PS Conducting Integrated Reservoir Studies in the Quartzite Hamra Reservoir-Tight Oil, Southern Periphery of Hassi-Messaoud Field, Algeria*

Ait Ali Zoulikha[1], Maâmar Djarir[1], Rafika Zenkhri[1], Abdellah Sokhal[1], Lounis El Hadi[1], Abdelkarim Aguenini[1], Gholamreza Zandkarimi[2], Philip Mosher[2], Donghai Xu[2], Fatmir Likrama[2], El Eraki Ahmed[2], and Mahmoud Noaman[2]

Search and Discovery Article #20392 (2017)**
Posted June 26, 2017

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

[1]PED, Sonatrach, Algiers, Algeria (gholamreza.zandkarimi@halliburton.com)
[2]CPM, Halliburton, Algiers, Algeria

Abstract

Characterization and analysis of naturally fractured reservoirs is challenging for oil and gas companies around the world. This paper describes how integrated reservoir studies including; geology, seismic, petrophysics, engineering; and geostatistical approaches with multiple realizations of reservoir parameters was used to help understand the risks and quantify the uncertainties for field development in the Hamra Quartzite tight, fractured, oil reservoir in Algeria. The focus is finding the sweet spots, quantifying the hydrocarbon-in-place, and optimizing the field development plans. The reservoir contains fractured quartzite and quartzitic sands with interbedded clays. The reservoir is sub-divided into six reservoir units (1, 2, 3, 4, 5 and 6), that show significant aerial and vertical heterogeneities. The sediments were tightly cemented and in most cases silicified during a series of different diagenetic processes. The tidal and clastic coastal depositional system represents the best fit for the existing characteristics on the described cores. The reservoir is characterized as low porosity and permeability quartzitic sands. These intervals may have been channels for fluid movement, causing subsequent diagenesis, including silicification, and either decreasing or increasing of secondary porosity, associated with micro fractures. One of the most challenging tasks of the reservoir characterization of the quartzitic formation is to deal with complexities associated with the inherent heterogeneity of the rock, uncertainty in influence of natural fractures in some areas, and understating the major efficient parameters in production. Several integration techniques were utilized in order to classify the existing rock types and accordingly distribute rock properties onto the geocellular model. This paper discusses the methods of integrating the results of seismic interpretation and inversion, geomechanical, fracture modeling, petrophysical, and engineering studies to build multiple 3D geological static reservoir model cases of a tight oil quartzitic sand reservoir and how major uncertainties associated with structural modeling, facies identifications and distributions and petrophysical parameter distributions were addressed in an integrated methodology. Ranking the multiple cases is ultimately done to select those necessary for further analysis. Keywords: Quartzite, tight oil, sweet spots, seismic inversion, fracture model, and uncertainty analysis.

References Cited

Al-Ajmi, F.A., and S.A. Holditch, 2000, Permeability Estimation Using Hydraulic Flow Units in a Central Arabia Reservoir: SPE 63254, Formation Evaluation.

Amaefule, J.O., D. Altunbay, D. Tiab, D.G. Kersey, and D.K. Keelan, 1993, Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells; SPE 26436.

Conducting Integrated Reservoir Studies in the Quartzite Hamra Reservoir Tight Oil, Southern Periphery of Hassi-Messaoud Field, Algeria

ABSTRACT:

Characterization and analysis of naturally fractured reservoirs is challenging for oil and gas companies around the world. This paper describes how integrated reservoir studies including; geology, seismic, petrophysics, engineering; and geostatistical approaches with multiple realizations of reservoir parameters was used to help understand the risks and quantify the uncertainties for field development in the Hamra Quartzite tight, fractured, oil reservoir in Algeria. The focus is finding the sweet spots, quantifying the hydrocarbon in place, and optimizing the field development plans.

The reservoir contains fractured quartzite and quartzitic sands with interbedded clays. The QH reservoir is subdivided into six reservoir units (1, 2, 3, 4, 5, and 6), that show significant aerial and vertical heterogeneities. The sediments were tightly cemented and in most cases silicified during a series of different diagenic processes. The tidal and clastic coastal depositional system represents the best fit for the existing characteristics on the described cores.

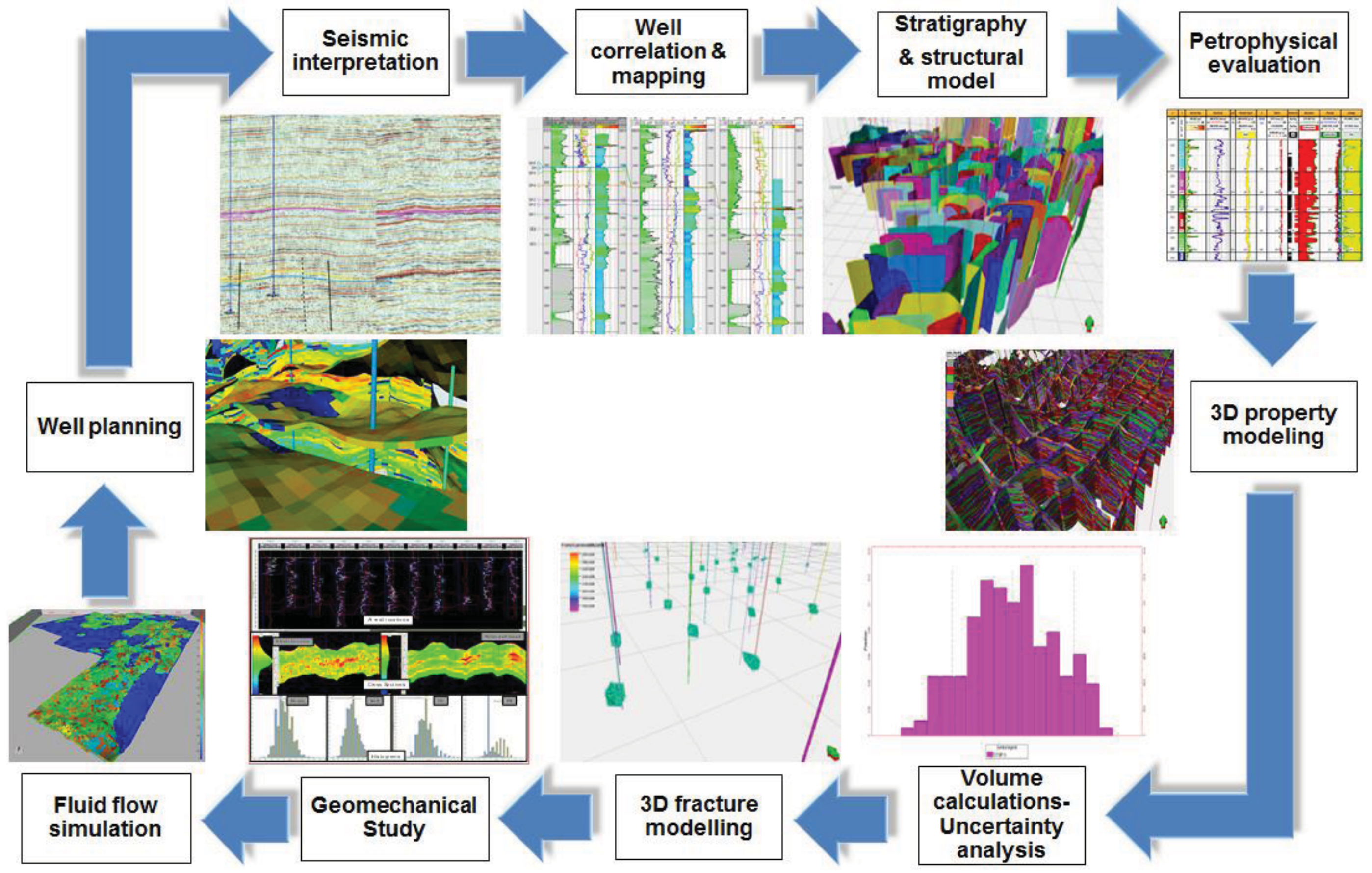
The reservoir is characterized as low porosity and permeability quartzitic sands. These intervals may have been channels for fluid movement, causing subsequent diagenesis, including silicification, and either decreasing or increasing of secondary porosity, associated with micro fractures.

One of the most challenging tasks of the reservoir characterization of the quartzitic formation is to deal with complexities associated with the inherent heterogeneity of the rock, uncertainty in influence of natural fractures in some areas, and understanding the major efficient parameters in production.

Several integration techniques were utilized in order to classify the existing rock types and accordingly distribute rock properties onto the geocellular model.

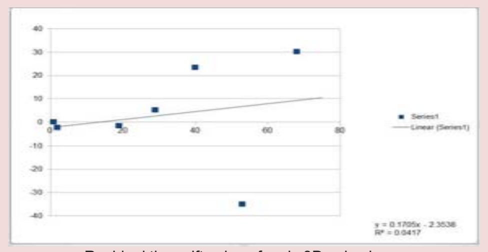
This paper discusses the methods of integrating the results of seismic interpretation and inversion, geomechanical, fracture modelling, petrophysical, and engineering studies to build multiple 3D geological static reservoir model cases of a tight oil quartzitic sand reservoir and how major uncertainties associated with structural modeling, facies identifications and distributions and petrophysical parameter distributions were addressed in an integrated methodology. Ranking the multiple cases is ultimately done to select those necessary for further analysis.

Keywords: Quartzite, tight oil, sweet spots, seismic inversion, fracture model, and uncertainty analysis.

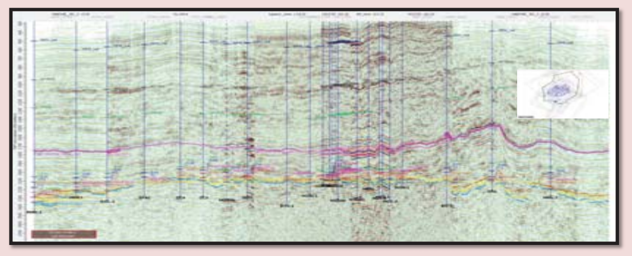


Seismic interpretation:

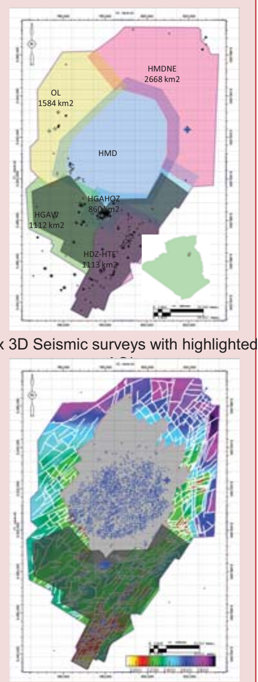
The target area is covered by six (6) seismic surveys of 3D data set acquired and processed separately in different periods. **The AOI, involving three 3D seismic surveys, is the southern outskirt of HMD area as highlighted on the maps.** The 3D seismic interpretation has been done for these areas as separate stratigraphic time horizons and structural fault framework for each seismic survey. Seismic to seismic tie has been checked at a number of points in the overlap areas among the different seismic volumes - taking HMD survey as the reference - which gave rise to observed time, phase and amplitude tie values. The best seismic to seismic tie has been achieved through least square fit line of the average shift values to calculate the residual time shift.



Residual time sift values for six 3D seismic surveys.



Regional arbitrary seismic line passing through six 3D seismic surveys after tie.



Six 3D Seismic surveys with highlighted

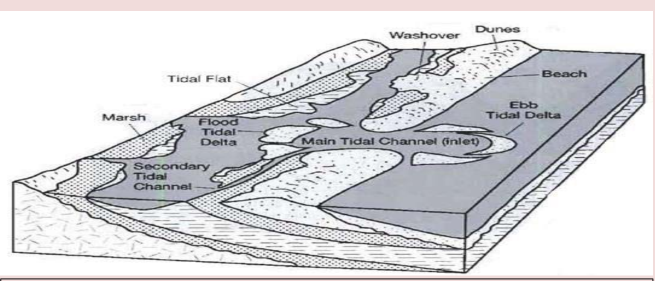
Quartzite Hamra depth surface with highlighted AOI.

In the seismic surveys overlap areas, and after seismic to seismic tie, the time horizons` tie and merge process` are smooth where there is no structure effect, however, editing of the horizons and faults interpretation were vital in the areas of miss-tie. One structural framework and one surface for Quartzite Hamra top and bottom all-over the surveys area after merge.

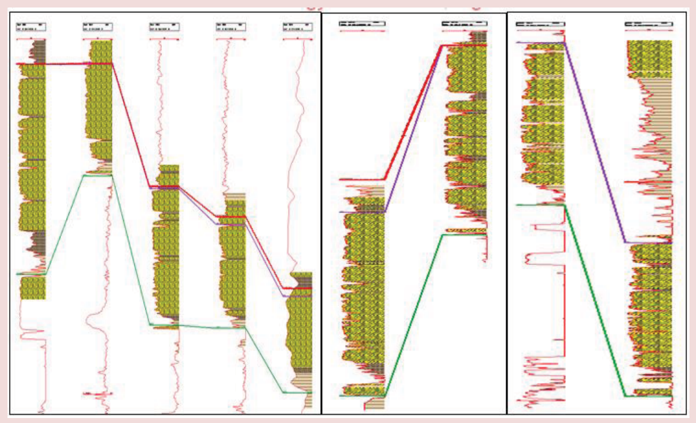
Geological review and core description:

The Hassi-Messaoud Periphery field has the structure of a monocline, dipping south from the main anticlinal dome structure inherited from the Hercynian orogeny, which was most active at the end of the Paleozoic. The erosional episode at the end of the Hercynian tectonic stage gave rise to progressive disappearance of the upper units of the reservoirs, from the center toward the periphery of the field, and the cutting of deep narrow valleys following major faults. The most deeply eroded valleys are filled with volcanic rocks. The field is extensively compartmentalized by regional fault systems trending NE-SW to NNE-SSW and by complex perpendicular and parallel systems on a smaller scale. The systems of fissures associated with the faults contribute to production by increasing permeability where they are opened and connected.

The Quartzite Hamra Formation is a shallow marine geological unit. Two parasequences are identified based on environmental deposition; the lower unit is composed of coastal plain, backshore, tidal channel deposits. The upper unit is composed of shore face, berm, deposits; this upper unit has more siliciclastic and diagenetic cementation, giving poor reservoir properties. The observed fracturing contributes to the reservoir communication; both upper and lower units might contain hydrocarbons by different patterns of migration in the fractures, faults and rock matrix. The lower unit has channel deposits with better reservoir quality (porosity & permeability). The upper unit has tidal channels in some areas, therefore it might contain hydrocarbons.



The clastic coastal environment, showing the Beach with shoreface, berm, dunes, the backshore. the tidal channel and other environments associated with the sea and continent transition.



Petrophysical evaluation:

Load and qualify control data

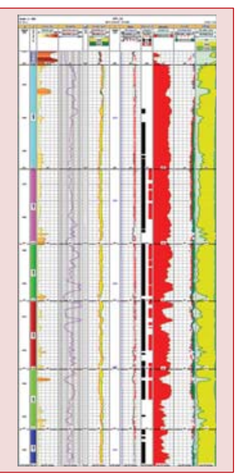
Load core data

The gamma–ray curve was used as primary shale indicator, due to possibility of non–shale radioactive minerals, the transformed GR curve was used to calculate volume of shale.

The preferred method for computing porosity was based on using neutron and density logs together. Sonic log was used as alternative option in case of severe washout existence in the borehole, or if neutron or density logs were absent. The effective porosity (clay corrected) was calibrated to core data.

Water saturation was computed for the wells using v-clay, porosity and resistivity logs. The Indonesian (Poupon-leveaux) shaly-sand equation was applied to mitigate for any conductive minerals (clay) in the QH field. The Archie parameters and connate water resistivity (rwa) were additional inputs.

The Gross net estimate was determined applying the cut offs VSH=35% and PHIE=5%, to Net pay, it is determined by VSH=35%, PHIE=5% and SW=65%.



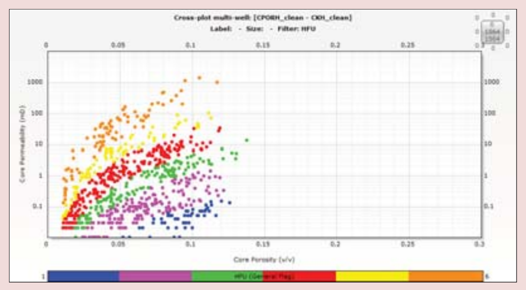
FZI classification and permeability log generating:

FZI classification and permeability log generating:

Rock type will help to construct a robust geological model in controlling the porosity population and the permeability perdiction. A hydraulic flow unit is a section of reservoir which is different from other parts by means of hydraulic characteristics or characters controlling fluid flow in reservoir (Amfauel and al; 1993). Thus, if we divide the reservoir into various flow units, permeability can be estimated with sufficient accuracy (Al Ajmi and al; 2000).

FZI (flow zone index) methodology have been used based on the available RCAL data of 60 wells. 2 clustering were performed, one based on the production (well test) and the second one based on the geographical position.

Rock types were repeatedly fined tuned until representative poro-perm relationships was obtained. The methodology of identification of hydraulic flow unit was carried out by using the ward classification. The analysis show there are 6 HFU in Hamra Quartzite. Figure shows a composite plot of core porosity and permeability from all the cored wells against the respective FZI. The best quality rocks correspond to the orange shaded points having the highest FZI values while the blue points represent the poorer quality rocks (Table).

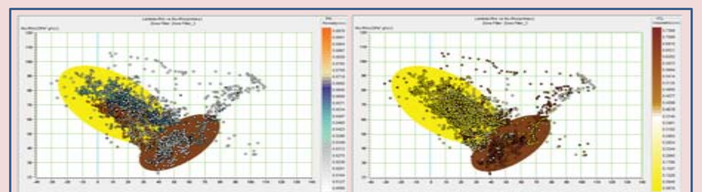


Name	Equation	R^2 adjusted	Number of samples	RMSE	Color	FZI
Reg1	Core Permeability = 32.45612 * pow(Core Porosity, 2.79973)	0.548856	97	0.206446		0<FZI<0,3
Reg2	Core Permeability = 125.1738 * pow(Core Porosity, 2.61349)	0.715396	370	0.275726		0,3<FZI<1
Reg3	Core Permeability = 2613.741 * pow(Core Porosity, 3.04938)	0.94638	301	0.174484		1<FZI<2
Reg4	Core Permeability = 10665.89 * pow(Core Porosity, 3.00453)	0.935011	468	0.217447		2<FZI<5
Reg5	Core Permeability = 79883.7 * pow(Core Porosity, 3.15599)	0.965986	159	0.16625		5<FZI<10
Reg6	Core Permeability = 1024755 * pow(Core Porosity, 3.33972)	0.914929	169	0.270219		FZI>10

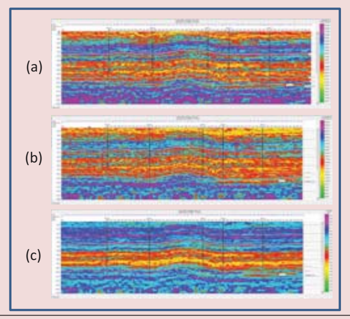
Seismic inversion:

The objective of the inversion is to incorporate information from Pre-Stack seismic data and well data to generate inverted Vp Vs and Density, Acoustic Impedance and Shear Impedance volumes ,from which ,advanced rock properties λρ and μρ are calculated and used to:

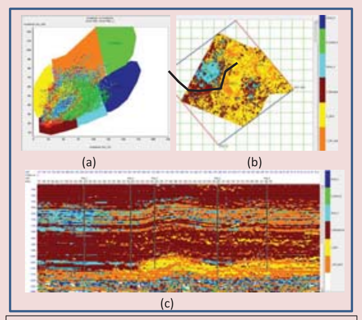
- Enhance reservoir characterization as an extra quantitative interpretation tool.
- Identify eruptive layer distribution and thickness in the area of interest.
- Distribute the reservoir geomechanical properties.
- Enhance and refine seismic interpretation in the target reservoirs.
- Porosity and reservoir quality prediction.
- Investigate for additional subtle volumes that were not clear on seismic data.



λρ and μρ well logs cross plots coloured by (a) Porosity (b)VSH



An arbitrary line passing through five wells of the area showing the final PreStack inversion results.(a)Inverted Acoustic Impedance, (b)Inverted Shear Impedance and (c)Inverted Density.



Cross plot and zonation filter of seismic inversion λρ and μρ (a). Arbitrary line on cross plot volume(b)and (c)Amplitude extraction on λρ and μρ cross plots zonation filter volume.

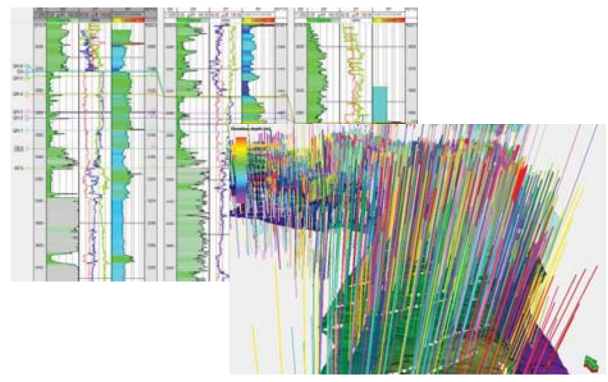
3D Geological Static Model

Geological static modeling was performed in *PETREL*™ software in different stages including: Project Setting, data loading and QC, stratigraphy and structural modelling ,property modelling (facies, porosity, permeability, water saturation, and net to gross), volume calculations & uncertainty analysis , and upscaling & exporting to Simulator.

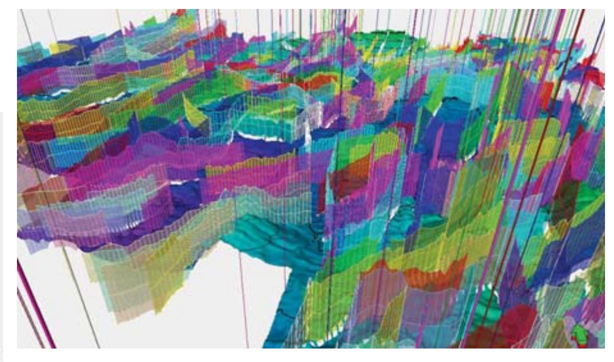
The main challenges in geomodelling:

1. Complexity of the structure including more than 400 faults
2. Facies definition and distribution
3. Property distribution, such as, permeability.
4. Different oil-water contacts (OWC)

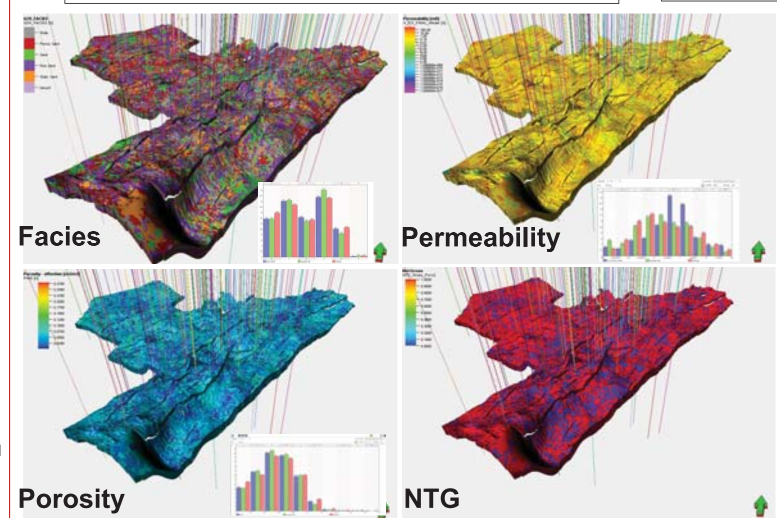
The geo-cellular model was upscaled and was exported to use in the simulator of *Nexus*.



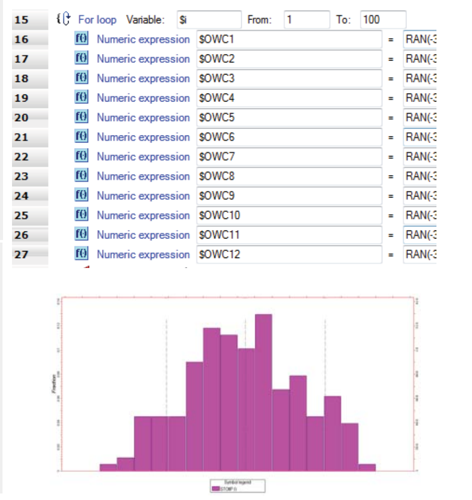
Data loading



Complex structural model



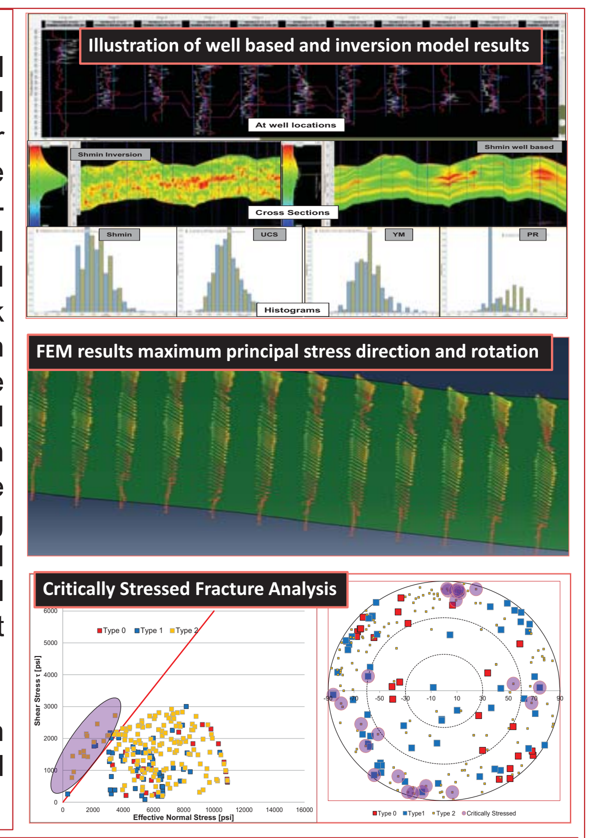
3D property modeling



HCPV - Uncertainty analysis

Geomechanics:

A geomechanical study was performed for the Hassi Guettar field with the objective of estimating the in-situ stress field (magnitudes and orientation) and rock elastic and strength properties in the reservoir, over and under-burden. Such results are used in the decision making process of drilling and well design, as well as complement reservoir characterization especially in relationship to natural fractures.



A well based geostatistical, a seismic inversion based 3 D model as well as an integrated/hybrid model were built to characterize the geomechanical properties of Hassi Guettar. The well based and inversion based models show reasonable agreement; they complement each other and together provide a better integrated model: a high (well log scale) vertical resolution with a lateral population of properties guided by the seismic inversion model results.

The material properties of the hybrid model were used as input to the Finite Element Method field scale model for Hassi Guettar which outputs a calibrated, fully 3D solved stress field which captures the complexity of the field.

A critically stressed fracture analysis is also performed on the natural fracture analysis. The conductivity of the natural fractures observed in wells was observed to correlate to the stress state and criticality of fractures. 3D maps of the stress field in Hassi Guettar were then used in characterizing and guiding the natural fracture network and its properties.

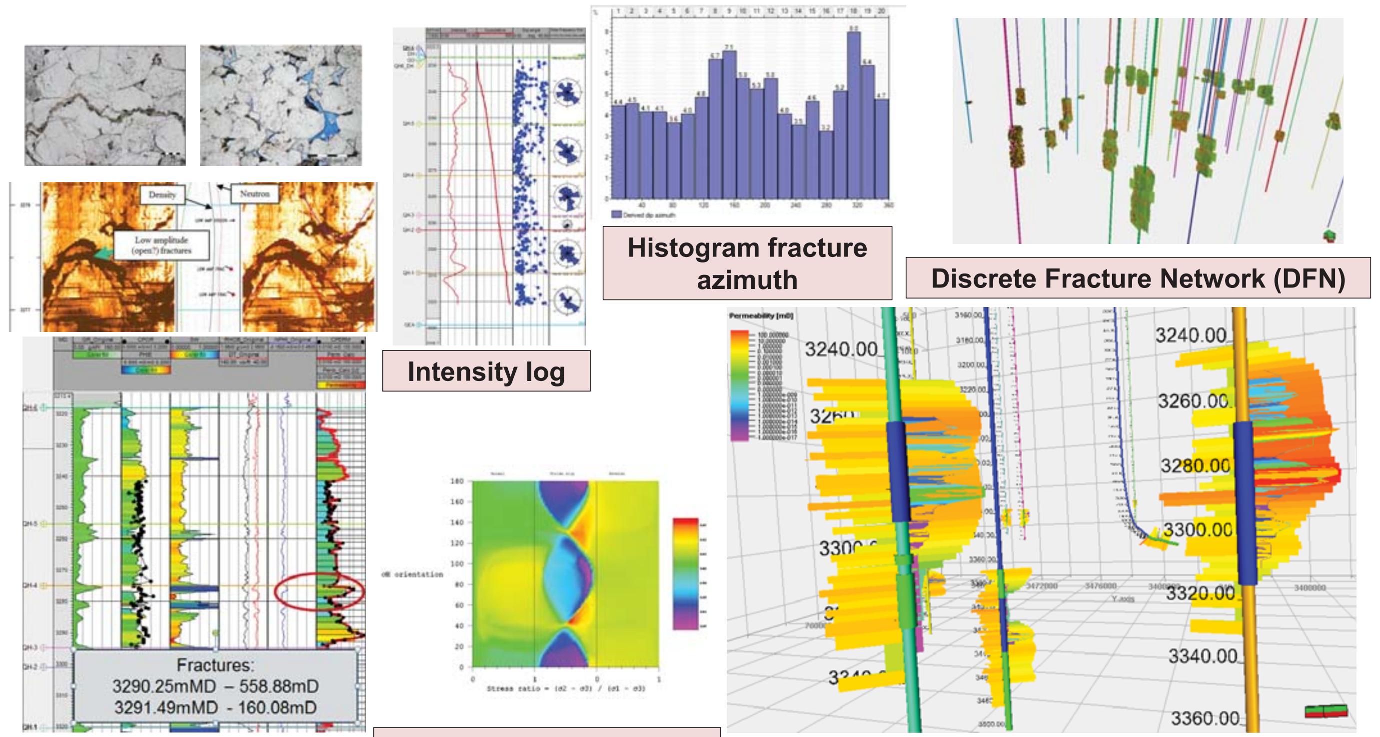
3D Fracture Model:

Fracture modeling was performed in different stages including:

1. Data Collection and loading:
   (Fracture data, mainly image log interpretation,
2. Fracture Driver Identification:
   Core description, seismic attributes and geo-mechanical data, completion data, Production data, PLT.
3. Fracture modelling (DFN/IFM)
   a. Tectonic Model
   b. Generate fracture network
      Distribution
      Geometry
      Orientation
4. Scale-Up
   Property upscaling
5. Export to simulator

Well Data & Loading → Data Analysis and Mapping → Fracture Modelling (DFN/IFM) → Scale-Up → Export to Simulator

Fracture modeling was performed using *PETREL*™ software. The results of fracture model is qualitative and must be calibrated with production data during fluid simulation modelling.



Core data

Intensity log

Histogram fracture azimuth

Discrete Fracture Network (DFN)

Tectonic model-stress domain

Fracture properties

Reservoir simulation modelling

Dynamic modeling was undertaken in the following workflow by using Halliburton Nexus® reservoir simulator:

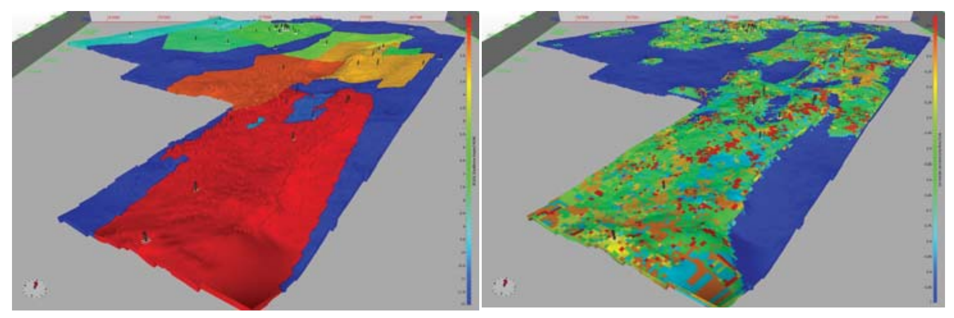
Pressure, Fluid Properties, SCAL, Fluid Contacts & Rock Data
Well Trajectories & Perforations
Production history

Import Grids and Properties from Static Model
Define Regions and Initial Conditions (P, T, OWC)
Input PVT, SCAL & Rock Compressibility
Initialize and Verify Hydrocarbon-In-Place

Import Well Trajectories, Perforations & Production
History Matching –Pressure and Fluid Rates

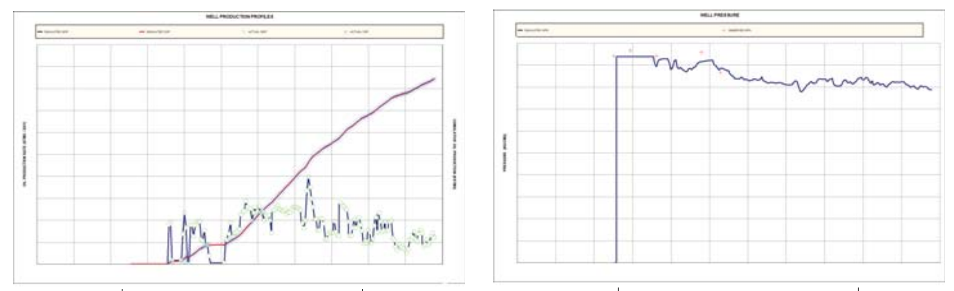
Well Optimization
Production Constraints
Development Scenarios
Production Rate & Ultimate Recovery

DATA
MODEL
- CONSTRUCTION
- CALIBRATION
PREDICTION



Twelve (12) equilibrium regions

Water saturation (Capillary pressure)



Well production profile

Well pressure

Conclusions:

1. An integrated workflow involving multi disciplines of geophysics, geology, petrophysicist, geomechanical, and reservoir engineering was performed to construct a 3D geocellular model for seven (7) fields

2. The main challenges of structural complexity of the reservoir, rock property heterogeneity, and fluid contacts uncertainty were considered in this study.

3. An essential results of geocellular/DFN modelling and geomechanical study assisted for better understanding of the fractures system.

4. The results of fracture modeling was used as guidance for history-matching and a good match between simulated and observed pressures/fluid productions was obtained.

5. The fracture modeling study will be further used to assist in well optimization for production forecast.

Authors:

(Sonatrach)
Ait Ali ZOULIKHA,
Maâmar DJARIR
Rafika ZENKHRI
Abdellah SOKHAL
Lounis EL HADI
Abdelkarim AGUENINI

(Halliburton)
Gholamreza ZANDKARIMI *(Presenter)*
Philip MOSHER
Donghai XU
Fatmir LIKRAMA
El Eraki AHMED
Mahmoud NOAMAN

Contributors:

(Sonatrach)
Khalil KARTOBI
Karim BELABeD
Feriel OURIRI
Mahida IDDIR
Boufedda DJAOUIDA
Ziani FERIEL
Fatiha ARTEBASSE
Abdelhamid CHOUAKI
Meksoud NOUDJOUD
Yekene SOFIANE
Khalida AMI
Hesham HASNAIN

(Halliburton)
Ali MURABET
Claudia SANTANA
Bikram BARUAH
Miguel PENA
Abdelfattah ELSHESHAEY

Acknowledgments:

Fekhar ABDENNOUR
Hesham TOKALI
Ali MURABET
Sayed SHOKEIR
Sofiane ALLOUTI

References:

J.O. Amaefule, D. Altunbay, D.Tiab, D.G. Kersey, D.K. Keelan, Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells, SPE 26436, 1993.

2. F.A. Al-Ajmi, S.A. Holditch, Permeability Estimation Using Hydraulic Flow Units in a Central Arabia Reservoir, SPE 63254, Formation Evaluation, 2000