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A New Empirical Model for Enhancing Well Log Permeability Prediction, Using Nonlinear regression method: Case study from Hassi-Berkine Oil Field Reservoir – Algeria

BELHOUCHET H.E., BENZAGOUTA M.S., DOBBI A., ALQURAISHI A., DUPLAY J.

Abstract

The reservoir permeability (K) factor is the key parameter for reservoir characterization. This parameter is considered as a determinant reservoir quality index. Depending on the data required and procedure availability, permeability can be defined from several methods such as; well test interpretation, wireline formation tester, and core data. These approaches can also be in assumption with permeability prediction targeting the non-cored sections. According to a similar status, well logs records can be an interesting support tool in use to reach the planned objectives. Thus, this investigation consists of finding out a model able to estimate the well log permeability and adjusting the outcome to the core permeability results.

In this led research, the applied approach to the core data, to start with, was aimed to determine the reservoir rock types (RRT) using the flow zone indicator (FZI) method. The obtained classification allows stating a permeability model for each rock type.

In order to calculate permeability from well logs, FZI has been founded out. A multi-regression technique was used to analyze the relationship of FZI with respect to specific logs such as Gamma-ray (GR), Density Log (RHOB), and Sonic log (DT). An objective function has been designated to minimize the quadratic error between the observed normalized FZI coming from core data, and the normalized FZI calculated from well logs. This process is carried out to identify a mathematical correlation allowing the estimation of FZI from porosity logs, leading to permeability determination. As results, permeability from logs was supporting relatively permeability defined from cores. The final results can be an accurate and real test for associating the exactitude performance of logging data records in boreholes with respect to the overall reservoir characterization sections. Thus, the applied investigation can be a genuine and quick method for essentially a specific deduction regarding the non-cored reservoir sections, with reference to rock typing, permeability and probably further reservoir factors.

Keywords

Permeability, Reservoir characterization, Rock typing, Hydraulic unite, Flow zone Indicator

1. Introduction

The development of an oil field is an entire range of research activities starting from exploration up to field development (Galard, Jean-Hector et Al., 2005). It consists of characterizing a sedimentary basin in detail. The exploration steps may involve seismic data, logging, and analysis up to geobodies identification. In order to get a stable, consistent and coherent model, specific studies have been developed (Al-Hajeri, M. et al., 2009). Dynamic modeling with reservoir fluid characterization, SCAL studies, and identification of initial conditions are also part of these orientations (Holtz, M. H., 2002). The reservoir characterization parameters in that purpose can be figured out by factors such as seismic attributes, rock typing and geostatic. These parameters concern can be through probabilistic function responsible for uncertainties.

Different researches on that purpose have been led. However, investigations can be exposed to some risks. Doubts can be issued from a reduction of exploration uncertainties and inefficiency related to the predicted potential and real reserves presence of hydrocarbons (Richard C. Selley and Stephen A.

Sonnenberg, 2015). In addition, any exploration achievement can be related to significant geologic elements processes and rock typing (Al-Hajeri, M. et al., 2009). Modeling system and fluid dynamics behavior can be key factors suitable for the reservoir potential evaluation and recovery challenge (Galard, Jean-Hector et Al., 2005).

The Rock typing is a process of rock classification based on mineralogical composition, grain size, shape and pore size distribution (PSD). Rock typing – fluid interaction, with fluid dynamic behavior, and capillary effect are of importance in this organization. In such circumstances, the envisaged process can involve: integrating, analyzing and synthesizing the real data supplied from different borehole records and cores analysis.

Other detailed parameters used, to define rock typing as part of the reservoir comprehension, characterization for fluid circulation aptitude is the hydraulic flow units (HFU). Rock typing classification can be allocated to the same dynamic properties, the same porosity, and permeability correlations results, identical capillary pressure profile and the same relative permeability curves. Similar characteristics are well supported by Shenawi, S. H. et al., (2009). The cited authors found that Hydraulic Unit (HU) determination and use is providing a useful and interesting advice and device for rock typing definition in relation to the porous media assessment.

Once the rock typing identification procedure is done, reliable estimated permeability can be extended to the non-cored wells. This assumption allows the generation of water saturation models and minimizing convergence problems. Therefore, the reservoir performance is then related to generating simulation sensitivities, involving possible rock classes endorsed by considered scaled field. Accordingly, figuring out reservoir properties, it can be carried out along the whole reservoir sections.

Therefore, the requirement of conceptual studies in that regard is in need of sensitive steps materializing the stability and convergence of the model as a digital one. For the case study, the reservoir characterization, based on permeability (K) determination will lead to developing an operational modeling device. This application is capable of calculating the permeability as a function of porosity and lithology (Enaworu, E. et al., 2016). The impact of the rock properties on the static and dynamic behavior of the fluid circulation, related to rock typing, is another essential controlling factor to consider (Attia, M. Attia and Shuaibu, Habibu , 2015).

Control on permeability prediction for rock typing determination is also related to the flow zone indicator (FZI). It is known that the FZI parameter is directly associated to the hydraulic unit for considered rock type as well as its porous media (Enaworu, E. et al., 2016). The method was proposed to decrease the absolute error between defined permeability from cores and the calculated one. In addition, applied method can ensure better development of the considered oilfield by optimizing the perforation intervals. With regards to the overall, an enhancement boreholes recovery can be set. Meanwhile, the method will guide avoiding the interval located in the aquifer section: Since underestimation of the permeability in the section near the oil-water contact (OWC) can be considered as the main issue for water breakthrough occurrence.

The preferred zone for perforation is generally carried out in interval above the oil-water contact. This scenario is intended to delay the water breakthrough arrival. On the other hand, owing to a similar scenario, the probability of having a good permeability in the reservoir section above the water-oil contact can be probably underestimated. Calculated permeability is affected by its estimation accuracy (Wu, Keliu and Li, X, 2013). The calculated permeability care can be subdued to some uncertainties regarding its estimation exactitude. This kind of statement might be proofed by water-wet rocks and high salinity formations (Elraies, Khaled Abdalla and Yunan, Mat Hussin, 2007).

The general complexity for the reservoir characterization related to permeability prediction especially in the non-cored borehole section, is conducted towards a variety of methods, which can be executed. Investigating on permeability and porosity characteristics, with regards to geological properties of the rocks, might carry considerable reserves. Texture and structure factors with mineral composition and their distribution (arrangement, packing, sorting distribution), remain an essential impact regarding uncertainties on rock typing and degree of heterogeneities statements (Benzagouta, Mohammed, 2015). Conversely, making use of parameters recorded from the formation evaluation, ambiguity concerns might be improved for sustaining the decrease in rock typing uncertainties (Mohammad Emami Niri and David Lumley, 2014, Pirrone, M. et al., 2014).

Similar statement is well known in the Lower Shaly – Triassic Sandstone Formation (TAG-I Formation, Algeria), where, the main characteristics controlling rock typing uncertainties, can be owed to rock solids textural and fractional compositional. In addition, contribution is expected from fluid flow filling pores and its properties.

For similar purposes and to clear out various doubts for the case study investigation, conducted tasks can be set as follow:

- Rock typing identification based on integrating, analyzing and synthesizing data from well logs and core analysis.
- Rock typing identification related to the volume of shale estimated from gamma-ray (GR), hydraulic units, capillary pressure profile, and saturation height function.
- Finding out relation between completed classification process using FZI method and permeability models specified for each rock type.
- Anticipating the determination of FZI from well logs application using the empirical model and non-linear regression approaches.
- Final objective is to calculated permeability from FZI based on rock typing classification in reservoir sections.

2. Field description and Well presentation

As part of the Saharan Platform, the Berkine Basin is located in South-Eastern Algeria, between latitude 29 degrees and 33 degrees North and longitude 5 degrees and 9 degrees East (Figure 1). It is limited to the North by the southern border of the Dahar Mole, to the south by the Mole D'Ahara which separates it from the Illizi basin, to the East by the Tunisian – Libyan borders and finally to the West by the structural extension North of the Amguide – El Biode – Hassi Messaoud Mole. The Berkine basin is of intracratonic type with a total area is 102,395 km2 (Souadnia, S. and Mezghache, H., 2009).

The EXP-01 exploration well has been drilled in the Berkine oil field Basin for assessing the H-C potential of sandstone part within the Triassic Lower Sandstone Clay TAG-I stratigraphic column (Figure 2) . A 15 m core thickness was picked up between 3247 m TVDSS (true vertical depth subsea) and 3262 m TVDSS. A total Core recovery was achieved without any loss (100% recovery). The core height has been found covering the entire reservoir targeted section. The core section has been described from sedimentological and petrographical points (figure 2). Results, based on the stratigraphic log of the core interval and the whole borehole section, indicate a detrital sandstone lithology dominance, which may be split up into different facies deposits according to Turner, P. et al., 2001 (figure2). From sedimentological point of view, the Berkine basin deposits have been found of braided to meandering fluvial environmental deposits (Turner, P. et al., 2001).

Reservoir characteristics have also been found of relatively up to good with porosity varying from 7 to 20 % and the permeability from 1 millidarcies to 850 millidarcies (mD). The PVT (Pressure, Volume,

and Temperature) analysis has indicated light oil, with a gravity of 40.4 API (Souadnia, S. and Mezghache, H., 2009).

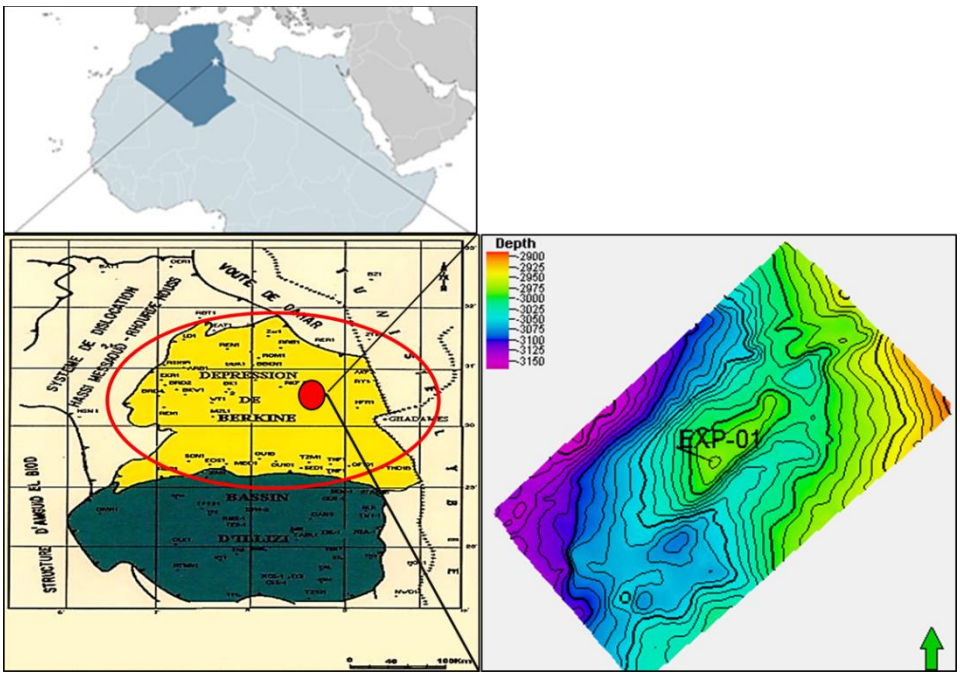

Figure 1: The localization of the study area and Well position (Souadnia, S. and Mezghache, H., 2009)

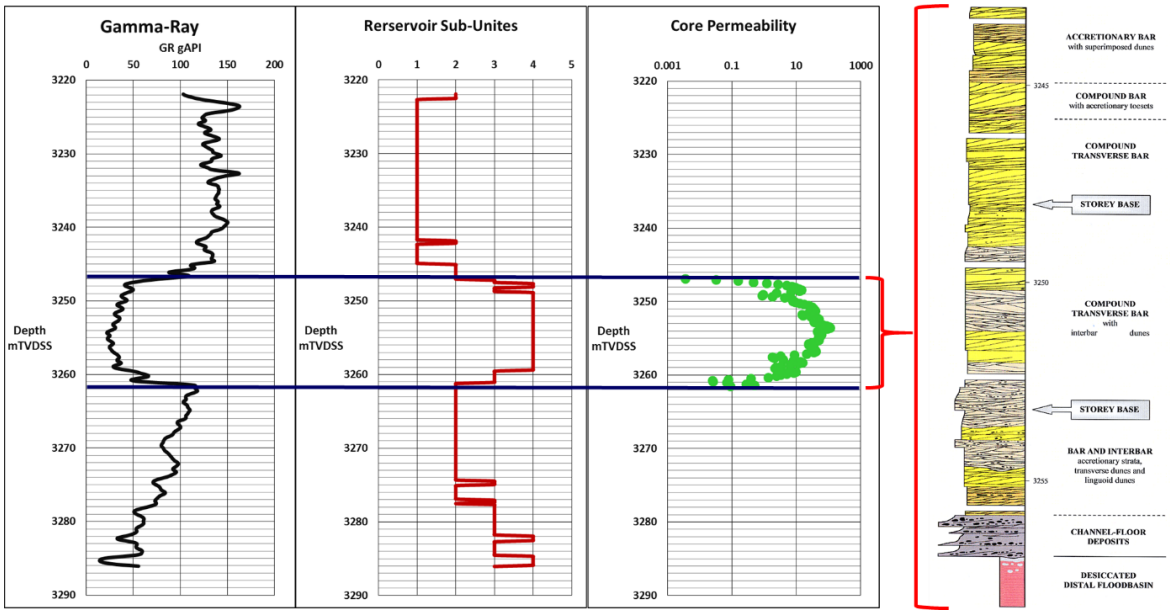

Figure 2: Stratigraphic column for reservoir coring section (Turner, P. et al., 2001).

3. Core Samples porosity and permeability measurements

42 conventional core measurements have been selected from the reservoir interval (essentially the Net pay sections) in the first exploration borehole. Porosity and the permeability are targeted in the assessment purpose. Six special core measurements with mercury intrusion-porosimetry have been selected to define capillary pressure (Pc). The experiments have been realized in the laboratory. Prior to petrophysical characteristics measurements, the core plugs underwent the following laboratory procedures, at ambient conditions.

- Cleaning procedure
- Helium derived porosity
- Klinkenberg corrected gas permeability

3.1 Cleaning and drying

The preferred Routine core analysis (RCA) method for cleaning of plugs has been the hot Soxhlet reflux cleaning with methanol and toluene as the most used cleaning liquids, followed by chloroform/methanol and finally methanol, Extended cleaning for 2-4 weeks are often necessary depending the core permeability. Drying is normally done at 105-110 °C to remove adsorbed humidity and obtain the most accurate porosity and grain density figures.

3.2 Helium porosity determination

Porosity was determined by helium injection using a Boyle's law porosimeter. The bulk volume was measured using the immersion in the Mercury technique. The method used for porosity calculation is based on consolidated rocks. The method was based on some cylindrical plugs allowing the volume calculation (bulk volume) (irregular shapes are not accurate): length and diameter have to be measured accurately.

We can determine the solid volume or the pore volume by saturation subsequent to air evacuation using a vacuum pump. Total Saturation of the sample is accomplished by a fluid of known density. The sample is weighted (Ww). Then Sample is dried (furnace). The difference in weight between saturated and dry samples can give us the pore volume according to fluid density (generally when it consists of water: water density = 1 g/cm3. The porosity is expressed as:

$$Porosity\ (\emptyset) = \frac{Volume\ of\ Pore\ (V_p)}{Total\ volume\ of\ rock\ (V_b)} * 100 \qquad (1)$$

3.3 Klinkenberg corrected gas permeability

The general measurement of permeability (K) is based on the type of fluid, its viscosity, pressure difference between the inlet and outlet, sample section and its length. The permeability measurement has been taken in the company laboratory. It has been measured by using core cylindrical samples according to the process: A fluid of known viscosity (μ) is pumped through a rock sample of known cross-sectional (A) area and length (L). The pressure drop across the sample is measured through pressure gauges ($\Delta p = P_{inlet} - P_{outlet}$).

The Darcy's Law as formulated by Muskat and Botset is as follows (MUSKAT, 1931):

$$Q = \frac{k * (P_1 - P_2) * A}{\mu * L} \qquad (2)$$

Where:
Q: Rate of flow (cm3/s)
k: Permeability (Darcy)
$(P_1 - P_2)$: Pressure drop across the sample (atmosphere)
A: Cross-sectional area of the sample (cm2)
μ: Viscosity of fluid (cP)
L: Length of the sample (cm)
Nothing that, in the form shown above, we assume that the equation (2) is occurring without any chemical reaction between the fluid and the rock, with only one fluid phase (after cleaning procedure). The permeability measurement procedure can be illustrated by the schematic diagram below (Figure 3):

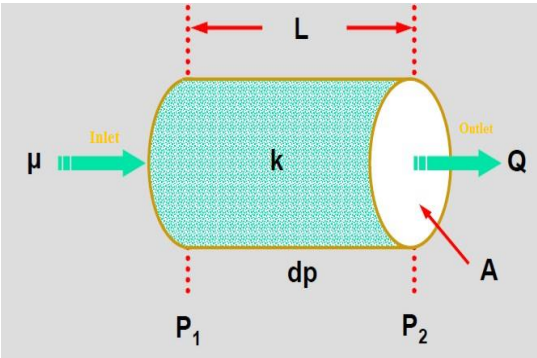

Figure 3: General permeability measurement scheme According to Darcy Law (Zand, A. et al., 2007)

Detailed information on the purpose of these procedures of laboratory measurements and various steps, for the core use, were figured out from laboratory core analysis and guides (McPhee et al., 2015, William Lyons, et al., 2015).

4. Rock Typing; Identification and assignment

In reservoir engineering, rock classification can be made on the basis of hydraulic unit identification, planned for fluid circulation ability and determination (Attia, M. Attia and Shuaibu, Habibu , 2015). These hydraulic units (HU) are used for modeling parameters such as permeability (K) (Mahjour, S.K. et al., 2016) in order to optimize simulation time. Rock typing is determined on the basis of reservoir petrophysical properties, porosity – permeability cross plot, capillary pressure curves, in addition to water saturation height function profiles. Generally, the determination of these parameters will help to define different rock classes and their contribution potential towards predicted recovery. Conducting similar research consists on making use of data from different sources (well logs and core data) to support identification of the different rock types. As mentioned previously, the static behavior (Lithology, rock type and physical properties) can be gathered to dynamic behavior (petrophysical parameters relationship and capillary pressure effect). In that principle, defined rock types must be calibrate in terms of the following defined setting:

- Lithofacies: the same type of rock in terms of lithology.
- Petrofacies: the process is based on the classification of cores data into sets having the same hydraulic unit (FZI method), the same pore size and similar capillary pressure profile.

5. Application for the case study: Results and Discussion

In the case study, exploitation of cores, coming from the first explored borehole in the Hassi - Berkine oil field (Algeria), has been used for rock typing identification. These cores have been characterized on the basis of porosity and permeability properties. These factors are considered as the main indicators for the reservoir classification process. Before going through this process, a plotting permeability versus porosity relation is required and becomes essential. According to permeability porosity distribution, and regarding the porosity evolution, two groups of samples distribution were set up main (normal) samples and anomalous samples. In addition, a relation between permeability and porosity was also established (Figure 4).

5.1 Permeability Porosity relationship

Permeability versus porosity relation, recorded from core analysis, presents a non – uniform cloud over which a representative mathematical model is privileged. This predicted model can be set on the basis of a best-provided correlation coefficient. Providentially, the rock type classification procedure begins

by removing core results located out of the main set of points. Permeability versus porosity recorded outcomes from core analysis indicates the best fit line, crossing a group with a correlation coefficient of 0.62 (Figure 4). This low value of the correlation coefficient provides a considerable margin of error. All calculations, depending directly or indirectly on absolute permeability, will be overestimated.

Therefore the numerical simulation model does not represent the real field performance. In that purpose, the application of the HFU parameter becomes necessary to predict the various reservoir rock types (RRT) and the degree of reservoir heterogeneities. With reference to parameters control, this request will possibly improve the absolute permeability calculation and subsequently extended to the uncored sections, thus, this prediction will be used to decrease the uncertainties surrounding the uncored zones.

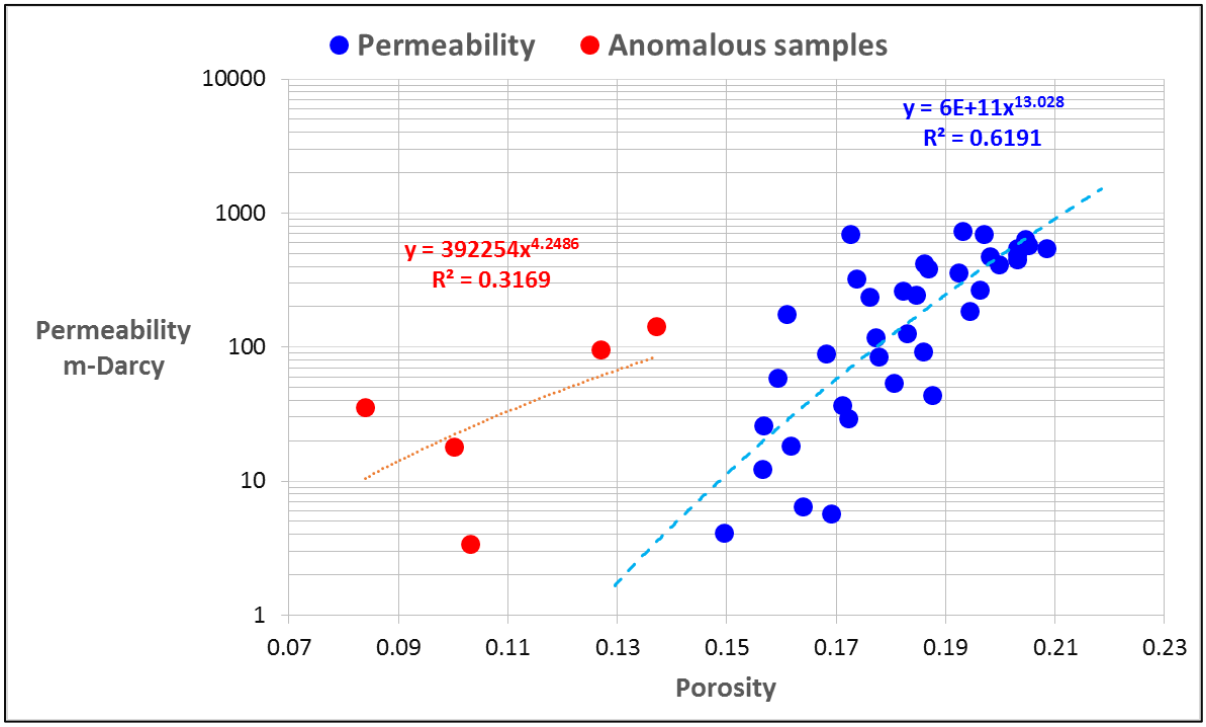

Figure 4: A cross plot indicating permeability versus porosity where heterogeneity is illustrated through a predetermined interval of distribution

5.2 Data availability and Quality Control (QC)

To carry out a complete study on reservoir rock types classification in the cored and uncored wells, a data preparation must be carried out, and presented as follows;

- Core data in cored wells, and well logs data in all wells should be prepared and quality controlled.
- Quality insurance of core data should be necessary; all cores destroyed during the sampling should be removed.
- Porosity estimation from well logs should be calibrated to that calculated from cores with consideration of the overburden phenomenon.
- Core data depth correction must be adjusted.

5.3 Rock Typing

According to Chehrazi, A. et al., (2011), reservoir rock typing is a process of classifying reservoir rocks into distinct units. From a geological point of view, it is characterized by similar geological conditions deposited in the same sedimentary environment and undergone through similar diagenetic alterations.

From the reservoir engineering point of view, it is characterized by identical fluid flow properties. Based on these definitions, given rock type can be imprinted by a unique permeability - porosity relationship, capillary pressure profile and saturation height functions above free water level (HFWL).

In the case study, reservoir rock types identification is the process by which rocks are regrouped in specific sets and are calibrated in terms of lithofacies and petrofacies. In the case study, two principal steps have been considered to define reservoir rock types:

5.3.1 Lithofacies identification

Lithofacies determination is derived from the description of core and cuttings obtained during the drilling phase. The different lithological units are grouped, as mentioned previously, to similarities in rock composition, texture, and sedimentary structures. Therefore, each lithofacies should be associated with a specific Rock type.

According to the carried out description of the cores and the cutting, the whole material consists on detrital deposits. Therefore, shaliness or clay content parameter constitutes a basic parameter to be used for splitting up between the different facies. The availability of Gamma ray records is a valid tool for this function (Turner, P. et al., 2001, Benzagouta, M.S. et al., 2001). For that purpose, the gamma-ray log has been used, as the main source for lithofacies identification and classification, matching the defined lithofacies from core description and cutting (Table 1). Based on this perceptive concept, five lithofacies were defined in Hassi Berkine Oil Field. Two defined types of lithofacies: organic-rich shale and shales are considered as non-reservoir with regards to the others. Plotting core permeability versus porosity for defined reservoir subunits shows that three lithofacies could be considered as probable reservoir efficient facies; Shaly sandstone, sandstone and clean sandstone (Figure 5).

Commun lithological description		Lithofacies	Codes
Non Reservoir	Dark clay rich in organic matter content	Organic-rich Shales	1
	Greenish clay deposits	Shales	
Reservoir (net pay)	Heterogeneous lithic facies alternating with fine to very fine sand and clay with some pebbles including coal fragments and some mud-clasts.	Shaly Sandstone	2
	fine to medium sandstone	Sandstone	3
	Medium to coarse clean sandstone	Clean Sandstone	4

Table 1: Table showing the main lithofacies characteristics in the considered reservoir according to Asquith, G. with Gibson C., 1983, Turner, P. et al., 2001 and Benzagouta, M.S. et al., 2001

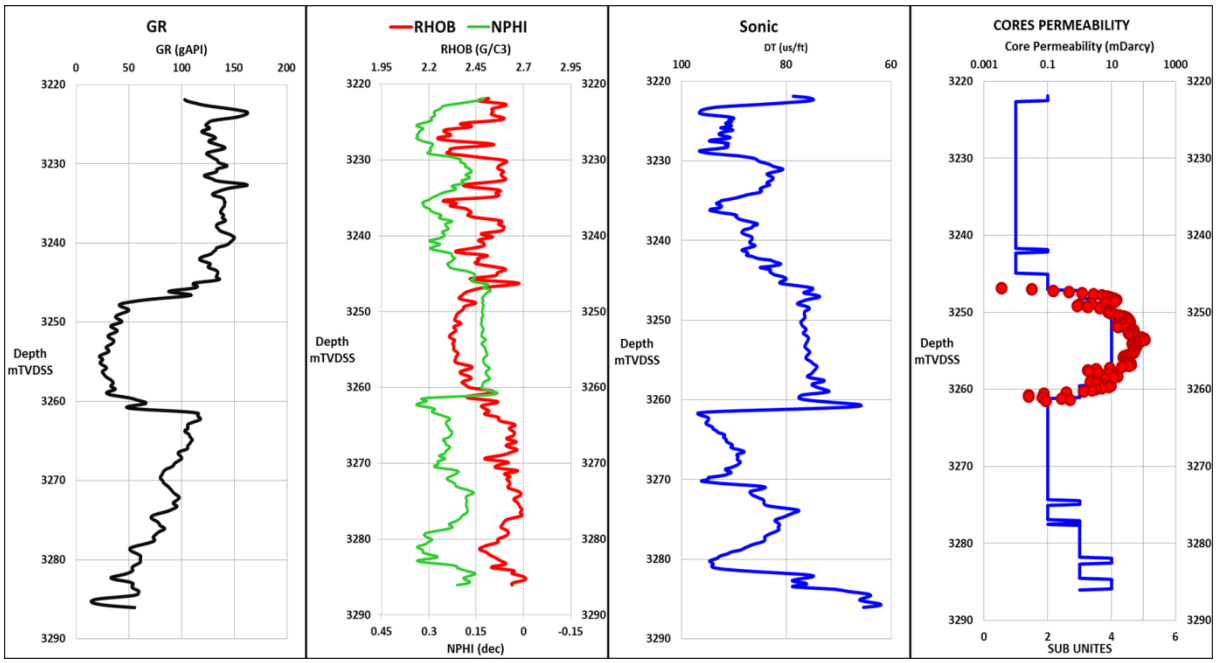

Figure 5: Well log interpretation based on GR classification indicating the location of core data in reservoir zones

5.3.2 Petrofacies determination

In this case study, Amaefule, J. O. et al., (1993) method was applied to identify hydraulic units. This latter parameter could be presented by a unique permeability – porosity relationship. Results are indicated in Figure 6. This method deals with the rock quality index (RQI) versus normal porosity ($\emptyset_z$). The calculation of these parameters has been achieved graphically based on the unit slope. As a result, six hydraulic units revealing six dynamic curve behaviors were obtained (Figure 6a).

For each hydraulic unit, permeability factor was obtained from FZI_{mean} and effective porosity using the equation below (equation 3) (Enaworu, E. et al., 2016). Consequently, various rock types are laid down (Figure 6b).

$$k = 1014 * FZI_{mean}^2 \left[\frac{\emptyset_e^3}{(1-\emptyset_e)^2}\right] \quad (3)$$

Then, the units were modeled by a linear, logarithmic, exponential and power-law in order to determine the best representative equation corresponding to each hydraulic unit (Table 2, Figure 6c). The choice of a mathematical model, representing the same set of points, is coupled to the correlation coefficient. This correlative coefficient is used to measure the strength of the relationship between the two essential petrophysical parameters: porosity and permeability. Figure 6d indicates, that the best correlation between the cited type of modeled and actual cores measurements permeability, with a high degree of accuracy, is set through the correlation coefficient value of 0.97.

In addition to the identification of the hydraulic units, six collected samples, from the reservoir area (net pay section or probable efficient section), were used to calculate the capillary pressure (Pc) by the Mercury Injection Capillary Pressure experiment (MICP). The principle is to evaluate the capillary behavior of these samples as a function of defined hydraulic units. Figure 7a is a graphical analysis of capillary pressure versus saturation: each capillary pressure value corresponds to a respective hydraulic unit. It is found that rock types RT-5 and RT-6 have the same initial water saturation (Figure 7b). This

can be a support to set together rock types RT-5 and RT-6 in the same rock type, sustaining a consistent classification, in terms of hydraulic units and capillary pressure profiles. Consequently, the petrophysical rock types will be summarized in five rock types RT-1, RT-2, RT-3, RT-4 and RT-5bis (RT-5 and RT-6).

According to the outcomes, from the figures 6a and 6b, the presence of more than one hydraulic unit and dissimilarities in the capillary pressure profiles can be ascribed to the heterogeneity of depositional environment change or lithological distribution variation. For supporting this hypothesis, pore size distribution has been calculated from capillary pressure and presented in figure 8.

Graphical analysis shows that pore throat is of mostly macroporous type, with a pore throat radius fluctuating between 2.5 and 10 microns meter, with minor variations of mesoporous (0.5 - 2.5 microns meter) and microporous category (0.2 - 0.5 microns meter).

Accordingly, the reservoir rock quality type can be determined according to factors such as porosity, permeability, hydraulic unites, capillary pressure and pore throat radius. The determination of the values of this last parameter can be an effective device to assess the heterogeneity degree. Based on pore size distribution profiles, reservoir facies could be considered as relatively homogenous along the field sections. The presence of more than one hydraulic unit can be related to variation in lithological facies distribution.

In the case study and as results, Hassi Berkine oil field reservoir rock types (RRT) have been classified into five lithofacies and six petrofacies, the results are shown in Table 3.

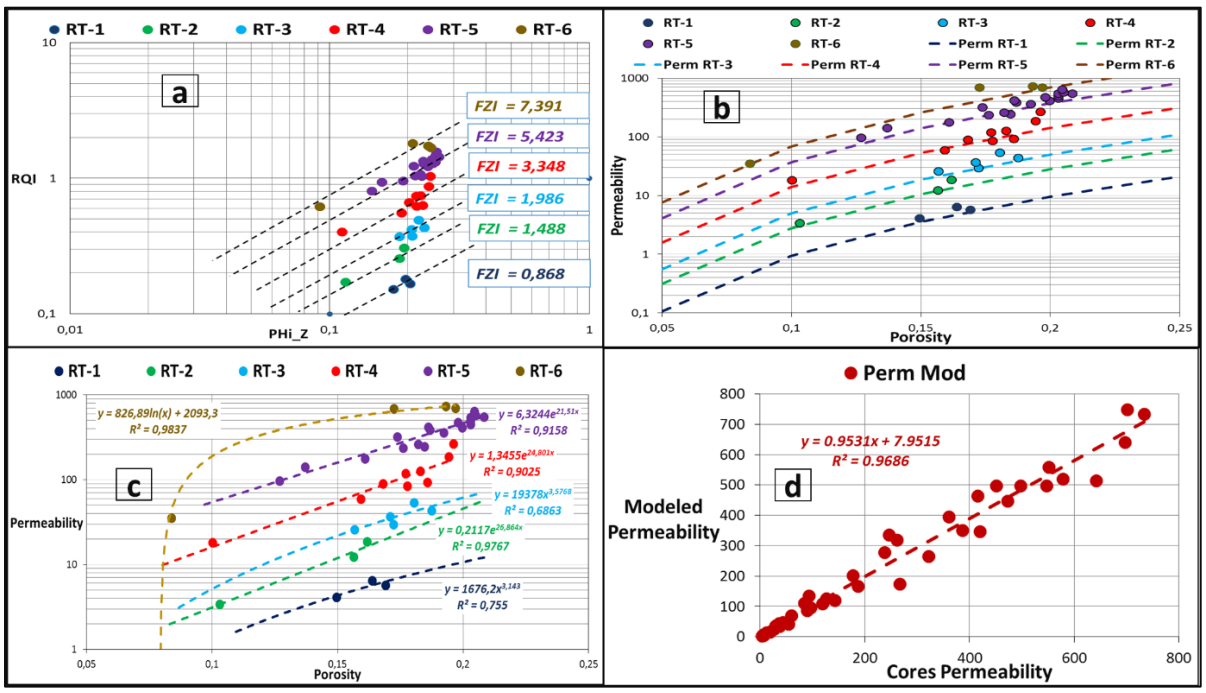

Figure 6: Permeability vs. porosity with the obtained different curves and correlation coefficient: Different clusters have come out with various hydraulic units leading to different rock typing (Amaefule, J. O. et al., 1993)

Rock Types	FZI Intervals	Function	Modelled Permeability	Correlation Coefficient
RT-1	**FZI < 0.9205**	Exponential	$0.2258 * exp^{19.677*\emptyset}$	0.7439
		Linear	$98.195 * \emptyset - 10.353$	0.6992
		Logarithmic	$15.698 \ln(\emptyset) + 34.147$	0.7109
		Power	$1676.2 * \emptyset^{3.143}$	0.755
RT-2	**0.9205 <FZI<1.8033**	Exponential	$0.2117 * exp^{26.864*\emptyset}$	0.9767
		Linear	$220.67 * \emptyset - 19.566$	0.8882
		Logarithmic	$28.369 * \ln(\emptyset) + 67.677$	0.8785
		Power	$8856.8 * \emptyset^{3.464}$	0.9719
RT-3	**1.8033 < FZI < 2.7785**	Exponential	$0.9859 * exp^{20.833*\emptyset}$	0.684
		Linear	$755.16 * \emptyset - 93.136$	0.6166
		Logarithmic	$129.53 * \ln \emptyset + 256.01$	0.6175
		Power	$19378 * \emptyset^{3.5768}$	0.6863
RT-4	**2.7785 < FZI < 4.5697**	Exponential	$1.3455 * exp^{24.801*\emptyset}$	0.9025
		Linear	$1876.7 * \emptyset - 205.29$	0.5569
		Logarithmic	$249.19 * \ln(\emptyset) + 559.96$	0.4901
		Power	$43352 * \emptyset^{3.4433}$	0.8683
RT-5	**4.5697 < FZI < 6.7378**	Exponential	$6.3244 * exp^{21.51*\emptyset}$	0.9158
		Linear	$6095.8 * \emptyset - 750.12$	0.7979
		Logarithmic	$992.79 * \ln(\emptyset) + 2061.4$	0.7575
		Power	$143020 * \emptyset^{3.5654}$	0.9007
RT-6	**FZI > 6.7378**	Exponential	$3.7498 * exp^{27.811*\emptyset}$	0.9616
		Linear	$6280.3 * \emptyset - 473.06$	0.9658
		Logarithmic	$826.89 * \ln(\emptyset) + 2093.3$	0.9837
		Power	$325345 * \emptyset^{3.6651}$	0.9812

Table 2: Table summarizing the classification of rocks based on FZI method

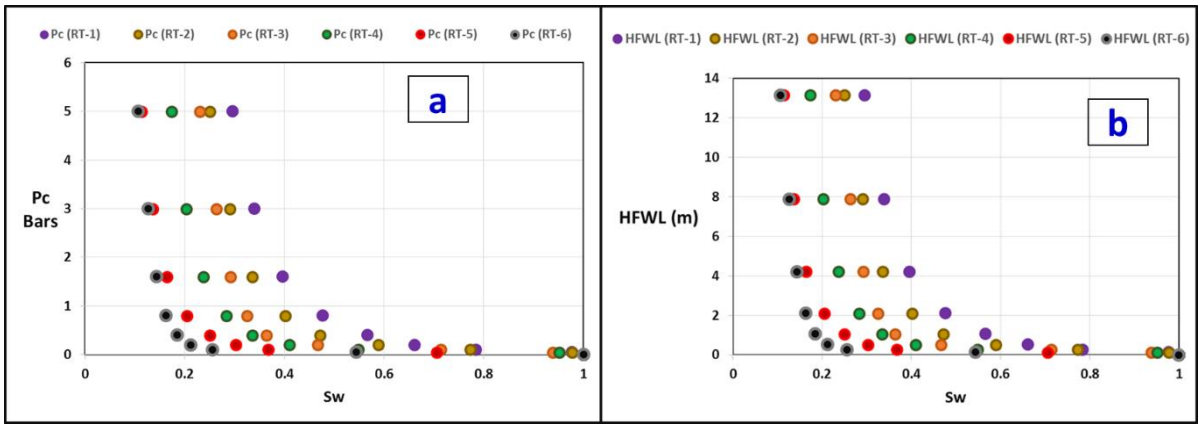

Figure 7: Capillary pressure (Pc) and Saturation height function (HFWL) profiles for each reservoir rock type (RRT)

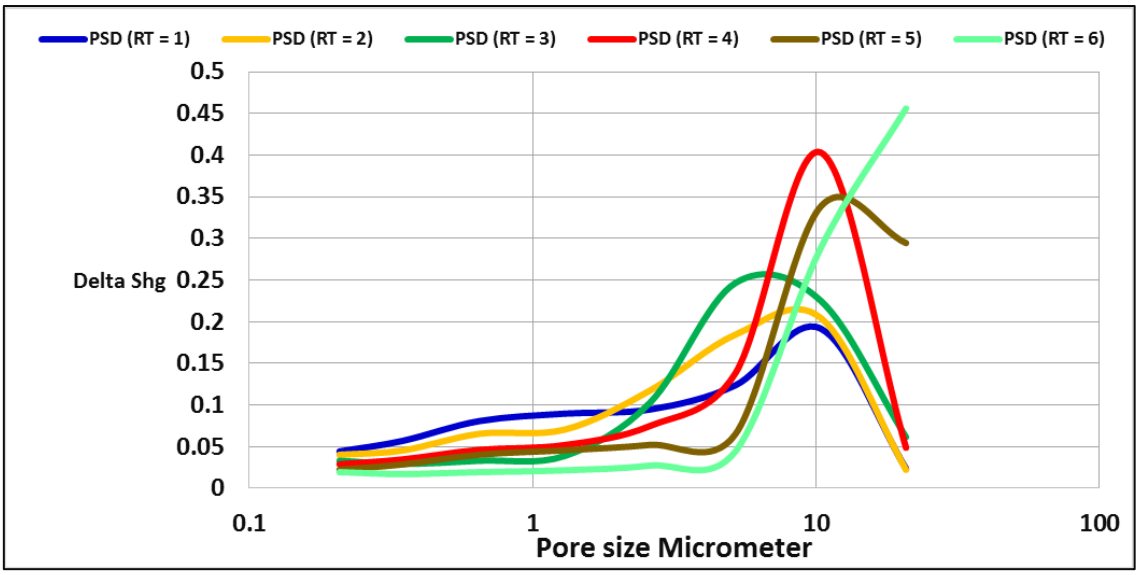

Figure 8: Pore size distribution deduced from capillary pressure (MICP method)

Reservoir/Non Reservoir	Lithofacies	Petrofacies	
Non Reservoir	Organic rich shales	RT0	Non Reservoir
	Shales		
Reservoir	Shaly-Sandstone	RT-1	FZI < 0.9205
		RT-2	0.9205 <FZI<1.8033
	Sandstone	RT-3	1.8033 < FZI < 2.7785
		RT-4	2.7785 < FZI < 4.5697
	Clean Sandstone	RT-5bis	FZI > 4.5697

Table 3: Reservoir rock types (RRT) Classification

5.4 Permeability Estimation for Non-Cored Section

According to the flow zone indicator method applying for rock typing identification, the permeability models for each rock type has been established and defined in the cored section (Enaworu, E. et al., 2016). In order to calculate the permeability for the non-cored section, the determination of FZI should be necessary. For that reason, nonlinear regression methods have been carried out to calculate FZI in the non-cored section.

For accomplishing the precedent purpose, well logs data should be used for analysis and interpretation. It will provide an approach allowing non-cored section classification into reservoir rock types. Thus, for such setting FZI and Permeability models could be applied.

In the case study, the volume of shale (V_{sh}) determination has subdivided the reservoir zone into four sub-zones. The sub-zones have been defined as Sand, Shaly-Sand, Sandy-Shale, and Shale (Table 4). Cores are located in the sandstone (unite 4) and shaly-sand (unite 3) zones (Figure 5, Table 4).

According to Tanmay Chandra (2008), FZI can be calculated from the combined use of well log data such as Gamma-ray (GR), NPHI, RHOB, and Sonic (DT) (Equation 4):

$$FZI = f(GR, NPHI, RHOB, DT) \quad (4)$$

GR Max	162.7971	GR readings	Reservoir Subunites	
GR Min	14.0944	**GR < 1/2 GR Mid**	Sandstone & Clean Sandstone	4
GR Mid	88.44575	**1/2 GR Mid < GR < GR Mid**	Shaly Sandstone	3
1/2 GR Mid	44.222875	**GR Mid < GR < 3/2 GR Mid**	Shale	2
3/2 GR Mid	132.668625	**GR > 3/2 GR Mid**	Organic Rich Shale	1

Table 4: Clay evolution (V_{sh}) in the reservoir based on GR readings

In this study, our approach is focusing on the determination of the normalized FZI from combined use of well log data such as Gamma-ray (GR), NPHI, RHOB, and Sonic (DT). Based on this understanding, empirical modeling (EM) was applied to create models based on the experimental data to predict the normalized FZI model calculated from well logs and accordingly used in permeability calculation through the application of the reservoir rock typing process. In order to achieve this objective, several models were produced on the basis of the combination of mathematical functions such as; linear, exponential, logarithmic, power and rational functions using conventional well logs such as; Gamma-ray, NPHI, RHOB, and DT. The best mathematical model must be related to the optimal subject function and characterized by its specific logs. The objective function or the optimized goal of the proposed model consists essentially to minimize the quadratic error. This later will be between the calculated and the observed normalized FZI as mentioned in the equation 5:

$$Obj_{func} = minimize\left(\sum_{i=1}^{n}(FZI^{*}_{obs} - FZI^{*}_{calc})^{2}\right) \quad (5)$$

Where:

Obj_{func}: The objective function

FZI^{*}_{obs}: Observed normalized FZI factor

FZI^{*}_{calc}: Calculated normalized FZI factor

n: The number of cores presented in this study ($n = 42$)

and normalized observed FZI (FZI^{*}_{obs}) has been calculated by applying Shier, D.E., (2004) formula as:

$$FZI^{*}_{obs} = \frac{FZI - FZI_{min}}{FZI_{max} - FZI_{min}} \quad (6)$$

Where FZI, FZI_{min} and FZI_{max} are considered from core data.

We note that FZI^{*} is constrained by the rock lithofacies (Shaly-Sandstone and Sandstone & clean Sandstone subzones), this means that each lithofacies has a specific mathematical model.

In this investigation, in order to solve the nonlinear optimization problem and compute the optimum model parameters according to the chosen subject function, the Generalized Reduced Gradient (GRG) method was performed (Maia A. et al., 2017). The mathematical models of normalized FZI (FZI^{*}_{calc}) for shaly-sandstone and sandstone & clean sandstone subzones were developed. They were performed on the basis of several scenarios carried out on the observed normalized FZI coming from cores and normalized FZI estimated from normalized well logs, RHOB* and DT*. NPHI* has been used as a parameter, but it has not led to good results. Thus, the mathematical models deduced for the two subzones are correspondingly:

- Shaly-Sandstone;

$$FZI^*_{calc} = 0.312739 * \ln(RHOB^* + 1.163084) + 1.105386 * \ln(DT^* + 0.789186) \quad (7)$$

- Sandstone & clean Sandstone;

$$FZI^*_{calc} = \frac{1.342524}{-1.00692 + 1.408993 * e^{4.16757*RHOB^*}} \quad (8)$$

Where $RHOB^*$ and DT^* are normalized parameters and are calculated by Shier, D.E., (2004):

$$Normalized_{log} = \frac{Reading\ Value - Min\ Value}{Max\ value - Min\ Value} \quad (9)$$

Based on the equation 6, the FZI log is calculated from the normalized FZI and stated as follows:

$$FZI_{log} = FZI^*_{calc} * (FZI_{max} - FZI_{min}) + FZI_{min} \quad (10)$$

For the permeability calculation, reservoir rock types were classified on the basis of the FZI values, in which a permeability model was defined for each rock type (Table 5). The results presented in figure 9 indicate a relative fine correlation between calculated and observed parameters (FZI and Permeability), and therefore, these inferred models can be used to calculate the permeability in the non-cored wells.

Rock Types	**FZI Intervals**	**Function**	**Modelled Permeability**	**Correlation Coefficient**
RT-1	FZI < 0.9205	Power	$1676.2 * \emptyset^{3.143}$	0.755
RT-2	0.9205 <FZI<1.8033	Exponential	$0.2117 * exp^{26.864*\emptyset}$	0.9767
RT-3	1.8033 < FZI < 2.7785	Power	$19378 * \emptyset^{3.5768}$	0.6863
RT-4	2.7785 < FZI < 4.5697	Exponential	$1.3455 * exp^{24.801*\emptyset}$	0.9025
RT-5bis	4.5697 < FZI < 6.7378	Exponential	$6.3244 * exp^{21.51*\emptyset}$	0.9158
	FZI > 6.7378.	Logarithmic	$826.89 * \ln(\emptyset) + 2093.3$	0.9837

Table 5: Table summarizing the permeability models for each rock type

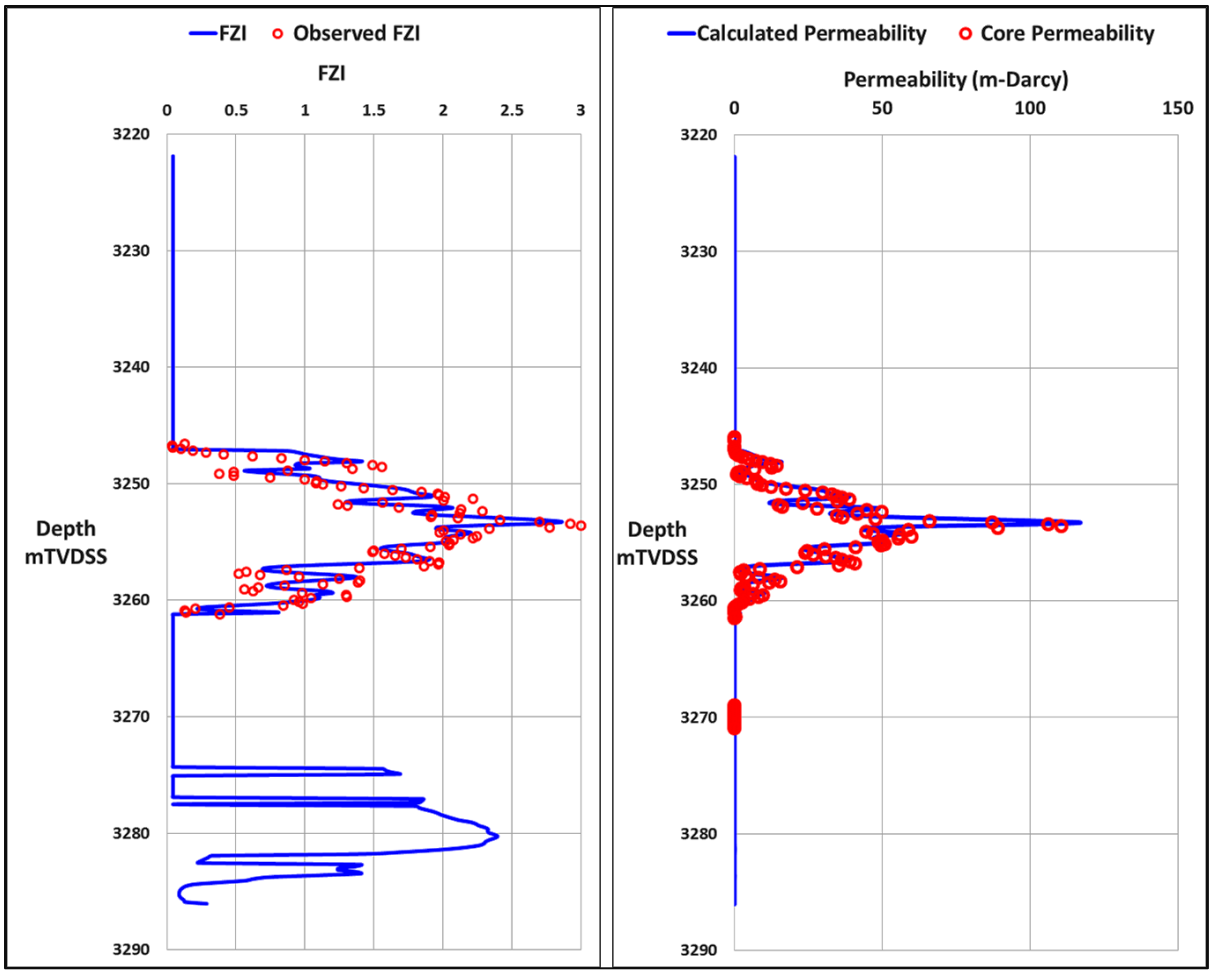

Figure 9: FZI and Permeability profiles calculated from well logs data

6. Conclusion

- Rock typing can be defined as integration and analysis of data from boreholes and core analysis.
- Rock typing determination can be due to various factors leading to various modifications.
- Lithofacies process is a helpful tool that can be used to link core data to Well log column data.
- Identification of hydraulic unit parameters such as HFU and FZI can be a vital compilation between the real cores and petrophysical characteristics.
- Capillary pressure and saturation height function are influencing factors regarding reservoir rock typing classification.
- Pore size distribution (PSD) could be introduced to identify the reservoir degree of homogeneity or heterogeneity.
- Uncertainties on data analysis with various obtained mathematical curves can be involved and useful to find out and support the correlation between hydraulic units issued from core data and well logs.
- The use of the classification process can be main concern for the permeability determination and its anticipation for each rock type.
- Similar investigation on reservoir characterization steps can be applied for other non-cored wells especially for boreholes set in the same structure and having broad-spectrum characteristics.

7. Conflict of interests

We attest and witness that there is no conflict of interest concerning the manuscript.

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