# An Engineered Approach to Hydraulically Fracture the Vaca Muerta Shale (SPE 189866)

Hernán Buijs, Sr. Reservoir Engineer (Wintershall Holding GmbH)

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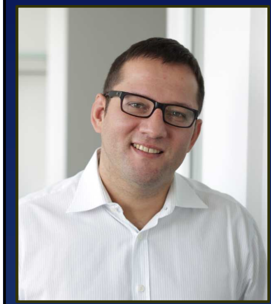

## Hernán Buijs

**Sr. Reservoir Engineer, Wintershall Holding GmbH**

Mr. Buijs' main interests lie on reservoir characterization, formation damage and reservoir stimulation, with a deep involvement in the area of hydraulic fracturing complex HP/HT reservoirs and all related technology. Hernan is extremely active within the Society of Petroleum Engineers (SPE), currently serving in the Completions & Business, Management and Leadership Advisory Committees. He developed and taught numerous custom made courses on hydraulic fracturing and reservoir characterization as university professor, invited speaker or company in-house expert on matter. He received several local, regional and international awards. He earned an Industrial Engineering and a Petroleum Engineering degree at the Institute of Technology of Buenos Aires, Argentina.

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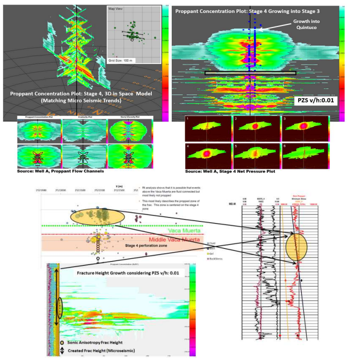
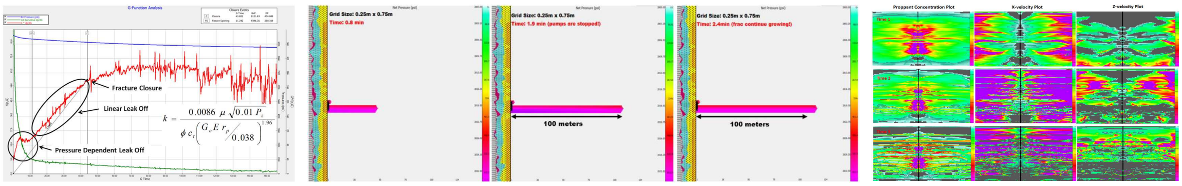
## Today's "Road Map"

- Maximizing well performance: How many variables do we control?
- How does a fracture looks like?
- Rock Mechanics – Lithology based 1DMEM.
- Synthetic Rock Mechanical Models.
- Numerical Models of Diagnostic Injections.
- "Slowness" based Permeability Model.
- Brittleness Index = Permeability!
- Brittleness Index ≠ "Slowing": <u>Excessive Frac Height Growth!</u>
- Modelling Fracture Geometry (Proppant Convection).
- Mechanistic Models for Horizontal Landing, Cluster Spacing and proppant material/volume selection.



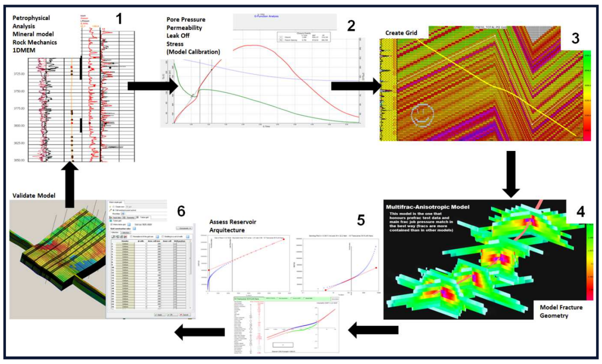



## Maximizing Production Performance

- How Many Variables do we Control?
  - How we Access the Host Rock:
    - Well Directionality (toe up-down / Landing point)
    - Completion Type
    - Number of Frac Stages / Cluster Spacing… Sequence?
  - Fracture Design:
    - Rate
    - Fluid
    - Proppant
  - How we produce our wells:
    - Drawdown Management

***There is a very limited number of variables we can control to improve well performance…***

***The way we handle them will define the economics of the project!***



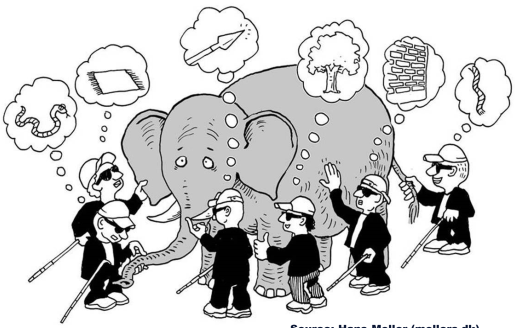

**Source: Hydraulic Fracturing Learning Cycle (T. Toth, H. Buijs *et al*, 2011-2018)**

## How does a “Fracture” Looks Like?

Webinars

- Diagnostics, Measurements and Interpretations!
  - Near Wellbore Measurements:
    - Acoustic Anisotropy
    - Non-Radioactive Proppant (NRT)
    - Tracers (water, oil & gas / radioactive)
    - Images
    - Videos
    - Core
  - Far Field Measurements :
    - Micro Seismic
    - Electromagnetics
    - Outcrops
    - Mine Backs
  - Laboratory Work
  - Rates & Pressures:
    - Diagnostic Injections (DFIT)
    - Hydraulic Fracture Modelling
    - Production Modelling:
      - Rate Transient Analysis (RTA)
      - Dynamic Simulation Models

***Each of these “Diagnostics” are independent interpretations. Without a Multidisciplinary Workflow that brings them together, these are just “HANDICAP” MODELS!***



**Source: Hans Moller (mollers.dk)**

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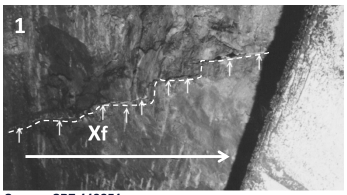
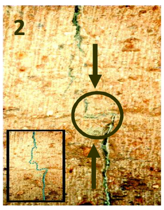
## How does a “Fracture” Looks Like?

Webinars

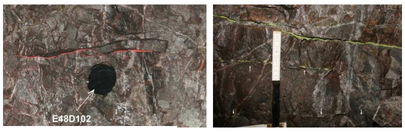
- Geology Controls Fracture Growth!
  - Fracs will follow stress globally and locally it follows the rock fabric (planes of weakness).
  - Several disconnection points might be present (vertical and lateral continuity can be jeopardized).
  - Fracture Complexity seems to be related to Lithology (enhanced permeability)!



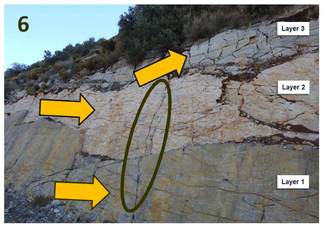

**Source: SPE 119351**



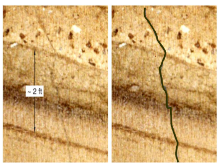

**Source: SPE 163863**



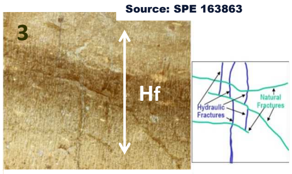
**Source: SPE 124919**



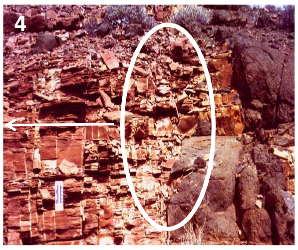

**Source: Tougrou, Marocco (Paul Veeken)**



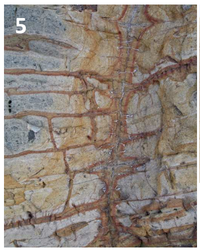
**Source: SPE 145949**




**Source: SPE 115771**




**Source: Magma Dike (Delaney-Pollard, 1986)**





**Source: Magma Dike (Paul Veeken)**

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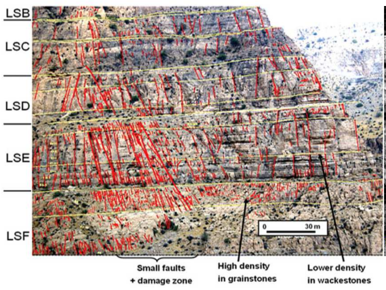
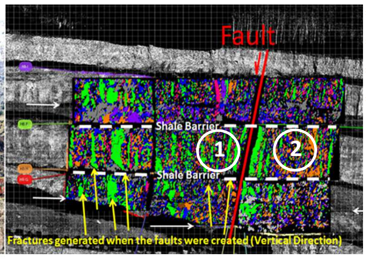
## How does a "Fracture" Looks Like?

- Geology not only Controls Fracture Growth but it also defines how much of the created geometry is contributing to flow!
  - Notice that fractures terminate at shales/bed boundaries and that none persist all the way from top to bottom of the section…but there is a continuity across permeable rocks!

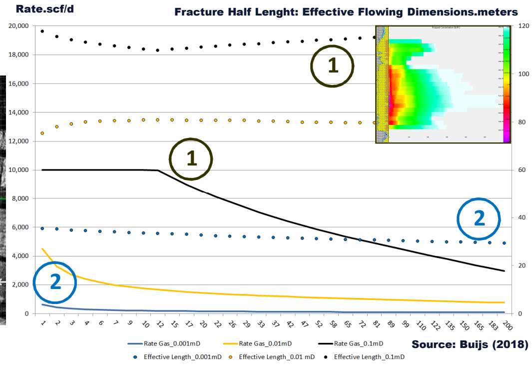
***GEOLOGY: Can't Change it, Don't Ignore it… Use it to your advantage!***




Source: lyellcollection.org




Source: WIDE Study, Koehrer et al. 2014 (SPE 167793)




Source: Buijs (2018)

***Reservoir flow capacity provides the energy to drive clean up and develop effective fracture length.***

## Rock Mechanics – Lithology based 1DMEM

- The "Wave Equations"…

$$E = \rho v_s^2 \frac{3v_p^2 - 4v_s^2}{v_p^2 - v_s^2}$$

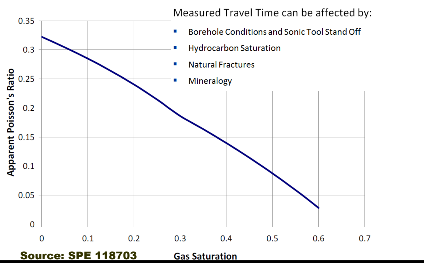
$$\nu = \frac{v_p^2 - 2v_s^2}{2(v_p^2 - v_s^2)}$$

Source: Petroleum Related Rock Mechanics, 2004

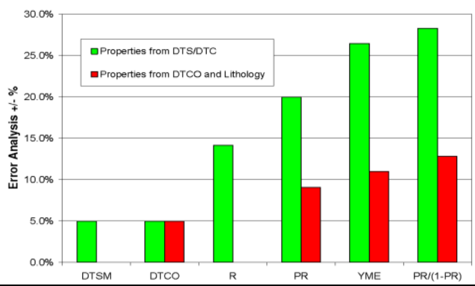
- Follows Newton's Second Law of Motion And Combines Hooke's Law.
- You need Compressional and Shear Sonic Data.
- Main Issues behind these equations:
  - When using a ratio of velocities, any error is magnified.
  - Results are affected by Pore Fluid Saturation and TOC.
  - Are a set of equations that are "Lithology-Blind"!

Source: hermentorcenter.com

Effect of gas saturation on Poisson's Ratio for variable DTC with constant DTS

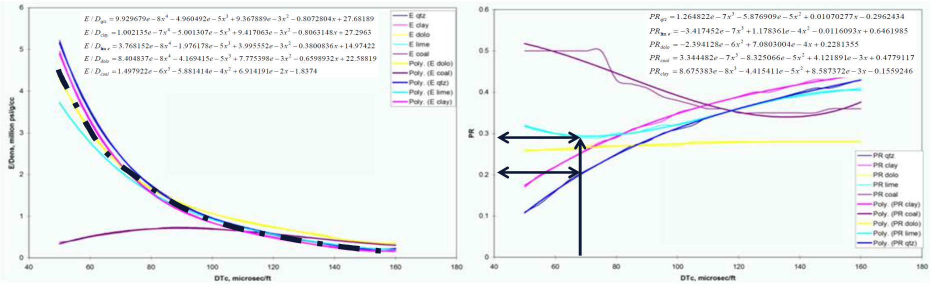



Source: SPE 118703



## Rock Mechanics – Lithology based 1DMEM

- Lithology based Rock Mechanics




Source: Dr Barree et al. (circa 1980s)

*There is no need to run expensive sonic tools… With a Compresional Sonic and some understanding on lithology you can build stress models with predictive capabilities!*

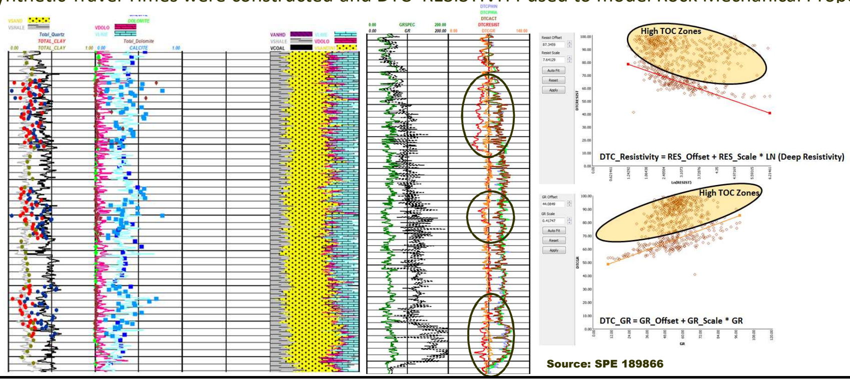
– These correlations were built through 100s of rock mechanics triaxial test performed across a wide range of stress conditions on 100% pure minerals vertical plugs saturated with water (we need to build a DTC (compressional travel time) curve that represents a 100% water saturated pore space to use these correlations).

– From the Poisson's Ratio graph we can understand that you may have the same travel time but, depending on the type of lithology you have, you will have totally different rock mechanical properties.

– If we have a lithology model, the compressional travel time can be used to estimate dynamic elastic properties of the rock using the curves shown (values for mixed lithologies can be estimated by interpolating between the pure lithology lines).

## Rock Mechanics – Lithology based 1DMEM

- Vaca Muerta Lithology based Rock Mechanical Model:
  - A lithology Model was built and constrained with XRD measurements.
    - Core and cuttings XRDs can be used for such purpose
  - Some portions of the contacted rock shows different synthetic travel times behaviours which were investigated by pumping DFITs on multiple wells (marked with black circles).
  - Synthetic Travel Times were constructed and DTC RESISTIVITY used to model Rock Mechanical Properties.

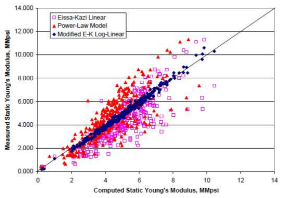



Source: SPE 189866

*A synthetic travel time that represent 100% water saturated pore space can be built by utilizing SGR or Deep Resistivity logging data.*

## Synthetic Rock Mechanics

- Synthetic Rock Mechanics can be built with SGR or Resistivity:
  - These correlations can reproduce the same rock mechanical properties in nearby wells and can be used at field level (we have tested in packs of 50 wells with an error of less than 20% - up to 15 Km apart).
  - This can be used to optimize costs of the logging suits to be run in upcoming wells.

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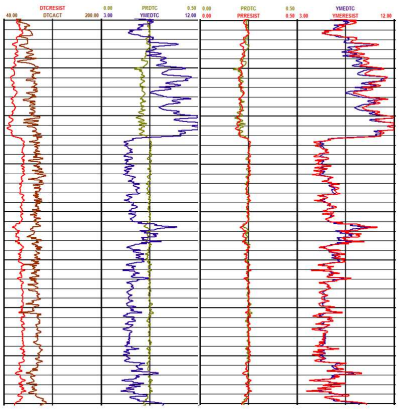
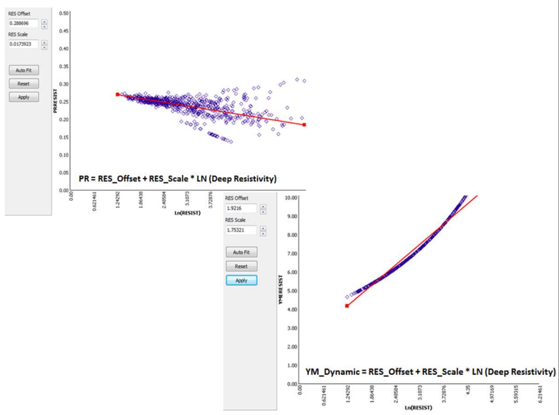





## Lithology based 1DMEM

- Uniaxial Strain Stress Equation

$$P_c = \frac{\nu}{(1-\nu)}[P_{ob} - \alpha_v P_p] + \alpha_h P_p + \varepsilon_x E + \sigma_t$$

Where,

Pc = closure pressure [psi]

σh = minimum horizontal in-situ stress [psi]

υ = Poisson's ratio

σv = overburden (vertical) stress [psi]

αv = vertical Biot's coefficient [unitless]

αh = horizontal Biot's coefficient [unitless]

Pp = pore pressure [psi]

εh = regional horizontal strain [μstrain]

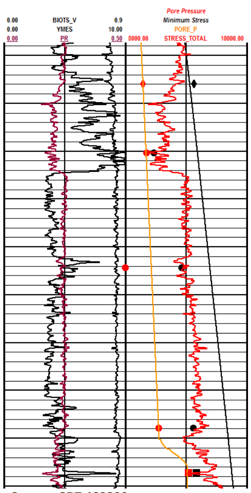
E = Young's Modulus [MMPsi]

σt = regional horizontal tectonic stress [psi]

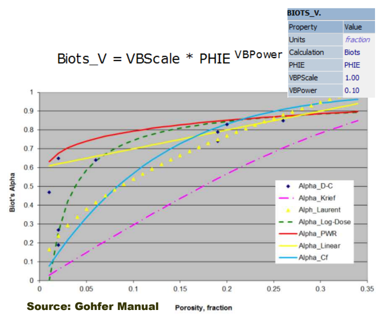
Source: SPE 118703

*Our models are very simplistic considering the complex depositional environment, diagenetic and deformational history of most reservoir systems. We tend to use lineal rock elastic theories to systems that tend not to behave as pure elastic materials.*

Source: Thiercelin (1994)




Source: SPE 189866




Source: Gohfer Manual

## Traditional vs Lithology based 1DMEM

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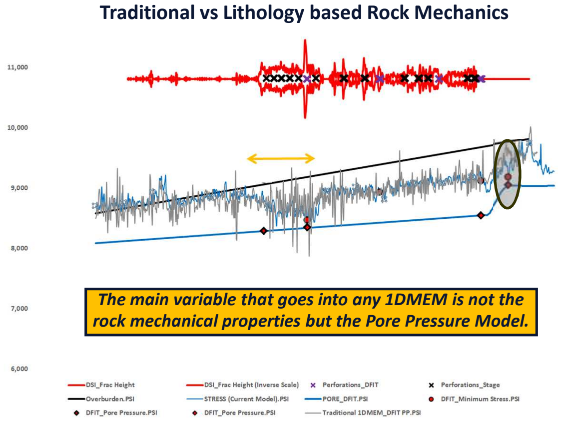
- Different rock mechanical property and stress models were run and compared with:
  - Multiple DFIT stress measurements.
  - DFIT numerical Models.
  - Near wellbore sonic anisotropy fracture heights.
  - Micro seismic trends in the upper Vaca Muerta.
- The lithology based 1DMEM provided much better predictive capabilities than any of the 1DMEM tested.




Source: SPE 189866

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## 1DMEMs Sensitivity analysis (Model Validation)

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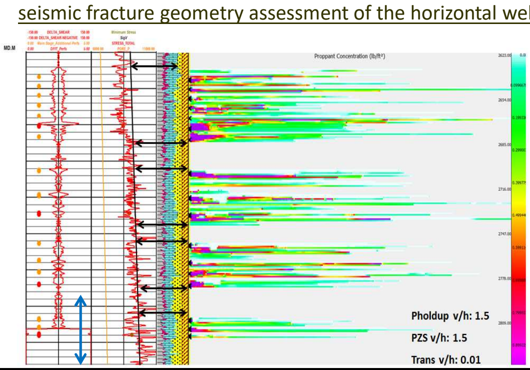
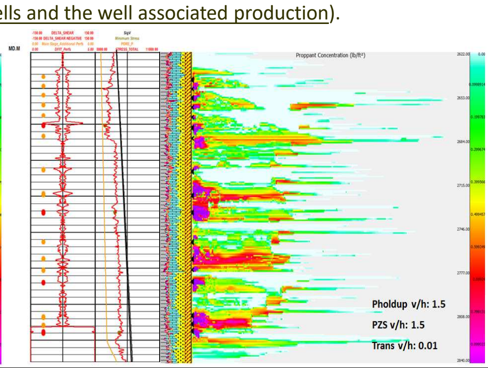
- Multiple 1DMEM were run and the modelled fracture height compared to near wellbore fracture height measurements:
  - Variable transverse isotropic (VTI) and traditional rock mechanics with a low pore pressure model cannot matched the measured fracture height (even though they match the rock mechanical and several minimum stress measurements).
  - Lithology based and traditional rock mechanics with a calibrated pore pressure model provide a decent match to the measured fracture height (<u>Still, the traditional 1DMEM cannot match all measured closure points nor explain the micro seismic fracture geometry assessment of the horizontal wells and the well associated production</u>).

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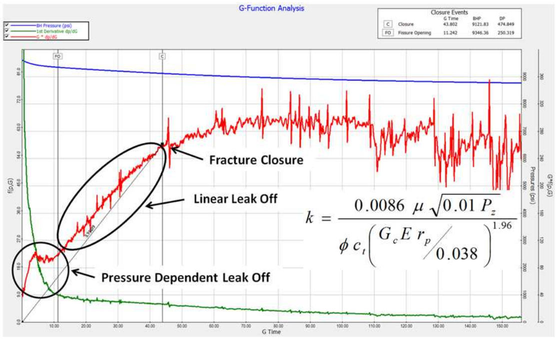
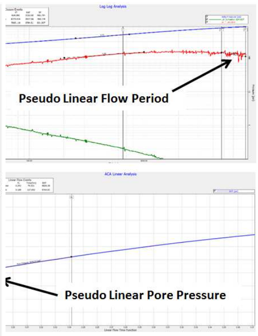
# Numerical Model of Diagnostic Injections

Webinars

- <u>The G-Function: A Robust Reservoir Characterization Tool!</u>
  - There is a relationship between the time it takes for the fracture to close and the host rock permeability (SPE 106085).
  - The difference between the ISIP and the identified closure stress will affect:
    - The modelled fracture height (defining the contacted KH).
    - The modelled fracture width (defining the conductivity of the fracture).
  - **Diagnostic Injections (DFIT) allowed us to drastically collapse our learning curve (in a cost effective manner!).**

***Pumping is one of the few processes we have to establish a "conversation" with our reservoir… The G-Function is the language we use to "talk" with the host rock!***




Source: SPE 189866

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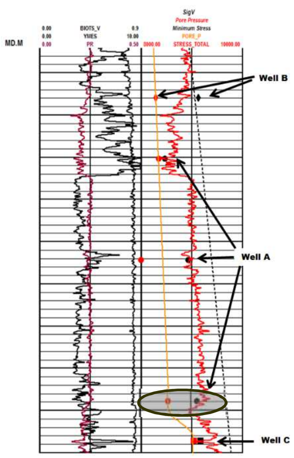
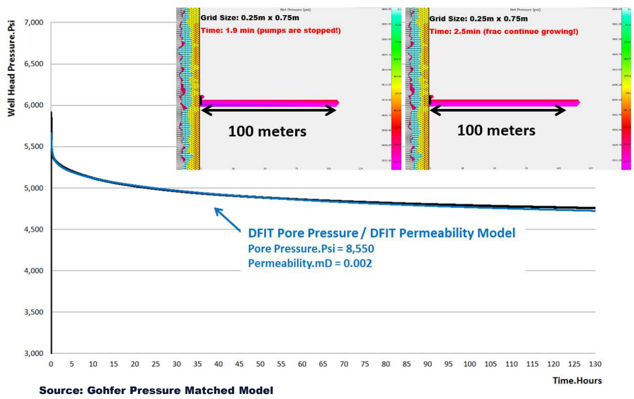
# Numerical Model of Diagnostic Injections

Webinars

- <u>"Tip Extension" Closure Mechanism</u>
  - Due to the low permeability of the contacted area, the fracture continues growing after the pumps are stopped.




Source: Gohfer Pressure Matched Model

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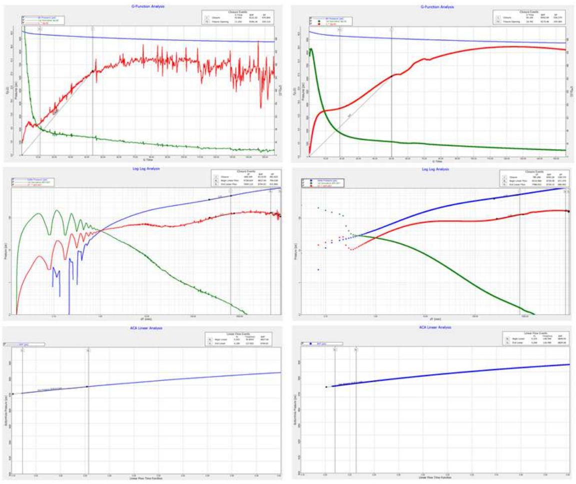
## Numerical Model of Diagnostic Injections

- "Tip Extension" Closure Mechanism
  - The simulated model gives out the same G-function type curve, minimum stress, time to reach closure and after closure pressure transients (pore pressure).
  - This can be translated into a model that was built using the correct rock mechanical properties, pore pressure, permeability, secondary leak off and stress solutions.
- **Can this technique be utilized to test different Flow Capacity and State of Stress hypothesis?**

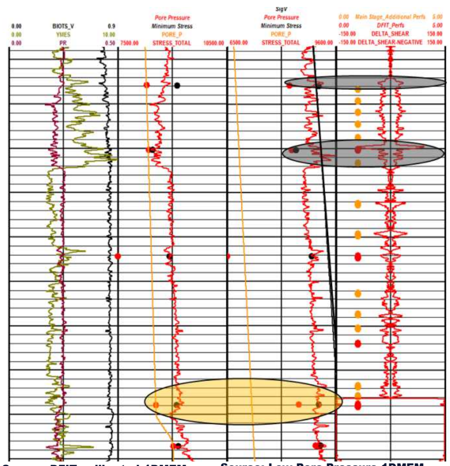


Source: Well A, DFIT Lower Vaca Muerta

Source: Well A, Simulated DFIT Lower Vaca Muerta

## Numerical Model of Diagnostic Injections

- Testing different Hypothesis
  - Same Rock Mechanical Properties and Mineralogy Model.
  - 2 different Pore Pressure Models (1,500 Psi pressure difference).
  - 2 extremely different stress models emerge (Model A vs Model B).
- Even though the models have the same "Brittleness Index", they recreate totally different stress scenarios that will generate different fracture geometries.
- **Which Model is the most representative?**




Source: DFIT calibrated 1DMEM (Model A)

Source: Low Pore Pressure 1DMEM (Model B)

***Having a 1DMEM that can match multiple closure points makes the model consistent but it does not make it valid or real!***

## Numerical Model of Diagnostic Injections

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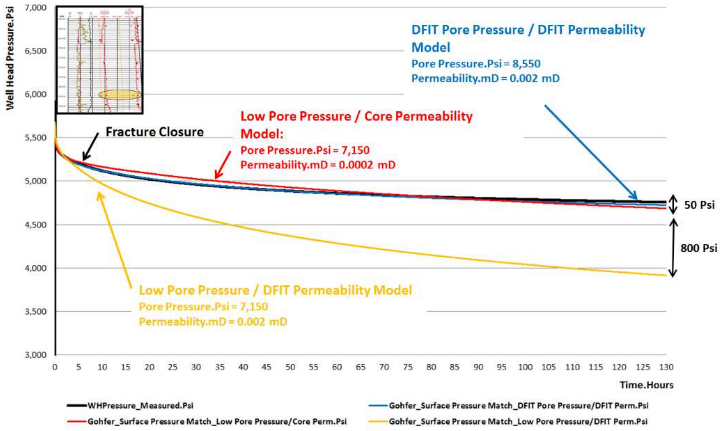
- Just by comparing the pressure match, both models seems to be correct…. Even though they use totally different permeability, pore pressure and stress assumptions.
- **Does being able to pressure match data makes the model valid?**

***You can pressure match different Fracture Models (planar, non-planar) with different fracture dimensions (lengths, widths, heights), pore pressure, stress and permeability models***

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## Numerical Model of Diagnostic Injections

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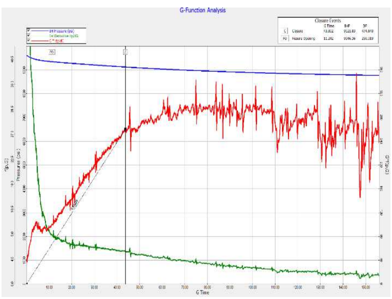
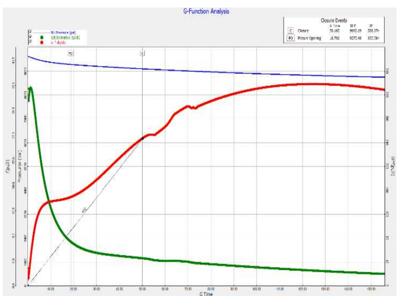
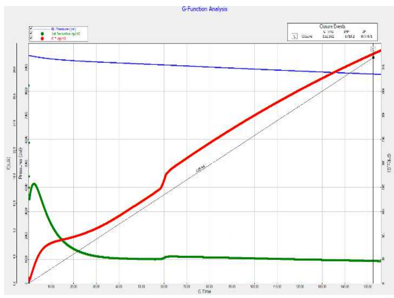



Source: Well A, Measured Data Gplot




Source: Well A, DFIT Pore Pressure / DFIT Perm Gplot (Model A)




Source: Well A, Low Pore Pressure/Core Perm Gplot (Model B)

- When comparing the G-plots from each pressure match, the low permeability model cannot reproduce the same signatures as seen on the measured data (the "frac" never closes due to the low permeability used in the model!).

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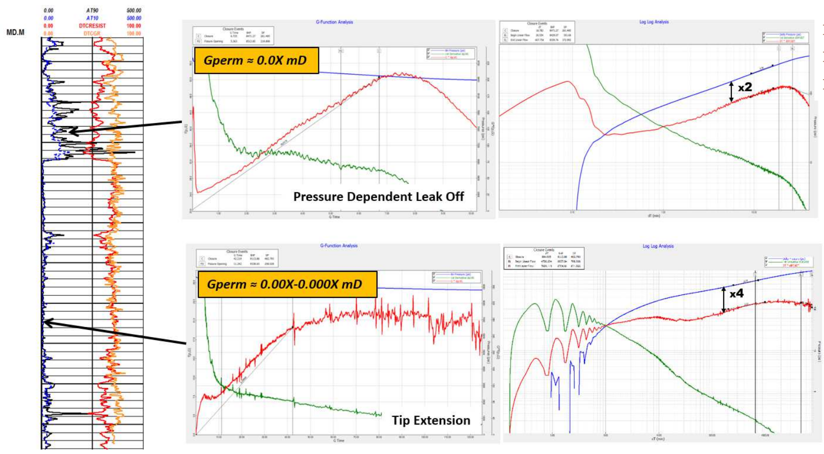
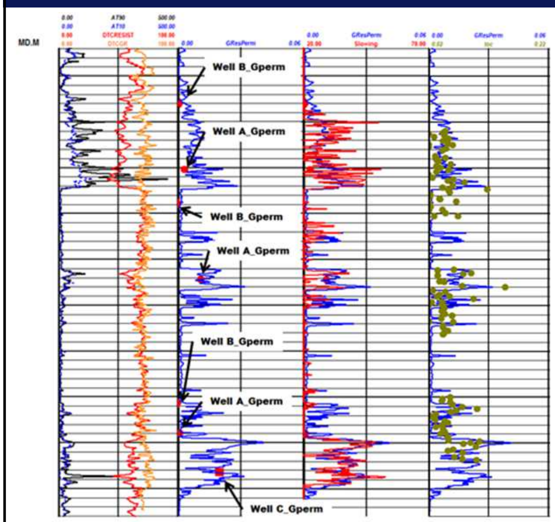
## “Slowness” based Permeability Model

- Permeabilities derived from DFIT closure time are higher within higher resistivity intervals.
- **There are cycles of low and high permeability intervals.**




Low Resistivity: A * PHIE^B
High Resistivity: C * PHIE^D
High Resistivity≥16 ohmm / Low Resistivity < 16ohmm

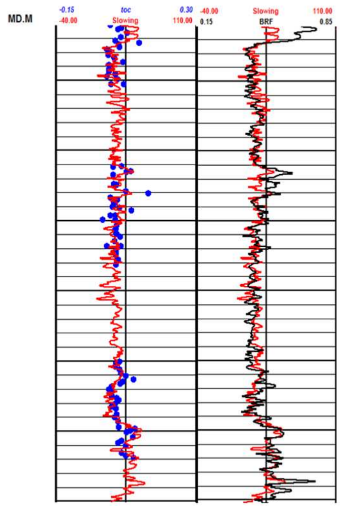
## “Slowness” based Permeability Model




- A permeability function was built by combining different logging measurements constrained by DFIT Data (GRESPerm).
- There is a strong correlation between the permeability function built and the TOC measurements performed on core.
- This suggests that the micro-fissures present are related to the maturation and sourcing of hydrocarbons.
- **Travel Time “Slowness” (Passey *et al.*) can be used to model and distribute permeability.**

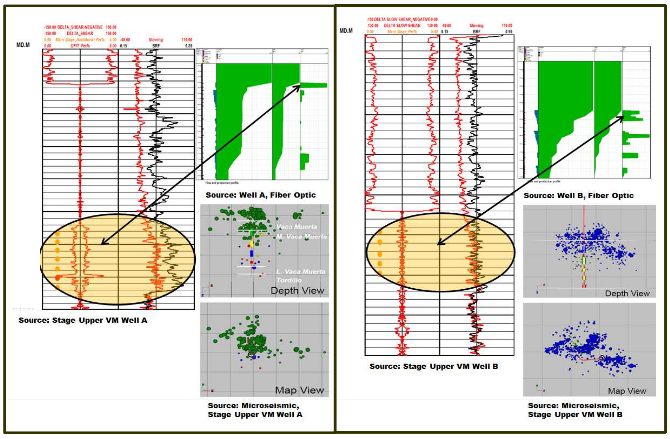
## Brittleness Index = Permeability!

- There is a strong correlation between Mullen's Brittleness Index (BI), the Travel Time Slowness and TOC.
- The Brittleness Index seems to be related more to Permeability than the actual rock mechanical properties.




## Brittleness Index ≠ "Slowness": Excessive Fracture Height Growth!

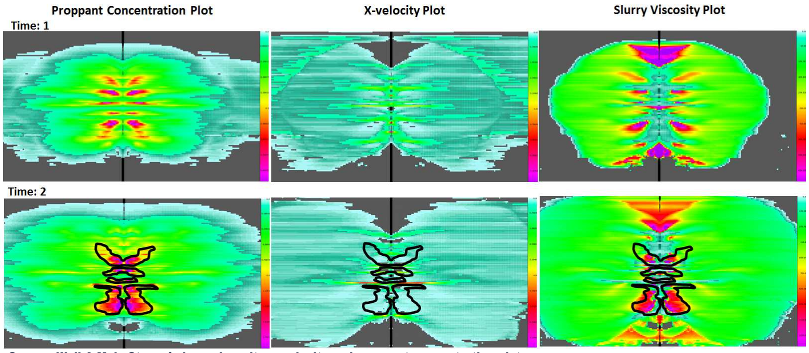
- When the BI and the Travel Time Slowness do not match, this is associated to open natural fractures where the fracture can grow excesively in height („Fractured Chimney").
- **When initiating the fracture within this annomally, better production performance can be achieved due to an improved vertical connectivity to the main frac body (Sweet Spot!).**




*Micro seismic events show similar fracture growth into Quintuco for both wells but the connection to such complex geometry was different depending on how we accessed the rock.*

## Modelling Fracture Geometry:
## "High Concentration Proppant Pillars"

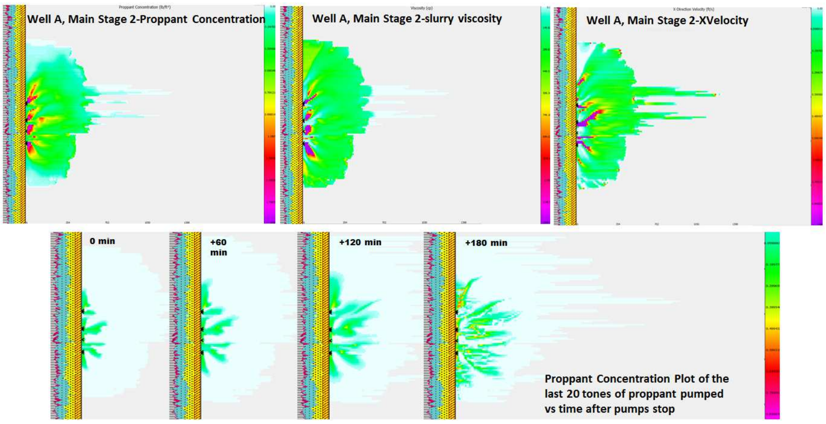
- <u>During Pumping we tend to develop Proppant Pillars:</u>
  – The frac slurry is pumped through the perforations and the fluid is sheared, losing viscosity within the flow channel (check high velocity regions vs low viscosity channels).
  – It can also be seen there are portions of the contacted rock that has high slurry viscosity and low velocities where proppant tends to accumulate forming channels (checked marked zone in the lower plot)



Source: Well A Main Stage 4-slurry viscosity, x-velocity and proppant concentration plots

## Modelling Fracture Geometry:
## "High Concentration Proppant Pillars"

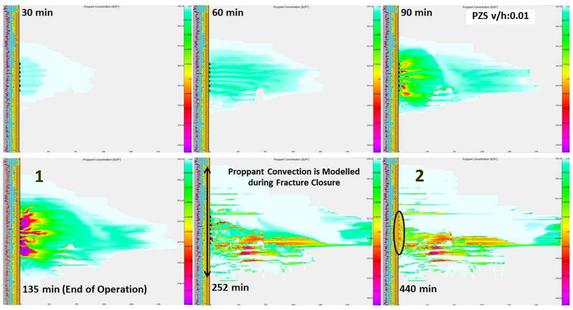
- The last proppant you pump, most likely wont be close to your well (is it worth it to pump large amounts of better quality proppants in the last stage? Most Likely not!)
- <u>When the pumps are stopped, the proppant will continue moving and these pillars collapse!</u>



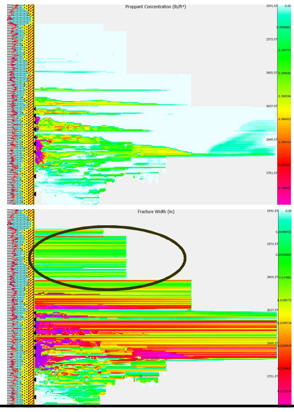
# Modelling Fracture Geometry: “Proppant Convection”

Webinars

- Simulating Proppant Convection made the model predictive.
- There is some residual unpropped width in the model by the created fracture that helps to increase production from this interval.
- **This can be translated into having a high conductivity flow channels connected with the main fracture body.**




***There is no direct relationship between the near wellbore assessment of the fracture height and the micro seismic event cloud.***



***When comparing the fracture geometry when the pumps are stopped (1) to the one achieved when the proppant bank stops moving (2), we can see that they are different. This suggests that the after job ISIP has no relationship to the placed fracture geometry.***

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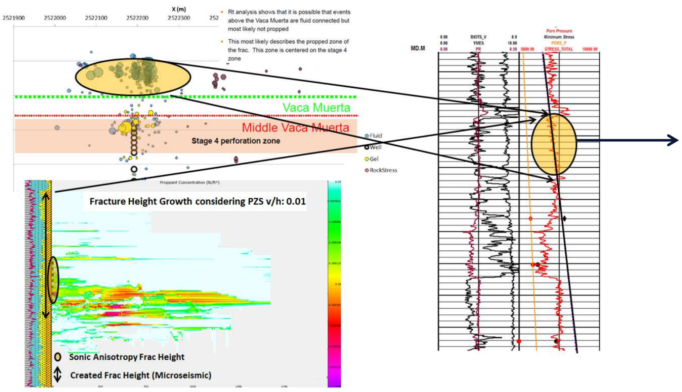
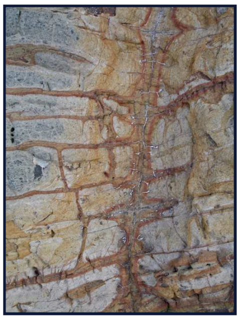
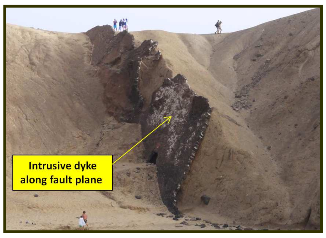
# Complex State of Stress in the Upper Vaca Muerta

Webinars

- Overburden and Minimum Stress are equal (maximum stress is very close):
  - The fracture does not know if it should grow in height or develop horizontal fractures.
  - We cannot place an horizontal wellbore in this position (rock will be very difficult to break and, if we get to breakdown the rock, the frac jobs most likely will screen out rapidly).
  - <u>We can access this additional high permeability pay from down below (staying connected is a different story)!</u>






Source: Magma Dike, Papagayo Beach (Courtesy of Paul Veeken)

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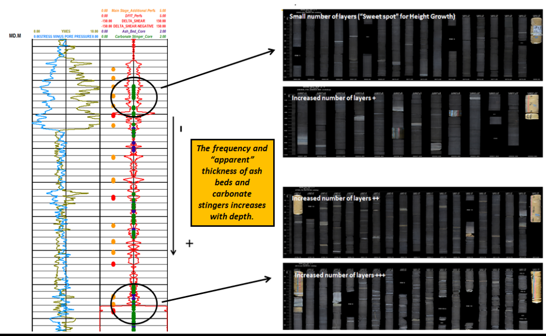
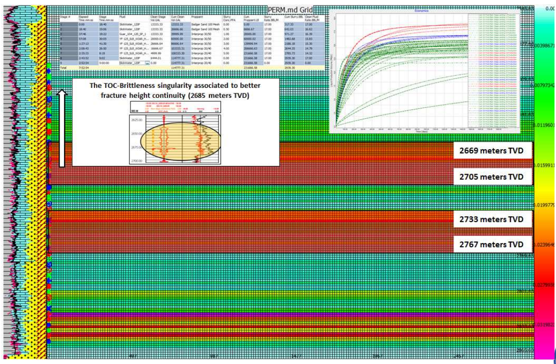
# Mechanistic Study:
# "Horizontal Landing Point"

Webinars

- With a Calibrated model, the same fracture design was pumped at over 50 different landing positions (115 tonnes of Ceramics simulating the created fracture geometry from one perforation cluster).
- 2 horizontal landing positions emerged (the analysis did not contemplate height growth into Quintuco, making the upper Vaca Muerta the most attractive way to access the rock).

***The model suggests that the highest permeability zone ("The Kitchen" or High TOC Zone) is not the best position to land an horizontal well.***

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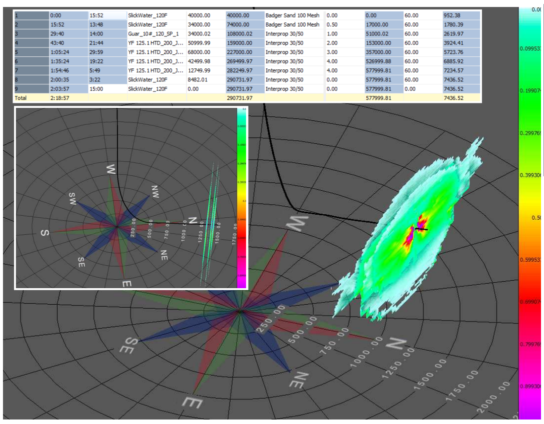
# Mechanistic Study:
# "Cluster Spacing"

Webinars

- The same Frac Design was pumped through 3 clusters with different spacing (300 tonnes of 30/50 ceramic):
  - 20 meters Cluster Spacing.
  - 30 meters Cluster Spacing.
  - 35 meters Cluster Spacing.
  - 40 meters Cluster Spacing.
  - 50 meters Cluster Spacing.
- 1000 meter lateral production was modelled for 6 years.
- The production model takes into consideration proppant pack clean up, multiphase non-Darcy flow and proppant pack permeability degradation.



***Depending on which variable you are trying to maximize (IP, EUR or NPV), you will follow a different completion optimization approach.***

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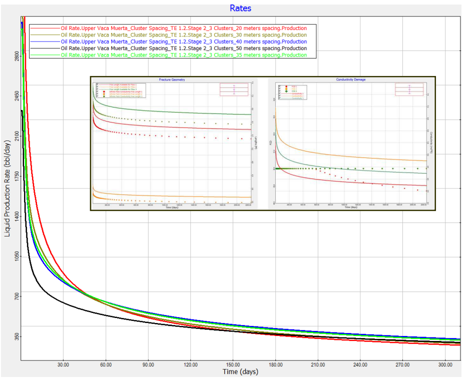
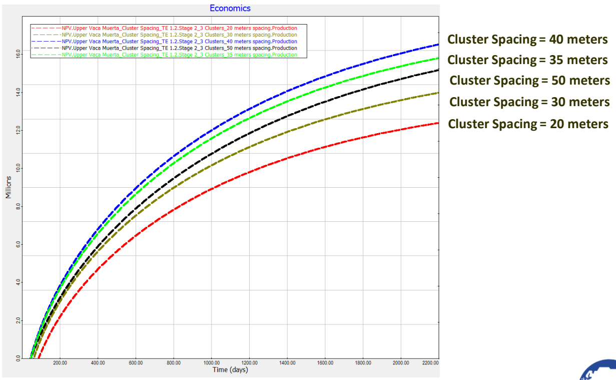
# Mechanistic Study:
## "Cluster Spacing"

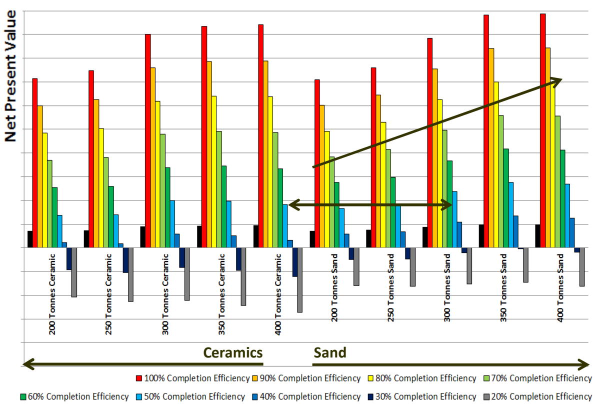
- There is an initial better production by placing clusters closer together (more volume is able to be produce at the same time due to having more fracs in the 1000 meter lateral).
- The NPV calculations shows that the best Cluster Spacing is between 35-40 meters (approx.).




# Mechanistic Study:
## "Fracture Design: Proppant Type and Volume"

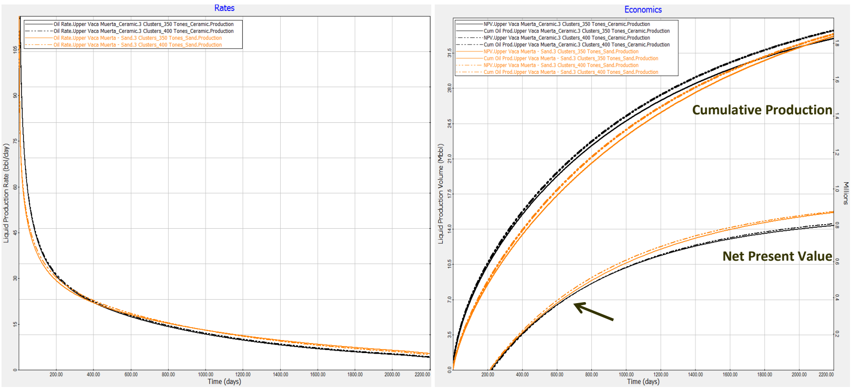
***Depending on the Completion Efficiency and your cost structure, the solution will be different (the results of the analysis will be different depending where you land the well!)***




- Variable mass fracture designs (200-400 tonnes of sand/ceramics) pumped through 3 perforation clusters spaced 35 meters were modelled for a 1km lateral (different drainage areas were evaluated).
- Cumulative Production increases when incrementing the amount of proppant pumped (propped fracture height increases with proppant mass up to 350-400 tonnes in this portion of the rock).
- Over 350 tonnes, Ceramics and Sand accumulate the same amount of hydrocarbons (still different proppant materials will accumulate Oil at a different rates).

## Mechanistic Study:
## "Proppant Discussion: Sand or Ceramics?"

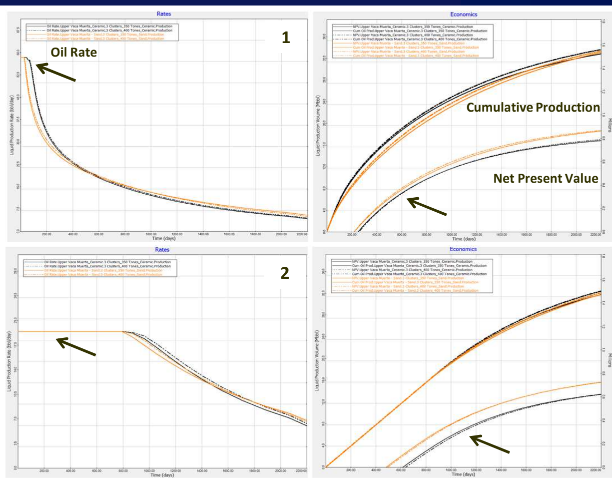
- This single stage simulations shows that (open flow potential):
  - Initial Production is higher with Ceramics for over 1 year and there is an initial better fluid uplift potential.
  - In between 1-3 years, production from both materials will be very similar.
  - After 3 years, Sand will produce better since it is still draining reservoir volume that was already drained by ceramics faster. Pumping Sand shows better well economics over ceramics during the whole analysed period!




***Proppant Pack Conductivity Matters… But it comes with a "Price Tag". Considering the cost of sand is half of ceramics, it is very difficult to justify ceramics as the best economic solution.***

## Mechanistic Study:
## "Drawdown Management"

- When constraining the rate we can see that:
  - Depending on your drawdown management strategy used to preserve the host rock permeability, you may see no benefit on production for several months (IP/Cumulative).
  - This will affect the NPV and make sand an even more attractive option to maximize well economics.
  - The main goal here is to find a balance among all these variables and we need a critical mass of wells to discover the right operating conditions that will maximize well economics (Optimization ends when drilling the last well in the field!).




***Depending on how much drawdown your natural fractured system can handle without collapsing (strategy)… you may never be able to utilize the potential of pumping ceramics!***

## Summary

- Numerical Models of DFITs can be used to validate/test different flow capacity and state of stress hypothesis.
- There are High Permeability Channels within the Vaca Muerta Shale.
- Permeability can be modeled/distributed based on Travel Time Slowness.
- Brittleness Index correlates more to Permeability than actual Rock Mechanical Properties.
- There are some anomalies between the Brittleness Index and the Slowness curve that are associated to open natural fractures and excesive fracture height growth.
- Proppant Convection needs to be modeled to better understand well performance. (there might be a residual width remaining within the host rock that may increase well performance).
- Mechanistic models can be used to build a strategy to complete horizontal wellbores (landing point, cluster spacing, proppant type & volumes).

## Thank You!


- We would like to thank Wintershall Holding, Wintershall Energia S.A. and GyP for allowing us to publish and present our experience from Aguada Federal Shale Oil Field in Vaca Muerta.
- Special thanks to Dr Barree, Dr Miskimins and K. Svatek for their constant support and education through out several years.