IMPROVED LOG ESTIMATION OF POROSITY AND WATER SATURATION IN SHALY RESERVOIRS- A NIGER DELTA CASE STUDY

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Abstract: In oil and gas prospecting, the impact of clay minerals on the overall formation resistivity makes water saturation and reserves estimation in shaly-sands, an intricate endeavor. The reason for this is that clay minerals present in the reservoir, affect the accuracy of results obtained from log measurements. This study presents careful evaluation of porosity, water saturation and reserves, in shaly reservoirs. Porosity and water saturation obtained from well logs were corrected by using Dewan's, Waxman-Smit's and Simandoux equations. To do this, formation water resistivity (R_w), mobility index of absorbed cations (B) and normalized cation exchange capacity (Q_{vn}) were estimated from relevant logs. Since Archie's water saturation log (S_w) was provided in the data, water saturation was re-estimated using Waxman-Smit's and Simandoux's equations for shaly-sands reservoirs. Results of the study showed that porosity and water saturations in the reservoir indeed need to be corrected because the mapped hydrocarbon reservoirs are within shaly-sand sequences. The volume of shale is high and is between 0.05 and 0.73. When Dewan's, Waxman-Smit's and Simandoux's saturation equations were used, lower values of porosity and water saturation in the hydrocarbon intervals were observed. Consequently, the application of Waxman-Smits and Simandoux models accounted for the effect of clay minerals within the reservoir matrix, provided reliable estimates of water saturation and porosity which resulted in optimum estimates of hydrocarbon reserves.

Keywords: Cation exchange capacity, clay minerals, porosity, reservoirs, shaly-sands

Introduction

Electrical conductivity in shaly sands is complicated by the presence of clays. This affects petrophysical measurements of porosity and water saturation. Shale is defined as a clay-rich heterogeneous rock which contains variable content of clay minerals (mostly illite, kaolinite, chlorite, and montmorillonite) and organic matter (Mehana and El-Monier, 2016). Therefore it is not possible to separate shale and clay minerals. Reservoir interpretation in shaly sands reservoirs does not follow the common Archie (1942) clean sand model because, with the presence of clay minerals, additional conductivities are expected in the formation. Additional conductivities, results in the formation, when excess ions in a diffuse double layer around clay particles provide current conduction pathways along the clay surface in addition to the current flow by ions diffusing through the bulk pore fluid (Mavko *et al*., 2009). The use of Archie's clean sand model to estimate water saturation in shaly sand formations, therefore, will result in higher level of water saturation (Schlumberger, 1989). Accurate water saturation of hydrocarbon bearing shaly formations can be determined by using clay ion cation exchange capacity (CEC) or available volume of shale (V_{sh}) models as inputs. However, most times, CEC data are either expensive to measure or difficult to estimate.

The volume of shale on the other hand, is easily calculated from well logs using available volume of shale equations and also, affects porosity and water saturation estimates. A study by Hilchie (1978) noted that the most significant effect of the volume of shale in a formation is to reduce resistivity contrast between oil, gas and water. Adeoye *et al*., (2017) observed that such resistivity contrast should be expected more in the Niger-Delta, because shale volumes are usually high within the reservoirs ranging from 0.01-0.9. This reason for high volume of shale in the Niger Delta is because the lithology in Niger Delta is mainly sands with substantial shale laminations (Weber and Daukoru, 1975). In addition, all the known shale distribution pattern (laminar, structural and dispersed shales) may occur simultaneously in a particular formation (Elvis and Adekunle, 2016). Therefore, to avoid errors in calculating porosity and water saturation, it is desirable to use well established models/scientific propositions in the analysis of shaly-sand reservoirs.

In summary, the dispersed and structural shales, in the shaly formations, need to be accounted for in water saturation modelling because they are complex, many times exists as materials dispersed throughout the sand, and may partially fill intergranular interstices. The additional conductivity that these clay minerals provide is the product of mobility index of absorbed cation (B) and cation exchange capacity per unit volume (Q_v) (Elvis and Adekunle, 2016). The cation exchange capacity per unit volume (Q_v) is usually derived from cation exchange capacity (CEC in meq/g) or it is estimated from log data using Juhasz, (1981) equation when CEC data are not available. Accounting for structural and dispersed clays is the focus of the Waxman-smits water saturation equation (Waxman and Smits, 1968).

One of the objectives of this study is to provide reservoir interval-based estimations of Q_v and B; such that these parameters can be used as inputs into the Waxman-Smits equation. The Simandoux (1963) water saturation equation, on the other hand, is probably the best known of the Volume of shale (V_{sh}) solutions (Cannon, 2016). It was included to correct for shale effects that may be related to the presence of laminated clays in the reservoir.

As outlined above, geophysical variables like porosity are also utilized in the accurate determination of hydrocarbon reserves because they are affected by the volume of shale (Adeoye *et al.*, 2018). Total porosity is generally measured from core analysis. Correcting porosity values reduces total porosity by removing the effect of clay-bounds and is therefore always less than or equal to total porosity depending on the volume of shale (Cannon, 2016). There are well documented procedures and established equations that can be used for correcting the effect of shale on porosity using log data when core data is not available.

The accurate determination of porosity and water saturation are important in shaly-sand analysis and the significance of a cautiously done shaly interpretation in volumetric estimation cannot be overemphasized (Cannon, 2016).

Geology of the study area

The study area is an offshore field located in the Niger Delta of Nigeria. The field location is not shown because of proprietorship reasons. Nevertheless, from field experience and previous works, the Geology of the study area, is an extension of the Niger Delta Geology (Adeoye *et al*., 2018). The Niger Delta consists of three broad formations (Short and Stauble, 1967).

Benin formation is the shallowest part of the sequence, composed virtually, entirely, of non-marine sand (Ajakaiye and Bailly, 2002). No commercial hydrocarbon has been found within it. The overall thickness of the formation is between 305m in the offshore (Kulke, 1995). The Agbada Formation which underlies the Benin Formation consists primarily of sand and shale. The Agbada Formation attains a maximum thickness of about 4500m (Weber and Daukoru, 1975). Most Exploration Wells in the Niger-Delta are drilled no lesser than the Agbada formation. The Akata formation on the other hand, is composed of shales, clays and silts at the base of the known Delta sequence. The thickness of this sequence is not really known but may reach 7000 m in the central part of the delta (Weber and Daukoru, 1975).

Doust and Omatsola (1990) describe a variety of hydrocarbon structural trapping elements, which include: Simple roll-over anticline, structure with multiple growth faults and others. The stratigraphic trap in the Niger Delta includes porosity pinch-out Structures. The possibilities of the source rock include variable contributions from the marine inter-bedded shale in the Agbada Formation and the marine Akata shale, and a Cretaceous shale (Weber and Daukoru, 1975).

Materials and Methods

The materials available for the study include Gamma ray, Deep resistivity, water saturation, bulk density and neutron logs which were analyzed on two wells. Core data was not available. Seismic data was used for structural interpretation in order to determine reserves. Schlumberger's *Petrel* software was used to analyze both well log and seismic data.

Determining the top and bottom depths of hydrocarbon shaly zones on well logs was the first step. These intervals were identified by analyzing the Gamma ray, resistivity and Archie's water saturation logs (Adeoye *et al*., 2017; Raji and Adeoye, 2014). A general form of Waxman-smit's equation defined in equation (1) was then used to correct the given formation resistivity (LLD) log (Waxman and Smits, 1968):

$$R_t = .\Phi^{-m} * S_w^{-m} * R_w / (1 + R_w * B * Q_v / S_w) \quad \ldots\ldots. (1)$$

Archie's water saturation log (SWARCH) was provided in the data. In order to have a better estimate of water saturation, the next procedure is to re-calculate water saturation (SWARCH) using the Waxman-Smit and the Simandoux equation as shown in equations (2) and (3):

$$Sw_{wax} = \frac{R_w}{R_t * \Phi^m (1 + R_w * B * Q_v / S_w)} \quad \ldots\ldots (2)$$

$$Sw_{simand} = \frac{C * R_w}{\Phi_e{}^2} \left[\sqrt{\frac{5 * \Phi^2}{R_w * R_t} + \left(\frac{V_{sh}}{R_{sh}}\right)^2} - \frac{V_{sh}}{R_{sh}}\right] \quad \ldots (3)$$

The input parameters R_w R_t, ϕ^m, ϕ_e, V_{sh}, R_{sh} and C are defined by Schlumberger (1989) and Mavko *et al*., (2009). The mobility index of absorbed cation on clay surfaces (B) however need to be expressed, in order to understand the factors affecting B, namely: temperature (T) and formation water resistivity (R_w) as shown in equation (4):

$$B = \frac{-5.41 + 0.133 * T - 1.253 * 10^{-4} * T^{-2}}{1 + R_w{}^{1.23}(0.025 * T - 1.07)} \quad \ldots.. (4)$$

Because core data is unavailable for this study, cation exchange capacity per unit volume (Q_v), required in the Waxman-Smits water saturation equation (Sw_{wax}), was computed on well logs using the normalized Q_v method (Q_{vn}) (Juhasz, 1981). The normalized model does not require cation exchange capacity derived from core data (CEC in meq/g) because it uses the volume shale (V_{sh}) derived from logs to estimate Q_v by normalizing it to the shale response as shown in equation 5:

$$Q_{vn} = \frac{V_{sh} * \phi_{sh}}{\phi} \quad \ldots\ldots\ldots.. (5)$$

Where V_{sh}=volume of shale and ϕ_{sh} = porosity of a nearby shale, ϕ =Porosity of the reservoir. Q_v can, thus, be calculated from logs at any point in the hydrocarbon section from Juhasz equation (Juhasz, 1981). Estimates of Q_v and water saturation were computed at different depths within the reservoir via *Petrel's* log calculator and porosity was corrected by using Dewan's equation (Dewan, 1983).

Using equation 6 by Asquith and Krygowski (2006), it was necessary to calculate the gas reserves such that reserve estimates of the shaly models can be compared with reserves estimates obtained by using Archie's water saturation model (SWARCH). A deterministic approach that averages petrophysical data gathered at various points (e.g. water saturation) in the reservoir, was used (Adeoye *et al*., 2018).

To calculate reserves, reservoir porosity (ϕ), reservoir area (A), height (h), water saturation (S_w), gas formation volume factor (B_{gi}) and the recovery factor (RF) were used as inputs. B_{gi} value of 0.3 was assumed since pressure data is not available, and RF of 60% was used:

$$G_f = 43560 * A * h * \phi * (1 - S_w) * B_{gi} * RF \quad \ldots\ldots (6)$$

Results and Discussion

This study demonstrated the impact of removing the effect of clay ions when estimating porosity and water saturation and reveals how such correction may affect the reserves estimate. The parameter, B (mobility index of absorbed cations), is one of the foundation parameter that must be calculated before estimating corrected water saturation values. This 'B' has a range of expected values for reservoirs before it can be used in any study (Payzone, 2016). Comparing the obtained 'B' values in the study, with results from Payzone (2016), the log sections of 'B' in the reservoir zone reveals that values obtained are conformable with the maximum ranges of B for aquifers below 130ºF. Fig. 1 shows that B is between 0 and 8.2 and formation temperature ranges between 70.48ºF and 120ºF. On the other hand, the calculated cation exchange capacity per volume (Q_v), which is also an important input for correcting water saturation ranges between 0.01 and 5 (Fig. 1). Both B and Q_v log values, were used to produce the Waxman-smit's water saturation log (Sw_{wax} log) (Fig. 1). Thus, water saturation values are corrected using the Waxman-smit's equation. The same reservoir sections are shown in Fig. 2 to emphasize reservoir top and bottom depths of 3207 – 3251 m and 3400 – 3430 m, respectively. Fig. 2 also shows the volume of shale within the reservoirs. Although the volume of shale is high (as shown by the VSHSTB log) and ranges from 0.05 to 0.73, the reservoirs display good petrophysical characteristics of water saturation. The good petrophysical characteristics are revealed by abrupt high resistivity values and very low water saturation values, suggesting that the reservoir is rich in hydrocarbon saturation and the reservoir quality is good for hydrocarbon harnessing. The figure also shows comparison between the deep reading resistivity log (LLD) and the corrected resistivity log (LLD_{corr}).

The actual reservoir conductivities reduced significantly within the reservoir interval when the resistivity log was corrected because the corrected resistivity log (LLD_{cor}) records higher values than the given LLD log. The difference between these resistivity values probably resulted in the observed changes between Archie's water saturation (SWARCH) and Waxman-smit's water saturation. A comparison between the values of Archie's water saturation and those derived from the Waxman-smit's equation revealed that the estimates from Waxman-smit's model (Sw_{wax}) is generally lower than those from Archie's water saturation equation (Fig. 2).

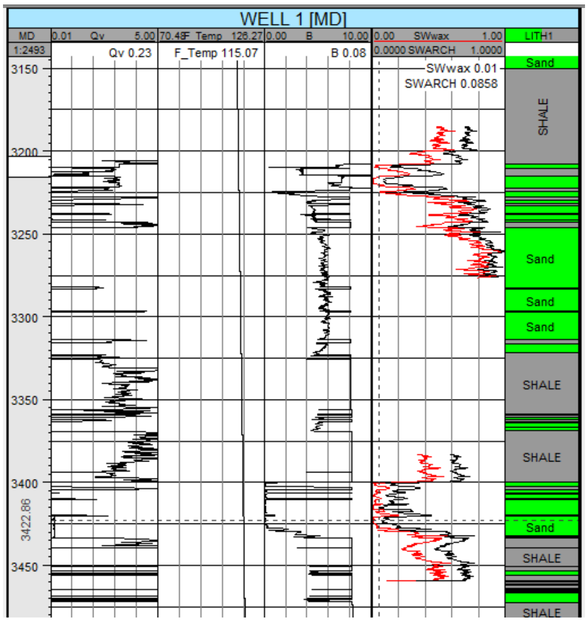

Figure 1: Log section showing, log inputs for water saturation correction

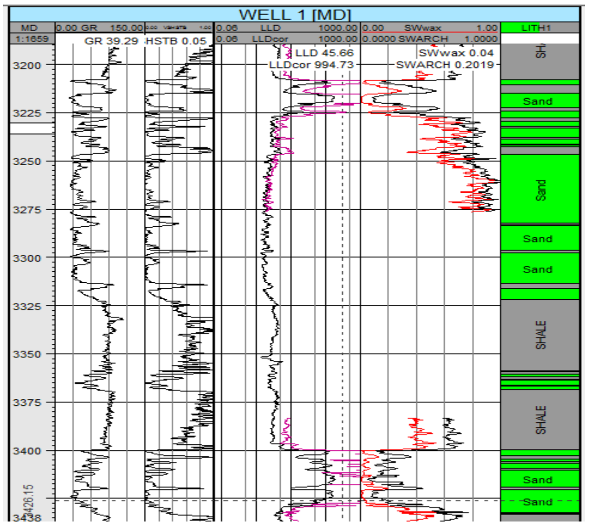

Figure 2: Log section showing the mapped reservoirs at depth intervals of 3207 – 3251 m and 3400 – 3430 m and estimated petrophysical log parameters

In Fig. 3, the reservoir zone in well 2 is an extension of the first reservoir in well 1 (with formation top at 3207 m in reservoir 1). In well 2, this reservoir is thin with the top at 3301 m and the base observed at 3309 m. In the Figure, density corrected porosity logs ($DPHI_{corr}$) was placed in the same track with the estimated porosity from density log (EstDPHI). As shown in the plot, the difference in the values was evident, and the $DPHI_{corr}$ log is consistently lower in the reservoir section compared to the EstDPHI. This implies that the density porosity logs (EstDPHI) consistently overestimated the porosity values in the reservoir section due to the presence of clay fractions.

The difference in the values of DPHIcorr and EstDPHI is up to 24% at some depth points in the hydrocarbon section. By comparing Sw_{wax} and S_w (SWARCH), the same type of trend was observed with the Archie's water saturation (SWARCH) increasing above the Sw_{wax} values. The volume of shale (VSH) in the reservoir is between 0.21 and 0.42.

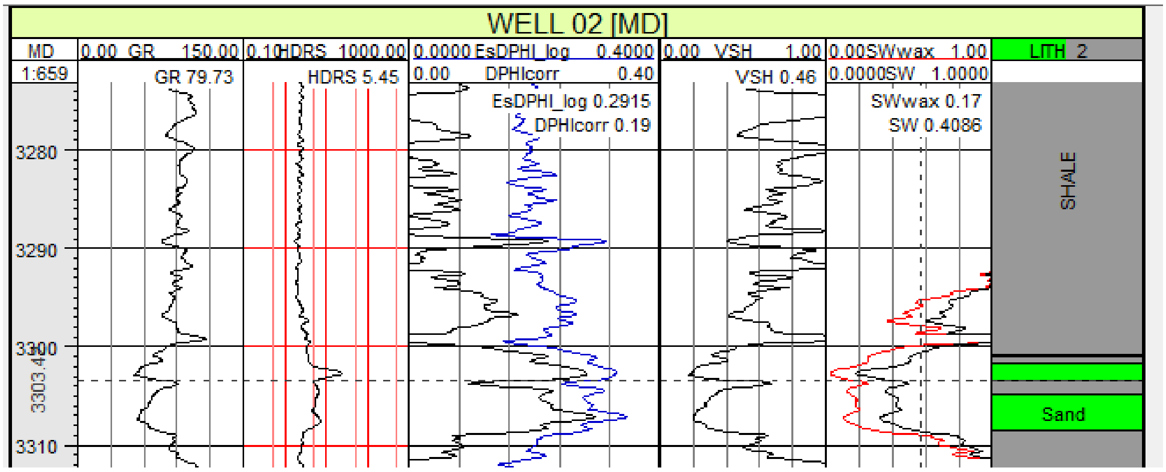

Fig. 3: Log section in well 2, showing reservoir zone between 3301 – 3309 m, porosity and water saturation values

In general, as seen in the results plotted in Fig. 4, Archie's water saturation varies between 0.07 and 0.43 while water saturation estimated from Waxman's model has value that ranges from 0.01 to 0.42. The difference in the two models reaches, about 25%. Furthermore, the highest water saturation in shaly sands was obtained from the Waxman-Smit's model. In the same way, the Simandoux water saturation (Sw_{simand}) values are lower than Archie's water saturation. An example is shown in Fig. 5. The water saturation for the Simandoux model ranges between 0.01 and 0.23 with an average difference of 19% when compared with its Archie's equivalent. All the reservoir zones had high shale content ranging from 0.05-0.73. The increase in shale volume may be one of the factors responsible for the differences in water saturation values between the SWARCH and Simandoux models. This is because the Simandoux equation is used to estimate shale effect on water saturation.

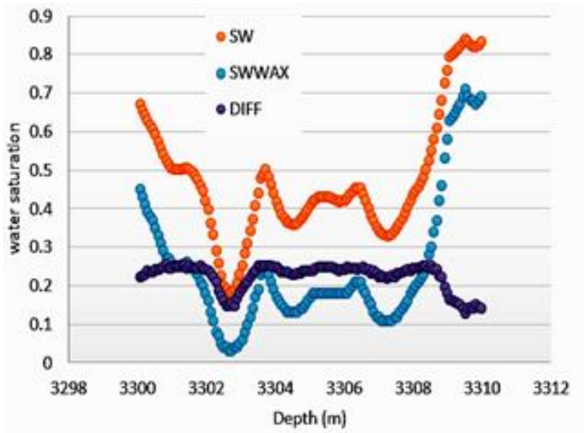

Fig. 4: Plots comparing Archie's water saturation (S_w) and Waxman-smit's water saturation (Swwax) and the difference, shown in black

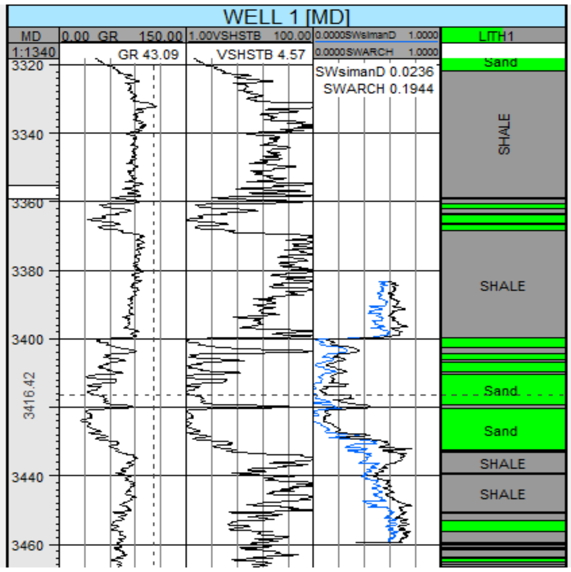

Fig. 5: Comparison between Archie's model (Sw_{ARCH}) and Simandoux model (Sw_{SIMAND}- in blue)

Table 2: comparison of some petrophysical parameters in Reservoir 2

ϕ	Sw_{ARCH}	GRV	B_{gi}	RF	Gas Reserves (SCF)
0.31	0.25	43,252	0.3	0.6	78,847,790
ϕ_{corr}	**Sw_{wax}**	**GRV**	**B_{gi}**	**RF**	**Gas Reserves (SCF)**
0.30	0.22	43,252	0.3	0.6	79,356,485
ϕ_{corr}	**Sw_{simand}**	**GRV**	**B_{gi}**	**RF**	**Gas Reserves (SCF)**
0.30	0.21	43,252	0.3	0.6	80,373,876

Figure 6 shows the depth structural map of horizon two. The reservoir interval is defined by the gas-water contact observed at the depth of 3240 m (colored in red). The gas-water contact was read from well logs in Fig. 6. Two faults are revealed on the map. Only one of them is cutting through the anticlinal structures represented by closing contours. Table 1 shows the estimate of the gas reserves from reservoir 1. The reserve estimates change as the water saturation values (Sw_{ARCH}, Sw_{wax} and Sw_{simand}) changes. The last row of the table, (where water saturation is calculated using simandoux equation (Sw_{SIMAND})), has the highest gas accumulation with a total estimate of 80,373,876 standard cubic feet (SCF) of gas. The reserves is high because porosity and water saturation are corrected. As, can be observed in the overlying row (where Waxman-Smit's S_w equation was used), this reserves reduces to 79,356,485 SCF but it is still greater than the reserves obtained when porosity and water saturation are not corrected (i.e. 78,847,790 SCF in row 1). In this study, it is clear that correcting water saturation values (Sw_{wax} and Sw_{simand}) leads to a higher estimation of reserves.

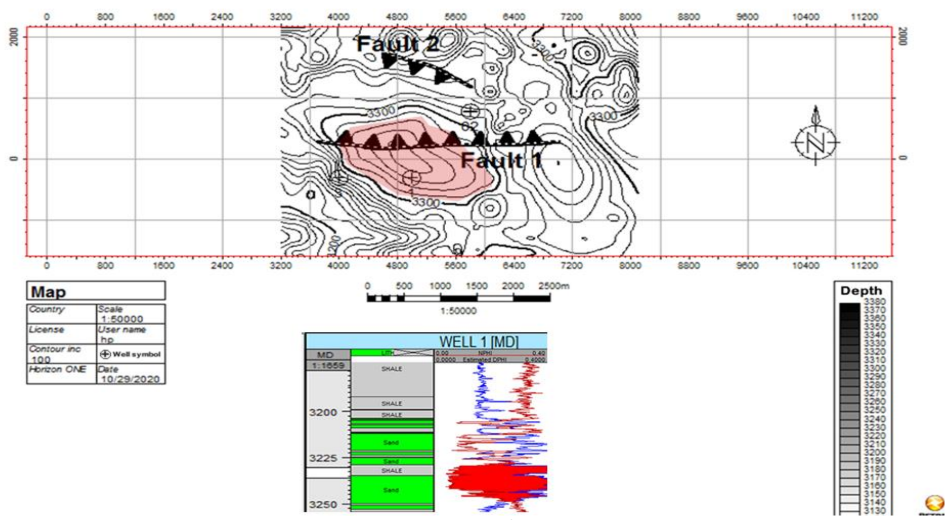

Fig. 6: Depth map showing reservoir area, the grid used for calculating the area and the gas contact on well logs in red (bottom)

Table 2 shows the estimate of the gas reserves from reservoir 2. A similar pattern to the result in Table 1 is observed here. Following correction for water saturation and porosity, the reserves in reservoir 2 increases compared to the reserves estimated using water saturation from Archie's equation. In reality, most reservoirs have some level of clay minerals with the reservoir sand matrix. Accounting for the effect of the clay particles in the reservoir using the Waxman-Smith's and Simandoux's equations will improve porosity and water saturation estimates and consequently the reserve estimate.

Conclusions

Hydrocarbon reservoirs from the Niger Delta Nigeria have been used to demonstrate the superiority of Waxman-Smit's and Simandoux's equations over Archie's equation for the estimation of water saturation and porosity in shaly sand reservoirs. Waxman-Smith and Simandoux's equations probably accounted for the effect of clay minerals bonded to sand matrix in reservoirs because petrophysical analysis of water saturation using Archie's equation and the shaly sand equivalent gave different results. This is also ubiquitous for porosity evaluation in the reservoir intervals. The water saturation values derived from the Waxman-Smit and Simandoux equations ranges from 0.01 and 0.42 compared to Archie's water saturation model where the values range from 0.07 – 0.43. The average difference between the estimates from the two models is about 25%. Similarly, the porosity obtained from the density log is higher than the density corrected porosity due to the consideration for the clay in the reservoir. The procedure highlighted by this study is applicable to all reservoirs that contain some clay particles within the reservoir sand grains. In comparison with the Archie's model, the application of Waxman-Smits and Simandoux models provided a different but better estimates of hydrocarbon reserves.

This study concludes that for reliable petrophysical and reserve estimates to be obtained in shaly sands, the Waxman-Smith's and Simandoux's equations, or other shaly-sand models, rather than Archie's equation, should always be used.

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