

Permeability Prediction for Carbonate Rocks using a Modified Flow Zone Indicator Method

Ahmed J. Mahmood^{1*} and Mohammed A. Jubair²

¹Department of Petroleum Engineering, Al-Farabi University College,
Baghdad, Iraq

²Department of Computer Technical Engineering, College of Information Technology, Imam Ja'afar Al-Sadiq University,
Al-Muthanna, 66002, Iraq

Abstract—Carbonate reservoir rocks are usually heterogeneous, so it is not an easy task to establish a relation between porosity and permeability in these types of reservoir rocks. First, Kozney and Kozney-carmen formulas were used to establish these relations. Later, the flow zone indicator (FZI) method was introduced, which was widely used to find such a relation since it shows better results than the two former methods. In this work, the classical FZI method and a modified form of the FZI method were utilized to identify the hydraulic flow units and rock quality index to predict permeability. In the modified FZI method, the cementation factor (m) was introduced in calculating the value of FZI. The data collected from core analysis of the cored intervals in the Tanuma and Khasib formations were used as a database for this work. The classical and the modified FZI methods were applied using the database to predict core permeability. The value of the cementation factor was tuned to get a better match between the predicted permeability resulting from applying the modified method and the measured permeability values. Results show that the correlation coefficients resulting from applying the modified FZI method are closer to unity compared with that resulting from the classical FZI method. Cementation factor (m) of $m = 3$ for Tanuma formation and $m = 3$ for Khasib formation are the best values used with the modified FZI method. The modified FZI method shows a regression factor of 0.9986 for Tanuma and 0.9942 for Khasib formation.

Index Terms – Cementation factor, FZI, Hydraulic flow unit, Modified FZI, Permeability prediction.

I. INTRODUCTION

The flow capacity and storage of petroleum reservoirs are mainly dependent on two important rock properties. They are permeability and porosity; because of their heterogeneity and inclination to be tight because of depositional and diagenetic processes, carbonate reservoirs provide several obstacles when attempting to characterize

them (Alobaidi, 2016; Haghighi, Shabaninejad and Afsari, 2011; Riazi, 2018).

In cored intervals, both permeability and porosity could be measured, but in uncored wells, permeability evaluation depends on the porosity evaluated by well logs. Many methods were proposed to calculate permeability, earlier The Kozeny, Kozeny–Carmen (K–C) correlation and their modifications are widely acceptable methodologies in the oil industry (Kozeny, 1927; Carman, 1937; Carman, 1938 and Shun, Yuzuru and Hide, 2018).

Amaefule, et al. (1993) presented a modification for K–C correlation. The reservoir quality index (RQI) and flow zone indicator (FZI) were proposed to improve its ability to represent the various behaviors of reservoir flow based on its respective characteristics. This was done to improve the capability of K–C correlation. However, there are difficulties associated with employing the initial correlation because of the inherent limits and oversimplified assumptions that it contains, both of which hinder correct definitions of the hydraulic flow unit (HFU) (Davies and Vessell, 1996; Barach, et al., 2022).

The concept introduced by Amaefule, et al. (1993), was modified by many researchers to establish a porosity permeability correlation having a correlation coefficient better than that resulting from the Amaefule method. Nooruddin and Hossain (2012) provided a modified K–C correlation by addressing the tortuosity factor in a more powerful manner. The model was validated with the help of core data taken from important carbonate reservoirs in Saudi Arabia. To demonstrate that the suggested model is applicable on a worldwide scale, additional data sets that were gleaned from the existing body of scholarly research on sandstone reservoirs were utilized. The findings indicate that one should anticipate a greater range of permeability values within a single HFU. Their results show that the traditional model greatly underestimates the permeability values found within a given HFU compared to the modified model.

Based on the well-log and core data, Abed (2014) was able to establish the flow zone indicator and then use K-means to divide the reservoir into several different HFUs. The next step is to develop a correlation between the HFUs from the core and the well-log data. This correlation is used

ARO-The Scientific Journal of Koya University
Vol. XII, No. 1 (2024), Article ID: ARO.11314. 7 pages
DOI: 10.14500/aro.11314

Received: 02 August 2023; Accepted: 04 December 2023

Regular research paper: Published: 28 February 2024

Corresponding author's email: dr.ahmed.jabir@alfarabiuc.edu.iq

Copyright ©2024 Ahmed J. Mahmood and Mohammed A. Jubair.

This is an open access article distributed under the Creative Commons Attribution License.



to estimate permeability in un-cored wells; moreover, these correlations enable reservoir permeability to be estimated at the “flow unit” scale. After obtaining an effective porosity and flow zone indicator, the final step was to determine the permeability in each HFU. The results of permeability prediction based on HFU were studied for several wells, and the measured permeability value of cores was compared with those results. A strong relationship was shown between the expected and measured permeability.

Onuh, David and Onuh (2017) updated the reservoir quality indicator (RQI) approach for HFU characterization using the normalized pore throat concept. A correlation coefficient of 0.78 for the proposed modified RQI demonstrates an improvement over a correlation coefficient of 0.31 for the classical RQI method. This improvement was demonstrated by the result of an analysis that was conducted on various genetic reservoir units.

The first K–C formula was as follows:

$$K = (1 / f_g \tau S^2)(\phi^3 / (1 - \phi)^2) \tag{1}$$

Where: - k is permeability in μm^2 , fg is the shape factor, dimensionless, τ is the tortuosity (dimensionless), S is the

surface area per unit bulk volume ($L2/L3$), and ϕ . is the effective porosity (fraction). Mathematical resolutions are applied on Eq. (1) to become as follows:

$$0.0314\sqrt{k / \phi} = [1 / s\sqrt{fg \tau}] [\phi / (1 - \phi)] \tag{2}$$

K in millidarcy. Amaefule, et al. (1993) introduced the following definitions.

$$RQI = 0.0314\sqrt{k / \phi} \tag{3}$$

$$\phi_z = \phi / (1 - \phi) \tag{4}$$

And

$$FZI = 1 / s\sqrt{fg \tau} \tag{5}$$

Hence.

$$RQI = FZI * \phi_z \tag{6}$$

Then RQI versus ϕ_z can be plotted on (log–log) paper, where similar FZI values of the core sample will appear as a straight line, whereas various FZI values of the core sample shown on other parallel straight lines (Amaefule, et al., 1993; Davies and Vessell, 1996). Based on a modified K–C model Nooruddin and Hossain (2012) incorporated the tortuosity term as:

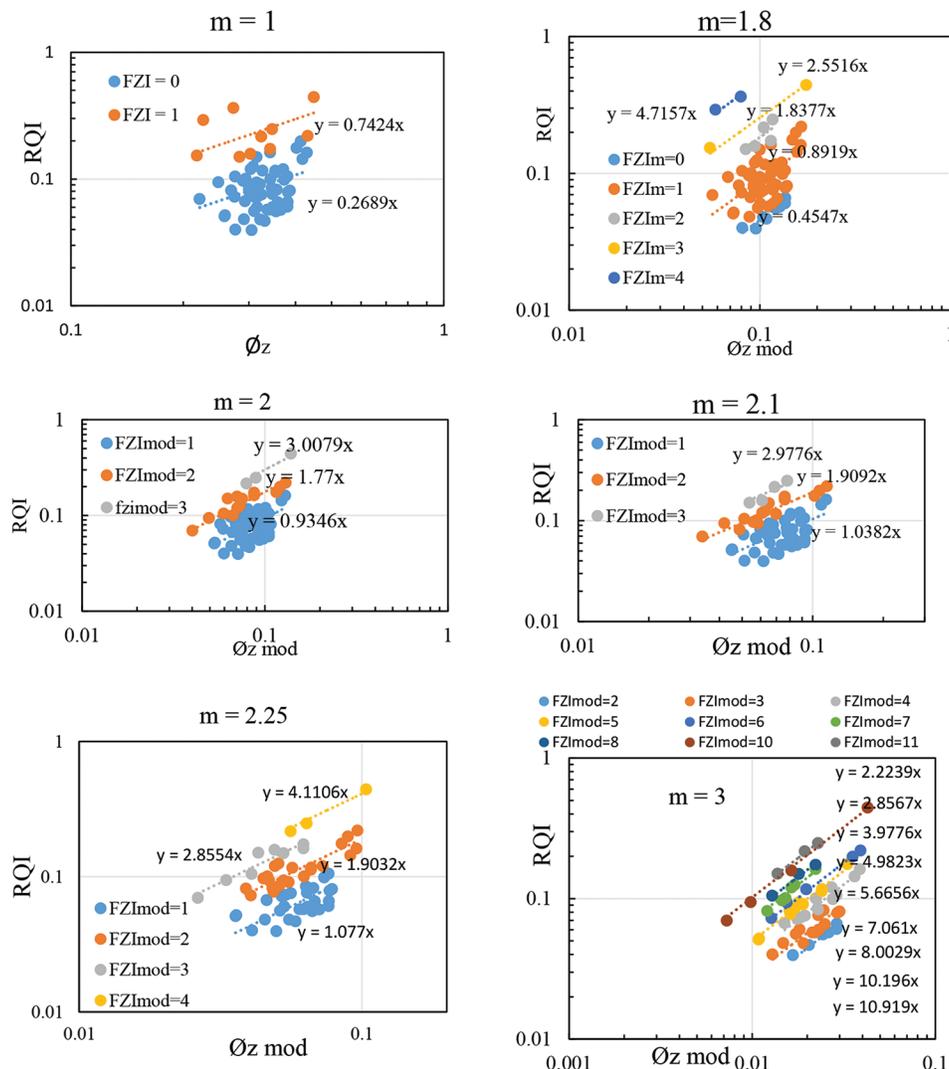


Fig. 1. Reservoir quality index versus ϕ_z for conventional ($m = 1$) and modified method ($m = 1.8, 2, 2.1, 2.25,$ and 3) for Tanuma formation.

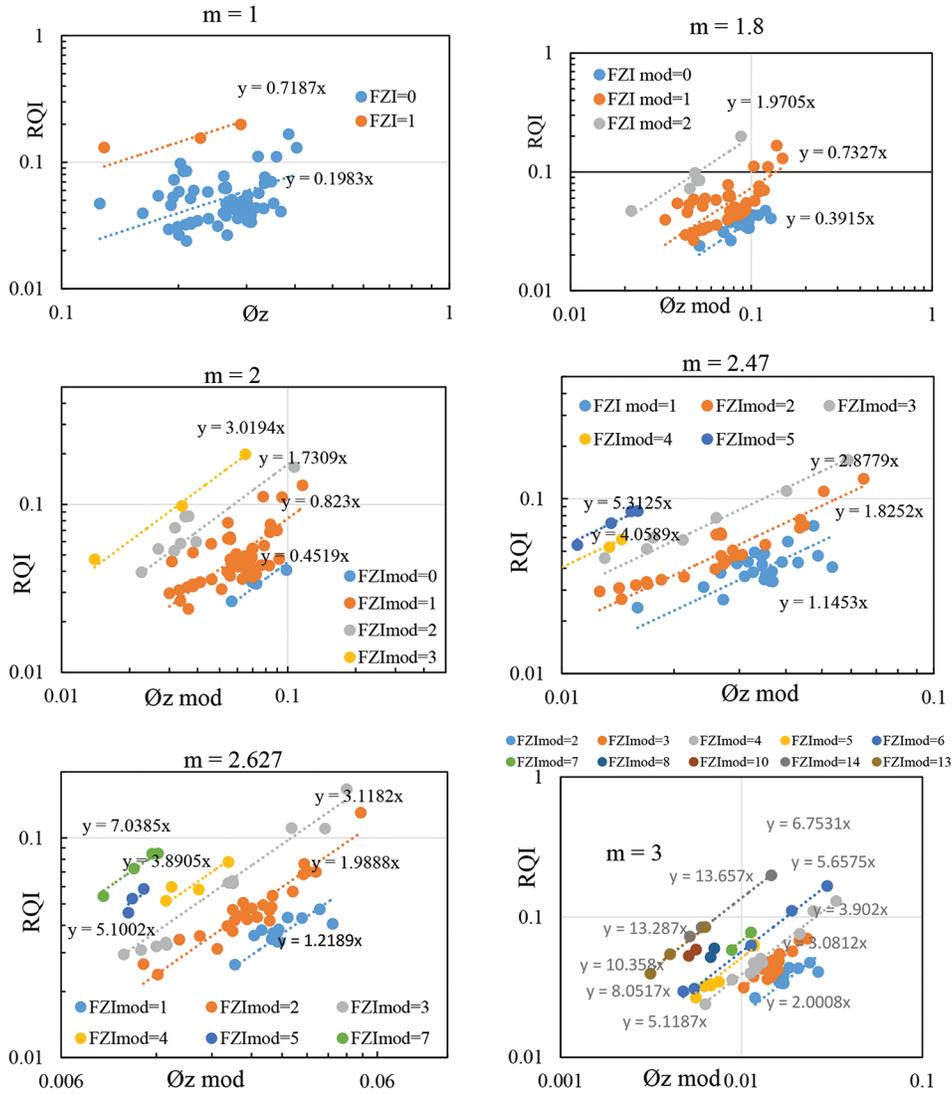


Fig. 2. Reservoir quality index versus Øz for conventional ($m = 1$) and modified method ($m = 1.8, 2, 2.47, 2.627$, and 3) for Khasib formation.

$$\tau = \left(a / \text{Ø}^{m-1} \right)^2 \tag{7}$$

Where a is the lithology factor and m is the cementation factor. Eq. (7) demonstrates the non-linear relationship between tortuosity and porosity and was incorporated into the original K-C model (Eq. 1). The proposed model is:

$$K = (1 / f_g a^2 S^2) (\text{Ø}^{2m+1} / (1 - \text{Ø})^2) \tag{8}$$

Rearranging and taking the square root of Eq. (8) resulting in the following form:

$$0.0314 \sqrt{k / \text{Ø}} = \left[1 / a s \sqrt{f_g} \right] \text{Ø}^m / (1 - \text{Ø}) \tag{9}$$

Using the relations in Eqs. (3) and (4) and considering the first part of RHS ($1 / a s \sqrt{f_g}$) as the modified flow zone indicator (FZIm) yields:

$$RQI = FZIm * \text{Ø}_z * \text{Ø}^{m-1} = FZIm * \text{Ø}_{zmod} \tag{10}$$

Where,

$$\text{Ø}_{zmod} = \text{Ø}_z * \text{Ø}^{m-1} \tag{11}$$

Taking the logarithm of both sides of Eq. (10) results in the following relationship:

$$\log RQI = \log FZIm + \log \text{Ø}_{zmod} \tag{12}$$

If the cementation exponent, (m), is equal to one, then Eq. (12) is the same as the model that Amaefule, et al. (1993) developed. The slope of the lines in the plot of RQI versus Ø_{zmod} on a log-log scale becomes steeper as the value of m grows. Every collection of rocks with a comparable FZI will be considered an HFU (Onuh, David and Onuh, 2017). Mathematically, the cementation factor (m) can vary from 1.0 to infinity. Practically, the cementation factor (m) for carbonate rocks ranges from 1.0 to 3.0 (Kadhim, Samsuri and Kamal, 2013). In this study, the value of m is considered between 1.0 and 3.0.

II. METHODOLOGY

The data set used in this work was from a well in the East-Baghdad oil field. The field is an Iraqi oil field. Tanuma and Khasib formations were recognized as reservoir rocks in this field. Tanuma formation is porous limestone having small vugs with evidence of shale in some sections. Khasib

formation is a porous limestone with shelly lime and chalky lime in some sections. The data set are readings of porosity and permeability at different depths resulting from core analysis for the cored intervals in well East-Baghdad – 35 (Ministry of Oil, 1983). The porosity range is (6–29.24) % and the permeability range is (0.1–28.9) md.

When applying the conventional FZI method, the porosity-permeability values for each formation were used to calculate RQI and ϕ_z adopting Eqs. (3) and (4). After calculating FZI from Eq. (6), different HFUs could be recognized corresponding to the rounded value of FZI. From the plot of RQI versus ϕ_z mathematical relation between porosity and permeability was derived for each rounded FZI value. These mathematical relations are employed to calculate core permeability depending on the measured porosity value. The former steps were followed when the modified FZI method was employed but Eq. (11) was utilized to calculate ϕ_{zmod} instead of Eq. (4) and FZIm was calculated through Eq. (10). The magnitude of m was used to calculate ϕ_{zmod} was

ranging from 1 to 3 and calculation steps were repeated for each m value. Permeability could be predicted depending on the mathematical relations resulting from plots of RQI versus ϕ_{zmod} for each m value.

To study the effectuality of the different FZI techniques, plots of the calculated permeability resulting from the different approaches versus the measured permeability were achieved. The correlation coefficients of these plots are considered the base for comparison between the different porosity–permeability relations for formations under study.

III. RESULTS AND DISCUSSION

The conventional FZI method ($m = 1$) and the modified FZI method ($m = 1.8, 2, 2.1, 2.25, \text{ and } 3$) were applied using the porosity and permeability data for Tanuma formation. Plots of RQI versus ϕ_z and RQI versus ϕ_{zmod} in log–log scale are shown in Fig. 1.

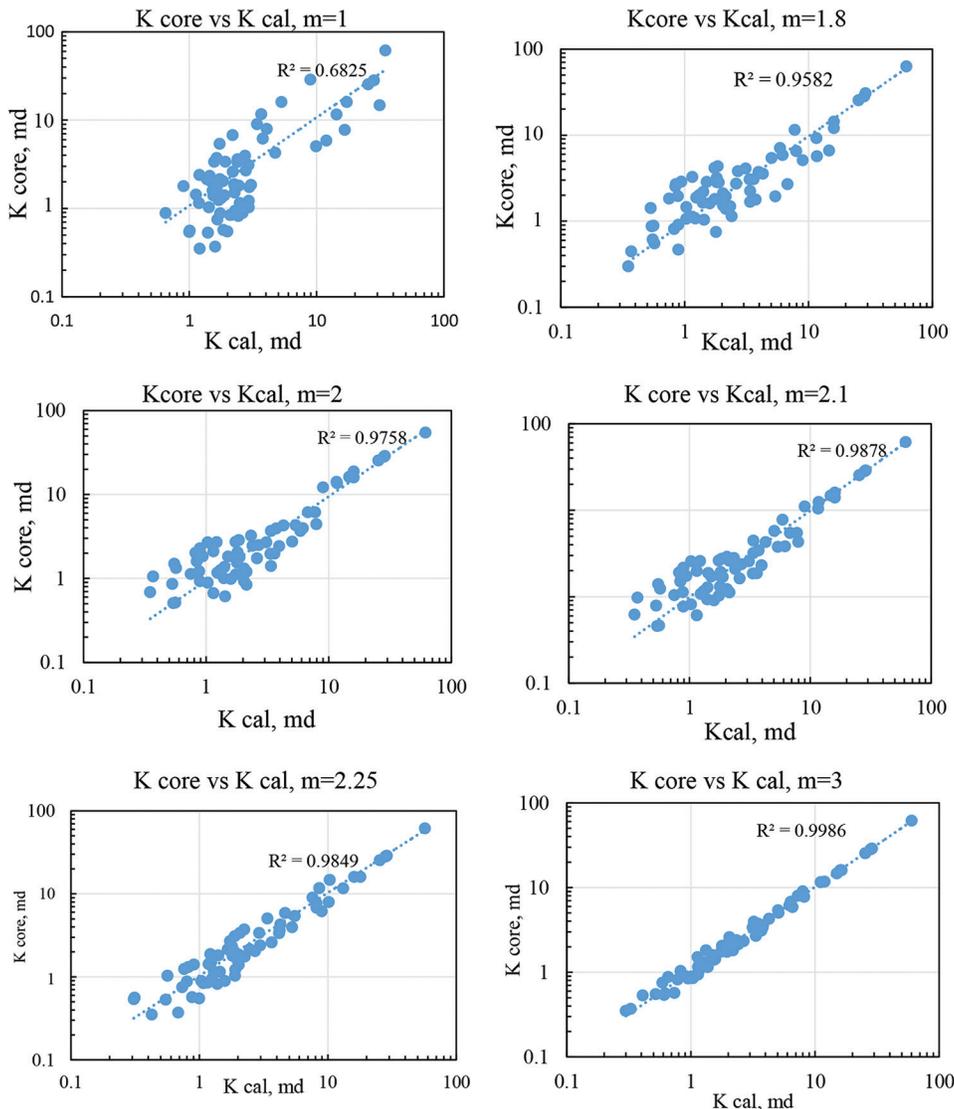


Fig. 3. Core permeability versus calculated permeability applying the conventional ($m = 1$) and the modified method ($m = 1.8, 2, 2.1, 2.25, \text{ and } 3$) Tanuma formation.

The same methods (conventional and modified FZI) were applied using the porosity and permeability data for Khasib formation. Plots of RQI versus ϕ_z and RQI versus ϕ_{zmod} in log-log scale are shown in Fig. 2.

The plots in Figs. 1 and 2 clarify that applying the modified method increases the number of HFUs (zones) as the value of m increases, more zones are identified. Mathematical relations between porosity and permeability were derived from x and y equations that appear with each specific FZI value. These derived relations were used to calculate core permeability depending on the measured porosity. To compare the measured core permeability values for each individual formation with the calculated permeability values resulting from applying the mathematical relations. Plots of core permeability versus the calculated permeability resulting from applying the conventional and the modified

FZI methods are presented in Fig. 3 for Tanuma formation and Fig. 4 for Khasib formation.

In Figs. 3 and 4, it is clearly seen that the conventional method ($m = 1$) yields a lower correlation coefficient ($R^2 = 0.6825$ for Tanuma and $R^2 = 0.5971$ for Khasib) compared to that resulted from the modified method. The value of the correlation coefficients is closer to unity as m increased in modified method. The best values of R^2 are at $m = 3$ for both formations (0.9986 for Tanuma and 0.9942 for Khasib). The improvement of the R^2 values as m increases is attributed to the increase of the HFU as m increases, this implies that more porosity – permeability relation will be identified. The different values of m and correlation coefficient are in Table I below.

The values in Table I indicate that generally, values of R^2 when applying the modified method are better (closer to

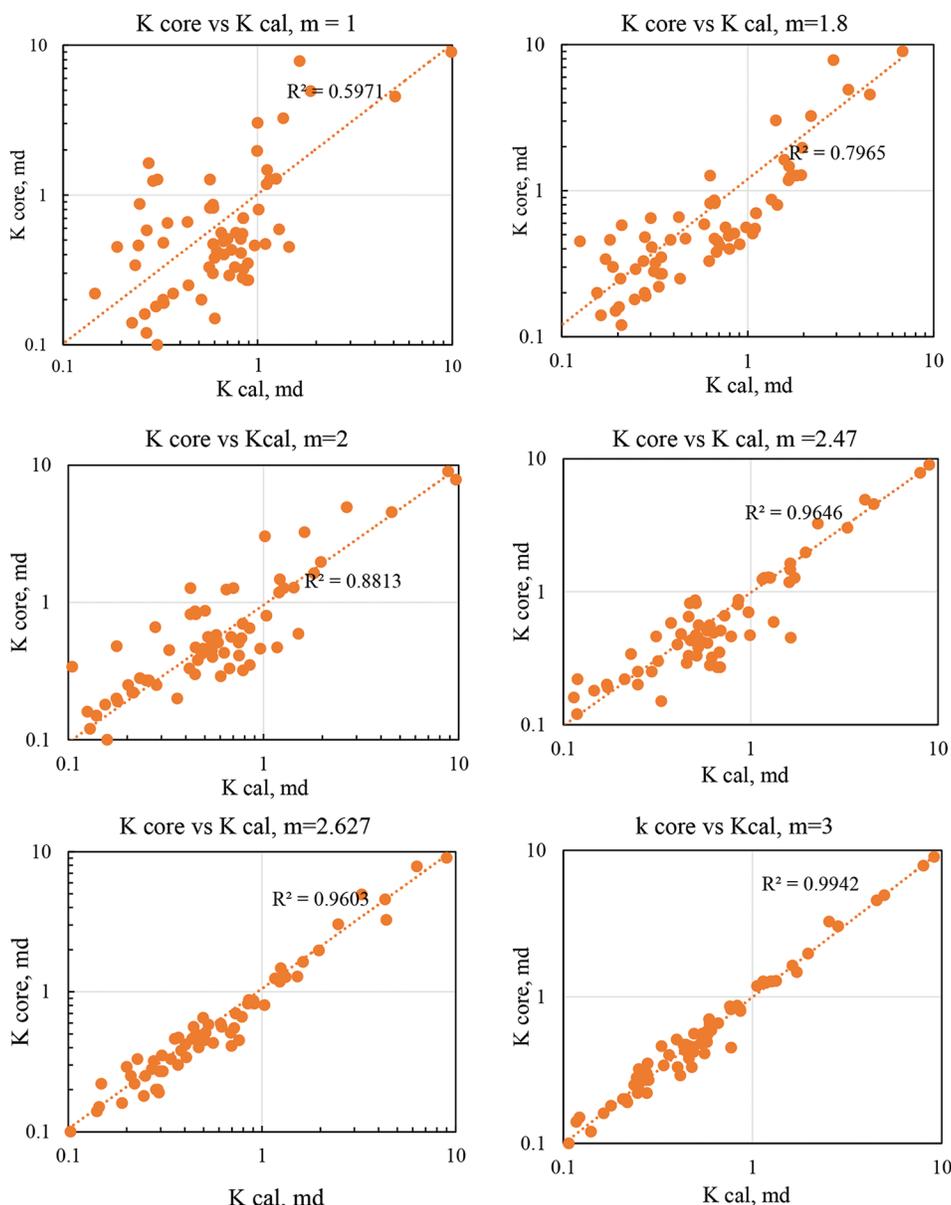


Fig. 4. Core permeability versus calculated permeability applying the conventional ($m = 1$) and the modified method ($m = 1.8, 2, 2.47, 2.627, \text{ and } 3$) Khasib formation.

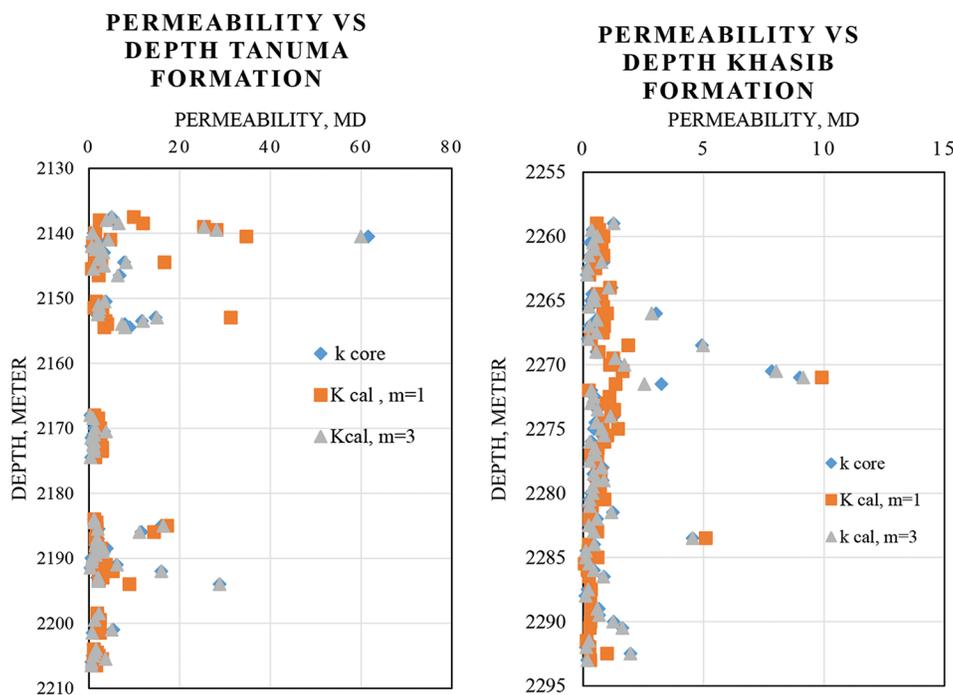


Fig. 5. Calculated permeability and core permeability versus depth for Tanuma and Khasib formations.

TABLE I

VALUES OF CORRELATION COEFFICIENT FOR TANUMA AND KHASIB FORMATIONS

Tanuma Formation		Khasib Formation	
m	R ²	m	R ²
1 (conventional)	0.6825	1 (conventional)	0.5971
1.8	0.9582	1.8	0.7965
2	0.9758	2	0.8813
2.1	0.9878	2.47	0.9646
2.25	0.9849	2.627	0.9603
3	0.9986	3	0.9942

unity) than that resulting from applying the conventional one. In Tanuma formation, R² increases from 0.6825 to 0.9582 when m increases from 1 to 1.8, whereas m needs to be 2.47 to reach R² value of 0.9646 in Khasib formation.

The plot of measured core permeability, permeability calculated by the conventional method, and permeability calculated by the modified method (m = 3) versus depth for Tanuma and Khasib formations are in Fig. 5.

IV. CONCLUSIONS

The modified FZI method is more accurate in permeability prediction than the conventional method. Better matches between calculated and measured permeability are recognized as the value of the cementation factor (m) increases. The best match between the measured and the predicted permeability is at m = 3 for both formations. It is better than the conventional method, so it is better to use the modified method for predicting permeability in uncored intervals. When applying the modified method to any other formations, different values of cementation factor (m)

must be tested to select the one having the best correlation coefficient.

REFERENCES

Abed, A.A., 2014. Hydraulic flow units and permeability prediction in a carbonate reservoir, Southern Iraq from well log data using non-parametric correlation. *International Journal of Enhanced Research in Science Technology and Engineering*, 3(1), pp.480-486.

Alobaidi, D.A., 2016. Permeability prediction in one of Iraqi carbonate reservoir using hydraulic flow units and neural networks. *Iraqi Journal of Chemical and Petroleum Engineering*, 17(1), pp.1-11.

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

Barach, B., Jaafar, M., Gaafar, G., Agi, A., Junin, R., Sidek, A., Gbadamosi, A., Yakasai, F., Oseh, J., and Gbonhibor, J., 2022. Development and Identification of Petrophysical Rock Typing for Effective Reservoir Characterization. In: *SPE Nigeria Annual International Conference and Exhibition*, Onepetro.

Carman, P.C., 1937. Fluid flow through granular beds. *Transactions of the Institution of Chemical Engineers*, 15, pp.150-166.

Carman, P.C., 1938. Fundamental principles of industrial filtration. *Transactions of the Institution of Chemical Engineers*, 16, pp.168-188.

Davies, D.K., and Vessell, R.K., 1996. Identification and Distribution of Hydraulic Flow Units in a Heterogeneous Carbonate Reservoir: North Robertson Unit, West Texas. In: *SPE Permian Basin Oil and Gas Recovery Conference*, Paper Number SPE-35183, SPE.

Haghighi, M.B., Shabaninejad, M., and Afsari, K., 2011. A permeability predictive model based on hydraulic flow unit for one of Iranian carbonate tight gas reservoir. In: *SPE Middle East Unconventional Resources Conference and Exhibition*, Paper Number SPE-142183, SPE.

Kadhim, F.S., Samsuri, A., and Kamal, A., 2013. A review in correlations between cementation factor and carbonate rocks properties. *Life Science Journal*, 10(4), pp.2451-2458.

Kozeny, J., 1927. *Über Kapillare Leitung des Wassers im Boden*. Vol. 136. Akademie der Wissenschaften, Sitz der Wien, pp.271-306.

Ministry of Oil, 1985. *Routine Core analysis (RCA) for Wells (EB-35)*. Reservoir Solutions (RES), United States.

Nooruddin, H.A., and Hossain, M.E., 2012. Modified Kozeny-correlation for enhanced hydraulic flow unit characterization. *Journal of Petroleum Science and Engineering*, 80, pp.107-115.

Onuh, H.M., David, O.O., and Onuh, C.Y., 2017. Modified reservoir quality indicator methodology for improved hydraulic flow unit characterization using the normalized pore throat methodology (Niger Delta field as case study). *Journal of Petroleum Exploration and Production Technology*, 7, pp.409-416.

Riazi, Z., 2018. Application of integrated rock typing and flow units identification methods for an Iranian carbonate reservoir. *Journal of Petroleum Science and Engineering*, 160, pp.483-497.

Shun, N., Yuzuru, Y., and Hide, S., 2018. Modified expression of Kozeny-Carman equation based on semilog-sigmoid function. *Soils and Foundations*, 58, pp.1350-1357.