Construction and Calibration of a Fractured Tight Reservoir in a Mature Field*

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Abstract

The Mogollon reservoir of Eocene age, located in Block X of the Talara Basin, has been developed since the 1950s by hydraulic stimulation of vertical wells. Given its low porosities (2-6%) and permeability (0.01-0.5md), there is tight reservoir behavior, recovering to date only 5% of the original oil in place. The basin actually has high production variability, due primarily to the existence of sets of natural fractures, which contribute 80% of the cumulative production. These drained fractures show high degrees of depletion.

Due to the lack of understanding the distribution of natural fractures in the reservoir and the poor-quality information in the field, a characterization study was performed to construct a three-dimensional fracture model that allow us to understand and predict the productive performance of this reservoir.

This work focuses on the construction of the fracture model and its calibration with production history. To achieve this goal, an area within Block X was selected to generate a 3D fracture model, which was useful in understanding the behavior of the reservoir production. The characterization of this model was initiated by the identification and classification of natural fractures for each well, based on information from conventional cores, well logs, and outcrops that allowed us to obtain the main attributes of the fractures, and then build the 3D fracture network model, which represents the distribution of open fractures within the reservoir.

The results of the simulation for this model show that there is a strong capillary-water release from matrix. This water acts to displace the remaining oil from fractures. Thus, the recovery factor for fractures reaches a maximum of 60%. At the same time, it shows that there is still remnant oil has not been extracted efficiently; so there are sets of fractures that have not been drained. This leads to the possibility of drilling additional wells in order to obtain a larger contact area in these sets of fractures and to increase efficiency in the recovery within the reservoir.

Finally, the generation and calibration of this model served to understand the distribution of fracture sets (drained and undrained) and matrix-fracture behavior involving fluid-flow system. Furthermore, this methodology is being extrapolated to the rest of Block X to identify possible areas where fractures have not been drained yet within the Mogollon reservoir.

Selected References

Pozo, E.G. and W. Alvarado, 2008, Identificación y Clasificación de Reservorios Naturalmente Fracturados: Fm. Mogollón-Yacimiento Peña Negra Lote X-Talara-Perú: INGEPET 2008.

Roldan Guevara, J.D., D.E, Escobedo Cabrera, A. Patrocinio, E.G. Pozo Calle, P.G. Manrique Caceres, and L.C. Arivilca. 2013, Integration of outcrop studies to naturally fractured subsurface models – Example of the Mogollon Formation, Block X, Talara Basin, Peru: Search and Discovery Article #10526 (2013). Website accessed February 18, 2016, http://www.searchanddiscovery.com/documents/2013/10526guevara/ndx_guevara.pdf.

Bustamante, E.J., V.C. Rios, D. Escobedo Cabrera, P. Manrique Cáceres, L. Choque, and W.T. Espíritu, 2014, Stochastic sensitivity analysis for effective parameters ranges on 3D fracture network using stress distribution, outcrops and wellbore data adjusted to well production history in mature field: Society of Petroleum Engineers SPE-169417-MS, 2014, 11p.

Narr, W., D.W. Schechter, and L.B. Thompson, 2006, Naturally Fractured Reservoir Characterization: SPE Bookstore, 115 p.

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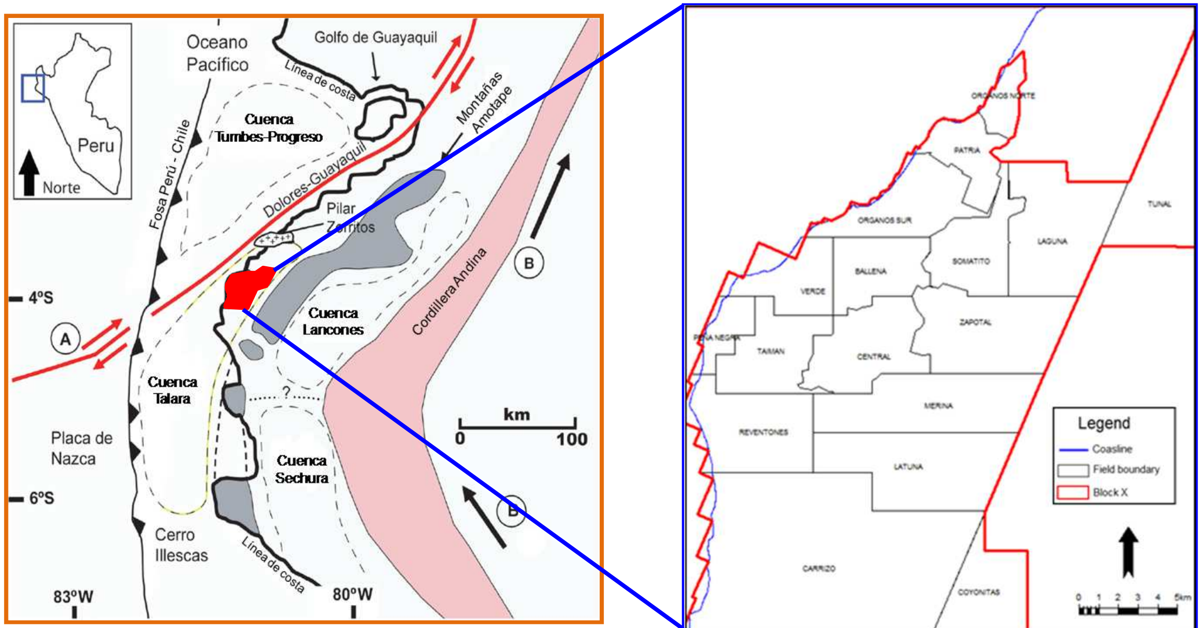
CONSTRUCTION AND CALIBRATION OF A FRACTURED TIGHT RESERVOIR IN A MATURE FIELD

GTW - 2015

J. Marin (Presenter), D. Escobedo

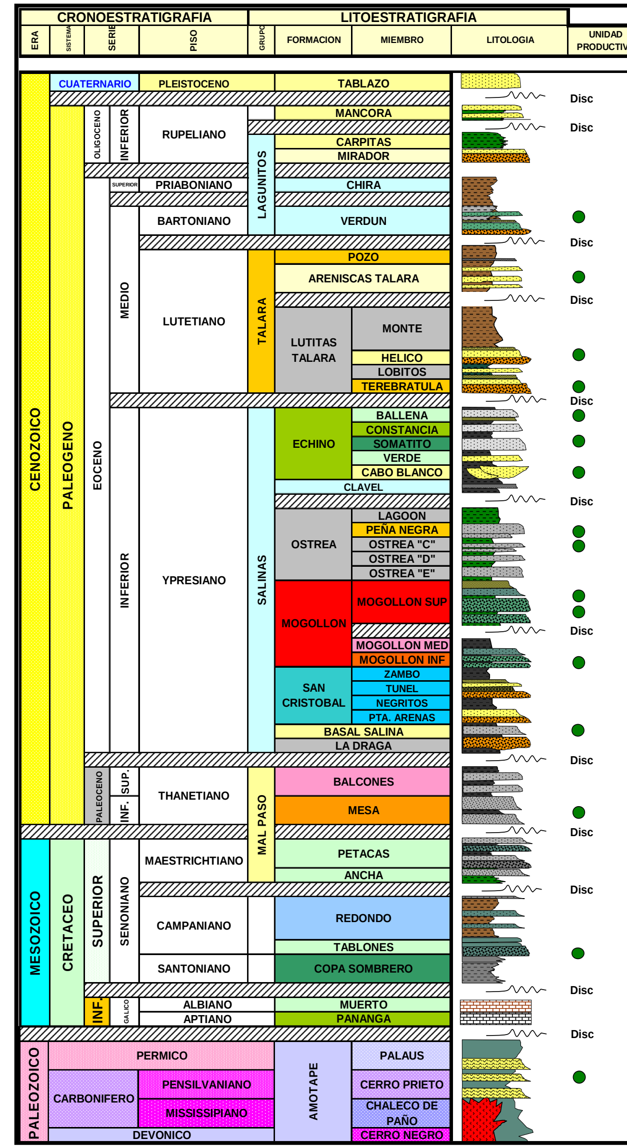
- ✓ Introduction
- ✓ Objectives
- ✓ Available data
- ✓ Identifying fractures
- ✓ Fracture sets characterization
- ✓ Modeling natural fracture networks
- ✓ Validation of the reservoir model
- ✓ Possible drilling strategies
- ✓ Conclusions

Introduction



Talara basin location, tectonic elements and block X (Daudt, 2009)

- ✓ Located in the Talara Basin on Peru's northern coast, Block X has a total extension of 470 km^2 and 3,226 active wells out of over 5,000 total drilled to date.
- ✓ Sedimentary fill of Talara Basin is roughly 9,000 meters thick with main productive intervals of the Eocene period.
- ✓ Talara's stratigraphic column is functionally divided into three depth categories to designate productive reservoirs: Shallow / Intermediate, ***Mogollon*** and Deep.
- ✓ Talara's structure and stratigraphy are highly complex, exhibiting low porosity and permeability.



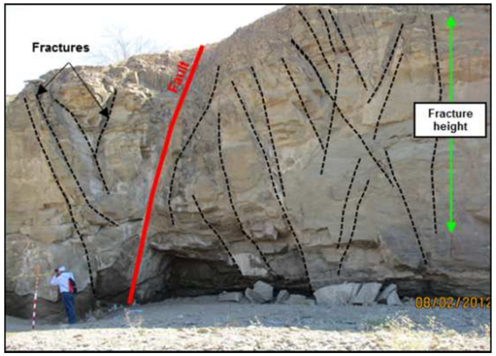
Stratigrraphic column – Talara Basin (Modified by G. Pozo, 2008)

Objectives

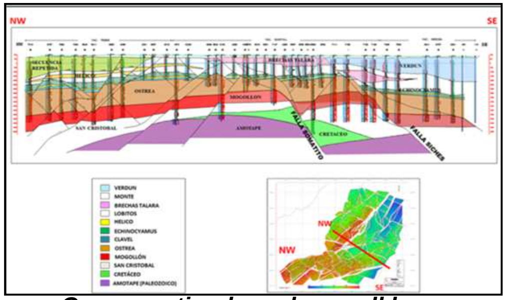
- ✓ Identify the natural fractures and their distribution in a tight reservoir
- ✓ Construction of a fractured tight reservoir model
- ✓ Calibration of the 3D fracture network model with historical production

Available data – Mogollon Fm

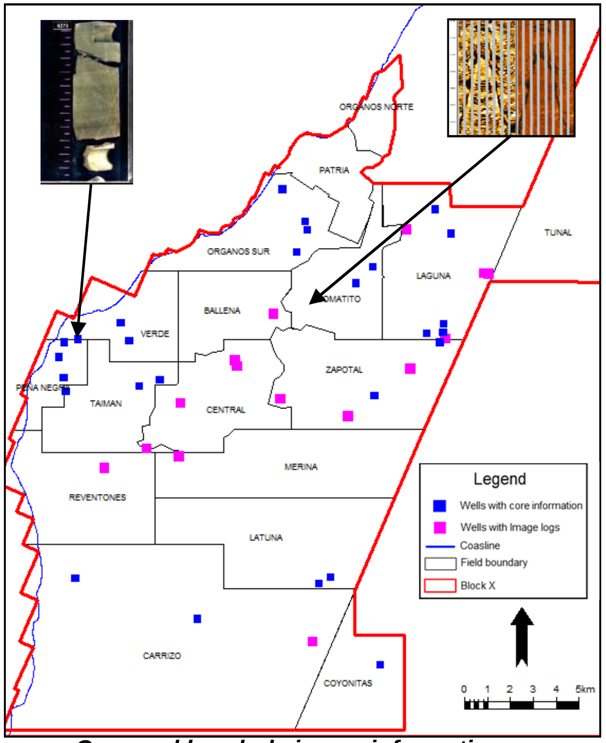
- ✓ Field observations (25 km to the southeast)
- ✓ Structural features: Interpreted cross sections based on well logs
- ✓ Core analysis (stratigraphic and petrophysical studies)
- ✓ Well logs (borehole images)
- ✓ Dynamic data (well testing, production, mud losses)



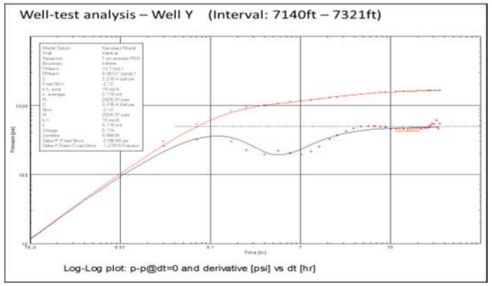
Outcrops of Mogollon Fm.



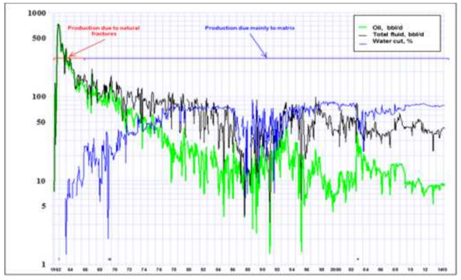
Cross section based on well logs



Core and borehole imaga information

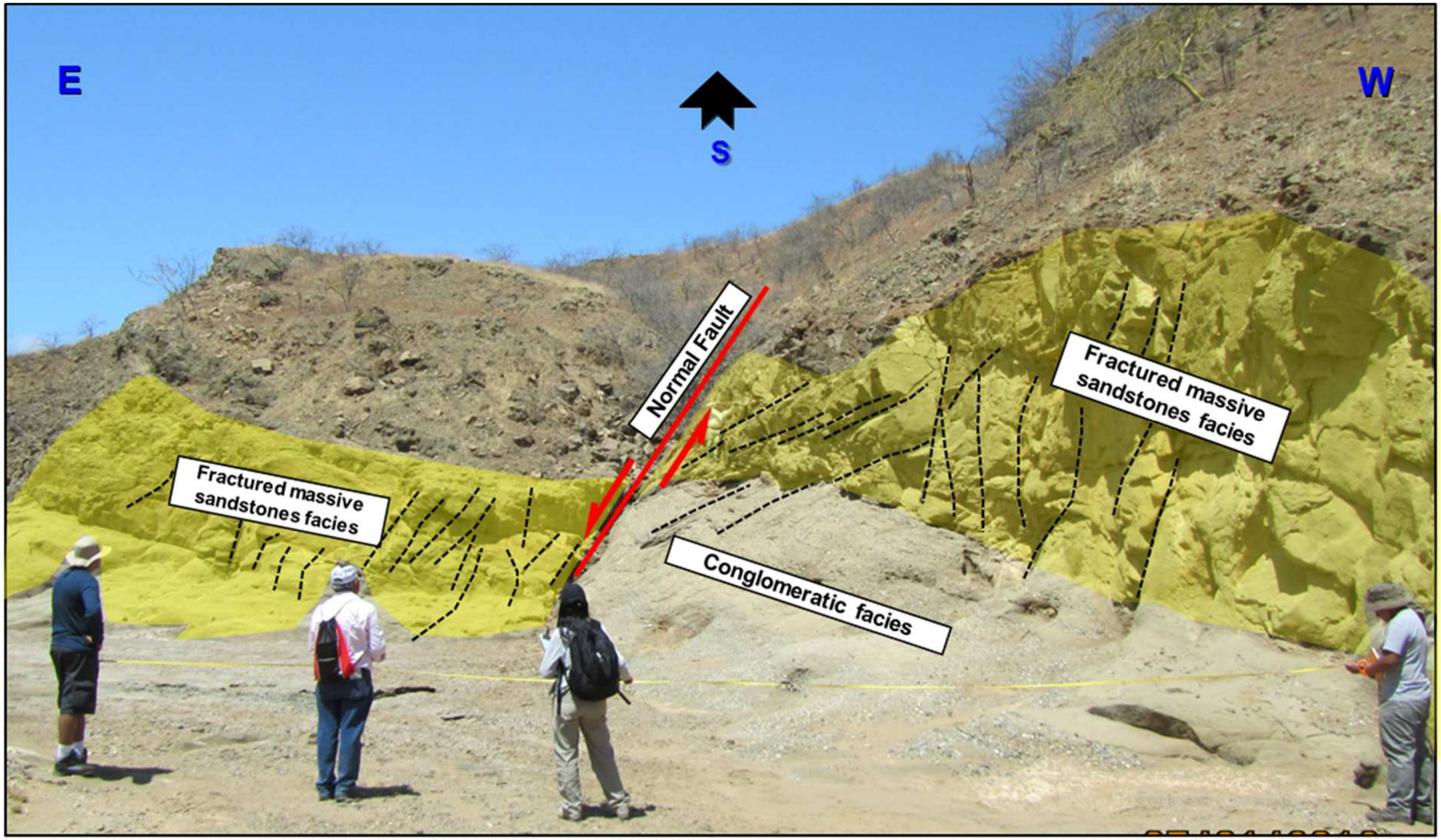


Well testing data



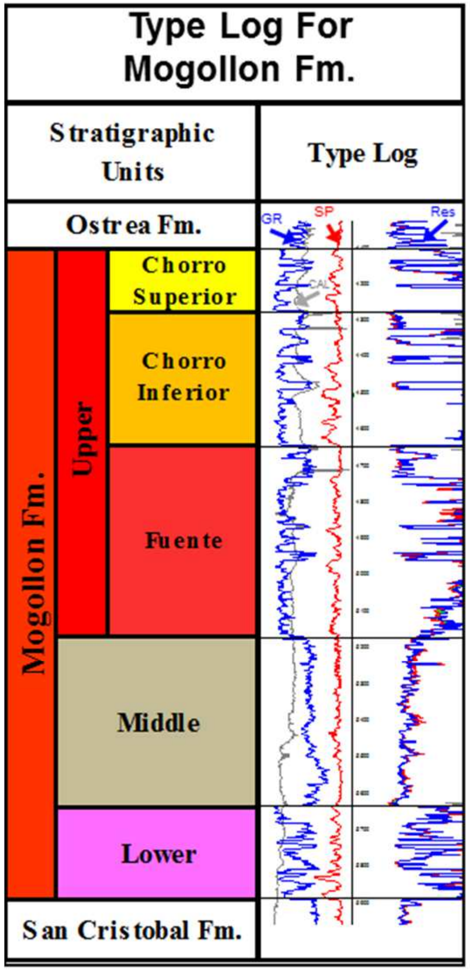
Production data

Identifying fractures – Field observations

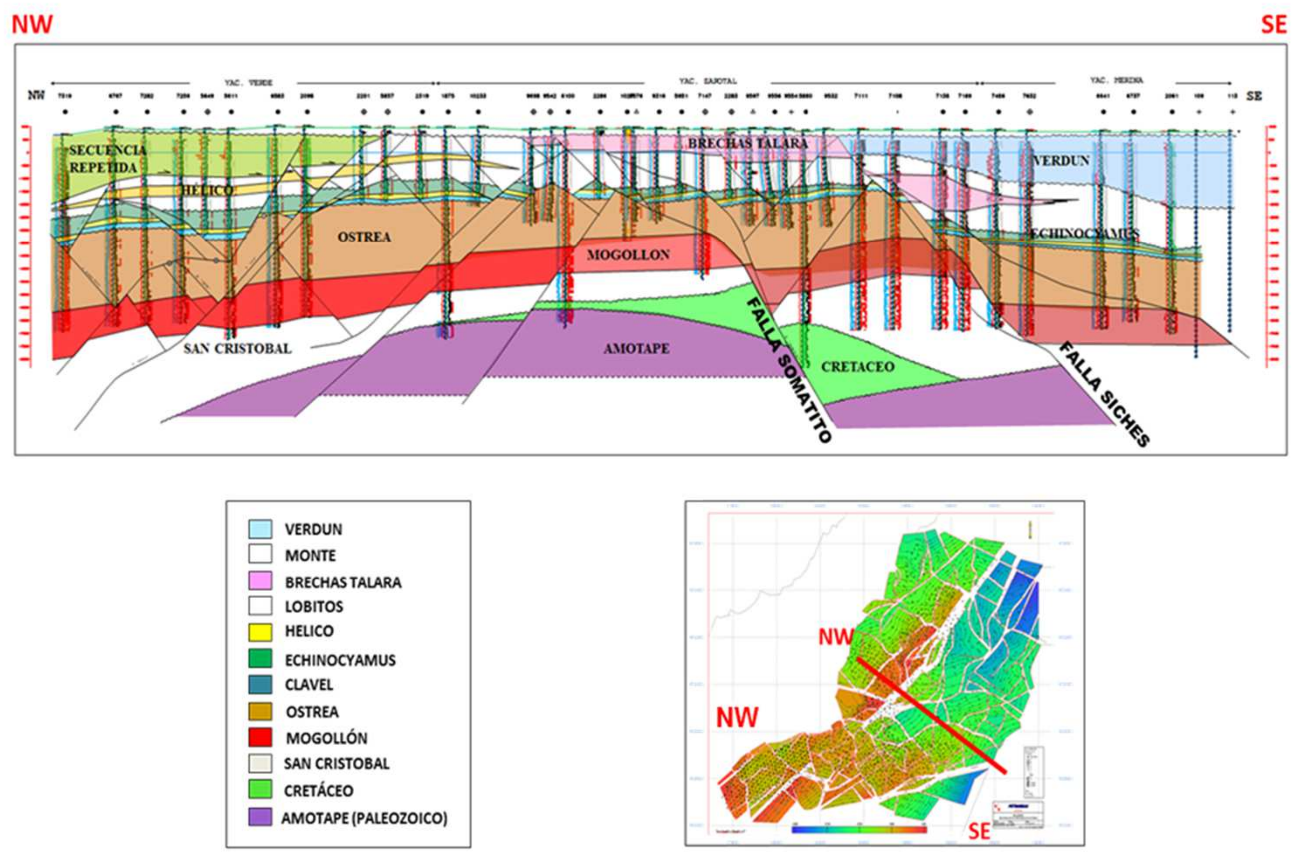


Fractures (dashed black lines) related to normal fault (red line) with azimuth/dip: N340°/50° in Qda. Salado (25 km to the southeast of Block X), Mogollon Formation.

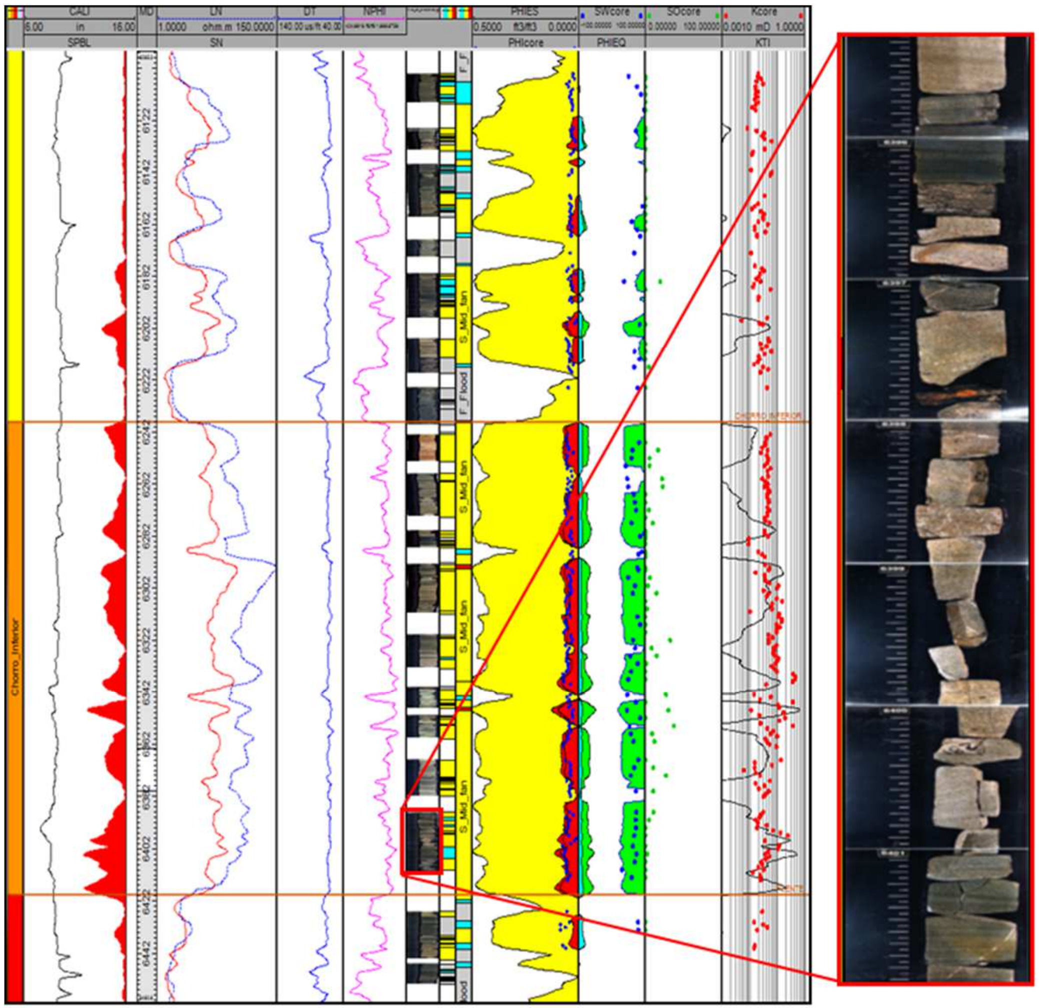
Identifying fractures – Structural features



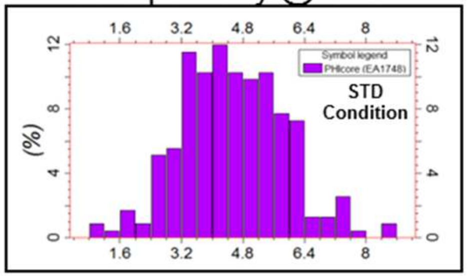
Interpreted structural section based on well logs



Identifying fractures – Core analysis

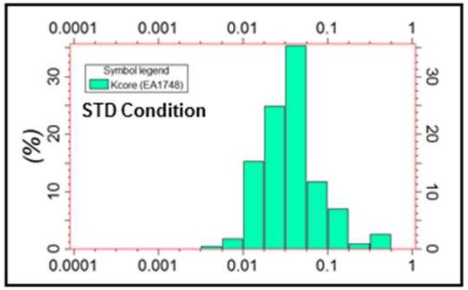


Core porosity @ STD



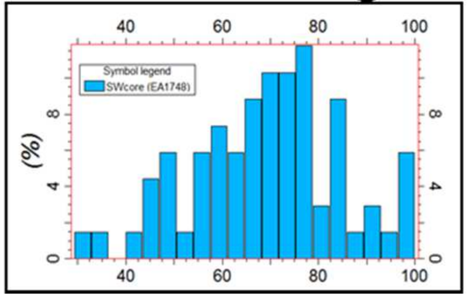
Min: 1.01%
Max: 8.63%
Media: 4.53%
Std. Dev.: 1.79%

Core permeability @ STD



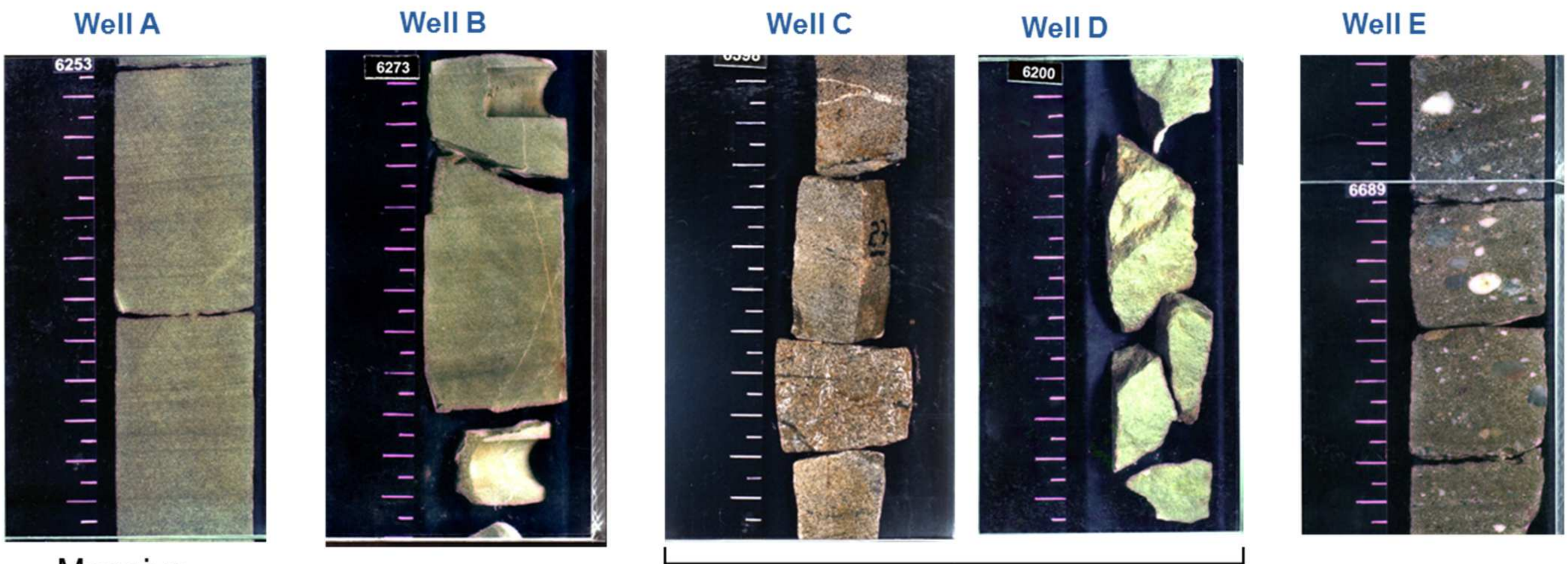
Min: 0.005md
Max: 0.42md
Media: 0.05md
Std. Dev.: 0.06md

Core water saturation @ STD



Min: 29.26%
Max: 100%
Media: 78.56%
Std. Dev.: 26.37%

Identifying fractures – Core analysis



Massive Sandstone with no visible fractures

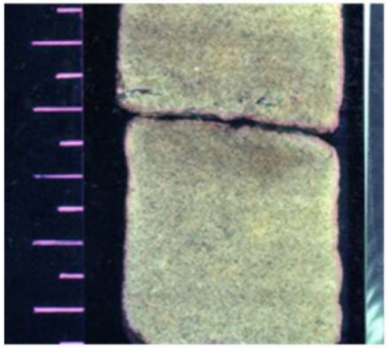
Fractures filled with calcite in sandstones

High fracturing in sandstones

Conglomerate

Identifying fractures – Core analysis

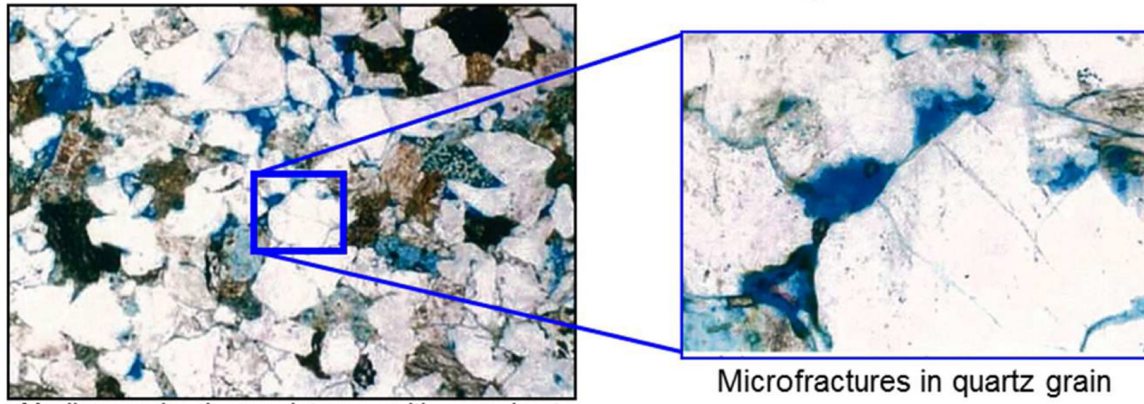
Well A



Depth : 6330 ft
Porosity : 5.76 %] @ 2800 psi
Kgas: 0.0331 md]

Magnification 40X

Magnification 200X

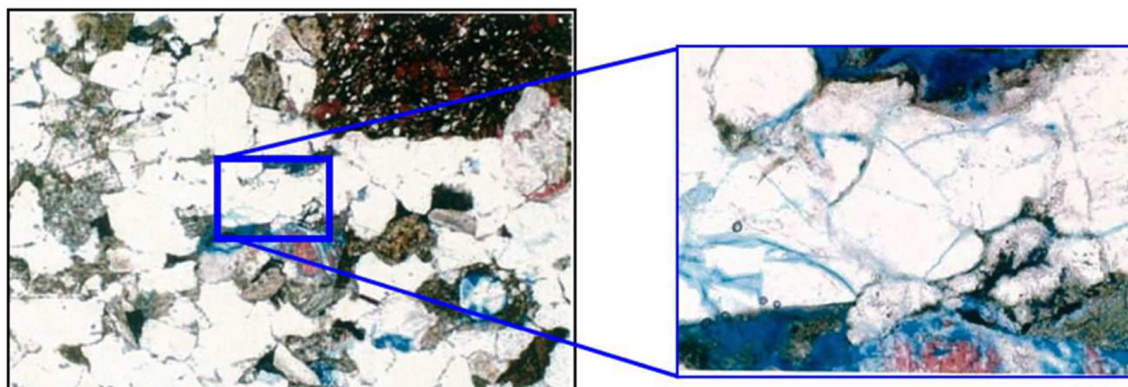


Medium-grained sandstone with moderate grain sorting. Secondary porosity is present (dissolution and microfracutres).

Microfractures in quartz grain

Well B

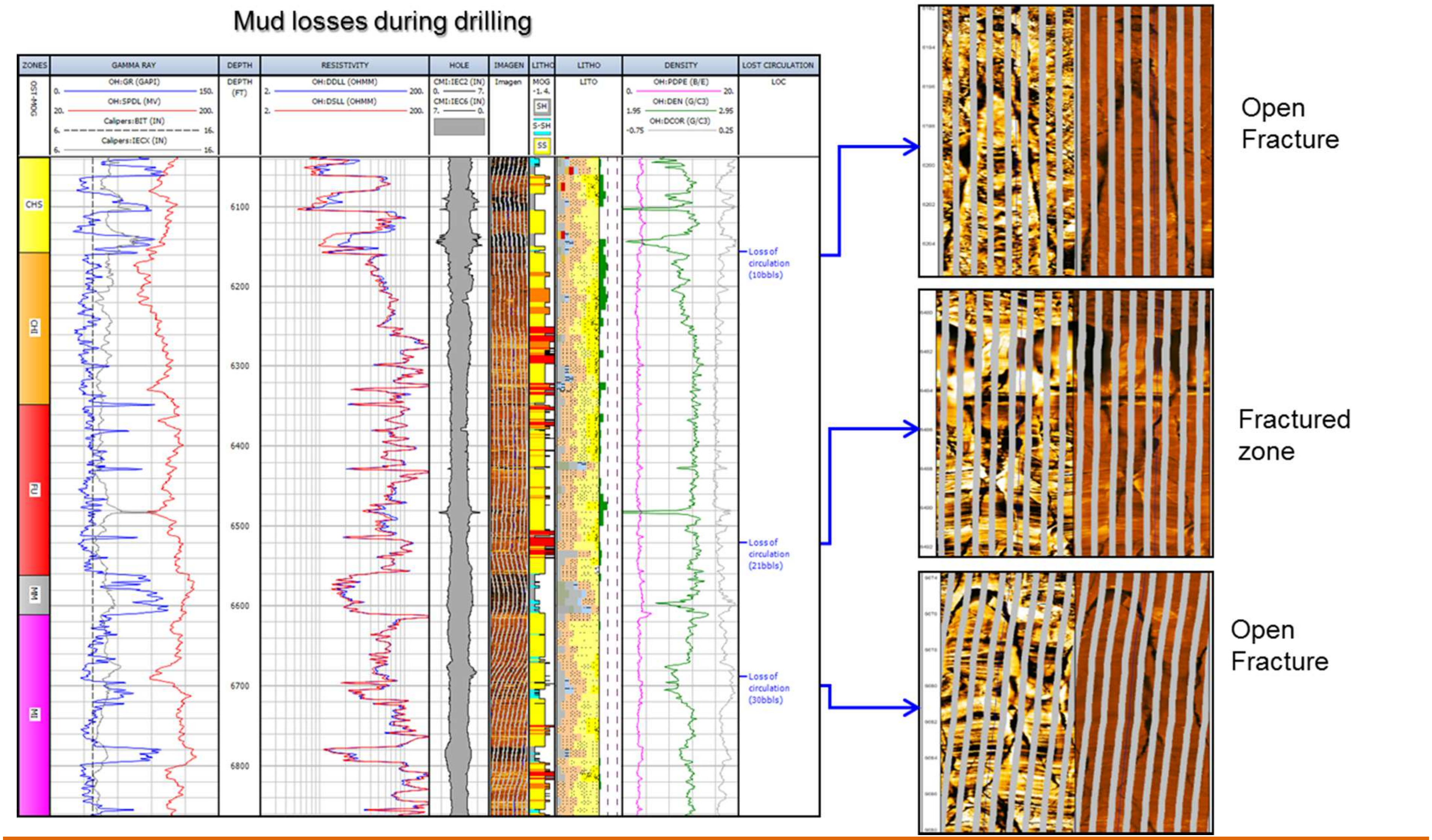
Depth : 6356 ft
Porosity : 4.57 %] @ 2800 psi
Kgas: 0.0079 md]



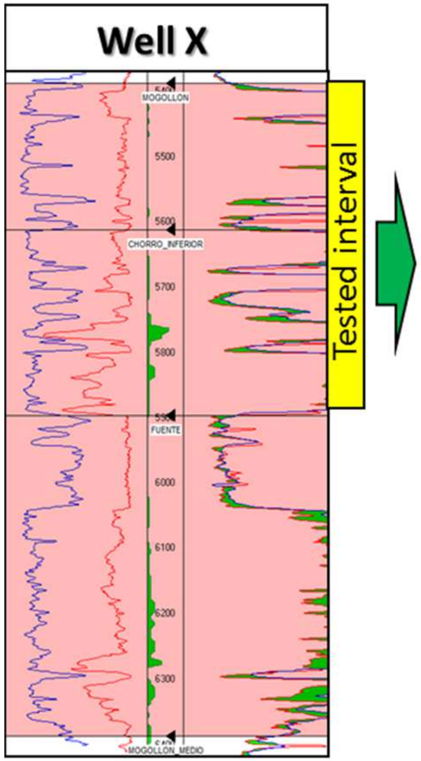
Moderately poorly sorted, medium grained sandstone.

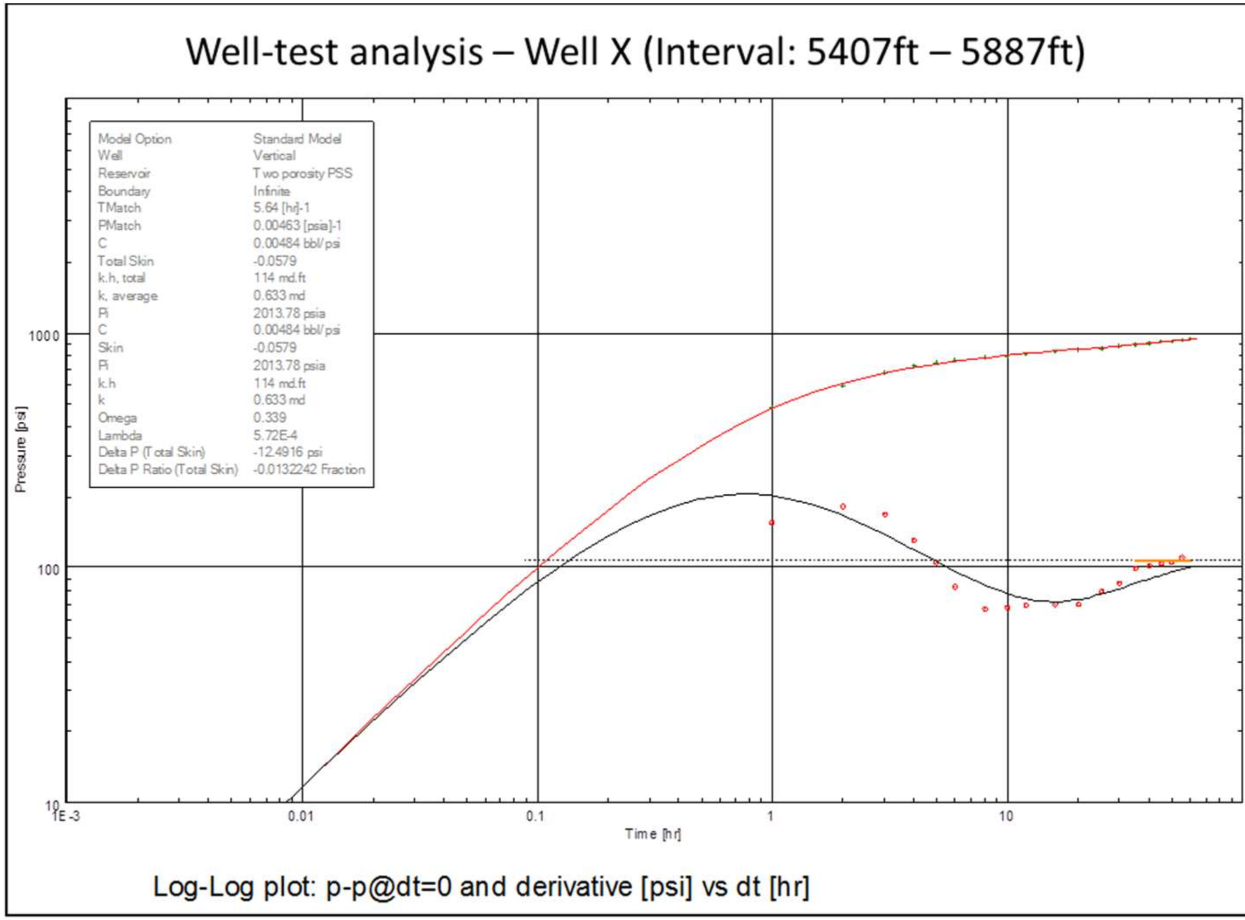
Secondary porosity: dissolution and microfractures

Identifying fractures – Borehole image log



Identifying fractures – Dynamic data

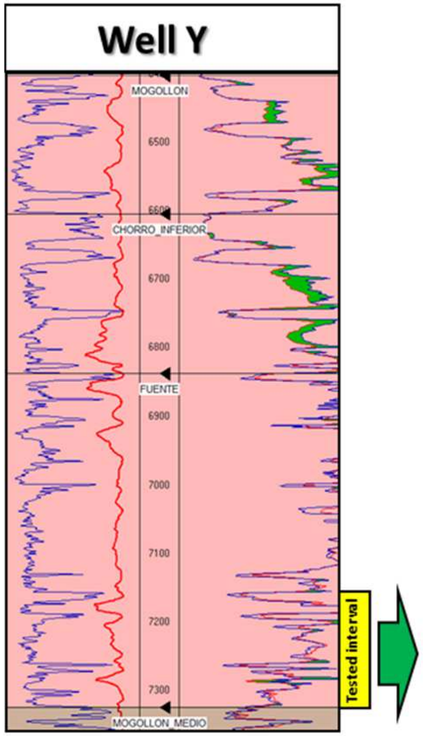




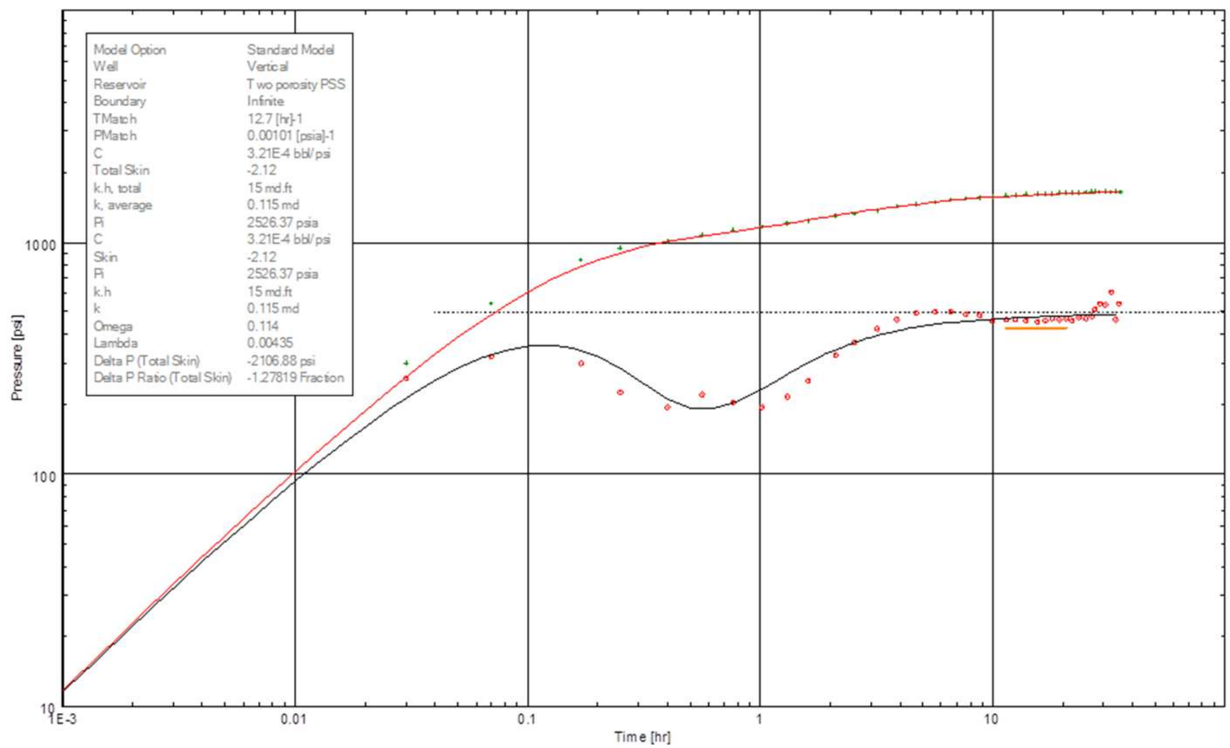
Data for tested interval
Hn = 60
Phi = 0.063
Sw = 0.581
K = 0.051

KH from well test interpretations (md.ft)	114
KH from logs (md.ft)	3.1
FCI: Fracture capacity index (Narr et al., 2006)	37.3

Identifying fractures – Dynamic data



Well-test analysis – Well Y (Interval: 7140ft – 7321ft)

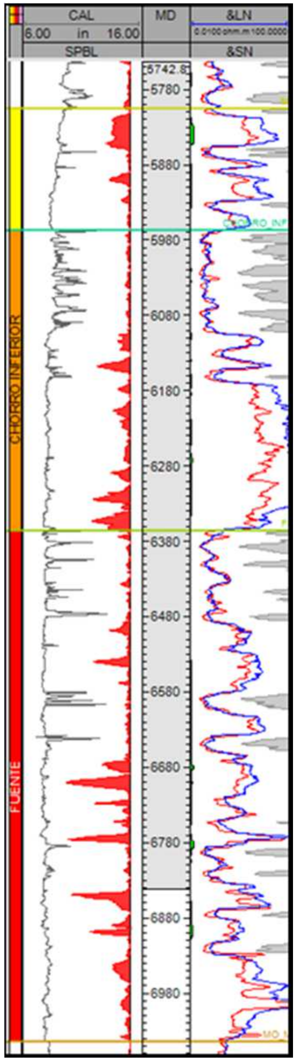


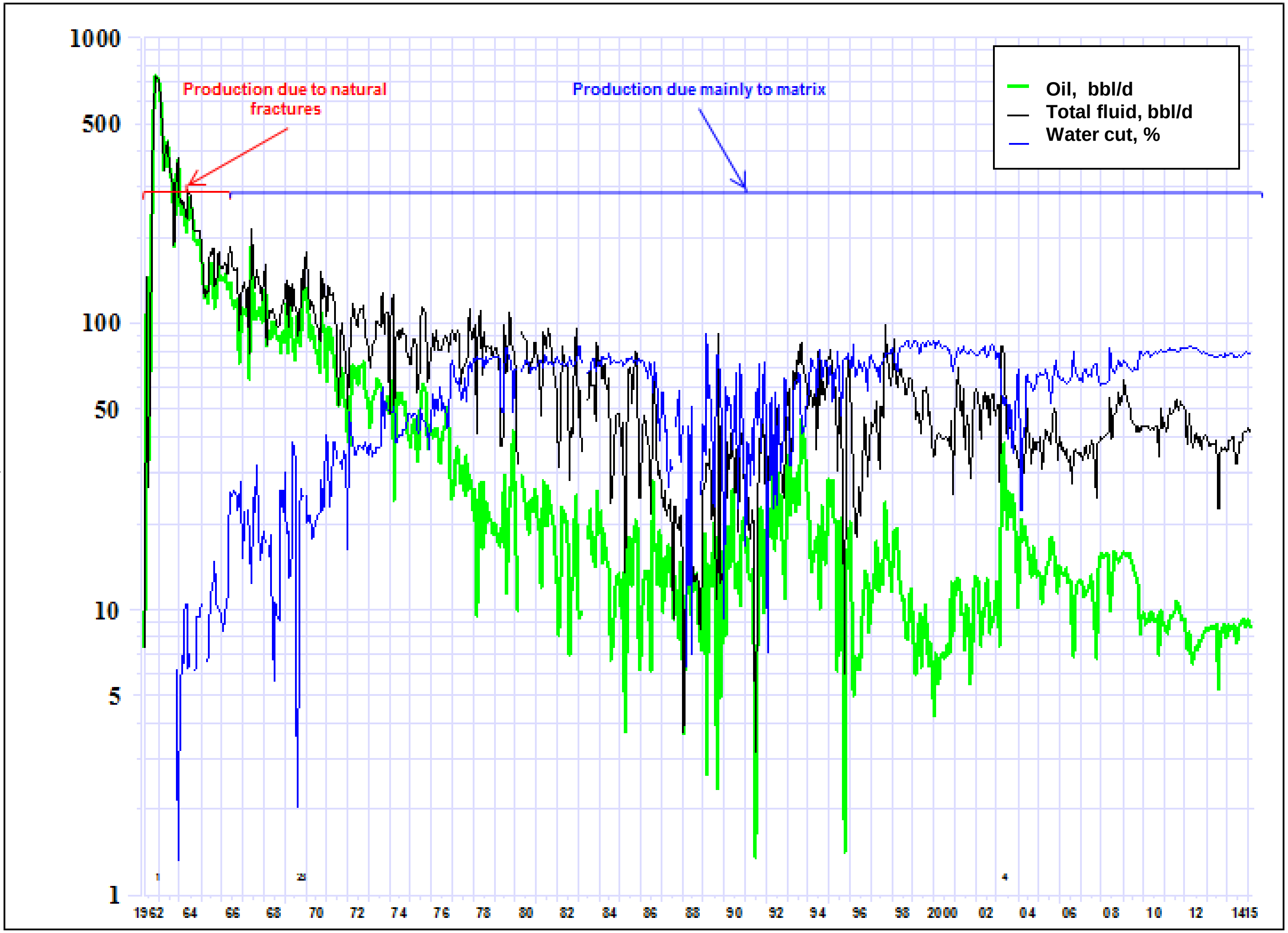
Log-Log plot: p-p@dt=0 and derivative [psi] vs dt [hr]

Data for tested interval
Hn = 20
Phi = 0.051
Sw = 0.593
K = 0.035

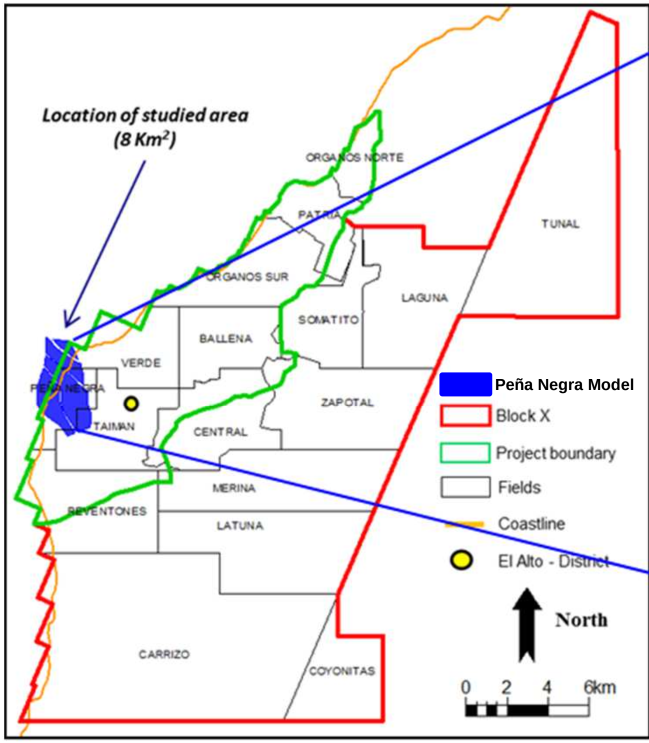
KH from well test interpretations (md.ft)	15
KH from logs (md.ft)	0.70
FCI: Fracture capacity index (Narr et al., 2006)	21.4

Identifying fractures – Dynamic data

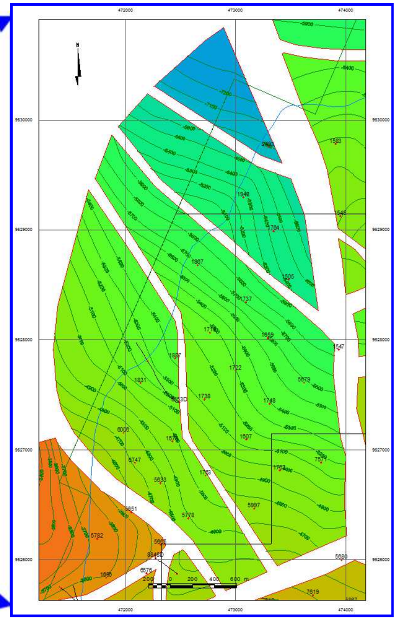




Fracture sets characterization – Case study: Peña Negra



Location of the studied area

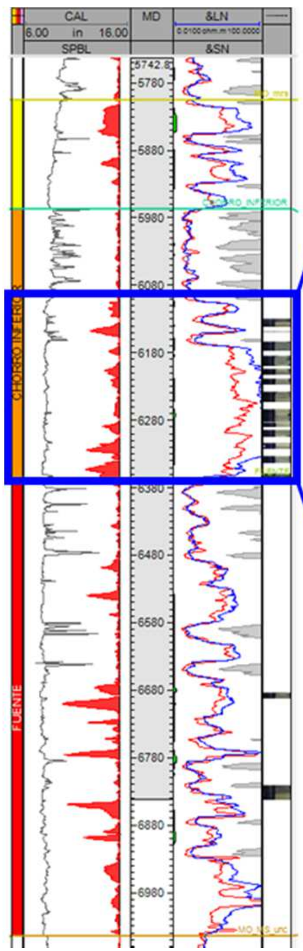


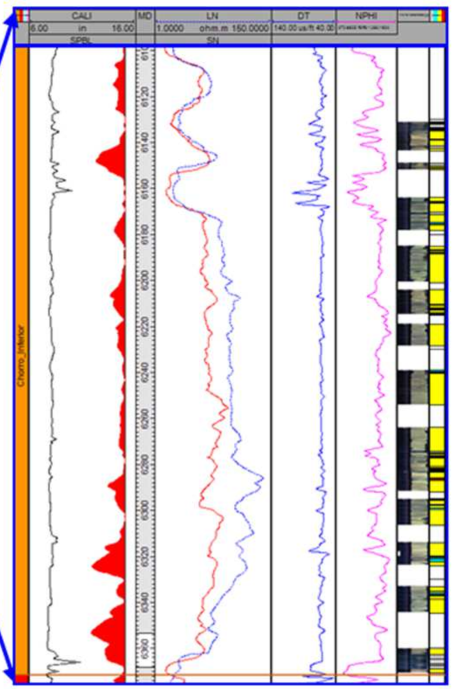
Structure map of the project

Parameters involved in the fracture characterization:

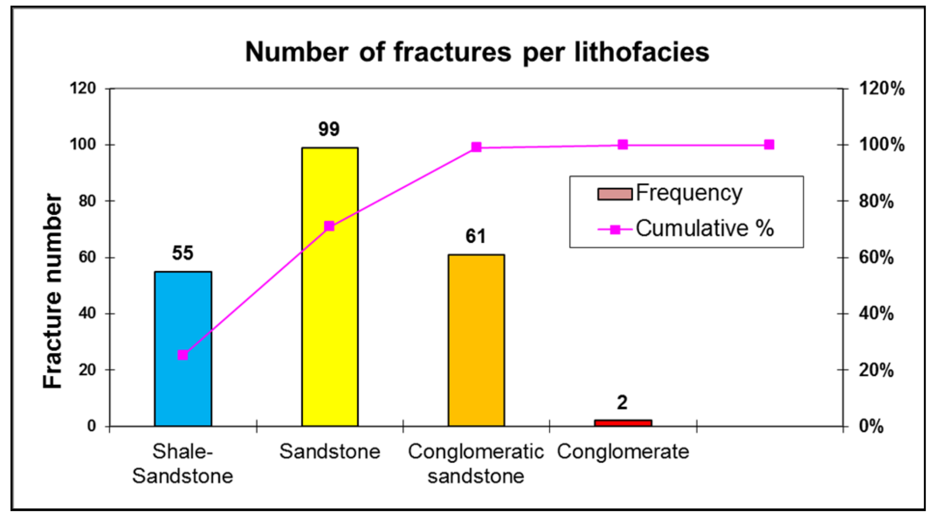
- ✓ **Distribution (lithofacies, fracture type, and intensity)**
- ✓ **Orientation (strike and dip angle of fractures)**
- ✓ **Geometry**
- ✓ **Aperture**

Fracture sets characterization – Fractures in lithofacies

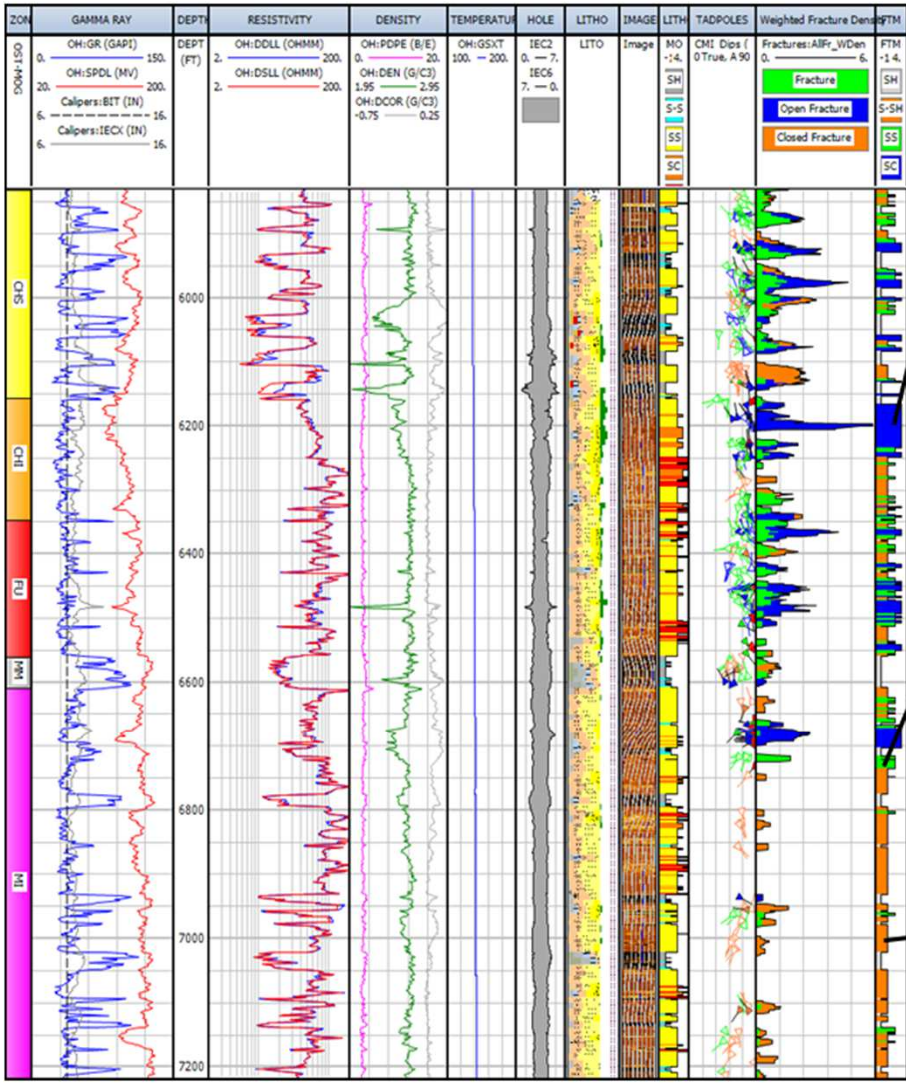


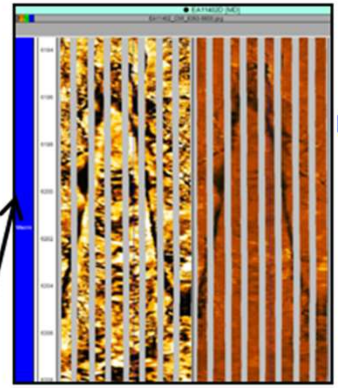


Core data in Chorro Inferior



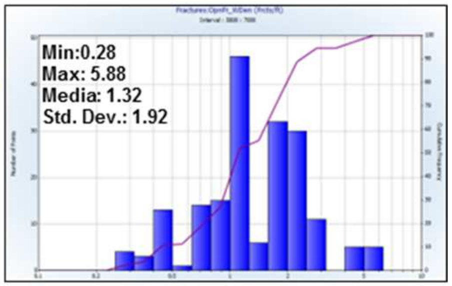
Fracture sets characterization – Fracture type classification

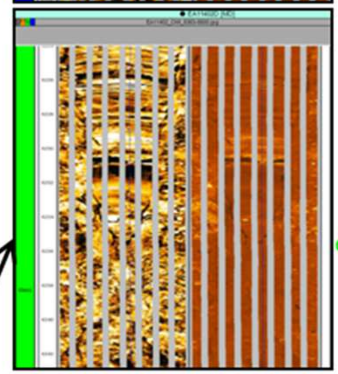




High fracturing and open fractures

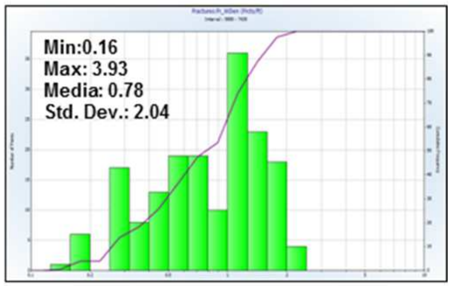
Fracture Intensity Histrogram

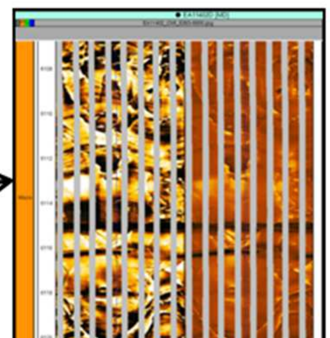




Moderate fracturing and partially open fractures

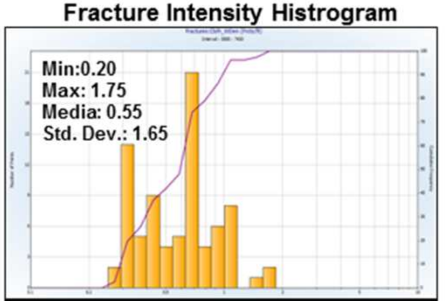
Fracture Intensity Histrogram



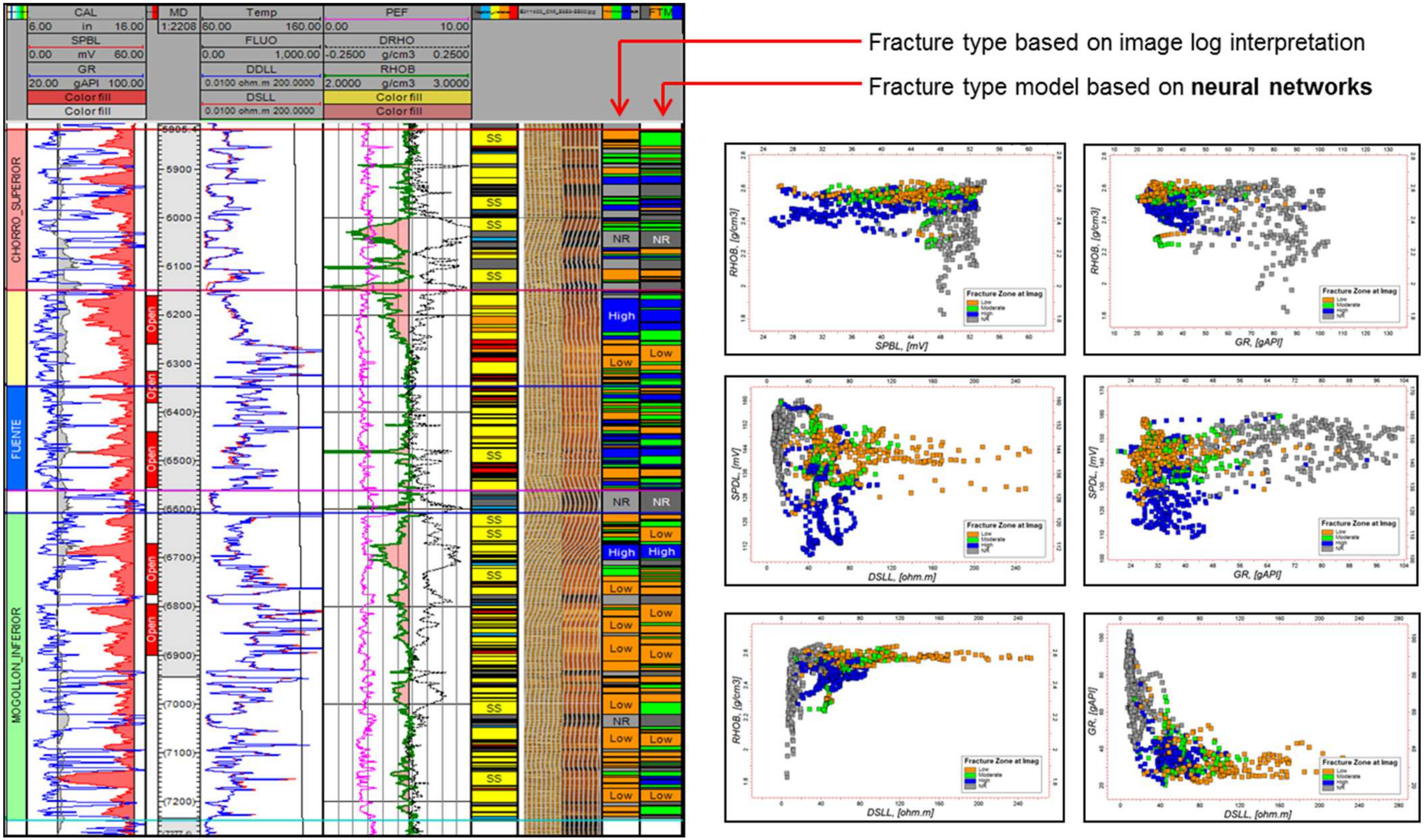


No fractures or closed fractures

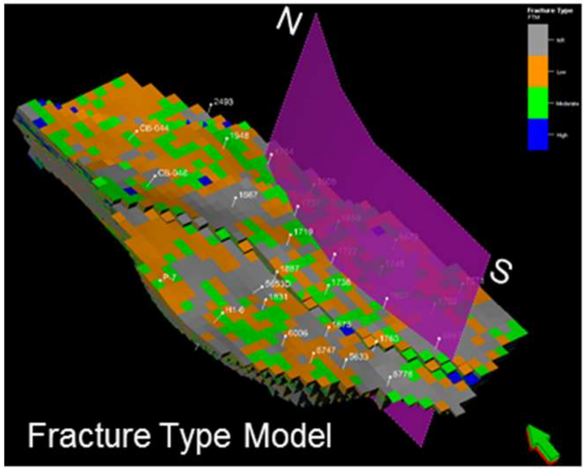
Fracture Intensity Histrogram

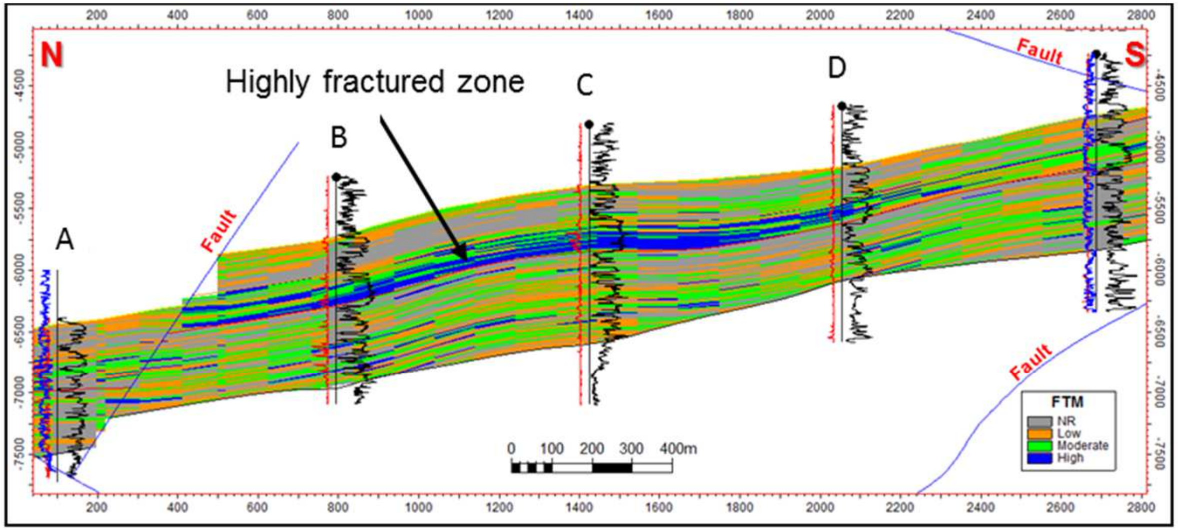


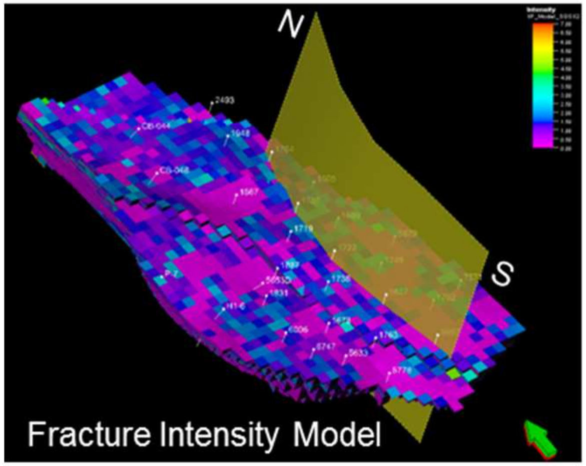
Fracture sets characterization – Fracture type classification

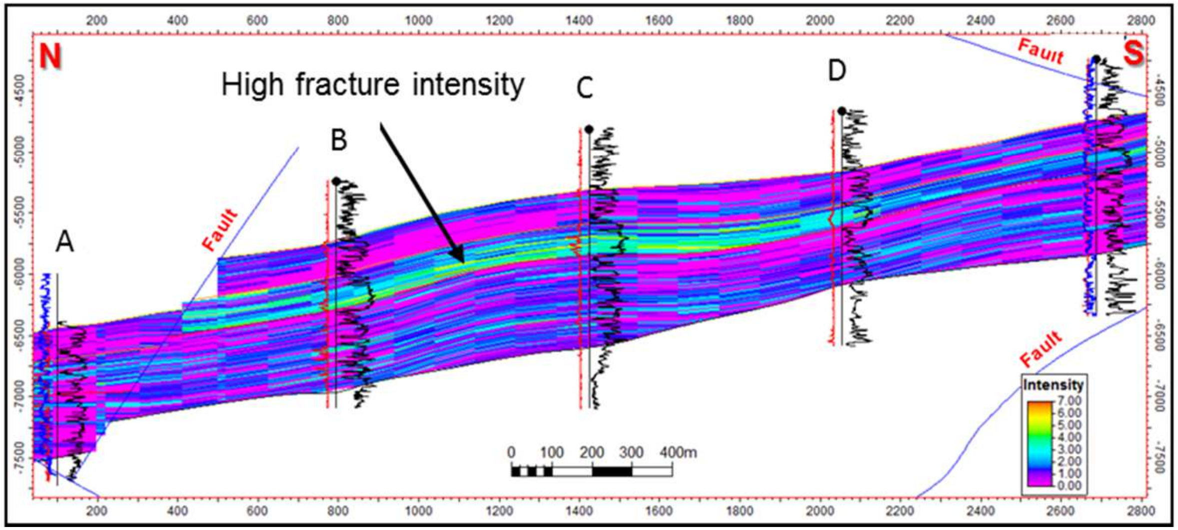


Fracture sets characterization – Fracture type & Intensity



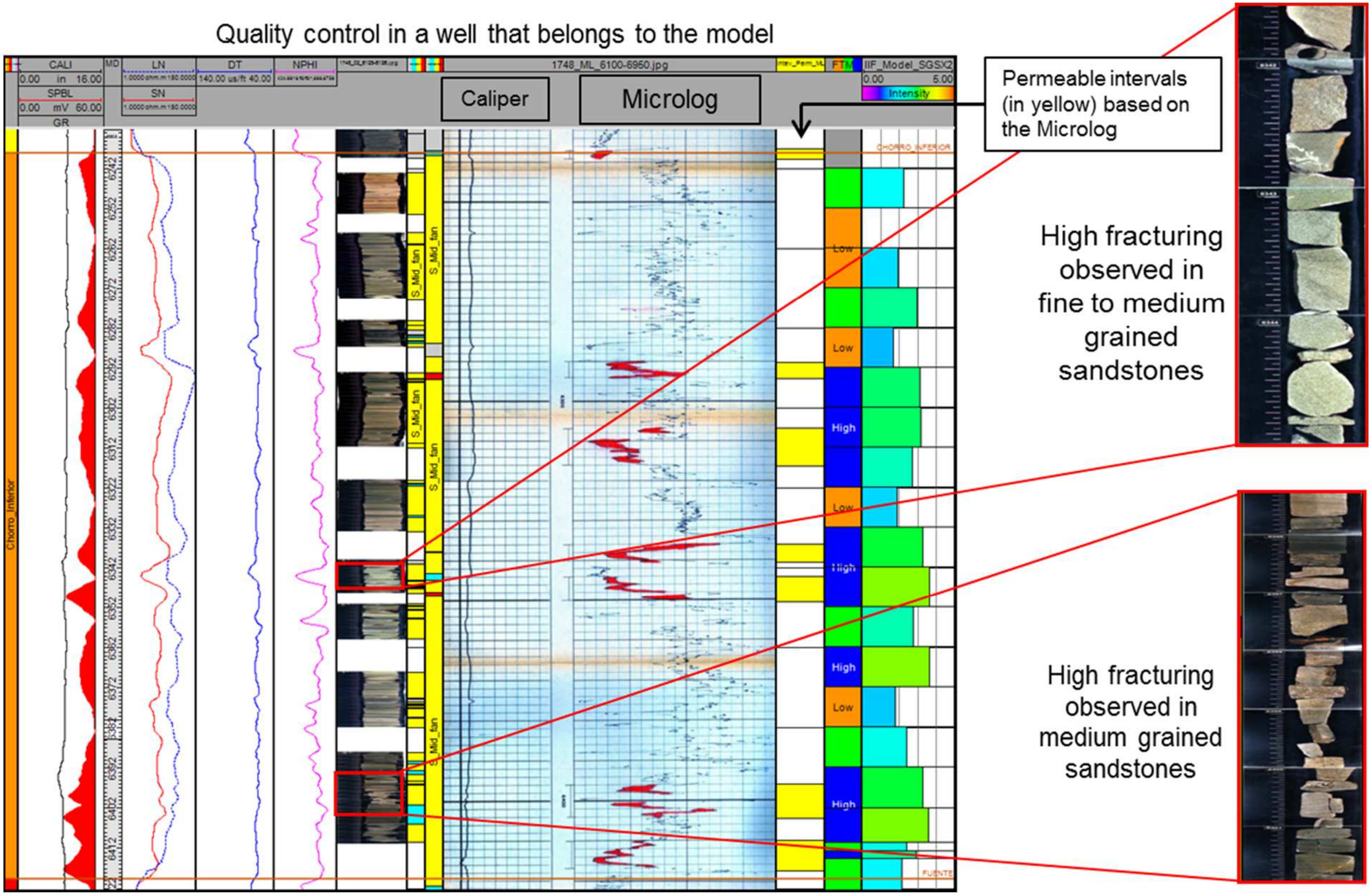






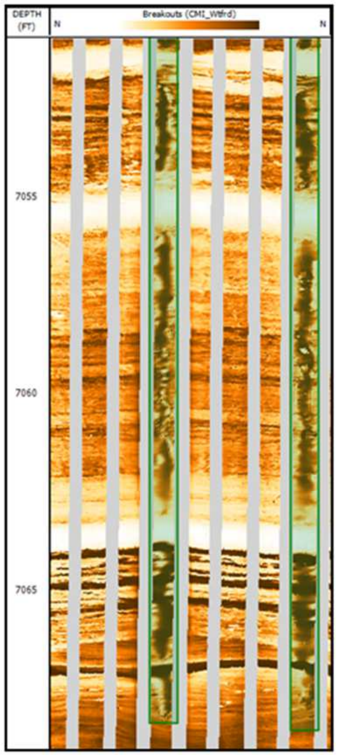
Fracture sets characterization – Fracture type & Intensity

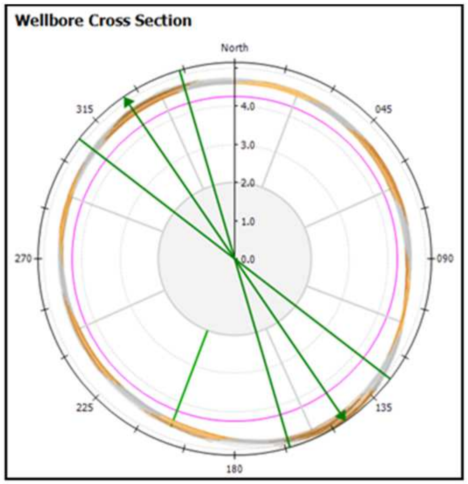
Quality control in a well that belongs to the model

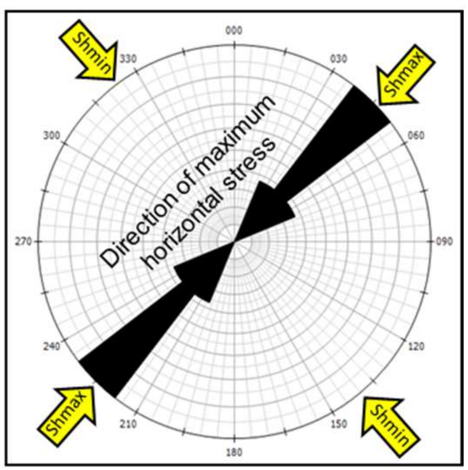


Fracture sets characterization – Stress Orientation

Breakout analysis

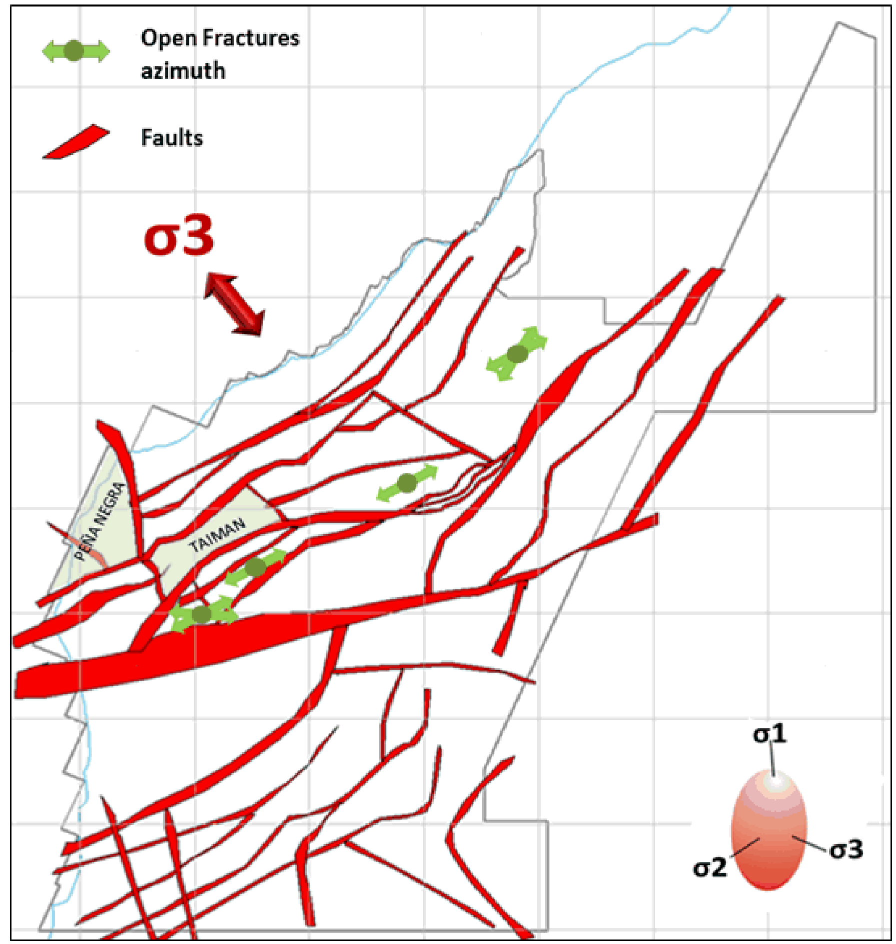






Breakout data
Depth: 7058 ft
Dip angle: 85°
Dip Azimuth: 326°
Width: 36°
Height 20.6 ft

Fracture system – Upper Mogollon



Source: E. Bustamante, 2013

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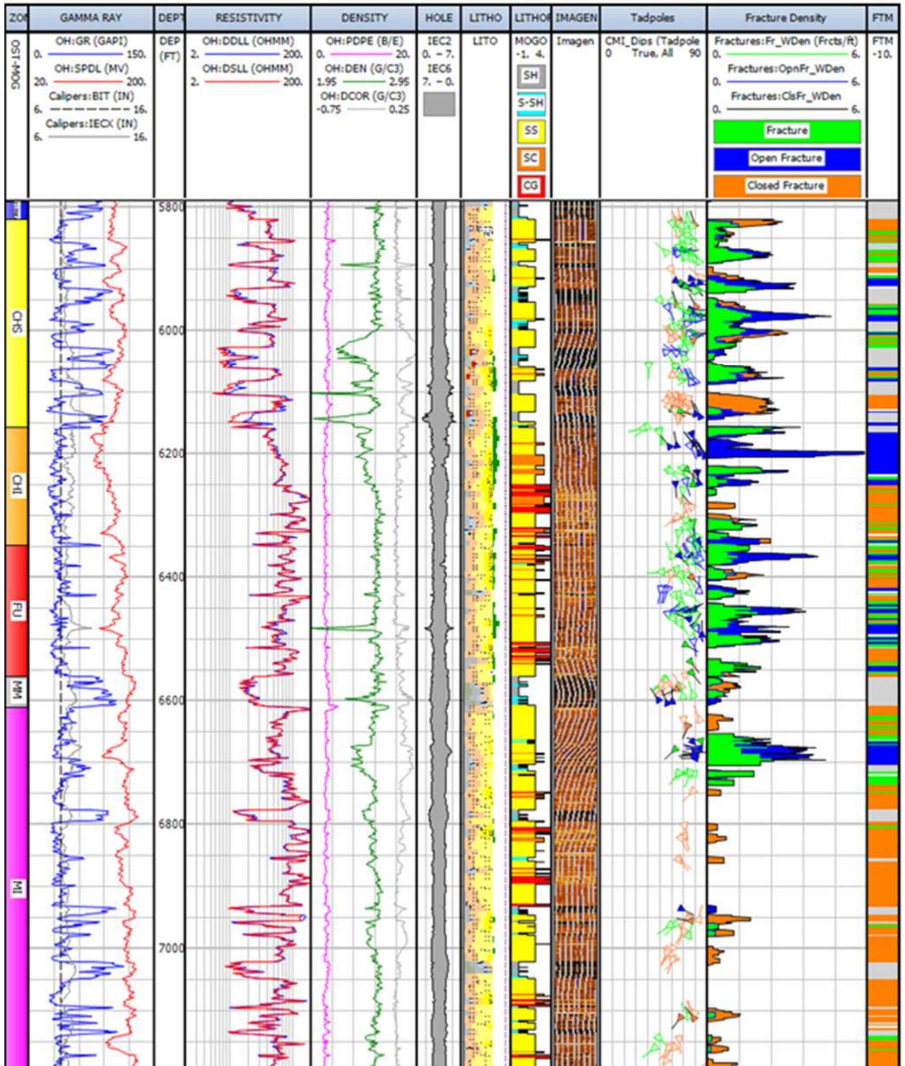
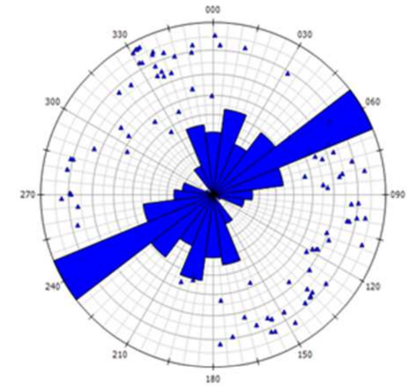
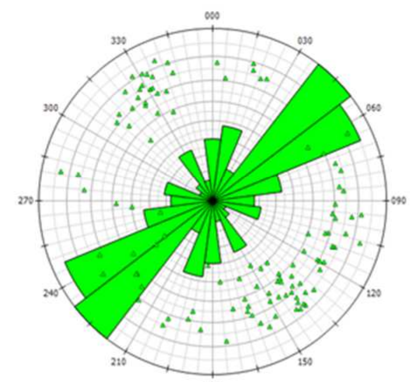
Fracture sets characterization – Fracture Orientation





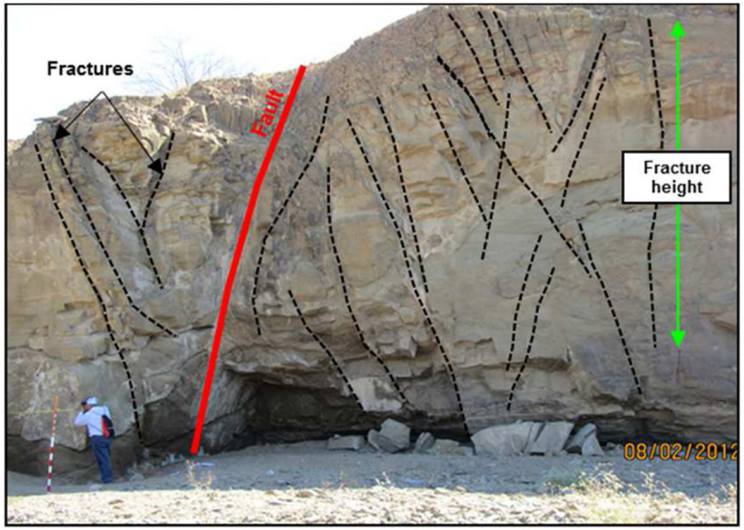
Open Fractures
Number of sets: 2
Strike: N50°E
Dip Angle: 65°
Data: 90 picks displayed

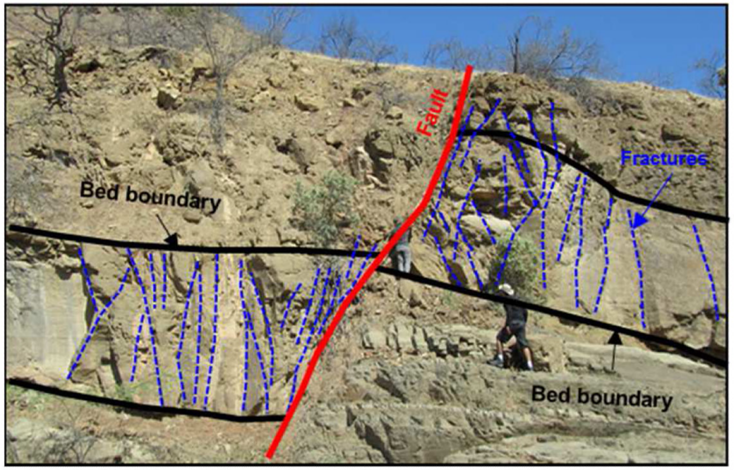


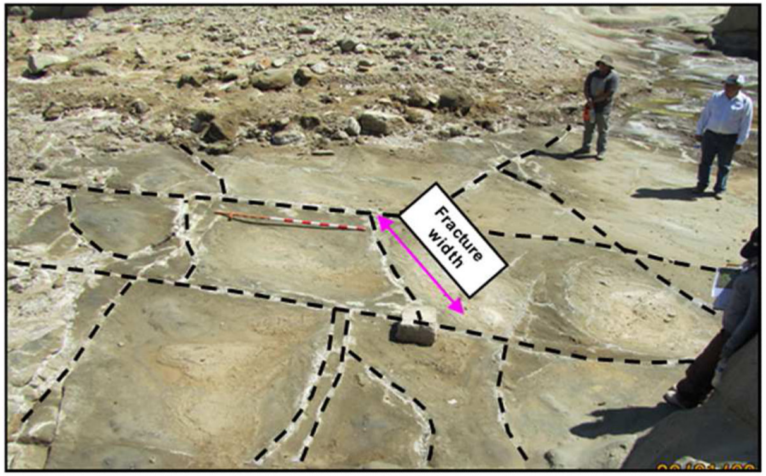
Partially Open Fractures
Number of sets: 2
Strike: N50°E
Dip Angle: 70°
Data: 112 picks displayed

Fracture sets characterization – Geometry

- ✓ Length of fractures were determined from outcrops in Qda Salado. Fractures with great extent are mainly vertical to sub-vertical. A power law was assumed.



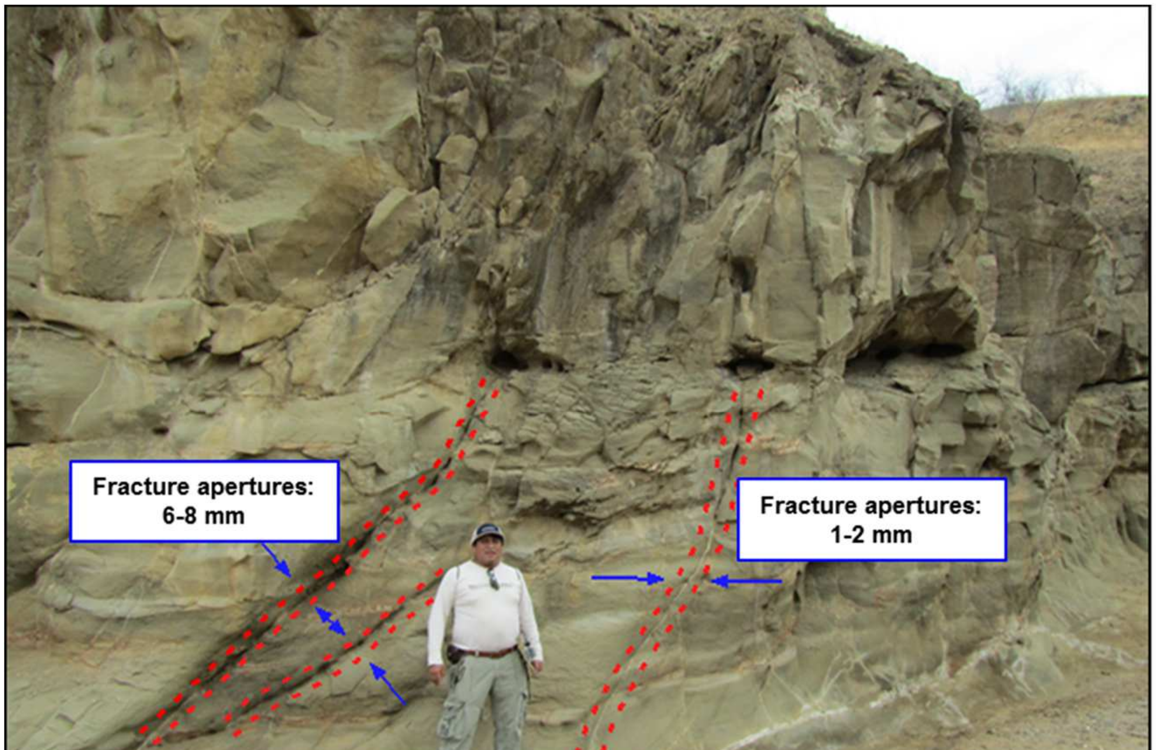




Mogollon Fm. in Qda Salado showing the geometry of the natural fractures

Fracture sets characterization – Aperture

✓ Apertures were measured in outcrops, cores and image logs. A log-normal distribution was given to the model.

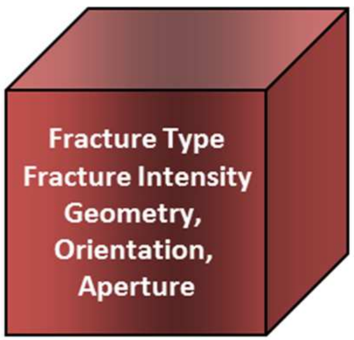


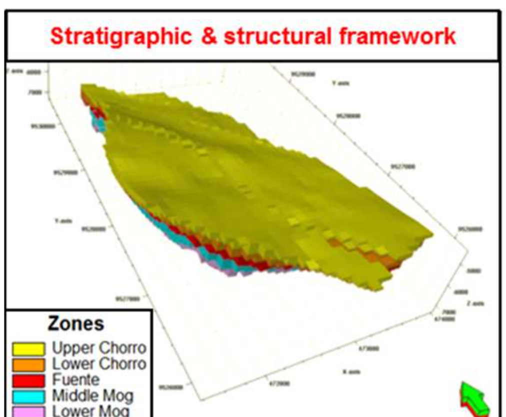
Qda Salado (Mogollon Formation)

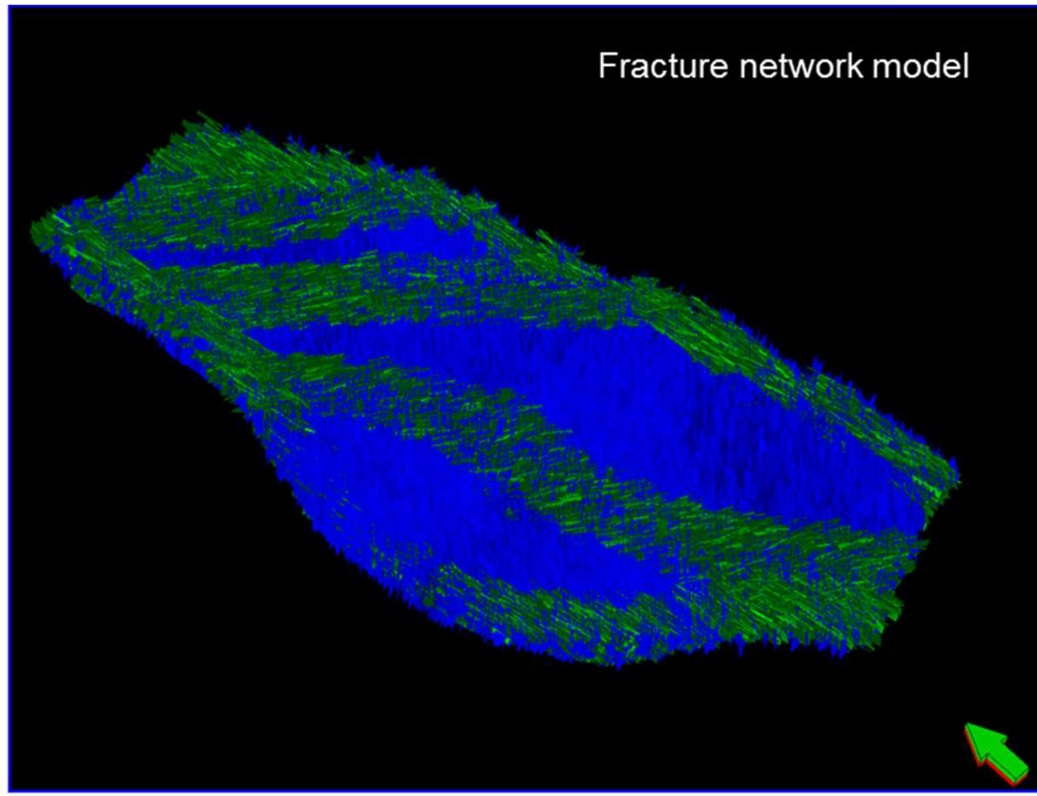
Fracture apertures from image log: Aproximately 5-6 mm

Modeling natural fracture networks

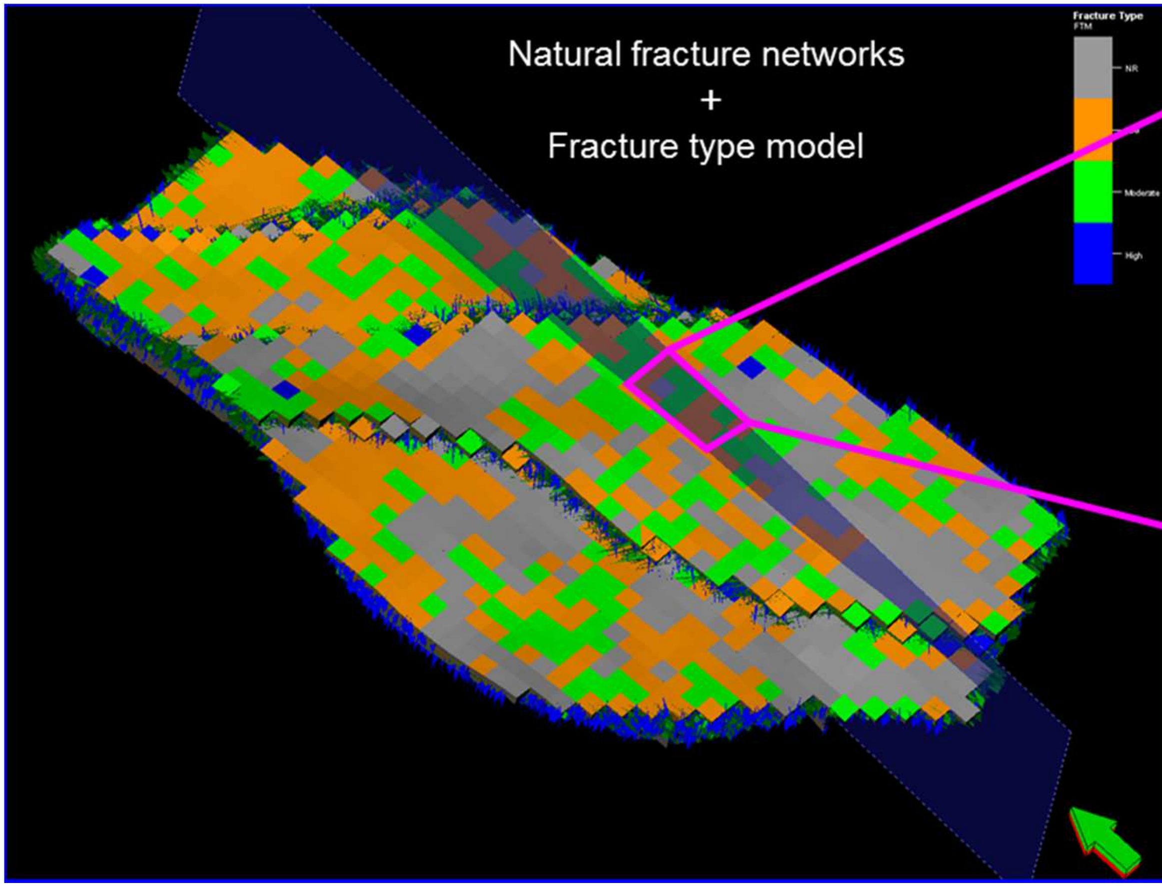
Fracture parameter for modeling natural fracture networks						
Fracture type model	Characteristics	Mean fracture density (#Fract/ft)	Orientation		Mean Length (m)	Mean Aperture (mm)
Moderate	Facies with partially open fracture and moderate fracture density	0.78	Main Strike	N50°E	80	0.61 mm
			Main Dip angle	65°		
High	Facies with Open fractures and high fracture density	1.32	Main Strike	N°50°E	80	1.83 mm
			Main Dip angle	70°		

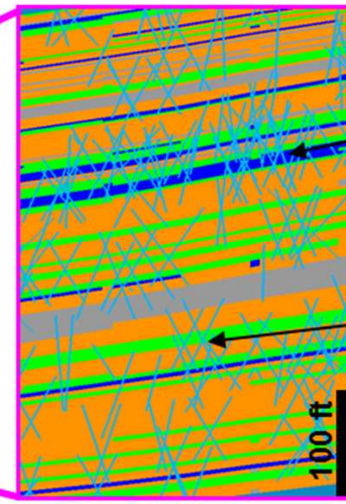






Modeling natural fracture networks

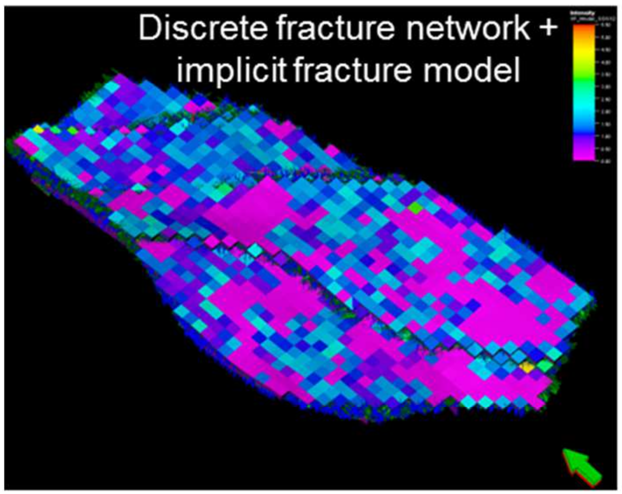


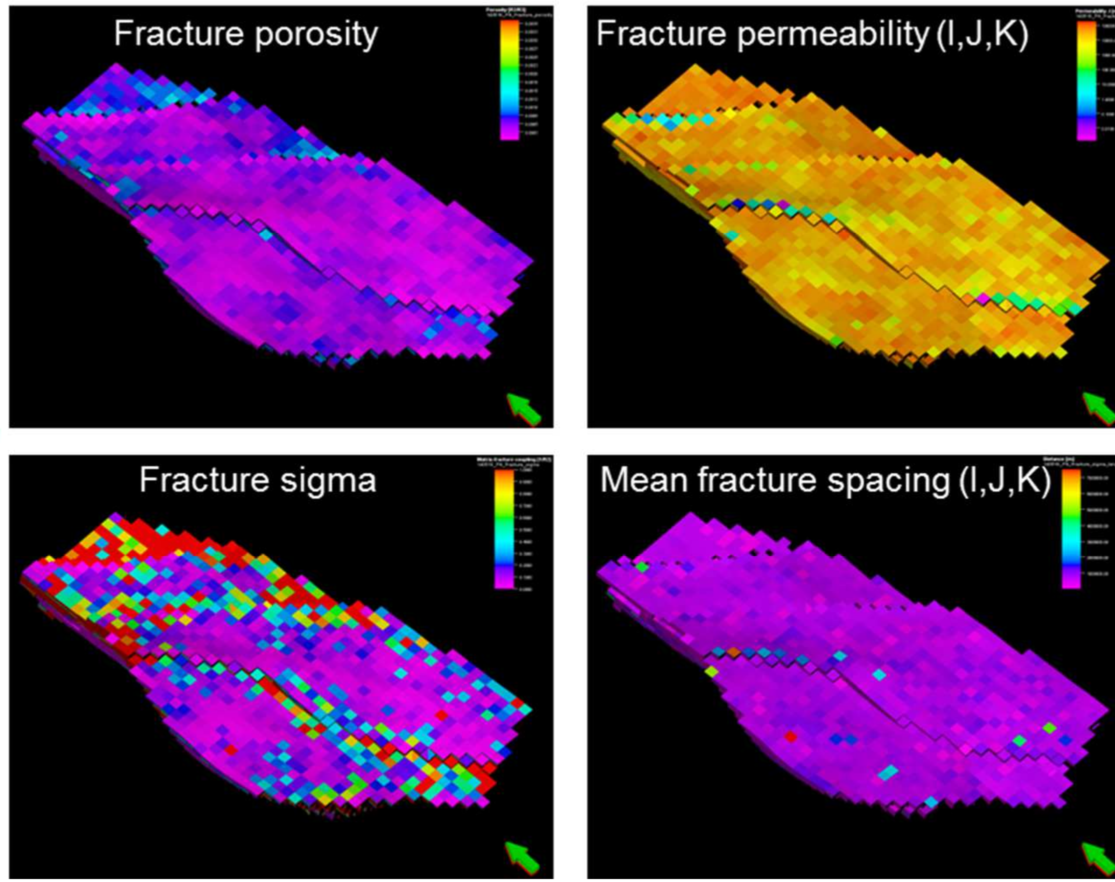


DFN model for fractures, showing the control of fracture types classification on fracture density.

Modeling natural fracture networks - Upscaling

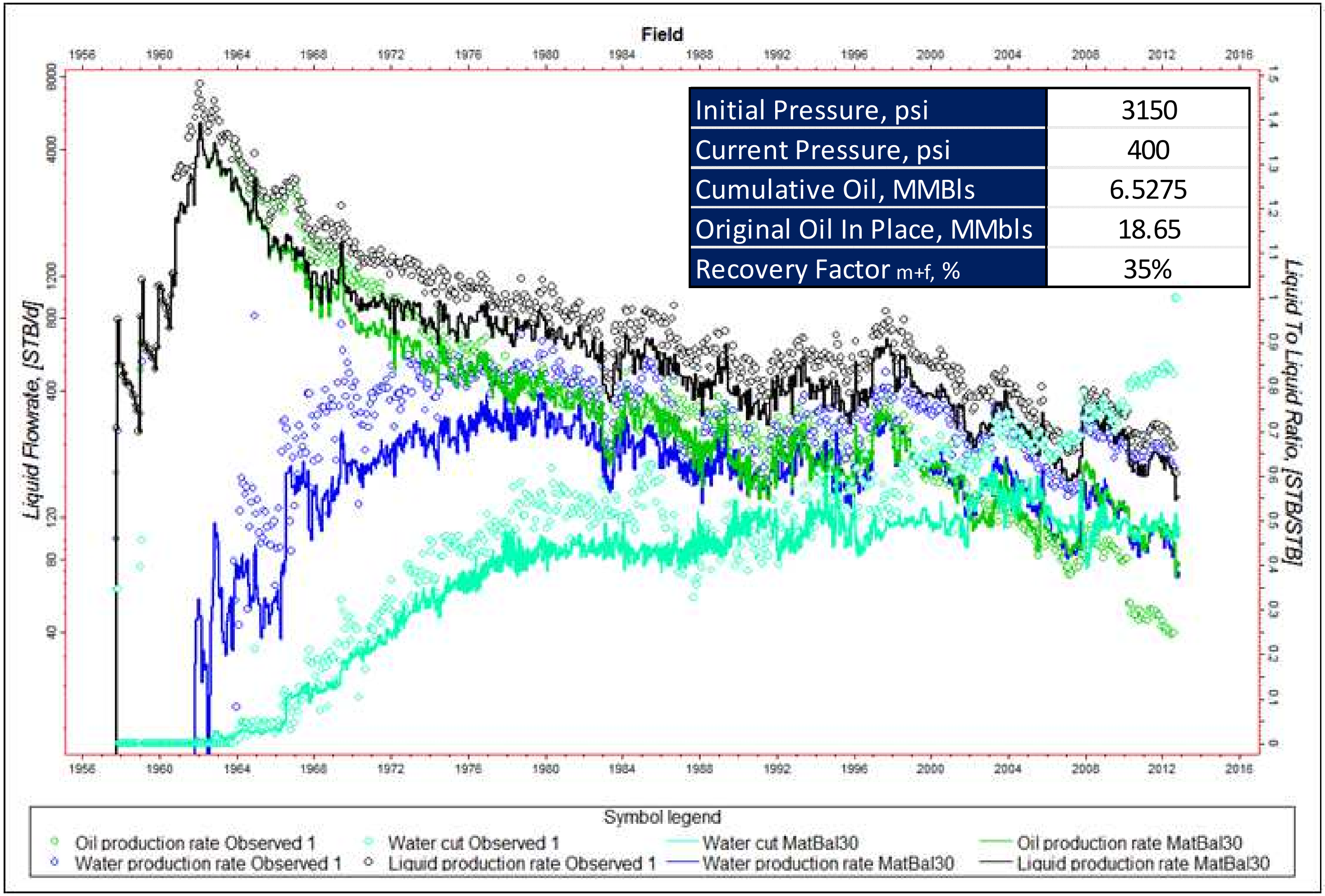
Upscaled fracture network attributes for simulation purposes





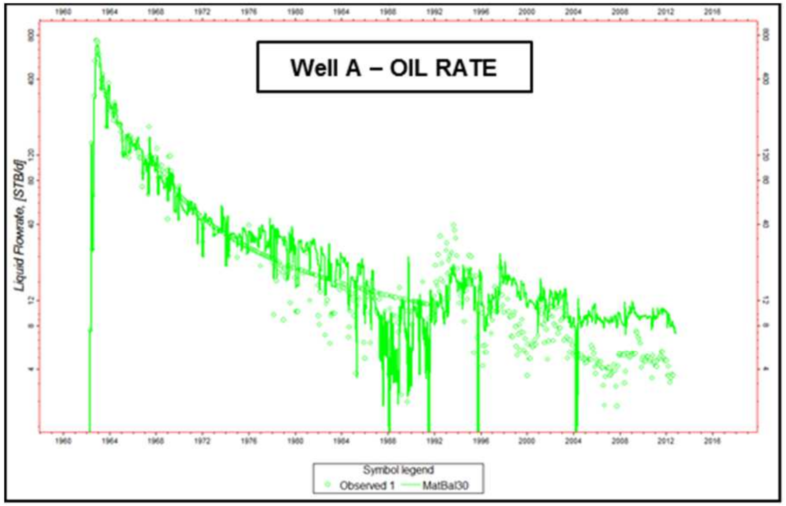
Validation of the reservoir model – History match for the whole model

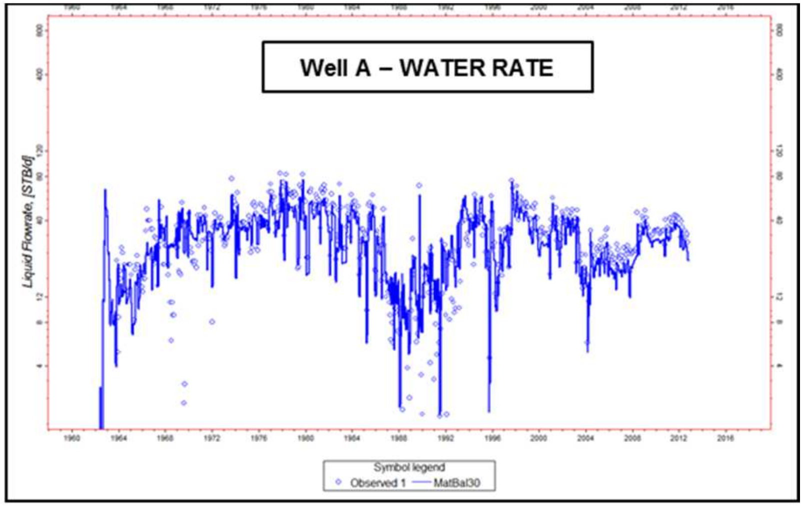
Initial history matching results for the Peña Negra model

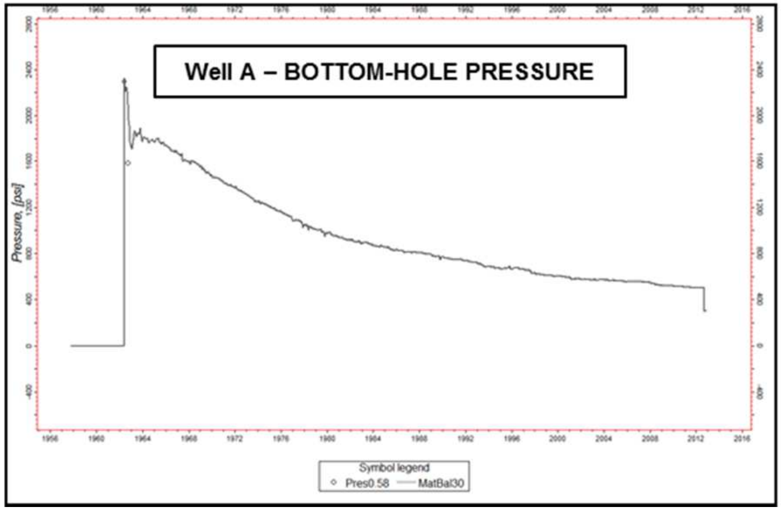


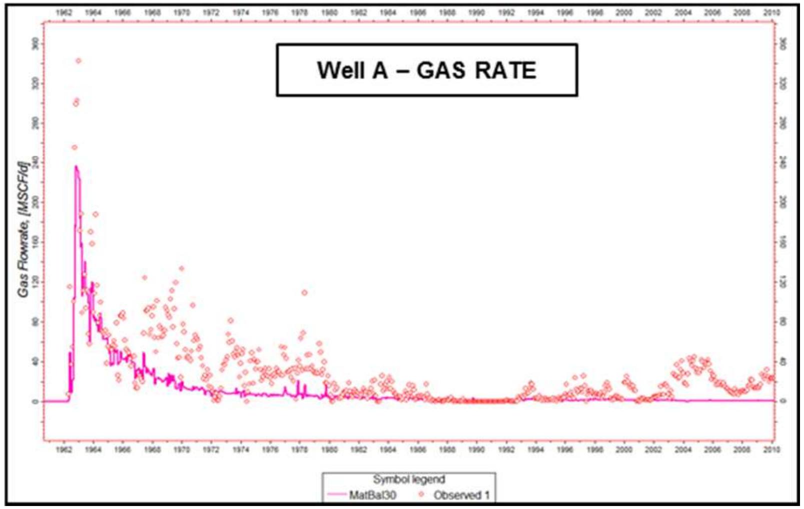
Initial Pressure, psi	3150
Current Pressure, psi	400
Cumulative Oil, MMBls	6.5275
Original Oil In Place, MMbls	18.65
Recovery Factor m+f, %	35%

Validation of the reservoir model – History match for one well in the model

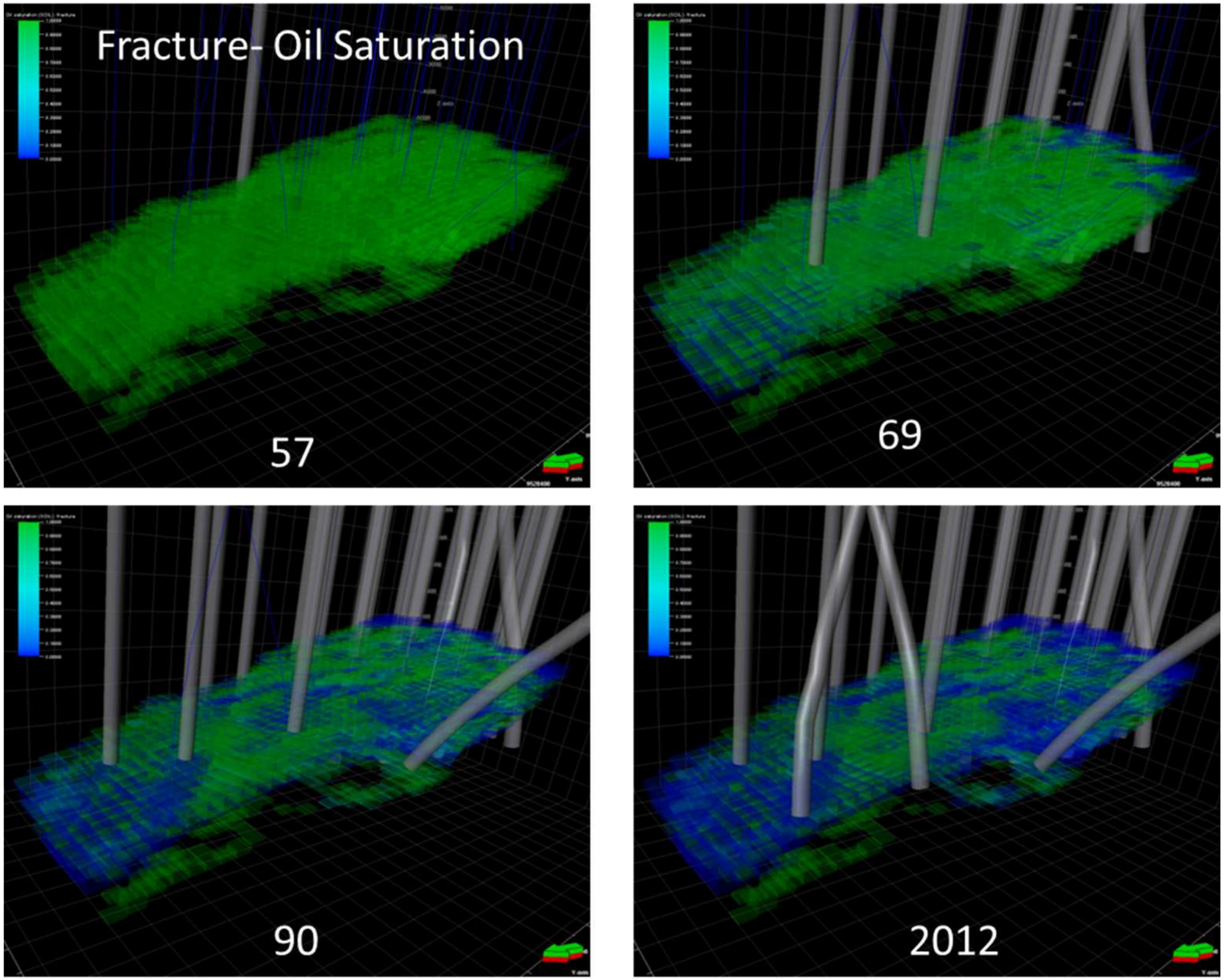






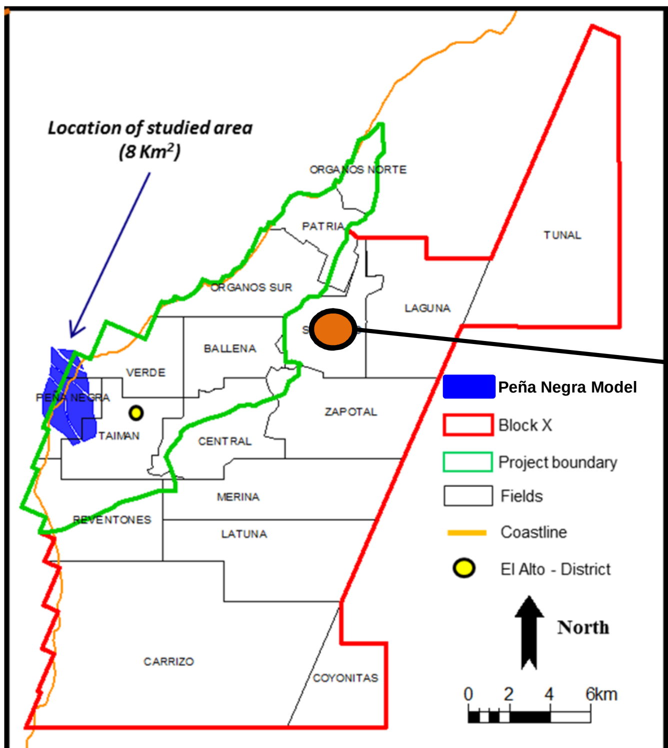


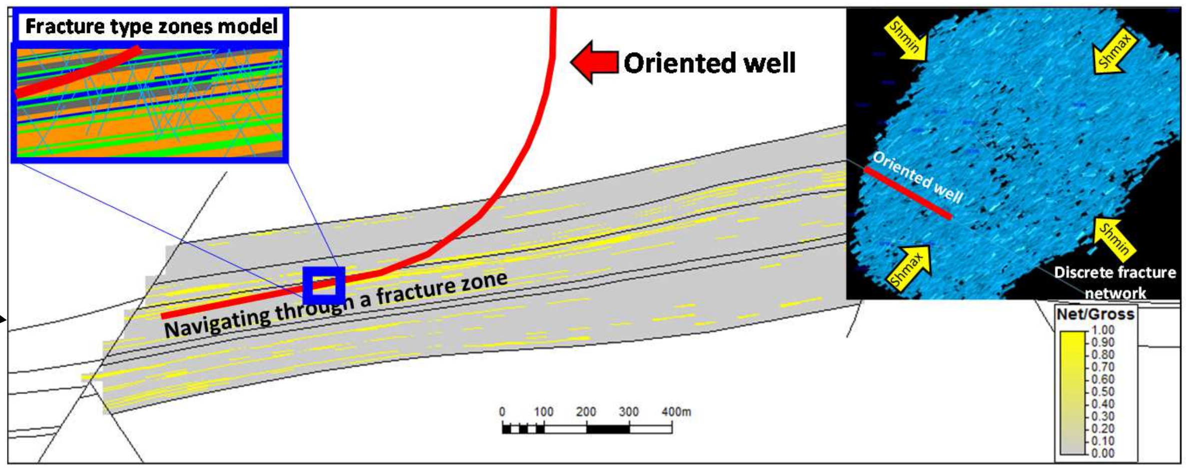
Calibration of the fracture model



Possible drilling strategies

This methodology is being extrapolated to other parts of the Block X, as in the field of Somatito where new drilling strategies are being proposed.





Conclusions

- The construction of the natural fracture network model was validated by the simulation model.
- Fluid flows come mainly from natural fracture networks in Mogollon Formation (Tight Sand Reservoir).
- Fractures are open in the direction of the least principal stress and align with the direction of the maximun horizontal stress.
- It is still possible to find undrained sets of fractures in the direction of the least principal stress and establish new development strategies.
- Possibility of drilling additional wells in order to obtain a larger contact area in these sets of fractures and to increase efficiency in the recovery within the reservoir.

THANK YOU FOR YOUR ATTENTION