PS Influence of Tectonic Stress Regime on Fracture Porosity of Tight Carbonate Reservoirs*

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Search and Discovery Article #42103 (2017)**
Posted July 10, 2017

*Adapted from poster presentation given at AAPG 2017 Annual Convention and Exhibition, Houston, Texas, United States, April 2-5, 2017

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Abstract

Fracture zones are usually characterized by an increased fracture density and thus a higher secondary porosity. In the studied area (Potwar Basin, Northern Pakistan), the porosities derived from a neutron log and fracture apertures (obtained via high-resolution resistivity images) are very low, even if the resistivity images show a high fracture density cataclastic zone. This analysis refers to a tight carbonate reservoir located close to a major fault zone, with a high density of fractures that do not contribute to fluid flow due to their small apertures. The compressive, reverse faulting regime with active hanging walls led to the formation of the main hydrocarbon traps, these being laterally delimited by such faults. Borehole breakouts and drilling-induced fractures were used for tectonic stress evaluation. The dominant minimum stress direction identified in the analyzed wells is WSW - ENE, normal to the direction of drilling-induced fractures, as indicators of the maximum stress direction, which are oriented NNW - SSE. The orientation of drilling-enhanced fractures confirms the maximum stress direction as determined via drilling-induced fractures. The alignment of the major fault and the natural fractures, parallel to the minimum horizontal stress direction, suggests a compressional tectonic regime at the moment of their formation. The maximum tectonic stress, normal to the fractures direction, has contributed to apertures closure and secondary porosity reduction. This explains why in an area characterized by intense cataclasis, resulted from the fault proximity, porosity is less than 2% and fracture apertures are, generally, less than 0.5 mm. However, the simultaneous presence of breakouts and drilling-induced fractures in the same well is an indicator of a strike-slip stress regime. One may conclude that a change in the tectonic stress regime took place, from a compressive to a strike-slip one. The major fault, which initially had a compressive character (dominantly vertical movement), later became a strike-slip one, with a dominantly horizontal component. Knowledge of the fractures' propagation direction with respect to maximum tectonic stress is extremely important for the potential design of horizontal wells. Experience has shown that production is highly correlated to fracture volume and connectivity in tight formations, implying the future successful economic development of this particular field lies in knowledge of the fracture propagation direction.

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100-th AAPG Annual Convention & Exhibition, Houston, Texas, 2 – 5 April, 2017

INFLUENCE OF TECTONIC STRESS REGIME ON FRACTURE POROSITY OF TIGHT CARBONATE RESERVOIRS

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1. Introduction

In certain types of reservoirs, fractures provide the major storage space for hydrocarbons, as well as their main flowing pathway. When primary porosity (represented by the pore network of reservoir rocks) is very low, secondary porosity (fissures, fractures and/or dissolution vugs) makes up the dominant part of total porosity. This situation is mostly encountered in compact rocks such as carbonates, crystalline or magmatic basement, or highly-cemented sandstones.
This study refers to a carbonate reservoir located in the proximity of a fault zone, with a high density of fractures which do not contribute to fluids flow due to their small apertures. The maximum tectonic stress, normal to the fractures direction, has contributed to apertures closure and, consequently, to secondary porosity reduction.

2. Geological Setting of the Area (I)

The studied area is situated in Potwar Basin and represents a part of the foreland zone of northwestern Himalayan fold and thrust belt, located in northern Pakistan. The Potwar Basin can be divided in two zones: a deformed, northern one (North Potwar Deformed Zone – NPDZ) and a less deformed southern one – the Soan Syncline (Fig. 1).
It has an elongated shape, of about 130 Km in length, developed in a N-S direction, being delimited by thrust faults at North (MBT- Main Boundary Thrust) and South (SRT-Salt Range Thrust) and strike-slip faults at East and West.

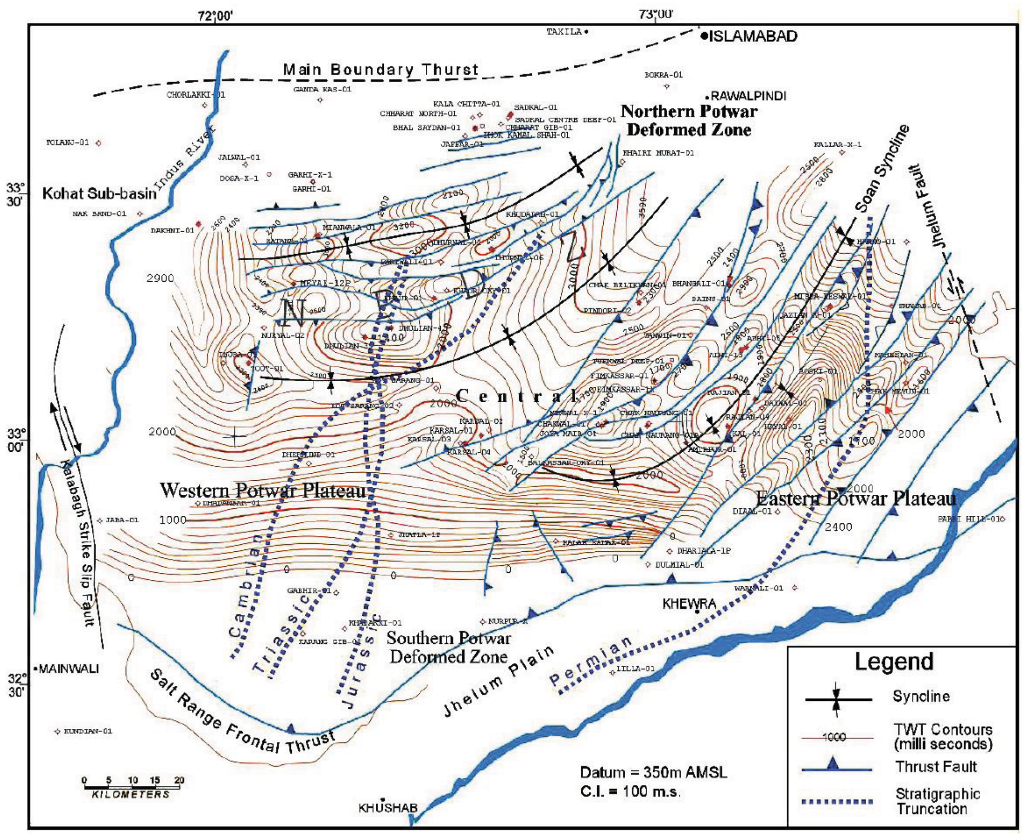

Fig. 1 *Two Way Time Map at Base Miocene in the Potwar Sub-basin, Pakistan (after Anwar Moghal et all, 2003)*

The compressive, reverse faulting regime with active hanging walls (overthrust fault) lead to the formation of the main hydrocarbon traps, these being laterally delimited by such faults.
The Pre-Cambrian Salt Range Formation is overlain by the Cambrian to Eocene platform sequences (Fig. 2).
In Potwar Basin, the Early to Middle Cambrian Jhelum Group lies on the Eocambrian Salt Range Formation (Gee, 1934). The Jhelum Group includes Cambrian Khewra and Kussak Formations. These were deposited in litoral to shallow marine environments. The basin was uplifted during Ordovician to Carboniferous; therefore, no sediments were deposited in Potwar Basin (Shami and Baig, 2002).
The Jhelum Group is disconformably overlain by the Permian Nilawahan Group. It includes the Tobra, Dandot, Warcha and Sardahi Formations. The Late Permian Zaluch Group was eroded or not deposited in the area. The Late Permian to Cretaceous rocks from west to east in the basin are eroded due to significant pre-Paleocene tectonic uplift in Potwar Basin.
The early Paleocene marine transgression caused thick deposition of the Paleocene to Eocene carbonate-shale sequence. It includes the Lockhart, Patala, Sakessar and Chorgali Formations. The carbonates of these formations form the principal reservoirs for the accumulation of oil in the area.
Hangu Formation is not identified in this part of Potwar Basin, which was eroded after deposition and is identifiable on outcrop representing residual environments of deposition.
The upper part of the stratigraphic section comprises of the Miocene to Pleistocene non-marine molasse deposits. The molasses deposits include the Murree, Kamlial, Chinji and Nagri Formations. The transgressive molasse sediments represent the erosional products of the southward advancing Himalayan thrust sheets.
Paleocene Patala shales have been proved as the principal sources of hydrocarbons, being deposited in anoxic environment.
The total organic carbon (TOC) content varies from 0.5 to more than 3.5%, with an average of 1.4%, the kerogen being of types II and III.

2. Geological Setting of the Area (II)

Generation of hydrocarbons most likely initiated in the Late Cretaceous time for Cambrian through Lower Cretaceous source rocks and again from Pliocene time to the present for younger source rocks.
Migration is primarily over short distances updip and vertically into adjacent reservoirs and through faults and fractures associated with plate collision and thrusting (Wandrey, C.J. et al, 2004).

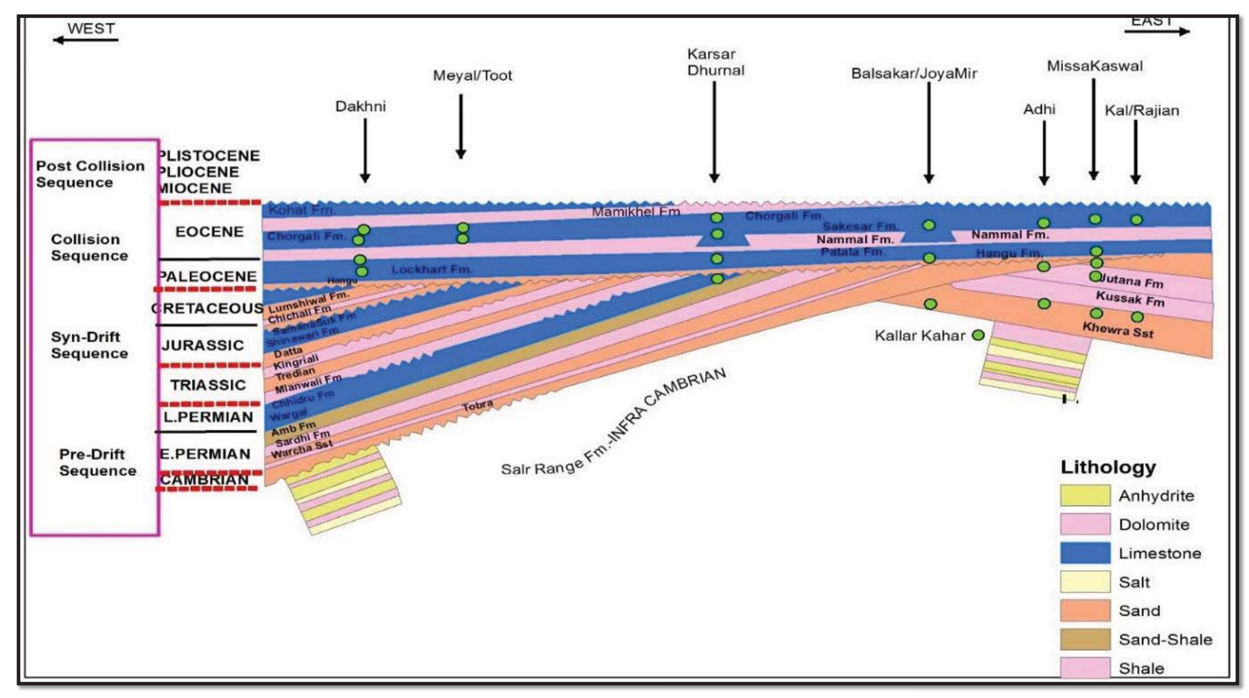

Fig.2 Generalized Stratigraphy of Potwar Basin (after Anwar Moghal et all.)

According to Law and others (1998), two distinct over pressuring regimes were reported. A Neogene over pressuring regime was attributed to tectonic compression and under compaction, and a pre-Neogene over pressuring regime is attributed to combined hydrocarbon generation and tectonic compression.

The burial-history plots (Fig. 3) of Law and others (1998) also indicate that maximum burial was reached approximately 2 million years ago. Even though there were probably two distinct periods of generation from two different group of source rocks.

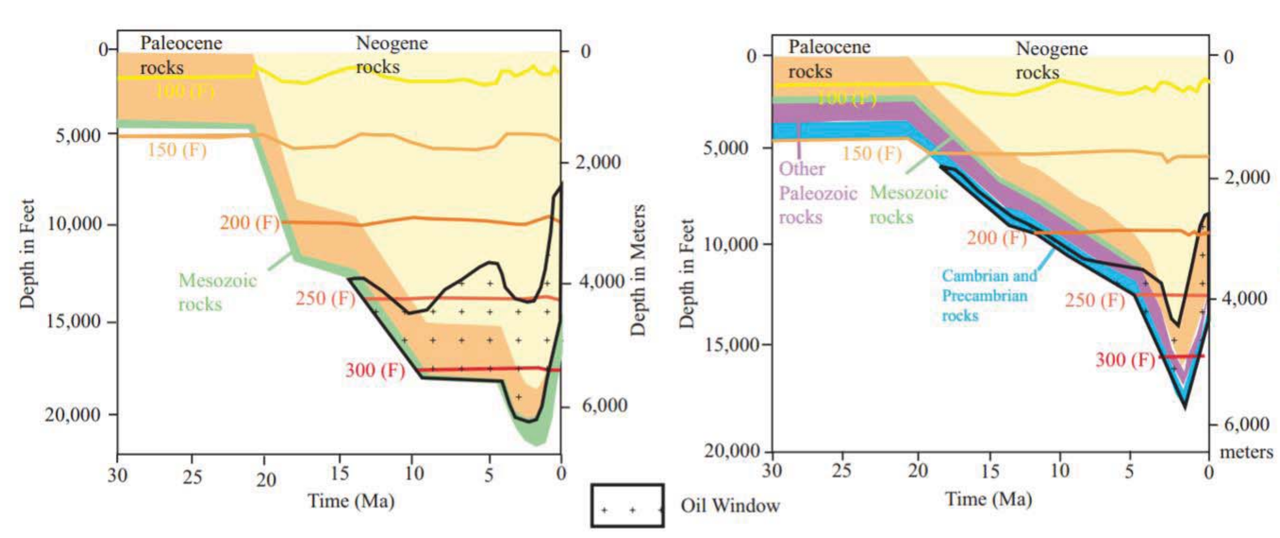

Fig. 3 *Generalized Burial-history for the OGDCL Dakhni 1 well (left) and Gulf Oil Fimkassar well (right) (modified from Law and others,1998)*

3. Integrated analysis of well data (I)

The structural seismic interpretation was done on available 2D seismic data and shows a faulted anticline (Fig. 4). The tectonics of the analyzed zone is very complex due to the impact of underlying Salt Range Formation.
The interpreted reflectors represent the lithological boundary of Cambrian, Permian, Paleocene and Eocene reservoirs.
This faulted anticline is further divided into two compartments: upthrown and downthrown with independent structural closure.

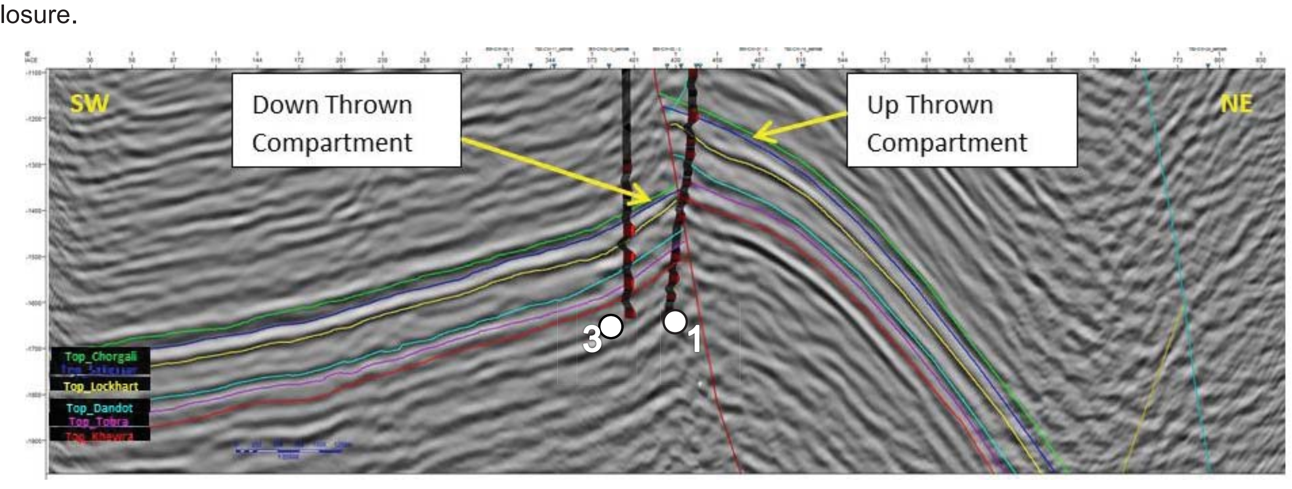

Fig. 4 *Detailed image of the seismic line in the studied area*

In this study, is presented an analysis of three vertical wells investigated with complex wireline logging methods, including high-resolution electrical imaging. The wells are located very close to a major fault (Fig. 4 and 5), which may be the source of cataclastic fractures observed on the geophysical image logs. Wells 1 and 2 have penetrated the hanging wall of the fault, at distances of about 100-150m and, respectively, 450m from the fault plane, whereas well 3 intercepted the foot wall, at about 700m distance from the fault plane.

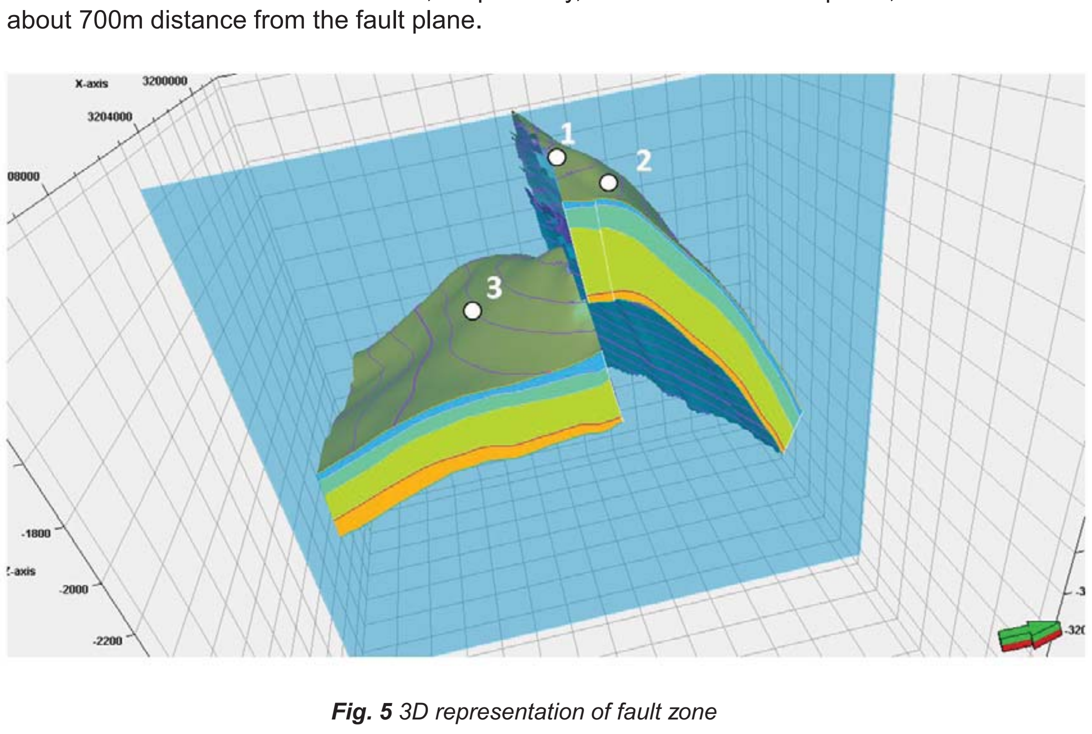

Fig. 5 *3D representation of fault zone*

3. Integrated analysis of well data (II)

As a result of the electrical resistivity images interpretation in the three wells, both natural fractures and tectonic stress indicators were identified. The natural fractures were classified in discontinuous-conductive (Fig. 6), resistive, conductive, cataclastic / chicken wire frame (Fig. 7 and 8) and drilling-enhanced (pre-existing). Also, microfaults were identified, in the cases when the disjunctive elements show an evident displacement. The most common fractures were the discontinuous-conductive ones, so they were used for statistical processing (the azimuths frequency diagrams).
The poor quality of the FMI image in well 1, due to the proximity of the fault zone, lead to the identification of only 121 discontinuous-conductive fractures, with an average dip angle of 44.1°. In wells 2 and 3 there were identified 266 and, respectively, 911 discontinuous-conductive fractures, with average dip angles of 50.59° and, respectively, 57.98°. The strike of these fractures is approximately WSW-ENE.

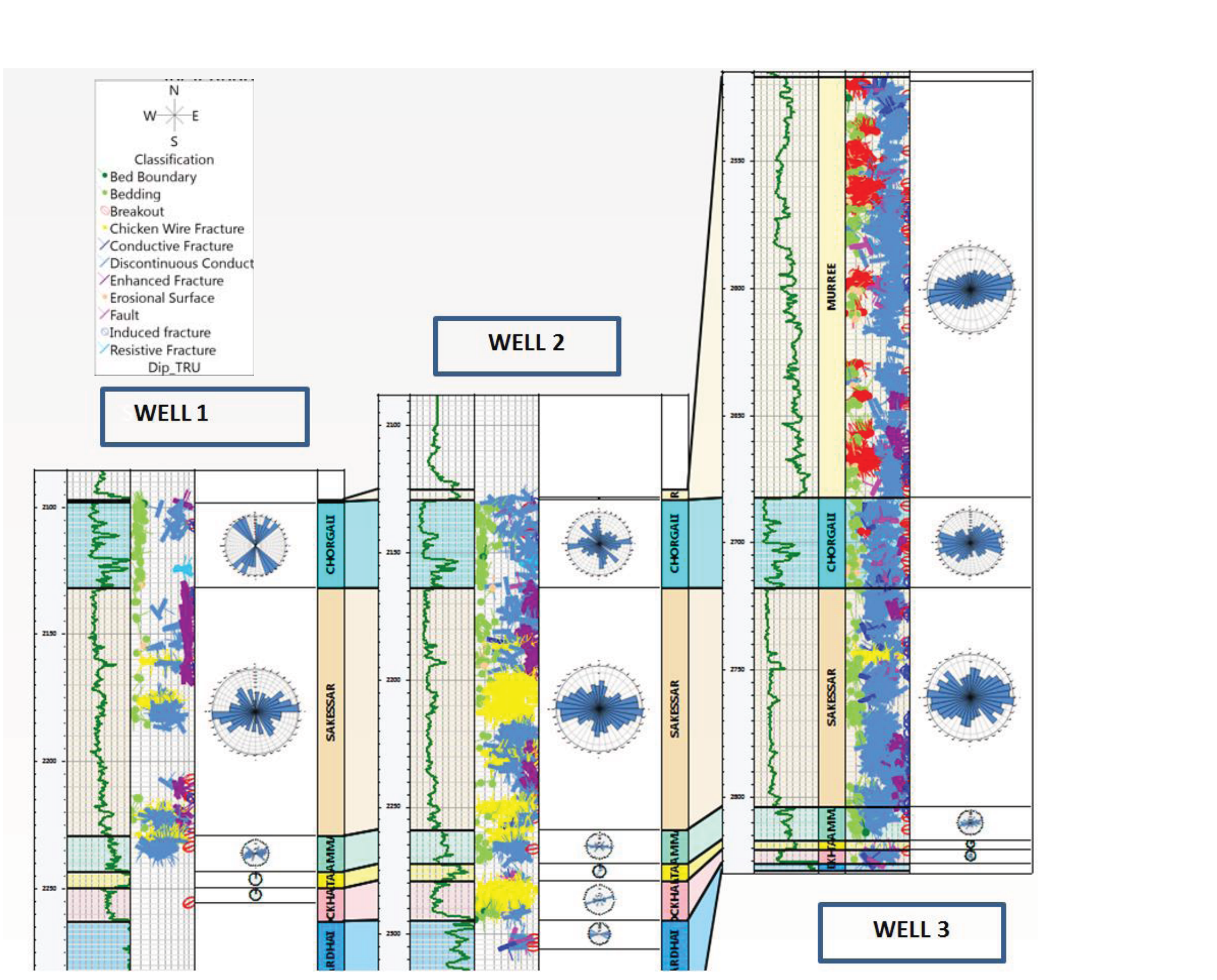

Fig. 6 *Azimuth frequency diagrams for the discontinuous-conductive fractures (with blue)*

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3. Integrated analysis of well data (III)

The cataclastic fractures are very frequent but show a random distribution of propagation directions (strikes).

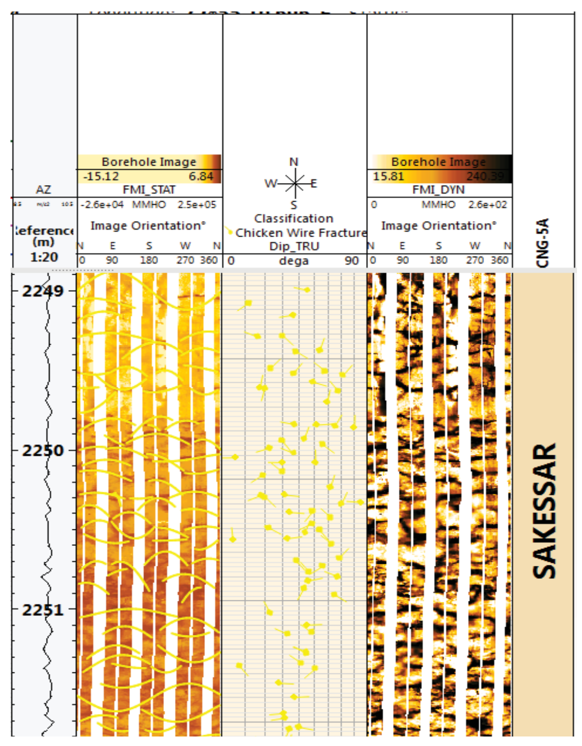

Fig. 7 Example of cataclastic / chicken wireframe fractures in Sakessar Formation

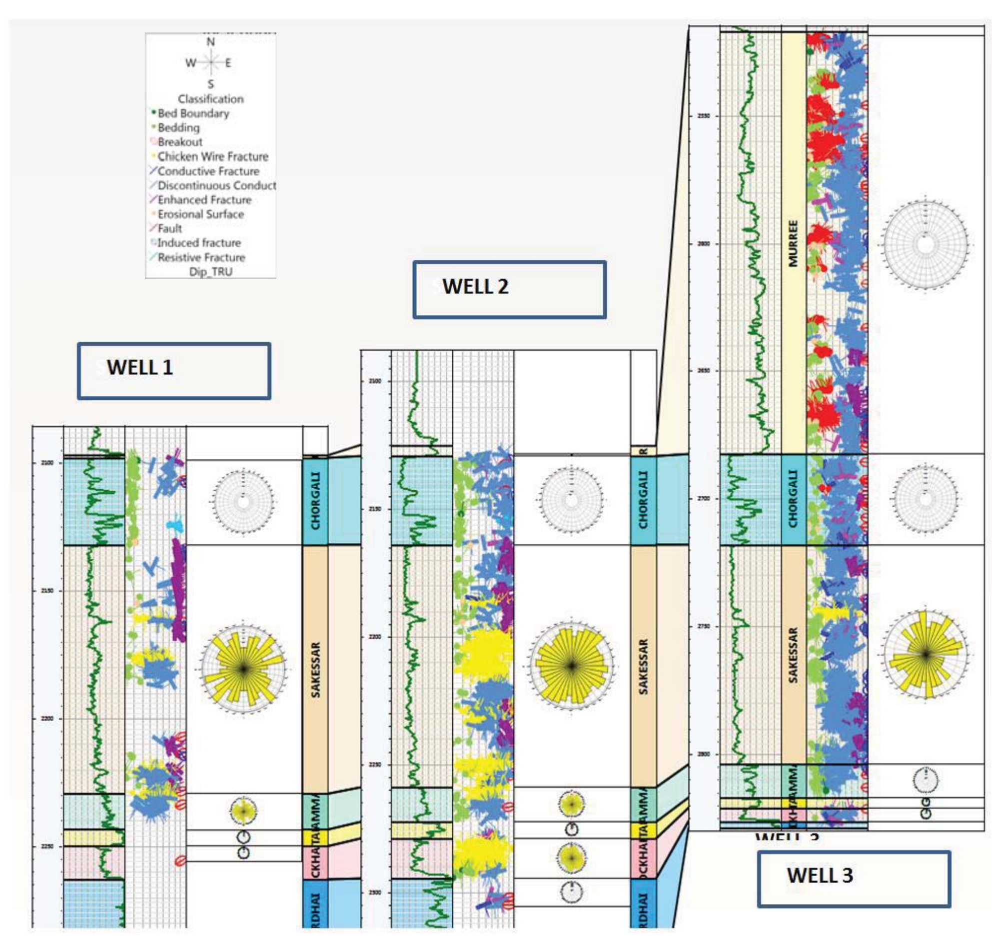

Fig. 8 Azimuth frequency diagrams for the cataclastic/chicken wireframe fractures

3. Integrated analysis of well data (IV)

Although fractures' density is high, their apertures are very small (less than 1 mm), as suggested by Fig.9. For the computation of fracture aperture sizes, an equation presented by Luthi & Souhaité (1990) was used; this equation is based on the electrical current excess in a zone of conductive or partially conductive fractures. The poor quality of FMI image from well 1 did not allow fractures aperture computations and, for this reason, this well was excluded from certain statistical analyses.

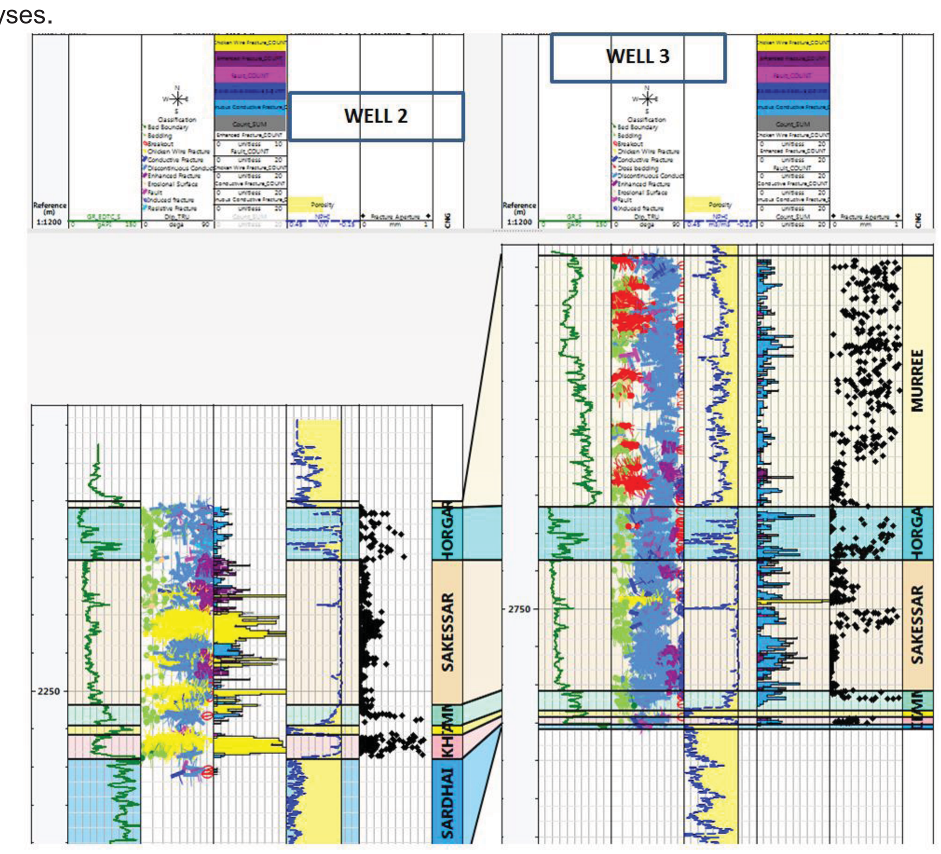

Fig. 9 Fractures density-Total Porosity-Fractures aperture sizes diagram for well 2 and 3

The porosity, derived from the neutron log (limestone calibrated), has very low values in the carbonate formations. This agrees with the very small fractures aperture obtained from resistivity images. Because the main hydrocarbons reservoir is located in the carbonate Sakessar Formation, the statistical analyses carried out will refer only to this reservoir. The total porosity of Sakkesar Formation (in zones with less than 5% shale content) in wells 2 and 3 is usually less than 2%, with occasional higher values in the zones with significant secondary porosity.

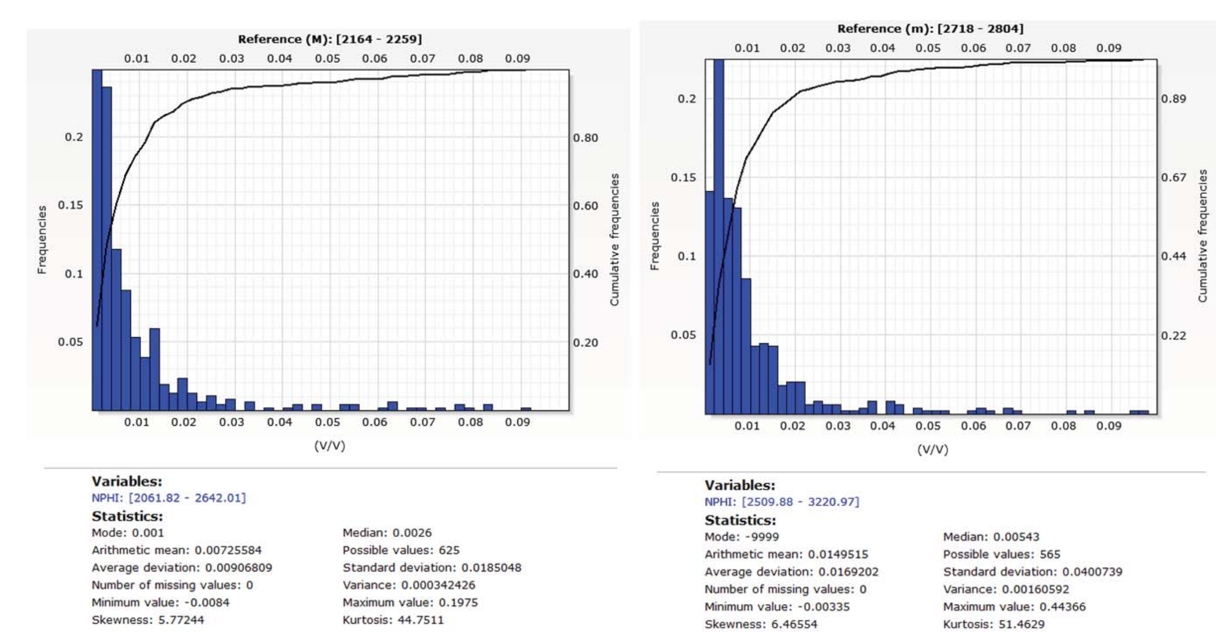

Fig. 10 Total porosity histograms for well 2 and 3

3. Integrated analysis of well data (V)

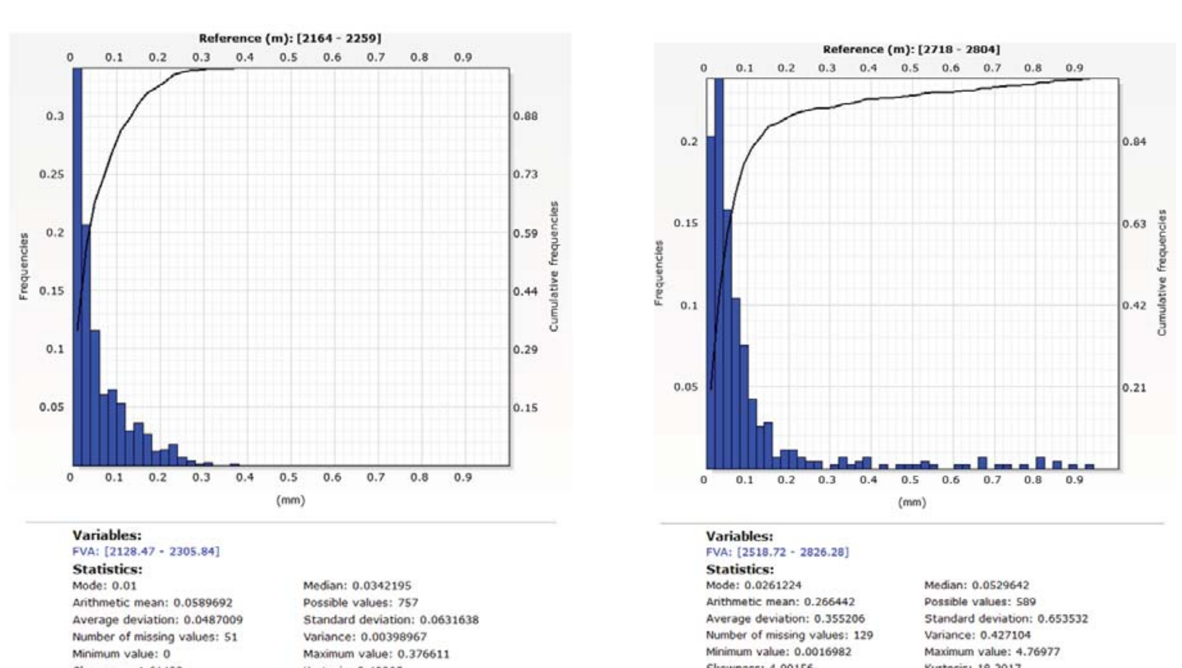

Fig. 11 Fractures aperture histograms for well 2 and 3

The analysis of fractures aperture histograms from wells 2 and 3 (Fig. 11) shows a majority of aperture values less than 0.3 mm. However, in well 3, located in the downthrown fault compartment, there are fractures with apertures between 0.3 and 1 mm, but their occurrence is rare (low frequency).

The borehole breakouts (Fig.12-left) and drilling-induced fractures (Fig. 12-middle) have been used as means for tectonic stress evaluation. In all three wells, pre-existing fractures enlarged by the drilling process have been identified (Fig.12-right), their orientation being parallel with the maximum tectonic stress direction.

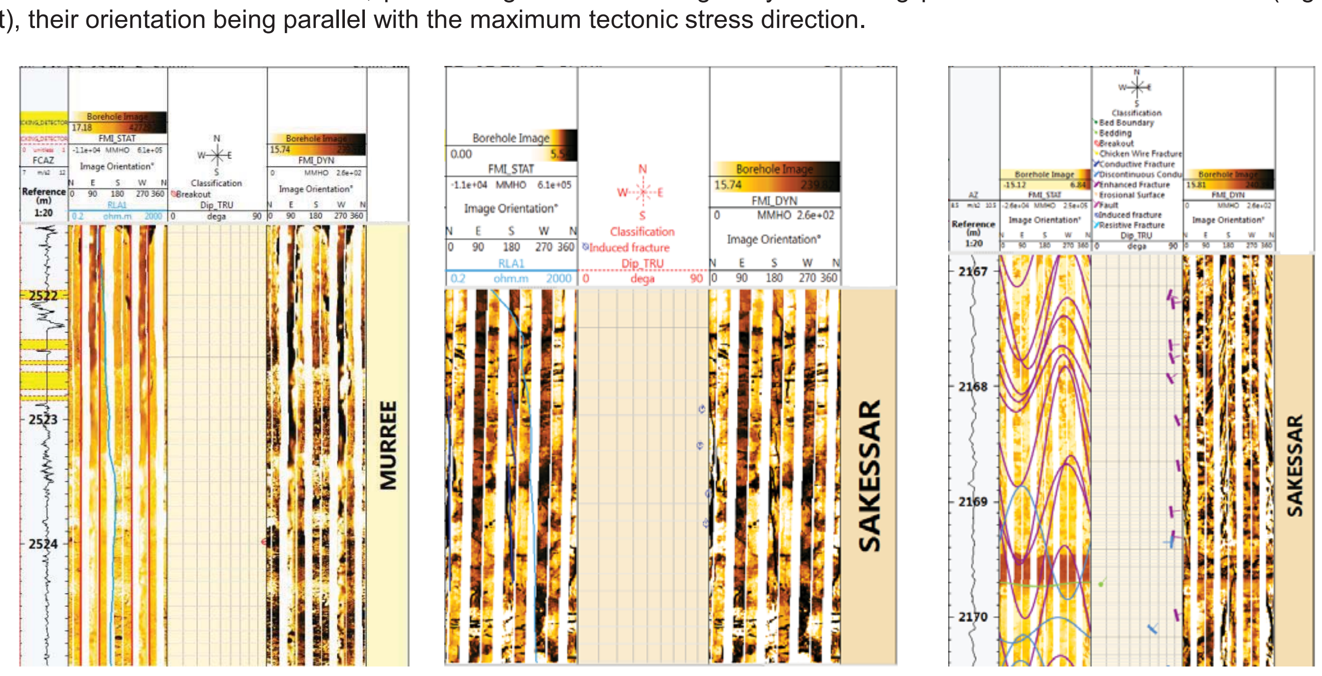

Fig. 12 Borehole breakouts, drilling-induced fractures and drilling enhanced fractures

3. Integrated analysis of well data (VI)

Given that the analyzed zone is highly tectonized, a change in the tectonic stress direction was observed on different depth intervals in a well (well 2). Nevertheless, a dominant breakout direction can be identified in all three wells: WSW - ENE. The drilling-induced fractures, as indicators of the maximum tectonic stress direction, are oriented NNW - SSE, normal to the breakouts direction (parallel to the minimum stress direction) (Fig. 13).

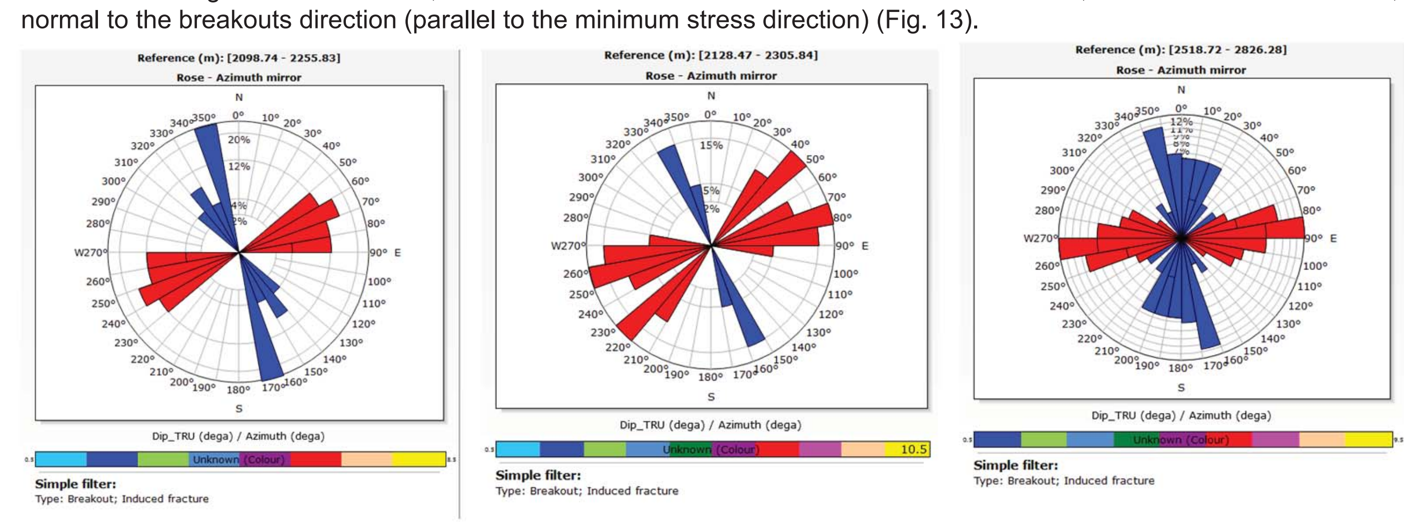

Fig. 13 Azimuth frequency diagrams for the borehole breakouts and the drilling induced fractures

The orientation of drilling enhanced fractures (Fig. 14) confirms the maximum tectonic stress direction as determined by using the drilling-induced fractures.

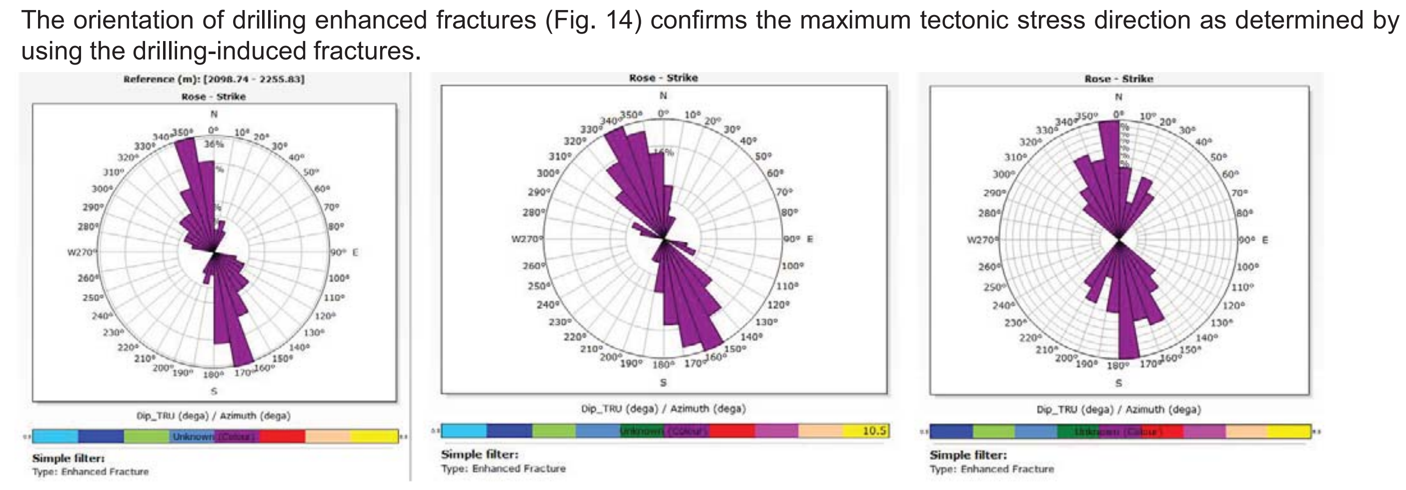

Fig. 14 Azimuth frequency diagrams for the borehole breakouts and the drilling induced fractures

An analysis of the logs quality control diagrams for the three wells shows that the imaging tool almost did not rotate in wells 1 and 2. The imaging tool's lack of rotation, indicated by the readings of the X and Y accelerometers and magnetometers, confirms the breakouts existence in these wells. In well 3, positioned 700m away from the fault zone, the imaging tool rotated 11 times; This indicates a decreased borehole ovalization either because of the distance with respect to the fault zone, or as a result of a higher tectonic stress in the hanging wall compartment of the fault with respect to the footwall compartment.

4. CONCLUSIONS

- The alignment of the major fault and fractures, parallel to the direction of the minimum horizontal stress, suggests the existence of a compressional tectonic regime at the moment of their formation.
- The simultaneous presence of breakouts and drilling-induced fractures in the same well is an indicator of a strike-slip tectonic regime. One may conclude that a change in the tectonic stress regime took place, from a compressive one to strike-slip one.
- The maximum tectonic stress orientation, normal to the fractures propagation direction, lead to closure of their apertures. This explains why in an area characterized by cataclasis, as a result of the fault proximity, porosity is less than 2% and fracture apertures are, generally, less than 0,5mm.
- Knowledge of the fractures' propagation direction with respect to the maximum stress is extremely important for the potential design of horizontal wells, attempting to keep the fracture apertures as open as possible.