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Resistivity zone index: A new approach in rock typing to enhance reservoir characterization using well log data

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ABSTRACT

Rock typing of reservoirs is a vital step for successful field development plans to improve oil and gas recovery. In this context, the current study addresses a new approach for reservoir rocks characterization based on their electrical properties obtained from mathematical processing of well logs. That is modifying the conventional Kozeny–Carman model is achieved by taking into consideration the True Formation Resistivity (R_T) obtained from deep well logs. A log–log correlation between R_T and square of normalized porosity (Φ_N^2) yields parallel straight lines (each represents a distinct Electrical Flow Unit (*EFU*)) the intercept of which (at $\Phi_N^2 = 1$) gives a unique parameter specified as "Resistivity Zone Index" (*RZI*). The validity of the proposed model is tested on log data obtained from 21 logged wells and 1135 core samples. *RZI* values (calculated for each *EFU)* show a marked accuracy for representing reservoir. Additionally, permeability is calculated by core analysis for different intervals, and the Flow Zone Indicator (*FZI*) concept is applied to characterize reservoirs by Amaefule technique. Moreover, irreducible water saturation (S_{wr}) can be calculated for each rock type as well.

1. Introduction

Accurate reservoir characterization is mostly required as input for effective Field Development Plan (FDP) and simulation. Reservoir characterization is a process for quantitatively assigning reservoir properties, recognizing geological information and uncertainties in spatial variability (Lake and Carroll, 1985).

As a sequence, effective reservoir characterization requires accurate determination of rock parameters. In this context, the concept of Hydraulic Flow Unit (*HFU*) is frequently used to characterize reservoir's rock (Nooruddin and Hossain, 2011; Al-Ajmi and Holditch, 2000; Abbaszadeh et al., 1996; Elkewidy, 1996) which is a representative elementary volume of the total reservoir's rock having internally consistent geological and petrophysical properties (Amaefule et al., 1993). Several other important parameters are used to assess the petrophysical characteristics of a certain reservoir in order to determine the distinct flow units accurately, e.g., pore shape, capillary pressure, pore throat size and arrangement (Davies and Vessell, 1996; Alramahi et al., 2005; Alshibli et al., 2006). Fluid flow through porous rock is dominated by the geometrical micro-scale attributes of pore and network which are connected with permeability ($\boldsymbol{k}$) and porosity (Φ_e) by using Kozeny–Carman equation (assuming a porous medium as a bundle of capillary tubes (Kozeny, 1927; Carman, 1937):

$$\boldsymbol{k} = \boldsymbol{\Phi}_e * \frac{\boldsymbol{r}_{mh}^2}{\boldsymbol{F_S} * \boldsymbol{\tau}^2} \tag{1}$$

where r_{mh} is the mean hydraulic unit radius (defined as the ratio of cross-sectional area to a wetted perimeter), τ hydraulic tortuosity (defined as the ratio of actual traveled length L_a to the system straight length L) (Shen and Chen, 2007; Yun et al., 2008; Cai et al., 2014), and F_S is the shape factor (= 2 for a circular tube) (Abouzar et al., 2018). Eq. (1) represents a relationship between macroscopic properties of a porous medium and its microscopic attributes which are derived by equating Hagen–Poissoulle's and Darcy's (Abouzar et al., 2018, 2015).

According to Kozeny (1927) and Carman (1937), r_{mh}, the surface grain volume, S_{gv}, and porosity, $\boldsymbol{\Phi}_e$, are related as:

$$S_{gv} = \frac{2}{r} * \left(\frac{\boldsymbol{\Phi}_e}{1-\boldsymbol{\Phi}_e}\right) = \frac{1}{r_{mh}}\left(\frac{\boldsymbol{\Phi}_e}{1-\boldsymbol{\Phi}_e}\right) \tag{2}$$

Thus, a generalized form of "Kozeny–Carman" equation is frequently given by:

$$\boldsymbol{k} = \frac{\boldsymbol{\Phi}_{\mathbf{e}}^3}{(1-\boldsymbol{\Phi}_{\mathbf{e}})^2} * \left[\frac{1}{\boldsymbol{F_S} * \boldsymbol{S_{gv}}^2 * \boldsymbol{\tau}}\right] \tag{3}$$

Amaefule et al. (1993) introduced a modified Kozeny–Carman equation in which the mean hydraulic radius concept is used to

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establish the reservoir quality index (*RQI*) by plotting the hydraulic unit vs. the normalized porosity (Φ_z) where a linear plot with slope close to unity is obtained and the intercept represents the flow zone indicator (*FZI*) (see Eq. (4)).

$$\log RQI = \log \Phi_Z + \log \mathrm{FZI} \tag{4}$$

Where,

$RQI = 0.0314\sqrt{k/\Phi_e}$

$\Phi_Z = \Phi_e/1 - \Phi_e$

$\mathrm{FZI} = \left[1/S_{gv} * \tau * \sqrt{F_S}\right]$

Amaefule's second form of the correlation (Eq. (5)) involved further modification of the Kozeny and Carman equation in which plotting the permeability ($\boldsymbol{k}$) vs Φ_R (on a log–log scale) generates straight lines with slopes close to unity, each line represents a distinct flow unit.

$$\mathrm{Log}k = \log \Phi_R + \log(1014\,(\mathrm{FZI})^2) \tag{5}$$

Where $\Phi_R = \frac{\Phi_e^3}{(1-\Phi_e)^2}$

And

$$\log k/\Phi_e = 2\log \Phi_Z + \log(1014(\mathrm{FZI})^2) \tag{6}$$

Thus, plotting k/Φ_e vs. Φ_Z (on log–log scale) yields a straight line with slope = 2 which intersects at $\Phi_z = 1$ and intercept = $1014(FZI)^2$. Applicability of the technique was studied by analyzing four examples of clastic reservoir rock fields in West Africa, Texas, South East Asia, and South America as well as there are two another carbonate reservoir rock fields in Canada and West Texas. It was concluded that flow zone indicator (*FZI*) technique is applicable in clastic and carbonate reservoirs to enhance reservoir description by hydraulic flow unit (*HFU*) identification.

Moreover, several other research groups introduced extensive studies utilizing various parameters to predict the petrophysical properties, e.g., permeability, FZI, reservoir quality index (RQI) of unlogged wells (Nooruddin and Hossain, 2011; Al-Ajmi and Holditch, 2000; Abbaszadeh et al., 1996; Lee et al., 2002; Lacentre and Carrica, 2003; Babadagli and Al-Salmi, 2004; Perez et al., 2005; Uguru et al., 2005; Desouky, 2005; D'Windt, 2007; Bagci and Akbas, 2007; Chandral, 2008; Akam et al., 2010; Izadi and Ghalambor, 2012; Zhang et al., 2012; Aguilar et al., 2014; Sokhal et al., 2016; D'Windt et al., 2018; David, 1993; Zhang and Knackstedt, 1995; Rezaee et al., 2007; Gunja et al., 2012). This includes the use of HFU, FZI concepts or using modified versions of Carman–Kozeny equation. For instance, Abbaszadeh et al. (1996) studied the calculation of the permeability distribution for uncored wells by using well logging based on the *HFU* concept by using a presented modified technique. The study discussed a core cluster analysis by regression, probability methods, and Wards algorithm. The study was applied on a laminated heterogeneous sand stone formation and carbonate heterogeneous formation based on the hydraulic flow unit approach. Permeability prediction is obtained by the following modified equation of Coates–Dumanior:

$$K = 125.9\varnothing^{3.76} \times R_t^{0.5} \tag{7}$$

where: R_t: is the formation true resistivity and $\varnothing$: is the formation porosity.

Moreover, Al-Ajmi and Holditch (2000), used the HFU concept to estimate reservoir rock permeability in the uncored intervals. Their study was applied on sandstone reservoir rock located in central Arabia. This study focused on formation evaluation by using well logging data nonparametric Regression to predict permeability of sand stone rock, that is by applying cluster analysis. New technique for clustering is developed to determine the clusters optimal number and permeability estimation is obtained by Alternating Conditional Expectation (ACE) in uncored wells. The following equation is developed by using ACE to predict *FZI* directly from well logs:

$$\begin{aligned}\boldsymbol{FZI^{predicted}} = \boldsymbol{\theta}^{*-1}\big[&\varnothing_1^*\,(\mathbf{ln\_}\boldsymbol{GR}) + \varnothing_2^*\left(\mathbf{ln\_}\boldsymbol{R_{d/sj}}\right) \\ &+ \varnothing_3^*\left(\varnothing_{\boldsymbol{ej}}\right) + \varnothing_4^*\left(\boldsymbol{Zone_j}\right)\big]\end{aligned} \tag{8}$$

Where *GR*, $\varnothing_{ej}$, $R_{d/sj}$, and $Zone_j$ are the well logging readings. They concluded that the results of permeability in uncored wells by using *HFU* method, showed agreement with core data which reflects the success of the study.

Lee et al. (2002), studied permeability prediction by using two step approach and also reservoir characterization. Multivariate analysis and regression are used to predict permeability by using well logging tools in the uncored reservoir sections. Electrofacies types are identified by using combination of discriminant analysis, component analysis and cluster analysis. The concept of determining rock permeability was built on applying well logging then use technique of nonparametric regression on the obtained data as. Study was implemented on carbonate rock reservoir in Permian basin which considered a heterogeneous carbonate reservoir rock. They concluded that nonparametric regression and electrofacies characterization could be used together to obtain higher accuracy of permeability predictions in complex carbonate rock reservoir.

Lacentre and Carrica (2003) studied permeability estimation by using standard well logging (LLS, GR,RHOB) in the uncored reservoir rock intervals in drilled reservoir. The proposed method depended on the Kozeny–Carman approach. Analysis followed two steps to predict permeability from standard well logging data and core data. Firstly, formation characterization and petrophysical interpretation should be applied by using mathematical tools to divide reservoir into distinct regions. Secondly, by using Artificial Neural Network (ANN), the permeability of core data are mapped along with data obtained from conventional well logging. They mentioned that the proposed method could be applied for any type of reservoir rock depending on the availability of enough data obtained from well logging and core analysis. The proposed method was applied and tested by using actual core and well logging data for sandstone reservoir rock located in Neuquén basin in Argentina.

Babadagli and Al-Salmi (2004) studied the possible use of conventional and non-conventional well logging Data to predict permeability and improve its accuracy for the uncored reservoir sections. Their study was applied on carbonate rock existing reservoir in Oman which are characterized as complex lithology. The mainly used logging tool is the Nuclear Magnetic Resonance (NMR). The results showed that for heterogeneous carbonate reservoir it is very difficult to estimate permeability because it gave very low correlation coefficient; on the other hand, for breccia units, a higher correlation coefficient is obtained by using conventional logs. For grain and mud stone, low correlation coefficients are obtained from the conventional well logs, but after using Nuclear Magnetic Resonance (NMR), higher values of correlation coefficient are obtained.

Perez et al. (2005) studied permeability prediction for the uncored wells or reservoir sections by using conventional well logging tools. The concept of the study is to classify the response of well logging according to HFUs, electrofacies and lithofacies. A new "classification tree analysis" technique is proposed, that helped in identifying the HFUs, electrofacies and lithofacies. They applied their study on carbonate rock for heterogeneous reservoir in west Texas and showed success of the proposed technique in predicting permeability for the uncored wells by using conventional well logs that by the classification of HFUs, electrofacies and lithofacies.

Uguru et al. (2005) studied permeability prediction improvement by using *FZI* that have been introduced in Amaefule et al. (1993) from wireline logs. This study was conducted on reservoirs of Nigeria delta based on: Classification of genetic unit and Neural Network application.

FZI could be calculated by the following proposed equation:

$$FZI = A_0 GR^{A1} SP^{A2} FDC^{A3} CNL^{A4} RES^{A5} \tag{9}$$

where:

GR: gamma ray response from well logging, SP: spontaneous potential response from well logging, FDC: density ray response from well logging, CNL: neutron ray response from well logging, and RES: resistivity response from well logging. Where A0, 1, 2, 3, 4, 5 are constants obtained from the intervals that cored. Their results showed great improvement of permeability estimation for reservoirs of Niger delta by using wireline logs.

Desouky (2005) studied the approach of HFU for permeability prediction in uncored sandstone reservoir rock located in Gulf of Suez, Egypt. In a Heterogeneity of reservoir, Reservoir Quality Index (RQI) and Flow Zone Indication (FZI) are determined for the existing reservoir. They used the following equation to predict permeability directly by using core data:

$$KK = 1014 \times (FZI_{core})^2 \times \varnothing \times \varnothing_Z^2 \tag{10}$$

Correlation of *FZI* from core data and well logging data:

$$FZI_{core} = 1.0034 \times (FZI_{LOG})^{1.0315} \tag{11}$$

Whereas, the permeability is calculated directly by using well logging for the un-cored intervals:

$$K = 1020.91 \times (FZI_{LOG})^{2.0632} \times \varnothing \times \varnothing_Z^2 \tag{12}$$

Their results showed that applying the approach of *HFU* for reservoir zonation improved the permeability predictions obtained from well logs for uncored intervals which enhance reservoir description.

D'Windt (2007) studied permeability prediction and reservoir rock zonation for the un cored sections of the reservoir rock. Hydraulic Flow Unit (HFU) concept is used to estimate permeability based on Carmen kozney concept.

Bagci and Akbas (2007) studied formation permeability evaluation from core data and well logs. This study implemented on carbonate reservoir rock on southeast turkey field composed of dolomite and limestone. The hydraulic flow unit (HFU) concept is used for reservoir zonation. Flow units are delineated by a petrophysical based method which uses core data and well logs.

From core plug data:

$$\log R_{35} = 0.732 + .88 \log \mathrm{k}_a - 0.864 \log \Phi \tag{13}$$

From well logging data:

$$\log K_a = 116.65 - 0.06\mathrm{GR}40.39\Phi_S + 1.17\Phi_{N-}.87\Phi_{D-N} - 0.17S_W + 40.69\rho_b - 0.0009Rt \tag{14}$$

After applying core plug analysis and well logs calculation, the results showed that there are mainly four different units for both. It was concluded that for carbonate reservoir there was an agreement between the results obtained from both core analysis calculated permeability and the permeability predicted from well logs.

Chandral (2008) studied permeability prediction technique obtained from well logging. The study concept was established on using FZI obtained from well logging data to estimate permeability in uncored wells. This study was applied on sand layers for porous and permeable formation with interval of 220 meters as total depth, the obtained results was for both water and hydrocarbon bearing zones. Combined log tools were used to obtain the value of FZI from well logs was by transforming gamma ray (GR), neutron porosity, density, and deep resistivity logs for multiple regression to obtain the value of FZI.

Permeability is calculated from the modified Carman–Kozeny relation,

$$k = 1014(FZI)^2 * \left(\Phi_e^3/(1-\Phi_e)^2\right) \tag{15}$$

Akam et al. (2010) studied an innovative approach for permeability prediction by using Flow Quality Indicator (*FQI*) concept for uncored wells by combining three main parameters:

Unpermeable member volume (Vimp), porosity and volume of remaining grain (VPm)

This study was applied on clastic rocks in Sabah (Malaysia). Empirical relations were developed by relating the permeability of core by *FQI*; thus prediction of permeability could be achieved.

Nooruddin and Hossain (2011) studied a new technique to enhance the accuracy of predicting permeability from uncored wells. They studied the flow behavior of reservoir accurately by reducing and minimizing the limitations and assumptions that exist in Kozeny–Carman model to determine HFU. The presented technique was based on modifying the concepts of low zone indicator and RQI that have been introduced in Amaefule et al. (1993). This study was applied in the middle east on a heterogeneous carbonate reservoir by conducting a simulation case study; taking into consideration the nonlinear relation between porosity and tortuosity. It was concluded that the modified approach resulted in better improvement in HFU determination; furthermore, the study results effectively match the actual data, and hence can be used to higher accuracy predictions.

Izadi and Ghalambor (2012) developed a new approach to improve the accuracy of determining and estimating HFU and permeability. Their study was implemented on 17 samples of Berea sand stone. By using the new approach, the petrophysical properties of reservoir rock could be predicted and obtained which helped in reservoir characterization improvement. Their concept was built on coupling both Darcy equation and flow equation of Poiseuille taking connate water saturation into consideration to give the final form of the following equation:

$$0.0314\sqrt{\boldsymbol{k}/\boldsymbol{\Phi_e}} * 1/1 - \boldsymbol{S_{wir}} = \left[\boldsymbol{\Phi_e^m}/1 - \boldsymbol{\Phi_e}\right] * \left[1/\boldsymbol{S_{gv}} * \boldsymbol{\tau} * \sqrt{\boldsymbol{F_g}}\right] \tag{16}$$

Their petrophysical model assumed the existence of several tortuous tubes and thus concluded that the RQI should be modified by taking the connate water saturation into consideration.

Zhang et al. (2012) studied Mercury Injection Capillary Pressure (MICP) method for permeability estimation, mainly in reservoirs that are characterized as sandstone low permeability rock. The MICP analysis was used to determine HFUs and established a correlation between RQI and Swanson parameter. Then reservoir air permeability is estimated by the established general model. This model could be used to predict permeability for all conventional formations. Air permeability and Swanson parameter relationship are compared together to estimate permeability.

Aguilar et al. (2014) presented a methodology for prediction of permeability and hydraulic unit determination which was applied on sandstone reservoir, the test implemented in Venzuelan Eocene reservoir. The presented methodology depended on the concept of HFU approach by using technique of cluster analysis. Optimal hydraulic units numbers are determined by the nonparametric algorithm MULTI – RESOLUTION – GRAPH – BASED – CLUSTERING (MRGC).

Sokhal et al. (2016) studied the permeability prediction and rock typing by using the FZI approach. The aim of the study was to characterize the uncored reservoir sections effectively by correlating the values of FZI obtained from well logs with those calculated from core analysis, then accurately predicting permeability. This study was implemented on Berkine Basin (Algerian sahara) where the existing formation is shaley sandstone. The HFUs were used to develop permeability correlation. This involved the calculation of FZI by plotting RQI vs Φz then estimate the value of FZI at the point of intersection of $\Phi_z = 1$. It was concluded that FZI method is considered an accurate approach for predicting permeability.

D'Windt et al. (2018) studied Bayesian approach on tight carbonate reservoir to predict permeability and identify the HFU. The concept of the study based on HFU theory then logging data were used to predict the rock permeability by Bayesian method. There were mainly three steps summarizing permeability prediction by using the Bayesian approach: (1) calculating the HFU optimal number that is by using F-test and optimization non-linearly, (2) using bayes' rule for core data clustering and (3) estimate permeability. This study showed success for clustering by using FZI; moreover, showed success in determining rock properties in carbonate rock and gave good results.

David (1993) indicated that the electrical and hydraulic paths are different. Also, the values of the tortuosity of the hydraulic path is much greater than the values of the tortuosity of the electrical path. Zhang and Knackstedt (1995) investigated that the electrical conductivity and fluid flow of the random porous three dimensional and found that the value of the electrical tortuosity is far smaller than the value of tortuosity of the hydraulic path in a manner that depended on the extent of the formation porosity.

Rezaee et al. (2007) established a new method that was used in order to classify the formation resistivity factor (F) and the porosity based on the EFU and the current zone indicator (CZI) in heterogeneous reservoirs due to inaccuracy in reserves estimations when using values of tortuosity and cementation.

Gunja et al. (2012) used the RQI to represent different rock types in the reservoir in combination with connate water saturation (S_{wc}) using the following equation:

$$S_{wc} = a * RQI^{-b} \tag{17}$$

where RQI is calculated from porosity and permeability obtained from core samples and a and b are constants. plotting RQI vs. S_{wc} represented different rock types through different trends on the plot. Each rock type will be represented by a different trend.

Moreover, Davarpanah et al. (2017, 2020, 2018) introduced valuable studies to enhance the optimization of the drilling parameters by analyzing the formation strength with an aim to reduce the required amount of energy for drilling formation. This is much done by developing a Mechanical Specific Energy parameter which is correlated to uniaxial compressive strength in several studied formations in Iran (Davarpanah et al., 2017). Also the formation damage effect was numerically analyzed by Davarpanah et al. (2020) to probe its harmful impact on the efficiency of drilling performance. In this study, an account for the porosity, permeability, water saturation, oil viscosity pressure drop, contact time and capillary pressure are taken as modeling parameters, where therein the results of the developed model were in a good agreement with the laboratory investigations for different cores. In another study, Davarpanah et al. (2018) developed integrated production logging techniques for the appropriate estimation of permeability as an essential parameter to decide the profitability of the production and exploration operations in petroleum industries. The term production logging tools (PLT) was developed which involved a wide variety of measurements tools and many sensors. The estimated permeability in several layers were close to each other confirming the reliability of the proposed PTL index, which could be used and avoid the costly core analysis tests (Davarpanah et al., 2018).

It is the aim of the current study to introduce a new approach for the accurate reservoir characterization using well log data based on a new parameter referred hereafter "Resistivity Zone Index, *RZI*". This index is developed to overcome the difficulty (and the high expenses) of obtaining the core data from laboratory which is frequently required for the characterization of reservoirs. Thus, the main novelty in this paper is to establish a new concept in reservoir characterization based on electrical resistivity measurements from log. In this regard, a new index is developed for reservoir characterization which is called Resistivity Zone Index (*RZI*) which is built on the true formation resistivity from logs in line with flow zone indicator (*FZI*) which depends on permeability and porosity. While *RZI* is based on the true formation resistivity together with permeability which led to enhanced reservoir characterization. Thus, allowing for the prediction of the reservoir characterization from well logs in case of shortage of core data from laboratory.

In this context, the oil fields under investigation (located in Algeria) include a Precambrian basement un-conformably overlain by thick Phanerozoic sediments. Paleozoic strata dip in the SE direction and are overlain by Mesozoic sedimentary layers that dip in the NW direction. The two sets of strata are separated by an unconformity surface.

Collision between Laurasia and Gondwana in the late Paleozoic (Carboniferous-Permian Hercynian event) caused the formation of folding accompanied by uplift and erosion as well as NE trending faults. Following the Hercynian, Triassic is characterized by rifting which reactivated the older NE faults. And finally, Cretaceous is characterized by a transtension that caused the formation of ENE-WSW faults. The main reservoirs in the area belong to Cambrian–Ordovician sandstones which are of fluvial to shallow marine environments with most of the discoveries are structurally controlled where previously described anticlines and faults form the main structural traps. The seal in these traps is represented by Triassic shale and salt.

2. Data and methodology

The generalized form of Kozeny–Carman relationship (Eq. (3)) can be written as:

$$\boldsymbol{k} = \frac{\boldsymbol{\Phi}_{\mathbf{e}}^{2}}{(1-\boldsymbol{\Phi}_{\mathbf{e}})^{2}} * \frac{\boldsymbol{\Phi}_{\mathbf{e}}}{\boldsymbol{\tau}^{2}} * \left[\frac{1}{\boldsymbol{F_S} * \boldsymbol{S_{gv}}^{2}}\right] \tag{18}$$

Wyllie (1950), Wyllie and Rose (1950) Perkins et al. (1956) and Attia (2005) showed that for a predetermination of the tortuosity of fully brine saturated sandstones, Archie parameters, the formation resistivity factor, F_r, tortuosity, τ, and porosity, $\boldsymbol{\Phi}_{\mathbf{e}}$, are related by:

$$\mathbf{F_r} = \frac{\boldsymbol{\tau}^{2}}{\boldsymbol{\Phi}_{\mathbf{e}}} \tag{19}$$

Thus, Eq. (18) can be written as:

$$\boldsymbol{k} = \frac{\boldsymbol{\Phi}_{\mathbf{e}}^{2}}{(1-\boldsymbol{\Phi}_{\mathbf{e}})^{2}} * \frac{1}{\mathbf{F_r}} * \left[\frac{1}{\boldsymbol{F_S} * \boldsymbol{S_{gv}}^{2}}\right] \tag{20}$$

Note that $\mathbf{F_r} = \frac{\boldsymbol{R_O}}{\boldsymbol{R_w}} = \frac{\boldsymbol{R_T}}{\boldsymbol{R_w} * \boldsymbol{I_r}}$ where, I_r (= R_T/R_0) is the resistivity index, R_O is the formation resistivity at 100% water saturation (aquifer), R_T is the true formation resistivity, R_w is formation water resistivity. And accordingly Eq. (20) becomes:

$$\boldsymbol{k} = \frac{\boldsymbol{\Phi}_{\mathbf{e}}^{2}}{(1-\boldsymbol{\Phi}_{\mathbf{e}})^{2}} * \frac{\boldsymbol{R_w} * \boldsymbol{I_r}}{\boldsymbol{R_T}} * \left[\frac{1}{\boldsymbol{F_S} * \boldsymbol{S_{gv}}^{2}}\right] \tag{21}$$

Putting $\boldsymbol{\Phi}_{\mathbf{N}} = \frac{\boldsymbol{\Phi}_{\mathbf{e}}}{1-\boldsymbol{\Phi}_{\mathbf{e}}}$, then Eq. (21) becomes:

$$\boldsymbol{R_T} = \left[\boldsymbol{\Phi}_{\mathbf{N}}^{2}\right] * \left[\frac{\boldsymbol{I_r} * \boldsymbol{R_w}}{\boldsymbol{k} * \boldsymbol{F_S} * \boldsymbol{S_{gv}}^{2}}\right] \tag{22}$$

Defining the Resistivity Zone Index ($\boldsymbol{RZI} = \frac{I_r * R_w}{k * F_S * {S_{gv}}^2}$), and taking logarithm of both sides of Eq. (22) gives:

$$log\, R_T = log\left[{\Phi_{\mathbf{N}}}^2\right] + log\,[RZI] \tag{23}$$

Eq. (23) represents the developed modified Kozeny–Carman model based on the newly developed terminology, i.e., *RZI*.

3. Results and discussion

3.1. Modified model verifications and well log data analysis

The well log data are manipulated using various well-known approaches to probe the rock typing of a given set of reservoirs and are compared with results of well log data analysis using the developed modified K–C equation (Eq. (23) above).

3.1.1. Applying conventional reservoir characterization techniques-using core analysis

It is worth mentioning here that the level of heterogeneity of reservoirs can be described by the extent of deviation from uniformity and consistency, i.e., the degree of discontinuity of the properties throughout the entire thickness of the reservoir. Also, it can be described as compound digenetic and sedimentary developments resulting from various tectonic changes. For a certain reservoir, the diversity of rock types and thus degree of heterogeneity necessitates accurate characterizations of the reservoir.

Reservoir rock heterogeneity is studied by constructing a correlation between horizontal permeability (k_h) versus effective porosity (Φ_e) to identify the formation homogeneity (Fig. 1A). Fig. 1A provides a quick look to identify the homogeneity or heterogeneity of the formation. In the current case, the absence of a clear correlation with high coefficient of determination (R^2) means that this formation is heterogeneous. This urged us to apply Dykstra–Parsons and Lorenz coefficient (L) techniques to determine the degree of heterogeneity (as shown in Figs. 1B and 1C), which yield a degree of heterogeneity VDP = 0.908). Then the third step is to convert this heterogeneous formation onto zonations each zone is represented by line reservoir quality index (*RQI*) vs. normalized porosity (ϕ_N), see Fig. 3. (developed by Amaefule).

Two techniques are used to determine the formation vertical heterogeneity. The first method Dykstra–Parsons (Wyllie and Rose, 1950) introduced the concept of permeability variation "V" (a theoretical measure of non-uniformity of a set of data). This concept is based on the porosity and permeability data from conventional core analysis. In this approach, required six steps for determining the degree of heterogeneity using permeability variation coefficient (v) which are described elsewhere (Dykstra and Parson, 1950). The Dykstra–Parsons permeability variation is defined by the following expression:

$v = \frac{K_{50} - K_{84.1}}{K_{50}}$ where K_{50} is the median permeability value, mD, and $K_{84.1}$ is the permeability at 84.1% probability (one standard deviation), mD. The permeability variation based on the Dykstra–Parson Technique in this study (VDP) is 0.908 as shown in Fig. 1B. This reflects complex lithological nature of the formation. That is why we established, herein, a new concept (Resistivity Zone Index "*RZI*") to divide this complex heterogeneous formation into zonation, each zone has similar properties which led to a certain value of *RZI*. Based on Jensen (Jensen and Lake, 1988) permeability variation classification of the formation is extremely heterogeneous.

The second method of determining the degree of heterogeneity is the Lorenz coefficient (L). Schmalz and Rahme (1950) established a method for quantifying the value of vertical heterogeneity through a single value. Values of Lorenz coefficient (L) usually ranging between zero and one. A value of $L = 0$ is a characteristic feature of a homogeneous reservoir (i.e., one rock type), whereas, a value of $L = 1$ indicates that the reservoir is completely heterogeneous. Lorenz coefficient technique is based on two factors, i.e., thickness and porosity of core samples. Schmalz and Rahme (1950) estimated the value of L by dividing the area under the straight line by the area above the straight line in the correlation between the cumulative flow capacity (K_h) vs cumulative storage capacity (Φ_h), as shown in Fig. 1C. A value of $L = 0.9111$ is obtained.

Over the past several years, lots efforts have been devoted to develop estimate the radius of the pore throat of the different types of rocks through mercury injection and measurements of capillary pressure. Kolodzie (1980) introduced a correlation to predict the radius of the pore throat (through injection of mercury) by relating permeability (k) and porosity (ϕ) of 300 samples obtained from Colorado Spindle field. The highest accuracy of the experiment was obtained at a mercury saturation of 35%. Thus, the radius of the pore throat at mercury saturation of 35% (R_{35}) is given by:

$$log(R35) = 0.732 + 0.588log(K) - 0.864log(\varnothing) \tag{24}$$

The Winland method is used to determine the point at which aperture of the pore model occurs, i.e., the point at which the core sample contained an ongoing route due to the connectivity of the pore system. Katz (1986) built on the above information and confirmed that in such cases can occur if the size of the pore throat is equal to the inflexion point of the size of the pore throat against mercury saturation. The various sets of R_{35} values characterize various petrophysical units. That is R_{35} values ranging from < 0.2, 0.2–0.5, 0.5–2.5, 2.5–10 and > 10 µm correspond to nano-, micro-, meso-, macro-, and mega-porous units, respectively. Fig. 2 shows a correlation between k versus Φ_e according to Winland R_{35} technique. The two figures (Figs. 1A and 2) show the absence of clear correlation or trend of variation between k and Φ_e. This indicates the heterogeneous nature of the formation that is why the Dykstra–Parsons technique to determine the degree of heterogeneity. Also, Amaefule approach is used (based on Eq. (4)) for reservoir characterization by plotting normalized porosity (Φ_N) versus *RQI* (on a log–log scale, Fig. 3). This figure shows more coherent correlations (compared to Figs. 1A and 2) in which different parallel lines (each line represents a distinct *HFU*) are obtained. The values of *FZI* are obtained at the intersection of the parallel lines at $\Phi_N = 1$. Note that the data points on each line represent a distinctive rock with specific properties of reservoir. Table 1 summarizes the results at varies *HFU* obtained by Amaefule technique.

3.1.2. Applying the new technique — reservoir characterization using well logs data

In this section, the modified model equation (Eq. (23)) is applied to characterize the reservoir using well log data (i.e., R_T, Φ_N and *RZI*). This is achieved by grouping of *RZI* with close values (representing a distinct *EFU*) then ${\Phi_{\mathbf{N}}}^2$ versus $R_{\boldsymbol{T}}$ (on a log–log scale). Applying this technique on an Algerian oil field (with distinct eight *EFU* similar to the number of *HFU* obtained by Amaefule technique), the results are displayed in Figs. 4A and 4B). Fig. 4A for well # 1 and Fig. 4B for all wells. Different parallel lines with slopes close to unity are obtained. Note that each figure represents the log data obtained from a specific well with distinct rock characteristics and each line represents a distinct *EFU*. The values of *RZI* are obtained at the intersection of the parallel lines at ${\Phi_{\mathbf{N}}}^2 = 1$. Table 2 summarizes the resulting values of the various parameters with a considerably high coefficient of determination (R^2) > 0.9 for most cases.

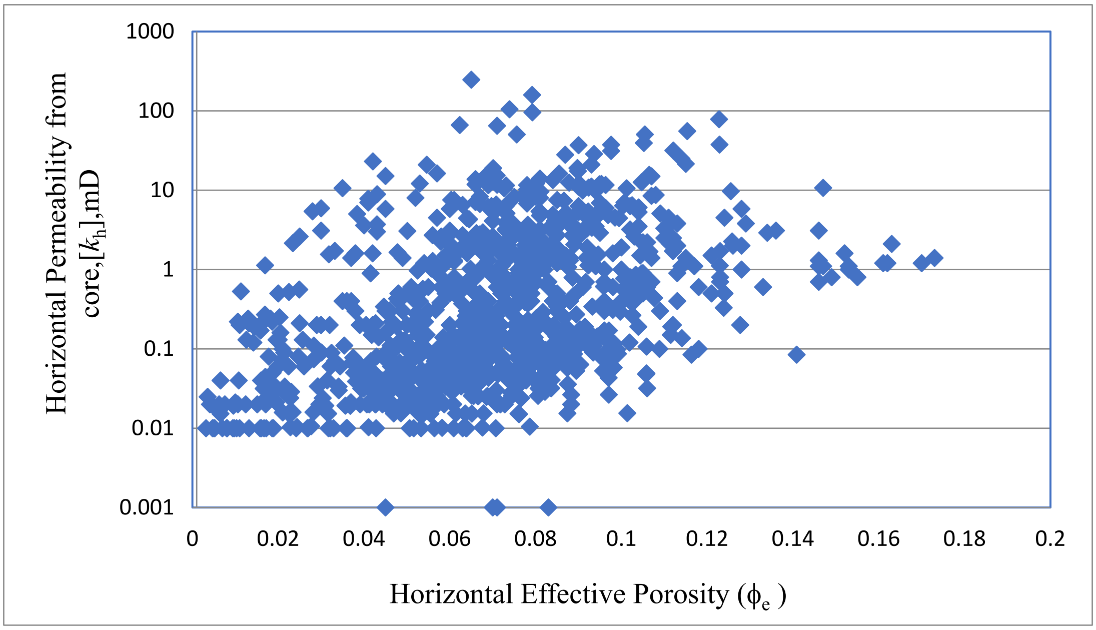


Fig. 1A. Horizontal Permeability (k_h) versus horizontal effective porosity (ϕ_e).

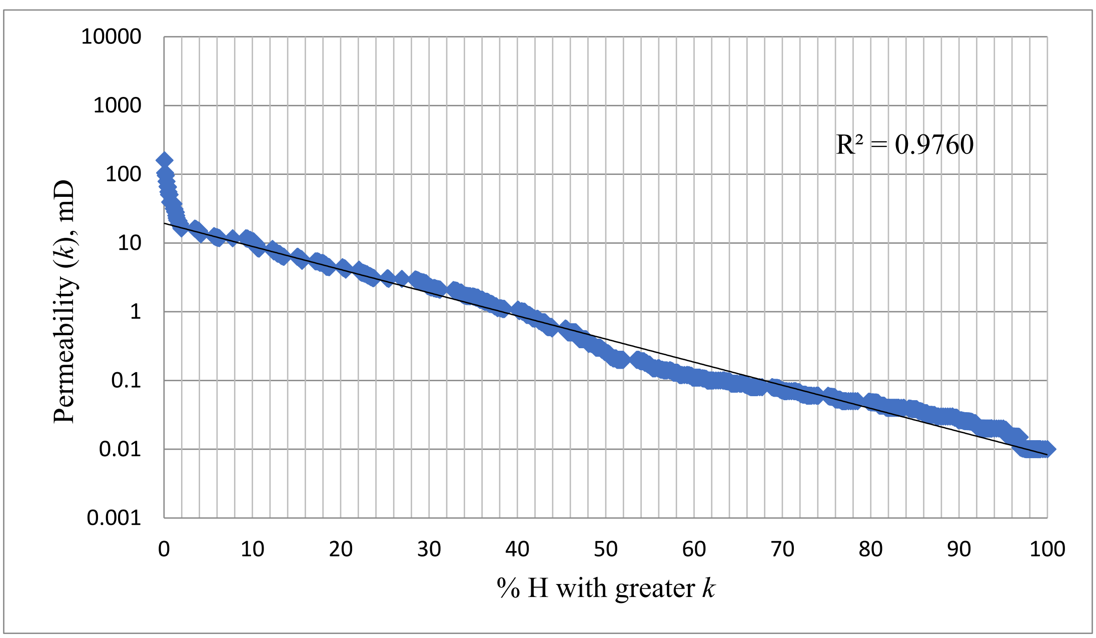


Fig. 1B. %H with greater k versus permeability (k), note that the permeability variation based on the Dykstra–Parson technique).

Table 1
Summary of the results obtained at various hydraulic flow units (*HFU*) by Amaefule technique.

Hydraulic flow units (*HFU*)	Empirical equation	*Coefficient of determination* (R^2)	*FZI*
HFU-1	$RQI = 11.411\Phi_N^{0.99}$	0.9172	11.411
HFU-2	$RQI = 5.2539\Phi_N^{0.99}$	0.9685	5.2539
HFU-3	$RQI = 2.571\Phi_N^{0.98}$	0.89	2.571
HFU-4	$RQI = 1.4648\Phi_N^{1.01}$	0.9147	1.4648
HFU-5	$RQI = 0.8928\Phi_N^{1.03}$	0.9222	0.8928
HFU-6	$RQI = 0.5139\Phi_N^{0.97}$	0.928	0.5139
HFU-7	$RQI = 0.3384\Phi_N^{0.96}$	0.8561	0.3384
HFU-8	$RQI = 0.2236\Phi_N^{0.98}$	0.7479	0.2236

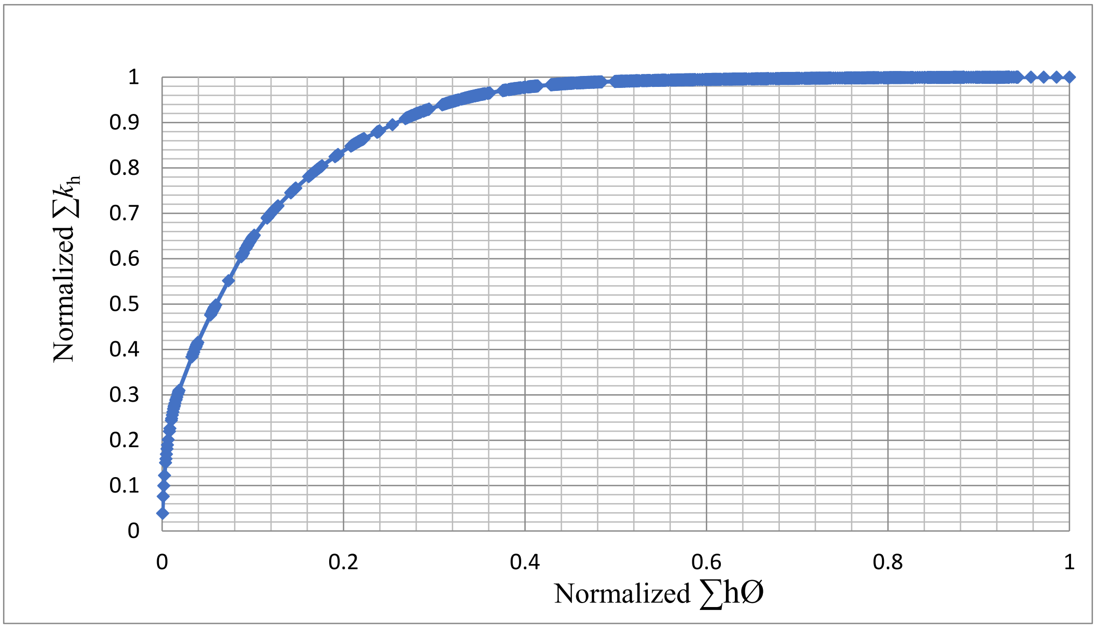


Fig. 1C. Normalized flow capacity vs. normalized Permeability. (Based on Lorenz coefficient (*L*) technique).

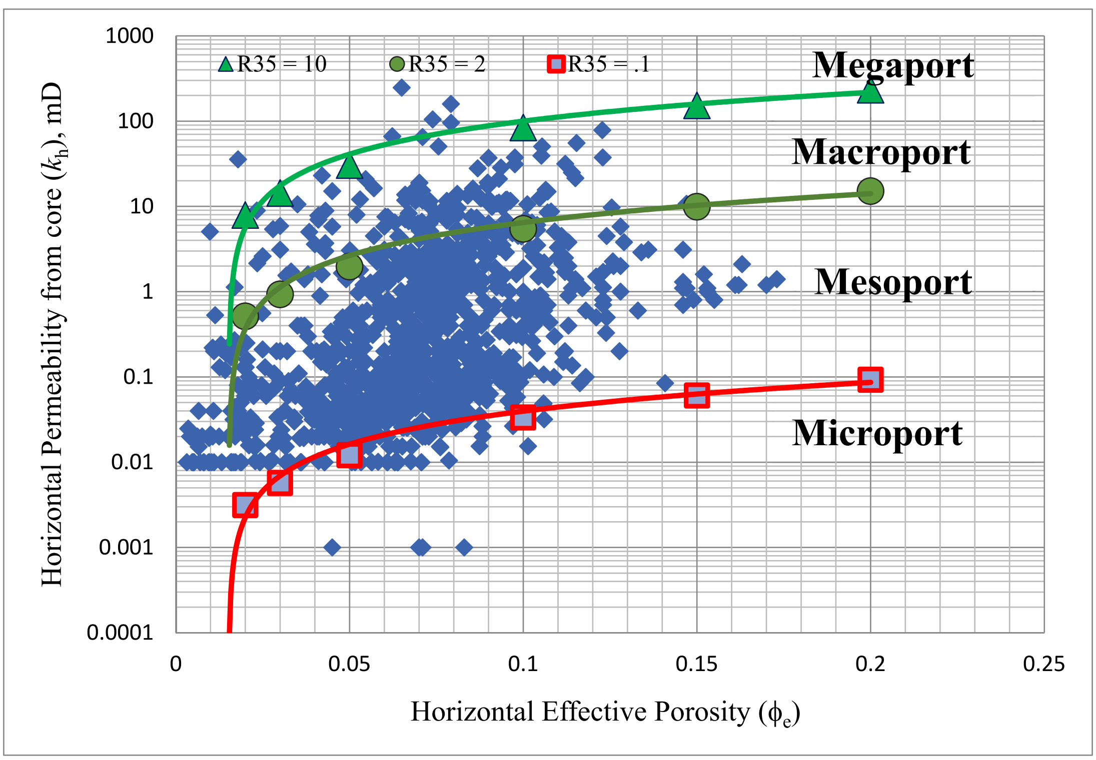


Fig. 2. Horizontal permeability (k_h) from core versus horizontal porosity (ϕ_e) using Winland R_{35} technique. Note that the solid line represent the predicted correlations at various R_{35} values of 0.1, 2 and 10 μm.

3.1.3. Applying the new technique – Calculation of true formation resistivity:

Based on the results obtained from Figs. 4A and 4B, an empirical correlation between R_T and Φ_N is given by:

$$\boldsymbol{R_{TCALC.}} = (\boldsymbol{a})\left[\boldsymbol{\Phi_N}^2\right]^{\boldsymbol{b}} \tag{25}$$

where ***a*** and ***b*** are the correlation constants. For each set of *EFU*, substitute with Φ_N to calculate R_T by using Eq. (25). Figs. 5A and 5B show plots of $R_{T\ CALC.}$ versus $R_{T\ LOG}$ for well # 1 and for all wells, respectively. Linear correlations (on a log–log scale) are shown with R^2 of 0.97 and 0.92, respectively. This figure indicates the consistency between $R_{T\ CALC.}$ and $R_{T\ LOG}$, and thus, the proved validation of the proposed model. Table 3 summarizes the data obtained at various *EFU* and *RZI* regions. By applying Archie's equation, (Archie, 1942) which one of the most important equation in well logging to calculate water saturation for each rock type corresponding to true formation resistivity obtained from Eq. (25). This equation shows the relationship between porosity, R_t,

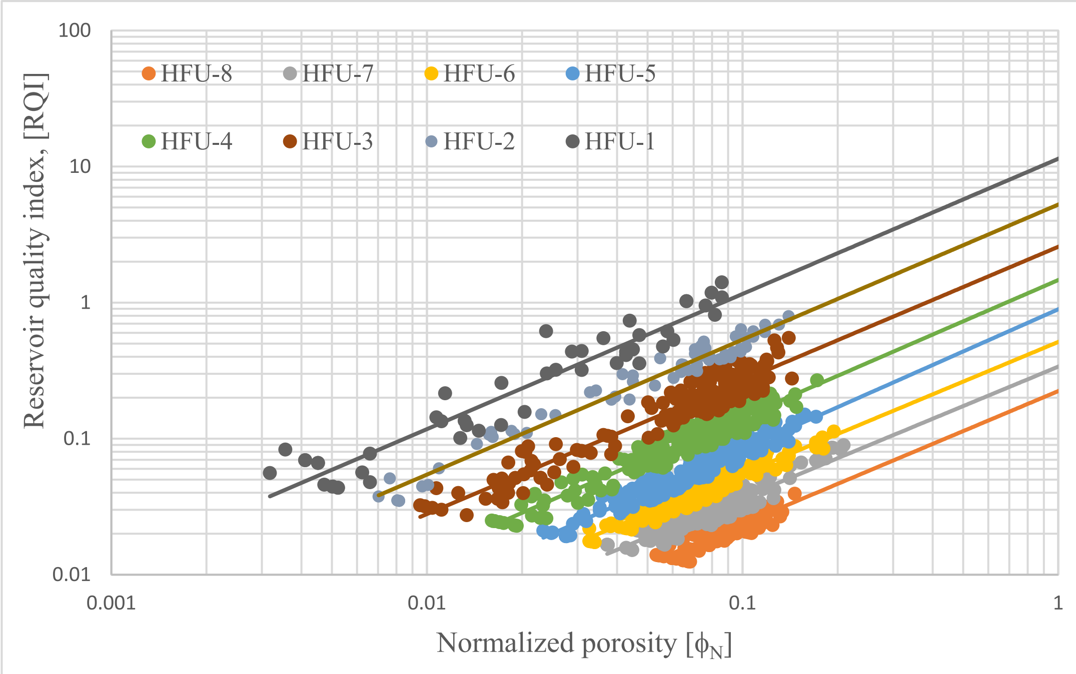


Fig. 3. Log–Log scale plot of reservoir quality index (*RQI*) versus normalized porosity (ϕ_N). Note that the heterogeneous formations are divided into zonations each zone is represented by line reservoir quality index (*RQI*) (developed by Amaefule)..

Table 2
Summary of the resulting values of the various electrical flow units (*EFU*).

Electrical flow units (*EFU*)	Empirical correlation between R_T and $\left[\Phi_N^2\right]$	*Coefficient of determination* (R^2)	*RZI*	Range
EFU-1	$R_T = 146553\left[\Phi_N^2\right]^{0.94}$	0.9606	146553	40000–399999
EFU-2	$R_T = 54386\left[\Phi_N^2\right]^{0.97}$	0.9613	54386	12000–39999
EFU-3	$R_T = 14999\left[\Phi_N^2\right]^{0.95}$	0.9282	14999	6500–11999
EFU-4	$R_T = 6488.1\left[\Phi_N^2\right]^{0.98}$	0.9355	6488.1	3500–6499
EFU-5	$R_T = 2470\left[\Phi_N^2\right]^{0.96}$	0.8822	2470	2000–3499
EFU-6	$R_T = 1185.2\left[\Phi_N^2\right]^{0.96}$	0.9033	1185.2	1000–1999
EFU-7	$R_T = 583.59\left[\Phi_N^2\right]^{0.96}$	0.8958	583.59	500–999
EFU-8	$R_T = 213.97\left[\Phi_N^2\right]^{0.90}$	0.773	213.97	200–499

Table 3
Summary of the empirical correlations between R_{Tlog} and R_{Tcal} obtained at various *EFU* and *RZI*.

Electrical flow units (*EFU*)	Empirical relation between R_{TLog} & $R_{TCalculated}$	*Coefficient of determination* (R^2)	*RZI* range
EFU-1	$R_{TCalc} = 3.5694\left[R_{TLOG}\right]^{0.92}$	0.9048	40000–399999
EFU-2	$R_{TCalc} = 4.1695\left[R_{TLOG}\right]^{0.92}$	0.9418	12000–39999
EFU-3	$R_{TCalc} = 2.8435\left[R_{TLOG}\right]^{0.93}$	0.9687	6500–11999
EFU-4	$R_{TCalc} = 1.7621\left[R_{TLOG}\right]^{0.96}$	0.9502	3500–6499
EFU-5	$R_{TCalc} = 1.4141\left[R_{TLOG}\right]^{0.93}$	0.9504	2000–3499
EFU-6	$R_{TCalc} = 1.2156\left[R_{TLOG}\right]^{0.91}$	0.9197	1000–1999
EFU-7	$R_{TCalc} = 1.1935\left[R_{TLOG}\right]^{0.91}$	0.9063	500–999
EFU-8	$R_{TCalc} = 1.3318\left[R_{TLOG}\right]^{0.78}$	0.7802	200–499
All RZI ranges	$R_{TCalc} = 0.9918\left[R_{TLOG}\right]^{1.15}$	0.9195	200–399999

R_w, tortuosity and water saturation (S_w) as follows:

$$S_w = \sqrt[n]{\frac{aR_w}{\varnothing^m R_t}} \tag{26}$$

Where, "*m*" is the cementation factor, "*a*" is the tortuosity factor and "*n*" is the water saturation exponent. Many techniques can be used to determine Archie's parameters *a*, *m* and *n* for each rock type.

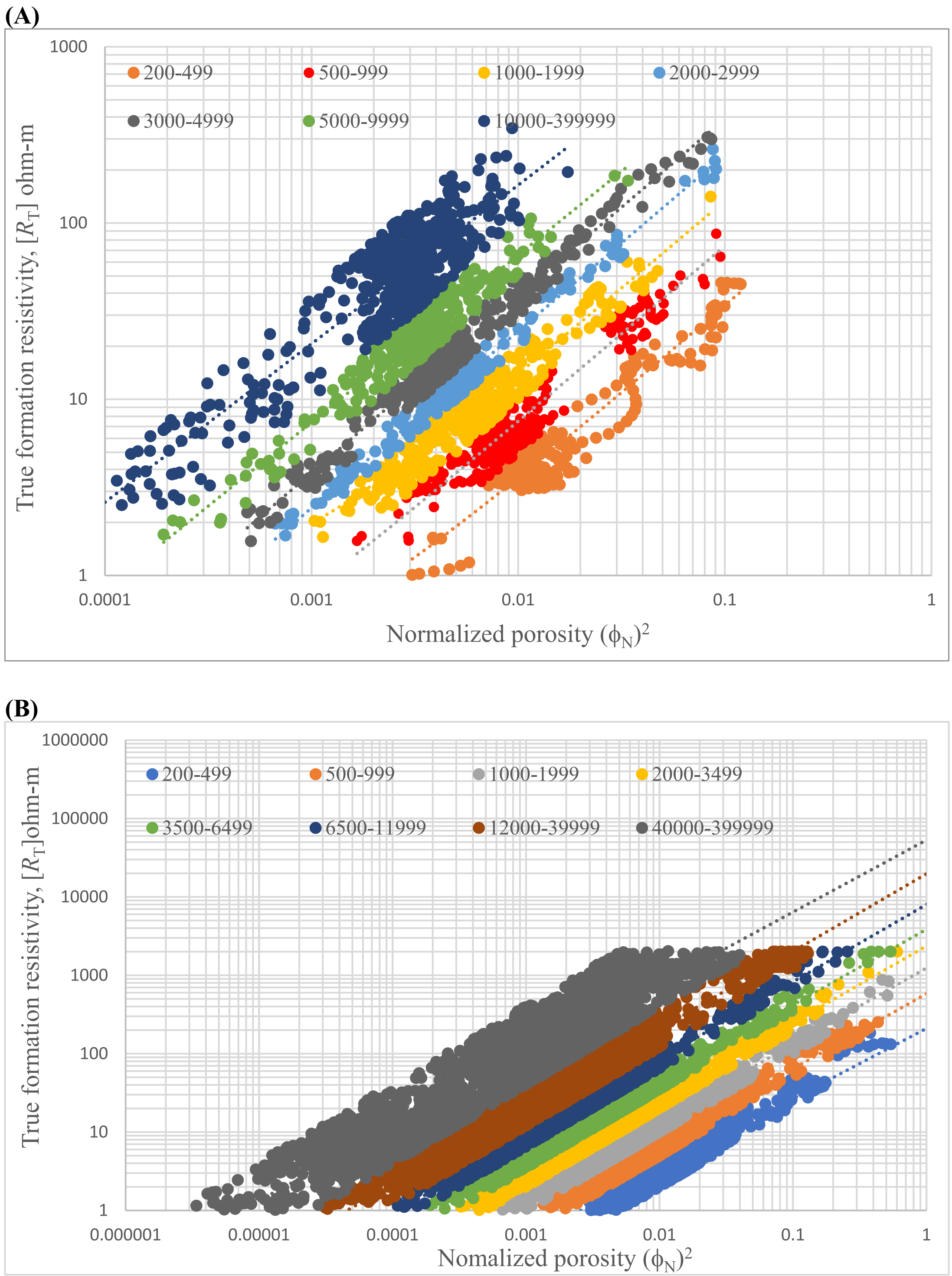


Fig. 4. True formation resistivity (R_T) versus square of normalized porosity $(\phi_N)^2$ for (A) well # one and (B) for all wells. Note that each set of data represents the log data obtained from a specific well with distinct rock characteristics and each line represents a distinct *EFU* similar to the number of *HFU* obtained by Amaefule technique.

3.1.4. Applying the new technique – Calculation of permeability from well logs

Based on the results obtained from Figs. 4A and Fig. 4B, the values of $\boldsymbol{k}$ are calculated by considering the value of $RZI = \frac{\boldsymbol{I_r} * \boldsymbol{R_w}}{\boldsymbol{k} * \boldsymbol{F_S} * \boldsymbol{S_{gv}}^2}$, **t**hen

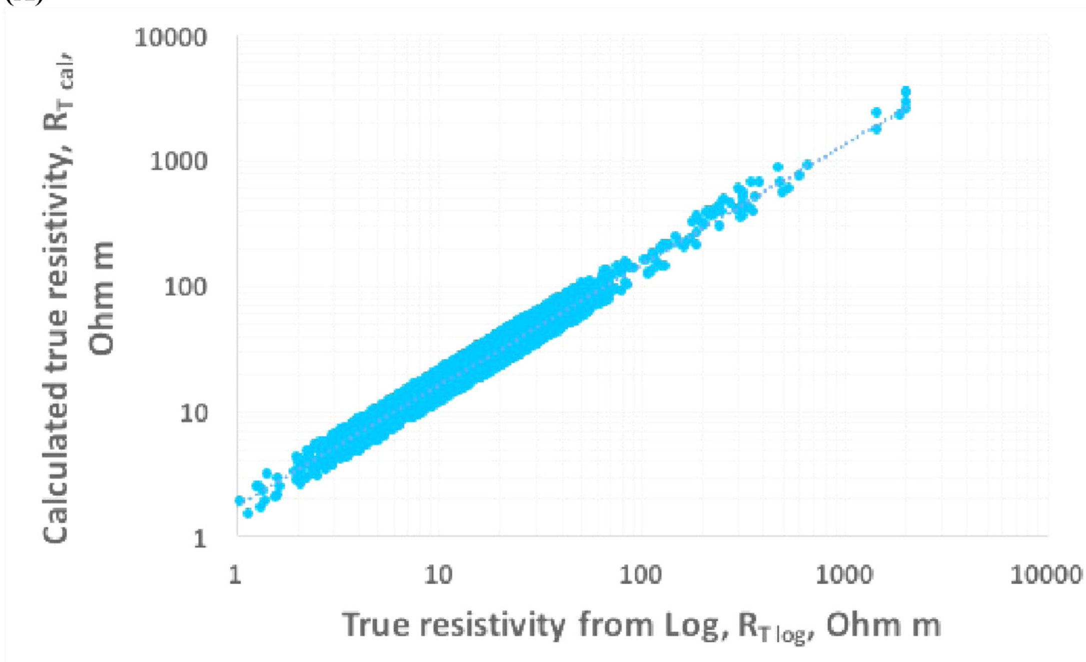
$$\boldsymbol{k} = \frac{\boldsymbol{I_r} * \boldsymbol{R_w}}{RZI\ * \boldsymbol{F_S}\ * \boldsymbol{S_{gv}}^2} = \frac{\boldsymbol{R_T} * \boldsymbol{R_w} * (1 - \boldsymbol{\Phi_e})^2 * \boldsymbol{r}^2}{\boldsymbol{R_O} * RZI\ * \boldsymbol{F_S}\ * 4 * \boldsymbol{\Phi_e}^2} \tag{27}$$

Note that F_S (= 2 for a circular tube) is the shape factor (Abouzar et al., 2018), then

$$\therefore \boldsymbol{k} = \frac{1}{8} * \frac{\boldsymbol{R_T} * \boldsymbol{R_w} * (1 - \boldsymbol{\Phi_e})^2 * \boldsymbol{r}^2}{\boldsymbol{R_O} * RZI * \boldsymbol{\Phi_e}^2} \tag{28}$$

By using Eq. (28), $\boldsymbol{k}$ is calculated using well logs. In the present case, the values of $R_w = 0.03$-ohm m and $R_0 = 0.3$-ohm m are used. Plots of $\boldsymbol{k}_{LOG}$ calculated from well logs versus $\boldsymbol{k}_{CORE}$ is

(A)



(B)

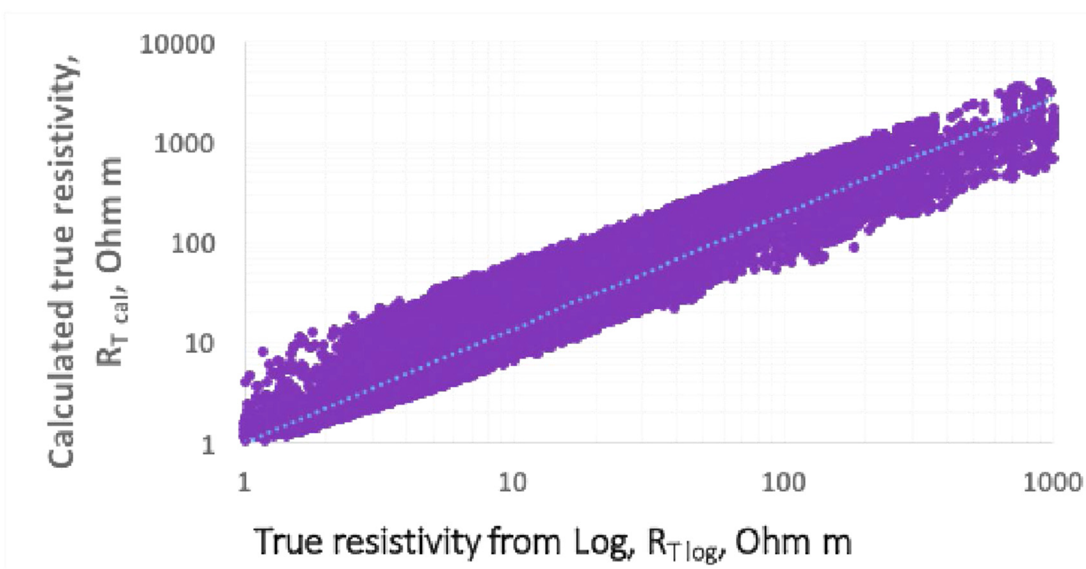


Fig. 5. Calculated true formation resistivity (R_{Tcal}) versus true formation resistivity from logs (R_{Tlog}) for (A) well one and (B) for all wells.

shown in Fig. 6A (for well # 1) and Fig. 6B (for all wells). This figure displays a good linear correlation (on a log–log scale) with R^2 close to 0.93. Table 4 summarizes the empirical correlations for k_{core} and k_{log} for all wells. Thus, the proposed model, herein, is reliable and could be applied satisfactorily for uncored wells while avoiding the costly core analysis tests.

3.2. Applications

The new technique can be used to determine the number of rock typing and reservoir description of each rock type using log data (Fig. 5) within a wide range of true formation resistivity 200 $\leq R_T \leq$ 400,000 ohm-m, rock permeability as shown in Fig. 7 at the same conditions, water saturation, *RZI* is a reasonable indicator for reservoir quality description and to determine the irreducible water saturation as follows;

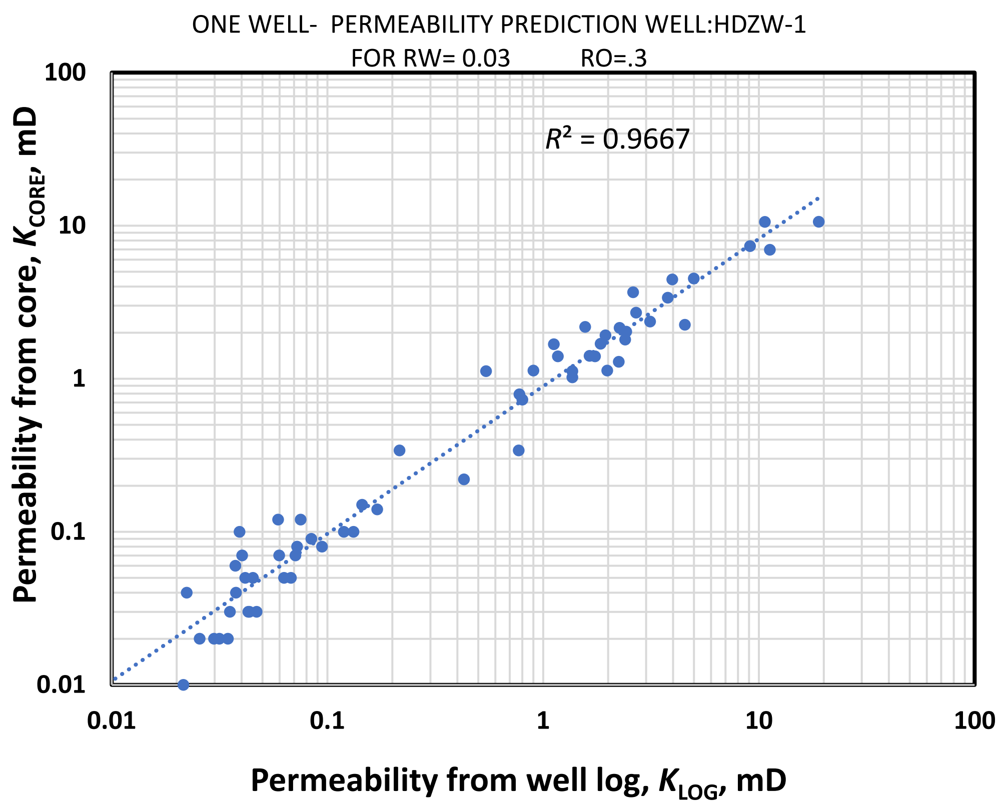
Amaefule et al. (1993) stated a correlation between irreducible water saturation (S_{wr}) and *FZI* with R^2 close to 0.998 as follows.

$$Swr = 1 - \left[\frac{1}{a + bFZI^{-c}}\right] \tag{29}$$

where $a = 1.12$, $b = 0.5634$ and $c = 1.44$.

In this study, the values of *FZI* and *RZI* for eight flow units are shown in Tables 1 and 2. These values are displaying in Fig. 7 demonstrating the perfect linear correlation between log *FZI* and

(A)



(B)

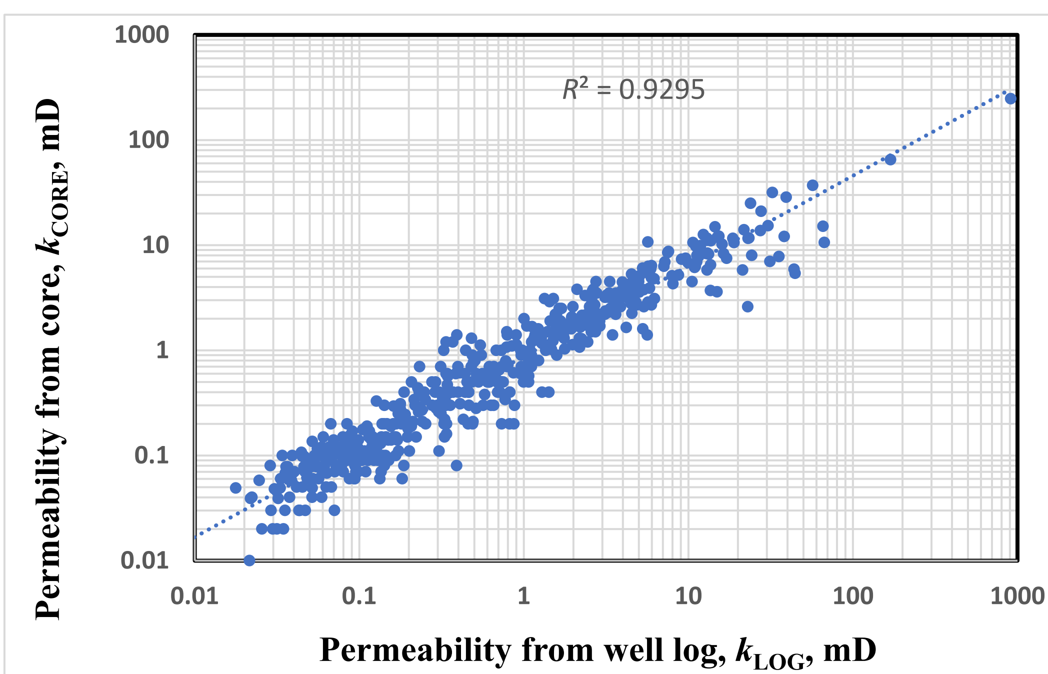


Fig. 6. Permeability calculated from core (K_{core}) versus permeability calculated from well logs (K_{log}) for (A) well # one and (B) for all wells logs.

log *RZI* with $R^2 = 0.99$, as follows.

$$FZI = 0.0076\,(RZI)^{0.6056} \tag{30}$$

Substituting Eq. (30) for *FZI* in Eq. (29), the following relationship is obtained:

$$Swr = 1 - \left[\frac{1}{a + 0.0076b\left[\left(RZI^{0.6056}\right)\right]^{-c}}\right] \tag{31}$$

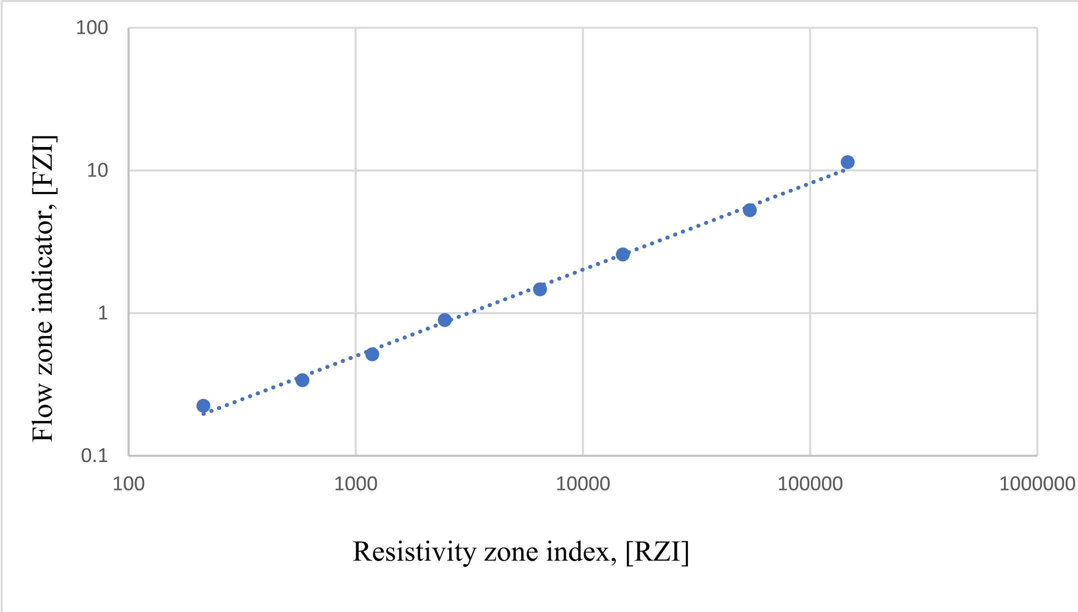


Fig. 7. Relation between *FZI* and *RZI* for the eight flow units.

Table 4
Summary of the empirical correlations between k_{core} and k_{log} for all wells.

Well no.	Relation between k_{CORE} & k_{LOG}	R^2
1	$k_{CORE} = 60.334\,[k_{LOG}]^{0.86}$	0.9546
2	$k_{CORE} = 75.276\,[k_{LOG}]^{0.96}$	0.9667
3	$k_{CORE} = 35.148\,[k_{LOG}]^{0.85}$	0.9450
4	$k_{CORE} = 31.464\,[k_{LOG}]^{0.76}$	0.8388
5	$k_{CORE} = 61.249\,[k_{LOG}]^{0.93}$	0.9573
All wells	$k_{CORE} = 45.765\,[k_{LOG}]^{0.86}$	0.9295

The results of S_{wr} from *RZI* are little decreasing with increasing *RZI* similar to the trend with *FZI* concluded by Amaefule et al. (1993). In addition, the values of S_{wr} obtained from *RZI* based on rock resistivity measurements are less than the corresponding values obtained from *FZI* which are confirmed by Attia et al. (2008), where the two values of irreducible brine saturation yield an upper and lower bound limits that can be used to estimate limits to the production capacity of the porous medium.

4. Conclusion

A new approach for petrophysical reservoir characterization from data obtained from well logs is introduced. The new approach is based on modifying the conventional Kozeny–Carman model by taking into consideration the formation True Resistivity R_T. The new technique is tested and validated by using log data obtained from 21 logged wells and 1135 core samples to check its applicability. The results successfully represent reservoir by the "Resistivity Zone Index" (*RZI*) which shows a unique value for each Electrical Flow Unit (EFU) at values of normalized porosity of unity. Applying *RZI* technique on an Algerian oil field characterizes reservoir into eight EFU (similar to Amaefule technique) with correlation coefficients of determination (R^2) ranging from 0.84 to 0.97. Concluded that the number of distinct flow units determined by the new technique from well logs, showed agreement with Amaefule technique with high accuracy. Empirical correlations were developed to calculate true formation resistivity and permeability from log data with average relative errors of 0.5% and 7%, respectively and can be applied for uncored wells. In addition, Sw and *Swr* can be calculated for each rock type.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix. Table of symbols and abbreviations

Symbol	
EFU	Electrical flow unit
F_r	Formation resistivity factor
F_s	Shape factor (= 2 for a circular tube)
FZI	Flow zone index
HFU	Hydraulic flow unit
I_r	R_T/ R_o
k	permeability
RQI	Reservoir quality index
R_o	Formation resistivity at 100% water saturation (aquifer)
RZI	Resistivity zone index
R_w	Formation water resistivity
r_{mh}	Mean hydraulic unit radius
R_T	True formation resistivity
R_{35}	Radius of the pore throat at mercury saturation of 35%
S_{wr}	Irreducible water saturation
S_{gv}	Surface grain volume
Sw	Water saturation
Φ_N	Normalized porosity
Φ_e	Effective porosity
τ	Hydraulic tortuosity

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