Anuário do Instituto de Geociências
Universidade Federal do Rio de Janeiro
https://revistas.ufrj.br/index.php/aigeo/

ISSN 0101-9759
e-ISSN 1982-3908

Petrophysical Characterization of Shaly Sand Reservoirs in Well UK-05 Eastern Niger Delta Basin, Nigeria

Caracterização Petrofísica de Reservatórios Areias Xistosas no Poço UK-05 na Bacia do Delta Oriental do Rio Niger, Nigéria

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Abstract

A petrophysical evaluation of Well UK-05 in the eastern Niger Delta Basin was carried out in order to determine reservoir zones, their porosity, permeability, fluid saturation and the effect of shaliness on the petrophysical parameters. Using interactive petrophysics software version 3.5, twenty five (25) reservoir zones were identified. The porosity values range from 15.77-34.66% and permeability from 2.76-546.54 mD. The Archie's, Simandoux, Dual-porosity, Waxman and Smith, and the Indonesian models were used to determine the fluid saturation. The water and hydrocarbon saturation values using the Indonesian model are 21.67-50.49% and 49.51-78.33% respectively. They slightly differ from the ones obtained using Simandoux, Dual Water and Waxman and Smith model (20.72-49.88% and 50.12-79.22%, 18.26-50.49% and 49.51-81.74%, 14.67-48.26% and 51.74-85.33% for water and hydrocarbon saturation respectively). The interpreted lithology shows that the formation penetrated by the Well UK-05 is dominated by alternating sands and shales with the sand being the dominant lithology. These lithostratigraphic characteristics correspond to those of the parallic Agbada Formation. The effective porosity values obtained range from 14.93 to 34.66%, which are lower than 0.013% to 94.08% obtained by other authors since they did not take into consideration the effect of shaliness. This shows that the more the shale volume, the higher the uncertainty of actual porosity of the reservoir.

Keywords: Reservoir rock; Hydrocarbon; Shale effect on petrophysical parameters

Resumo

Uma avaliação petrofísica do poço UK-05 na Bacia do Delta Oriental do Niger foi realizada a fim de determinar as zonas do reservatório, sua porosidade, permeabilidade, saturação de fluido e o efeito da sombra sobre os parâmetros petrofísicos. Foram identificadas vinte e cinco (25) zonas de reservatório usando o software interactive petrophysics versão 3.5. Os valores de porosidade variam de 15,77-34,66% e de permeabilidade entre 2,76-546,54 mD. Os modelos Archie's, Simandoux, Dual-porosity, Waxman e Smith, e Indonésio foram usados para determinar a saturação do fluido. Os valores de saturação de água e hidrocarbonetos usando o modelo Indonésio são 21,67-50,49% e 49,51-78,33%, respectivamente. Diferindo ligeiramente dos obtidos usando o modelo de Simandoux, Dual Waterand Waxmanand Smith (20,72-49,88% e 50,12-79,22%, 18.26-50.49% e 49.51-81.74%, 14.67-48.26% e 51.74-85.33% para saturação de água e hidrocarbonetos, respectivamente). A litologia interpretada mostra que a formação penetrada pelo Poço UK-05 e dominada por areias e folhelhos alternados, sendo a areia a litologia dominante. Essas características litoestratigráficas correspondem as da Formação Paralica Agbada. Os valores de porosidade efetiva obtidos variam de 14,93 a 34,66% que são inferiores a 0,013% a 94,08% obtidos por outros autores por não levarem em consideração o efeito do sombreamento. Isso mostra que quanto maior o volume de xisto, maior a incerteza da porosidade real do reservatório.

Palavras-chave: Rocha do reservatório; Hidrocarbonetos; Efeito do xisto nos parâmetros petrofisicos

Received: 07 June 2021; Accepted: 23 January 2022

1 Introduction

Petroleum remains a very vital resource to the economy of several nations of the world. The high cost of exploration for this important resource makes it necessary for the attainment of high level of perfection in the methods adopted for its detection and quantification (Edigbue et al. 2014). In an oil prone area like the Niger Delta, even though hydrocarbons are within the subsurface, they cannot impulsively move to the surface when penetrated by a production well (Aigbedionand Iyayi 2007). On the contrary, most hydrocarbon reservoirs reside in the microscopic porespaces or open fractures of sedimentary rocks such as sandstones and limestones (Schlumberger 1989). To produce them, detailed geological and petrophysical knowledge and data are needed to guide the placement of production platforms and well paths (Adeoye & Ofomola 2013). The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province (Klett et al. 1997; Fozao et al. 2018). It underlies the coastal plain, continental shelf and slope of Nigeria, western Cameroon and northern Equatorial Guinea west of Bioko Island (Michele et al. 1999). The portion of the Delta in western Cameroon and Equatorial Guinea is known as Rio del Rey Basin (Agyingi et al. 2012).

Some research done on the Niger Delta Basin to analyze shaly reservoirs and petrophysical properties has been achieved by integrating two or more data types. These works include those of Omoboriowo et al. (2012) who studied the petrophysical characteristics of "Lepa" reservoir, Amma Field, in the eastern part of the basin from the integration of wireline log and core data. Amigun et al. (2014) carried out petrophysical analysis of well logs for reservoir evaluation in the 'Holu' oil field.

All these researchers were able to characterize reservoirs and the effects of shales on reservoir rocks. Thus, geophysical well logs approach has been an effective exploration tool to characterize reservoirs and effects of shales in reservoir rocks within the Niger Delta Basin. The purpose of this work was to characterize shaly sand reservoirs in Well U-05 and to evaluate their hydrocarbon potentials, in order to contribute to the exploration effort in the basin.

1.1 Location of the Study Area

The Niger Delta according to Klett et al. (1997) is situated within the Gulf of Guinea with extension throughout the Niger Delta Province. It is located in the southern part of Nigeria between longitude 4^{o} – 9^{o} East and latitude 4^{o} – 6^{o} North.

Well UK-05 is located in the Eastern offshore Niger Delta Basin (Figure 1) which is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of the continents of South America and Africa in the Cretaceous, (Doust 1990; Whiteman, 1982).

2 Tectonic Framework of Niger Delta

The Nigerian pericratonic basin was formed by rift faulting of the Pre-Cambrian (Figure 2A). The outlines of the delta are controlled by deep-seated faults, e.g. along the "Benin" and "Calabar" hinge lines. At least three major sedimentary cycles have been deposited in the basin since early Cretaceous times (Murat 1970). The delta started growing during the second cycle between Campanian and Paleocene transgressions.

The third sedimentary cycle, commencing in the Paleocene, is responsible for the main part of the delta's growth. The deltaic sequence consists essentially of clayey marine sediments overlain by paralic sediments, i.e. mixed continental, brackish water and marine deposits, which are covered by continental sands and gravels (Figure 2B). In cross section a time stratigraphic unit of such deltaic sediments is characteristically S-shaped (Merki 1972).

The stratigraphy of the Niger Delta is intimately related to its structure (Figure 3). The stratigraphy of the Niger Delta is a direct product of the various depositional processes prevalent in the area. The Delta displays a concentric arrangement of terrestrial and transitional depositional environments (Selley 1997).

The environment can be broadly categorized into three distinct facies belt. These are (1) Continental Delta top facies (2) The paralic Delta front facies and (3) Pro-Delta facies. The above depositional environments resulting from fluvial, coastal, marine processes, including turbidity current coupled with the rise and fall of sea-level have determined the stratigraphic fill of the Niger Delta. The Niger Delta basin consists of a series of depocenters or belts (Stacher 1995).

Major structure building growth fault determine the location of each depo-belt. The entire sedimentary wedge was laid down sequentially in five major depo-belt each 30-60 km wide, with the oldest lying further inland and the youngest located off shore (Reijers 1996). Due to the continuous deltaic progradation which commenced since in Early Tertiary, the stratigraphic unit in the Niger Delta is strongly diachronous and difficult to subdivide and correlate using marine biostratigraphic criteria. Hence sequence stratigraphy is applicable in the delta in that the fundamental building block of the Niger Delta succession is well defined cyclic offlaping parasequence set.

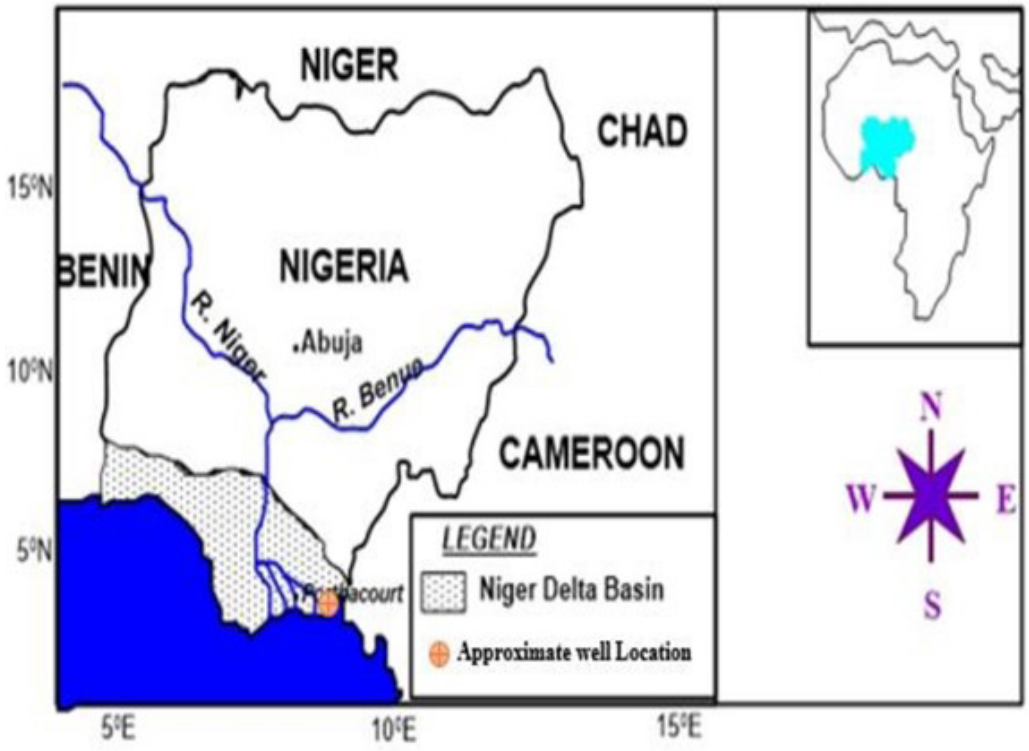

Figure 1 Map of Nigeria, showing the study area. Source: modified after Agyingi et al. (2012)

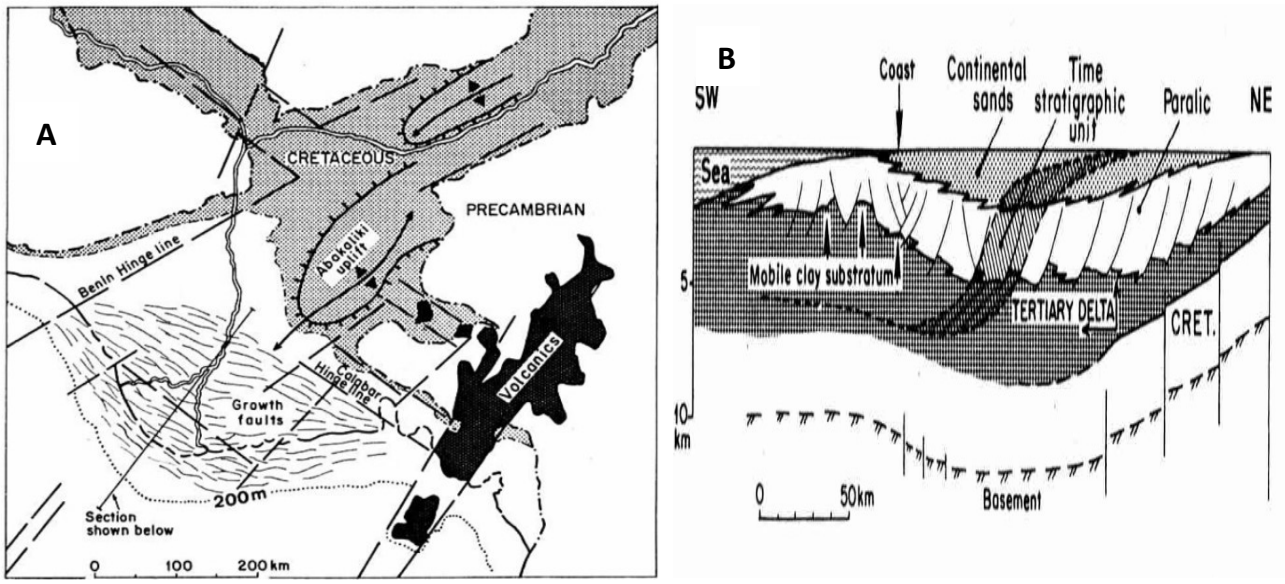

Figure 2 A. Niger Delta, mega-tectonic elements and growth fault area (Weber, 1971); B. Schematic section of the Niger Delta Basin perpendicular to the coastline (Weber, 1971)

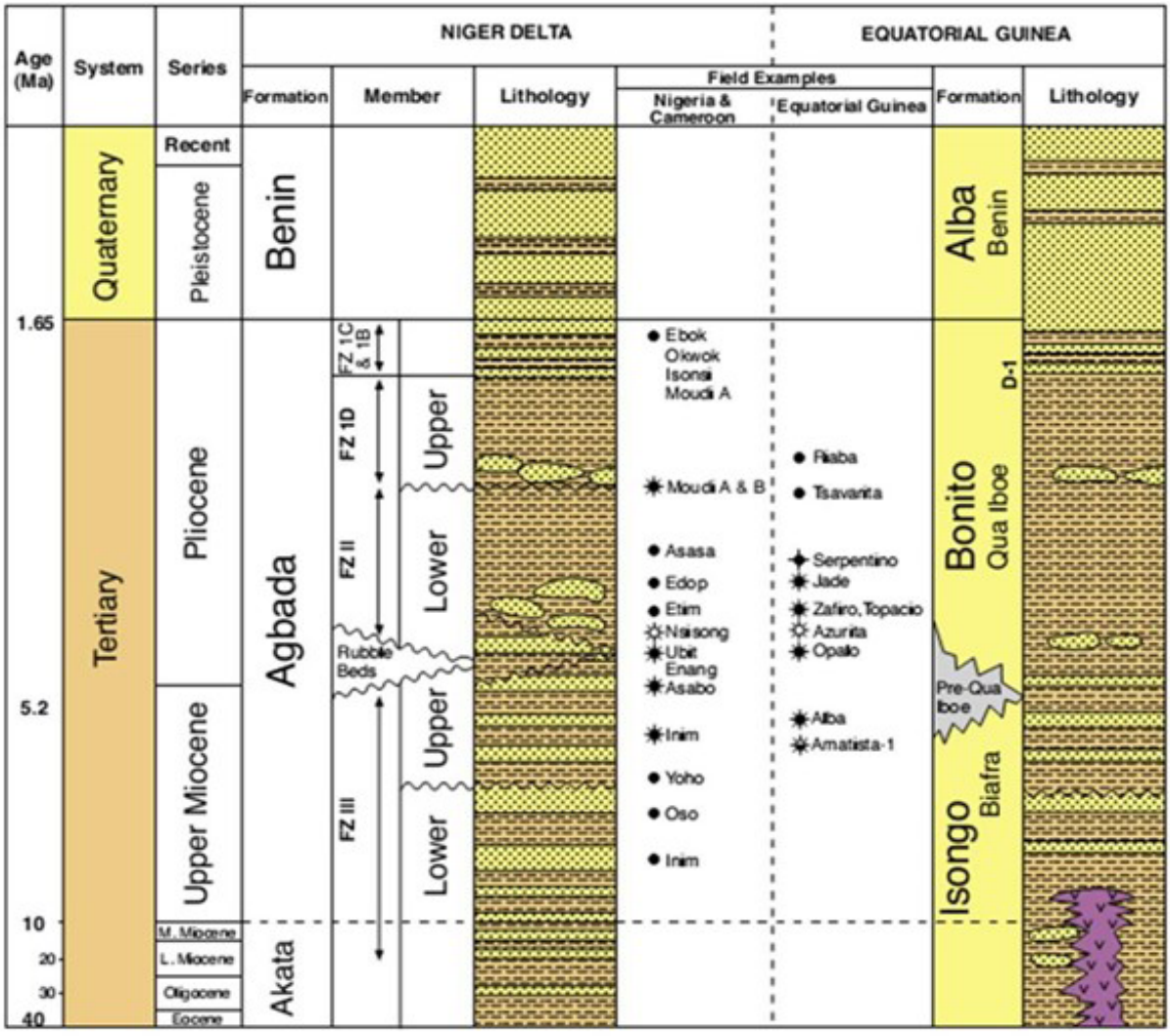

Figure 3 Stratigraphic column of the East Niger Delta Basin (Doust and Omatsola, 1990)

Each parasequence set consist of a marine clay that represent marine flooding surface, that change upward into proximal fluviomarine interlaminated silt, sand and clay, usually followed by various types of lower and upper shoreface sand and coastal plain continental deposit (Selley 1997).

Three main subdivisions have been recognized in the subsurface of the Niger Delta complex – Benin, Agbada and Akata, representing prograding depositional facies distinguished mostly on the basis of sand-shale ratio and further subdivided into depobelts as progradation proceeds into the deeper waters (Short & Stäuble 1965, 1967; Doust & Omatsola 1990; Kulke 1995).

2.1 Petroleum Geology

The Niger Delta is the most important in the West African continental margin and ranked amongst the world's major hydrocarbon provinces (Tuttle et al. 1999). It is the sole productive basin in the country till date (Obaje et al. 2004); with proven reserves put at 32 billion barrels (bbl) for oil and about 170 trillion standard ft3of gas (Nexant 2003).

Petroleum occurs throughout the Agbada Formation of the Niger delta. However, several directional trends form an "oil-rich belt" having the largest field and lowest gas: oil ratio (Ejedawe 1981; Evamy et al. 1978; Doust & Omatsola 1990). The Niger Delta Province contains only one identified petroleum system (Figure 4).

This system is referred to as the Tertiary Niger Delta (Akata –Agbada) Petroleum System (Kulke 1995). Stacher (1995), using sequence stratigraphy, developed a hydrocarbon habitat model for the Niger delta (Figure 5) and provides a short summary of basin, trap, reservoir, source rock and hydrocarbon character (Table 1). Source rocks in the Niger Delta might include marine interbedded shale in the Agbada Formation, marine Akata Formation shale and underlying Cretaceous shale (Evamy et al. 1978; Doust & Omatsola 1990).

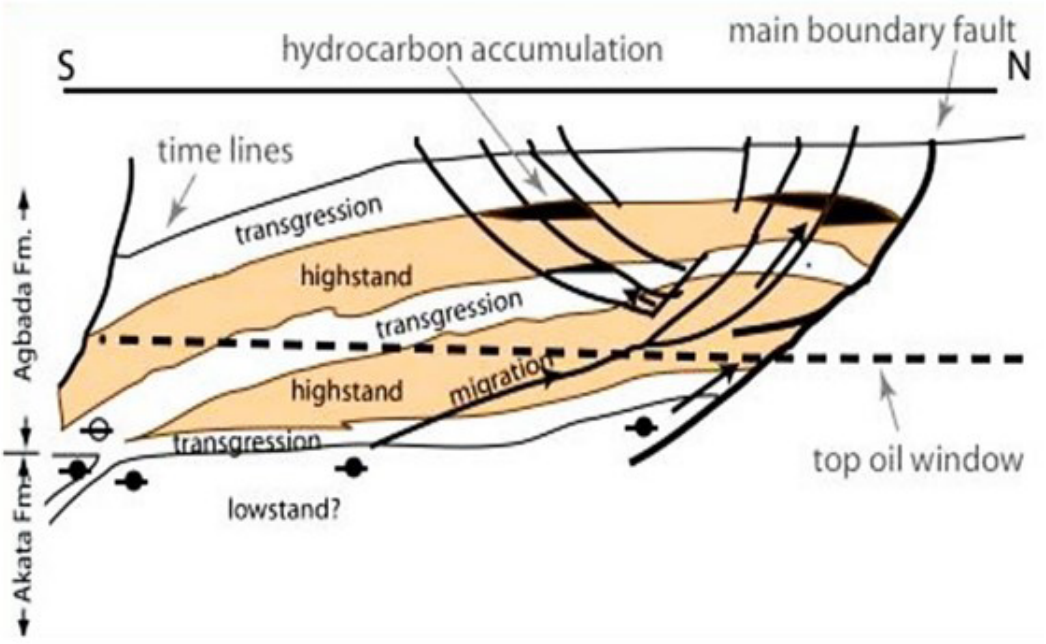

Figure 4 Geological cross section showing stratigraphic units of the Niger Delta (Michele et al., 1999)

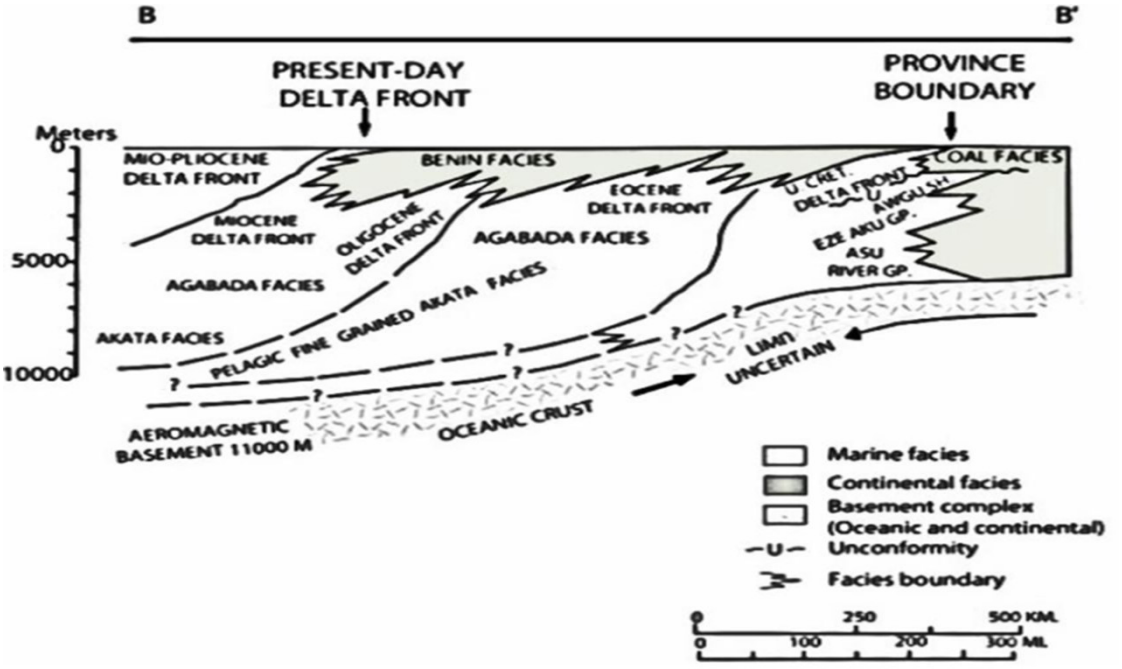

Figure 5 Sequence stratigraphic model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon traps related to growth faults (Stacher, 1995)

Table 1 Summary results of the petrophysical parameters obtained from wireline log analysis of well UK-05.

Sand	Top (m)	Bottom (m)	Thickness (m)	Φ (%)	Vsh (%)	Φ_e (%)	S_w (%)	S_H (%)	BVW	K (md)
A	1989.5	1996	6.5	33.16	41.01	33.16	45.85	54.15	0.15	384
B	1996	2013	17	34.3	24.74	34.3	36.91	63.09	0.13	546.54
C	2019.5	2032.5	13	30.59	17.89	30.59	35.21	64.79	0.1	420.31
D	2034	2048	14	29.42	20.03	29.42	40.88	59.12	0.12	229.82
E	2057.5	2067	9.5	32.7	9.97	32.7	42.21	57.79	0.14	296.58
F	2077	2083.5	6.5	31.26	37.79	31.26	46.1	53.9	0.13	423.18
G	2096.5	2113.5	17	30.77	14.73	30.77	45.03	54.97	0.14	254.86
H	2115.5	2137	21.5	31.96	27	31.96	38.32	61.68	0.12	389.1
I	2147	2154.5	7.5	21.54	35.56	21.54	59.78	40.22	0.12	74.29
J	2157.5	2173	15.5	30.26	29.87	30.26	35.77	64.23	0.11	421.26
K	2177	2188	11	31.69	10.53	31.69	32.78	67.22	0.1	516.83
L	2208	2220	12	31.27	22.01	31.27	40.52	59.48	0.13	286.86
M	2246	2253	7	34.66	51.67	34.66	43.72	56.28	0.15	433.98
N	2266.5	2280	13.5	29.56	36.51	29.56	43.65	56.35	0.13	240.8
O	2393	2407	14	27.92	27.1	27.92	47.47	52.53	0.13	123.44
P	2410	2422	12	26.52	14.88	26.52	48.25	51.75	0.13	93.91
Q	3160	3179.5	19.5	23.65	13.42	21.01	40.01	59.99	0.08	17.31
R	3810.5	3821.5	11	20.49	25.58	18.47	49.71	50.29	0.09	9.02
S	3854.5	3859.5	5	19.7	21.86	17.55	43.26	56.74	0.07	8.03
T	3865.5	3876	10.5	17.9	16.43	15.77	44.04	55.96	0.07	2.76
U	4000.5	4009	8.5	18.13	8.3	17.73	21.95	78.07	0.04	6.13
V	4020.5	4029	8.5	18.26	14.04	17.25	48.32	51.68	0.08	7.94
W	4176.5	4184	7.5	17.09	2.76	16.28	30.04	69.96	0.04	18.23
X	4195	4203.5	8.5	16.31	9.1	14.93	47.9	52.1	0.07	3.55
Y	4299	4306.5	7.5	15.77	6.56	15.45	46.98	53.02	0.07	3.82

3 Methodology

The study was initiated with the acquisition of data. The data consist of a well log from Well U-05 in the eastern Niger delta basin. The well log consists of a composite of gamma ray (GR_COMP), deep and flush zone resistivity (RT_COMP, RXO_COMP respectively), porosity (density and neutron) and photoelectric logs.

3.1 Determination of Petrophysical Parameters of Reservoir Zones

Petrophysical evaluation is concerned with the rock proportion that determines the quality, quantity and recoverability of hydrocarbon in a reservoir. The potential and performance of a reservoir is determined by its porosity, permeability and fluid saturation, which are fundamental parameters. The relationships among these properties are used to identify and evaluate reservoirs. Hence, the following properties will be evaluated: shale volume, porosity, permeability, hydrocarbon and water saturation, bulk water volume.

3.1.1. Shale Volume (VSh)

The gamma ray index (I_{GR}) was used to determine the amount of shale present in each of the reservoir zones. This is because GR readings increase with increase in shale

content. The volume of shale is very important to note because it is used to evaluate other petrophysical parameters like reservoir net thickness, irreducible water saturation (S_{wirr}), effective porosity and thus the permeability. The gamma ray index (I_{GR}) was determined from Equation 1 which is known as the linear gamma ray index (Linear Gr Index).

$$I_{GR} = \frac{GR_{Log} - GR_{min}}{GR_{max} - GR_{min}} \quad \textbf{(1)}$$

where, GR_{log} = GR reading of formation
GR_{min} = minimum GR reading (clean sand or carbonates)
GR_{max} = maximum GR (shale base line value)

The volume of shale was then determined using the Larionov (1969), Equation 2

$$V_{sh} = 0.083\left(2^{3.7I_{GR}} - 1.0\right)\ 2 \quad \textbf{(2)}$$

For Tertiary rocks, since reservoirs of the Agbada Formation are of Tertiary age.

3.1.2. Porosity (Ø)

Porosity values for the hydrocarbon reservoirs were estimated. The amount of internal space or voids in the rock is a measure of the amount of fluid (notably, oil or gas) the rock will hold. The porosity log utilized was the bulk density log which records only the bulk density of the formation; therefore, density porosity was estimated using Asquith and Krygowski equations (2004) (Equation 3 and 4) for the intervals of interest (hydrocarbon bearing intervals).

Porosity calculated using the formulas:

$$\varnothing = \sqrt{\varnothing_N + \varnothing_D}, \textit{for Liquid Saturation}\ 3 \quad \textbf{(3)}$$

$$\varnothing = \sqrt{\frac{\varnothing^2 N + \varnothing^2 D}{2}}, \textit{for Gas Saturation}\ 4 \quad \textbf{(4)}$$

$Ø_N$ = neutron porosity obtained from the neutron log, $Ø_D$ = density porosity determined from Wyllie's Equation (Equation 5)

$$\varnothing_D = \left(\frac{\delta ma - \delta b}{\delta ma - \delta fl}\right) \quad \textbf{(5)}$$

where, δ_{ma}= matrix density, $Ø_D$= porosity derived from density log, δ_b= bulk density.

Because of the considerable presence of shale in the reservoirs, the measured porosity was corrected for the volume of shale using Dewan (1983) equations to obtain the effective porosity (Equation 6 and 7) and the shale bound water (Equation 8).

$$\varnothing_e = \left[\frac{\ddot{a}_{ma} - \ddot{a}_b}{\ddot{a}_{ma} - \ddot{a}_{fl}}\right] - \left[V_{sh} * \left(\frac{\ddot{a}_{sh} - \ddot{a}_b}{\ddot{a}_{sh} - \ddot{a}_{fl}}\right)\right] \quad \textbf{(6)}$$

$$\text{i.e.,} \varnothing_e = \varnothing - V_{sh} * \varnothing_{sh} \quad \textbf{(7)}$$

where, $Ø_e$ = effective porosity and δ_{sh}= density of shale.

$$V_{sh} \div \left(\frac{\delta_{sh} - \delta_b}{\delta_{sh} - \delta_{fl}}\right) = \textit{Shale Bound Water} \quad \textbf{(8)}$$

(δ_{ma}= 2.65g/cc, δ_w=1g/cc, δ_{sh}= 2.66g/cc, δ_g= 0.6g/cc,δ_{oil} = 0.8g/cc,)

3.1.3. Water Saturation (Sw)

From porosity the formation resistivity factor (F) was calculated using equation (Equation 9). Water saturation (S_w) is the proportion of the pore space that is occupied by water was then calculated using formation water resistivity (Rw) (Equation 10). The water saturation was calculated using the Archie's equation (Equation 11), hydrocarbon saturation (S_{HC}) (Equation 12) Simandoux (1963) equation (Equation 13) and Indonesian (Leveaux & Poupon 1971) equation (Equation 14) Saturation is a relative measurement and commonly expressed in decimal/fractional units or else as percentage.

$$F = \frac{a}{\varnothing^m} \quad \textbf{(9)}$$

where **a** is the tortuosity factor for sand given as 0.81 m is cementation factor given as 2.

The water saturation (S_w) of the reservoirs was then calculated using formation water resistivity (Rw).

$$R_w = \frac{R_o}{F} \quad \textbf{(10)}$$

in the Archie (1942) equation (Equation 11).

$$S_w = \sqrt{\frac{F \times R_w}{R_t}} \quad \textbf{(11)}$$

where Ro is resistivity of water bearing formation (ILD at water formation).
R_t is true formation resistivity (from ILD).

- Having determined S_w, hydrocarbon saturation (S_{HC}) was then calculated from the equation (Equation 12)

$$S_{HC} = 1 - S_w \quad (12)$$

$$S_{w\ simandoux} = \frac{a.R_w}{2.\varnothing^m}\left[\sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{4\varnothing^m}{a.R_w R_t}} - \frac{V_{sh}}{R_{sh}}\right] \quad (13)$$

$$\frac{1}{\sqrt{R_t}} = \left[\frac{V_{sh}^{1-\frac{V_{sh}}{2}}}{\sqrt{R_{sh}}} + \frac{\varnothing_e}{\sqrt{R_w}}\right].S_w \quad (14)$$

3.1.4. Permeability Determination (K)

Permeability is the capacity of a reservoir rock to permit fluid to flow. It is a function of interconnected pore volume; therefore, a rock is perable if it has an effective porosity. For the permeability (K) of the reservoir to be determined, the irreducible water saturation, (S_{wirr}) (that is the proportion of water adsorbed on a mineral surface or held within microspores by capillary action) must be known (Equation 15).

S_{wirr} is given as

$$S_{wirr} = \frac{C}{\Phi} \quad (15)$$

where C= constant (for sandstone 0.02-0.10).

The Wyllie and Rose, (1950) equation below (Equation 16 and 17) was used to determine the K.

$$k = \left(79 * \frac{\varnothing^3}{S_{wirr}}\right)^2, \text{dry gas } 16 \quad (16)$$

$$k = \left(250 * \frac{\varnothing^3}{S_{wirr}}\right)^2, \text{medium gravity oils } 17 \quad (17)$$

3.1.5. Bulk Volume Water (BVW)

The BVW in a reservoir is simply the product of the Water saturation (S_w) and the porosity (Φ) as given in Equation 18.

$$BVW = S_w \Phi \quad (18)$$

It is important in that it indicates whether or not a reservoir is at $S_{wirr.}$ At $S_{wirr,}$ a reservoir produces Water – free hydrocarbons because all the formation water is held through surface tension or capillary pressure by the grains. A reservoir at S_{wirr} exhibit BVW values that are constant or nearly constant throughout (Dewan, 1983; Asquith and Krygowski, 2004). This mean that when BVW is calculated at different points through an interval, the values should be the same or very close to the same for an essentially water-free completion.

4 Results

4.1 Lithostratigraphy

The different lithologieswere established using the log signature GR_COMP, and the fluid types were established using the resistivity log signature (RT_COMP). The results from the gamma ray log shows a lithology of alternating sands and shales with the sand occurring frequently at the top while shale thickness increases as the gamma ray log deepens into the well and the results from the resistivity log shows that the reservoirs are saturated with gas (reservoir Q, R and U) and the remaining reservoirs are saturated with oil (Figure 6A-B) which illustrate lithology and fluid type.

4.2 Petrophysical Parameters

Petrophysical properties were determined for only the hydrocarbon bearing sandstones units of the basin (Table 1 and 2). The relationship between shale volume, water and hydrocarbon saturation was plotted in order to know the effect of shale volume on fluid saturation (Figure 6A-D).

5 Interpretation and Discussion

5.1 Lithostratigraphy

The well shows alternation of sands and shale lithology which is an indication of the presence of one lithostratigraphic unit in Well UK-05, the paralic Agbada Formation based on the geology of the Niger Delta (Short & Stäuble 1967; Whiteman 1982). The Agbada Formation, as shown in the well (Figure 7A-B), is typically a sequence of sandstones alternating with shales, with sands predominating up-section (Silvestre et al. 2020) with coarsening upward and occasionally fining upward log signatures.

5.2 Reservoir Zones and Fluid Saturation

Petrophysical interpretations of reservoir zones reveal the following:

Table 2 Summary results of the Simandoux, Dual-water and Indonesian water and hydrocarbon saturation values for Well UK-05.

Sand	Top (m)	Bottom (m)	S_wDW (%)	S_hDW (%)	S_wWS (%)	S_hWS (%)	S_wSim (%)	S_hSim (%)	S_wId (%)	S_hId (%)
A	1989.5	1996	45.85	54.15	45.85	54.15	45.85	54.15	45.85	54.15
B	1996	2013	36.91	63.09	36.91	63.09	36.91	63.09	36.91	63.09
C	2019.5	2032.5	35.21	64.79	34.1	65.9	33.58	66.42	35.21	64.79
D	2034	2048	40.88	59.12	40.88	59.12	40.88	59.12	40.88	59.12
E	2057.5	2067	42.21	57.79	42.21	57.79	39.98	60.03	42.21	57.79
F	2077	2083.5	41.95	58.05	39.06	60.94	41.95	58.05	41.95	58.05
G	2096.5	2113.5	45.03	54.97	45.03	54.97	40.65	59.35	45.03	54.97
H	2115.5	2137	38.32	61.68	38.32	61.68	38.32	61.68	38.32	61.68
I	2147	2154.5	50.49	49.51	44.97	55.03	49.88	50.12	50.49	49.51
J	2157.5	2173	35.77	64.23	34.67	65.33	35.76	64.24	35.77	64.23
K	2177	2188	32.78	67.22	32.78	67.22	30.67	69.33	32.78	67.22
L	2208	2220	40.52	59.48	40.52	59.48	40.52	59.48	40.52	59.48
M	2246	2253	43.72	56.28	43.72	56.28	43.72	56.28	43.72	56.28
N	2266.5	2280	43.65	56.35	41.84	58.16	43.65	56.35	43.65	56.35
O	2393	2407	47.47	52.53	47.47	52.53	47.47	52.53	47.47	52.53
P	2410	2422	48.26	51.74	48.26	51.74	41.22	58.78	48.25	51.75
Q	3160	3179.5	19.71	80.29	27.29	72.71	33.58	66.42	36.91	63.09
R	3810.5	3821.5	28.21	71.79	35	65	40.91	59.05	44.25	55.75
S	3854.5	3859.5	23.15	76.85	30.61	69.39	36.51	63.45	40.39	59.61
T	3865.5	3876	22.06	77.94	28.32	71.68	36.13	63.88	40.87	59.13
U	4000.5	4009	18.26	81.74	17.98	82.02	20.78	79.22	21.67	78.33
V	4020.5	4029	38.03	61.97	41.89	58.11	44.69	55.31	46.82	53.18
W	4176.5	4184	21.3	78.7	14.67	85.33	26.72	73.28	28.75	71.25
X	4195	4203.5	32.36	67.64	28.76	71.24	42.15	57.85	45.39	54.61
Y	4299	4306.5	43.03	56.97	29.71	70.29	45.38	54.62	46.36	53.64

For the Well UK-05, 25 reservoir zones were identified (Table 1), Applying a cut of value of <20% for shale volume, and 50-60% for water saturation to define net pay or productivity, and a >15% porosity and >50% permeability, five (5) hydrocarbon bearing reservoir were identified labeled C, E, G, K, P.

The reservoirs C, E, G, K and P occur at depths of 2019.5-2032.5 m (13 m thick), 2057.5-2067 m (9.5 m thick), 2096.5-2113.5 m (17 m thick), 2177-2188 m (11 m thick) and 2410-2422 m (12 m thick) respectively. From the Neutron porosity and density log the reservoirs are interpreted to contain oil and gas. The average shale volume within these zones lies between 9.97 and 17.89%, which is below the limit of 20% that can affect the water saturation value and fluid flow in these reservoirs (Hilchie 1978). Their average effective porosities ranges from 26.52 to 32.7% due to the presence of shale. Average permeability values ranges from 93.91-420.31 mD, BVW ranges from 0.10- 0.14 and S_H ranges from 51.75-67.22%.

According to the BVW classification by Buckles (1965) the reservoirs have an average grain size of 1.0-0.5 mm which is described as being coarse grained. According to Rider (1986) porosity and permeability classification, the porosities of the reservoirs are very good for reservoir P and excellent for reservoirs C, E, G and K, their permeability values is good for sand (reservoir P) and very good for sand (reservoir C, E, G and K) which are good enough to permit free flow of hydrocarbons.

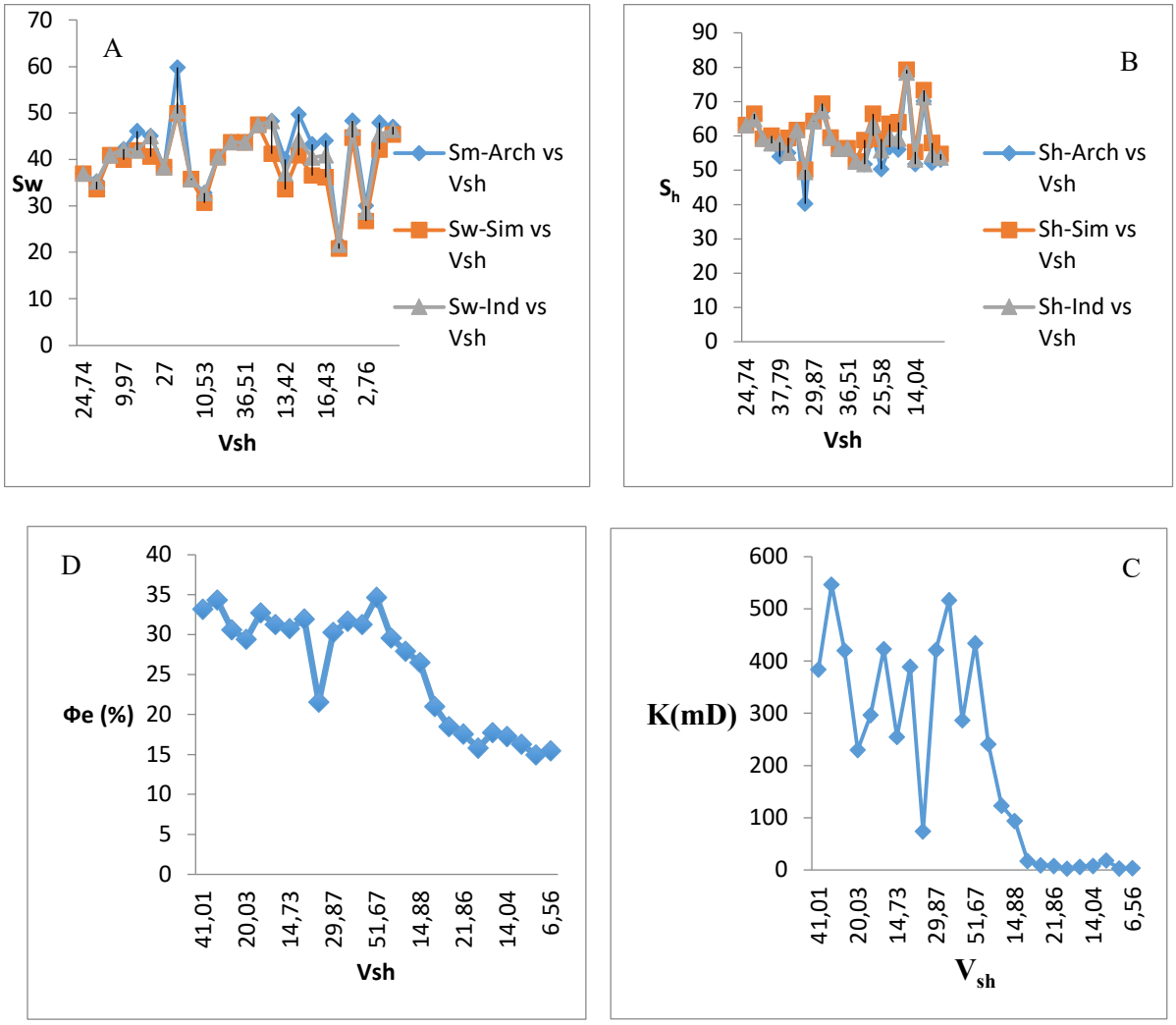

Figure 6 A. Influence of shale on water saturation; B. Influence of shale on hydrocarbon saturation; C. Relationship between shale volume and permeability; D. Shale effect on effective porosity

These results are similar to 3.42 to 29.09% of shale volume, 22.25 to 28.32% of effective porosity, 10 to 42% of water saturation and 58 to 90% of hydrocarbon saturation obtained by (Fozao et al. 2019).

5.2.1. Effects of Reservoir Shaliness on Porosity

The influence of reservoir shaliness on effective porosity was determined using Equations 6 and 7 by Dewan (1983) for effective porosity calculations. Obtained values were plotted against shale volume (Figure 6D). From Figure 6C, it can be seen that as the amount of shale (Vsh) changes from a minimum value of 2.76 to 41.01% with a mean of 21.34%, the corrected Φ e changes from 14.93 to 34.66% with a mean value of 26.56% which are lower than 0.013% to 94.08% obtained by Akankpo et al. (2015) and slightly the same with 20% to 25% obtained by Gilbert et al. (2018) in the Douala Basin.

From the log interpretation and calculations made, the general trend of porosity (effective porosity), the corrected effective porosity shows an increase with increase in shale volumes. The high values of Φ e, signify that the presence of shale in sandstone reservoirs, overestimates the porosity, that is, it causes the logging tool to read higher porosities than are the porosities available for the reservoir (Fozao et al. 2019). This shows that the more the shale volume, the higher the uncertainty of actual porosity of the reservoir, which will affect the reservoir productivity potential.

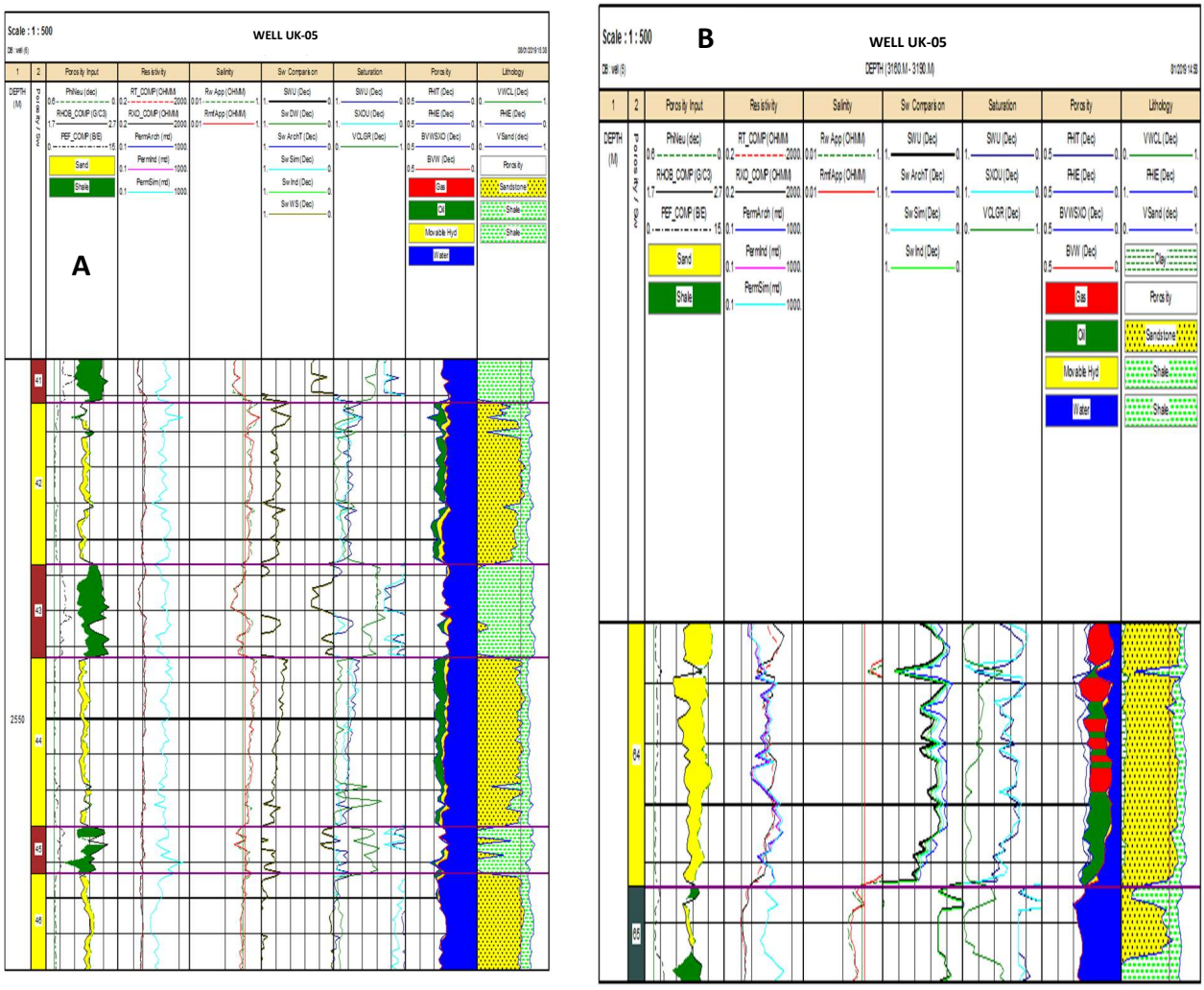

Figure 7 A. Wireline log for Well UK-05 with interpreted lithology showing alternation of sands and shales with the fluids saturating the reservoirs being gas, oil and water; B. Wireline log for Well UK-05 with interpreted lithology showing alternation of sands and shales with the fluids saturating the reservoirs being gas, oil and water

5.2.2. Effect of Reservoir Shaliness on Fluid (Water and Hydrocarbon) Saturation

The influence of reservoir shaliness on water saturation was determined using Archie (1942) Equation in Equation 10 above, Indonesian water saturation equation (Equation 13), Simandoux water saturation equation (Equation 12), water saturation after which obtained values were plotted against shale volume (Figure 6A).

From Figure 6A, it can be seen that as the amount of shale (Vsh) changes, the Archie's water saturation changes from 21.95 to 59.78% with a mean of 42.19%, the Simandoux water saturation changes from 20.72-49.88% with a mean of 39.12%, the Indonesian water saturation changes from 21.67-50.49% with a mean of 40.82%, while the results show hydrocarbon saturations of 40.22 to 78.07% with a mean of 57.81% for Archie's, for Simandoux hydrocarbon saturation ranges from 50.12-79.22% with a mean of 60.88%, Indonesian hydrocarbon saturation ranges from 49.51-78.33% with a mean of 59.18%.

Results of hydrocarbon saturation (Sh), shows a decreasing but relatively constant trend with increasing shale volume (Fozao et al. 2019). However, the values of hydrocarbon saturation increase simultaneously from Archie, Indonesian and then to Simandoux model at a given value of shale volume (Figure 6B).

Results of this work after correction show, effective porosities ranging averagely from 14.93-34.66%, which according to Ulasi et al. (2012), are very good values.

Permeability ranges from 2.78 to 546.54 mD for Archie's, 2.84 to 546.54 for Indonesian and 3.47 to 546.54 for Simandoux, Vsh values ranges from 2.76 to 51.67%. Archie's, Indonesian and Simandoux water saturation values range from 21.95 to 59.78%, 21.67-50.49% and 20.72-49.88% thus pointing to economic reservoir, if proper cost effective exploration and exploitation techniques are applied.

5.2.3. Effect of Reservoir Shaliness on Permeability

The influence of reservoir shaliness on permeability was determined using the Wyllie and Rose (1950) (Equation 15 and 16 for dry gas and medium gravity oil respectively) for computing the permeability. Values for Φ were substituted in Equation 15 and 16 to obtain the estimated permeability corrected for shale.

Obtained values were plotted against shale volume (Figure 6C). From Figure 6C, it can be seen that as the amount of shale (Vsh) changes, the shale corrected permeability changes from 2.76 to 546.54 mD with a mean of 208.502 mD. Because of the low permeability of shales, their presence in the reservoir reduces the connectivity between pores. Thus an increase in shale volume reduces permeability in a reservoir (Fozao et al. 2019).

5.2.4. Porosity Trends

In the 25 reservoirs, the average Porosity values range from 15.77% to 34.66%. The results of this study show that clean sand reservoirs have better porosity than shaly sand reservoirs (Fozao et al. 2019). In the clean sand reservoirs, the thickness of the reservoir is directly related to the porosity. For those reservoirs, higher porosity values were obtained for higher sand column and vice versa. This study also shows that zones of coarsely packed sand stones in a reservoir have better porosity than zones of finely packed sandstones in the same reservoir (Fozao et al. 2019).

Porosity was calculated for hydrocarbon and water-bearing reservoirs using Asquith and Krygowski equation (2004) Equation 3 and 4. The plot of effective porosity data against shale volume as shown in Figure 6D. This plot shows that effective porosity decreases with shale volume. In the Niger Delta, shale lithology increases with depth, while sand stone decreases. The observation confirms the results of Friedman and Sanders (1978), Blatt et al. (1980) and Selly (1982) that effective porosity is lost with increasing depth (increase in shale volume) of burial. It follows that effective porosity varies with lithology and depth, that is it decreases with increase in shale volume.

5.2.5. Fluid Saturation

During water saturation interpretation, difficulties arise whenever the portions of clay minerals in a shaly-sand formation are high. These clay minerals lead to an increase of the overall conductivity. In large quantities, their conductivity becomes as important as the conductivity of the formation water (Kurniawan 2002).

An increase in formation conductivity due to the presence of shale in a reservoir reduces the formation true resistivity (RT_COMP) and thus causes the derived water saturations (Sw) to be higher, since water saturation and formation true resistivity are inversely proportional. According to Alao et al. (2013), Archie"s equation was developed for clean sands, and it does not account for the extra conductivity caused by the clay present in shaly sands. Using Archie's equation in shaly sands results in very high water saturation, thus the Simandoux and Indonesian model were used in this work to correct for the high water saturation values.

The log derived formation water saturation shows decreasing values from Archie's model to Indonesian model, and then to Simandoux model. From the results, the Simandoux model also shows higher values of hydrocarbon saturation. These results correspond to those of Adeoti et al. (2015), which concluded that, the Simandoux and Indonesian models provide favorable petrophysical parameters indicating higher hydrocarbon potential than Archie model. This implies that the Simandoux and Indonesian model could be valuable tools in shaly sand environments.

6 Conclusions

Interpretation of gamma ray log of the well UK-05 studied showed that the lithology is dominated by alternating sand and shale meanwhile fluid type is oil and gas. The delineated zones of interest have average net sand thicknesses of 5.0 - 19.5 m, average effective porosities in the range of 14.93-34.66% and average hydrocarbon saturations, S_H ranging from 40.22-78.07% that are good indicators for commercial hydrocarbon accumulation.

It can be concluded that shales in a reservoir can cause complications in interpretation for the petrophysicist because of their general conductivity and low permeability. As a result, the high resistance characteristics of hydrocarbons may be masked, leading to potential hydrocarbon zones being missed out.

Twenty five potential reservoir zones were identified labeled A-Y. The stratigraphic unit from where the log

data was derived is mainly composed of an intercalation of sandstones and shales corresponding to the Agbada Formation of Short and Stäuble (1967) and the reservoirs are identified to contain oil, gas and water.

The complex lithology model is suitable for shale corrections of the reservoir porosity and permeability in the Niger delta, while the Archie's model is use for shale corrections of fluid saturations. The saturation of formation water increases with increase in shale volume while, effective porosity, hydrocarbon saturation and permeability decrease with increase in shale volume.

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How to cite:

Wotanie, L.V., Mbaringong, C.A. & Anatole, D.L. 2022, 'Petrophysical Characterization of Shaly Sand Reservoirs in Well UK-05 Eastern Niger Delta Basin, Nigeria', *Anuário do Instituto de Geociências,* 45:41534. https://doi.org/10.11137/1982-3908_2022_45_41534

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Ligbwah Victor Wotanie: formal analysis; methodology; validation; writing-original draft; writing- review and editing. **Christopher M. Agyingi:** conceptualization; methodology; validation; visualization; editing; supervision. **D-Lordon Anatole Eugene**: conceptualization; methodology; validation; editing; supervision.

Conflict of interest

The authors declare no potential conflict of interest.

Data availability statement

All data included in this study are publicly available in the literature.

Funding information

Not applicable

Editor-in-chief

Dr. Claudine Dereczynski

Associate Editor

Dr. Márcio Fernandes Leão