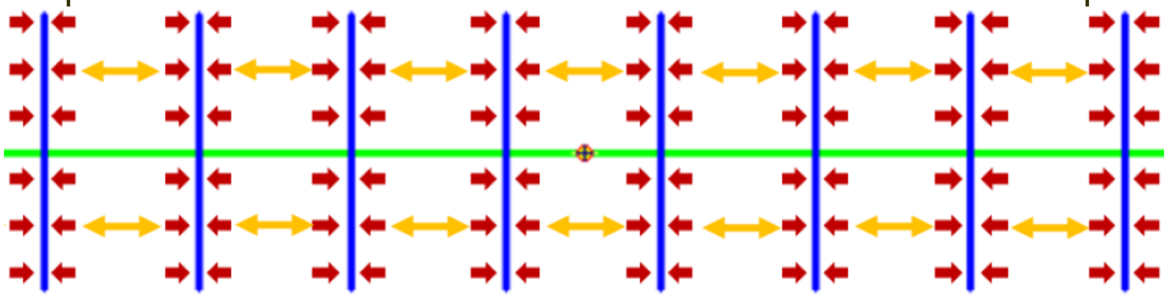
Slide Keys:
When dx Is > 2 * Hfrac
There Is Marginal Effect
On Frac Pressure &
Width!

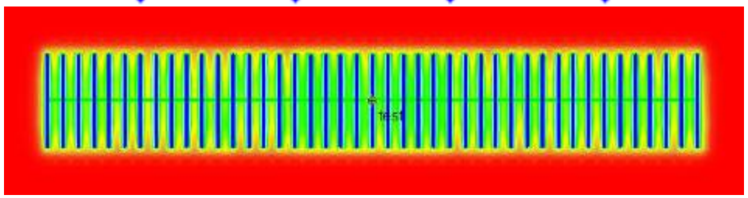


Source: Britt, 2011

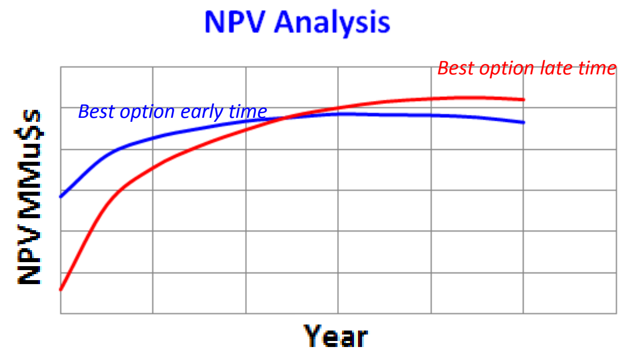
FRACTURES NUMBER AND SPACING

- Production interference: as soon as individual HF's start producing, pressure wave travels until it reaches the one from the nearest HFs, at this point it can be considered HF reached a virtual boundary. Drainage volume increases until it reaches a limit, thereafter drains at constant volume
- Economics: high number of fractures along the wellbore will give higher IPs but soon enough production interference will be observed. Need to balance production profile with total well cost



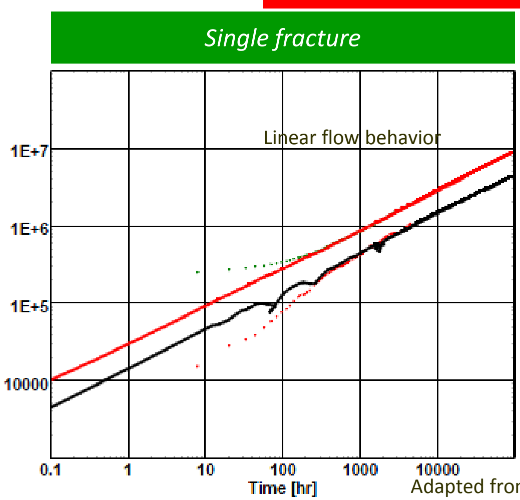


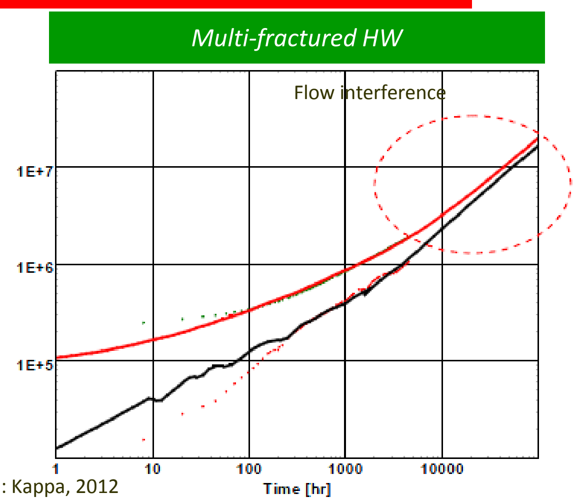
Source: Kappa, 2011



Interference between fractures Hz wells

k mD	Xf ft	t_interf hrs	t_interf days	t_interf years
0.1	100	2.28	0.095	0.0
0.1	300	20.52	0.855	0.0
0.01	100	22.8	0.95	0.0
0.01	300	205.2	8.55	0.0
0.001	100	228	9.5	0.0
0.001	300	2052	85.5	0.2
0.0001	100	2280	95	0.3
0.0001	300	20520	855	2.3
0.00001	100	22800	950	2.6
0.00001	300	205200	8550	23.4
1E-06	100	228000	9500	26.0
1E-06	300	2052000	85500	234.2

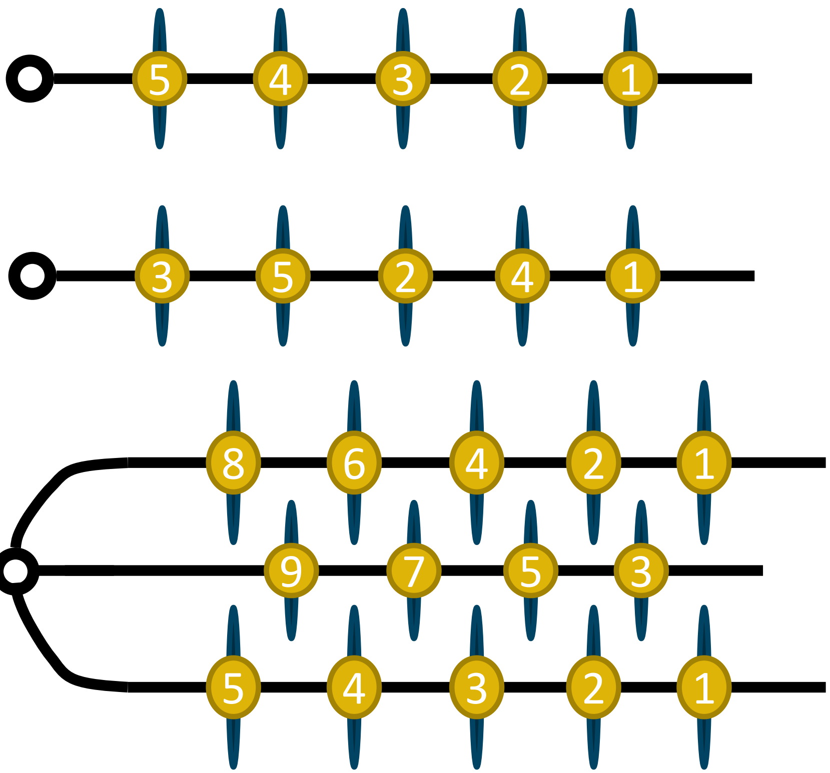




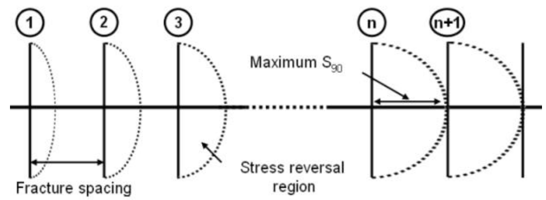
Adapted from: Kappa, 2012

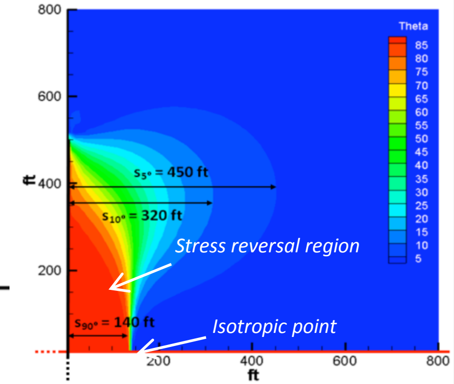
STRESS SHADOWING WORKING FOR US

- Consecutive and alternating fracs: more than two fracs in the same well. Lower stress shadowing in practice. Hard to apply in practice
- Zipper fracs: two or more parallel wells at the same time. Alternating positions. Higher production. Larger SRV
- Simo fracs: two or more parallel wells at the same time. Same positions. Higher production. Greater SRV

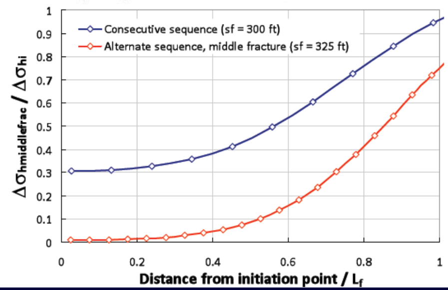


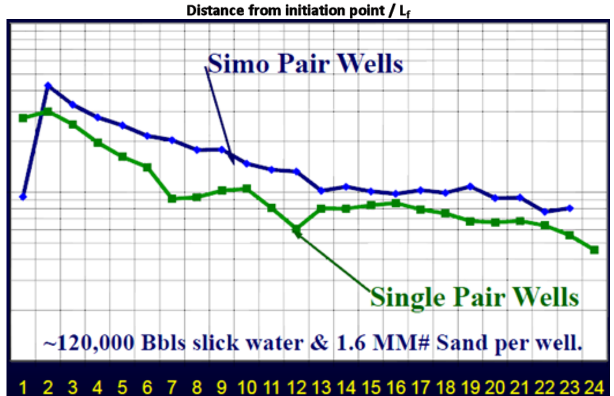
Source: Schein, 2008

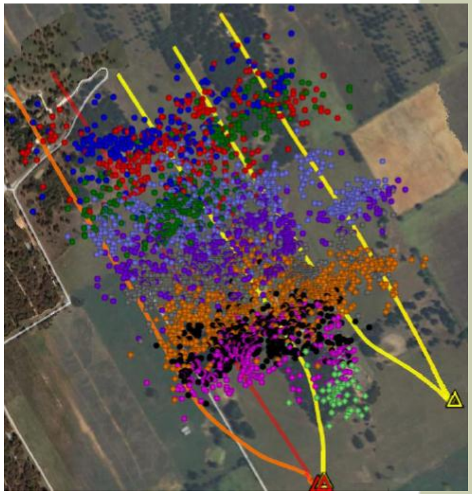




Source: Roussel, 2011







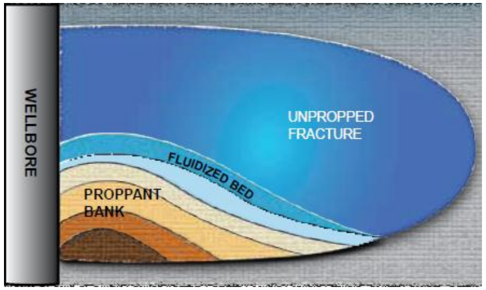
Source: Zoback, 2011

PROPPANT TRANSPORT IN THE FRACTURES

- Linear and X-linked fluids: viscosity is the driver. Excellent carrier fluids
  - Long and narrow tortuous fractures: high internal friction. Interaction of proppant grains among them and against fracture walls at high rate
  - Reduced fracture width limits the proppant mesh size. Reason to use smaller diameters
  - Dilation of natural fissures is not big enough to accept proppant. Maybe only 100 mesh and 40/70 are able to go thru in those fissures close to the main HF
- Slick water transport mechanism is based on rate (actually velocity). Dune behavior
  - Settling is a major issue, low weight proppants and small sieve sizes help mitigating this issue, most used proppant sizes are 100 mesh, 50/80, 40/70, 30/50 and 20/40
  - Rate is high at wellbore, but as soon as multiple fractures are created, velocity is strongly impacted, thus reducing the ability to transport proppant
  - Very common to pump slugs of proppant followed by sweeps. Used to enhance transportation process. Concentration of every slug is increased slightly and also mesh size is incremented too
  - As HF connection with wellbore is limited, generally the last part of the proppant schedule is tailed in with bigger size and/or higher strength proppant

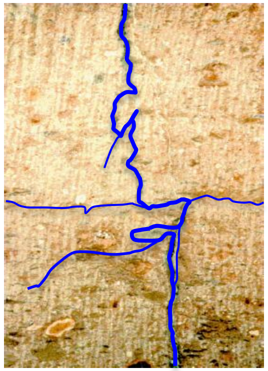
Soft rock

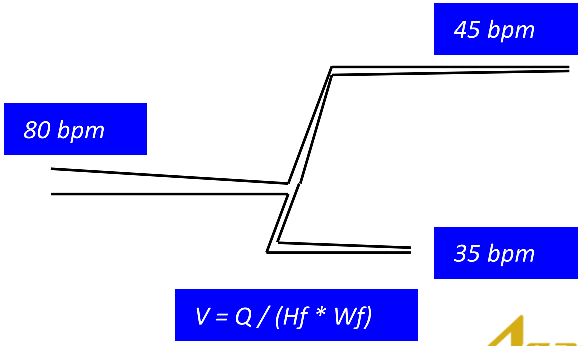
Hard rock



Slick water

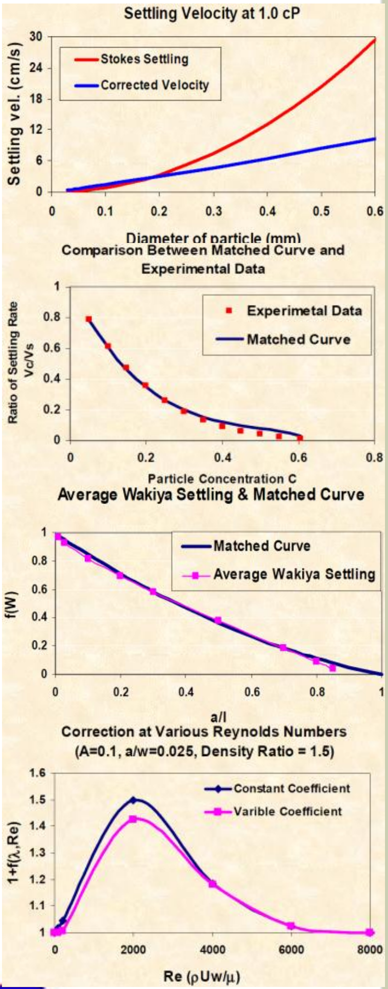
Source: Trican, 2012

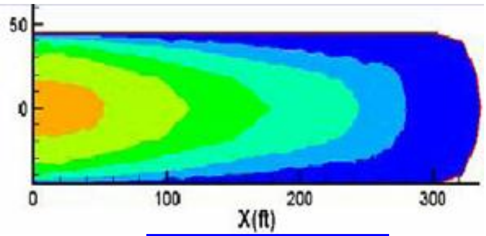




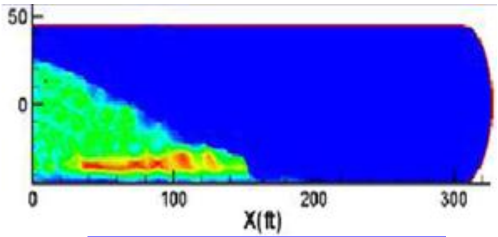
PROPPANT TRANSPORT IN SLICK WATER FRACS (SWF)

- Gravitational force dominates over viscous one. Proppant settling
  - Rate governs proppant transport in SWF
  - Other tools at hand to help proppant transport
    - Small proppant mesh size. e.g. 100 mesh sand, 50/70 mesh proppant
    - Low proppant density. e.g. natural frac sand, ultra light weight proppants
    - Fluid viscosity. e.g. sweeps, hybrid fracs
- Mechanisms
  - Fluid creates turbulent eddies near the entry points (e.g. perfs) Distance between entrance and stagnation point could be large depending on frac rate
  - Early proppant stages form a dune after the stagnation point
  - Remaining proppant flow and slide over the dune to make it larger
- Stokes´s eq can not be used. Wrong results = poor frac designs
  - Proppant drag and settling depends on inertial, concentration, wall and turbulence effects that are function of rate, proppant diameter, concentration, density and frac width

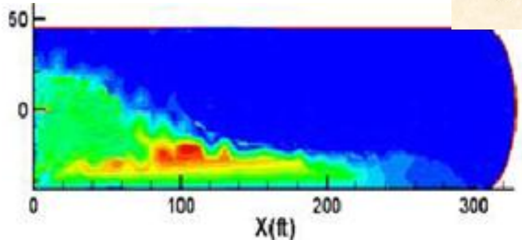




Without settling



With Stokes´s Eq settling



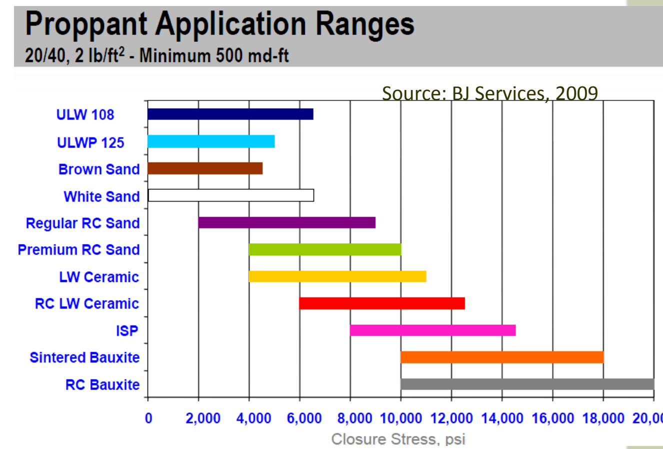
With corrected settling

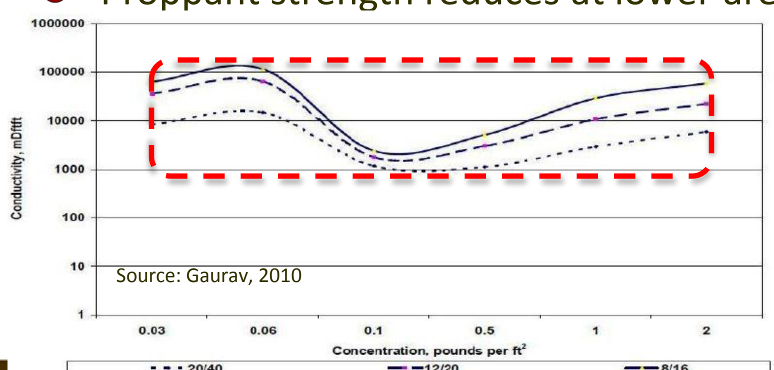
Source: Sharma, 2003

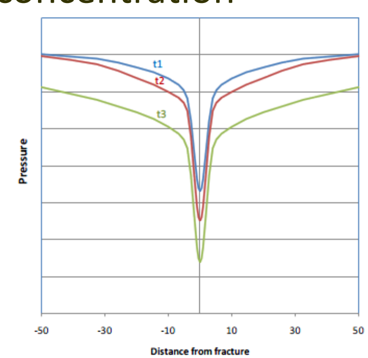
Apache

PROPPANT SELECTION & CONDUCTIVITY

- Is conductivity important or not?
  - As reservoir permeability decreases so does conductivity importance
  - Flow dominated by matrix flow to fissures and from there to main HF
- Proppant size (range: from 100 mesh to 20/40)
  - Smaller and lighter proppants travel further inside the HF
- Proppant strength:
  - Smaller grains withstand larger stresses. As strength and conductivity are directly related same considerations apply
    - Widespread use of natural frac sand. Cost related in many cases
    - Ceramics for high confinement pressures
    - Proppant close to the wellbore withstands highest stress
- Areal concentration:
  - Difficult to place high proppant concentration per unit of area. Conductivity charts are built at 2 lbm/ft². If we are lucky we will get something between 0 to 1 lbm/ft². Most likely < 0.5 lbm/ft²
  - Proppant strength reduces at lower areal concentration







Source: He, 2011

FRAC DESIGN GUIDELINES

- Frac fluid system depends mainly on rock properties (brittleness) and density of fissures
  - Slick water
  - Linear gel
  - X-linked gel
  - Hybrids (combinations of previous systems at different stages)
- Fracturing rate dictated by transport issues (rate & fracture width related) and brittleness
  - In general no less than 30 bpm and up to 200 bpm. Blender capacity to feed HP pumps is critical!
- Frac volume. As success is dictated by SRV in general large volumes are better
  - Acid spearhead, pad less than 25 %, 2000/3000 gal/ft of formation height (try your formula!)
- Proppant concentration
  - For gas is not a big issue, 2 – 3ppg is enough, for tight oil up to 6 ppg. Tail in with bigger mesh size
- Proppant mesh size is not constant along the treatment. Bigger size for tight oil
  - Common sequence for gas is 100 mesh – 40/70 – 30/60 – 20/40
  - For tight oil most common sequence is: 100 mesh – 30/60 – 20/40

Brittleness	YM	Fluid system	Fluid viscosity	Natural fractures	Frac rate	Proppant conc	Frac fluid volume	Proppant volume	Fracture geometry	Frac width
Brittle	7 E6	SWF	Low	Severe	High	Low	High	Low	Network	Very narrow
	6 E6	SWF	Low							
	5 E6	Hybrid	Low/medium							
	4 E6	Linear	Medium							
	3 E6	Foam	Medium							
	2 E6	X-Linked	High							
Ductile	1 E6	X-Linked	High	No fracs	Low	High	Low	High	Two-wing	Narrow

Barnett shale

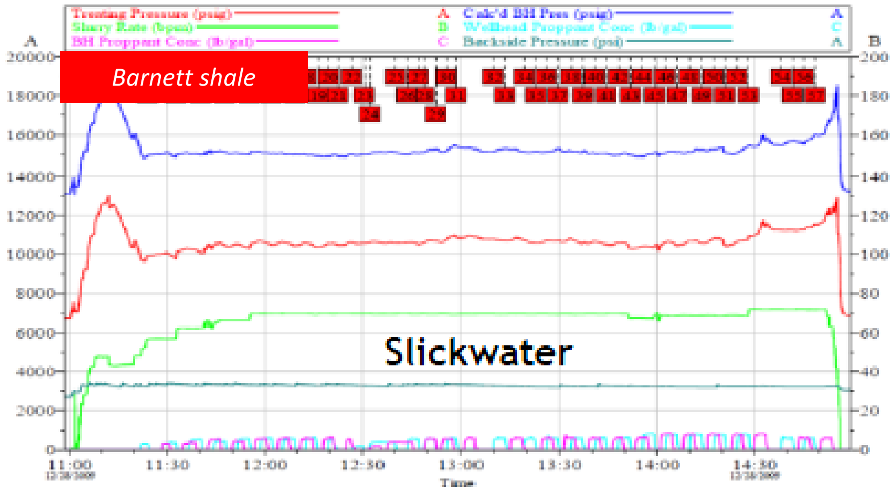
Marcellus shale

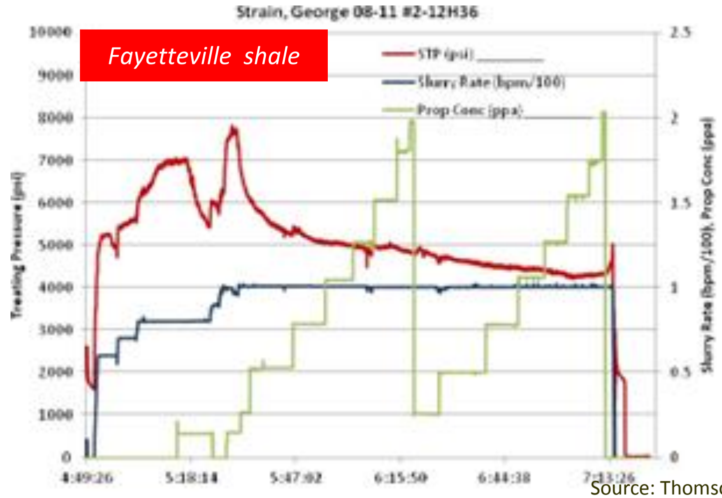
Eagleford shale

Haynesville shale

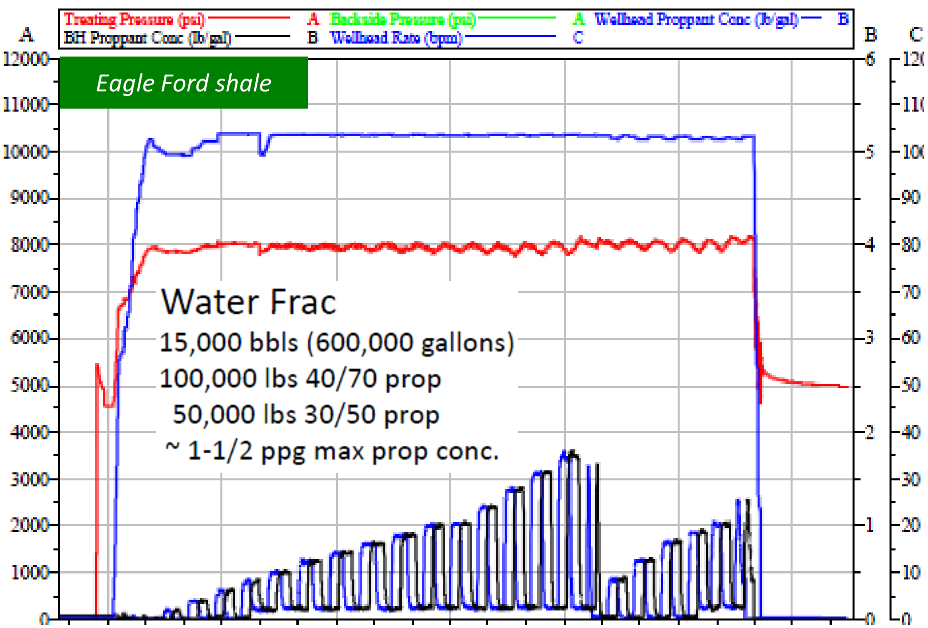
Apache

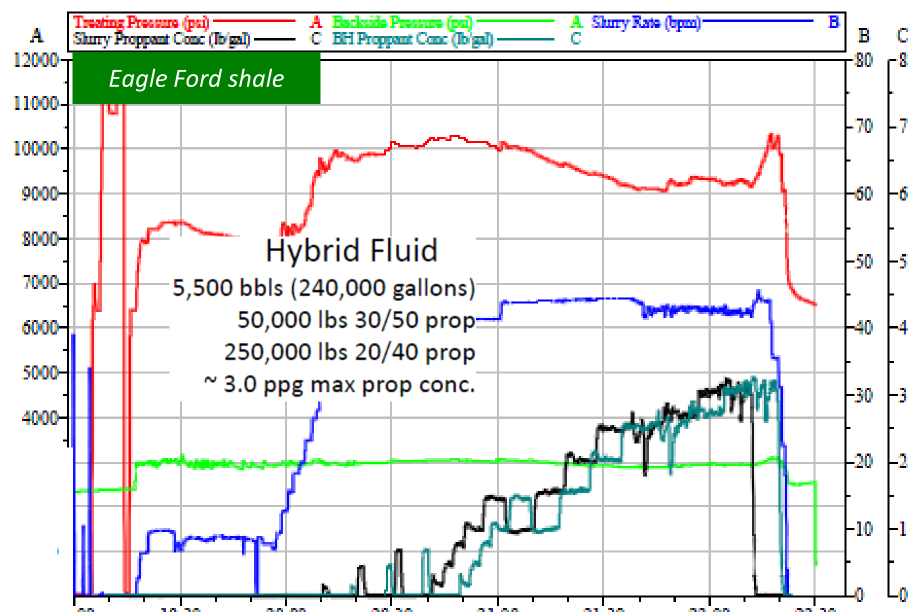
FRAC DESIGNS EXAMPLES





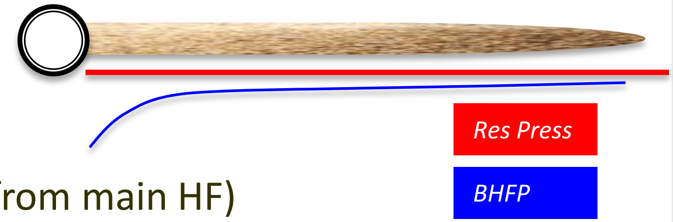
Source: Thomson, 2011



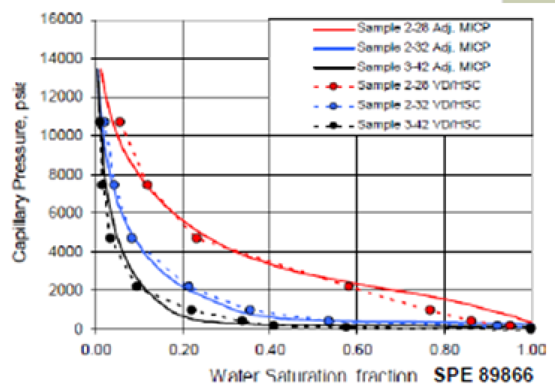


Source: Stegent, 2011

WHERE DOES FRAC WATER GO AND STAY?



- Flowback accounts for 20 to 40 % of the injected fluid
  - Mainly comes from main HF and adjacent closest area
  - Multi-phase flow
  - Water rate decreases steeply and then stabilizes (volume from main HF)
  - Drivers: rock compressibility, stress created (extremely low pressure dissipation), difference between reservoir and flowing pressure
  - Leak-off is the responsible for natural frac dilation and frac network creation
  - In Barnett shale if load recovery is higher than 55 %, well is a poor or bad producer. SRV is small or not created



- Imbibition into the matrix pore space
  - S_w increases to 10 – 50 % at least
  - Minimal K_{rw}. High capillary pressure. Has capillary pressure reached conditions of equilibrium? Need to consider other internal forces (related to pore and molecule size)?
  - Water more viscous than gas. Several orders of magnitude
  - Practically immobile (remains in the reservoir for ever)
  - Sub-saturated shale takes water until it get saturated. Never produced
- Trapped in fissures and secondary fractures
  - Disconnected fissures and fractures at fracture closing

$$p_c = p_g(S_w) - p_w(S_w)$$

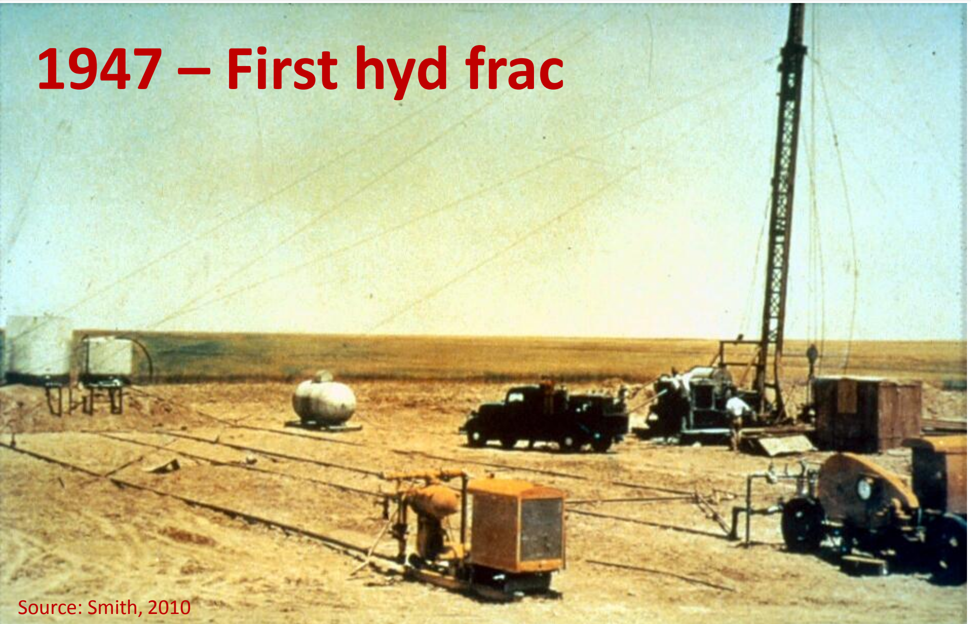
$$q_g = \frac{kk_{rg}}{\mu_g} A \nabla p_g$$

$$q_w = \frac{kk_{rw}}{\mu_w} A \nabla p_w$$

Apache

WANT TO GAIN EXPERIENCE IN SHALE?

Execute, execute, execute…



Thanks for your attention!