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Petrophysical Evaluation of H-field, Onshore Niger Delta Sedimentary Basin, Nigeria

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Authors' contributions

This work was carried out in collaboration between both authors. Author EHE designed the study, performed the statistical analysis, wrote the protocol and wrote the first draft of the manuscript as part of her BSc research. Author AOB supervised the research and assisted in the development of this manuscript. Both authors read and approved the final manuscript.

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ABSTRACT

Petrophysical evaluations for three reservoirs, H_3, H_5 and H_7 in four wells, H-002, H-007, H-009 and H-011 were carried out to evaluate the distribution of hydrocarbon in the reservoir rocks found within H-field onshore Niger Delta. A suite of well logs such as gamma ray (GR), resistivity (LLD), caliper (CALI), compressional sonic (DT) and density (RHOB) logs were analyzed over H-field and shale volume, total porosity, effective porosity, water saturation and permeability were the petrophysical parameters estimated. Three reservoir sand were identified and correlated from four wells (H-002, H-007, H-009, H-011) using gamma ray and the average thickness for the three reservoirs H_3, H_5 and H_7 estimated were 106.50 ft, 23 ft and 174.25 ft respectively. The average values of volume of shale, effective porosity, total porosity, permeability, water saturation and hydrocarbon saturation of the delineated reservoir sands are 16.04 ft, 3.14 ft and 24.18 ft for shale volume, 18.5%, 18%, 18% for effective porosity, 20.25%, 20.25%, and 20% for total porosity, 1582.3515 mD, 1278.8912 mD and 1570.058 mD for permeability, 44%, 42.75% and 44% for water saturation and 56%, 57.25% and 56% for hydrocarbon saturation for reservoirs H_3, H_5 and H_7 respectively. Due to the low value of shale volume, water saturation and the good porosity and permeability nature of the reservoir which depicts the distribution of hydrocarbon in the wells within the field. Core data Acquisition, volumetric analysis and Interpretation within the reservoirs should be carried out to reduce uncertainties in exploration and production risk.

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Keywords: Petrophysical evaluations; shale volume; porosity; water saturation; permeability.

1. INTRODUCTION

The increasing human population has demanded the increases in energy consumption, to boost the production of hydrocarbon, a proper identification, delineation, evaluation and estimation of the hydrocarbon reservoirs are highly necessary [1]. And this is based on the individual interpretation of various reservoir properties from the data acquired [2].

Reservoir rock is a rock structures that have the ability to retain hydrocarbon from migrating laterally or vertically [3] and contains a significant amount of exploitable hydrocarbon due to its porosity and permeability [2]. Reservoir characterization using petrophysical evaluation is undertaken to determine its capability to both store and transmit fluid. Therefore, characterization deals with the determination, interpretation, and estimation of reservoir properties such as porosity (Φ), permeability (K), fluid saturation, and Net Pay thickness [4]

[5] evaluated the petrophysical properties of coast swamp depobelt in Niger delta region from two well log data and the result showed hydrocarbon accumulation to be high in sand formation with high values of total and effective porosity, fair in sand-shale formation with fair values of total and effective porosity and low in shale formation with low values of total and effective porosity. The average values of the petrophysical parameters such as volume of shale, total and effective porosity water saturation and permeability ranged from 0.004 – 0.299 dec, 0.178 – 0.207 dec and 0.154 – 0.194 dec 0.277 – 0.447 dec and 36.637 - 7808.519 mD respectively and the thickness of the reservoir ranged from 66 – 248.5ft. However, there is uncertainty in the hydrocarbon formation evaluation and production caused by reduction in water saturation and effective porosity due to existence of shale in the formation [5].

According to [6], hydrocarbon reservoirs were characterized by using well logs to evaluate prospectivity of the field, hydrocarbon and water bearing zones delineation and petrophysical properties analysis of the hydrocarbon reservoirs of interest. The result from this study showed that there is an increase in porosity with an increase in permeability in nine zones of interest (sand bodies) out of the twenty-two zones of interest (sand bodies) delineated and correlated. The evaluated petrophysical parameter indicated that porosity ranges between (18-31%), water saturation (14-44%), hydrocarbon saturation (56-86%), permeability (138-10662 mD) and petrophysical parameter estimation revealed that the reservoir quality is strongly influenced by the presence of sand bodies as a result of the presence of high values of porosity and permeability to [6].

1.1 Location of the Study Area

The study area is located within the onshore area of Niger delta in Nigeria (Fig. 1) which is located within the Onshore Niger Delta region of Nigeria. The Niger Delta Basin is situated at the southern end of Nigeria boarding the Atlantic Ocean and extends from about Longitudes 6°16"25'E and 6°20"8'E and Latitude 4°35"37'N and 4°39"6'N. The field is located within the Central Swamp Depobelt, Onshore Niger Delta [2,7].

1.2 Geology of the Niger Delta

Niger Delta is found in the Gulf of Guinea (Fig. 2) [9] and increases down the Niger Delta Province and varies from the Eocene age to this Present time [9-10]. The delta has prograded southwestward, creating depobelts that constitute the most vital part of the delta at every development stage [9,11].

According to [12], the Tertiary Niger Delta extends over an area of approximately 75,000 sq km and consists of a regressive clastic sequence, which attains a topmost thickness of 12,000 m. The Niger Delta is regarded one of the most prolific oil and gas provinces in the world [13]. The lithostratigraphy of the Tertiary Niger Delta (Fig. 3) can be separated into three distinct formations that are renowned mostly on the premise of their sand-shale ratio [9]: Benin, Agbada and Akata, formations, with depositional environments ranging from marine, transitional and continental settings respectively [9,11,14]. The Benin, Agbada and Akata formations lie over stretched continental and oceanic crusts [15]. Their ages range from Eocene to Recent, yet transgress time boundaries [16]. These prograding depositional facies can be recognized mainly by their sand-shale ratios.

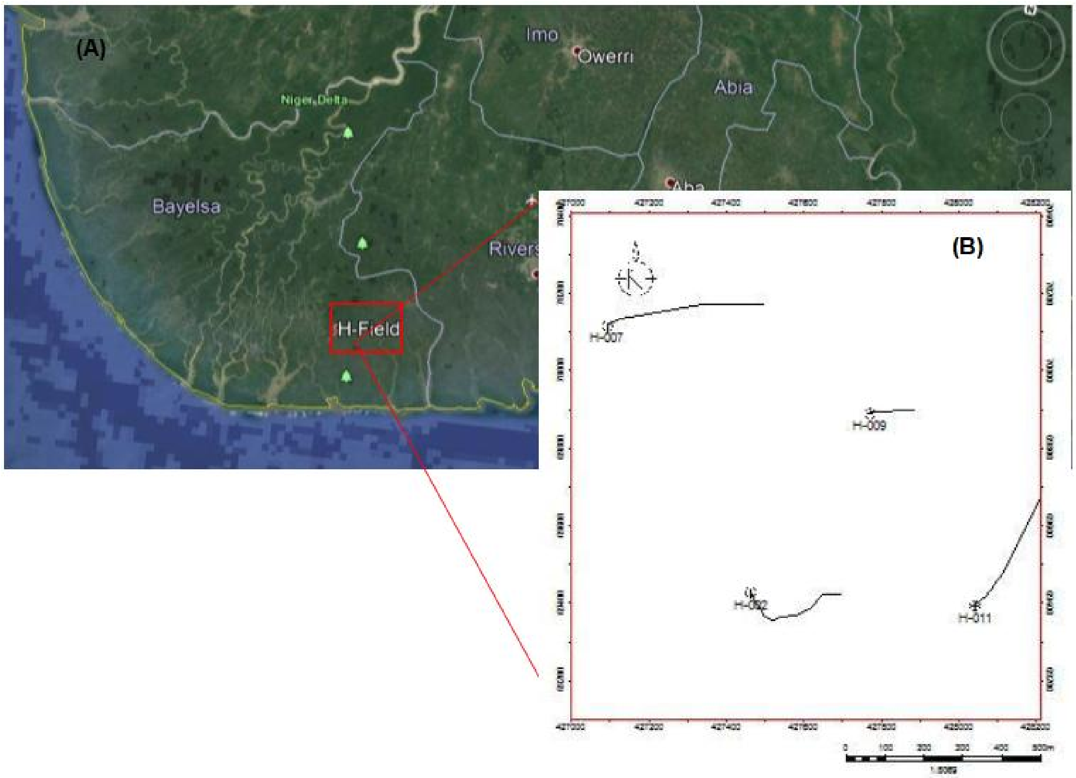

Fig. 1. (A) Location of the study area [8] and (B) base map for "H" Field showing the distribution of wells within the area

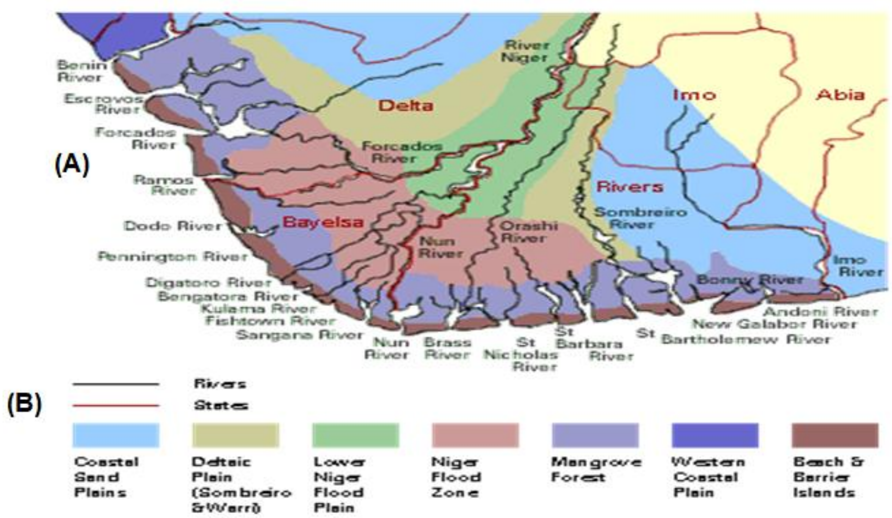

Fig. 2. (A) Niger delta stratigraphic sequence and (B) present shoreline of the Niger Delta showing major rivers and waterways [17]

1.3 The Benin Formation

This is the uppermost and continental deposits of the Delta Onshore and in some coastal regions, the Benin Formation lie on top of the Agbada Formation and it consist upper coastal plain deposits of Late Eocene to Recent deposits of alluvial that are up to 2 km (6600 ft) thick, which

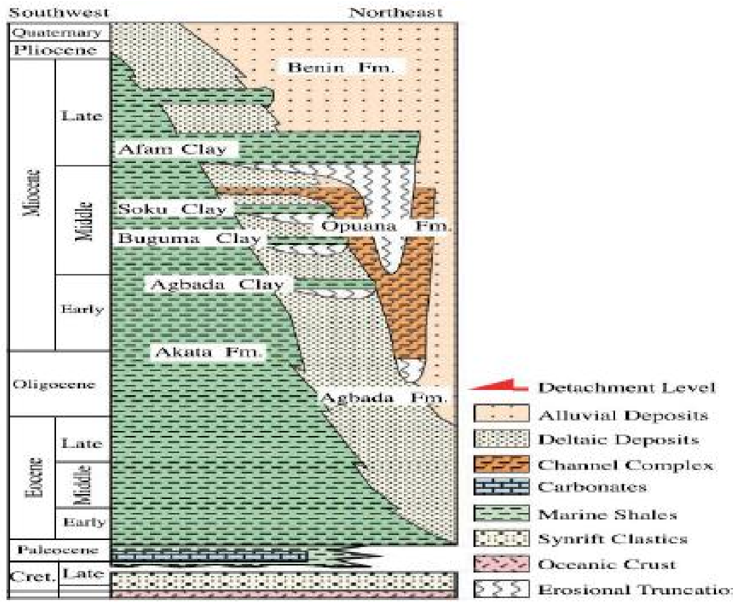

Fig. 3. Regional stratigraphy of the Niger Delta [13,22]

outcrops in Benin, Onitsha and Owerri Provinces, and elsewhere in the delta area [16]. Sand was deposited as point bars while finer grains and shale were deposited in back swamps and oxbows The formation is generally water bearing zone, hence is the main source of potable groundwater in the Niger Delta, though very little oil has been found in the Benin Formation (mainly minor oil shows) [18-19].

1.4 The Agbada Formation

This is the main oil and gas bearing formation in the Niger Delta [20]. It overlies the Akata Formation and consists of alternations of sand and shale layers [16]. The Agbada Formation is characterized by paralic to marine-coastal and fluvial-marine deposits majorly consisted of shale and sandstone arranged into coarsening upward off-lap cycles [9,16,21]. According to [13], the Agbada Formation consists of paralic siliciclastics that are more than 3500 m (11,500 ft) thick and they represent the real deltaic part of the succession that accumulated in delta front, delta-top set and fluvio-deltaic environments [16].

1.5 The Akata Formation

The Akata Formation is the basal sedimentary unit of the delta. According to [16], the composition is of uniform dark grey over-pressured marine shales with sandy turbidites and channel fills. Its age scales from Late Eocene to Recent [16]. [17] said that the Akata Formation may be about 6.5km (21,400 ft) thick, while from 2000 m (6600 ft) at the most distal portion of the delta to 7000 m (23,000 ft) beneath the continental shelf range was suggested [11,13] also added that the thickness is about 5000m (16,400 ft) for the deep fold and thrust belts in the offshore Niger Delta [16]. The Akata Formation has generally been regarded as the main source rock for oil in the delta.

2. MATERIALS AND METHODS

The materials used for the study are wireline logs (gamma ray (GR), resistivity (LLD), caliper (CALI), compressional sonic (DT), and density (RHOB) logs) along with well headers and deviation logs for four wells (H-002, H-007, H-009, H-011). Schlumberger Petrel (2014.1 edition) was used for the interpretation.

To discriminate between sand and shales, the gamma ray log was used. Shales are more radioactive than sand due to the presence of certain clay minerals within them that are highly radioactive. The scale of the gamma ray log is set at 0-150 API, with zero at the left and 150 at the right side of the gamma ray tract. The mid-point (75 API) is considered the sand/shale cutoff. Deflections of the gamma ray curve to the left of the established cut-off are sand while deflections to the right of the curve are termed shales. This process aided in differentiating reservoir sands from shales.

Table 1. Petrophysical parameters and their empirical formulas

Petrophysical parameters	Empirical formulas	
Volume of Shale (Vsh)	$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$ I_{GR} = *Gamma ray index describes a linear response to shale content* GR_{log} = *Log reading at the depth of interest* GR_{min} = *Gamma Ray value in a nearby clean sand zone* GR_{max} = *Gamma Ray value in a nearby shale* [24]	.$\mathbf{V_{SH} = 0.083 * \left(2^{(3.7 * I_{GR})} - 1\right)}$ V_{SH} = *Volume of shale* I_{GR} = *Gamma ray index*[25]
Porosity Estimation	$\emptyset_T = \frac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}}$ $\emptyset_T$ = *Total porosity* ρ_{ma} = *Matrix density* = 2.65 ρ_{bulk} = *Bulk density reading read from density log* ρ_{fl} = *Fluid density* (0.74 *forgas*, 0.9 *for oil and* 1.0 *for water*)	$\emptyset e = (1 - V_{SH}) \times \emptyset_T$ $\emptyset_e$ = *Effective porosity* $\emptyset_T$ = *Total porosity* V_{SH} = *Shale volume*[26].
Permeability Estimation	$K(mD) = 307 + 26552(\emptyset_e^2) - 34540\ (\emptyset_e \times S_w)^2$ $K(mD)$ = *Permeability in milliDarcy* $\emptyset_e$ = *effective porosity* S_w = *water saturation* [27]	
Water Saturation	$S_w = \sqrt{\frac{R_o}{R_t}}$ S_w = *Water saturation* R_o = *Resistivity of the oil leg*	
Hydrocarbon saturation	$S_H = 1 - S_w$ S_H = *Hydrocarbon saturation*, S_w = *Water saturation* [29].	
Net-To-Gross	$\text{Net} - \text{to} - \text{gross} = \frac{NT}{GT} \times 100$ *NT* = *Net thickness*, *GT* = *Gross thickness*	

3. RESULTS AND DISCUSSION

Gamma ray logs revealed two lithologies from top to bottom in four well (H-002, H-007, H-009, H-011). The lithologies included sand and shale. A total of three reservoirs units (H_3, H_5 and H_7) were identified and correlated across to other wells (Fig. 4). The reservoirs are intercalated by layers of shales which serve as both seals and source rocks. All three reservoirs had some shaliness at various sections, indicating that the reservoir sands identified are shaly.

3.1 Gross Thickness

The gross thickness of a reservoir is the entire thickness from the top of the reservoir to the base of the reservoir (Fig. 4). The thickness of the reservoirs varies from one well to the other across the field. The thickness of reservoir H_3 is 78 ft in well H-002, 95 ft in H-007, 130 ft in H-009 and 123 ft in well H-011 (Table 2). Reservoir H_5 has a thickness of 27 ft in well H-002, 26 ft in H-007, 25 ft in H-009 and 14 ft in well H-011. Similarly, reservoir H_7 had varying thicknesses across all four wells. The thickness of reservoir H_7 is 177 ft in well H-002, 188 ft in H-007, 143 ft in well H-009 and 189 ft in well H-011. On average, gross thickness of reservoir H_3 is 106.50ft, 23ft for reservoir H_5 and 174.25 ft for reservoir H_7 respectively (Table 3). The average gross thickness of the reservoirs shows that reservoir H_7 has the highest thickness while reservoir H_5 has the lowest thickness. These results show that the reservoir sands are of sufficient thickness to accumulate hydrocarbons in economic quantities.

3.2 Shale Volume (Vsh)

Shale volume is the percentage of shale contained within the reservoir (Fig. 9). The higher the shale content the poorer the reservoir quality to yield hydrocarbons. This is because shales act as barrier to the flow of hydrocarbons. In reservoir H_3, shale volume is 0.09 in H-002, 0.15 in H-007, 0.15 in H-009 and 0.19 in H-011 well (Table 2).

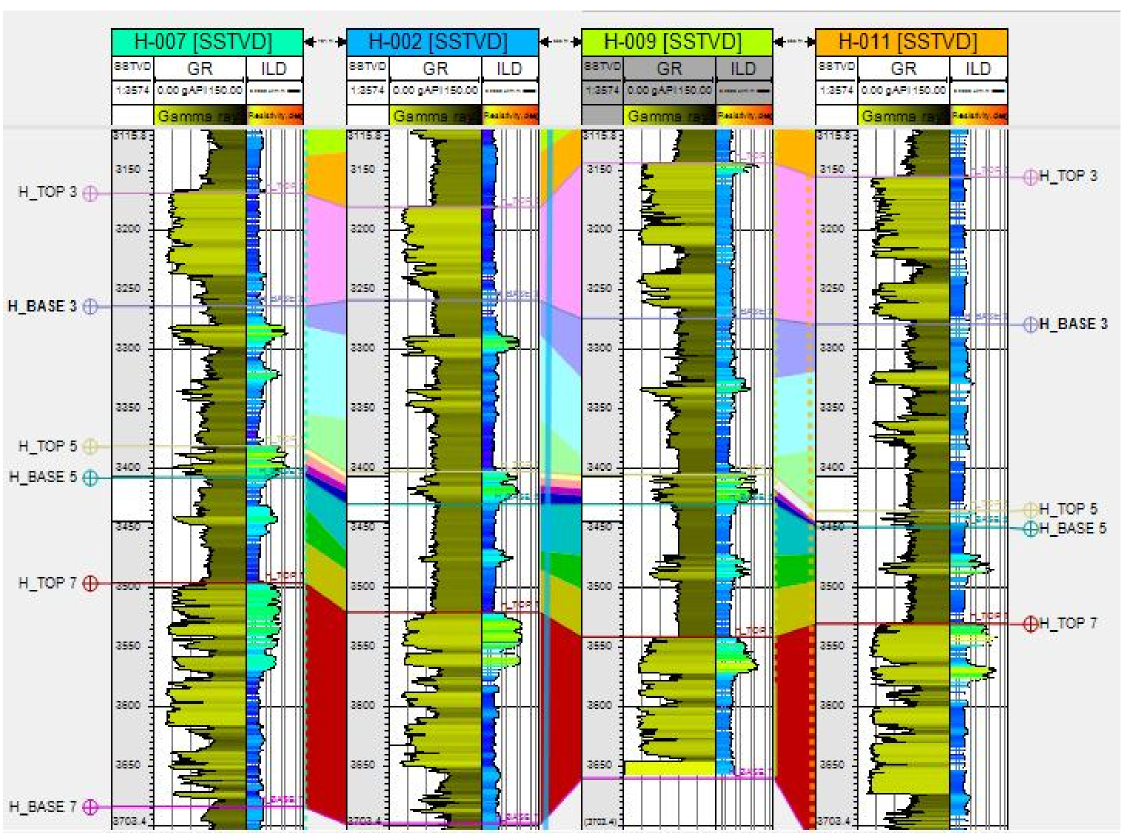

Fig. 4. Well log correlation panel of H-field

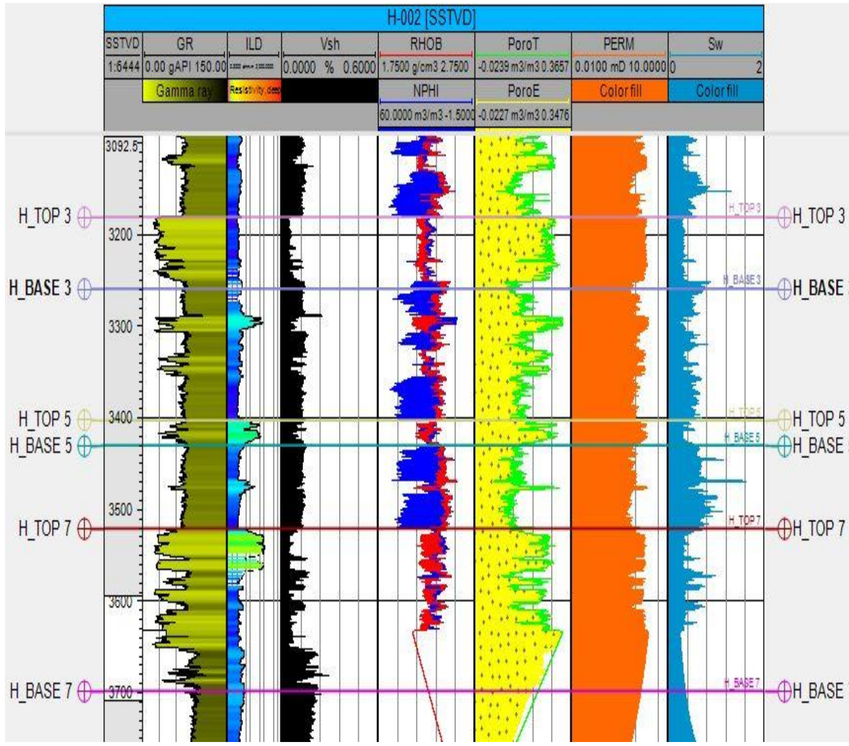

Fig. 5. Petrophysical parameters correlated for Well H-002

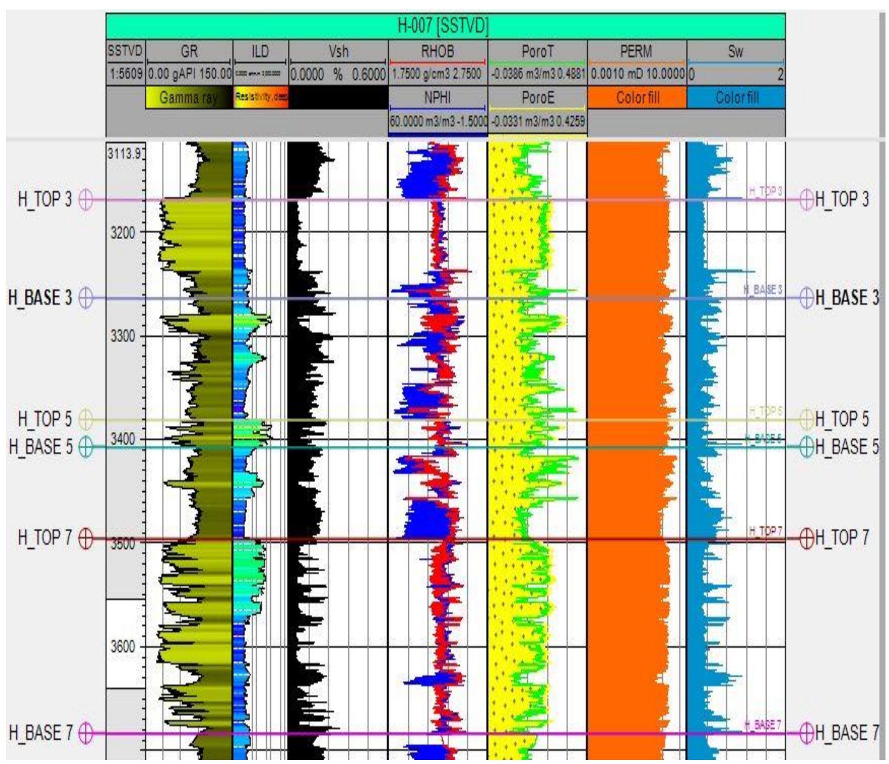

Fig. 6. Petrophysical parameters correlated for Well H-007

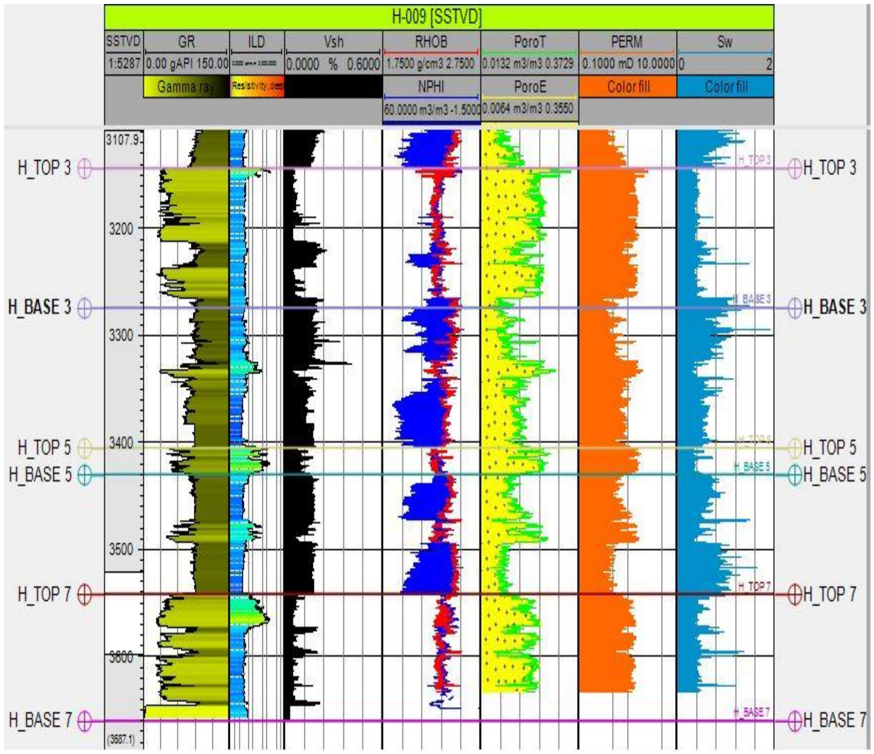

Fig. 7. Petrophysical parameters correlated for Well H-009

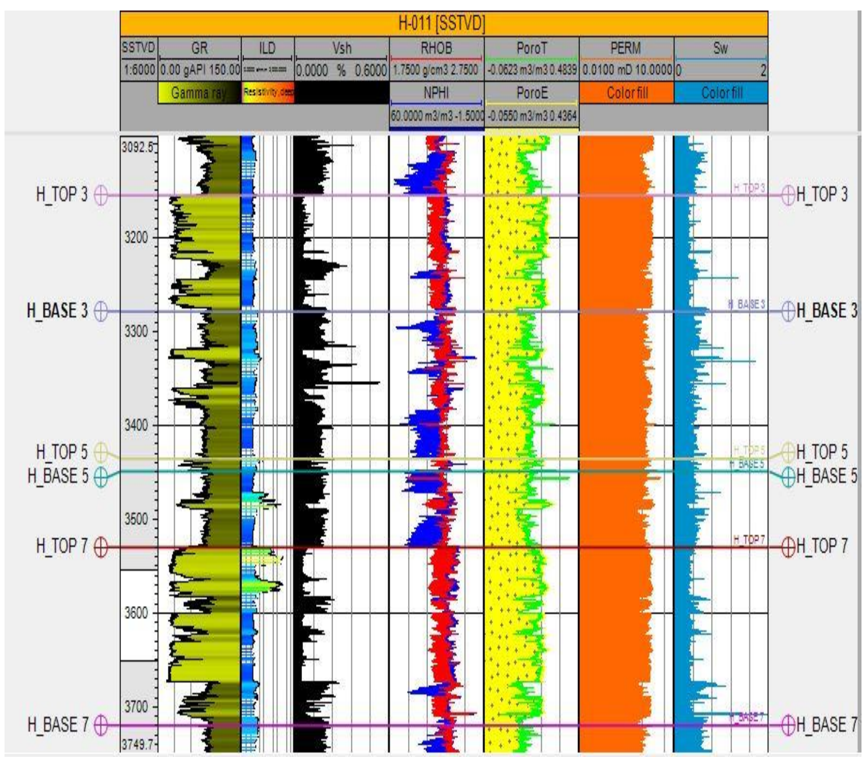

Fig. 8. Petrophysical parameters correlated for Well H-011

Table 2. Results of petro physical evaluation of three reservoir units for four wells in the H-field

Wells	sand	Top (ft)	Base (ft)	Gross thickness (ft)	Shale vol(%)	Shale vol (ft)	Net sand (ft)	Net to Gross (%)	Total Por(%)	EffPor (%)	S_W(%)	Permeability (mD)	S_H(%)	Fluid type
H-002	H_3	3181	3259	78	9%	7.02	70.98	91.00%	23%	21%	54%	1723.462	46%	O&W
	H_5	3402	3429	27	12%	3.24	23.76	88.00%	17%	15%	47%	966.5316	53%	O&W
	H_7	3521	3698	177	13%	23.01	153.99	75.04%	20%	19%	49%	1636.679	51%	O&W
H-007	H_3	3169	3264	95	15%	14.25	80.75	85.00%	19%	17%	42%	1386.71	58%	O&W
	H_5	3381	3407	26	14%	3.7	22.3	85.77%	25%	21%	35%	1821.851	65%	Oil
	H_7	3496	3684	188	14%	26.32	161.68	86.00%	26%	22%	31%	2213.988	69%	Oil
H-009	H_3	3144	3274	130	15%	19.5	110.5	85.00%	20%	19%	38%	1749.591	62%	O&W
	H_5	3405	3430	25	13%	3.25	21.75	87.00%	19%	17%	41%	1254.445	59%	O&W
	H_7	3541	3684	143	12%	17.16	125.84	88.00%	15%	14%	42%	995.244	58%	O&W
H-011	H_3	3155	3278	123	19%	23.37	99.63	81.00%	19%	17%	42%	1469.643	58%	O&W
	H_5	3435	3449	14	17%	2.38	11.62	83.00%	20%	19%	48%	1072.737	52%	O&W
	H_7	3530	3719	189	16%	30.24	158.76	84.00%	19%	17%	54%	1434.321	46%	O&W

Table 3. The average values of petro physical evaluation of three reservoir units for four wells in the H-field

Sand	Gross thickness (ft)	Shale vol (ft)	Net sand (ft)	Net to gross (%)	Total Por(%)	EffPor (%)	S_W(%)	Permeability (mD)	S_H(%)
H_3	106.50	16.04	90.47	85.50%	20.25%	18.50%	44%	1582.3515	56%
H_5	23	3.14	19.86	85.94%	20.25%	18%	42.75%	1278.8912	57.25%
H_7	174.25	24.18	150.07	83.26%	20%	18%	44%	1570.058	56%

This accounts for a thickness of 7.02 ft of the entire gross thickness in H-002 well, 14.25 ft in H-007 well, 19.5 ft in H-007 well and 23.37 ft in H-011 well. In reservoir H_5, shale volume is 0.12, 0.14, 0.13 and 0.17 in H-002, H-007, H-009 and H-011 well respectively. Quantifying the shale volume in terms of thickness shows that 3.24 ft, 3.7 ft, 3.25 ft and 2.38 ft are the thicknesses of shales in reservoir H_5 in H-002, H-007, H-009 and H-011 well respectively (Table 2). Meanwhile shale volume in reservoir H_7 is 0.13 in H-002 well, 0.14 in H-007 well, 0.12 in H-009 well and 0.16 in H-011 well, which translates to a thickness of 23.01 ft, 26.32 ft, 17.16ft and 30.24 ft in H-002, H-007, H-009 and H-011 respectively. On average, shale volume thickness is 16.04ft in reservoir H_3, 3.14 ft in reservoir H_5 and 24.18ft in reservoir H_7 (Table 3). This suggests that about 16.04 ft of the average gross thickness in reservoir H_3 is occupied by shale, 3.14ft of the average gross thickness of reservoir H_5 is occupied by shale and 24.18ft of the average gross thickness of reservoir H_7 is shaly. The frequency distribution of the average gross thickness, shale volume thickness and net sand thickness of thevarious sands encountered by the three wells in the study area are described in Fig. 10.

3.3 Net thickness

The reservoir net thickness is the proportion of the reservoir (clean sand) that can be produced. The net reservoir thickness is obtained after the shale volume is removed from the overall gross volume of the reservoir. The net sand thickness of reservoir H_3 is 70.98 ft in H-002 well, 80.75 ft in H-007, 110.5 ft in H-009 and 99.63ft in H-011 well (Table 2). In reservoir H_5, net sand thickness is 23.76 ft in H-002 well, 22.3 ft in H-007, 21.75 ft in H-009 and 11.62 ft in H-011 well respectively. Similarly, reservoir H_7 has a net sand thickness of 153.77 ft, 161.68 ft, 125.84 ft and 158.76 ft in H-002, H-007, H-007 and H-011 wells respectively. The average net sand (clean sand) thickness for reservoir H_3 is 90.47 ft, 19.86ft for reservoir H_5 and 150.07 ft for reservoir H_7 (Table 3).

3.4 Net to Gross

The net to gross is the ratio of the thickness of the clean sand (net sand thickness) divided by the total gross thickness of the reservoir. The net to gross gives an indication of the total amount of the reservoir section that can be produced. The larger the net to gross value (in percentage), the better the quality of the reservoir. For Reservoir H_3, net to gross ratio is 91.00% in H-002, 85.00% in H-007, 85.00% in H-009 and 81.00% in H-011 well (Table 2). For reservoir H_5, the value of net to gross is 88.00%, 85.77%, 87.00% and 83.00% in H-002, H-007, H-009 and H-011 wells respectively. Similarly, for reservoir H_7, the net to gross has a value of 75.04% in H-002, 86.00% in H-007, 88.00% in H-009 and 84% in H-011 well. The average net to gross ratio for reservoir H_3, H_5 and H_7 are 85.5%, 85.94% and 83.26% respectively (Table 3).

3.5 Porosity

Total porosity is the sum total of both the interconnected pores and the isolated pore spaces (Fig. 11). In this study, the result of total porosity for reservoir H_3 is 23% in H-002 well, 19% in H-007, 20% in H-009 and 19% in H-011 well (Table 2). Meanwhile effective porosity is 21%, 17%, 19% and 17% in H-002, H-007, H-009 and H-011 wells respectively. For reservoir H_5, total and effective porosity are 17% and 15% for well H-002, 25% and 21% for H-007, 19% and 17% for H-009 and 20% and 19% for well H-011. Similarly, for reservoir H_7, total porosity is 20%, 26%, 15% and 19% while effective porosity is 19%, 22%, 14% and 17% for H-002, H-007, H-009 and H-011 wells respectively. The average total and effective porosity for reservoir H_3 is 20.25% and 18.5%, 20.25% and 18% for reservoir H_5 and 20% and 18% for reservoir H_7 respectively(Table 3). According to [30], porosity measurements <5% are negligible, between 5-10% are poor, >10-20% are good, >20-30% are very good and >30 are excellent. Based on this classification scheme which is globally accepted for porosity classification, the total porosity recorded from reservoir H_3, H_5 and H_7 are classed as very good to excellent while effective porosity recorded for reservoir H_3, H_5 and H_7 are classed as good to excellent. Fig. 12 described the frequency distribution of the average porosity, effective porosity, water saturation and hydrocarbon saturations calculated for the three reservoir intervals.

3.6 Permeability

Permeability is the ability of fluids to flow through a reservoir rock. Fig. 13 shows the permeability measurements calculated in this study. The results of permeability for reservoir H_3 is 1723.462 mD in H-002 well, 1386.71 mD in H-007, 1749.591 mD in H-009 and 1469.643 mD in

H-011 well (Table 2). For reservoir H_5, permeability is 966.53168 mD, 1821.851 mD, 1254.445 mD and 1072.737 mD in H-002, H-007, H-009 and H-011 wells respectively. Meanwhile for reservoir H_7, permeability values are 1636.679 mD, 2213.988mD, 995.244 mD and 1434.321mD in H-002, H-007, H-009 and H-011 wells. On average, permeability values are 1582.3515 mD, 1278.8912 mD and 1570.058 mD in reservoirs H_3, H_5 and H_7 respectively (Fig. 14; Table 3). [30] classification of reservoir quality based on permeability values are as follows; < 10mD (poor to fair), >10-50 mD (moderate), >50-250 mD (Good), >250-1000 mD

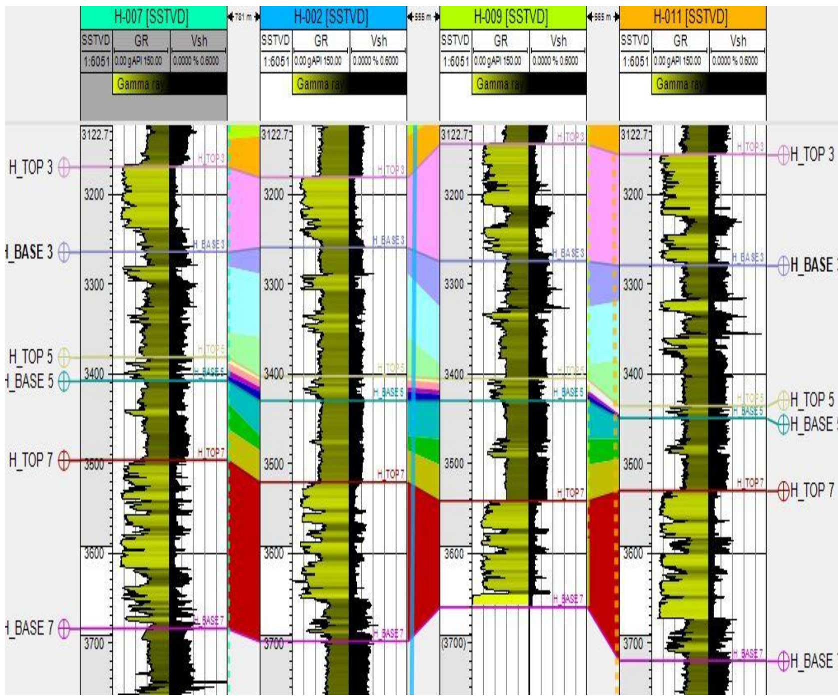

FIG. 9. The distribution of the volume of shale for across the three reservoir units

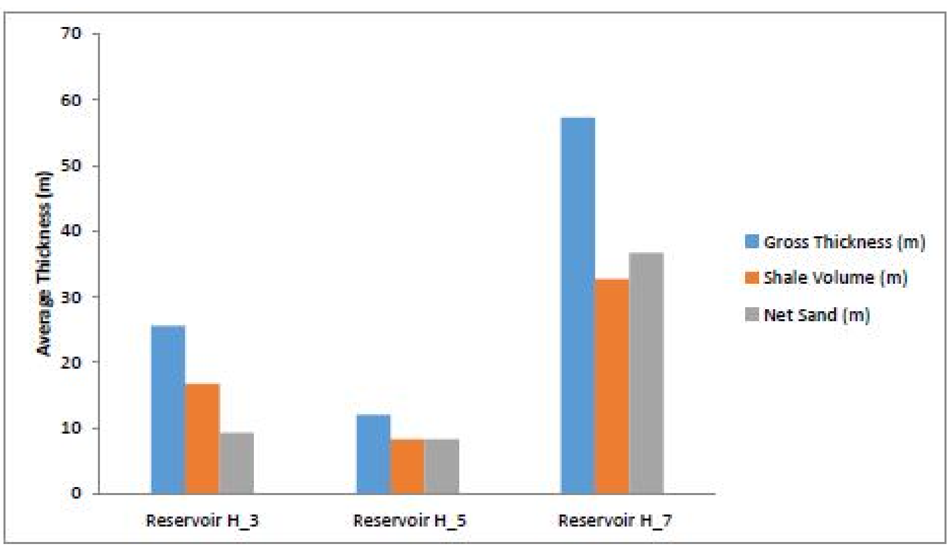

Fig. 10. Average gross thickness, shale volume thickness and net sand thickness for the three reservoir intervals.

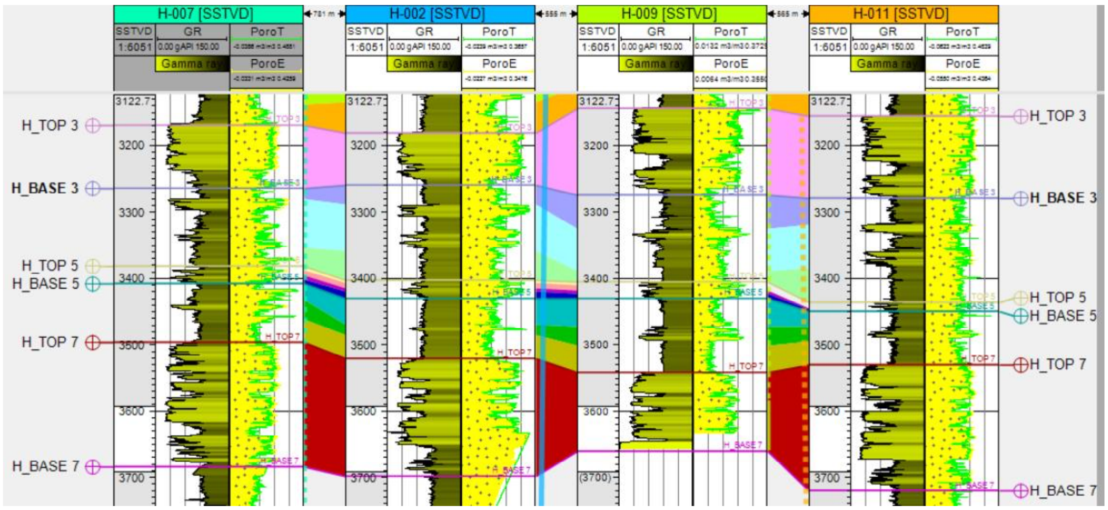

Fig. 11. Total and effective porosity calculated for the three reservoir intervals across all four wells. Total porosity is coloured green while effective porosity is coloured yellow

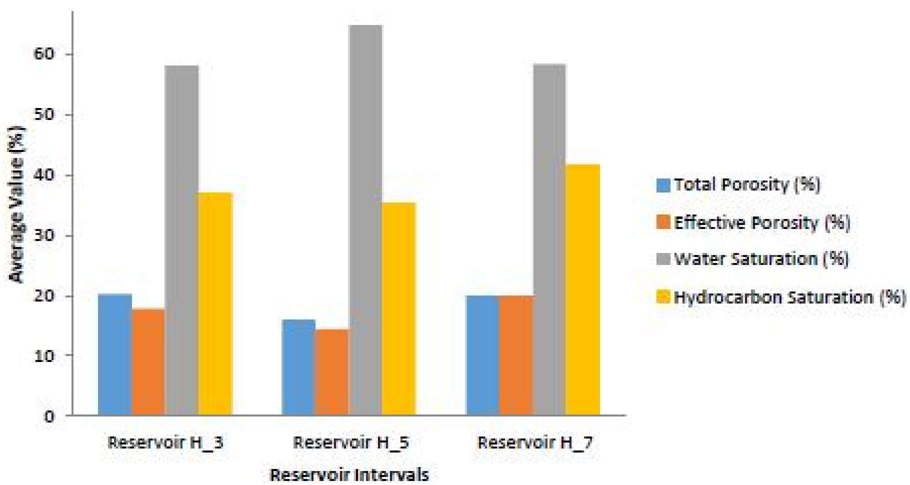

Fig. 12. Average porosity, effective porosity, water saturation and hydrocarbon saturations calculated for the three reservoir intervals

(very good) and >1000 mD (excellent). Based on this classification scheme, reservoir H_3, reservoir H_5 and reservoir H_7 can be classed as very good to excellent reservoirs because they have average permeability values ranges between 250-1000 mD and >1000 mD. These results show that all the reservoirs in the field have very good to excellent permeability values which are necessary requirements for hydrocarbon flow and production in economic quantities.

3.7 Fluid type

In a reservoir rock, three types of fluids are commonly found in the pores. The fluids can either be gas, oil, water (fresh or brine) or a combination of two or the entire three fluid phases. The resistivity log was used to determine the presence of oil and water in the reservoirs because oil is much more resistive and water is less resistive. Hence a sharp increase in the resistivity log measurement indicated the presence of an oil water contact in the reservoir. In this study, reservoir H_3 is oil and water bearing in well H-002, H-007, H-009 and H-011. Reservoirs H_5 and H_7 are oil and water bearing in H-002, H-009 and H-011 wells while Oil for H-007 (Table 2). These results show that all the reservoir intervals are hydrocarbon bearing and can be produced.

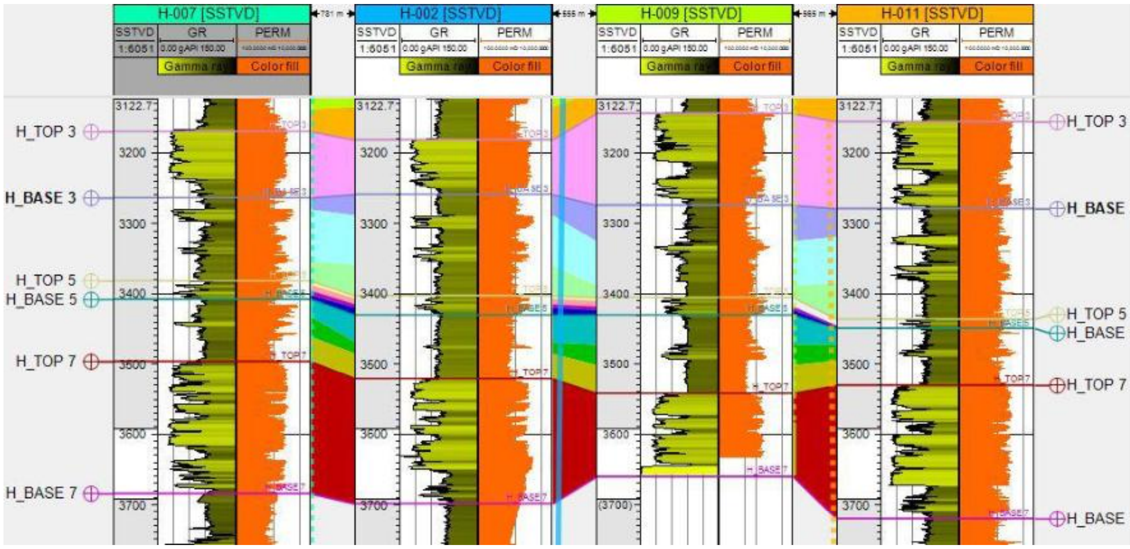

Fig. 13. Permeability values calculated for the three reservoir intervals and correlated across all four wells

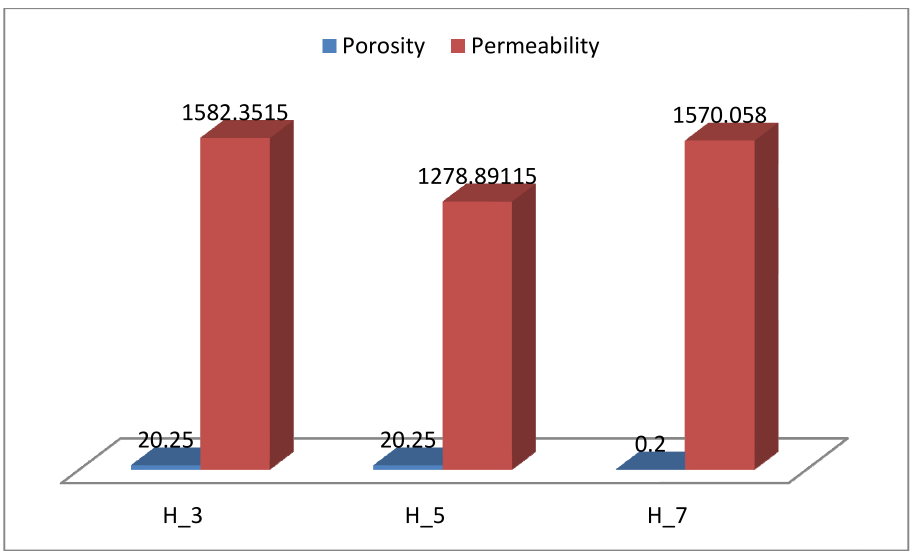

Fig. 14. The average values of porosity and permeability calculated for the three reservoir intervals

3.8 Fluid Saturation

The fluids saturation in the reservoirs was determined using the Archie's equation. Water saturation calculated for reservoir H_3 is 54% in H-002 well, 42% in H-007, 38% in H-009 and 42% in H-011 well. This accounts for an equivalent hydrocarbon saturation of 46%, 58%, 62% and 58% in H-002, H-007, H-009 and H-011 wells respectively (Table 2). For reservoir H_5, water saturation is 47% in H-002, 35% in H-007, 41% in H-009 and 48% in H-011 well, resulting in an equivalent hydrocarbon saturation of 53%, 65%, 59% and 52% in H-002, H-007, H-009 and H-011 wells respectively. Meanwhile in reservoir H_7, water saturation values are 49%, 31%, 42% and 54% in H-002, H-007, H-009 and H-011 wells respectively (Fig. 15). Accordingly, hydrocarbon saturation in reservoir H_7 is as follows; 51%, 69%, 58% and 46% in H-002, H-007, H-009 and H-011 wells. The average water and hydrocarbon saturation values for reservoir

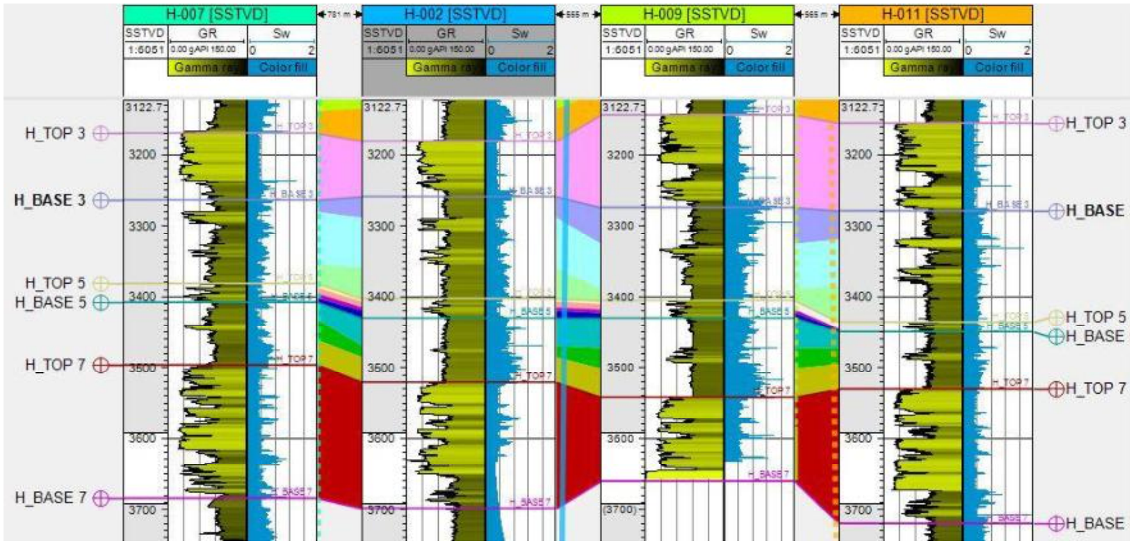

Fig. 15. Water saturation calculated for the three reservoir intervals and correlated across all four wells

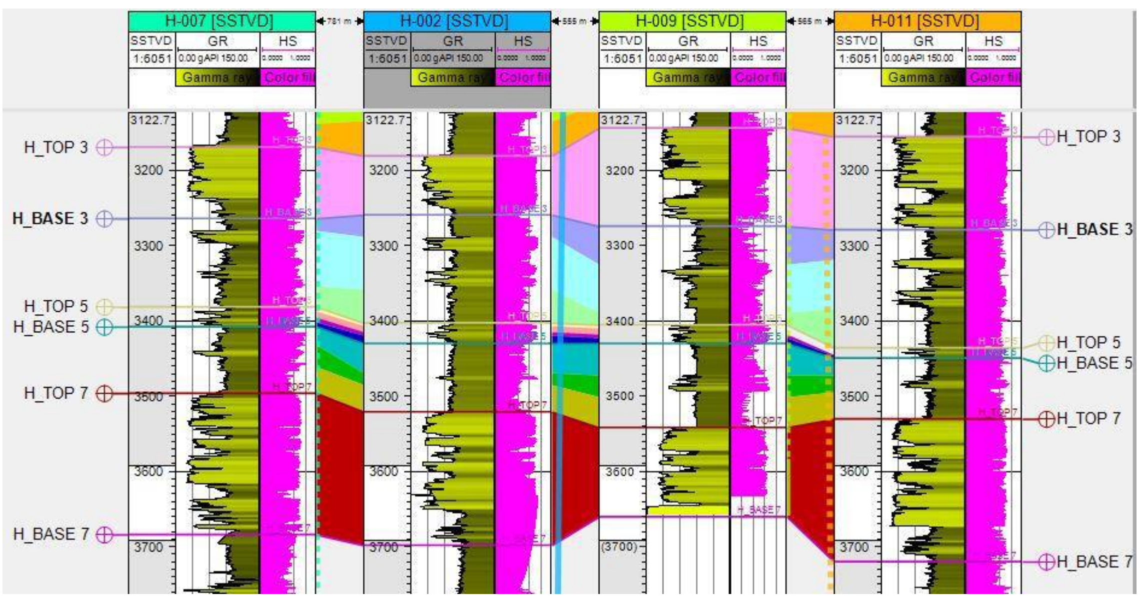

Fig. 16. Hydrocarbon saturation calculated for the three reservoir intervals and correlated across all four wells

H_3, H_5 and H_7 are 44% and 56%, 42.75% and 57.25% and 44% and 56% respectively (Fig. 16). These results show that reservoir H_5 and H_7 in Well H-007 have the highest hydrocarbon saturation while reservoir H_3 in Well H-002 and H_5 in Well H-011 have the least hydrocarbon saturation measurement (Table 2) and on the average reservoir H_5 has the highest hydrocarbon saturation (Table 3).

4. CONCLUSION

The petrophysical analysis showed that for the three reservoirs unit identified were of good reservoir quantities as the effective and total porosities were high, with good permeability and water saturation. Three reservoirs identified and correlated for four wells (H-002, H-007, H-009, H-011) using gamma ray, the average thickness for the three reservoirs H_3, H_5 and H_7 estimated were 106.50 ft, 23 ft and 174.25 ft respectively. On average the volume of shale, effective porosity, total porosity, permeability, water saturation and hydrocarbon saturation were calculated for the four wells to be 16.04 ft, 3.14 ft and 24.18 ft for shale volume, 18.5%, 18%, 18% for effective porosity, 20.25%, 20.25% and 20%for total porosity, 1582.3515 mD, 1278.8912 mD and 1570.058 mD for permeability, 44%, 42.75% and 44% for water saturation and 56%, 57.25% and 56% for hydrocarbon saturation for reservoirs H_3, H_5 and H_7 respectively.

Due to the low value of shale volume, water saturation and the moderate to good porosity and permeability nature of the reservoirs H_5 and H_7 in well H-002; H_3, H_5 and H_7 in Well H-005; H_3, H_5 and H_7 in Well H-007; H_3 and H_5 in Well H-011 have good hydrocarbon recoverability, high producibility and economically viable while reservoirs H_3 and H_7 in wells H-002 and H-011 respectively contains more water than hydrocarbon having fair producibility but are still good potential hydrocarbon reservoir and economically viable.

The result from Table 2 shows that reservoirs H_5 and H_7 in well H-007 has the highest value of hydrocarbon saturation and these is indicative of the fact that the reservoir quality increases in the values of porosity and permeability in this reservoir. It also suggests possible good fluid mobility.

On the average, the results indicate that H-field is a good hydrocarbon bearing reservoirs and the reserves have the potential to enhance the state of the economy of the country. Although petrophysical analysis has helped to quantify the reservoirs, volumetric analysis is still required to estimate the amount of hydrocarbon whether it is of commercial quantity.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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