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Reliable Fracture Characterisation and Value Addition through Special Core Reorientation: Kuwait Case Study

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Abstract

Reliable fracture characterization is essential for efficient field development of tight carbonate reservoirs. A comprehensive campaign of core based fracture analysis was carried out on more than 7,000ft of deep tight carbonate (over 14500ft TVD and 3pu avg. porosity and 0.1 mD avg. perm) cores of Kuwait, spread over a number of wells covering a large area of over 1000sq km.

The aim of the study was to provide inputs for a detailed structural analysis of the area, with the help of reorientation of cores focusing on the geometrical and structural characteristics of each well. The reorientation procedure used a special core Goniometry process, which permits a totally hands-free 3D digitization of all planar and linear features. Reorientation of the cores is established using either the deviation data from the wells or through comparison with image log data.

In addition to the detailed integrated description of type, size, aperture and filling of fractures, a porosity/permeability model was generated after calculation of fracture frequency. By calculating the orientation and value of the permeability vectors, an indication of optimum direction of drilling was established for each well/area.

The natural fracture network obtained with open, partially-open and cemented fractures, together with induced stress-release fractures analysis, contributed to a better understanding of tectonic history and present-day stress in the studied area. A field synthesis map highlighted the main direction of all types of fractures and an actual stress map was worked out by compiling all directions of the maximum horizontal stress observed in the wells and oriented by the petal and centreline induced fractures.

The integration of the results with analyses of image log data, well log correlation data and seismic data provided critical information about the reservoir properties.

Introduction

Deep tight Carbonate reservoirs of North Kuwait present many challenges for field development due to the inherent very low porosity/permeability characteristics. Natural fractures play main role in producibility of these reservoirs. An improved understanding of the fracture system may help to explain well behavior and could help in evaluation of reservoir properties. Application of seismic attributes along with core reorientation work has significant value addition in indicating areas of potential high fracture densities, assisting the well placement process in this purely fracture driven play.

A better understanding of the fracture spatial orientation and fracture properties in the fields has a strong influence on further development plans of the fields in the studied area.

Cemented and closed fractures act as barriers to flow, whereas open fractures intersected by the wellbore may increase the flow rates or result in early water breakthrough. Open fracture networks can cause some losses during drilling. Although the present-day in-situ stress regime controls the hydraulic-fracture propagation, the presence of fractures may affect the success of well stimulation as they influence the development.

Thus, a regional study was carried out with the objective to identify the fracture network geometry, the tectonic significance of the fractures, and the impact of fractures on reservoir behavior.

Since fractures are small-scale structures, they are below the resolution of seismic data as well as most conventional well logs; so they can only be sampled correctly by cores.

A systematic methodology needs therefore to be applied to all core data in order to integrate and compare the data sets.

This paper is focused to provide inputs for a detailed structural analysis of the area, with the help of reorientation of cores focusing on the geometrical and structural characteristics of each well. Integration of well data with the structural style, faults and seismic derived attributes helps in high grading potential areas of fracture corridors for the Najmah-Sarjelu reservoir in the deep carbonate fields of North Kuwait (Figure1-Location map).

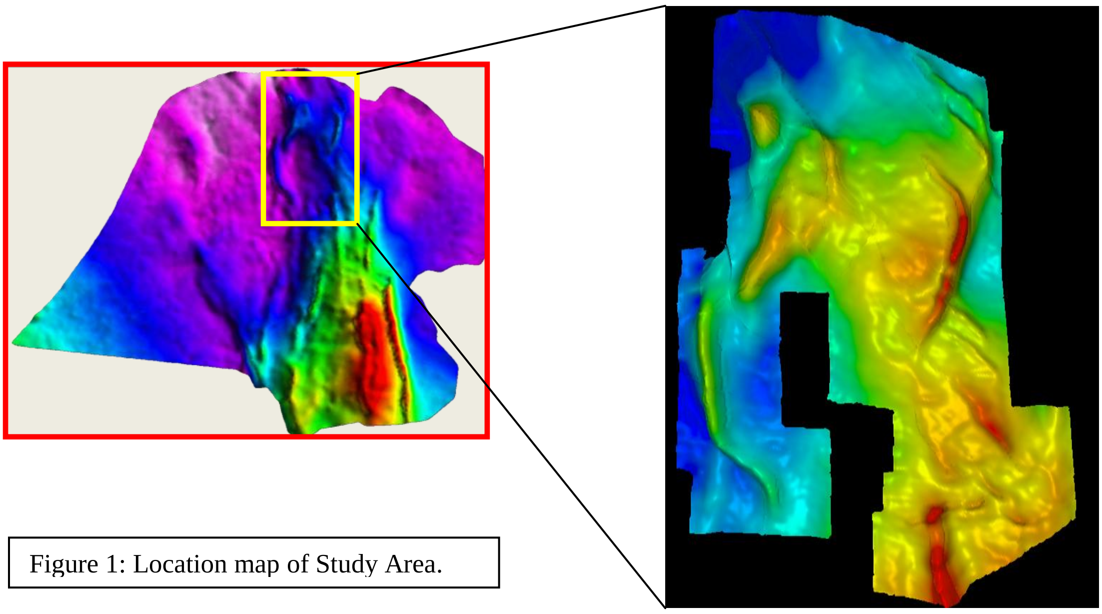

Figure 1: Location map of Study Area.

Geology Settings

Kimmeridgian-Bajocian age Najmah-Sargelu formations are established source rocks throughout the Middle-East. However, reservoir potential of these formations is severely limited by low porosity and permeability characteristics.

This deep carbonate section is divided from bottom to top into the Marrat, Dharuma, Sargelu, Najmah, Gotnia and Hith formations. The Najmah-Sargelu formations represent the uppermost carbonate reservoirs in this area. The underlying Sargelu Formation consists of peloidal and coated grain mudstones and wackstones with a few oncoids deposited in a bathyal depth range. The upper portion of the Sargelu is marked by the first appearance of organic rich shales. The organic rich shale member of the Najmah Formation overlies Sargelu and was probably deposited in water depths representative of outer shelf or bathyal conditions.

The limestone member of Najmah Formation representing a shallowing upward succession overlies the shale member and appears to have been deposited in an outer shelf environment aggrading upward to shallower inner shelf. The top of the Najmah Formation is an unconformity at the base of Gotnia Formation, which consists of alternations of crystalline salts and anhydrites with features of sabkha and subaqueous deposition and acts as excellent regional seal.

Najmah-Sarjelu section, in the study area, occurs at a depth range of 13000-14000 ft with an average thickness of 230 ft, matrix porosity of less than 2% and permeability of .1mD. Geological and petrophysical data and production tests have shown that fractures play the primary role in attaining sustainable production from Najmah-Sarjelu formations.

Tectonic history and Structural style

This region of Arabian plate had a long and complex history of tectonic evolution – including Paleozoic Passive margin setting, Triassic through Jurassic Extension, Late Cretaceous through present day Compression (Zagros orogeny) and the Halokinesis (Pre-Cambrian Hormuz and late Jurassic Gotnia salt layers adding to the structural complexity. From a regional standpoint the deep carbonate complex of North Kuwait is situated along the western margin of the northwestern trending Zagors foredeep. It is postulated, based on the regional tectonics of Arabian plate that, in the Sabriyah and the Raudhatain the initial development as drape folds occurred as a result of reactivation along preexisting basement faults (Wadi-Batin and Najd fault systems)(Bahroudi et al.,2003, Al-Husseini, 2000). From the seismic data it is observed that the Raudhatain and the Sabriyah structures at deep carbonate level (up to Najmah) manifest as tight positive flower structures as a result of transpression probably related to right lateral shear zones extending out from the Zagros and are envisaged to be modified/developed during Oligocene associated with Arabian and Iranian plate convergence. The clear axial shift between the Cretaceous and Jurassic sections of the Sabriyah and the Raudhatain structures is due to the specific geomechanical character of the stratigraphic column which enables detachment folding at Gotnia salt level. Gotnia salt is squeezed out over the crestal part of the structure at Najmah level. The major structural trends / faults observed in this part of the area are NNE-SSW and these are interconnected/offset by the subtle NW-SE and E-W faults/lineaments (with possibly localized minor dextral and sinistral displacement) forming a complex Structural Assemblage associated with a restraining bend. The fracture density is greater in the neighborhood of faults / lineaments and in areas of high curvature as observed from drilled well data and in conformity with seismic attribute studies.

Based on the well break-outs, a consistent present day maximum horizontal stress direction is estimated to be N45E, in-line with the active present day Zagros collision.

Sampling and reorientation methodology

The core reorientation work is based on the use of the AS3D Goniometer which permits a totally hand free 3D digitization of all planar and linear features. The main result of this digitization is to provide data measurements that can be imported into dedicated software and combined with other existing information. In the studied wells, geometry of sedimentary and tectonic structures from the core was collected with AS3D.

Orientation

The original data points obtained from the reference lines are computed and restored in their real spatial position by a reorientation process in two steps, depending on the deviation of wells. The data are first plotted on a stereonet with respect to each reference line. This is reprocessed to obtain the best reorientation corresponding to the most coherent geometry of sedimentary and tectonic structures in core. The sedimentary and tectonic trends for each scribeline are then superposed to obtain the general trends for the core. In case of deviated well, deviation data is used to reorient the data to true geographic position. A schematic view of core reorientation methodology is shown in figure-2.

With the AS3D goniometer, the orientations of the bedding and the fracture planes are measured relative to a fixed reference system with the axis parallel to the core axis. This reference system is then rotated within the general geographic system so that the core axis becomes parallel to the well trajectory. A step-by-step rotation is then applied around the core axis until the bedding match the known features (i.e., from seismic or image log data). The same rotations are then applied to the fractures to obtain their orientation with respect to North. This method allows sampling of large parts of the core at relatively low costs and is easily implemented.

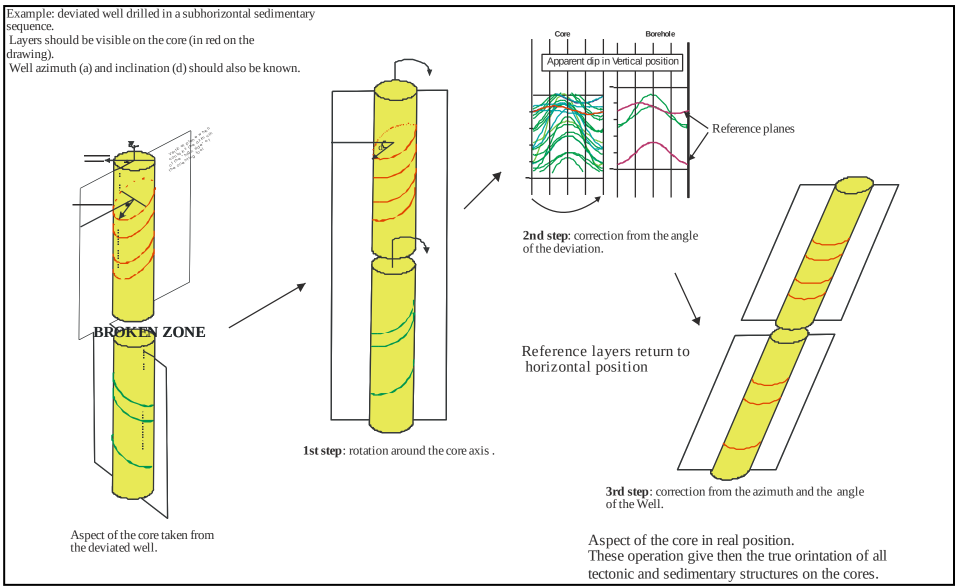

Figure 2: A schematic view of core reorientation.

The stereonet plot of raw core data are compared with available image log data to reorient with respect to true north, as shown in Figure 3.

This reorientation process is done only on good preserved core fragments to reduce the uncertainty. The degree of confidence is about +/- 10° for the direction and +/- 5° for the dips.

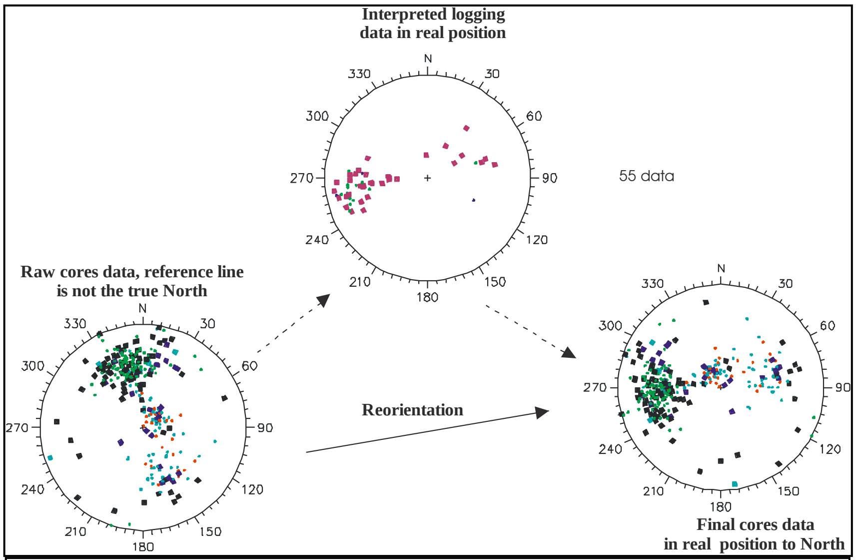

Figure 3: Example of reorientation in a vertical well with image log.

Fracture types and mode according to their kinematics

The mechanical origin of fractures (Hancock, 1985;Price & Cosgrove, 1990) indicates the stress regime under which the fractures are formed (Engelder & Geiser,1980; Bergerat et al., 1992) and is a key parameter to understand their impact on reservoir behavior (Loosveld & Franssen, 1992; Fulljames et al., 1996).The following four mechanical origins are commonly distinguished (Price & Cosgrove, 1990):

1. **Tension fractures** form perpendicular to σ_3 (smallest principal stress) and are characterized by movement perpendicular to the fracture plane. If not cemented, joints improve reservoir permeability and connectivity.

2. **Shear fractures** form as conjugate sets of slip planes oblique to σ_1 (largest principal stress).The intersection of the fracture planes is parallel to σ_2 (intermediate principal stress). They are characterized by movement in the fracture plane. Generally, shear fractures result in permeability reduction. One should distinguish, however (Loosveld &Franssen, 1992), between particulate-shear fractures(i.e., the sliding and rolling of intact grains past each other, occurring under shallow-depth conditions by fracture dilatation) and cataclastic shear fractures (i.e., grain crushing occurring under high pressure and temperature by fracture compaction or dilatation). Particulate-flow shear fractures can lead to permeability increase and cataclastic shear fractures generally result in permeability reduction.

3. **Dilational shear fractures** have movement components in, and perpendicular to, the fracture planes.

4. **Coring-induced fractures** form in response to stress changes induced by the drilling and coring process (Kulander et al., 1990).

In the present study, the following core features have been distinguished (Figure-4):

1. **Partially open fractures and open fractures**: thin natural open fractures, generally sub vertical and visible along several centimetres. The partially open show for most of them a filling of carbonate material and sometimes anhydrite or occasionally a secondary filling of clay or salt. This partial filling permits communication of voids ("bridged fractures").
2. **Cemented fractures**: these planes are mineralised fractures. The thickness range generally from 0.2 to few mm.
3. **Micro faults**: these planes are small micro-faults with partial filling and indication of movements. Some of them can show low dips as they are probably related to some bed to bed adjustment.
4. **Tectonic stylolites:** thin joints with a very small thickness from 0.1 to 0.5mm and undulated by stylolitisation. These stylolites present generally only horizontal “teeth” that have small amplitude.
5. **Gliding planes**: planes generally low to medium dipping, with orientation near the sedimentary layers and presenting indication of movement on clay surface.

6. **Petal/centerline** coring-induced fractures which initiate from near the core boundary and propagate downwards from a dip angle of 30° to 85°. Some of the fractures form at the same depth on opposite sides of the cores

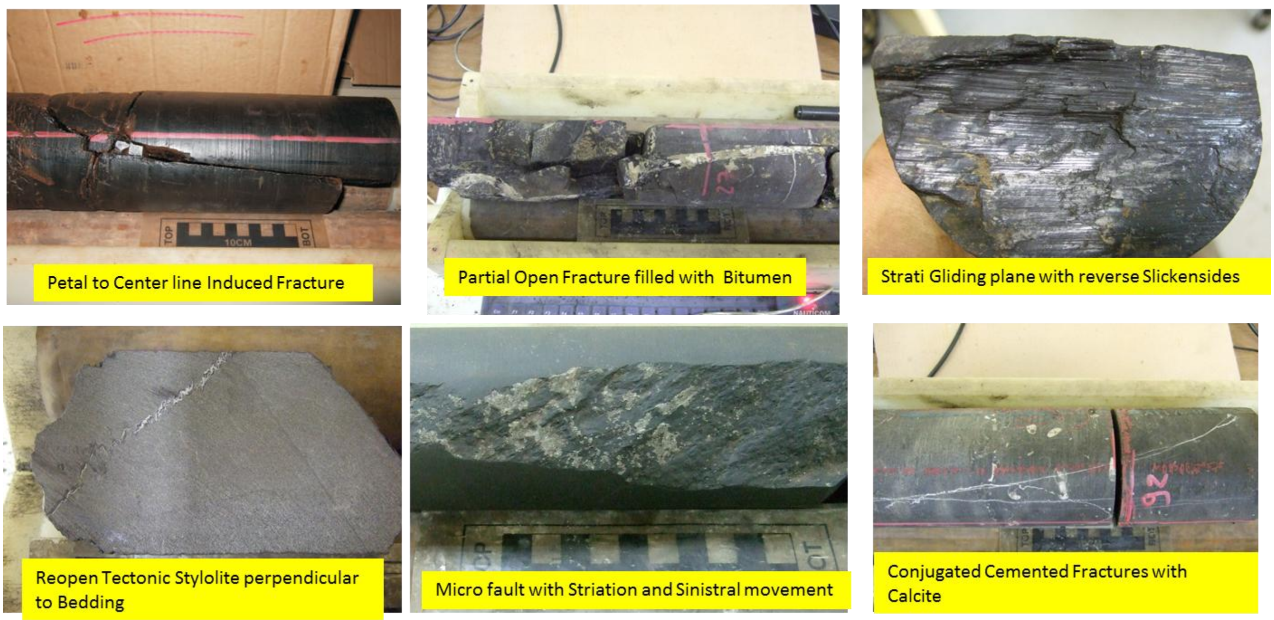

Figure 4: Example of features observed in Cores.

Fracture Modes

The physical associations of the different kinematic types of fractures are used to detect the micro tectonic stress regimes that caused them. These regimes are defined by the orientation of maximum, intermediate, and minimum principal stresses (σ_1, σ_2, and σ_3, respectively) at the time of the deformation.

The following stress regimes were detected:

1. Extensional regime: Characterized by vertical σ_1 and horizontal σ_2 and σ_3 plane. This is evident from steeply dipping tensile fractures and veins, some of which are associated with gently dipping bedding stylolites and dip-slip normal faults (Figure 5, Ameen et. al, 2010).

2. Strike-slip regime: Results from horizontal σ_1 and σ_3. This is evident from strike-slip faults, tectonic stylolites associated with vertical tensile fractures or veins (Figure 6, Ameen et. al , 2010).

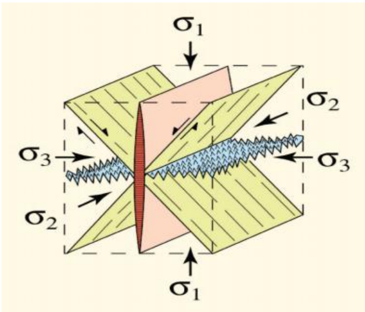

Figure 5 : Extensional Regime.

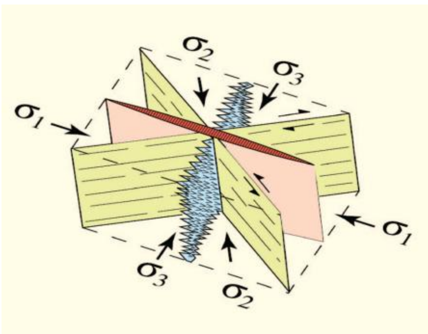

Figure 6 : Strike-slip Regime.

The strike-slip regime is less dominant than the extensional regime, which is evident from the common occurrence of tensile fractures associated with bedding stylolites.

The dominance of the tensile fractures over faults in the study area indicates a relatively mild regional tectonic regime. Analysis of the fracture orientation indicates the presence of regional systematic fracture trends.

Timing

Timing (relative) should be considered in order to assess the development of the fracture network and to relate fracture formation to the structural evolution of the area. The relative timing of fracture development can be established from abutting relationships (Engelder, 1985; Price & Cosgrove, 1990). Joints tend to abut against any pre-existing plane of weakness (i.e., bedding, stylolites, and older fractures).

The joints can therefore be assumed to be younger if a joint set systematically abuts against another set. In contrast, shear fractures tend to offset older fracture planes. Consequently, shear-fracture set that systematically cross-cuts another set can therefore be assumed to be the younger set. In order to apply these abutting relationships, a clear determination of the fracture origin and a statistical approach based on a large number of observations are required.

Geometrical parameters

The following three geometrical parameters are required for quantifying a fracture network: orientation, size and frequency.

Orientation

The orientations of the fractures were obtained by integrating AS3D, image and well devation, as discussed above.

Size of fractures

Determination of the average size of fractures intersected by a simple core is practically impossible. The probability of a core to intersect a fracture, and the chance of that fracture to terminate in the core depends on the fracture and borehole size (Gauthier). A geometric probability model allows estimation of the fracture size. The model relates the extent of the fracture to the probability of this fracture to intersect the core versus the probability of the same fracture to terminate within the core. Again, this approach is not expected to give absolute estimates of fracture size since it is sensitive to sampling. However, allows assessment of relative size of each fracture set objectively.

Spacing/frequency

Fracture spacing describes the distance between the fractures planes measured along a scanline oriented parallel to the average fracture pole. Due to limited sampling, true fracture spacing can seldom be measured in well data. In addition, other parameters such as lithology, grain size, porosity, and structural position (amount of deformation) also influence spacing. Narr & Lerche (1984) proposed various probabilistic methods to determine joint spacing in layered rocks from core data. Based on field data, several spacing distribution types have been described: log-normal (Narr & Suppe, 1991), exponential (Priest & Hudson, 1976) and normal (Huang & Angelier, 1989). In reservoir-characterization studies, however, estimation of the aggregate fracture frequency (i.e., the inverse of spacing) of the complete fracture network (comprising various sets) is required.

Frequency computing

The fracture frequency here after refers to the number of fracture counted along a one meter line perpendicularly to a considered set of "parallel" fractures. Such a set will also be called a fracture family. This notion is also known as spacing, the distance (perpendicularly) between two successive fractures (of a same set).

The figure 7 illustrates the calculation, in the case of a core with a specific diameter with a measured fracture density for each fracture family. The mathematic formulation is:

In the case of a borehole of **N** meter long, affected by a number of **I** different fracture families,

$\mathbf{Z_n}$ = Depth [m] of the nth meter of the borehole for which the frequency is calculated $\mathbf{1=<n=<N}$

$\mathbf{F_{in}}$ = Frequency of the ith fracture family at the depth $\mathbf{Z_n}$ $\mathbf{1=<i=<I}$

$\mathbf{d_{in}}$ = density [fract/m] of the ith fracture family (number of fractures counted each meter)

L = discretization length [m]

α_i = angle between the fractures of the ith fracture family and the bore hole

D = Core section (diameter) [m]

The investigation length is:

$$\mathbf{l_{in} = L \sin \alpha_i + D \cos \alpha_i}$$

And the frequency will be given by:

$$\mathbf{F_{in} = d_{in}\, L / l_{in}}$$

The angle α is given by:

$\cos(\pi/2-\alpha) = \sin\alpha = <V1,V2>/N(V1)\,N(V2)$ with **V1** vector parallel to the bore hole and **V2** normal vector to the fracture plane; **N(V1)** = Normal of vector **V1**; <> vectorial product.

If the borehole is vertical, $\alpha = \pi/2$ **- Dip**

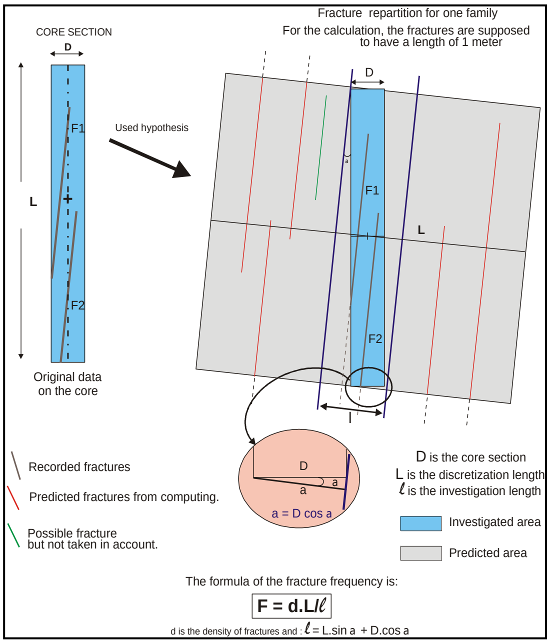

Figure 7 : Fracture Frequency Computaion.

Porosity/Permeability computing

Porosity

The porosity is computed, according to the *following statements*:

In general the core characteristics are supposed to be reliable for at least one cubic meter of rock centered on the core (the core crosses the cube of rock from its upper to its lower face). Therefore the porosity values refer to one cubic meter of rock and are computed every meter along the borehole. Thus the small diameter of the studied core is extrapolated to one cubic meter of rock centered on the core. The surface of the fractures is at least one square meter. Such statement shall be regarded as an approximation because in reality other fractures or other geological planes frequently stop the fractures.

The existence of a relation between the length and the aperture of a fracture is a widely admitted fact. Although the relationship between the length and the aperture could be difficult to assess, there is usually a concomitant increase of both parameters. Thus the length error will preferably affect the "small" apertures, with lengths under one meter. Inside a fractured block, the influence of the "small" open fractures is minor when compared with the influence of "large" open fractures and consequently the error in the calculated porosity values will be reduced.The calculation is done by cumulating the porosity of all individual fractures. Furthermore the porosity of each fracture family is computed from the above cumulating. The aperture value of each fracture is supposed to be constant and should be already "averaged" by the operator. Thus, in case of partial opening, like ‘bridge fractures’, only the effective opening has been used for the studied cores. The opening is considered as a constant only for every successive cubic meter of rock along the borehole.

Permeability

The permeability was calculated, based on the following *additional statements*:

The fracture length is supposed to be ‘infinite’. In reality when there is more than one fracture system, the fractures belonging to one set are intercepted by the others, resulting into a considerable length. When at least two systems of fractures exist and if their frequencies reach 4F/m, the influence of their length (>1m) could easily be neglected, especially when compared with the uncertainty of the opening on the permeability.

The codes used for the computation of the fracture frequency have been derived from the permeability tensor theory. It is noted that while the values of permeability are high, only the position of the values along the well is significant. In an anisotropic pervious rock medium, such as a fractured reservoir, it could be crucial to define the orientation of a well regarding the 3D fracture network and the related computed permeability ellipsoid.

If the well objective is to get the best drainage from the fractures (e.g. if productivity index is a key point), the well should crosscut the maximum of fractures and should be perpendicular to the K1-K2 plane and parallel to the K3 vector. Statistically, the best spatial distribution of the K3 vector is found by drawing a density stereonet and then determining the mean lineation vector. Thus, the ‘ideal’ position deduced from this analysis would be almost close to this mean vector.

MAIN RESULTS

Fracture description

At least thirty wells have been studied and more than 4500 fractures have been measured and analyzed using core and image log data. The detailed results of each well and field are beyond the scope of the present paper and are limited to general descriptions and conclusions.

From the reorientation and frequency calculation, the main families of fractures have been sorted out for each well for Najmah Sargelu sections. Figure 8 is synthesis tables showing the length of studied cores, number of fractures and density and frequency when available.

length in ft	Open and partially open frac				Cemented frac	
	Directions	number data	density tot	frequency tot	Directions	Data
116	N70,N120,N170	64			N50,N100,N170	87
138	N45,N120	90			N60,N110,N0	89
253	N10,N105	162			N90,N40,N0	35
257		52	48	249.8	N145	108
147		109	99	544.9	N0	92
178		56	54	291.7	N50,N105,N160	100
75		40	40	243.1	*	1
236	N40	42			N140,N105	23
218	N30,N140,N90	66			N10,N120	102
193	N100	79	73	353.2	N70,N140,N100	67
136		42	42	200.2	N100,N20	16
160		45	37	127.5	N170,N80	92
239		65	60	323.5	N120, N70	35
148	N50,N125	85			N25,N60,N100	12
209		102	70	298.9	N140, N70	177
236		47	43	148.8	N130	45
243		113	92	279.2	N50	133
169		72	64	162.2	N105, N0	100
39		13	13	33.7	N20,N80,N105	25
80		21	18	40.9	N110	6
171		42	40	178.6	N25, N105	68
228	N60,N100	91			N20,N170,N80	58
276		44	40	132	N140,N70,N0	38

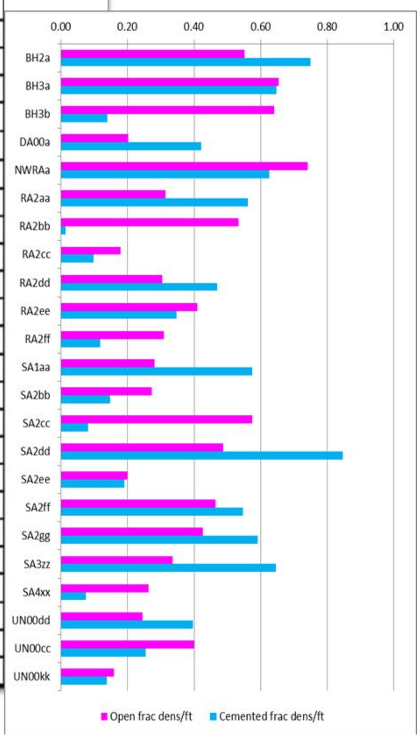

Figure 8: Synthesis table and histogram for density: Najmah Sargelu section.

As shown on the histograms, the mean density (number of fractures counted on the core) and the mean frequency (calculated frequency per meter) are showing high heterogeneity between different wells in terms of number and in terms of proportion from open or cemented (figure-8).

Fracture Density vs Frequency

An overview of the fracture trends that have been identified in the studied areas is shown in the tables for Najmah Sargelu formation (figure 8). It is easy to observe the well wise variation in terms of fracture frequency (blue circle) and density (red circle) as shown in figure-9.

The fracture networks are relatively complex and vary as a function of the structural location. Four main fracture trends have been observed based on the frequency analysis: NW-SE, NE-SW, N-S and E-W.The fractures form vertical to subvertical sets or conjugate systems. Within each well, the dominant fracture trend often matches the orientation of the nearest seismically imaged fault trend or it's conjugate. Figure 10 shows field wise distributions of the fracture frequency with respect to the four major fracture trends.

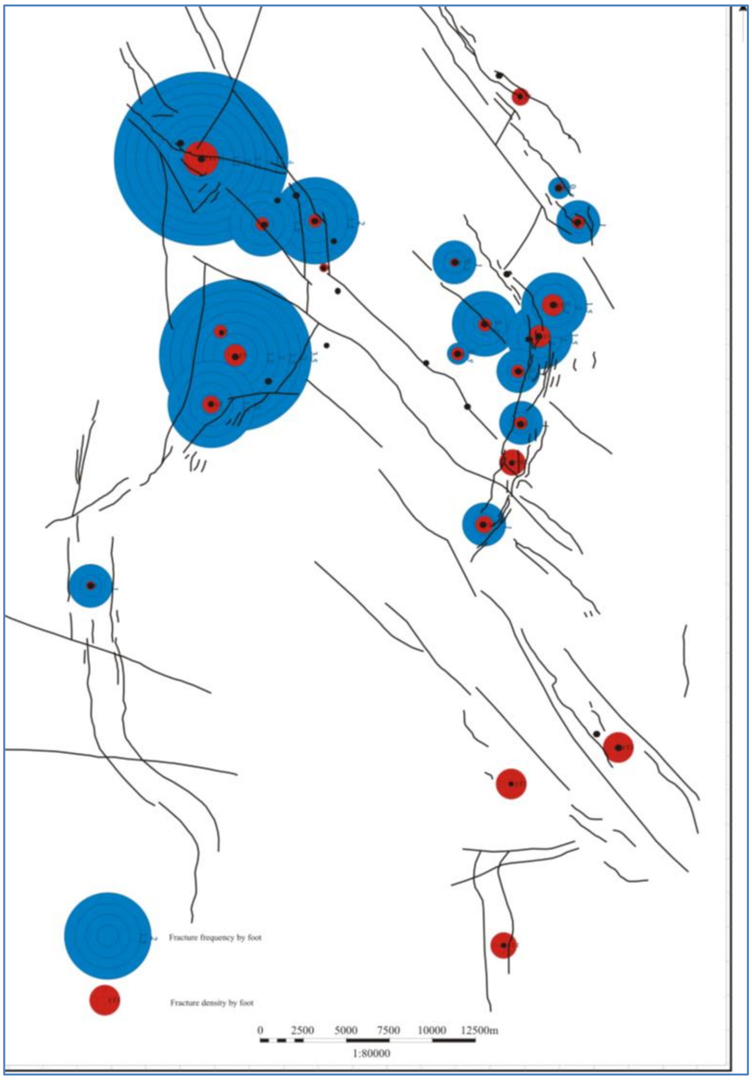

Figure 9: Well wise variation in terms of the ratio between frequency (blue circle) and density (red circle).

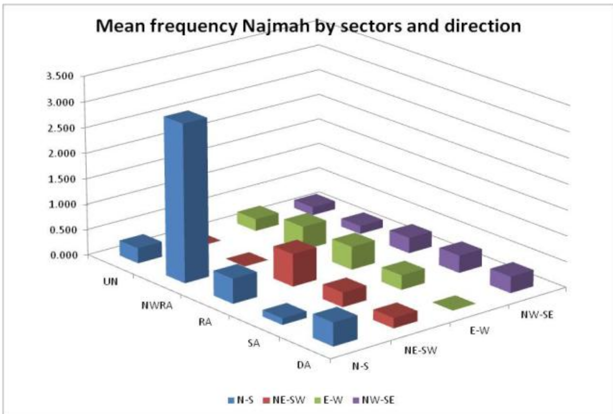

Figure 10: The histograms are showing field wise distributions of the fracture frequency with respect to the four major fracture trends.

Fracture direction and K3 permeability vector

Based on the the reorientation and frequency calculation, the main directions of fractures observed for each well are presented as red lines in figure 11. The relative length of each line represents the number of data for the respective family.

The minimum permeability vectors K3 (blue arrow) are also presented on the same map which show the optimum drilling direction to encounter maximum permeability.

Figure 11: Map showing the main fractures direction and orientation of K3 permeability vector.

Actual horizontal stress deduced from induced fractures reorientation

In most of the studied wells, a large number of induced fractures (petal or centerline) have been observed in the reoriented cores.The direction of these induced fractures represents the maximum horizontal stress direction. From this study, it is observed that the general regional trend of maximum horizontal stress is NE-SW. The map below (figure-12) shows all the main directions observed in the wells for Najmah Sargelu cored section. However some wells show departure from the regional trend as marked in red box.

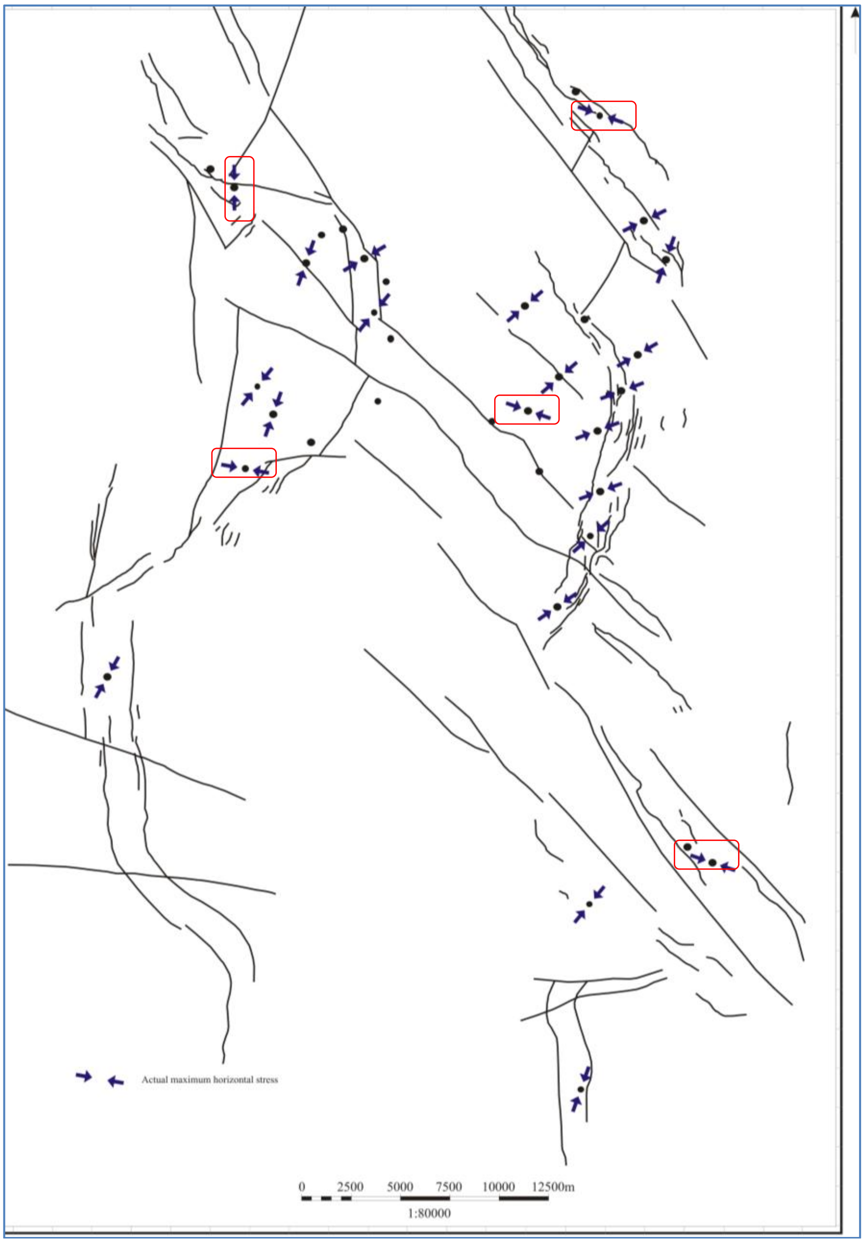

Figure 12: Map showing the actual in situ maximum horizontal stress deduced from induced fractures for Najmah Sargelu section.

Data integration and early results

Core reorientation work has significant value addition in indicating areas of potential high fracture densities thus assisting the well placement process. Fracture analysis established strong correlation between open /partial open fractures along present-day maximum horizontal stress and the flowing zones (Figure 13).Good match was established between fracture porosity and permeability estimated from the core studies and Flow meter logs.

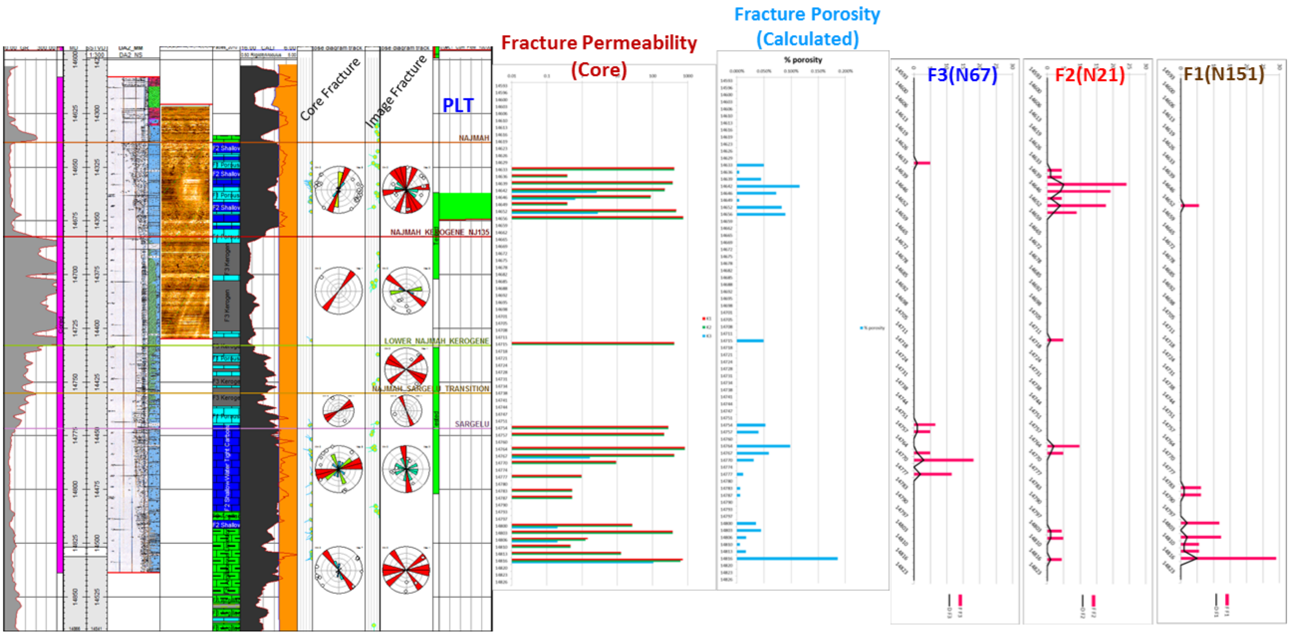

Figure 13: Showing integration of different data set along with the core fracture data.

Conclusions

The integration of the data derived from core reorientation with image log data, and seismic data provided critical insights into the fracture properties in the study area. The core reorientation work assisted in optimizing well placement to penetrate the most heavily fractured corridors. Fracture analysis established strong correlation between open /partial open fractures along present-day maximum horizontal stress and the flowing zones.Good match was established between fracture porosity and permeability estimated from the core studies and Flow meter logs. Recent drilling results, based on these integrated studies have corroborated the interpretation by encountering fractures in the predicted direction.

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