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Original Research Article

Hydrocarbon Movability Properties of Sandstone Reservoirs of Sapele Shallow Field, Niger Delta, Southern Nigeria

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KEYWORDS
Sandstone,
Hydrocarbon movability,
Prolific,
Interbedded,
Water saturation.

ABSTRACT
Sapele shallow field is a prolific oil field which forms the proximal portion of Sapele field in the Niger Delta oil province, Nigeria. The Sapele field itself is an onshore field of OML 41 located in the North-western part (Greater Ughelli deposit) of the Niger Delta oil province. The Greater Ughelli deposit is characterized by paralic interbedded sandstone and shale with a thickness of over 3000 m. Well logs from six wells, well 21, well 22, well 29, well 30, well 31 and well 32 were integrated to study the hydrocarbon movability potential of the field. The hydrocarbon movability potential of the field was delineated by looking at the various hydrocarbon movability factors such as the flushed zone obtained from water saturation parameter, movable oil saturation which is arrived at by subtracting water saturation from flushed zone, residual oil saturation evaluated from the difference between hydrocarbon saturation and movable oil saturation, and hydrocarbon movability index which is the ratio of water saturation and flushed zone. The study area on an average has flushed zone water saturation (S_{xo}) of 0.88, an average hydrocarbon saturation of 0.47, an average movable hydrocarbon saturation of 0.35, residual hydrocarbon saturation of 0.12 and an average movable hydrocarbon index of 0.6. This study has shown that Sapele shallow field just like Sapele deep field is very viable with good hydrocarbon storage and transmission ability.

CITATION
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INTRODUCTION

Sapele Shallow field is an onshore field of OML 41, located in the Northwestern part (Greater Ughelli depobelt) of the Niger Delta oil province (Figures 1 and 2). It lies within Latitude 5^0 53' 54.43" N and Longitude 5^0 33' 42.22" E (Airen and Mujakperuo, 2023a). Sapele Shallow as the name implies, is made up of shallow reservoirs with heavy oil as its hydrocarbon content. The field is in the Northwestern part of the Niger Delta, which has been actively producing for over 3 decades and for the past few years, has been experiencing production decline and sometimes failed wells. Thus, there is a need to approach the study area with an improved reservoir hydrocarbon movability study for a better understanding of the geologic complexities of the field, to improve hydrocarbon recovery from existing oil and gas reservoirs of the study area. However, Sapele field is in the Niger Delta basin and so, the focus will be on the Niger Delta basin. Cenozoic Niger Delta complex was developed as a regressive offlap sequences. The delta complex which has been described as an arcuate-lobate shape was built across the Anambra Basin and the Cross-River margins and eventually extended onto the Late Cretaceous continental margin. Geologists believe that these sediments were part of the West African miogeocline derived from adjoining older rocks which were transported and deposited by the help of the Rivers Niger and Benue onto the cooling and subsiding oceanic crust which has been generated as the South American and African Continents spread apart (Tuttle *et al.,* 1999). The Geophysicists and Geologists have shown that the Niger Delta Basin has spectacularly maintained a thick sedimentary apron and salient petroleum geological features favorable for petroleum generation, expulsion and trapping from the Onshore through the Continental Shelf and to the deep-water terrains. In 1956, the first commercial onshore discovery was made in Oloibiri by Shell and about seven years after, Chevron discovered the Okan field, the first commercial offshore field in 1963 (Raji and Abejide, 2013). Thus, among the sedimentary basins in Nigeria, aggressive exploration has been concentrated in the Niger Delta Basin. The Niger Delta Basin to date is the most prolific and economic sedimentary basin in Nigeria by the virtue of the impact size petroleum accumulations, discovered and produced as well as the spatial distribution of the petroleum resources to the Onshore, Continental Shelf through Deepwater terrains. Classic integrated geological studies have shown that several different depobelts are abound in the Niger delta basin (Oyebanjo et al, 2018). Reservoir's characterization has evolved over the past 20 years, from a simple engineering evaluation to multidisciplinary teams of geologists, geophysicists, petrophysicists, and petroleum engineers working together. The integration of these various disciplines has changed our perception of the characteristics of oil and gas reservoirs (Mujakperuo and Airen, 2024). Whereas it used to be commonly perceived that oil and gas reservoirs were relatively simple geologic features, the reality is that they are quite complex, and they can be subdivided into architectural elements or compartments on the basis of several structural and stratigraphic features. Part of the misconception comes from the fact that one cannot see a reservoir, because it is beneath ground level in the subsurface (Airen and Mujakperuo, 2023b). During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the Residual Oil Saturation, ROS. The ROS is usually associated with the non-wetting phase when it is being displaced by a wetting phase (Airen and Mujakperuo, 2023c). The shale gas and/or oil reservoir is characterized by low porosity and permeability. On average, the shale reservoirs have porosities of less than 10%, permeabilities of between 1×10^{-9}-1×10^{-3}μm^2, with generally poor pore connectivity which restricts the exploration of associated oil and gas. Although, shale reservoirs have tightly packed grains with diverse pore types (such as intergranular, intragranular and organic pores), it can be beneficial for the enrichment of shale oil and gas (Su et al., 2023)

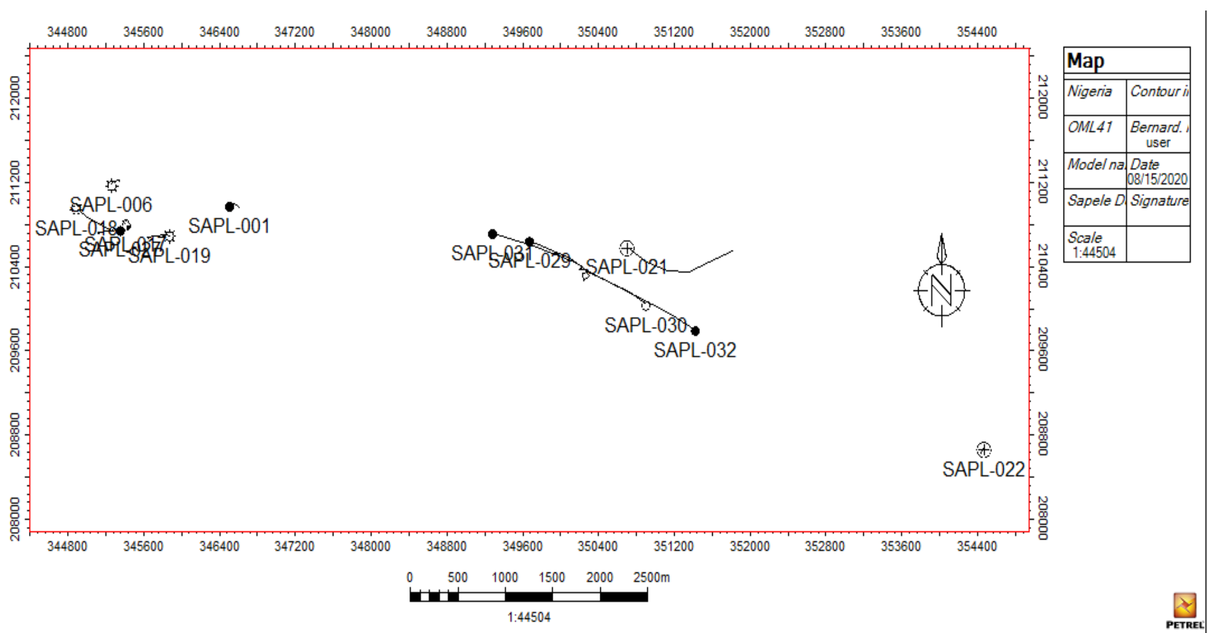

Figure 1: Base map of oil wells in the study area (Using Petrel®2016)

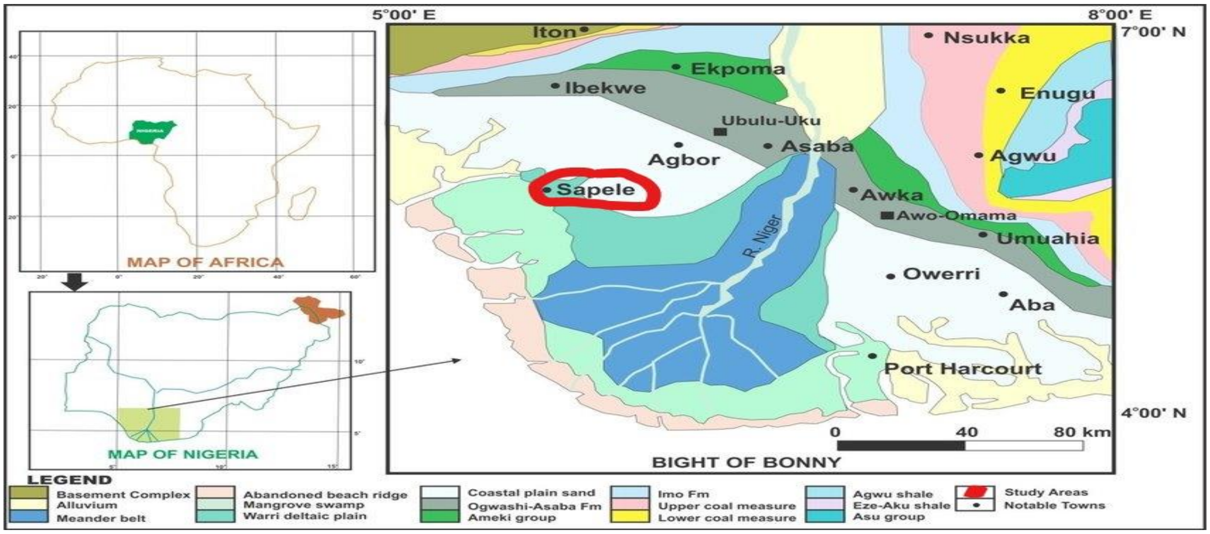

Figure 2: Geological Map of the Niger Delta Basin showing the Study Area (Oyebanjo et al., 2018)

Geological Setting

Allen (1964), Hospers (1971), Burke et al., (1972) and Whiteman (1982), establish in detail, the history, evolution, and structural features of the Niger Delta. Stoneley (1966), examined the mega tectonic setting of the Niger Delta. The syn-sedimentary tectonics of the tertiary delta was extensively analyzed by Evamy et al., (1978).

According to Lehner and De Ruiter (1977), the tectonic framework of the continental margin in the Niger Delta is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges divide the margin into individual basins and in Nigeria, form the boundary faults of the Cretaceous Benue-Abakaliki trough, which cuts extreme into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous. Asseez (1976) reviewed the stratigraphy, sedimentation, and structures of the Niger Delta. Merki (1972), described the structural geology of the Tertiary Niger Delta, which is on the overlap sequence that is deformed by syn-sedimentary faulting and folding. Ekweozor and Daukoru (1984, 1994), presented a detailed report on the petroleum geology and stratigraphy of the Niger Delta showing the relationship between depositional patterns, structures and stratigraphy and their influence on the oil generation in the Niger Delta basin.

The Niger Delta Basin is also known as the Niger Delta province. It is an extensional rift basin located between the Niger Delta and the Gulf of Guinea on the Passive Continental Margin near the Western Coast of Nigeria with suspected access to Cameroon, Equatorial Guinea and Sao Tome and Principe. The Basin is very complex and carries very high economic value as it contains a very productive petroleum system. The Niger Delta Basin is one of the largest subarea basins in Africa. It has a subarea of about 75,00km^2, a total area of 300,000km^2 and a sediment fill of about 500,000km^3, a depth of about 9 to 12km. It is composed of several different geologic formations that indicate how the basin could have been formed as well as the relationship of layered rocks with time (Maju-Oyovwikowhe and Lucas, 2019)

MATERIALS AND METHODS

Data Gathering

The materials used while carrying out this research work are a suit of subsurface data which includes; 3D seismic cube, well logs data provided across the fields, biostratigraphy data and a pressure volume temperature data. These subsurface data belong to Seplat Petroleum Development Company PLC and were released under the approval of the Department of Petroleum Resources (DPR), Nigeria. Figure 3 shows the step-by-step procedures (workflow) for each aspect of this research work.

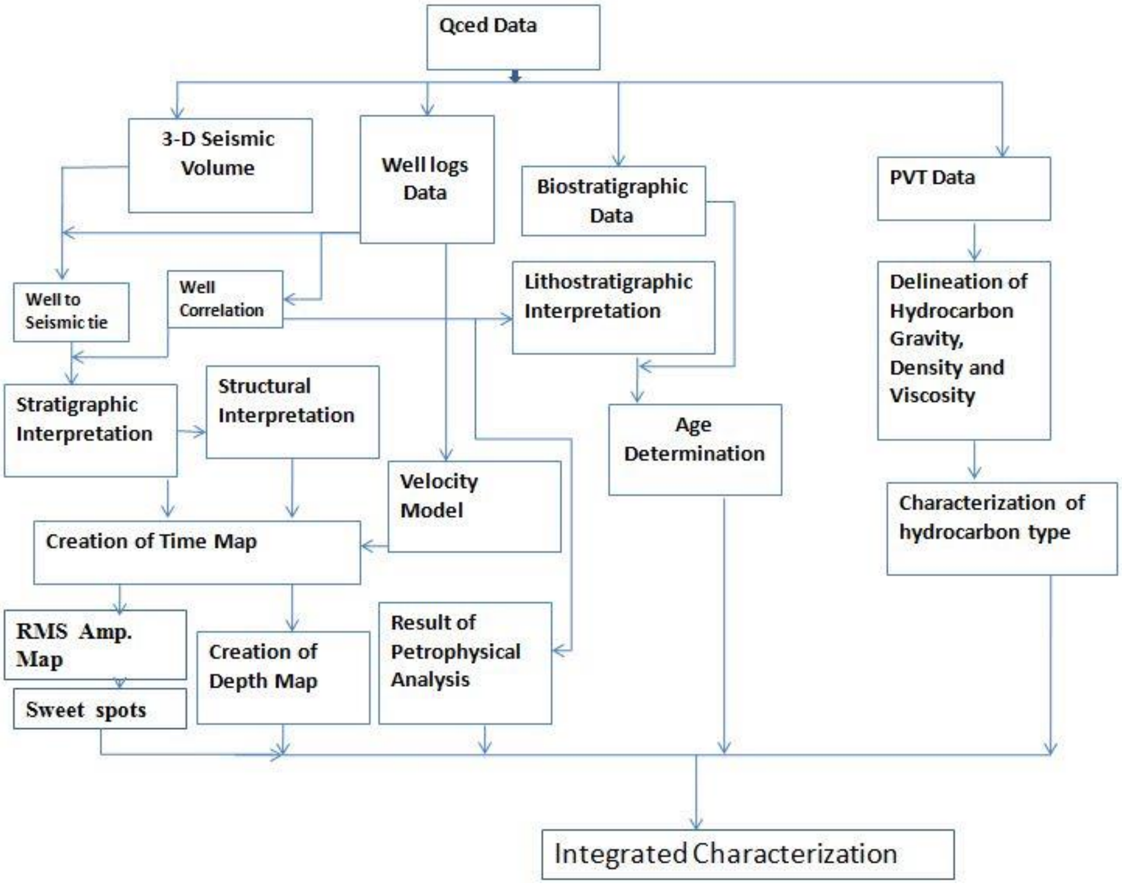

Figure 3: Study workflow

Data Processing
Petrel®2016 (Schlumberger software) was used in the interpretation of seismic and well log data. The Niger Delta Chronostratigraphic Chart of SPDC (2010) and Cenozoic Chronostratigraphic Chart of Blow (1969), Berggren *et al.*, (1995) and Wade *et al.,* (2011) were used in the biostratigraphy interpretation, while the Pressure Volume Temperature (PVT) data was used to interpret the hydrocarbon chemical components, API unit, viscosity, specific gravity and fluid density. This study employed and integrated existing models such as Asquith and Gibson (1982) and Schlumberger (1989) to analyse the Sapele field sandstone reservoir properties as itemized:

Hydrocarbon Movability Analysis
The ability of hydrocarbon to move from a reservoir to earth surface (well head) can be delineated by looking at the various hydrocarbon movability factors such as the flushed zone, movable oil saturation, residual oil saturation and hydrocarbon movability index (Hamada, 2006).

Water and Hydrocarbon Saturation Model
Saturation models are models which relate measured resistivity to water saturation from which hydrocarbon content can be determined. The saturation models used for this study were that of Archie and Waxman-Smits.

Archie Equation/Model
In 1942, Archie from empirical observation, suggested that the resistivity of brine saturated rock, R_o, was related to the brine resistivity, R_w. He established that the ratio of the resistivity of R_O to R_w was a constant for every given rock sample. The name, resistivity formation factor (F) was given to this proportionality constant. Hence, according to Archie,

$$\mathrm{F} = \frac{R_o}{R_w} \quad (1)$$

Archie (1942) also showed that there was a strong linear relationship between the logarithms transform of F and porosity (Φ) in sandstones i.e. F depends only on porosity.

$$F = 1/\Phi^m \quad (2)$$

Where m, the porosity exponent, takes different values for variety of sandstone and limestone. Archie estimated it to be approximately 2, combining equation 1 and equation 2, gives the well-known Archie's equation expressed as the electrical resistivity of water saturated sediments (R_o) as:

$$R_o = a\ {R_w}/{\Phi^m} \quad (3)$$

Archie also showed that if hydrocarbon partially saturates the pore space, we multiply R_o by a factor called the resistivity index I, to obtain true resistivity, R_t.

$$I = {R_t}/{R_o} \quad (4)$$

Which led him to propose

$$I = (1/S_w^n) \quad (5)$$

The combination of these equations led to the Archie's equation for water saturation (S_w) and hydrocarbon saturation (S_h) in a formation.

$$S_w = [(a/\Phi^m)(R_w/R_t)]^{(1/n)} \quad (6)$$

$$S_h = 1 - S_w \quad (7)$$

where: $S_w =$ water saturation, $S_h =$ Hydrocarbon saturation, $F =$ Porosity, $R_w =$ formation water resistivity, $R_t =$ true resistivity of the formation, $a =$ constant (often taken to be 1), $m =$ cementation factor (varies around 2), $n =$ saturation exponent (generally 2)

Waxman- Smits Equation/Model

The Waxman-Smits equation is a semi empirical extension of the Archie's equation, considering the additional conductivity caused by shale (Aigbedion et al., 2018). The Waxman- Smits equation is mostly used for dispersed shaly sandstones. In case of laminated shaly sandstones, either the Archie or the Waxman-Smits equation can be used in combination with specialist software. It is easier to arrive at the Waxman-Smits equation by working with conductivities rather than resistivity's. Therefore,

$$C_t = \Phi_m S_w N C_w \quad (8)$$

where: $C_t =$ conductivity of the hydrocarbon- bearing rock = $1/R_t$, $C_w =$ conductivity of brine = $1/R_w$.

Again, Waxman-Smits began with equation (3.13) but replace "W" by an equivalent water conductivity ($w + C_w + C_e/S_w$), thus taking the additional clay conductivity into account. Since the surface to volume ratio for the brine has now changed with this factor, the additional term S_w arises (Evenick, 2008).

The tortuosity factor Φ^m acts on this clay conductivity in some way as it acts on the brine conductivity, as a result, the Waxman-Smits equation for hydrocarbon bearing shaly sandstone becomes:

$$C_t = \Phi^m[S_w (C_w + \frac{C_e}{S_w})] \quad (9)$$

Or

$$C_t = \Phi^m S_w [(C_w + \frac{BQ_v}{S_w})] \quad (10)$$

By substituting B. Q_V for C_e

where: m = Cementation exponent in the Waxman- Smits equation, n= Saturation exponent of the Waxman- Smits equation.

Equation (10) is the general form of the Waxman- Smits equation. It can be written in terms of resistivity rather than conductivity, which result in

$$C_t = \Phi^m S_w - \frac{mR_w}{\left[1 + \frac{R_w BQ_v}{S_w}\right]} \quad (11)$$

(v) Flushed Zone

When a permeable zone is penetrated by the drill bit, the drilling mud will try to penetrate the permeable formation. If the size of the pores in the formation are smaller than the solids in the drilling fluid, then the solids will be trapped on the surface of the wellbore and the fluid in the drilling mud will pass through the solids into the formation. When invasion occurs, the wellbore is coated with a thin film of solids known as the "filter cake" and the formation next to the wellbore is flushed by the mud filtrate moving into the formation and is therefore known as the "flush Zone".

Krygowski (2003), established that flushed zone (S_{xo}) can be computed by applying equation 12, that is;

$$S_{xo} = S_w^{0.2} \quad (12)$$

where: S_{xo} = Flushed Zone and S_w = Water Saturation

Movable Oil Saturation

It is important to recognize that only a fraction of oil in place is ultimately produced in most reservoirs. This poses a challenge to attain better recovery, requiring a better understanding of reservoir behavior. This necessitates the estimation of movable oil saturation which represents the maximum volume of oil that can be moved or produced ultimately from a reservoir. According to Asquith and Gibson (1982), Movable Oil Saturation (MOS) can be calculated from;

$$MOS = S_{xo} - S_w \quad (13)$$

Residual Oil Saturation

At the end of the productive life of a reservoir, the oil saturation left behind in the reservoir is referred to as the residual oil saturation.

During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment) there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the Residual Oil Saturation, ROS. The term residual saturation is usually associated with the non-wetting phase when it is being displaced by a wetting phase.

Residual hydrocarbon saturation (ROS) was delineated, using equation 13, (Asquith and Gibson, 1982).

$$ROS = S_h - MOS \quad (14)$$

Hydrocarbon Movability Index (HMI)

According to Ilavalagan (2018), the movable hydrocarbon index is the ratio of the uninvaded zone and flushed zone which is estimated using the empirical relation in equation 14.

As per the ratio method (Schlumberger, 1989), published in AAPG Methods in Exploration Series 16, (2003), established that:

If HMI ≥ 1: Hydrocarbon will not move out of the reservoir.

HMI < 0.7: Movable hydrocarbon indicated (Sandstone).

HMI < 0.6: Movable Hydrocarbon indicated (Carbonate).

Hamada (2006) established that when HMI is less than 0.25, it represents movable gas and 0.25 - 0.75 represents movable oil.

$$HMI = \frac{Sw}{Sxo} \quad (15)$$

where: HMI = Hydrocarbon Movable Index

RESULTS AND DISCUSSION

Petrophysical evaluation of the six (06) wells was carried out to obtain the hydrocarbon movability properties of sandstone reservoir "A" in Sapele shallow field, Niger Delta, Nigeria with the aim of ascertaining if the sand bodies have good hydrocarbon storage and transmission ability with results of evaluation of the wells showing that field is a very sound one with high hydrocarbon movability ratio. As the name implies, reservoir "A" which is the only delineated reservoir in Sapele shallow was encountered at a shallow depth range of 672.16 m (2218.13) – 2115.06 m (6979.70 ft) across the field. The field has an area extent of 17137.18 acres, oil formation volume factor of 1.2 and an average oil viscosity of 39.94. The field is made up of wells 21, 22, 29, 30, 31 and 32.

Hydrocarbon Movability Analysis of well 21 Reservoir

The hydrocarbon movability properties of well 21 reservoir is shown in Figure 4. The reservoir was delineated with well tops at depth of 1418.80 m (4682.14 ft) as top of reservoir and at 2152.30 m (7102.72 ft) as the base. The lithology of the formation is sand dominated with little shale intercalation which was delineated with the aid of the gamma ray log. As shown from the neutron-density combination in Figure 4, reservoir "A" is a single phase (oil) reservoir with no visible balloon shape neutron density separation.

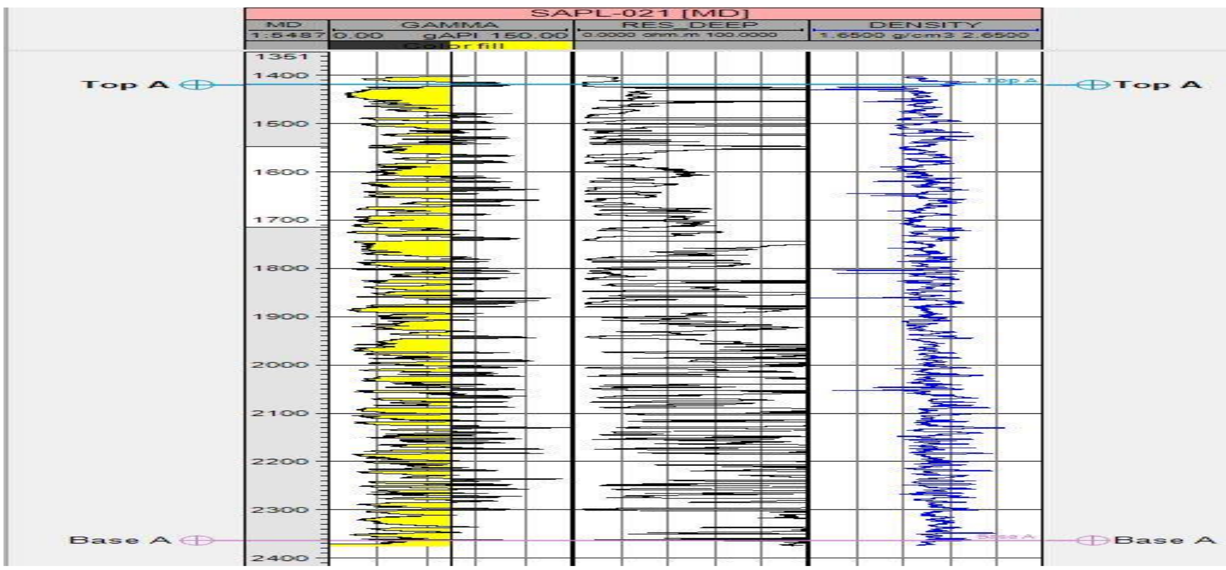

Figure 4: Well Log Signature of Well 21 (Using Petrel®2016)

Table 1 highlights the average values of petrophysical parameters of well 21. The reservoir, in general, has very good petrophysical properties with 51% hydrocarbon saturation. However, before drawing a conclusion if the reservoir is economically viable or not, there is need to determine the recoverable percentage of hydrocarbon present in the reservoir because every reservoir has what is called "Residual Hydrocarbon". To achieve this, we use the empirical relations as;

Reservoir gross thickness: 2152.3m – 1418.8m = 733.5 m (2420.55 ft)

Net-to-Gross ratio: (∑Net sand)/Gross thickness) = 656.36/733.5 = 0.8

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = 0.49 $^{0.2}$ = 0.87 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.87 – 0.49 = 0.38

From the above calculation, 0.38 (38%) of hydrocarbon present in the reservoir, will move to the surface or wellhead during production.

Table 1: Petrophysical values of Reservoir "A" of Well 21

$Start\ MD$ (m)	V_{sh}	Net Sand (m)	Φ	$Eff\Phi$	$K(mD)$	F	S_{wirr}	S_w	S_h
1418.8	0.21	111.83	0.32	0.26	3017.6	8.49	0.07	0.63	0.37
1586.2	0.22	110.39	0.31	0.25	2847.3	9.05	0.07	0.59	0.41
1744.4	0.19	134.86	0.31	0.26	2814.5	9.13	0.07	0.49	0.51
1928.8	0.27	147.22	0.29	0.22	2478.8	11.04	0.07	0.40	0.60
2152.3	0.21	152.06	0.28	0.23	2381.2	11.33	0.08	0.32	0.68
Average									
1766.1	**0.22**	**131.27**	**0.30**	**0.24**	**2707.9**	**9.8**	**0.07**	**0.49**	**0.51**

Residual Hydrocarbon Saturation (RHS)

$RHS = S_h - MHS$

RHS = 0.51 – 0.38 = 0.13

Therefore, the residual hydrocarbon saturation of the reservoir is 0.13 (13%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

HMI = $\frac{\mathrm{Sw}}{\mathrm{Sxo}}$

HMI = $\frac{0.49}{0.87}$ = 0.56

According to Schlumberger (1989) and Hamada (2006), if HMI is not greater than 0.7, then it is movable hydrocarbon. Therefore, with HMI of 0.56 (56%), the hydrocarbon presents in reservoir "A" of well 21 will move to the surface during production.

Hydrocarbon Movability Analysis of well 22 Reservoir

Hydrocarbon analysis was also done on well 22 (Figure 5). The well was delineated with well tops at a depth of 738.75 m (2437.88 ft) as reservoir top and the base at 1833.20 m (6049.56 ft). The petrophysical properties of the reservoir is good with 42% hydrocarbon saturation (Table 2).

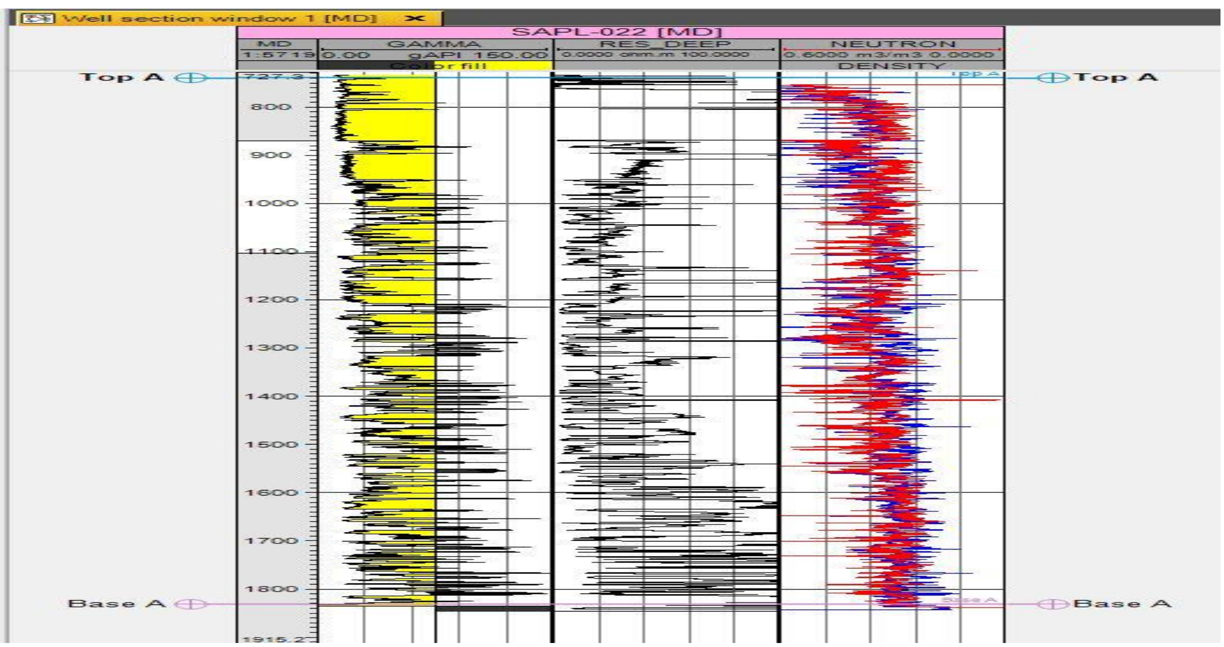

Figure 5: Well Log Signature of Well 22 (Using Petrel®2016)

Table 2: Petrophysical values of Reservoir "A" of Well 22

$Start\ MD$ (m)	V_{sh}	Net Sand (m)	Φ	$Eff\Phi$	$K(mD)$	F	S_{wirr}	S_w	S_h
738.75	0.01	237.43	0.37	0.31	3902.2	4.93	0.05	0.55	0.45
984.56	0.12	124.94	0.34	0.30	3346.1	7.55	0.06	0.66	0.34
1138.91	0.17	120.67	0.36	0.31	3746.5	7.41	0.06	0.67	0.33
1302.34	0.25	183.65	0.32	0.25	2980.1	10.77	0.07	0.65	0.35
1833.20	0.26	181.30	0.29	0.23	2535.4	10.89	0.07	0.40	0.60
Average 1199.55	**0.16**	**169.60**	**0.33**	**0.28**	**3302.0**	**8.31**	**0.06**	**0.58**	**0.42**

Reservoir gross thickness:1833.20 – 738.75 = **1094.45 m (3611.68 ft)**
Net-to-Gross ratio: (∑Net sand)/Gross thickness) = 847.99/1094.45 = **0.77**

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = $0.58^{0.2}$ = 0.90 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.90 – 0.58 = 0.32

From the above calculation, 0.32 (32%) of hydrocarbon saturation will move to the surface or wellhead during production.

Residual Hydrocarbon Saturation (RHS)

$RHS = S_h - MHS$

RHS = 0.42 – 0.32 = 0.10

Therefore, the residual hydrocarbon saturation of the reservoir is 0.10 (10%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

$HMI = \frac{\text{Sw}}{\text{Sxo}}$

$HMI = \frac{0.58}{0.90} = 0.64$

HMI less than 0.7 is movable hydrocarbon. Therefore, HMI of 0.64 indicates that the hydrocarbon presents in reservoir "A" of well 22 will move to the surface during production.

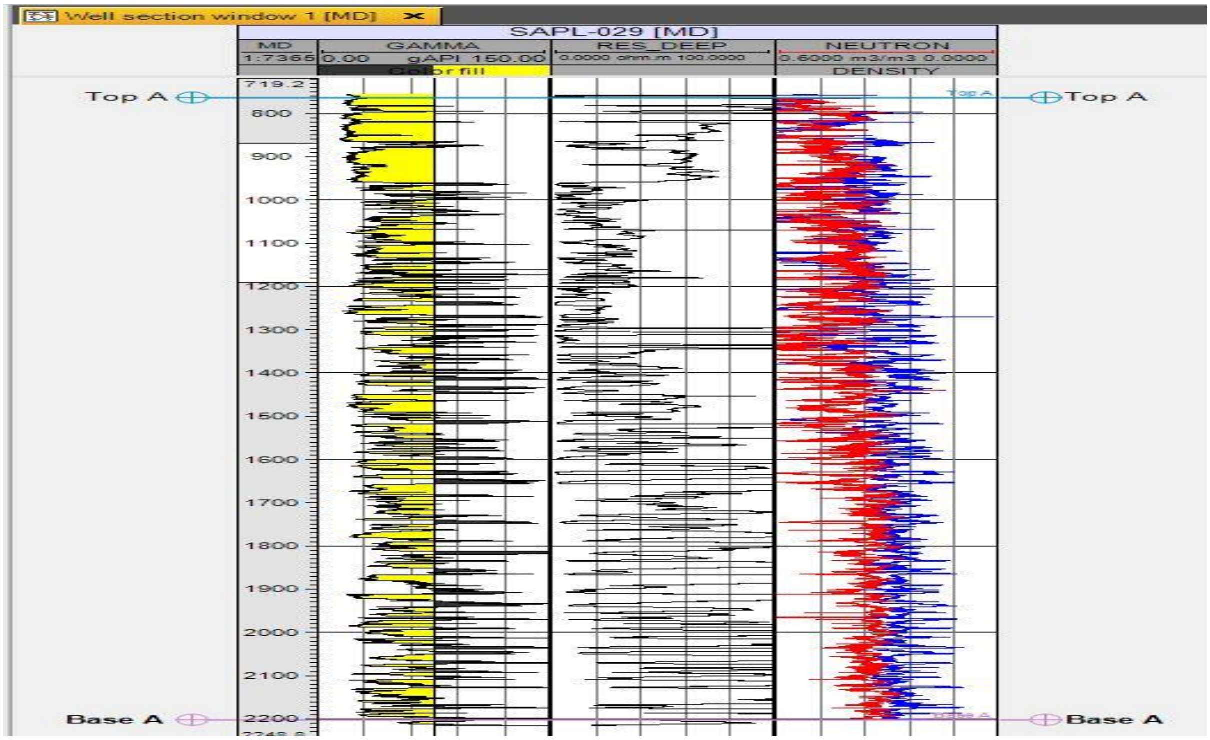

Figure 6: Well Log Signature of Well 29 (Using Petrel®2016)

Hydrocarbon Movability Analysis of well 29 Reservoir

Results obtained from reservoir "A" of well 29 shows a top depth of 763.38 m (2519.15 ft) and base of 2200.00 m (7260.00 ft) as seen in Figure 6. With water saturation of 0.53 compared to Seplat water saturation cut-off of 0.70, it therefore implies that the reservoir has a reasonable hydrocarbon saturation (0.47) but it is of paramount importance to determine if this hydrocarbon will move out of the reservoir to well head during production and the percentage of hydrocarbon present in the reservoir that will move.

Table 3: Petrophysical values of Reservoir "A" of Well 29

$\boldsymbol{Start\ MD}$ (m)	$\boldsymbol{V_{sh}}$	Net Sand (m)	$\boldsymbol{\Phi}$	$\boldsymbol{Eff\Phi}$	$\boldsymbol{K(mD)}$	$\boldsymbol{F}$	$\boldsymbol{S_{wirr}}$	$\boldsymbol{S_w}$	$\boldsymbol{S_h}$
763.38	0.11	224.93	0.44	0.40	5447.99	5.44	0.05	0.52	0.48
1034.41	0.23	159.81	0.40	0.33	4628.18	6.46	0.06	0.68	0.32
1251.15	0.42	184.96	0.33	0.22	3199.79	11.87	0.08	0.67	0.33
1545.37	0.89	185.58	0.28	0.06	2434.98	11.23	0.07	0.46	0.54
2200.00	0.44	219	0.27	0.18	2218.04	13.9	0.08	0.34	0.66
Average									
1358.86	**0.42**	**194.86**	**0.35**	**0.24**	**3585.79**	**9.78**	**0.07**	**0.53**	**0.47**

Reservoir gross thickness: 2200 m – 763.38 m = **1436.62 m (4740.85ft)**

Net-to-Gross ratio: (∑Net sand)/Gross thickness = 974.28/1436.62 = **0.68**

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = $0.53^{0.2}$ = 0.88 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.88 – 0.53 = 0.35

From the above calculation, 0.35 (35%) of hydrocarbon present in the reservoir will move to the surface or wellhead during production.

Residual Hydrocarbon Saturation (RHS)

RHS = S_h – MHS

RHS = 0.47 – 0.35 = 0.12

Therefore, the residual hydrocarbon saturation of the reservoir is 0.12 (12%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

HMI = $\frac{\mathrm{Sw}}{\mathrm{Sxo}}$

HMI = $\frac{0.53}{0.88}$ = 0.60

With HMI of 0.60, the hydrocarbon presents in reservoir "A" of well 29 will move to the surface during production because it is less than 0.7. This corroborates with Schlumberger (1989) and Hamada (2006).

Hydrocarbon Movability Analysis of well 30 Reservoir

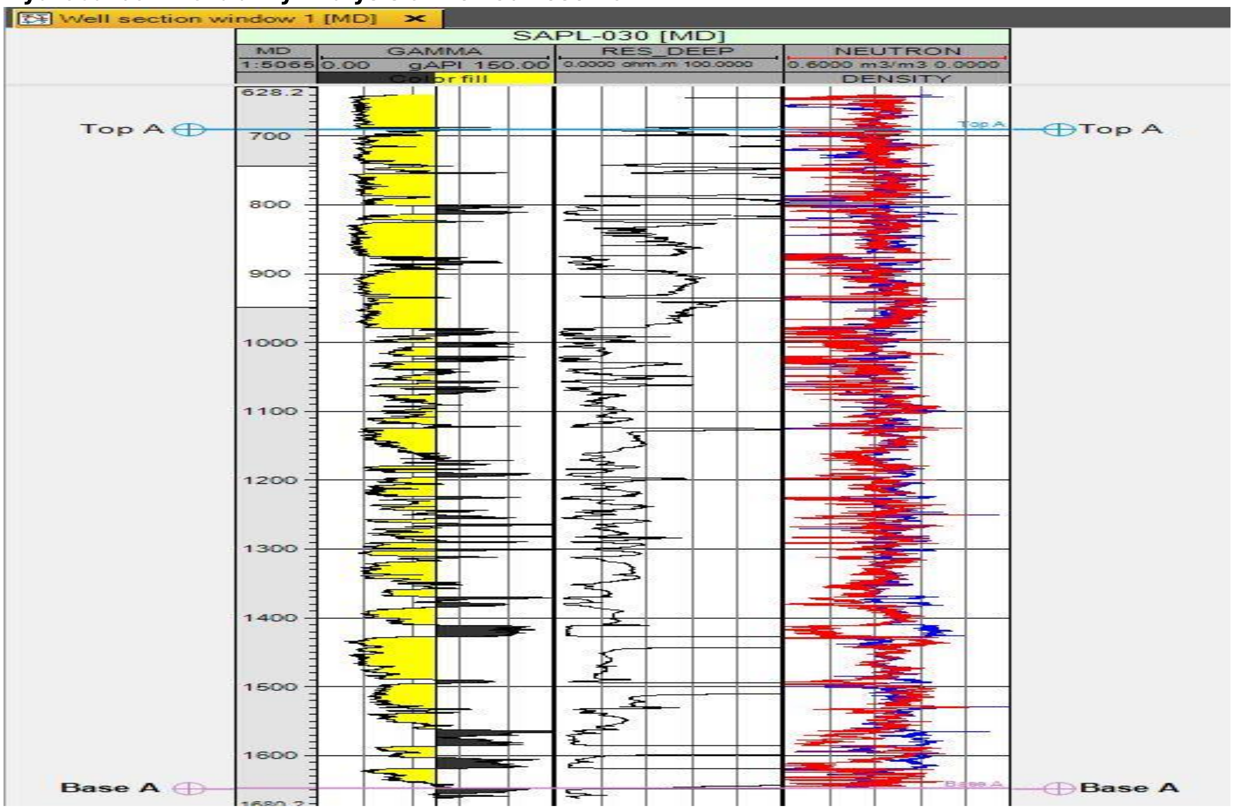

Figure 7: Well Log Signature of Well 30 (Using Petrel®2016)

Figure 7 reveals that well 30 reservoir "A" was delineated at a top depth of 690.48 m (2278.58 ft) as the top of the reservoir and base of 1648.40 m (5439.72 ft) as reveal by the well tops markers.

Table 4: Petrophysical values of Reservoir "A" of Well 30

$Start\ MD$ (m)	V_{sh}	Net Sand (m)	Φ	$Eff\Phi$	$K(mD)$	F	S_{wirr}	S_w	S_h
690.48	0.11	162.5	0.39	0.36	4368.71	6.58	0.06	0.38	0.62
876.16	0.17	105.03	0.38	0.32	4079.17	6.7	0.06	0.54	0.46
1011.51	0.23	112.92	0.37	0.29	3934.48	6.77	0.06	0.62	0.38
1187.06	0.49	126.93	0.33	0.19	3174.11	8.95	0.07	0.61	0.39
1648.4	0.39	175.87	0.32	0.22	3052.81	11.64	0.08	0.53	0.47
Average 1082.72	**0.28**	**136.65**	**0.36**	**0.27**	**3721.86**	**8.13**	**0.06**	**0.54**	**0.46**

Reservoir gross thickness: 1648.4 m – 690.48m = **957.92 m (3161.14 ft)**
Net-to-Gross ratio: (∑Net sand)/Gross thickness = 683.25/957.92 = **0.71**

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = 0.54$^{0.2}$ = 0.88 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.88 – 0.54 = 0.34

From the above calculation, 0.34 (34%) of hydrocarbon saturation will move to the surface or wellhead during production.

Residual Hydrocarbon Saturation (RHS)

RHS = S_h – MHSRHS = 0.46 – 0.34 = 0.12

Therefore, the residual hydrocarbon saturation of the reservoir is 0.12 (12%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

HMI = $\frac{\text{Sw}}{\text{Sxo}}$

HMI = $\frac{0.54}{0.88}$ = 0.61

HMI of 0.61 which is less than 0.7, signifies movable hydrocarbon in reservoir "A" of well 30.

Hydrocarbon Movability Analysis of well 31 Reservoir

From Figure 8, reservoir "A" of well 31 was delineated at a top depth of 997.35 m (3291.26 ft) as the top of the reservoir and base of 1974 m (6514.20 ft) as reveal by the well tops markers.

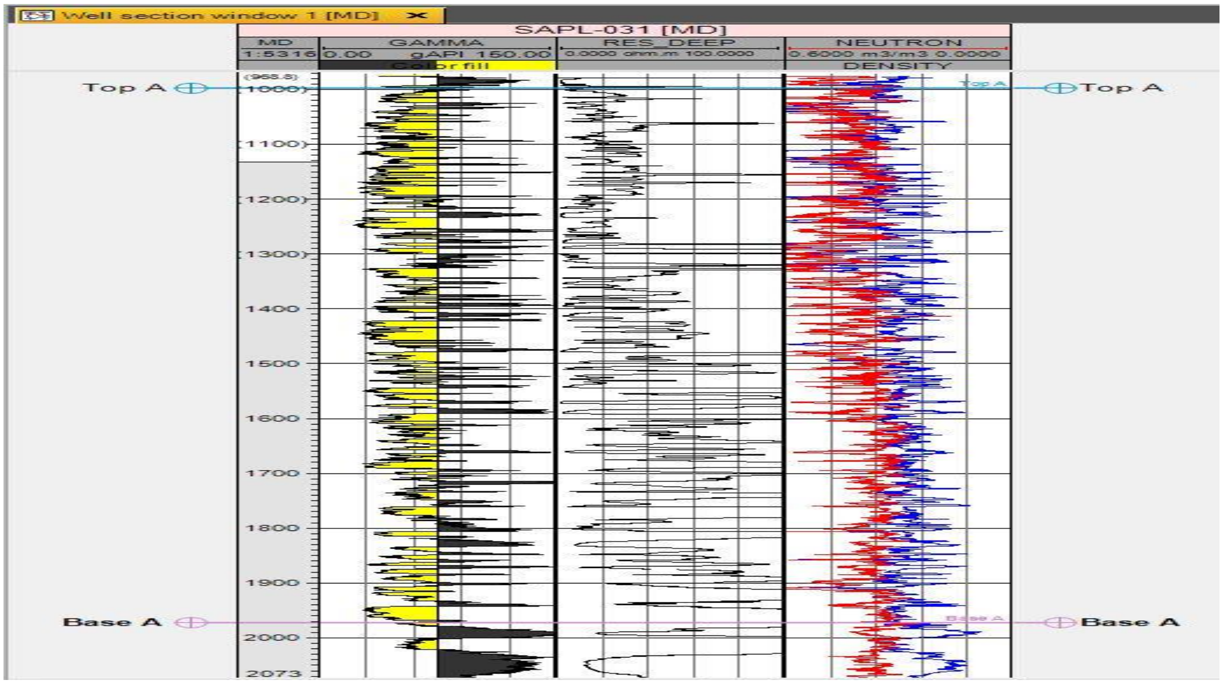

Figure 8: Well Log Signature of Well 31 (Using Petrel®2016)

Table 5: Petrophysical values of Reservoir "A" of Well 31

$Start\ MD$ (m)	V_{sh}	Net Sand (m)	Φ	$Eff\Phi$	$K(mD)$	F	S_{wirr}	S_w	S_h
997.35	0.26	167.73	0.4	0.3	4494.27	6.53	0.06	0.66	0.34
1234.68	0.49	115.59	0.34	0.21	3377.88	10.72	0.07	0.71	0.29
1440.04	0.39	122.57	0.31	0.2	2794.83	10.15	0.07	0.55	0.45
1625.7	0.56	104.01	0.27	0.13	2271.27	12.55	0.08	0.43	0.57
1974	0.65	103.05	0.29	0.17	2499.84	13	0.08	0.3	0.7
Average									
1454.35	**0.47**	**122.59**	**0.32**	**0.2**	**3087.62**	**10.59**	**0.07**	**0.53**	**0.47**

Reservoir gross thickness: 1974 m – 997.35 m = **976.65 m (3222.95 ft)**

Net-to-Gross ratio: (∑Net sand)/Gross thickness = 612.95/976.65 = **0.63**

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = $0.53^{0.2}$ = 0.88 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.88 – 0.53 = 0.35

From the above calculation, 0.35 (35%) of hydrocarbon saturation will move to the surface production.

Residual Hydrocarbon Saturation (RHS)

RHS = S_h – MHS

RHS = 0.47 – 0.35 = 0.12

Therefore, the residual hydrocarbon saturation of the reservoir is 0.12 (12%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

HMI = $\frac{\text{Sw}}{\text{Sxo}}$

HMI = $\frac{0.53}{0.88}$ = 0.60

HMI less than 0.7 is movable hydrocarbon. Therefore, HMI of 0.60 specifies movable hydrocarbon in reservoir "A" of well 31.

Hydrocarbon Movability Analysis of well 32 Reservoir

The result of analysis carried out on well 32 as indicated in Figure 9, shows a top depth of 672.16 m (2218.13 ft) as the top of the reservoir and base of 2480.23 m (8184.56 ft) as reveal by the well tops markers. The reservoir was delineated by defining the lithology at depth with the help of the gamma ray log which segregate the shale and sand bodies, with a matching high resistivity signature that displays the presence of hydrocarbon sand body in the reservoirs. The reservoir is a sole phase (oil) reservoir with no noticeable balloon shape neutron-density parting.

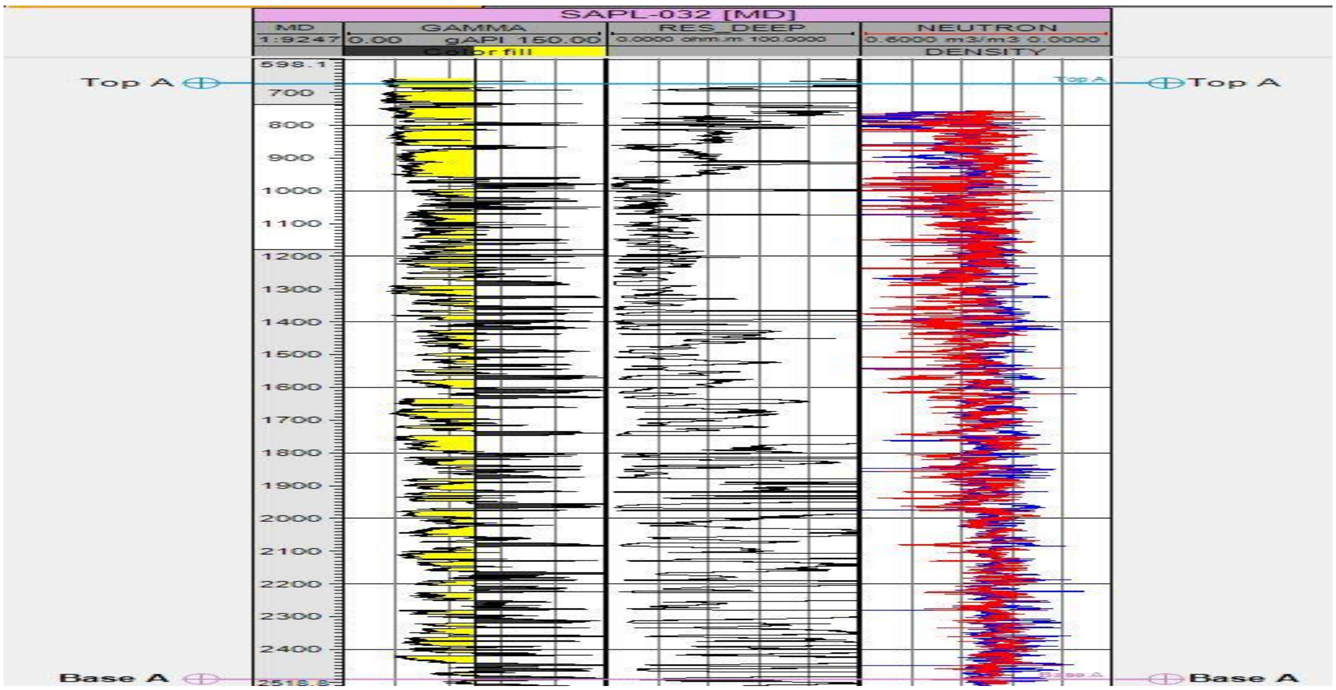

Figure 9: Well Log Signature of Well 32 (Using Petrel®2016)

Table 6: Petrophysical values of Reservoir "A" of Well 32

$Start\ MD$ (m)	V_{sh}	Net Sand (m)	Φ	$Eff\Phi$	$K(mD)$	F	S_{wirr}	S_w	S_h
672.16	0.15	261.29	0.41	0.35	4701.47	5.87	0.05	0.46	0.54
980.78	0.89	238.96	0.34	0.1	3396.52	7.94	0.06	0.72	0.28
1376.15	0.48	190.65	0.31	0.18	2883.45	9.56	0.07	0.57	0.43
1704.01	0.41	249.08	0.3	0.2	2711.06	10.07	0.07	0.44	0.56
2480.23	0.65	184.96	0.28	0.12	2348.5	12.77	0.08	0.36	0.64
Average									
1442.67	**0.51**	**224.99**	**0.33**	**0.19**	**3208.2**	**9.24**	**0.07**	**0.51**	**0.49**

Reservoir thickness:2480.23 m – 672.16 m =**1808.07 m (5966.63 ft)**

Net-to-Gross ratio:(∑Net sand)/Gross thickness) =1124.94 /1808.07 =**0.62**

Water Saturation of Flushed Zone (S_{xo})

$S_{xo} = S_w^{0.2}$

S_{xo} = $0.51^{0.2}$ = 0.87 (Water saturation of flushed zone)

Movable Hydrocarbon Saturation (MHS)

$MHS = S_{xo} - S_w$

MHS = 0.87 – 0.51 = 0.36

From the estimation of MHS, 0.36 (36%) of oil saturating the reservoir will move to wellhead during production.

Residual Hydrocarbon Saturation (RHS)

RHS = S_h – MHS

RHS = 0.49 – 0.36 = 0.13

Therefore, the residual hydrocarbon saturation of the reservoir is 0.13 (13%) of the entire hydrocarbon saturation.

Hydrocarbon Movability Index (HMI)

HMI = $\frac{Sw}{Sxo}$

HMI = $\frac{0.51}{0.87}$ = 0.59

HMI of 0.59 indicates movable hydrocarbon in reservoir "A" of well 32 because it is less than 0.7.

Table 7: Cumulative Average Hydrocarbon Movability of Sapele Shallow

Wells	S_{xo}	S_h	***MHS***	***RSH***	***MHI***
Well 21	0.87	0.51	0.38	0.13	0.56
Well 22	0.90	0.42	0.32	0.10	0.64
Well 29	0.88	0.47	0.35	0.12	0.60
Well 30	0.88	0.46	0.34	0.12	0.61
Well 31	0.88	0.47	0.35	0.12	0.60
Well 32	0.87	0.49	0.36	0.13	0.59
Average	**0.88**	**0.47**	**0.35**	**0.12**	**0.6**

Table 7 is a summary of the various Hydrocarbon Movability parameters of Sapele Shallow Field, Niger Delta, Southern Nigeria. As shown in the Table, Sapele shallow has an average flushed zone water saturation (S_{xo}) of 0.88, an average hydrocarbon saturation of 0.47, an average movable hydrocarbon saturation of 0.35, residual hydrocarbon saturation of 0.12, an average movable hydrocarbon index of 0.6. and a low recovery factor of 42% (0.42) which is due to the lack of gas and appreciable water drive. The above analysis implies that out of 0.47 (47%) hydrocarbon saturation (S_h), 0.35 (35%) will move to the surface (wellhead) during production and the remaining 0.12 (12%) are unmovable hydrocarbon.

CONCLUSION

One hydrocarbon sand body was delineated and correlated across the study area. The sand body was encountered at depth range of 672.16 m (2218.13 ft) – 2480.23 m (8184.76 ft). Petrophysical analysis reveals that the study area has very good to excellent petrophysical properties with high value of average gross thickness, moderately high average net sand thickness, low average porosity, very high average permeability, low average shale volume, high average net-to-gross value and high average water saturation index. The petrophysical properties infers that the delineated sand bodies possess good hydrocarbon storage and transmission ability, which are the two main qualities to look out for in a reservoir and from log evaluations.

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