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HYDROCARBON PLAY ASSESSMENT OF THE SAPELE FIELD, FOR MOVEABLE HYDROCARBON INDICES, ONSHORE NIGER DELTA.

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ABSTRACT

A field's hydrocarbon evaluation takes into account the productivity of the hydrocarbon reservoir bearing unit. It basically includes a thorough examination of the geological interpretation of petrophysical parameter indices deduced from well logs. This study uses moveable hydrocarbon index (MHI) and proven integrated methodologies including well logs analysis, petrophysical computing, to evaluate the Sapele-field with the objective of establishing its fluid types and hydrocarbon saturations. Three formations across eight wells in the field were delineated using the quick look analysis approach at low gamma ray intervals corresponding to high resistivity kicks. Correlation of the wells was conducted to specifically check the continuity in stratigraphy of the formations across the wells. Petrophysical parameters evaluation were conducted to qualitatively access the formations across the eight wells. Porosity, permeability, water saturation, Net pay thickness, water saturation and MHI were calculated as first and second degrees petrophysical parameters. Results revealed a characteristic thin beddings in the formation across the eight wells, with the same range of net pay thickness. MHI results (0.24-0.61) revealed the formations hydrocarbons are moveable during invasion and this is in agreement with the formations tendencies to accommodate and transmit hydrocarbon (0.14-0.24 porosities and over 250mD) with good hydrocarbon saturations of over 55%. This study has shown that the Sapele field is viable with good hydrocarbon mobility tendency during invasion.

INTRODUCTION

The assessment of all hydrocarbon reservoir for saturation and movability depends on porosity, permeability and water saturation as the core petrophysical parameters of the reservoir rock (Ibe et al, 2018). Recent hydrocarbon reservoir studies has focus majorly, on hydrocarbon reservoir qualities, hydrocarbon fluid recoverability and estimation of hydrocarbon volume in place, as the demand for energy surges. While these statistics play major roles in the petroleum industry, a key market bargaining tool in the industry, both in the upstream and downstream is the moveable hydrocarbon index. In the upstream, it is a function of degree of connectivity of the rock matrix pore volume, the hydrocarbon fluid type and the pressure gradient (Hamada, 2004). While in the downstream it is a function of the light or heavy fractions contained in the hydrocarbon volume. The demand for Light fractions hydrocarbon like the premium motor spirit is on the steady rice unlike the heavy fractions like fuel oil and black oil that are used to power heavy duty machines.

This study presents the hydrocarbon formations study for moveable hydrocarbon index in the Sapele field using well logs data. Ravinder et al, 2013, applied integrated approach for identification of moveable hydrocarbon in tight reservoir. He observed that hydrocarbon moveability factor is an excellent indicator hydrocarbon mobility, which infers depth of good hydrocarbon production within tight reservoirs. Hamada 2004, studied formation's hydrocarbon moveabilty and type, using the resistivity log and observed that recovery factor determined from resistivity logs may be considered as primary recovery factor in case of water drive reservoir and as indicator for other types of reservoirs. Ibe and Oyewole in 2018 studied the hydrocarbon play assessment of X-Field, onshore Niger Delta and noted good hydrocarbon saturations with good moveability indices.

STUDY AREA

Data for this proposes research originates from the Sapele producing field of OML41, which covers an area of 291km2 and is 50km from Warri, Delta State.

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The commercially producing Sapele field forms part of the Tertiary Niger Delta (Akata–Agbada) petroleum system (https://www.seplatenergy.com/our-company/our-operations/upstream/omls-4-34-41/).

The Akata Formation is of marine origin and comprises the thick shale sequences, turbidite sandstones (6600ft) at the most distal part of the delta to 7000m (23,000ft) beneath the continental shelf.

The Agbada Formation overlain the Akata formation, and it is alternation of sandstones and shales sequence, whose sandstone reservoirs account for oil and gas production in the delta (Nwachukwu and Odjegba, 2001). The Agbada Formation characterized by paralic interbedded sandstone and shale, with over 3700m thickness. The formation represents the actual deltaic portion of the sequence (Reijers 1996).

(potential reservoirs in deep water), and infinitesimal amounts of silt (Omatsola et al, 1990). Whiteman (1982) suggested that the formation may be about 6,500m (21,400ft) thick, while Doust and Omatsola (1990) suggested that the thickness ranges from 2000m

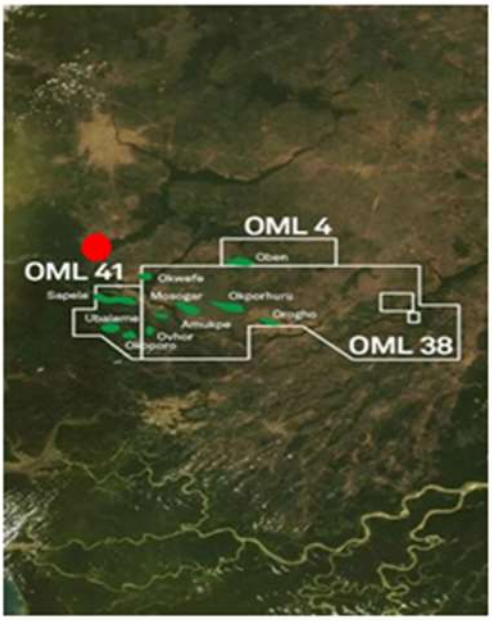

Figure1: Showing the Sapele Field

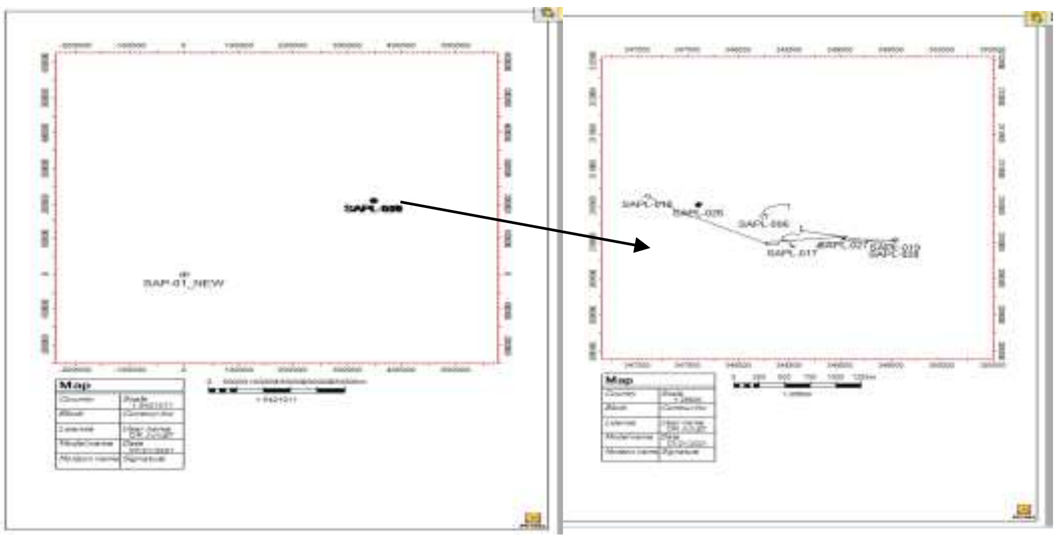

Figure 2: Showing the base map of the Sapele Field.

MATERIALS AND METHOD

Figure 2 present the base map, showing the proximity of the eight wells from one another in the study area. Well logs data were employed in this study using the Schlumberger PETREL platform. Bad data points were analyzed and removed to guide against interpretation draw backs.

The well logs data were uploaded and extensively engaged, hydrocarbon pay zones of interest, hydrocarbon fluid type and contacts were identified using the high resistivity kicks and the Neutron-Density overlay Technique (see figure 3 and 4). Petrophysical parameter were calculated for the Sapele field using the logs from Gamma ray Log (GR)., Resistivity Log (LLD), Density Log (RHOB) and equation models (see equation1-10). Hydrocarbon movability index (HMI) was calculated using the Krygowski equation model and the Schlumberger ratio method (Krygowski, 2003 and Schlumberger, 1989) (see equation 11-12). The stratigraphic continuities across eight wells in the field were manually picked using the gamma ray signatures.

The following Petrophysical analysis was carried out for the formations A, B and C across the wells (from wireline logs) using equation models as shown below; The evaluated parameters included hydrocarbonand water saturations (S_w and S_h), volume of shale, porosity (Φ) and the moveable hydrocarbon index (MHI).

Water saturation was derived using the method reported by Archie (1942), who stated that the experimental water saturation of a clean formation can be evaluated in terms of its true resistivity expressed as equation 1

$$S_W = \left[\frac{F\ Rw}{Rt}\right]^{1/n} \quad (1)$$

Since, $= \frac{R_0}{R_W}$, then $R_0 = FR_W$. Therefore, by substitution for R_W , equation 1 becomes,

$$S_W = \left[\frac{R_0}{Rt}\right]^{1/n} \quad (2)$$

where F is the formation factor., R_W is the resistivity of the formation water., R_T is the true resistivity obtained from the deep reading tool, Ro is the resistivity of the formation when it is 100% saturated with water with resistivity Rw (Schlumberger, 1989), S_W is water saturation and n is the saturation exponent (commonly 2.0)

Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbons. It is calculated from equation 3 below:

$$S_H = 1 - S_W \quad (3)$$

where S_H = Hydrocarbon saturation, S_W = Water saturation., 1 = Unity.

The formation factor of a porous formation within the target depth interval was determined using humble' formula for unconsolidated formations, which are typical of the Niger Delta. This is given by: $F = {}^{a}/_{\Phi^m}$ (4)

Where: F is the formation factor, Φ is the porosity, 'a' is the tortuosity constant and m is an exponent called cementation factor m = exponent called cementation factor

For sands**;** $F = {}^{0.62}/_{\Phi^{2.15}}$ (5)

The volume of shale in unconsolidated tertiary rocks unit is given by:

$$V_{SH} = 0.33\ (2^{(2 \times Igr)} - 1.0) \quad (6)$$

where: V_{SH} is the volume of the shale and I_{GR} is the gamma ray index,

$$I_{gr} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (7)$$

The porosity is derived from bulk density of clean liquid-filled formations when the matrix density, ρ_{ma}, and the density of the saturating fluid, ρ_f, are known

$$\Phi den = \frac{\rho ma - \rho b}{\rho ma - \rho f} \quad (8)$$

where: Φden is the density derived porosity, ρma is the matrix density (2.65g/cm^3).
ρb is the formation bulk density, ρf is fluid density (0.85g/cm^3 for oil and 1.1g/cm^3 for water).
According to Schlumberger (1989), the irreducible water saturation (Swirr) can be expressed according to equation 9

$$S_W irr = \left\lfloor\frac{F}{2000}\right\rfloor^{0.5} \quad (9)$$

where $S_W$irr is the irreducible water saturation and F is Formation factor
Tixier equation was used for the determination of permeability (K) , expressed as equation 10

$$K^{1/2} = \frac{250\ \Phi^{\wedge}3}{Swirr} \quad (10)$$

where: Φ is the Porosity.

The water saturation for flushed zone for moderate invasion and average hydrocarbon saturation is given by the equation 11 below. (Krygowski, 2003)

$$S_{xo} = [Sw]^{1/5} \tag{11}$$

Where Sxo= water saturation of the flushed zone
Sw= water saturation of the uninvaded zone

Movable hydrocarbon index (MHI) was calculated using the Schlumberger ratio method (Schlumberger, 1989) as shown below.

$$MHI = \left[\frac{Sw}{Sxo}\right] \tag{12}$$

RESULTS AND DISCUSSION

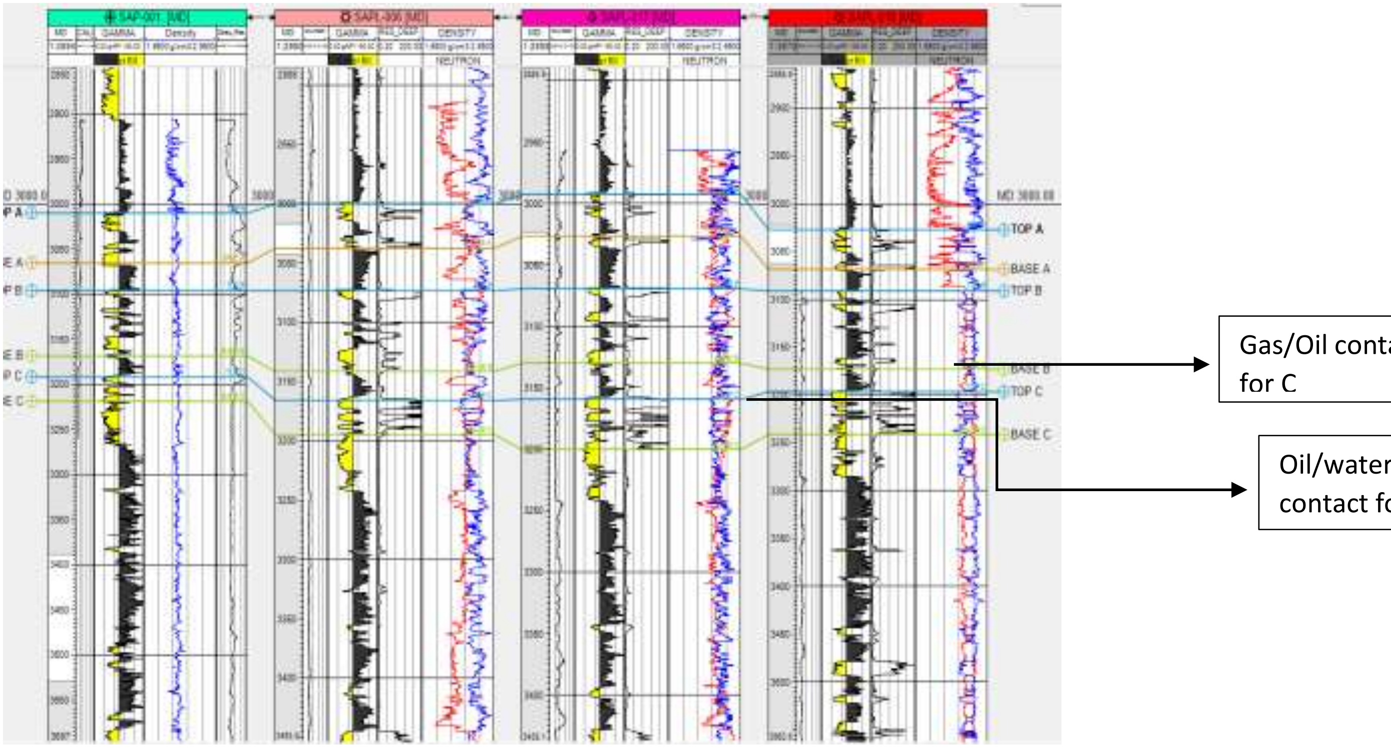

Figure 3. Delineated payzones showing the hydrocarbon fluid type and contacts.

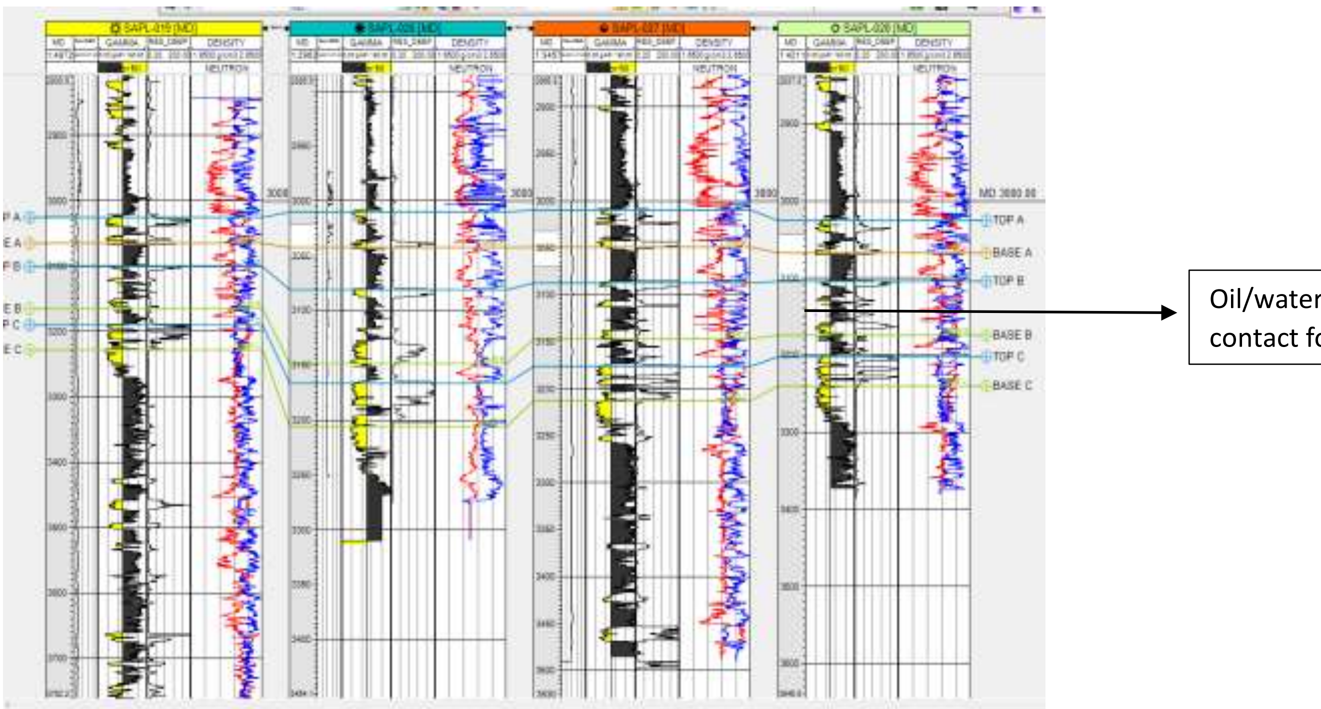

Figure 4: Delineated payzones showing the hydrocarbon fluid type and contacts across the wells cont'd

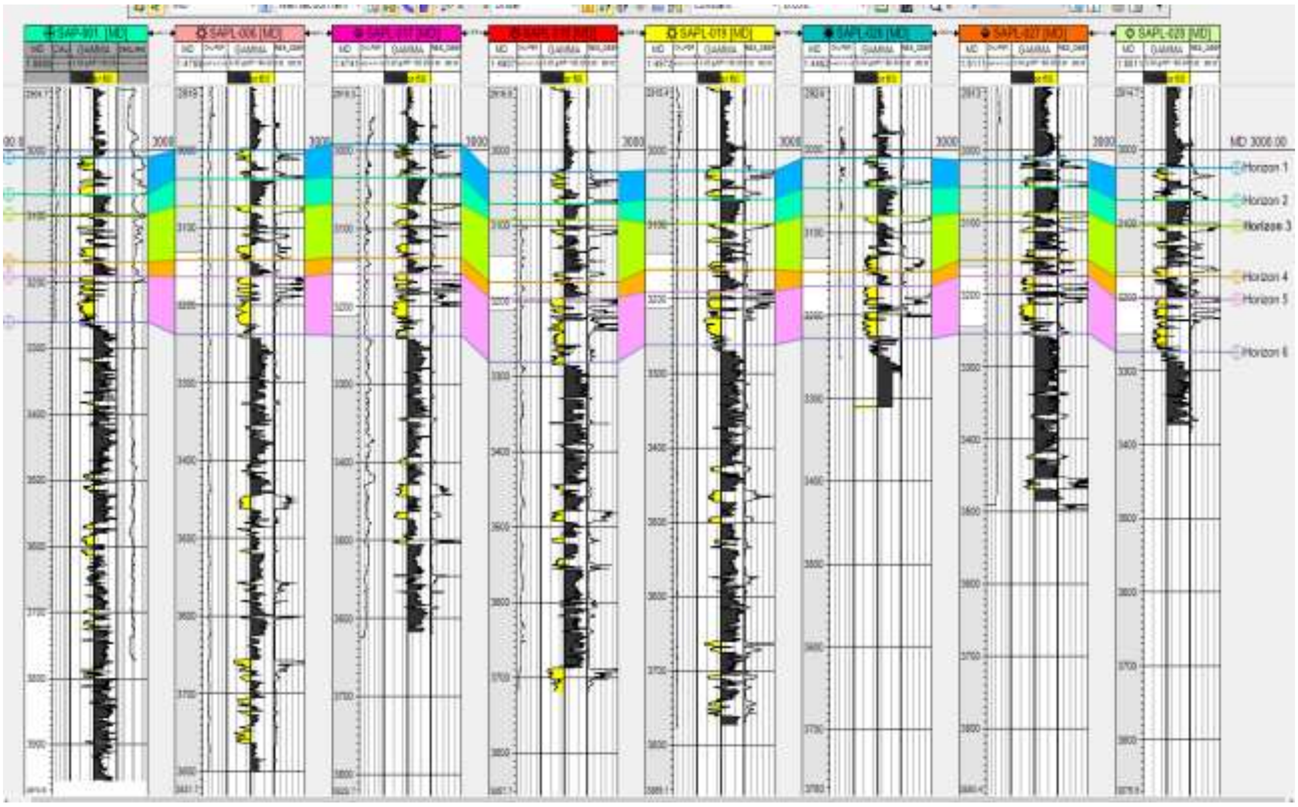

Figure 5: Correlation of eight wells, showing stratigraphic continuity.

Correlation of the reservoir sands

The correlation was done from the top to the bottom of the well logs (see figure 5). Gamma ray (GR) logs are the main logs used for correlation as they exhibits log signatures that are easier to spot between wells and such provides a dependable means for correlation (Ogbe et al,2013).

Depositional environment

The environments of deposition of the formation bodies were classified as Deltaic clastic marine settings by comparing the gamma-ray signature with standard log motifs.

The well logs data of the Sapele deep field has been carefully observed, analyzed and interpreted. A quick and careful look interpretation approach was adopted for the total of eight wells to delineate three hydrocarbon bearing formations tagged A, B and C (figures 3 and 4). Well SAP-001, formation A has a start measured depth (MD) of 3010.09 and a net pay of 31.56m, formation B has a start depth (tops) of

3096.17 and zero net pay (using 40% cut-off for water saturation and volume of shale), and formation C with a start MD of 3191.79m has 19.35m net pay respectively, indicating a characteristic thin beds with same thickness range across the formations in well SAP001 (Table1). The formations have movable hydrocarbon indices of 0.31, 0.53 and 0.56 respectively. These indices which are indicative of hydrocarbon oil movement during invasion (Schlumberger, 1989) is in line with the fair-good formations tendency to accommodate hydrocarbon (with porosity values of 0.16, 0.15 and 0.14) and transmit the hydrocarbon (377 – 402mD) according to Levorsen, 1967 and Baker, 1992.

Table 1: Showing formations' petrophysical results of SAP-001

Well tops	SAP-001A.	SAP-001.B	SAP-001.C
Start MD(m)	3010.09	3096.17	3191.79
Vsh	0.16	0.29	0.13
NTG	0.84	0.71	0.87
Net Pay (m)	31.56	15.8(0)	19.35
Porosity	0.16	0.15	0.14
effPorosity	0.13	0.1	0.12
S_w	0.23	0.46	0.49
S_h	0.77	0.54	0.51
Swirr	0.18	0.2	0.2
K(mD)	402	383	377
MHI	0.31	0.53	0.56

Table 2,3,4,5,6,7 and 8 presents petrophysical results for three formations of well SAP-006, SAPL-017, SAPL-018, SAPL-019, SAPL-026, SAPL-027 and SAPL-028. SAP-006 has a start MD of 3000.18m and net pay of 19.24m, start MD of 3073.19 and 20.76m net pay and start MD of 3165.60m and a net pay of 19.07m for formation A, B and C respectively. SAPL-017 well has a start MD of 2992.40m and net pay of 11.25m, start MD of 3069.15m and 12.53m net pay and start MD of 3159.13m and a net pay of 28.03m; Well SAPL-018 has a start MD of 3027.08m and net pay of 22.81m, start MD of 3090.96m and 6.97m net pay and start MD of 3196.34m and a net pay of 31.80m; SAPL-019 well has a start MD of 3025.29m and net pay of 19.88m, start MD of 3100.56m and zero net pay for a 40% cut-off for Vsh and $S_{w,}$ and start MD of 3190.02m and a net pay of 26.87m; SAPL-026 well SAPL-017 well has a start MD of 3010.05m and net pay of 11.22m, start MD of 3081.08m and 22.16m net pay and start MD of 3166.52m and a net pay of 29.29m; SAPL-027 has a start MD of 3009.77m and net pay of 14.05m, start MD of 3087.31m and zero net pay (Vsh=0.72, Sw=0.54) and start MD 3176.04m and a net pay of 15.86m; SAPL-28 has a start MD of 3025.49m and net pay of 18.63m, start MD of 3104.11m and zero(Vsh=0.53) net pay and start MD of 3202.16m and a net pay of 29.73m respectively, which like the SAP001 well show characteristic of thin sand beddings across the three formations in the Sapele field. The formations across the eight wells exhibit a similar repetitive serrate pattern (see figure5) of inter-bedded sandstone-shale-sandstone sequence (Lardner, 1984) with the same thickness range. Petrophysical results for the formations across well SAPL-006, 017, 018, 019, 026, 027 and 028 revealed good hydrocarbon saturation(except SAPL-019B with Vsh=44%,Sw=46% and SAPL-027B with Sw=54%). Oil and gas were delineated as the

hydrocarbon type for the three formations across the eight wells with the use of Schlumber, 1989 MHI ratio standard and the neutron-density overlain technique (see figures 3 and 4). MHI for the three formations across the eight wells ranges from 0.24-0.61. Therefore, according to Schlumberger, 1989, the hydrocarbon in the three formations across the wells are moveable during invasion and this is in agreement with the formations' fair-very good capacity to accommodate hydrocarbon as revealed in the porosity values (0.14-0.24)(Levorsen, 1967) and it very good tendency to transmit the hydrocarbon as evidenced in the permeability results (Baker, 1992).

Table 2. Showing formations' petrophysical results of SAP-006

Well tops	SAP-006A.	SAP-006.B	SAP-006.C
Start MD (m)	3000.18	3073.19	3165.6
Vsh	0.18	0.17	0.1
NTG	0.82	0.83	0.9
Net pay (m)	19.24	20.76	19.07
Porosity	0.18	0.18	0.24
effPorosity	0.16	0.14	0.22
S_w	0.39	0.24	0.19
S_h	0.61	0.76	0.81
Swirr	0.13	0.21	0.12
K(mD)	453	442	703
MHI	0.47	0.32	0.26

Table 3: Showing formations' petrophysical results of SAP-017

Well tops	SAPL-017A	SAPL-017.B	SAPL-017.C
Start MD (m)	2992.4	3069.15	3159.13
Vsh	0.21	0.29	0.13
NTG	0.79	0.71	0.87
Net pay (m)	11.25	12.53	28.03
Porosity	0.2	0.19	0.22
effPorosity	0.14	0.14	0.2
S_w	0.24	0.35	0.18
S_h	0.76	0.65	0.82
Swirr	0.18	0.16	0.12
K(mD)	508	483	601
MHI	0.32	0.43	0.25

Table 4: Showing formations' petrophysical results of SAP-018

Well tops	SAPL-018A	SAPL-018.B	SAPL-018C
Start MD (m)	3027.08	3090.96	3196.34
Vsh	0.2	0.39	0.17
NTG	0.8	0.61	0.83
Net pay (m)	22.81	6.97	31.80
Porosity	0.18	0.14	0.21
effPorosity	0.16	0.1	0.18
S_w	0.36	0.35	0.19
S_h	0.64	0.65	0.81
Swirr	0.25	0.22	0.15
K(mD)	451	386	538
MHI	0.45	0.43	0.26

Table 5: Showing formations' petrophysical results of SAP-019

Well tops	SAPL-019A	SAPL-019.B	SAPL-019.C
Start MD (m)	3025.29	3100.56	3190.02
Vsh	0.2235	0.44	0.2
NTG	0.78	0.56	0.8
Net pay (m)	19.88	0	26.87
Porosity	0.19	0.16	0.2
effPorosity	0.16	0.11	0.17
S_w	0.41	0.46	0.29
S_h	0.59	0.54	0.71
Swirr	0.32	0.22	0.14
K(mD)	460	417	518
MHI	0.49	0.54	0.37

Table 6: Showing formations' petrophysical results of SAP-026

Well tops	SAPL-026A	SAPL-026.B	SAPL-026.C
Start MD (m)	3010.05	3081.08	3166.52
Vsh	0.19	0.26	0.17
NTG	0.81	0.74	0.83
Net pay (m)	11.22	22.16	29.29
Porosity	0.18	0.14	0.2
effPorosity	0.15	0.12	0.17
S_w	0.52	0.27	0.18
S_h	0.48	0.73	0.82
Swirr	0.39	0.19	0.12
K(mD)	437	377	519
MHI	0.59	0.35	0.25

Table 7: Showing formations' petrophysical results of SAP-027

Well tops	SAPL-027.A	SAPL-027.B	SAPL-027.C
Start MD (m)	3009.77	3087.31	3176.04
Vsh	0.31	0.72	0.42
NTG	0.69	0.28	0.58
Net Pay (m)	14.05	0	15.86
Porosity	0.2	0.14	0.2
effPorosity	0.17	0.09	0.14
S_w	0.33	0.54	0.17
S_h	0.67	0.46	0.83
Swirr	0.12	0.25	0.15
K(mD)	514	386	520
MHI	0.41	0.61	0.24

Table 8: Showing formations' petrophysical results of SAP-028

Well tops	SAPL-028A	SAPL-028B	SAPL-028C
Start MD	3025.49	3104.11	3202.16
Vsh	0.23	0.53	0.27
NTG	0.77	0.47	0.73
Net pay (m)	18.63	0	29.73
Porosity	0.23	0.19	0.24
effPorosity	0.2	0.08	0.19
S_w	0.37	0.31	0.23
S_h	0.63	0.69	0.77
Swirr	0.33	0.21	0.12
K(mD)	580	478	658
MHI	0.45	0.39	0.32

CONCLUSION

Three formations tagged A, B and C across eight wells in the Sapele Field have been analyzed with the aim of ascertaining the moveable hydrocarbon indices. The formations were delineated using the quick look analysis approach at low gamma ray intervals corresponding to high resistivity kicks. Correlation of the wells was conducted to specifically check the continuity in stratigraphy of the formations across the wells. The environment of deposition by comparing the gamma ray signatures with standard log motifs revealed clastic marine settings. Petrophysical parameters evaluation were conducted to qualitatively access the formations across the eight wells. Porosity, permeability, water saturation, Net pay thickness, water saturation and MHI were calculated as first and second degrees petrophysical parameters. MHI results (0.24-0.61) revealed the formations' hydrocarbon are moveable during invasion and this is in agreement with the formations' tendencies to accommodate and transmit hydrocarbon as evidenced in the tabulated results. This study has shown that the Sapele field is characterized with thin netpay sands, of same thickness range, good hydrocarbon saturations and good hydrocarbon mobility tendency during invasion. The study can be used as a blue print for good development planning in the Sapele Field.

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