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Estimation of Original Oil in Place Using Pickett's and Buckle's Plots, Offshore Niger Delta, Nigeria

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Abstract

Quick look analysis was performed in five (5) wells across a depobelt in the Niger Delta region, Nigeria using lithology (gamma), porosity (sonic, neutron and density) and saturation (resistivity) logs to infer six possible hydrocarbon plays. These plays showed good hydrocarbon saturation with a thickness between 11ft (3.35m) and 120ft (36.58m) that occur at a depth from 6223.5ft (1896.93m) to 11216.5ft (3418.79m). The average estimated porosity falls between 21.8% to 33.7% and the average volume of shale reported between 0.072 to 0.187, indicating sandstone reservoirs with good porosity. Water saturation was then estimated using Archie and modified Archie's equations from Pickett's plot. The original oil in place (OOIP) derived from Archie's (445.299 bbl. to 1488.735 bbl.) and Pickett's (150.120 bbl. to 1290.596 bbl.) techniques were compared showing a percentage difference between 5.30% to 86.28%. Archie's equation overestimated the original oil in place (OOIP) values across the reserves in the study area. Porosity exponent from Pickett's was between 1.74 to 2.09 as compared to Archie's constant of 2. The variation of the porosity exponent across the study area is attributed to the variations in shape of grains and pores, type of grain, pore system and overburden pressure. This influence is clearly seen from the Buckle's plot, which was used to delineate the variation using Buckle's number, and subsequently compared with the standard values for sandstones. This study highlighted the importance of porosity exponent and apparent formation water resistivity for estimation of water saturation, formation factor and in consequence the reserves.

Keywords*: Buckle's Plot; Pickett's Plot; Niger Delta; Original Oil in Place.*

1. Introduction

According to Adebayo *et al.*, [1], the application of Archie's equation is used to determine the formation factor F, where the formation factor of rock is defined as the ratio of rock resistivity when 100% saturated by brine, R_o, to the brine water resistivity, R_w [2–3]. According to Archie [4], the value of the formation resistivity factor (F) for any given rock sample will remain essentially constant for a wide range of formation water resistivity (R_w) measured in reservoir rocks. In routine formation evaluation, the primary goal typically involves reasonable determination to the OOIP. Archie's parameters a, m and n are normally set respectively to the default values of 1, 2 and 2 in the carbonate reservoirs and 0.62, 2.15 and 2 in the sandstone reservoirs with the water saturation exponent (n) equals 2 only in a water-wet homogeneous reservoir [5]. However, in heterogeneous reservoirs the water saturation exponent (n) typically varies from 20 in highly oil-wet reservoir to 2 in considerably water-wet reservoir conditions [6–7]. The wettability represents an important parameter in partial water saturation of the core sample [8–9].

Oil discoveries was aided by geologist, geophysicist and petroleum engineers (as well as some sort of good luck), all of the assessments of the volume of hydrocarbon reserves were made using data from petrophysical measurements together with a set of relationship that originated with Archie's water saturation equation [4]. Archie's equation presents a relationship between electrical resistivity of a rock to its porosity and the fractional water saturation of the pore space [10]. These are used to calculate the hydrocarbon saturation of the reservoir rock from which the reserves are inconsequence calculated. Archie's equation contains two exponents, porosity exponent (m) and saturation exponent (n), the conductivity of the hydrocarbon saturated rock is highly sensitive to changes in both exponent [11].

Determination of Archie's parameters is very important, as determination of recoverable hydrocarbon in a place is the main goal of the formation evaluation process [12–13]. The common practice in formation evaluation is to held Archie's parameter constant in sandstone reservoirs [14–15]. Pickett plot (Resistivity–Porosity Relationship) technique is utilized for calculating reservoir petrophysical exponents [16]. This plot shows a useful model for putting together the petrophysical parameters including water saturation, permeability, capillary pressure, pore throat radii and height above free water level [17–18]. This technique highlights Pickett's plot as one of the most important plots for reservoir evaluation, where several keys of geological and reservoir engineering parameters are evaluated in one plot. Estimation of petrophysical exponents greatly affect the estimation of water saturation and consequently reservoir productivity, therefore it is important to accurately evaluate these exponents [19–20]. Porosity exponent is affected by several influences including shape of grains and pores, types of grains, pore system etc. [21–23], this influences lead to the use of Buckle's ploy to confirm the porosity exponent values.

In 2018, there were approximately 1.73 trillion barrels of oil in the world, enough to secure energy supply for another 50 years since the world uses 95 million barrels per day [24]. Nigeria has 37,062 million of barrels as 2018 reserves [24].

Even a tiny uncertainty in a saturation exponent of 2, say 0.01, (*i.e.* 0.5 % or 2 ± 0.01) would result in an error in the reserve calculations of about USD ±254.36 billion [25]. When n = 2 ± 0.01 is considered, a change of ± 0.3245 % in hydrocarbon saturation is calculated, allowing a change in global reserves to be recalculated. However, the degree to which we can carry out the real calculations does not match this precision. Uncertainty in input parameters of representative seismic and petrophysical parameters together with the difficulties of heterogeneity and anisotropy in the real calculations have uncertainty in the order of ±20–40 % [25].

It is interesting that the uncertainty in reserve estimate is controlled by a choice of petrophysical exponent and constant. This work demonstrates a statistical analysis of such uncertainty and highlights the result of error propagation in reserve estimate. In addition, the statistical approach allows a comparative study on the effect of Archie's derived exponent and estimated exponent on reserve estimate.

2. Geology of the study area

The Niger Delta Province includes Nigeria, Cameroon and the Equatorial Guinea. This province is situated in the Gulf of Guinea with one petroleum system, identified so far, and designated in Nigeria as the Tertiary Niger Delta (Akata-Agbada) petroleum system [26]. Tuttle [27] outlined the formation of the Niger Delta at a rift triple junction related to the opening of the southern Atlantic started in the Late Jurassic and continued up to the Cretaceous. The proper delta is developed in the Eocene with accumulating sediments over 10 kilometres thick. The primary source rock is the upper Akata Formation, marine-shale facies of delta with possibly a contribution from interbedded marine shale of the lower most Agbada Formation [26].

The Niger Delta covers an aerial stretch over 70,000 km² within the Federal Republic of Nigeria, representing about one-fourteenth of the total land mass of the country. The Niger Delta Province remains the youngest of three depositional cycles leading to the development of the coastal sedimentary basin of Nigeria with three stratigraphic subdivisions, namely the Benin Formation, the Agbada Formation and the Akata Formation [28].

Lithologically, the upper portion of the Niger Delta Province (Benin formation) is mainly sandstone while the middle Agbada formation comprises an intervening unit of alternating sandstone and shale with the lower Akata formation, predominantly shale [29]. According to Short and Stauble [30], three units extending across the entire delta are related to the present outcrops and environments of deposition and represent prograding depositional facies that are distinguished mostly based on sand-shale ratios.

Tuttle *et al.*, [27] investigated the hydrocarbon potential of the Niger Delta and indicated that he Niger Delta petroleum is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation that are controlled by depositional environment and depth of burial. In 1999, the Niger Delta Province of Nigeria was estimated to hold recoverable oil and gas of approximately 35 billion barrels (bbl.) of oil and 94 trillion standard cubic feet (ft^3) of gas.

3. Methodology

This work uses five well log data in the Niger Delta Region, Nigeria with six potential oil and gas reservoirs were identified. Log data include Gamma Ray, Compensated Neutron, Sonic, Resistivity (Deep) and Density logs.

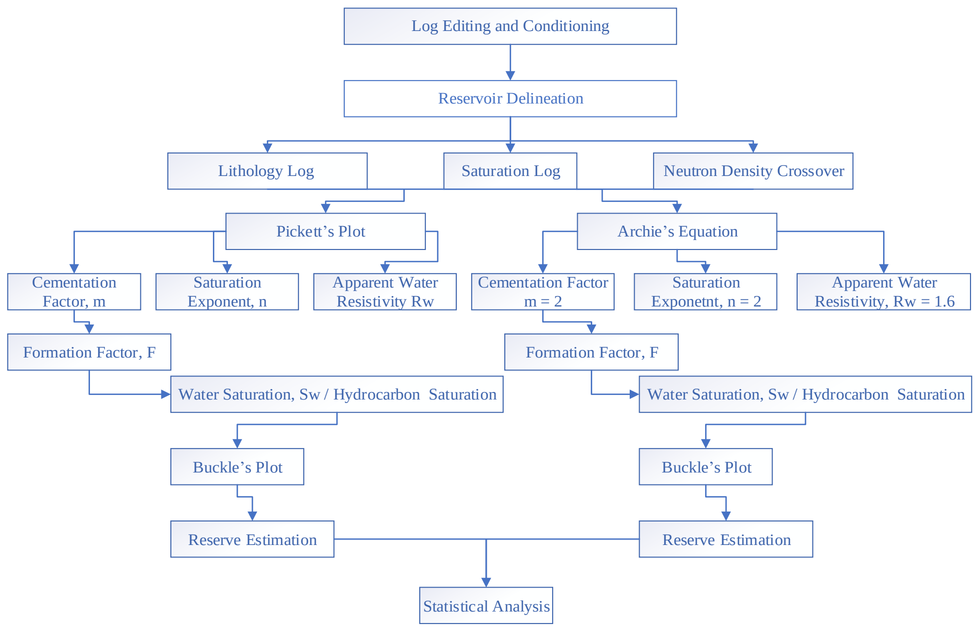

Fig. 1. A flowchart for Reserve Estimation from Pickett's plot and Archie's Equation

Original oil in place (OOIP) and original gas in place (OGIP) refer to the total volume of hydrocarbon stored in a reservoir prior to production. Volumetric estimates of OOIP and OGIP are based on a geological model that geometrically describes the volume of hydrocarbons in the reservoir.

One basic volumetric equation is

$$\mathrm{OOIP} = \frac{7758\mathrm{Ah}\phi(1-\mathrm{S_w})}{\mathrm{B_{oi}}} \quad (1), \text{ or}$$

$$\mathrm{OOIP} = \frac{7758V_b\phi(1-\mathrm{S_w})}{\mathrm{B_{oi}}} \quad (2)$$

where, N = OOIP (STB); 7758 = conversion factor from acre-ft to bbl; A = area of reservoir (acres) from map data; h = height or thickness of pay zone (ft) from log and/or core data; V_b = bulk reservoir volume; ø = porosity (decimal) from log and/or core data; S_w = connate water saturation (decimal) from log and/or core data; B_{oi} = formation volume factor for oil at initial conditions (reservoir bbl/STB) from lab data; a quick estimate is $B_{oi} = 1.05 + (N \times 0.05)$, where N is the number of hundreds of ft^3 of gas produced per bbl of oil [for example, in a well with a GOR of 1000, $B_{oi} = 1.05 + (10 \times 0.05)$].

Pickett plots [31-32], have been long recognized as very useful technique in log interpretation. In Pickett's method, a resistivity index, "I", and water saturation, "S_w" are calculated from log-log plots of true (in some cases apparent) resistivity versus porosity or response of a porosity tool. This technique not only gives estimation of water saturation (S_w), but also helps in determination of Formation water resistivity (R_w), Cementation factor ˝m˝, and matrix parameters for porosity logs (Δt_{ma} and ρ_{ma}). The Pickett method is based upon the observation that true resistivity (R_t) is a function of porosity, water saturation (S_w), and cementation factor "m". The Pickett cross plot developed by plotting porosity values with deep resistivity values on two-by- three cycle log-log paper. The theory of this plot started with Archie's equation, as follows:

$S_w = I^{\frac{-1}{n}}$ (3)

$I = \frac{R_t}{R_o} = \frac{R_t}{F \times R_w}$ (4)

$F = \frac{a}{\phi^m}$ (5)

Equations 3, 4 and 5 can be combined to yield.

$R_t = \frac{aR_w}{\phi^m}(I)$ (6)

$R_t = \frac{aR_w}{\phi^m}(S_w^{-n})$ (7)

If the logarithm with base 10 has been taken, the equation [31] leads to:

$\log R_t = \log(aR_w) - \log(\phi^m) + \log I$ (8)

$\log R_t = \log(aR_w) - m\log(\phi) + \log I$ (9)

This is the equation of a straight line, on log –log paper, can be written in the form:

$y = mx + b$ (10)

According to equation 9, a plot of log $R_t$vs. log ϕ can be drawn in a straight line with a negative slope controlled by ˝m˝, where m = 1/slope. The slope is determined manually by measuring a distance on the R_t axis (in cm) and dividing it by the corresponding distance on the porosity axis. The value of (aR_w) is derived from the intercept of such a line with the porosity axis at ϕ = 1.

Using this convention, the intercept is equated directly with R_w, and the slope of m becomes an average estimate of cementation factor within the reservoir.

Calculations of water saturation from either the Archie equations or the Pickett plot when combined with porosity give values which describe the volume of water and hydrocarbon as a fraction of either pore space or the total rock volume. The bulk volume of water (BVW) is a useful measurement controlled by both pore size and possible position in the hydrocarbon column, and can improve predictions of fluid productivity.

Buckles, [33] made an extensive numerical analysis of reservoir measurements and concluded that the quadrilateral hyperbolic function was a good first-order approximation to real field data. Low values of *C* (Buckle's number) reflected large average pore sizes, as a direct consequence of a control by internal surface area. The quantity *C*, is simply the irreducible bulk volume of water (BVW_i) which will be effectively a constant, provided that there is a limited range in pore size. Zones with comparable pore size that have higher values of bulk water volume should be the water-cut or totally water-bearing. When computed for a field or a reservoir, the characteristic value is often known as the "Buckles number".

Pickett, [32] had recognized that reservoir zones at irreducible water saturation tend to lie on a steeper linear trend, whose intercept with the water line reflected the grain- or pore-size. This observation reflects the fact that the hyperbolic relationship of:

$C = \phi \times S_w$ (11), can be linearized to

$\log S_w = \log C - \log \phi$ (12)

Substituting the Archie equation solution for water saturation and rearranging, the relationship becomes:

$\log R_t = \log(aR_w) - n\log C + (n - m)\log\phi$ (13)

Equation 13 describes a line on the Pickett plot with a slope of (n – m) and an intersection with the water line at a porosity corresponding to the water line.

4. Results of analysis

Results of petrophysical analysis for six (6) potential reservoirs from five (5) wells in a field in of the Niger Delta Region are presented with log panels and cross plotting. A cross plot of Pickett's and Buckle's was generated from constants of Archie's equation and Pickett's plot for all potential reservoirs. A summary of petrophysical results for each reservoir is presented in Table 1 and showing minimum and average values of gamma ray, neutron, density, sonic, resistivity, porosity and volume of shale at a given depth interval and net pay zone. Table 2 presents the minimum and average values of bulk volume of water, hydrocarbon and water saturation, and Buckle's Number for Pickett's and Archie's values for each identified reservoir in the well(s).

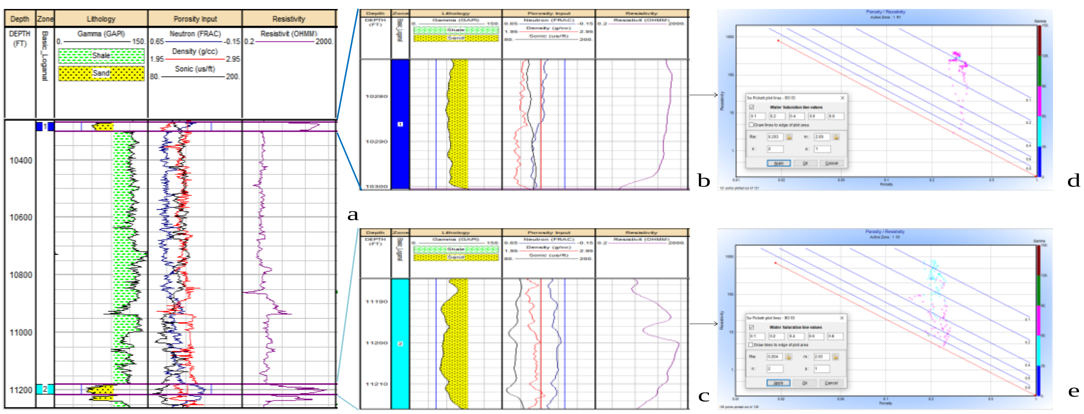

Fig. 2 (a) Basic log view for sand units in well A01 (b) Reservoir A01 R1 (c) Reservoir A01 R2 (d) Pickett's plot for A01 R1 (e) Pickett's plot for A01 R2

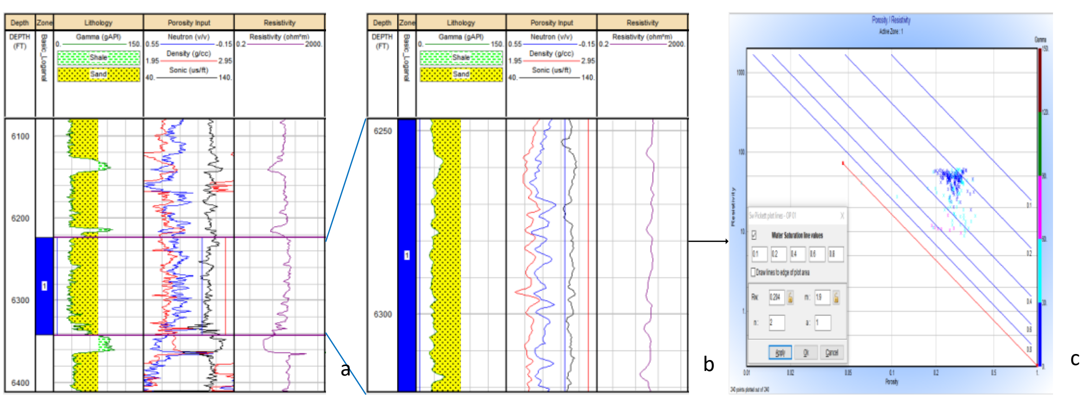

Fig. 3. (a) Basic log view for sand units in well A02 (b) Reservoir A02 R1 (c) Reservoir Pickett's plot for A02 R1

Well A01 show two distinct Petro-facies within the reservoir's interval, were identified between 10270 – 10300ft and 11182.75 – 11216.5ft, Well A01 shows a sandstone sequence with various thick shale bed. Reservoirs A01 R1 and A01 R2 have a mean gamma ray value of 64.897 and 61.68gAPI, mean resistivity value of 215.825 and 195.687 ohmm respectively. A distinct Petro-facies within the interval 6233.5 – 6343ft, was identified in Well A02 and shows a sandstone sequence with various thick shale bed. A02 R1 has a mean gamma ray value of 31.775gAPI, mean resistivity value of 40.916 ohmm. Well A03 shows a distinct Petro-facies w (9269.5 – 9289ft) within Well A03 of sandstone sequence with various thick shale bed. The reservoir A03 R1 has a mean gamma ray value of 28.262gAPI and mean resistivity value of 1.639 ohmm. Well A04 show a sandstone interval between 8904 – 8914.5ft, with a shaly sequence of various thick sand sequence. Reservoir A04 R1 has a mean gamma ray value of 74.006 gAPI, and a mean resistivity value of 13.143 ohmm. Petrophysical analysis on well A05 detected one reservoir at interval 9402.5 - 9438ft. Well A05 show a shaly sequence with various thick shale sequence with a mean gamma ray value of 35.026 gAPI and mean resistivity value of 197.963 ohmm. The net pay zone in all the reservoirs is between 11 – 120 ft indicating a viable economical hydrocarbon potential.

Table 1. Basic log values for two identified reservoirs in well A01, A02, A03, A04 and A05

		Curve	Gamma	Neutron	Density	Sonic	Resistivity	Porosity	Volume of shale
		Units	gAPI	frac	g/cc	us/ft	ohmm	Dec	Dec
A01 R1	Top:10270ft Bottom:10300 Net:30.25	Min	58.369	0.244	2.077	111.612	2.963	0.26	0.133
		Max	89.48	0.407	2.215	123.314	391.928	0.343	0.389
		Mean	64.897	0.332	2.143	116.677	215.825	0.303	0.187
A01 R2	Top:11182.75 Bottom:11216.5 Net:34	Min	49.122	0.146	2.2	84.758	4.056	0.143	0.056
		Max	93.083	0.3	2.408	106.852	788.237	0.267	0.419
		Mean	61.68	0.206	2.286	98.074	195.687	0.218	0.16
A02 R1	Top: 6223.5ft Bottom: 6343ft Net: 120ft	Min	21.062	0.106	2.023	88.743	8.915	0.062	0.104
		Max	78.881	0.422	2.538	123.9	61.126	0.374	0.488
		Mean	31.775	0.29	2.199	111.032	40.916	0.267	0.175
A03 R1	Top: 9269.5ft Bottom: 9289ft Net: 20ft	Min	17.739	0.325	1.936	112.86	1.522	0.283	0
		Max	35.358	0.421	2.185	128.949	2.048	0.434	0.121
		Mean	28.262	0.373	2.095	120.531	1.639	0.337	0.072
A04 R1	Top: 8904ft Bottom 8914.5ft Net 11ft	Min	69.774	0.139	1.852	100.969	2.031	0.313	0.36
		Max	84.63	0.37	2.121	116.153	25.389	0.475	0.448
		Mean	74.006	0.21	1.951	107.812	13.143	0.416	0.385
A05 R1	Top: 9402.5ft, Bottom: 9438.5ft, Net: 36.5ft	Min	22.628	0.079	2.009	87.804	4.355	0.18	0.051
		Max	72.436	0.247	2.337	99.165	804.01	0.386	0.287
		Mean	35.026	0.119	2.113	92.737	197.963	0.322	0.11

Table 2. Mean bulk volume of water, water and hydrocarbon saturation values in well A01, A02, A03, A04 and A05

		Archie's	Pickett's			Archie's	Pickett's
A01 R1	BVW	0.03	0.045	A03 R1	BVW	0.247	0.306
	S_W	0.099	0.149		S_W	0.736	0.911
	S_H	0.901	0.851		S_H	0.264	0.089
A01 R2	BVW	0.046	0.068	A04 R1	BVW	0.11	0.157
	S_W	0.208	0.304		S_W	0.285	0.404
	S_H	0.792	0.696		S_H	0.715	0.596
A02 R1	BVW	0.054	0.071	A05 R1	BVW	0.049	0.065
	S_W	0.206	0.273		S_W	0.18	0.239
	S_H	0.794	0.727		S_H	0.82	0.761

Table 1 shows the minimum, maximum and mean values of lithology log (gamma), saturation log (resistivity), porosity log (neutron, density and sonic), porosity and volume of shale values. The porosity values are seen to decrease with depth, while the volume of shale

(18.7%, 16.0%) values confirms with the gamma ray (64.897 gAPI, 61.680 gAPI) values as high values indicates sand units in both reservoirs in well A01. For well A02, the volume of shale (mean 17.5%) confirms with the gamma ray (mean 31.755gAPI) as high sand units in the reservoir. The volume of shale (mean 7.2%) confirms with the gamma ray (mean 28.262 gAPI) as high sand units in both of the reservoir in well A03. For well A04, the volume of shale (mean 38.5%) confirms with the gamma ray (mean 74.006gAPI) as high sand units in the reservoir. The volume of shale (mean 11.0%) values confirms with the gamma ray (mean 35.026gAPI) values as high sand units for the reservoirs in well A05.

The Pickett's plot (Figures 2d, 2e and 3c) is a crossplot of resistivity against porosity, with water saturation lines of 0.1, 0.2, 0.4, 0.6 and 0.8. At 100% porosity the intercept on the Resistivity axis is the apparent formation water resistivity (R_w) while the slope of the crossplot is the porosity exponent (m), assuming saturation constant (n) equal 2 and tortuosity (a) equals 1. The values of apparent formation water resistivity (R_w) is 0.204 for most of the reservoirs in the study area, exception of reservoir A03 R1. The estimated porosity exponent (m) are 2.03 for A01 R1 and 2.09 for A01 R1, 1.90 for A02 R1, 1.72 for A03 R1, 1.99 for A04 R1 and 1.89 for A05 R1.

Table 2 shows the mean bulk volume of water, water and hydrocarbon saturation for Archie's equation and Pickett's plot for all the reservoirs in the study area. For well A01, Buckle's plots for these reservoirs was plotted using the calculated water saturation from Archie's equation and Pickett's plot. Porosity range of 21.8 – 30.0% are corresponding to water saturation of 9 – 20.8% (Archie's equation) and 14.9 – 30.4% (Pickett's plot). Most of the plotted points cluster around Buckle line of 0.02 – 0.04, representing coarse to medium grain sandstone. For well A02, Buckle's plots for this reservoir was plotted using the calculated water saturation of Archie's equation and Pickett's plot. Porosity of 26.7% corresponded to water saturation of 20.6% (Archie's equation) and 27.3% of (Pickett's plot). Most points clustered around Buckle lines of 0.06 – 0.08, indicating fine grain sandstone. For well A03, Porosity of 33.7% is equivalent to water saturation of 73.6% (Archie's equation) and 91.1% (Pickett's plot) and the data points clustered around Buckle lines above 0.18, characterizing very fine grain sandstone. In well A04, Porosity of 41.6% calculated water saturation of 28.5% of (Archie's equation) and 40.4% (Pickett's plot). Most of the points are clustered around Buckle line of 0.08, representing fine grain sandstones. For well A05, Buckle's plots for this reservoir was plotted using the calculated water saturation from Archie's equation and Pickett's plot. Porosity range of 32.2% corresponding to 18.0% of water saturation (Archie's equation) and 23.9% of water saturation (Pickett's plot) of water saturation. Most of the points are clustered around Buckle line of 0.02, which represent coarse grain sandstones.

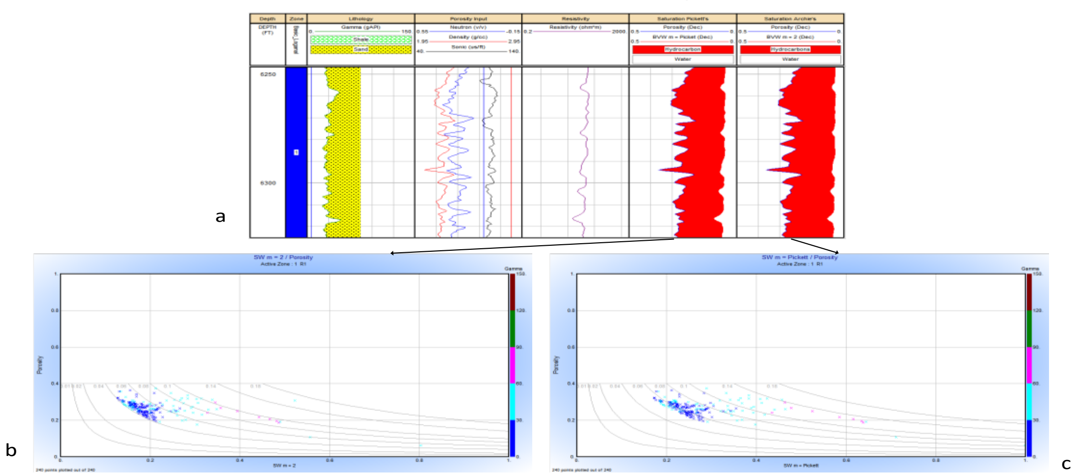

Fig. 4 (a) Comparative plot of saturation calculated from Archie's and Pickett's exponent, A02 (b) Archie's Buckle plot A02 (c) Pickett's Buckle plot A02

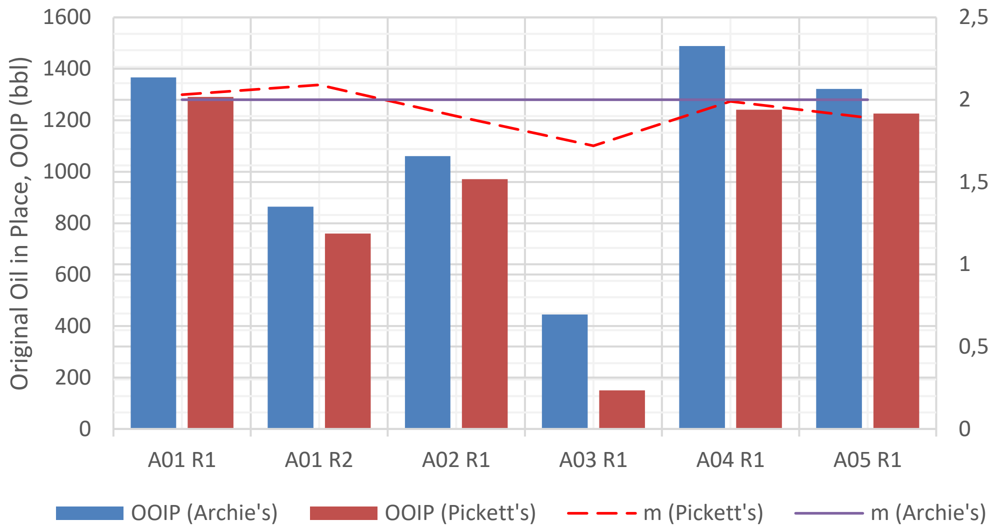

Fig. 5. Histogram of Original Oil in Place calculated from Picket's and Archie's cementation exponent and line plot for Pickett's and Archie's cementation exponent

In the five wells, porosity exponent ranged from 1.72 to 2.09, and the apparent formation water resistivity for the zones reported 0.204 Ohm.m, except for interval A03 R1 that showed 0.208 Ohm.m. The thickness of these reservoirs is highly variable and ranged from 11ft in well A04 R1 to 120ft in well A02 R1. The lowest correlation (33.71%) is encountered in Reservoir interval A03 R1 where m exponent recorded the lowest m value (1.72) from Pickett plot, with corresponding Archie's m of 2.00. Low reserves estimate in this reservoir (150.12 bbl) demonstrated the role of the cementation exponent on reserve calculations where the reservoir had high porosity value of 33.7%. This high variation in the estimated OOIP in A03 R1 between Archies and Picketts (66.29%) techniques is symptomatic of the fine grain facies as confirmed by the Buckle's number above 0.18. In this zone, Archie's equation and the Pickett's in-situ cementation exponents were matchable as indicated by the values of m that fell within 1.8 – 2.0 for water and hydrocarbon saturation estimation [34]. However, the Pickett's m value may be more representative to the changes in the reservoir facies.

For example, in well A01, Archie exponent yielded a Buckle's number of 0.02 (which is indicative of coarse grain sandstone) but Pickett's plot predicted a value of 0.04 indicative of medium size grain sandstone. Therefore, for reservoirs in the study area, there is a close relationship between Archie's exponent (m) and Pickett's exponent values.

Generally, in all wells, Archie equation overestimated the OOIP compared to Pickett plot with the minimal differences (5%) reported in most wells while the largest difference (300%) is encountered in well A03 (Figure 5). Similarly, the cementation exponent (m) is almost matchable in most wells (A01, A04, A05) but significantly different in well A03 (Figure 5).

5. Conclusion

Six (6) reservoirs from five (5) wells in the Niger Delta region, Nigeria was used to evaluate reserves from Archie's and modified Archie's equation. Quick look method was used to delineate the reservoirs. The reservoirs showed good accumulation of hydrocarbon with a thickness of 11ft (3.35m) – 120ft (36.58m) found within a depth of 6223.5ft (1896.93m) – 11216.5ft (3418.79m).

Pickett's plot was employed to estimate porosity exponent, m (1.72 to 2.09) using in-situ logs, also apparent formation water resistivity (R_w) (0.204 – 0.208). The in-situ values were used to calculate water saturation and original oil in place. The results were then compared with results from Archie's water saturation equation, and this comparison shows that the Archie's equation overestimated the calculation of water saturation across the depobelt with the percentage between 5.55% to 68.53%.

The Buckle's plot was used to confirm the calculated Archie's water saturation values. Buckle's number from the Buckle's plot was obtained from each of the reservoirs, reservoir A01 R1 with 5.55% difference in OOIP between Archie (1366.424bbl) and Pickett's (1290.596bbl) having a very close relationship between the Buckle's number of Archie (0.02, coarse grain) and Pickett's (0.04, medium grain). While the reservoir with the highest percentage difference 68.53% (A03 R1) of OOIP between Archie's (445.299bbl) and Pickett's (150.12 bbl.), the Buckle number from Archie (0.18, extremely fine grain) and Pickett (above 0.18, extremely fine grain).

The porosity exponent (m) exhibits wide variation from interval to interval in the same medium (well A01). In-situ logs with the help of Pickett's and Buckle's plot have been used to estimate porosity exponent, apparent formation water resistivity and Buckle's number that was used to estimate original oil in place (OOIP) across the reservoir in the study area.

Nomenclature

A	*area of reservoir from map data*
a	*tutorisity*
Boi	*formation volume factor for oil at initial conditions*
BVW	*bulk volume of water*
BVWi	*irreducible bulk volume of water*
C	*buckle's number*
F	*formation factor*
h	*height or thickness of pay zone*
I	*resistivity index*
n	*saturation exponent*
m	*porosity exponent*
OOIP	*Original Oil in Place*
OGIP	*Original Gas in Place*
R_t	*true resistivity*
R_w	*formation water resistivity*
S_w	*water saturation*
S_H	*hydrocarbon saturation*
V_b	*bulk reservoir volume*
V_{sh}	*volume of shale*
ϕ	*porosity*

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