VOL. 14, NO. 20, OCTOBER 2019 ISSN 1819-6608
ARPN Journal of Engineering and Applied Sciences

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ESTIMATION OF WATER SATURATION OF GELAMA MERAH FIELD BY ARCHIE MODEL, TOTAL SHALE MODEL, SIMANDOUX MODEL AND INDONESIAN MODEL

Maqsood Ahmad[1], Millian Edward Kei[1] and Vahid Atashbari[2]
[1]Department of Petroleum Engineering, Universiti Teknologi PETRONAS, Bandar Seri Iskandar, Perak, Malaysia
[2]Department of Petroleum Engineering University of Alaska Fairbanks, Alaska, United States
E-Mail: maqsood.ahmad@utp.edu.my

ABSTRACT

Gelama Merah field is located in offshore Sabah approximately 43km from Labuan and 130km from Kota Kinabalu in Malaysia. This study compares water saturation results of Gelama Merah field computed by four different models namely; Archie model, Total Shale model, Simandoux model and Indonesian model. Porosity, volume of shale and true resistivity of formation were determined from logs acquired from GM-1 well. Other data such as the Archie saturation exponent, n, cementation factor, m, and resistivity of water, Rw were determined from special core analysis of samples acquired from the well. Accordingly, the resistivity of brine and shale were determined as 0.265 Ω.m, and 2.7 Ω.m respectively while Archie's cementation and saturation exponents were considered 2.0. The results shows that, at porosity less than 9%, Archie model gives unreasonable water saturation estimates in which values of water saturation greater than 1.0 were observed. In contrast, the corresponding results for Total Shale model, Simandoux model and Indonesian model were less than 1.0 for the same interval. The results indicate that Archie's model is more affected by large clay volume compared to the other models. Because of their relative stability and simplicity, Simandoux and Indonesian model have been commonly used to derive water saturation of clay-rich formations.

Keywords: shaly formation; water saturation; simandoux model; Indonesian model; total shale model; archie model.

INTRODUCTION

The Gelama Merah complex is a series of oil and gas fields discovered in the late Miocene Stage IVC sediments along the footwall of Morrison fault. Two exploration wells, GM-1 (vertical profile) and GM-ST1 (sidetracked) were drilled. Wire line logs run in these wells indicate the main lithofacies are cross-bedded sandstones, planar bedded sandstone, laminated sandstone, massive sandstone, fossiliferous sandstone and shales.

The dominant parasequence stacking pattern is coarsening upwards, however overall the sequence is fining upwards. Also, Shelfal to deltaic fluvio-marine sedimentary elements such as inner shoreface sand bars and fluvial channels, splays, tidal channels and mud-flats are evident. The dominant lithology is siliciclastics, pebbly-coarse grained to mud size particles. Furthermore, production tests carried out in GM-1 well indicates the field's oil gravity of 23.7 ˚API. Figure-1 and Figure-2 below show the location and deposition model of Gelama Merah Complex respectively.

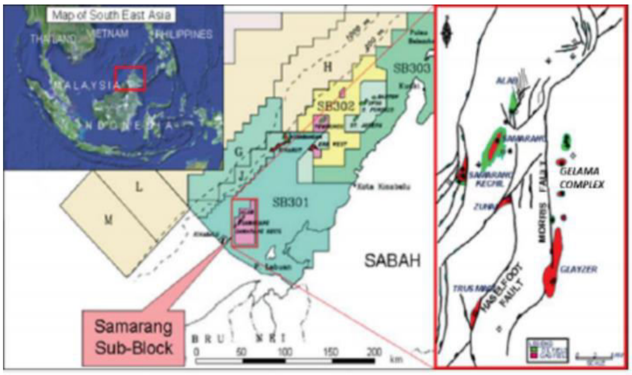

Figure-1. Map showing the location of Gelama Merah Complex.

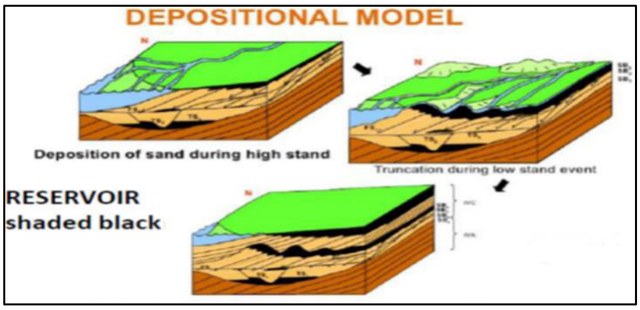

Figure-2. Deposition model of Gelama Merah Complex.

The high shale content of Gelama Complex has made estimation of water saturation of the field challenging. One of the complexities of evaluating water saturation of shale formation could be linked to shale deposition pattern where by shale may occur as laminar,

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dispersed or total shale (Aguilera, 1990) in which conventional siliciclastic models for water saturation estimation such as Archie model becomes unreliable (John, 2009). In connection to this, Worthington (2011) notes that, the complications of shale formations, if not tactfully addressed, could result in overestimation, underestimation or in other cases, unreasonable estimates of water saturation. Overestimation of water saturation could cause substantial error in hydrocarbon estimates in which potential hydrocarbon reserves may be overlooked and this has negative impact on field development decisions. As more of the conventional sandstone reservoirs get depleted, the need for improved and more reliable evaluation techniques for shaly or clay-rich formation becomes vital. Principally, Archie's model has been used to estimate water saturation for most reservoirs. However, the weakest point of Archie model has been cited in evaluation of water saturation of shaly formations. Consequently, numerous models which account for the effect of shale have been published. Accordingly, this paper shall analyze four of these models as well as the impact of shale on the models.

LITERATURE REVIEW

Shale sandstone reservoirs differ appreciably from sandstone formations. The contrasts range from physical characteristics such as grain size, mineralogy and texture to electrical properties such as conductivity and resistivity of the clay minerals in the formation.

Concept of Shale Effects

Evaluation of water saturation of shale sandstone reservoirs has proved difficult by the conventional methods. Shale effect primarily emanates from the relatively high conductive nature of clay minerals. The relationships of conductivity, formation resistivity and the resistivity of brine have been presented in Archie's first and second laws for clean sandstones saturated with brine of salinity between 20,000 - 100,000 ppm NaCl.

Studies show that conductivity of formation is directly proportional to conductivity of saturating electrolyte (1), where, C_o is the conductivity of rock fully saturated with water, C_w is conductivity of the saturating water and F is formation factor

$$Co = \frac{Cw}{F} \tag{1}$$

Equation (1) suggests that a plot of C_o against C_w results in a straight line graph passing through the origin (Archie, 1942). Figure-3 shows a plot of conductivity of a clean sandstone and shaly formation as a function of electrolyte conductivity.

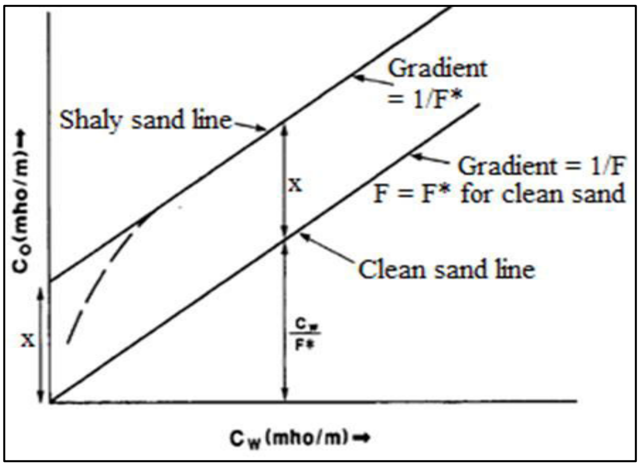

Figure-3. A graph of rock conductivity, C_o vs electrolyte conductivity, C_w of a fully water saturated rock. (Worthington and Johnson, 1991).

For clean sandstone, it can be observed that the straight line passes through the origin while for shaly sand the intersection of the straight line with the vertical axis occurs "X" mho/m above the origin. Physically, the separation of the two parallel axes represents the excess conductivity of clay minerals in the shale formation. Shaw and Weaver (1965) have shown that, clay minerals account for over 60 wt% of the total shale fabric as opposed to sandstones in which the dominant minerals may be quartz and feldspars. In addition, based on study of 10,000 samples of average shales, Ruhovets & Fertl (1981) showed that illite was the dominant mineral with composition of 59%; followed by Quartz and Chert, 20%; Feldspars, 8%; carbonates, 7%; Iron oxides 3%; Organic materials, 1%; others 2%. This statistics implies clays can have strong influence on the properties of shale formations. The common clay minerals in shale formation have been identified as kaolinite, chlorites, smectites and illites (Ahmad *et al*., 2013).

Clay formations present numerous problems to water saturation estimation as well as productivity of wells. For instance clay minerals may swell when in contact with water and this de-creases porosity and permeability of the reservoir. Besides, Ahmad *et al*. (2013) identified the challenges of evaluating water saturation of shaly formation as highly variable brine salinity and high clay content (V_{sh}) which results in very low resistivity. For example, in Bekapai shale formation in Indonesia, Worthington and Johnson (2003) observed that formation resistivity of less than 3 Ω.m was common. It has also been noted that, salinity of water in hydrocarbon zone is often many times higher than salinity in the water zone. As a result, Worthington *et al.* (2003) cautions against computing water saturation using water-zone salinity rather than salinity in hydrocarbon-bearing zone as this would result in very high water saturation estimates.

Due to difference of mineralogy between sandstones and shale formations, the models used to estimate water saturation in sandstones may not directly apply to reservoirs with significant clay content. The

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approaches to determine water saturation in shale formation have been broadly classified based on resistivity of shale concept (shale volume models) or cation exchange capacity concept (John, 2009). Shale volume models are modified form of Archie model in which an adjustment term is introduced to account for shale volume and resistivity. In general, shale volume methods are represented by equation 2, where the X term is electrical parameter of shaliness.

$$\frac{I}{Rt} = \frac{Sw^2}{FRw} + X \tag{2}$$

Various authors have interpreted the X term of equation (2) differently. For shaly formations, particular control must be exercised in evaluation of the shaliness parameter since error in X parameter may be transmitted to hydrocarbon estimation as well. Three main challenges have been underscored in the interpretation of the shaliness parameter, X and these include: the physical significance of X, downhole measurement of X and analysis of the relationship of X to other electrical parameters.

Physical Significance of X

Generally, the shaliness parameter has been estimated using three parameters: the cation exchange capacity per unit volume, Q_v, the shale-volume fraction, V_{sh}, and the pore surface area per unit volume, S_{por}. Table-1 shows representation of the X term by different researchers.

Table-1. Different Interpretation of shaliness parameter, X (Worthington & Johnson, 2003).

Investigator	Parametric Representation of X
Hossin (1960)	V_{sh}^{2} / R_{sh}
Simandoux (1963)	V_{sh} / R_{sh}
Poupon and Leveaux (1971)	$\left(V_{sh}^{2-V_{sh}}\right) / R_{sh}$
Waxman and Smits (1968)	BQ_v / F^*
Street (1961)	$S_{por} C_s / F_l$
Rink and chopper (1974)	$S_{por} \sigma\beta / \lambda^2 F_l$
Clavier *et al*. (1984)	$V_Q Q_v \left(C_{bw} - C_w\right) / F_o$

In practice, the shale-volume and cation exchange method have been commonly used in determination of hydrocarbon in shaly formations. The Q_v approach takes into account the distribution of clay minerals in the formation; however, the fact that Q_v cannot be measured downhole is a major limitation for the use of the method. On the other hand, V_{sh} method does not account for distribution of clay minerals in the reservoir, however, 85% of oil companies use the V_{sh} method because the volume of shale can be easily measured both downhole and in laboratory (Worthington & Johnson 2003).

Downhole Measurement of X

There are no direct methods for measuring X downhole and as such, X is inferred indirectly from other parameters. The approaches used to determine X includes:

a) Measurement of V_{sh} from shale indicators and evaluation of R_{sh} from resistivity log response of an adjacent shale bed in which the ratio V_{sh}/R_{sh} provides an estimate of X.

b) Correlation of Q_v and V_{sh} in which X is estimated from the ratio BQ_v/F^*, where B is the equivalent conductance of sodium-clay exchange cations, and F* is intrinsic formation factor.

c) Prediction of Q_v from porosity, Φ, that is, usually in the absence of core data. Similarly, the ratio BQ_v/F^*, provides an estimate of X. However, the relationship between Q_v and Φ, presented by Hook (1983) is considered weak and therefore X term derived by this method is unreliable (Worthington, 2003).

Relationship of X and Other Electrical Parameters

Another challenge worth noting is to relate X to other electrical parameters. In order to accurately estimate water saturation of shaly formation, the relationship of the X term to conductivity must be clearly uncovered.

Over the years the relationship of clay minerals and resistivity has been investigated. Wang *et al.* (2013) have shown a linear relationship between shale volume and formation conductivity. As a result, resistivity signal from clay-rich formations would be very low. Figure-4 shows the graph of clay volume against conductivity.

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ARPN Journal of Engineering and Applied Sciences

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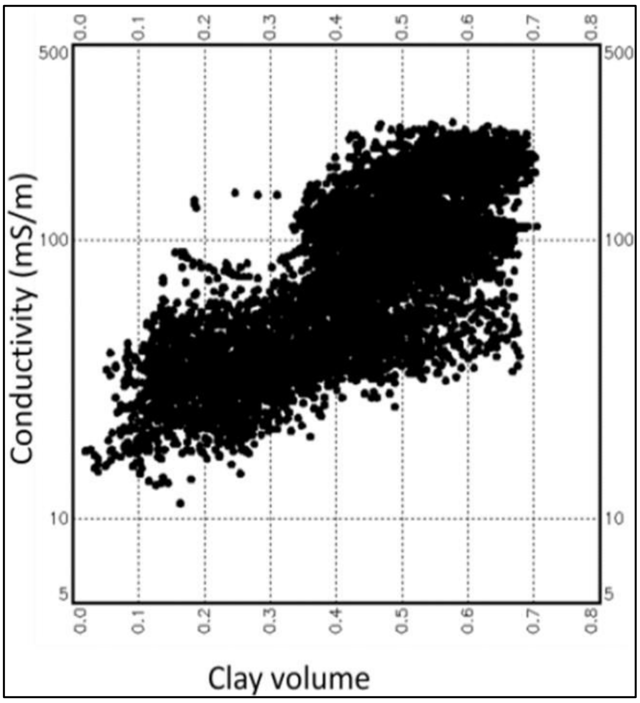

Figure-4. Relationship of clay volume and conductivity (Wang *et al*., 2013).

Determination of Clay Volume

Volume of shale can be determined by linear approaches such as Steiber method or non-linear approaches such as Larionov and Clavier methods. Petrophysical studies indicate that linear volume of shale models often overestimate the volume of shale compared to core analysis data (Ali-Nandalal, 2010). Also, Worthington *et al*. noted "in the absence of a sound basis for a shale correction, the well logs overestimate both porosity and water saturation". In this study the volume of shale was determined by linear volume of shale model (V_{sh}). Figure-5 shows comparison of different methods used to estimate volume of shale.

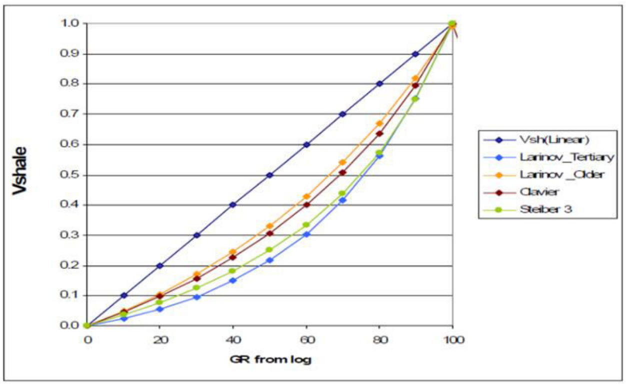

Figure-5. Comparison of linear versus non-linear V_{sh} calculations (Ahmad *et al*., 2013).

METHODOLOGY

The data to compute water saturation were evaluated from logs of GM-1 well, comprising a gamma ray log, resistivity log and neutron-density logs (Appendix 2). Accordingly, resistivity was determined from the resistivity log while porosity was derived from neutron-density logs. The parameters were evaluated at 1512 m, 1513 m and 1514 m depths where the corresponding gamma ray indices were 87˚API, 78˚API and 85˚API respectively. Volume of shale, V_{sh}, and total porosity were calculated from equations 5 and equation 6 respectively (Appendix 1). Table-2 summarizes the petrophysical data interpreted from the logs. Also, from core analysis, the resistivity of water, R_w, was 0.265 Ω.m and tortuosity factor, a, was determined to be 1.0 while the saturation exponent, n, and cementation factor, m, were assumed equals 2.0. The resistivity of clay, R_{sh}, computed from 100% shale zone was 2.7 Ω.m.

RESULTS AND DISCUSSIONS

Water saturations for Gelama Merah field were computed by Total Shale (Schlumberger) Model, Archie model, Simandoux Model and Indonesian Model and the results are summarized in Table-2.

Table-2. Water saturation results for shale interval.

Depth (m)	Porosity (Fraction)	SWArchie Model(Fraction)	SW Total Shale Model(Fraction)	SWS imandoux Model (Fraction)	SWIndonesian Model (Fraction)
1512.00	0.170	1.2912	0.7516	0.6194	0.6284
1513.00	0.152	1.5965	0.8551	0.8764	0.8892
1514.00	0.158	1.5191	0.6294	0.7586	0.7492

It can be observed that water saturations computed by Total shale model, Simandoux model and Indonesian model were less than 1.0 magnitude for all three depths examined in the shale section. On the contrary, the corresponding water saturations computed by Archie model were greater than 1.0 in magnitude. The unreasonable water saturation values obtained by Archie equation as shown in Table-3 can be attributed to low resistivity of the shale formation.

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Table-3. Log data of Gelama Merah well.

Depth (m)	Gamma Ray (°API)	True Resistivity (Ω.m)	Density (g/cc)	Volume of Shale (Fraction)	Total Porosity (Fraction)	Effective Porosity (Fraction)
1512.00	87	5.50	2.370	0.689	0.170	0.053
1513.00	78	4.50	2.400	0.541	0.152	0.070
1514.00	85	4.60	2.390	0.656	0.158	0.054

Water saturation is a strong function of resistivity, volume of shale and properties of mineral in the formation (Bust *et al.,* 2011). The pit-falls of using Archie model to evaluate water saturation in shale formation have also been proven from Australian Murteree and Roseneath shale gas reservoir in which unreasonable water saturation values were observed (Ahmad *et al*., 2013).

Sensitivity Analysis

Sensitivity analysis was performed to study how water saturation is affected with variation of porosity. Table-4 shows the results and the range of porosity considered.

Table-4. Sensitivity of water saturation to variation in porosity.

Density Porosity, ϕ (Fraction)	Archie Model S_W (Fraction)	Total Shale Model S_W (Fraction)	Simandoux Model S_W (Fraction)	Indonesian Model S_W (Fraction)
0.020	11.511	20.903	0.857	0.853
0.060	3.837	2.675	0.823	0.743
0.080	2.878	1.631	0.797	0.698
0.100	2.302	1.124	0.767	0.658
0.110	2.093	0.959	0.752	0.640
0.120	1.918	0.830	0.736	0.622
0.140	1.644	0.640	0.705	0.591
0.160	1.439	0.507	0.675	0.562
0.180	1.279	0.409	0.645	0.536
0.200	1.151	0.334	0.617	0.512
0.220	1.046	0.275	0.591	0.490
0.240	0.959	0.226	0.566	0.470
0.260	0.885	0.186	0.542	0.452
0.280	0.822	0.152	0.521	0.435
0.300	0.767	0.123	0.500	0.419
0.320	0.719	0.097	0.481	0.404
0.340	0.677	0.075	0.463	0.390
0.360	0.639	0.056	0.447	0.378
0.380	0.606	0.039	0.431	0.366
0.400	0.576	0.023	0.416	0.354

For Simandoux, Indonesian and Total Shale models, the volume of shale was 70.5% while resistivity of formation was assumed 5.0 Ω.m. The results for Archie model were generally high such that water saturation values exceeded 1.0 as porosity fell below 24%. Surprisingly, total shale model showed inconsistent results. Unlike Archie model, water saturation results for Total shale model have been extremely high at low porosity and extremely very low for porosity values greater than 20%. Very close agreement was observed between Simandoux and Indonesian models with reasonable and consistent water saturation estimates over the entire range of porosity investigated.

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CONCLUSIONS

Water saturation for Gelama Merah formation has been computed by Archie model, Total Shale model, Simandoux model and Indonesian model. The results for Archie and Total Shale models were relatively high compared to Simandoux and Indonesian models. The abnormal results for Archie model have been attributed to significant shale volume which results in low formation resistivity. Besides shale volume, resistivity of the formation also depends on brine salinity, presence of conductive minerals and clay bound water. Additionally, sensitivity analysis was conducted to determine changes of water saturation due to variation of porosity. With resistivity of formation 5 Ω.m and volume of shale of 70.5%, it was found that Archie model and Total Shale model shows unreasonable water saturation estimates at porosity values less than 24% and 11% respectively. The study proved that Indonesian model and Simandoux model provide more reasonable estimates of water saturation of shale formations than Archie model or Total Shale model. The authors also recommend that future studies investigate the effect of clay on water saturation estimation by cation exchange capacity models such as Waxman-Smits method which have not been treated in this paper.

ACKNOWLEDGEMENT

We would like to extend our sincere appreciation to Dr. Maqsood Ahmad, senior lecturer, Uni-versiti Teknologi Petronas for the technical support and time he accorded to review this project. Without his contribution, this project would not have been successful. Secondly, we would like to applaud the petroleum engineering department Universiti Teknologi Petronas for providing the data and facilities used for this study. Finally we would like to thank all technicians for the directives and guidance they offered in various stages of this study.

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NOMENCLATURE

V_{sh}	= Volume of shale (fraction)
R_{sh}	= Resistivity of shale (ohm-m)
R_t	= True formation resistivity (ohm-m)
R_w	= Resistivity of brine (ohm-m)
S_w	= Water saturation (fraction)
a	= Turtuosity factor (dimensionless)
m	= Cementation factor (dimensionless)
n	= Saturation exponent (fraction)
ρ_m	= Density of shaly sandstone (g/cm^3)
ρ_f	= Density of brine (g/cm^3)
ρ_{log}	= Density from log (g/cm^3)
GR_{max}	= Gamma ray maximum value, ˚API
GR_{min}	= Gamma ray minimum value, ˚API
Φ_t	= Total porosity (fraction)
Φ_e	= Effective porosity (fraction)
F	= Archie formation factor (ratio)
F*	= Intrinsic formation factor (ratio)
X	= Electrical parameter of shaliness (mho m^{-1})
B	= Charge mobility in double layer (mho m^{-1} meq^{-1} cm^3)
λ	= tortuosity associated with the double layer (ratio)
S_{por}	= Pore surface area per unit area (m^{-1})
C_{bw}	= Conductivity of bound water (mho m^{-1})
Q_v	= Cation exchange capacity per unit pore volume (meq cm^{-3})

CONSTANTS

GR_{max}	= 106˚API
GR_{min}	= 45˚API
R_w	= 0.265 Ω-m
ρ_m	= 2.65 g/cm^3
ρ_f	= 1.0 g/cm^3