PETROLEUM POTENTIEL OF TIGHT SAND IN ALGERIA BASIN

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Keywords: Unconventional Tight Sand Reservoir, Illizi basin

ABSTRACT

Recoverable reserves in Algeria fields are mainly from conventional reservoirs, discovered prior to 1970. Complex and subtle plays were not pursued at that time because of limited knowledge of the petroleum system, high costs and risks. Important resources still remain in unconventional Paleozoic reservoirs which could be accessed by using advanced technologies effectively. These reservoirs are complex and often difficult to produce with very low matrix permeability. Pore morphology is dominated by the extensive diagenesis that has resulted in porosity reduction by predominantly silica cementation but also with some clay, carbonate, and pyritic cements. Some reservoirs are naturally fractured but require artificial stimulation to increase the matrix permeability by connecting existing natural fractures and inducing new ones, typically through hydraulic fracturing. Recent intense exploration activity has achieved excellent results that confirm the hydrocarbon interest associated with this new concept and justify ongoing investigation efforts in this domain. Successful development of these resources requires a thorough understanding of the geology, stratigraphy, petrophysics and geomechanics to determine the best drilling and completion methods. The purpose of this paper is to optimize the well formation evaluation, reduce uncertainties and advice solutions. The Ordovician reservoirs, located in Illizi basin represent our case study.

INTRODUCTION

Tight sand reservoirs are generally defined as having less than 0.1mD matrix permeability and less than ten percent matrix porosity (Fig.1). Such reservoirs cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by a horizontal wellbore.

Increasing demand for natural gas, combined with new drilling and completion technologies developed during the intervening years, pushed development of low-permeability resources.

These reservoir types require specific (E&P) strategies and adequate formation evaluation techniques.

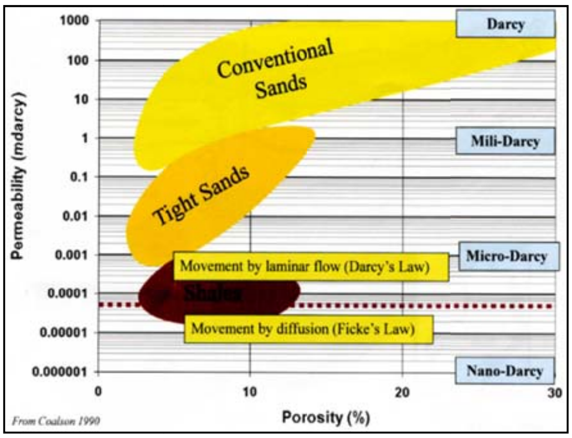

Fig.1 Cross-Plot PHI/K

ILLIZI BASIN CASE STUDY

The Illizi basin which corresponds to a broad intra-cratonic Paleozoic depression is bounded by the Amguid-Hassi Messaoud ridge to the West and the Tihemboka arch farther to the East Fig.2.

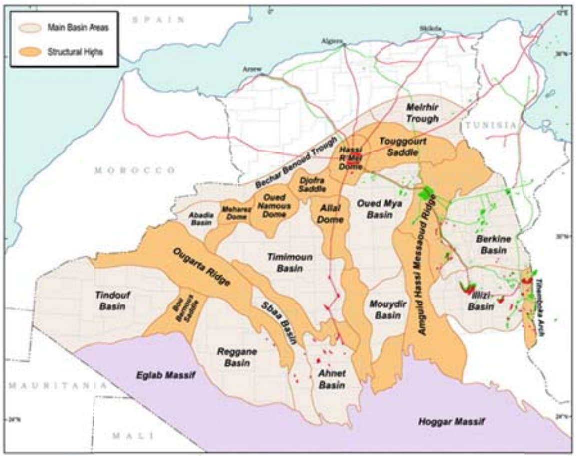

Fig. 2: Illizi Basin on the East South flank of the Saharan Platform

It is shallow marine deposit located close to a continental margin subjected to a period of intense erosion that resulted in the establishment of a Paleozoic and Mesozoic sedimentary column Fig.3.

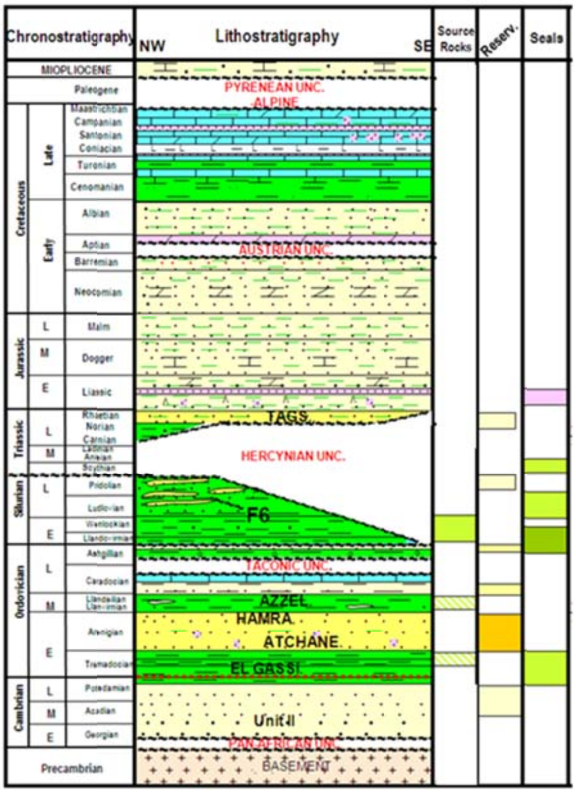

Fig.3: Illizi Basin Stratigraphic column

The Ordovician Hamra Quartzite constitutes a major Hydrocarbon reservoir in Illizi basin, objective of our study.

The Hamra Quartzite is made of medium to coarse quartzitic sandstone rich in sigmoidal cross bedding grading upward to massive sandstone rich in Skolithos. It is interpreted as a progradational sequence with a lower erosive boundary. The upper part of Hamra Quartzite is affected by early diagenesis materialized by several stage of dissolution suggesting immersion prior to the major flooding event of the Ouargla sandstone.

The Hamra Quartzite represents one of the best prolific reservoirs in Illizi basin. The flow rate from this reservoir is in close relation to the fracture intensity with permeability less than 1mD.

WELL FORMATION EVALUATION AND UNCERTAINTIES

Three Wells A, B and C within a same field are considered in this paper among many others to illustrate Tight Sand reservoirs. Each well requires a careful analysis of the objectives and local conditions to develop a comprehensive well evaluation program based on logs, cores and testing.

The Hamra Quartzite reservoir is characterized by a very low radioactivity, GR less than 15 °API, a high resistivity and low porosity causing a lack of accuracy in all porosity logs and fluid contact.

Despite of the poor reservoir quality the evaluation of logs suggests the presence of an important hydrocarbon bearing zone in three wells Fig.4, 5 & 6

The petrophysical results derived from the available logs are summarized in the table1.

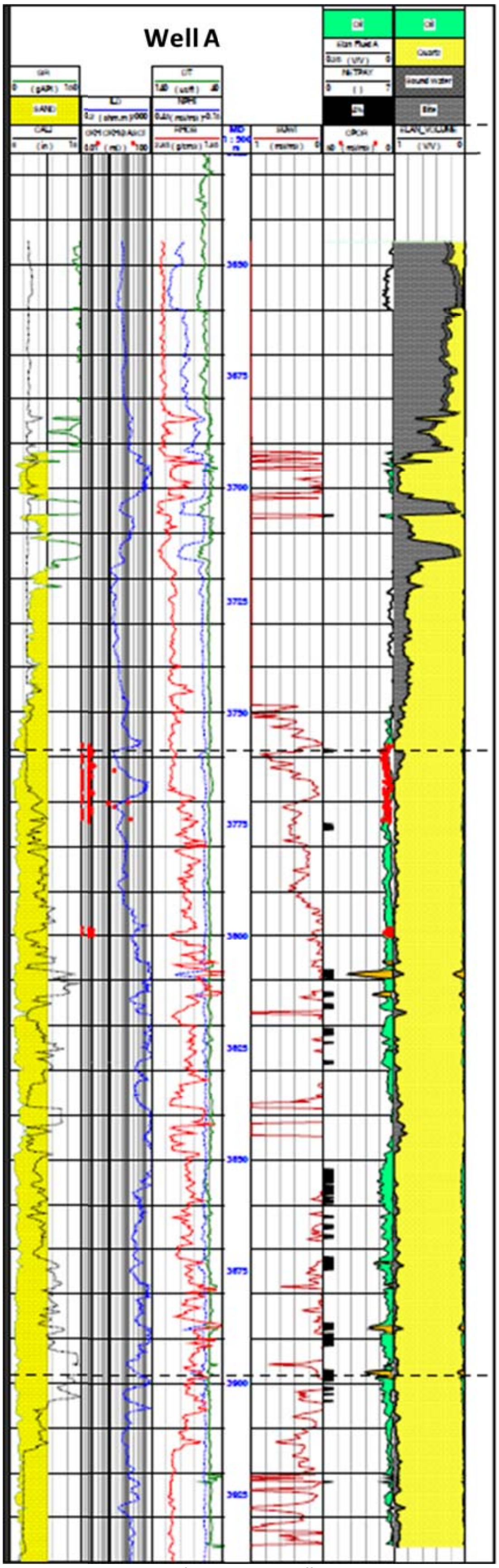

Fig.4 ELAN Well A

Well	Available Logs	Studies	Results
A Drilled 1979	GR/CALI/ILD/DT NPHI/RHOB	Sedimentological &Fracture characterization study.	pay interval =26m Phie=5% , Sw=10% Barefoot tested mud with gas & oiL shows
B Drilled 2009	GR/caliper/sonic -Density -No formation pressure measurement -No borehole images	-Laboratory Rock mechanical tests -1D MEM geomecanical study	Pay interval= 34m Phie=4% , Sw=15% DST-1: 212m3/h gas 0.54m3/h oil Flowed postfrac test. 2572 m3/h of gas 7.23m3/h of oil BSW= 5-10%
C Drilled 2010	-GR /HDIL - GR/LDT/CNL - HNGS - GR/CBL/VDL - Sonic scanner -Borehole images UBI/OBMI	-1D MEM geomecanical study. -Processing and interpretation of sonic scanner & borehole images	Pay interval=37m Phie=4.5% , Sw=25% Flowed during 6h40'after barefoot DST-1 738m3/h of gas 3.2 m3/h of oil 350l/h of water on BSW= 10%

Table.1

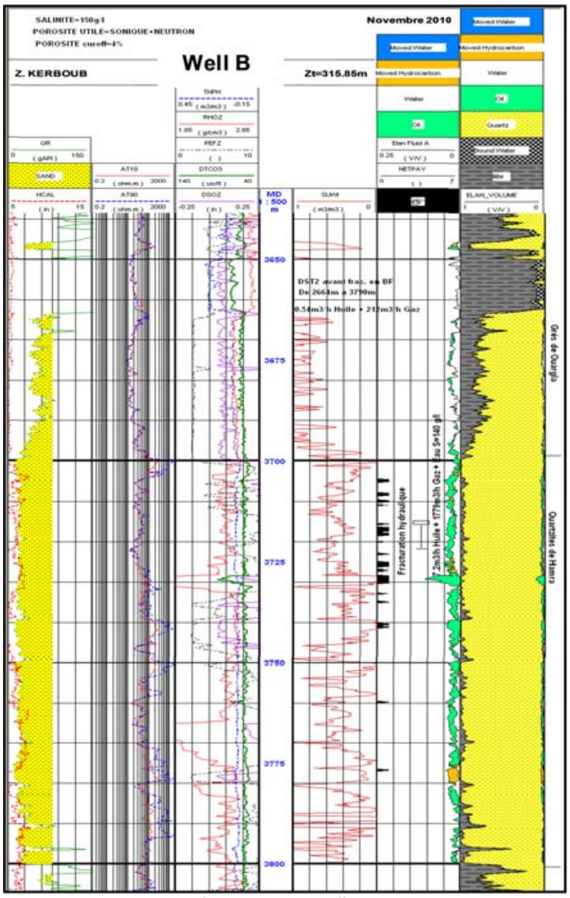

Fig.5 ELAN Well B

Formation evaluation with conventional logging and interpretation methods are problematic. Uncertainties are generally associated with physics of tool measurements, signal processing and interpretation methods.

Effectively, the formation water resistivity Rw parameter is difficult to estimate. Rw determined from PS is not even reliable because there is no development of a deflection. Often there is absence of a water-bearing level for calibration. Pickett plot can tend to overestimate Rw and water saturation Sw.

The cementation factor decreases with decreasing porosity and leads to lower the water saturation.

The porosity determination is difficult due to matrix changes, incomplete invasion and clay presence.

Shale models are complex and may not yield correct answers.

Archie equation breaks down at very low porosities.

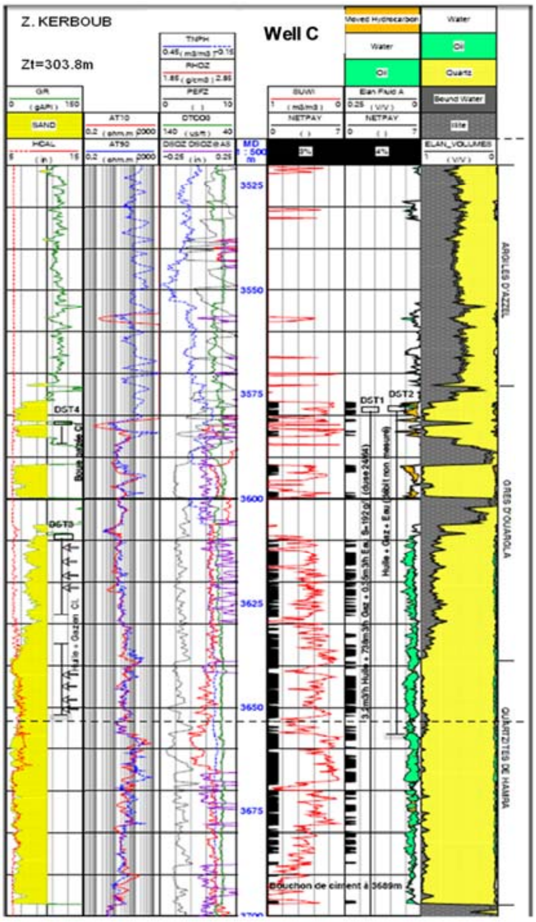

Fig.6 ELAN Well C

To better define the petrophysical properties and to reduce the uncertainties in the estimation of hydrocarbon in place and fluid contact in tight reservoirs, an extensive laboratory analysis for Archie parameters is needed.

Some advanced wireline logging allows reliable formation evaluation as follow:
- In low porosity and permeability sandstones the resistivity contrast is very high requires resistivity modeling.
- Accelerator neutron porosity logs offer a better signal-to-noise ratio and smaller environmental effects
- Magnetic resonance logging offers a direct measure of effective and total porosity with no matrix response uncertainty.
- Wellbore imaging logs are essential for both depositional environment and fracture evaluation studies.
- The Sonic Scanner tool offers better measurements of fast formation velocities and aids in evaluating open fractures and stress distributions from both Stoneley and shears wave anisotropy analysis.

SEDIMENTOLOGICAL STUDY

The sedimentological core analyses and the log to core calibration lead to the subdivision of the Ordovician in several lithofacies and genetic parasequences including a variety of prograding lower-middle shoreface and glacio-fluvial/marine deposit.

The Hamra quartzite constitutes a regional marker Fig.7 and is characterized by homogeneous facies dominated by clean quartz sand cemented to quartzite.

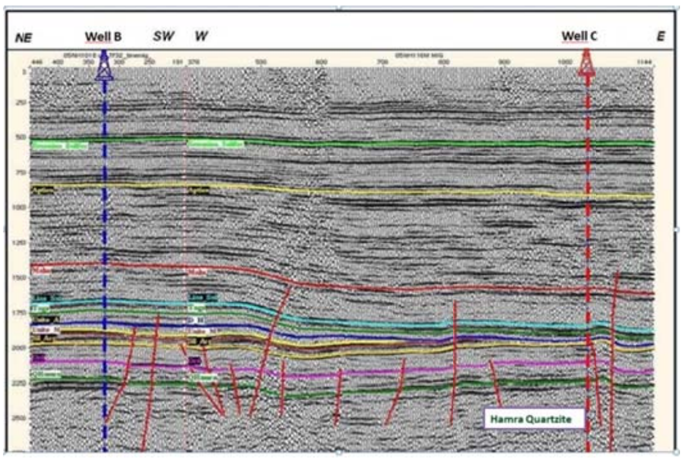

Fig.7 Seismic section NE-SW/W-E

The core description of several wells allowed identifying two distinct facies:

- Quartzitic Sandstone with Sigmoidal cross bedding
- Massive Quartzitic Sandstone with Skolitos bedding

The upper part of the Hamra Quartzite is dominated by massive quartzitic sandstone rich in Skolitos. The quartz grains are medium to fine, moderately sorted and frequently cemented by silica.

The Ordovician reservoirs were subject to several diagenetic events leading to the transformation of both mineralogical composition and the interstitial space. The main significant diagenetic alteration which affect the petrophysical properties are the pervasive precipitation of quartz cements and Illite as well as the dissolution of quartz at grain contacts favourable to quartz overgrowths Fig.8.

The sequence of diagenesis in the Hamra Quartzite is as follows:

-Dissolution of feldspar and rock fragment;
-Quartzovergrowth;
-Growth of authigenic feldspar;
-Dissolution of authigenic feldspar;
-Growth of pore-bridging and pervasive pore-filling Illite;-Insignificant carbonate, Chlorite and Kaolinte cement;
-Fracturing occur after the Hamra sediment had been lithified by quartz cementation and grain-contact dissolution.

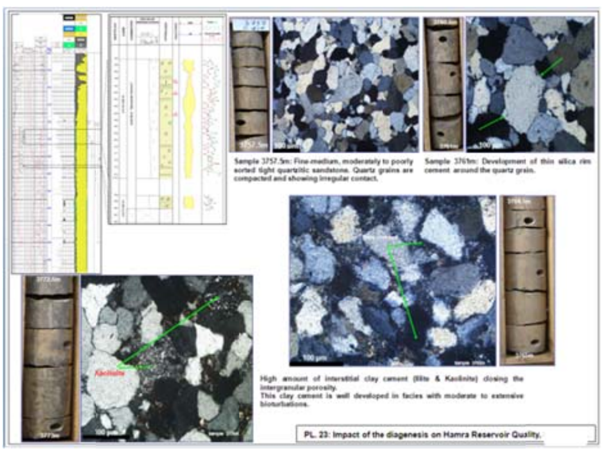

Fig.8 Thin section well A

It seems likely that diagenetic changes occurred to buried reservoir at temperatures up to 100°C causing reservoir degradation resulting in permeability mainly less than 1mD and low porosity averaging 5% Fig.9.

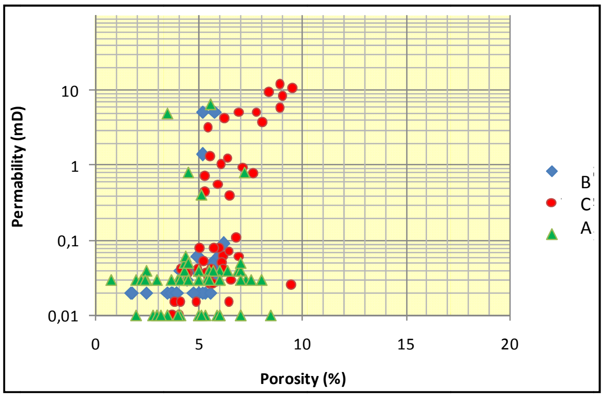

Fig.9 Cross-Plot PHI/K

Despite its poor reservoir quality the Hamra Quartzite was subjected to an early and late dissolution event leading to the development of secondary porosity. There is some evidence for the development and preservation of secondary porosity associated with feldspar dissolution. Porosity tends to be better towards the upper layers of this reservoir. A common attribute of this reservoir is that they were subaerially exposed under warm and heavy rainfall conditions.Fig.10, 11.

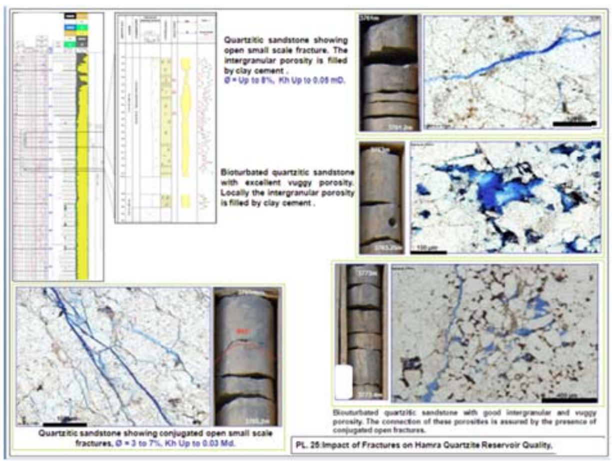

Fig.10 Thin section well A

FRACTURE NETWORK CHARACTERIZATION

Tight reservoirs are prone to intense fracturing with a strong impact on drilling, exploration & production activities.
From fracture study of about 122m cores, higher fracture density (N45° & N10° to N20°) are observed in the proximity of NE-SW faults. Most of these fractures are opened and/or partially filled by silica or clay cement Fig.10. It has been established that the presence of numerous tensile N45° fractures seem to be sufficient for hydrocarbon production.

Two families of natural fracture can be distinguished: the N°45 & N°10 fractures. The fracture may be opened, partially cemented or completely cemented by clay or silica cement.

The upper Hamra reservoir shows numerous stylolites and a natural fracture system of low intensity. These fractures are mainly NS and N45° implying that current maximum horizontal stress is oriented NW-SE.

The permeability of the Hamra rock matrix is extremely low and the porosity can range from low to moderate. Without the development of open fracture network system this reservoir would be non productive. However, the interpretation and the characterization of the N45°, N10° to 20°, observed in cores suggest that only open or partially cemented N45° fractures with small spacing have a great impact on reservoir properties and they will affect the reservoir flow behaviour. Fig11.

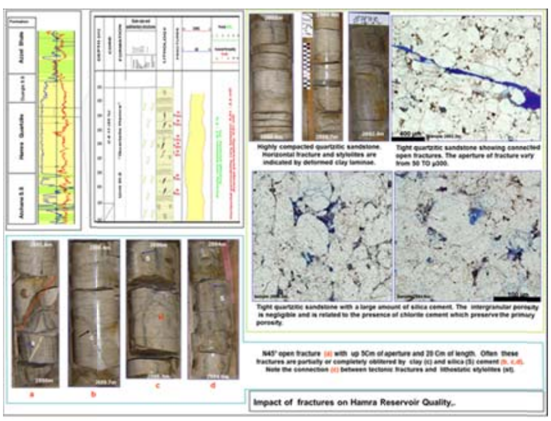

Fig.11

GEOMECANICAL STUDY

Most tight reservoirs are thick, up to 200m in our case study (Fig.12) that must be hydraulically fracture treated to produce at commercial gas-flow rates. To optimize the completion it is necessary to understand the mechanical properties of all the layers above, within, and below the hydrocarbon pay intervals of Hamra quartzites.

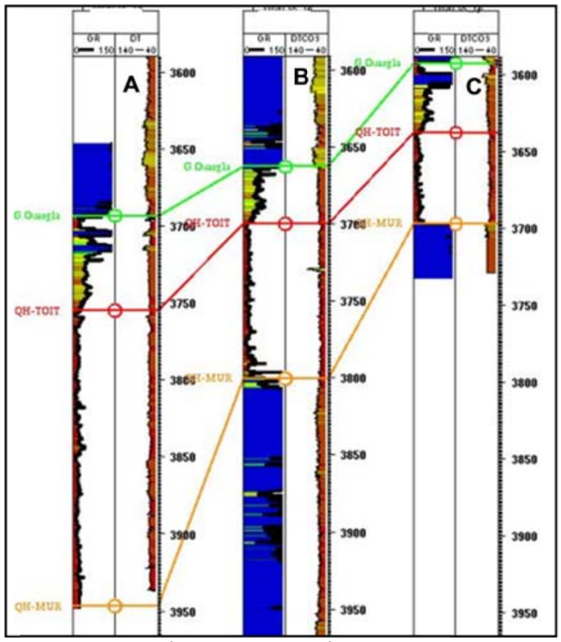

Fig.12 Cross Section E-W

A 1D mechanical earth model (MEM) workflow was established in both wells B and C. Fig.13

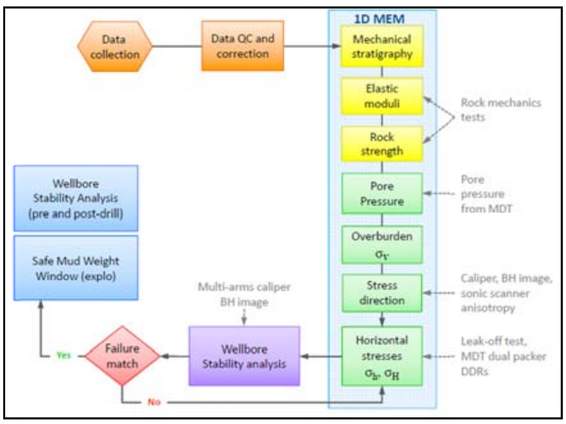

Fig.13 1D MEM WorkFlow

Basic rock properties such as the in-situ stress field, Young's modulus, and Poisson's ratio, were determined to design a fracture treatment by using logs, cores and well test data Fig.14 &15.

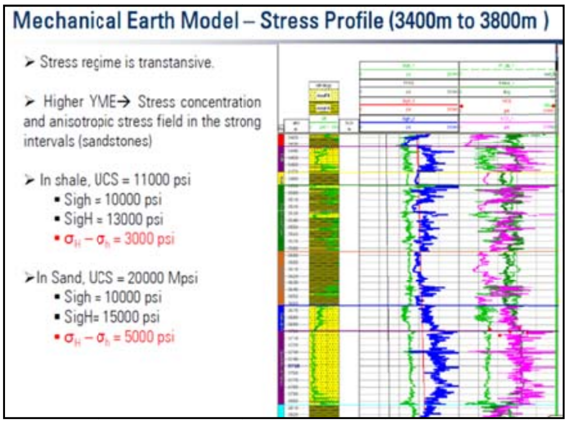

Fig.14 Stress Profil

The shaly zones remain stable because of their homogeneity. The breakout observed in Hamra quartzites section is due to a stress imbalance.

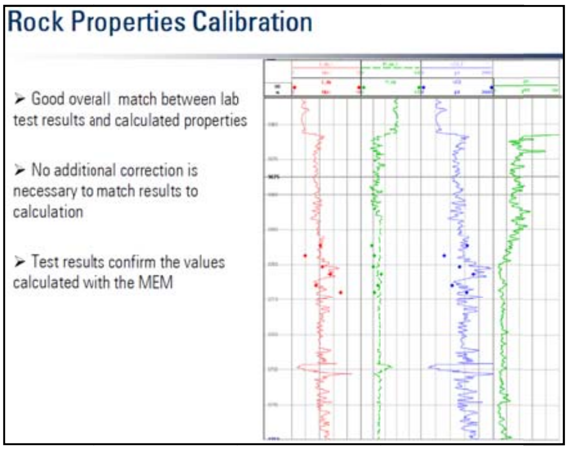

Fig.15 Rock Properties Calibration

The mechanical earth model study recommended raising the mud weight in well C to mitigate breakouts and avoid excessive back reaming, since numerous technical constraints (jamming, break, and fishing) were registered in well B, leading to a considerable waste of time.

CONCLUSIONS

This integrated study implies that the Ordovician target is a promising play in Illizi basin even though it has an extremely poor poroperm property.

The Hamra Quartzite which is considered as a potential reservoir is characterized by remarkable thickness of clean fine to medium-grained sandstones with a strong silica cementation giving to the rock a tight aspect. The upper part of Hamra Quartzite was subjected to many digenetic alterations presents the best reservoir parameters.

The reservoir quality of Hamra Quartzite is largely controlled by fracturing and diagenetic alteration. The diagenetic sequence includes quartz overgrowths that partially and/or totally destroyed the primary porosity but inhibits compaction, late dissolution of the silica cement creating a few vuggy porosity and finally, precipitation of clay cements.

Generally the Hamra Quartzite has a low density of faulting and fractures; open and cemented N45° fractures are observed in core, whilst mud losses suggest some fractures are conductive.

The Hamra Quartzite is characterized by high resisitivity related probably to the presence of residual oil and/or the reservoir is very tight. Despite his poor reservoir quality, the evaluation of well A, B and C well logs suggest the presence of oil bearing in entire zone of Hamra Quartzite.

Well C evaluated as a hydrocarbon bearing interval with no indication of aquifer presence was tested four times in different zones. Only the first well test comprising the entire interval was successful and a small amount of gas, oil and water flowed. It was considered as bad candidate to hydraulic fracture treatment according to the fluid contact uncertainty.

In Well B the hydraulic fracture treatment was successful and improved the flow of gas and oil thirteen times. The flow from this reservoir is related to fracture-enhanced permeability.

Well A drilled in 1979 has similar hydrocarbon potential to well B and C but just shows of gas and oil were observed in the well test. The well was abandoned definitively that time.

The well formation evaluation of tight sand remains complex and full of uncertainties that can be reduced by using appropriate parameters, interpretation methodology and logging tools.

Production of such reservoirs involves in several cases horizontal drilling and/or induced fracture program which is strongly dependant on correct characterization of the natural fracture systems and in situ stress conditions.

Considerable efforts are undertaken to develop and produce tight gas reservoirs in different basins of Algeria. An intensified program is conducted to optimize completion and fracture treatment at economic rates.

Table 2 presents the largest successful tight gas fields in Algeria where appropriate process has been implemented.

Field & location	Reservoir	Formation type	Reservoir Properties Phi%	KmD	Applied Technology
Tiguentour S-W of Algeria	Lower Devonian	Sandstone	20	<1	- Underbalance drilling. -Horizontal drilling & Fracturing. -Multi hydraulic frac stages.
Krechba S-W of Algeria	Lower Devonian	Sandstone	8.5	<1	-Horizontal drilling. -Geosteering. -Multi hydraulic frac stages.
InSalah S-W of Algeria	Lower Devonian	Sandstone	10		-3D multi-azimuth seismic survey. -Nuclear Magnetic Resonance. -Directional drilling. - Hydraulic fracturing. -Improved proppant

Table.2

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