Improved water saturation estimation in shaly sandstone through variable cementation factor

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Abstract

Estimation of water saturation, S_w , in shaly sandstone is an intricate process. The surface conduction of clay minerals adds up to the electrolyte conduction in the pore spaces, thus generating high formation conductivity that overshadows the hydrocarbon effect. In each resistivity-based water saturation model, the key parameter is formation factor, F , which is typically derived from Archie's Law. Referring to a log–log plot between formation factor and porosity, cementation factor reflects the slope of the straight line abiding Archie's Law. In the case of shaly sandstone, derivation based on Archie's Law in combination with Waxman–Smits equation leads to higher cementation factor, m^* . In the shaly parts of the reservoir, high m^* is counterbalanced by clay conductivity. Nonetheless, high m^* used in clean parts increases S_w estimation. In this study, the variable cementation factor equation is introduced into the standard correlation of S_w versus Resistivity Index, RI , to develop a water saturation model with shaly sandstone parameters. Data retrieved from two fields that yielded mean arctangent absolute percentage error (MAAPE) were analysed to determine the difference between calculated and measured data within the 0.01–0.15 range for variable cementation factor method. The conventional method yielded maximum MAAPE at 0.46.

Keywords Shaly sandstone · Formation factor · Variable cementation factor · Water saturation

Introduction

Water saturation, S_w , refers to crucial petrophysical information for volumetric estimation. This parameter can be determined from the formation resistivity in combination with porosity and several other constants. The most common method used to estimate S_w is by using Archie's model described in the equation given below:

$$S_w^n = \frac{FR_w}{R_t} \quad (1)$$

where R_w =formation fluid resistivity (ohm m), R_t =true formation resistivity (ohm.m), n =saturation exponent, m =porosity exponent or cementation factor.

According to Archie (1942), the equation was established based on several prior studies, including Martin et al. (1938), Jakosky and Hopper (1937), Wyckoff and Botset (1936), and Leverett (1941). Archie expanded the equation by embedding quantity F , also known as the formation resistivity factor or simply referred as formation factor. This quantity denotes the resistivity ratio of fully water-saturated rock, R_o , to the formation fluid resistivity, R_w . In terms of conductivity, it signifies the ratio of formation fluid conductivity, C_w , to the conductivity of fully water-saturated rock, C_o (see Eq. 2).

$$F = \frac{R_o}{R_w} = \frac{C_w}{C_o} \quad (2)$$

Archie prescribed that the formation factor, F , is always constant for a given rock since R_o increases linearly with

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increment in R_w . Hence, F is a function of rock type and characteristics (Archie 1942). However, the following studies found that the formation factor is not constant, especially for sample with high clay content saturated in low brine conductivity (Patnode and Wyllie 1952; Winsauer and McCardell 1953; Wyllie and Southwick 1954; Sauer et al. 1955). More studies depicted that the conductance behaviour in samples with high clay content differed from that in clean samples (Waxman and Smits 1968; Clavier et al. 1984). The conductance pattern on a C_o versus C_w plot can be divided into two regions; nonlinear and linear (see Fig. 1). In the nonlinear zone, the formation factor, inverse of the graph slope, is not constant until a point where sufficiently high C_w is reached. The formation factor becomes constant after this point as C_w displays further increment.

The linear region is manageable since the formation factor is constant and its log–log plot against porosity can result in straight law based on Archie's law. However, for nonlinear region, it is questionable if the plot still conforms to Archie's law since the formation factor is not constant. The nonlinear zone indicates the significant impact of clay conductivity on total conductivity. This has been the basis for the parallel resistors theory (Patnode and Wyllie 1952; Clavier et al. 1984) that defines resistivity from clay surface and resistivity from electrolyte in pore spaces as two resistors connected in parallel.

Based on numerous shaly sandstone conductivity model initiated during the early years, clay conductivity was introduced as an additional parameter; X to the bulk conductivity, as expressed in Eq. 3 (Worthington 1985). This shows that the formation factor is a constant of proportionality for the relationship between C_o and C_w with X as the intercept on y-axis.

Fig. 1 Typical conductivity C_o – C_w plot for shaly sandstone. Source: Worthington (1985)

$$C_o = \frac{C_w}{F} + X \quad (3)$$

Equation 3 solves for the formation factor in linear region (high conductivity region) from the slope of the plot and the value of clay conductivity is represented by X . The bulk conductivity is shifted by the amount of X determined from the ordinate intercept. Since the formation factor can be derived from the slope of linear line, this approach technically solves for the intrinsic value rather than formation factor for shaly sandstone, which is also known as a non-constant. For S_w estimation in shaly sandstone, the efficacy of this formation factor when embedded into the equation is still unclear because the intrinsic formation factor is meant for clean sandstone only. In most complex heterogeneous lithology, the formation factor varies even within the same reservoir.

Water saturation from variable cementation factor

Bakar et al. (2019) proposed an improved equation to model the formation factor by varying the cementation factor with clay conductivity and porosity. Clay conductivity is defined as cations mobility, B , multiplied by effective clay concentration, Q_v .

$$F^* = \frac{1}{\phi^{\frac{\log_{10}(1+BQ_vR_w)}{\log_{10}\phi} + m}} \quad (4)$$

Referring to Eq. 4, the exponent of porosity $\left(\frac{\log_{10}(1+BQ_vR_w)}{\log_{10}\phi} + m\right)$ is the cementation factor for shaly sandstone, m^* . The value varies with both clay conductivity and porosity, which enables F^* to change accordingly.

Resistivity Index, RI , measurement is the basis for the derivation of S_w equation. It is defined as the ratio of true core plug resistivity, R_t , to fully water-saturated core plug resistivity, R_o . The general relationship between RI and S_w is expressed in Eq. 5. This equation is valid for any type of formation as long as it is water-wet (Mungan and Moore 1968).

$$RI = \frac{1}{S_w^n} \quad (5)$$

The parameters in RI for shaly sandstone are represented by asterisks, as given below:

$$RI^* = \frac{1}{S_w^{n^*}} \quad (6)$$

All asterisk parameters represent measurement in shaly sandstone. For shaly sandstone, RI is as follows:

$$RI^* = \frac{R_t^*}{R_o^*} = \frac{C_o^*}{C_t^*} \quad (7)$$

Hence, the total conductivity of shaly sandstone in terms of S_w is expressed as follows:

$$\frac{C_t^*}{C_o^*} = S_w^{n^*} \quad (8)$$

This equation can be applied to predict if the measured conductivity, C_t^* , is proportional to the percentage of water in the pore spaces. This is because the medium for electrical current flow is mainly through electrolyte. Next, C_t^* is reduced from the initial value of C_o^* , along with reduction in water portion in pore spaces. The impact of reduction in electrical current path is on both electrolyte and clay surface conduction. Equation 8 is rearranged and the bulk conductivity of shaly sandstone is expanded into its terms in BQ_v to yield the following:

$$S_w^{n^*} = \frac{C_t^*}{C_o^*} = \frac{C_t^*}{\frac{1}{F}(C_w + BQ_v)} \quad (9)$$

Conversion of C_w to R_w :

$$S_w^{n^*} = \frac{C_t^*}{\frac{1}{FR_w}(1 + BQ_vR_w)} \quad (10)$$

$$S_w^{n^*} = \frac{FR_w C_t^*}{(1 + BQ_vR_w)} \quad (11)$$

C_t^* in terms of R_t^* :

$$S_w^{n^*} = \frac{FR_w}{R_t^*(1 + BQ_vR_w)} \quad (12)$$

Formation factor of shaly sandstone is given as follows:

$$F^* = \frac{F}{(1 + BQ_vR_w)} \quad (13)$$

Equation 13 is simplified to:

$$S_w^{n^*} = \frac{F^*R_w}{R_t^*} \quad (14)$$

Equation 14 denotes Archie's S_w equation. All parameters in this equation must be properly defined to only reflect the shaly sandstone vicinity. Hence, the formation factor, F^* , in Eq. 14 is substituted by Eq. 4, which demands information pertaining to intrinsic cementation factor, m .

In conventional approach, the intrinsic cementation factor, m , is determined from the slope of bi-logarithmic plot of formation factor versus porosity, which is in accordance to Archie's Law:

$$F = \frac{1}{\phi^m} \quad (15)$$

This technique leaves cementation factor constant for the entire zone represented by the respective core samples. The shaly sandstone cementation factor, m^* , is estimated based on the slope of bi-logarithmic plot of shaly sandstone formation factor, F^* , versus porosity. F^* is calculated using Waxman–Smits equation (Waxman and Smits 1968); $F^* = F(1 + BQ_vR_w)$, which leads to $m^* > m$. The shortcoming of this technique can be observed in heterogeneous reservoir. This is particularly in less shaly zone, in which higher m^* derived from this technique leads to overestimation of S_w .

Turning to this present study, its aim is to validate the feasibility of Eq. 14 in estimating S_w . The estimated S_w from Eq. 14 was later compared with measured S_w in RI laboratory analysis because in RI analysis, R_t measurement is directly related to measured S_w . Prior to S_w estimation, formation factor, F^* , determined from Eq. 4, was analysed because F^* is an important parameter in Eq. 14. If Eq. 14 can estimate S_w close to the measured value, the equation is feasible for log interpretation after identifying BQ_v . In this study, the accuracy of Eq. 14 in estimating S_w was compared with the conventional method that used constant m .

Core data and S_w estimation techniques

Two sets of RI data obtained from Sabah Basin with arbitrary name Fields A and B were deployed in this study to analyse F^* and S_w .

Field A: m^* from conventional method

The core samples from Field A had high porosity that ranged at 40–45%. The cation exchange capacity (CEC) ranged from 1.74 to 14.42 meq/100 g with corresponding Q_v of 0.07–0.49 meq/ml. The conventional method using Waxman–Smits equation for m^* determination resulted in the value of 2.30 with corresponding m at 1.94 (see Fig. 2). In this method, the linear line was forced to 1.00 point following Archie's Law (see Eq. 15). Both m and m^* are the porosity exponent of the respective derived correlations. Notably, m was derived from the equation of F versus porosity, ϕ , while m^* was retrieved from F^* versus ϕ ; whereby $F^* = F(1 + BQ_vR_w)$.

Field B: m^* from conventional method

The core samples from Field B were composed of silty to fine grained, poor to moderately cemented sandstone. The CEC value ranged from 1.28 to 11.41 meq/100 g with

Fig. 2 Determination of m and m^* using conventional method for Field A

Fig. 3 Determination of m and m^* using conventional method for Field B

corresponding Q_v of 0.07–1.51 meq/ml. The conventional method using Waxman–Smits equation for m^* determination resulted in the value of 1.86 with corresponding m of 1.64 (see Fig. 3).

Using the conventional method, m was determined first from the slope of linear regression of laboratory-measured formation factor, F , plotted against porosity. The shaly sandstone cementation factor, m^* , which was obtained from the linear regression of F^* (calculated from F multiplied by $(1 + BQ_v R_w)$), generated a higher value than m . This result contravenes the Waxman and Smits theory on excess clay conductivity, which depicts that the cementation factor is

always lower in the condition that the clay conductivity is significant. Besides, the conventional approach did not justify the deviation from Archie's straight line observed in most laboratory and well log data. Due to the higher calculated F^* value, the conventional approach assumes that bulk conductivity, R_o , is higher in shaly sandstone. This is an unjustifiable assumption since excess clay conductivity reduces R_o .

Variable cementation factor for Fields A and B

In the proposed variable cementation factor method, m was estimated based on the fitting technique since a single value of R_w was used to measure formation factor in the laboratory. The fitting technique yielded some intrinsic cementation factors with m for varied sand units (see Table 1). As m depended on rock characteristics, Archie (1942) proposed that m ranging at 1.3–2.0 denotes loosely or partly consolidated sandstones. Additionally, m also depends on grain shape (Atkins and Smith 1961; Salem and Chilingarian 1999), cementation (Wyllie and Gregory 2012; Perez 1982), lithology and mineral compositions (Ehrlich et al. 1991), tortuosity, and pore geometry (Winsauer et al. 1952; Ehrlich et al. 1991; Aguilera 1976; Owen 1952). The value of cementation exponent m increases as the degree of connectedness of the pore network diminishes, all while relying on rock characteristics. The values of m (Table 1) were substituted into Eq. 4 to calculate shaly sandstone formation factor, F^* . Equation 14 was used to calculate S_w for each resistivity point of RI data.

Analysis and validation

Variable Formation Factor, F^* , from variable cementation factor

Equation 4 proposed by Bakar et al. presents a new approach to estimate formation factor, F^* , in shaly sandstone. In this approach, F^* is not the total geometric factor (as true formation factor should be), but it is the relative changes of bulk formation conductivity with respect to changes in saturating brine conductivity. This equation allows F^* to change with clay content. Hence, its value is a variable that corresponds to both clay effect and porosity; not limited to porosity as in the conventional method. This explains the changes of formation factor in nonlinear region of the conductivity curve.

The formation factor, F^* , estimated with Eq. 4 gave good approximation to the laboratory-measured F^* for data from Fields A and B. This is shown in the plot of F^* calculated with Eq. 4 versus laboratory-measured F^* , which fell around the unity constant of proportionality line (see Figs. 4 and 5). The MAAPE values were 0.06 and 0.05 for Fields A and B

Table 1 Estimated cementation factor, m , for each sand unit of Fields A and B

Data	Sample number	Porosity	Q_v (meq/cm ³)	Estimated cementation factor, m
<i>Field A</i>				
Field A in Sabah Basin				
Sand Unit 1	Sample 1	0.379	0.07	2.10
	Sample 2	0.393	0.11	
	Sample 3	0.425	0.13	
Sand Unit 2	Sample 4	0.423	0.49	2.50
	Sample 5	0.436	0.43	
<i>Field B</i>				
Field B in Sabah Basin				
Sand Unit 1	Sample 1	0.33	0.07	1.80
	Sample 2	0.30	0.28	
Sand Unit 2	Sample 3	0.34	0.08	1.75
	Sample 4	0.26	0.65	
	Sample 5	0.29	0.51	
	Sample 6	0.32	0.07	
	Sample 7	0.29	0.17	
	Sample 8	0.15	0.98	
Sand Unit 3	Sample 9	0.17	1.45	2.20
	Sample 10	0.19	1.04

Fig. 4 Calculated F^* versus measured F^* for data from Field A **Fig. 5** Calculated F^* versus measured F^* for data from Field B

data points, respectively (see Table 2). The MAAPE was calculated using Eqs. 16 and 17, as prescribed by Kim and Kim (2016).

$$MAAPE = \frac{1}{N} \sum_{i=1}^N AAPE_i, \text{ for } i = 1, \dots, N \quad (16)$$

where

$$AAPE_i = \arctan \left(\left| \frac{\text{measured value} - \text{calculate value}}{\text{measured value}} \right| \right) \quad (17)$$

Large errors were noted in some samples. For example, Samples 4 and 2 of Fields A and B had AAPE values of 0.21 and 0.22, respectively. This is ascribed to inaccurate prediction of m values as input to Eq. 4. Sample 4 was predicted to share a similar sand unit as Sample 5, which

Table 2 Mean arctangent absolute percentage error (MAAPE) for Fields A and B data points

Sample number	Calculated F^*	Measured F^*	AAPE
<i>Field A, Sabah</i>			
Sample 1	6.89	6.80	0.01
Sample 2	6.03	5.90	0.02
Sample 3	4.98	4.80	0.04
Sample 4	4.79	6.10	0.21
Sample 5	4.69	4.80	0.02
MAAPE			0.06
<i>Field B, Sabah</i>			
Sample 1	6.81	6.80	0.00
Sample 2	7.11	9.20	0.22
Sample 3	6.27	5.70	0.10
Sample 4	6.57	6.50	0.01
Sample 5	6.07	6.20	0.02
Sample 6	6.88	6.70	0.03
Sample 7	7.53	7.60	0.01
Sample 8	14.59	15.30	0.05
Sample 9	21.92	21.70	0.01
Sample 10	20.75	19.90	0.04
MAAPE			0.05

scored $m = 2.50$. This prediction was inaccurate as the samples might not derive from the same sand unit. In this present study, sand unit was predicted based on the depth from where the samples were taken and the porosity of the samples. However, only the two mentioned samples in the sand unit caused some difficulty in determining the most accurate m . A similar case was observed for Sample 2 of Field B, which displayed a similar sand unit with only Sample 1.

S_w from conventional and variable m^* methods

Typically, the conventional method employs established shaly sandstone water saturation models, which are manipulated from the inverse power law correlation between S_w and RI . In the established shaly sandstone water saturation models, the formation factor via Archie's Law is applied. The inverse power law relationship of S_w - RI signifies that the electrical current flow is dependent on brine geometry (Herrick and Kennedy 2009). The abrupt increase of C_t^* in low water saturation regime is attributed to the percolation theory by Ghanbarian et al. (2014); depicting that abrupt increment in relative tortuosity is related to reduction in water content. The relative tortuosity gradually increases from fully saturated to near the threshold water content and diverges as the water content approaches its irreducible values. In fact, tortuosity has better definition in terms of connectivity and connectedness of electrical current paths (Glover, 2009). Cai et al. (2019) reported that fluid flow and

Fig. 6 S_w^{n*} plotted against $R_w R_t^{*-1}$ for Samples 1 and 2 of Field A (straight line denotes linear relationship)

electrical conduction display similar behaviour. The validity of this assumption is supported by the notion that free electrolyte and clay surface conduction have the same path.

In Eq. 14, all parameters, i.e. n^* , F^* , and R_t^* , represent shaly condition. It is predicted that when water saturation reduces, S_w will reduce electrical conduction through free electrolytes and clay surface cations. Note that our assumption on clay surface conductance differs from that proposed by Waxman and Smits—clay surface conductance or BQ_v increases with reduction in S_w . Therefore, clay surface conduction becomes higher as S_w approaches zero. Nonetheless, the saturation exponent, n^* (represents changes in R_t^* with respect to changes in water portion), depends on the decreasing connectivity and connectedness of the electrical current path, which has either direct or indirect link with the geometric factor of the rock.

Since the generic term RI refers to changes in measured resistivity, R_p , relative to fully water-saturated resistivity, R_o ; in which R_o is fixed, the power law describes R_t profile with changes in S_w . In shaly sandstone, the correlation can be deployed in well log interpretation as long as R_o^* is identified. With respect to laboratory measurement, F^* is not a total geometric factor, but instead, a ratio of measured resistivity of fully water-saturated shaly, R_o^* , to saturating water resistivity, R_w . Thus, R_o^* can be determined from $F^* R_w$; with F^* defined by Eq. 4.

Referring to Eq. 14, the measured S_w^{n*} has a linear relationship with $R_w R_t^{*-1}$ with a constant of proportionality of F^* . The plot of S_w^{n*} against $R_w R_t^{*-1}$ should yield a straight line with slope equals to F^* . Figures 6 and 7 portray the straight lines for S_w^{n*} plotted against $R_w R_t^{*-1}$; signifying the linear correlation between the two parameters. Thus,

Fig. 7 $S_w n^*$ plotted against $R_w R_t^{*-1}$ for Samples 1 and 2 of Field B (straight line denotes linear relationship)

Fig. 8 F^* from slope plotted against measured F^* for all samples from Field A (all data fell on the unity constant of proportionality line)

F^* of each sample was determined from the slope of the graph and plotted against laboratory-measured F^* from the formation factor analysis. Next, Figs. 8 and 9 display that all data points from both fields fell on the unity constant of proportionality line. This proves that F^* measured in $RI-S_w$ analysis is similar to the measured F^* in formation factor analysis. Hence, the assigned F^* in Eq. 14 is indeed a valid assumption.

In the conventional method, it is common to deploy Waxman–Smits equations for both m^* and S_w . The comparison of calculated S_w values between variable m^* method and conventional method for Field A is presented in Figs. 10,

Fig. 9 F^* from slope plotted against measured F^* for all samples from Field B (all data fell on the unity constant of proportionality line)

Fig. 10 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 1 in Field A (data for the proposed method fell on the unity constant of proportionality line)

11, 12, 13, 14, and 15. All plots show that the variable m^* method yielded better S_w estimation, in comparison with the conventional method.

Data calculated using variable m^* method fell on the unity constant of proportionality line, which indicated that the calculated S_w matched the measured S_w . This is supported by low MAAPE at 0.02 for the proposed method (see Table 3). The conventional method gave good prediction of S_w at lower saturation, but resulted in overestimation at higher saturation with the last data point scoring above 1.0 S_w estimation.

The S_w prediction for Sample 2 revealed similar trend with prediction on Sample 1. The proposed method yielded

Fig. 11 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 2 in Field A (data of the proposed method fell on the unity constant of proportionality line)

Fig. 12 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 3 in Field A (data of the proposed method fell on the unity constant of proportionality line, while the conventional method overestimated at high saturation)

accurate estimation of S_w , whereas the conventional method overestimated S_w at high saturation. The MAAPE value for the proposed method was 0.04, while 0.20 for the conventional method. This observed trend is ascribed to the fixing of cementation factor m in Waxman–Smits equation, while constantly kept the S_w high. A similar pattern is noted for Sample 3 in Fig. 12.

For Samples 4 and 5 displayed in Figs. 13 and 14, respectively, the proposed method continued providing good approximation although S_w was slightly underestimated, especially at high saturation region. The conventional

Fig. 13 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 4 in Field A (prediction for both methods fell below the unity line)

Fig. 14 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 5 in Field A (the proposed method gave good prediction, while the conventional method underestimated S_w)

method, on the other hand, yielded massive errors with MAAPE values of 0.46 and 0.30, respectively, for Samples 4 and 5. The MAAPE values for the proposed method were 0.15 and 0.03, respectively. The huge error found for Sample 4 is attributable to the underestimation of F^* , as tabulated in Table 3.

The proportionality and MAAPE analysis of both methods for each sample are listed in Table 3. The conventional method had overestimated S_w , thus contributing to massive errors. The MAAPE for the proposed method was low; signifying the feasibility of the method in estimating S_w .

Similar to the data extracted from Field A, the proposed method displayed better match between calculated and measured S_w in all Field B core samples. The conventional method

Fig. 15 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 1 in Field B (data points from both methods fell on the unity constant of proportionality line)

Fig. 16 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 3 in Field B (good estimation by the proposed method, while overestimation of S_w by the conventional method)

Table 3 MAAPE analysis for both methods for Field A

Sample number	MAAPE	
	Variable m^* method	Conventional method
Sample 1	0.02	0.12
Sample 2	0.04	0.20
Sample 3	0.04	0.19
Sample 4	0.15	0.46
Sample 5	0.03	0.30

via Waxman–Smits equation gave good estimation of S_w in some samples (e.g. Sample 1 of Field B in Fig. 15) and either underestimation or overestimation in others (see Figs. 16 and 17).

Figures 16 and 17 illustrate that the conventional method either underestimated or overestimated S_w , especially in the high saturation region. This scenario is ascribed to the fixing of cementation factor m in the Waxman–Smits model. The Waxman–Smits model predicted stronger Q_v effect on low water saturation that contributed to more accurate prediction for region with low saturation. The error analysis for all samples in Field B is summarised in Table 4. The outcomes depict that the application of Eqs. 4 and 14 in the variable m^* method offers better S_w estimates with lower MAAPE values.

Fig. 17 The calculated S_w versus laboratory-measured S_w for the proposed and conventional methods of Sample 10 in Field B (good estimation by the proposed method, while underestimation of S_w by the conventional method)

Conclusion

The variable cementation factor method yielded good estimation to the laboratory-measured values. This denotes the significance of accurately estimating formation factor in S_w prediction. Referring to Eq. 4, instead of averaging the cementation factor to a single value to represent a particular reservoir, the cementation factor is varied with lithology type in the aspect of clay content and types, as well as geometric factor. This enables the formation factor to vary with both clay and porosity effects. In shaly part, S_w accounts for clay conductivity. In less shaly zone, the

Table 4 MAAPE analysis for both methods for Field B

Sample number	MAAPE	
	Variable m^* method	Conventional method
Sample 1	0.01	0.04
Sample 2	0.13	0.10
Sample 3	0.02	0.16
Sample 4	0.02	0.10
Sample 5	0.01	0.08
Sample 6	0.09	0.21
Sample 7	0.03	0.11
Sample 8	0.02	0.13
Sample 9	0.01	0.30
Sample 10	0.05	0.26

value was close to that predicted by Archie's equation as BQ_v approached zero. This outcome shows that water saturation estimation can be improved at anywhere, especially in a complex heterogeneous reservoir. The analysis of data extracted from the two fields located in Sabah yielded MAAPE values that ranged at 0.01–0.15 and 0.04–0.46 for variable cementation factor and conventional method, respectively.

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Declarations

Conflict of interest On behalf of the authors, the corresponding author would like to state that neither known competing financial interest nor personal relationships have influenced the work reported in this paper.

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