An Engineered Approach to Optimize Completion & Stimulations in Unconventional Reservoirs

Jornadas «El Desafío del Gas No Convencional»
SPE / IAPG - Neuquén

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  - Reservoir rock permeability
Roadmap
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  - Organic rich shale reservoirs
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  - Flow in shales
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**Reservoir Rock Permeability**

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

- **Qg \ K_gas**
  - **10 mD**: 924,000 m³gpd
  - **1 mD**: 92,400 m³gpd
  - **0.1 mD**: 9,240 m³gpd
  - **0.01 mD**: 924 m³gpd

- For dry gas, no commercial rates below 0.1 mD unless well is hydraulically fractured.
- If multiphase flow exists, gas production is much lower.

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*Apache*
Roadmap

Reservoir
- Geology
- Seismic analysis
- Petrophysics
- Mineralogy
- Log response
- P & T

Fluids & Production Rates
- Fluid composition
- Water geochemistry
- Expected rates
- Production profile

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

Well Design
- Surface facilities
- Wellhead
- Section sizes
- Tubular sizes, strength & connections
- Directional profile

Drilling
- Rig selection
- Surface location
- Mud selection
- Directional drilling & bits
- LWD
- Torque & drag
- SIMOPS

Environmental issues
- Contamination & remediation
- Surface ground disturbance
- Water sources & disposal
- Cutting disposal

Cost related
- Hydrocarbon prices
- Taxes increment
- Materials & services costs
- Gas & oil transportation costs

Community related
- Land access
- Impact on local economy
- Safety concerns
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.

One common categorization (and very broad by the way) is:
- Tight reservoirs
- Organic shale reservoirs
- CBM
- Hydrates
- Tar sands and 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…
Tight Reservoirs

- By definition, reservoirs with permeability less than 0.1 mD to gas. Really ambiguous
- Hydrocarbons were generated at another source rock. Negligible organic material
- Migration occurs and hydrocarbons get trapped due to seals or extremely low permeability barriers
  - If hydrocarbons migrate there is enough permeability to gas to flow and porosity to store them, ergo:
  - Flow mechanism: Darcy’s flow
  - Storage: pore volume
- Rock types:
  - Sandstones: mostly quartz with clays and cementitious materials
  - Carbonates: low to very low permeability carbonates
  - Igneous and metamorphic rocks like basement
- Requires massive hydraulic fractures to get commercial rates or gas volume

Source: adapted from Franco, 2011
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
- Due to its extremely low permeability, hydrocarbons did not have enough time to migrate
  - As there is low permeability there is also low porosity
  - Presence of organic material not converted to hydrocarbon (kerogen)
- Flow mechanism: Darcy’s flow in the matrix, Fick’s law in the organic portion
- Storage: pore volume and adsorption in the organic material

Rock types:
- Siliceous
- Carbonaceous
- Argillaceous

Source, trap & reservoir rock

Organic rich shale reservoirs

Source: Woodford shale, Bustin, 2009
Source: Barnet, SPE 124253
Source: SPE 115258

Organic content % wt
Structural Discontinuities

Due to the very low to extremely low permeability, something else is required to assist the gas to flow acting also as storage volume for hydrocarbons = natural fractures (called cleats in CBM reservoirs). Great impact on stimulation

- Origin. Uplifts. Faulted folds. Reservoir thickness
- 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: Adapted from Marcellus shale. Gary Lash. SUNY
Source: Gale. 2009
Source: K. Marfurt’s presentation

Source: Apache
Natural fractures

- In TR they are not necessary but its presence has a huge impact on production
  - In basement, altered zones and natural fractures are the storage volume and flow path for gas to hydraulic fractures
- In SR they are critical
  - Dilation and interconnection with other fissures to create a network
  - Reactivation of closed or healed fractures
  - Flow path to main HF

Source: Gale, 2008
Source: Barnett Shale. AAPG. Gale, 2009
Source: Cox, 2011
Stress Azimuth & Natural Fractures

- Globally HF follows stress fields, locally HF follows fabric (fissures, planes of weakness)
  - Initiation at wellbore depends on well alignment related to principal stresses
  - Fracture initiation at wellbore is different in open hole from cased and cemented hole
  - Perforated interval plays a major role on fracture initiation and behavior

- From production perspective, it has been proved orthogonal fractures to wellbore axis are best option instead of longitudinal ones
  - Need to consider orientation of principal sets of natural fractures related to principal stress fields
  - If NF’s are aligned to one of the principal stresses an option to study is to drill the well to a certain angle related to the least horizontal principal stress to make the rock fails in shear mode and increase the fracture network

Interval perforated < 4 Wellbore Diameter  Local stress effect ~ 10 Dwellbore

Adapted from: SLB
Stress Magnitudes & Natural Fractures

- In SR is critical to create a large stimulated volume (SRV) in order to contact large areas.
- The 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.

\[ \text{Stress anisotropy (SA)} = \text{SH} - \text{Sh} \]

Low SA = fracture network = SRV
High SA = planar fractures

Adapted from: SPE 131779
from: SPE 95568

SRV = 1450 MM ft³
**Hydrocarbons Storage & Flow Mechanisms**

In TR, hydrocarbons are stored in void space which include pores and fissures.

In SR, total gas composed of three sources:

- **Free gas**
  - Matrix gas = \( f(\text{por, Sw, So, P}) \)
  - Fracture gas = \( f(\text{por, Sw, So, P}) \)
- **Sorbed gas** = \( f(\text{kerogen, n.s. clays, P, T}) \)
- **Dissolved gas** = \( f(\text{Sw, So, GOR, P, T}) \)
**Flow 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.

![Diagram of flow in shales]

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

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<th>Xf, ft / m</th>
<th>L_int, hr</th>
<th>T_int, days</th>
<th>T_int, yrs</th>
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Source: adapted from SPE 144583

$ t \geq \frac{1.14 \times 10^4 \phi c F_{tr} X_f^2}{k} $  But Xf,eff = D/2 !

**Source:** PetroHawk, 2010
Anisotropy describes an attribute as a function of the direction of measurement.

Conventional reservoirs are generally considered isotropic.

Tight reservoirs are slightly to moderately anisotropic.

Sedimentation process and geologic events make the difference.

Shale itself is moderately to highly anisotropic.

Layering microstructure causes vertical transverse anisotropy (VTI).

Presence of natural fissures and faults creates horizontal transverse anisotropy (HTI).

As a consequence shale can be described as an orthotropic anisotropic medium.
Anisotropy Impact on 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.

For UR it is recommended to use VTI, HTI, TTI or OR models.

TR and SR show clear anisotropy at different levels turning the conventional stress model useless.

TR: slight to medium anisotropy, if fissures are present VTI model works very well.

SR: if lamination dominates a HTI model is recommended, if also fractures are present, a HTI + VTI is the option, for more complex situations a TTI or OR model should be applied.

\[
\sigma_k - \alpha \sigma_{pp} = \frac{1}{1 - v} \left( \sigma_{\gamma} - \alpha \sigma_{pp} \right) + \frac{E}{1 - v^2} \sigma_{\gamma} + \frac{E_v}{1 - v^2} \sigma_h
\]

\[
\sigma_h - \alpha \sigma_{pp} = \frac{E_{\text{horz}} v_{\text{vert}}}{E_{\text{vert}} (1 - v_{\text{horz}})} (\sigma_{\gamma} - \alpha (1 - \xi) \sigma_{pp}) + \frac{E_{\text{horz}}}{1 - v_{\text{horz}}} \sigma_\gamma + \frac{E_{\text{horz}} v_{\text{horz}}}{1 - v_{\text{horz}}} \sigma_h
\]

- ISO
- HTI
- HTI + VTI or OR

Argillaceous shale bed:
- $E_h = 6 \times 10^6$ psi
- $E_v = 3 \times 10^6$ psi
- $v_h = 0.26$
- $v_v = 0.25$
- ISO $S_h = 0.66$ psi/ft
- Ani $S_h = 0.87$ psi/ft

Large stress contrast = barrier

Siliceous shale bed:
- $E_h = 8 \times 10^6$ psi
- $E_v = 6 \times 10^6$ psi
- $v_h = 0.16$
- $v_v = 0.13$
- ISO $S_h = 0.53$ psi/ft
- Ani $S_h = 0.57$ psi/ft

Adapted from: Lewis
Anisotropy Effect on Fracture Growth

- Stress contrast is the main reason for fracture growth containment
- If conventional modeling for estimating stress profile is used, fracture height estimation might be wrong
  - Important for shales
  - Not too important for tight rocks unless there is clear evidence of anisotropy
- Need to run dipolar sonic logs or quadripolar sonic logs

Adapted from: Geomechanics for Hydraulic Fracturing. SLB’s presentation
TR Completion & Stimulation

By reservoir type
- Multiple stacked layers: multi hydraulically fractured vertical wells.
- Single or double individual reservoirs: mostly horizontal wells. First wells must be vertical for gathering information. Multiple hydraulic fractures

By completion type
- Cased and un-cemented completions. Packers for zonal or compartment isolation
- Cased hole: cemented
By reservoir type

- Single reservoir: multi hydraulically fractured horizontal wells. Few verticals at beginning for gathering information
- Double individual reservoirs: dual horizontal wells with multiple hydraulic fractures

By completion type

- Cased and un-cemented completions. Packers for zonal or compartment isolation

Source: PackersPlus
Adapted from: Martinez, 2011

Source: www.srbc.net
**Rock mechanics & Frac Design**

- Fundamental to know rock mechanic properties and mineralogy
  - Stress profile to estimate fracture growth
  - Mineralogy for brittleness and expected type of frac behavior
  - Shales are mainly composed of quartz, carbonates, clays and other minor components
  - Brittle rock is more likely to be naturally fractured and it is easier to create a dendritic network. The lower the Poisson’s ratio and the higher the Young’s modulus, the higher the brittleness.
  - Ductile rock tends to heal or close as soon as the fracture is finished. Hard to create a frac network. Clay related behavior. More likely conventional two-wings fractures
  - Rock properties either from cores and/or logs. As porosity is low little difference between static and dynamic rock properties. Full wave log highly valuable for YM, PR, anisotropy, rock brittleness, fluid presence, etc

Adapted from: SPE 115258

\[ TIV_{ratio} = \frac{DTS_{slow}}{DTS_{fast}} \]

Low TIV ratio = more brittle, higher fracture complexity
High TIV ratio = more ductile, less fracture complexity

from: Buller, Haynesville Shale

Adapted from: SPE 115258

Adapted from: SPE 136183
**Horizontal Well Azimuth**

- In vertical wells, there are no issues as fracture can initiate anywhere around the wellbore. Unless deviation exists, most of the fracture will be connected to the 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 that the entire fracture is connected to the wellbore.
  - Transverse fractures: best option for reservoirs with permeability less than 0.1 mD. As the contact point with the wellbore is reduced, choked flow is observed.
  - Fractures at any other angle: hard to initiate. Fracture tends to start growing parallel to the 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*
Frac Design Approach

- Frac fluid system depends mainly on reservoir type and density of fissures
  - TR: most used linear, X-linked or hybrid
  - SR: mainly slick water
- Fracturing rate dictated by reservoir type
  - TR: proppant transport governed by viscosity
  - SR: velocity is the transport mechanism
- Frac volume
  - TR: contacted area is the main factor
  - SR: SRV is the key factor. Larger is better
- Proppant concentration
  - TR: low to medium. Generally 4 - 5 ppg maximum
  - SR: low. No more than 2 ppg as final conc
- Proppant mesh size
  - TR: governed by frac width
  - SR: governed by frac width and proppant transport capability

<table>
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<th>Britteness</th>
<th>Fluid system</th>
<th>Fluid viscosity</th>
<th>Natural fractures</th>
<th>Frac rate</th>
<th>Proppant conc</th>
<th>Frac fluid volume</th>
<th>Proppant volume</th>
<th>Fracture geometry</th>
<th>Frac width</th>
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<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>Network</td>
<td>Very narrow</td>
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<td>Low</td>
<td>High</td>
<td>Two-wing</td>
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</table>

from: SPE 115258
Formation Sensitivity

- Formation (clay) sensitivity to fracturing fluids (water based)
  - More important than clay content is type of clay (mixed layer clay). CEC is a good indicator of clay swelling. Mineralogy does not tell the whole story
  - Mostly water based fluids are used
  - Capillary pressure for flowback practices and clay swelling potential. Capillary suction tests correlates with clay swelling potential. Imbibition tests also very useful
  - Acid solubility tests. In general shales have carbonates. There is strong correlation between AST and carbonate content

![Graph showing permeability ratio vs. pore volumes for different fluids]

Adapted from: Neasham, 1977

![Graph showing capillary suction time test for different fluids]

CST < 1 = No sensitivity
1 < CST < 1.5 = Moderate
CST > 1.5 = High

Adapted from: Neasham, 1977

from: Haynesville shale. Buller

from: SPE 115258
Fracture Spacing & Number of Fractures

Basically governed by three factors:

- **Stress interference or shadow**: due to very low permeability, once the first HF is created, pressure within the fracture does not decline very fast, causing an excess of stress. Next fracture will “suffer” it. If both horizontal principal stresses are closed, most likely there will be changes of orientation at wellbore, denoted by higher pressures and tortuosity.

- **Production interference**: as soon as individual HFs start producing, pressure wave travels until it reaches the ones from the nearest HFs, at this point it can be considered HF reached a boundary.

- **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: Weijers, 2006

Source: Britt, 2011

Source: Barree, 2011
**Proppant Transport within Fractures**

- X-linked fluids have enough viscosity to transport proppant far away from wellbore but...
  - Long fractures imply friction of proppant grains among them and against the fracture walls that limits the transport. Friction is mainly consequence of fracture walls roughness
  - High rock strength = narrow fracture width. Difficult to pump big proppant mesh sizes
  - Aperture of natural fissures is not big enough to accept all proppant mesh sizes, maybe only 100 mesh and 40/70 are able to go thru

- Slick water transport mechanism is based on rate (actually velocity)
  - 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
  - Despite rate is high at wellbore as soon as multiple fractures are created, velocity is strongly impacted, thus reducing the ability to transport proppant
  - Instead of pumping increasing concentrations of proppant, slugs of proppant followed by sweeps are used to help the transportation process and also to increase stimulated volume
  - Fracture width is more critical than in TR
  - As HF connection with wellbore is limited, generally the last part of the proppant schedule is tailed in with bigger proppant size

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**Equation:**

\[ V = \frac{Q}{(Hf \times WF)} \]

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**Graphs and Images:**

- Graph showing flow rate and pressure over time.
- Graphs comparing different flows rates and proppant concentrations.
- Images of proppant particles and fracture patterns.

**Notes:**

- Soft rock vs Hard rock.
- 80 bpm, 45 bpm, 35 bpm.
Big debate around this issue. Let’s separate commercialization from engineering!

Open hole: can be uncased, cased without mechanical diversion or cased and isolated
- True open hole, pre-perforated or slotted liners and frac ports + isolation packers
- If natural fractures 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
- If faults from deeper zones that produce water are present, it is an option to consider
- 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
Stimulation Success & Optimization

The only way of being successful and continue improving the development of UR is to push the limits of existing technologies and apply new ones. Need to check technology effectiveness

Verify if what we planned is what we got. Check assumptions, calibrate and test changes. Currently four major technologies are used:

- Microseismic
- Tracers
- Production logs
- Production transient analysis

Source: Griffin, 2006
Source: Blasingame, 2010
Source: epmag.com
Well Cost Optimization

- Longer horizontals outperform shorter laterals but there are constraints
- The higher the number of fracs, the bigger the impact on cumulative production, of course restricted by factors discussed previously
- More than ever unconventional reservoir development driven by well cost and gas & oil price. Industry has never seen so many new technologies in a couple of years
  - Pumping services takes at least 1/3 of the total cost
    - Frac factory approach. Some operators manage their own pumping services
    - Frac design, proppant selection, strong focus on post frac analysis
  - Drilling is another big chunk of the total well cost, in general about ¼ of it
    - Dedicated rigs. Pad drilling. Some independents operate their own fleet of drilling and service rigs
  - Tubulars impact about ¼ of the total cost
    - Strong efforts to reduce the number of casings thru better drilling practices

### Item | % Total Cost | Remarks
--- | --- | ---
Drilling | 25 - 30 | Drilling rig, directional services and mud
Tubulars | 15 - 25 | Casing, tubing and line pipe
Pumping | 30 - 35 | Stimulation (proppant + frac fluid + services)
Other | 10 - 30 | Wellhead, location, roads, hauling, remediation

Cum Prod vs Lat Length

Cum Prod vs Nº Fracs

![Graphs showing cumulative production vs lateral length and number of fracs]