RESERVOIR CHARACTERIZATION AND HYDROCARBON POTENTIALS OF GEOZFIELD, WESTERN NIGER DELTA BASIN, NIGERIA.

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ABSTRACT

Reservoir sand bodies were evaluated from log suites consisting of gamma ray, resistivity, density and neutron logs of three wells (Geoz 01, Geoz 02, and Geoz 04). The aim of the study was to determine the reservoir characteristics and hydrocarbon potential of the reservoirs, the objectives were to identify the lithology of the Geoz Field, evaluate the petrophysical properties, identify the hydrocarbon bearing zones and predict the reservoir quality. Based on the Gamma ray log evaluation, Geoz Field revealed the presence of sandstone and shale intercalations, three reservoir sand bodies were correlatable. The reservoirs were found to be continuous across the wells with an average gross thickness of 300ft (91.1 m), 64ft(20 m) and 53ft(16 m) respectively. The fluid types in the reservoirs based on the neutron density log signatures were basically water, oil and gas, identified as hydrocarbon bearing zones. Based on their petrophysical properties, Reservoir A has an average Net to Gross (22.17 %),Porosity Ø (29.0 %),Permeability K (3894.47 md), Water Saturation Sw (9.0 %) Hydrocarbon Saturation Sh (91%); Reservoir B an average Net to Gross (36.23 %), Ø (31.0 %), K (4039.80 md), Sw (8.0 %) and Sh (92%) while Reservoir C has an average Net to Gross (27.65 %), Ø (29.0%), K(4015.61 mD), Sw (6.0%) and Sh(94%) respectively. The cross plots of the reservoirs A,B and C in the Geoz Field indicate compaction and primary mineralogy influenced by palaeodepositional environments. From this study, the reservoirs may be considered a good quality for hydrocarbon prospects.

Keywords: *Reservoir characterization, Petrophysical Properties, Reservoir, Porosity, Permeability, Water Saturation.*

INTRODUCTION

Reservoir characterization involves the acquisition of crucial and useful information needed for an accurate description of a reservoir, resulting from discovery of oil or gas field sections to the last phases of hydrocarbon field development and production (Chopra and Marfurt 2007; Chambers and Yarus 2010). The reservoir has the capacity to accumulate and produce hydrocarbons in substantial quantity for economic returns of investment. It is important to understand the geometry, model and distribution of the reservoir properties such as porosity, permeability, heterogeneity, net to gross thickness, fluid contents and contacts within the reservoir. This reservoir information will help reduce costly expenditures, increase production rates, revitalize oil fields, anticipate future reservoir performance, and aid oil company management in creating precise financial models (Ameloko & Omali, 2013). The critical challenge during geophysical exploration for oil and gas is identifying reservoir rock types in the Niger Delta Basin since they exhibit a wide range of complexities in their sedimentological and petrophysical characteristics due to differences in hydrodynamic conditions and their depositional settings (Nton and Adesina, 2009). A practical tool for tackling this challenge is to identify the relation between the petrophysical properties in the reservoir rock of interest by integrating well log data to quantify producible hydrocarbon (Schlumberger, 1989; Asquith *et al.*,2004; Ebong *et al.*, 2019). With the aid of available geological data, the depositional and facies environments in the reservoir can as well be characterized. A wide range of previous works have been done by researchers using geophysical data to properly characterize hydrocarbon reservoirs in the Niger Delta Basin. Iboyi and Odedede (2014) investigated the depositional and diagenetic controls on reservoir characteristics of X-well and K-well, Ogbau Field in the Niger Delta Basin utilizing detailed sedimentological description from core data and wire line logs evaluation. The findings reported a barrier complex deposit of fluviodeltaic shallow marine environment. Other research works were carried for volumetric estimation of a reservoir on Idje Field Niger Delta which revealed 15.8 million barrels of oil and 32 billion cubic feet of gas (Ukuedojor and Maju-Oyovwikowhe, 2019).Ten oil wells in a particular oil field in the Niger Delta basin had their overpressure predicted through the utilization of key petrophysical, geochemical and pressure data, where the analysis revealed a reliable forecast for the development of pressure at greater depths (Chiazor and Beka 2019).These research works enabled an understanding of hydrocarbons and provided information on reservoir rocks. The increasing demand of hydrocarbon products to meet global needs in the 21st century with the call for transition energy and global energy has led to reservoir characterization of the Geoz Field in the western Niger Delta Basin to enhance development and optimization of hydrocarbon production. This current study therefore focuses on the petrophysical characteristics and the hydrocarbon potentials of the Geoz Field. The Geoz Field is located in onshore, part of the Coastal swamp Depobelt, Niger Delta-Basin.(Fig. 1)

REGIONAL GEOLOGY OF THE NIGER DELTA BASIN

The Niger Delta Basin comprises three stratigraphic units (Short and Stauble, 1967); the Akata, Agbada, and Benin formations (Fig. 2 and 3).The Akata Formation is the oldest formation (Paleocene to Recent) it is about 6,000 m thick. It comprises of 90 % shale and 10 % sandstone.It is known majorly as the source rock of the Niger Delta Basin (Doust and Omatsola, 1989).The Agbada Formation overlies the Akata Formation; it consists of alternating sequence of sandstone and shale with an age range from Eocene to the Recent (Ayolabi and Adegun, 2013).The formation has a maximum thickness of about 4000 m. The sandstone of the Agbada Formation is considered as petroleum reservoir of the Niger Delta Basin (Doust and Omatsola, 1989). The Benin Formation range from Late Eocene to Holocene.It consists of mainly sands and gravel with thickness of about 2000 m (Short and Stauble, 1967). The sands and sandstones are coarse to fine grained and commonly granular in texture and can be partly unconsolidated (Short and Stauble, 1967). Below are illustration of the stratigraphic column showing the three formations of the Niger Delta Basin (Fig.2) showing the subsurface formations and their outcropping stratigraphic equivalents(Fig.3) overlying the Cretaceous sediments of the Anambra Basin in southeastern Nigeria (adapted from Ogbe,2020).

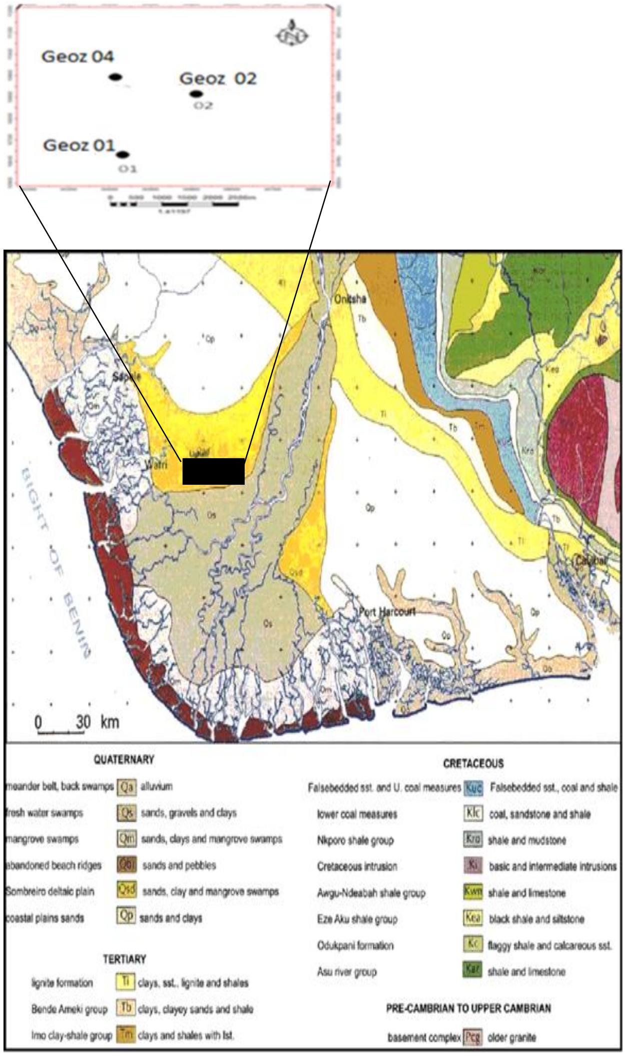


Figure. 1: Map of Niger Delta showing the location of the studied field (Reijers, 2011).

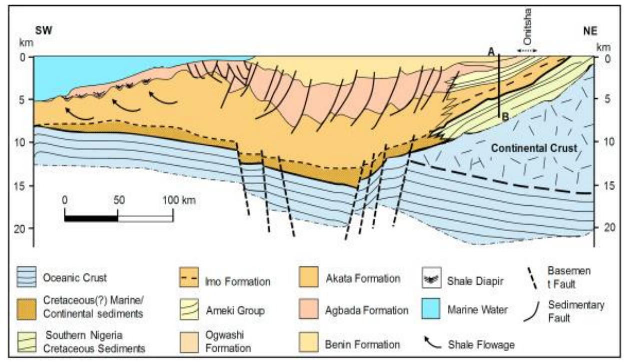


Figure.2: Cross-section of the Cenozoic Niger Delta Basin indicating various formations and their outcropping stratigraphic equivalents overlying the Cretaceous sediments of the Anambra Basin in southeastern Nigeria. (adapted from Ogbe,2020).

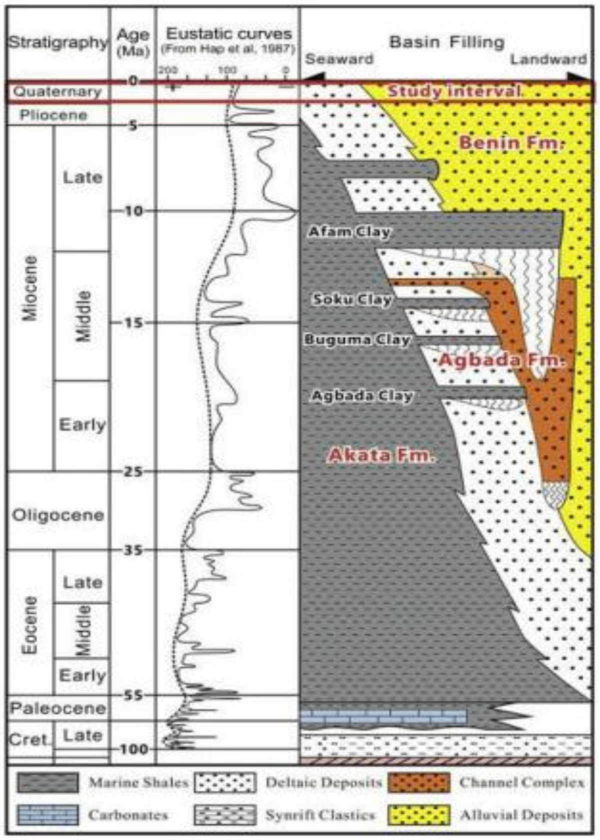


Figure. 3: The stratigraphic column showing the Marine Akata shale,the paralic Agbada Formation and the continental Benin sandstone of the Niger Delta Basin (after Zhao *et al*., 2018; Corredor et al., 2005).

MATERIALS AND METHODS

The materials used in this study consists of geophysical logs: gamma ray (GR), resistivity, density, and neutron logs from three exploratory wells (Geoz01, 02 and 04) within the Geoz Field. The datasets were uploaded into Schlumberger's Petrel interpretation software 2017. The images were calibrated, depth and the scale axis were set and the grid was created. The signatures and patterns displayed on these well logs were interpreted for the lithologies penetrated by the wells. The potential reservoir rocks were delineated using a combination of GR, resistivity and porosity logs. Appropriate petrophysical models and standard equations were utilized for the estimation of reservoir properties in this study.

Estimation of Porosity (Φ)

Porosity**(Φ)**was determined by using the equation proposed by Asquith et al., 2004.

Density Porosity

$\emptyset_{den} = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f}$ - - - - - - (1)(Asquith *et al*., 2004).

Where:

Φden = density derived porosity; ρma = matrix density;ρb = formation bulk density; ρf = fluid density (1.0 for fresh mud); ρf =Fluid density (either oil or gas); ρf = 0.85 for oil and 0.2 for gas ; ρma =Matrix (or grain) density = 2.65g/cm3 for sandstone

Permeability (K)

Permeability (K) was determined by using Konzeny-Carman model equation.

$$K = \frac{1014(FZI)^2 \emptyset^3}{(1-\emptyset)^2} \text{ - - - - - - - - (2)}$$

Where: K = Permeability, Φ = porosity, FZI = Flow zone index

Volume of shale (Vsh)

Volume of shale (Vsh) is calculated and estimated by volume of shale in unconsolidated rocks of Tertiary Niger Delta Basin using equation by (Asquith *et al*., 2004).

$$I_{gr} = \frac{GR_{log} - GR_{min}}{GRp_{max} - GR_{min}} \text{ - - - - - - - (3)}$$

(Asquith *et al*., 2004). - - - - - (4)

Where:V*sh* = Shale volume ; GR log = Gamma ray log reading in zone of interest; GR max = Gamma ray log reading in 100% shale; GR min = Gamma ray log reading in 100% clean sand zone; Igr = Gamma ray index

3.4. Water saturation (S_W)

The water saturation **(S_W)** was determined by using Archie's equation

(Archie,1942) ---------------------------- (5)

Where: F = Formation factor; Rw = Resistivity of formation water;Rt = True resistivity; S_w = Water saturation.

Hydrocarbon saturation (Sh)

Hydrocarbon saturation was determined by the difference between unity and water saturation in fraction. It is given as:

$S_h = 1 - S_w$ - - - - - - - - (6)

Where: S_h = Hydrocarbon saturation (fraction), S_w = Water saturation (fraction), 1 = Unit

Bulk Volume Water (BVW)

BVW= $S_w \times \Phi$ - - - - - - -(7)

Where: BVW = bulk volume water; S_w = water saturation of uninvaded zone; Φ = porosity

Irreducible Water Saturation (Swirr)

Irreducible water saturation is determined by:

Swirr= $F/2000^{1/2}$ - - - - - - - - (8)

Where:F = formation factor; Swirr = irreducible water saturation.

Determination of Net-to-gross pay zone.

The thicknesses of the shale within the reservoir sands were obtained and subtracted from the gross reservoir thickness. The net reservoir thickness was thereby obtained for all the reservoirs in the wells.

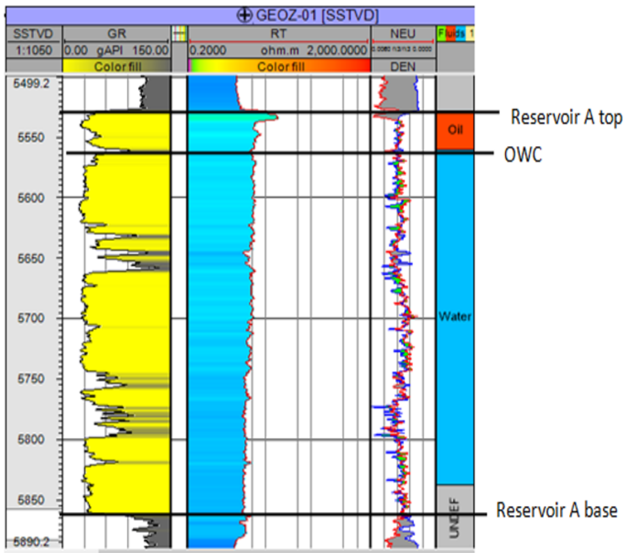
$h = H - h_{shale}$

Net /Gross = $h/$ H

Where: H = gross reservoir thickness; h= net reservoir thickness; h_{shale}=net shale thickness

RESULTS

4.1 Description of the Reservoir sands in the Geoz 01, 02 & 04 wells.



KEY
SHALE SAND

Fig 4: a. Geoz 01 well log for Reservoir A, describing fluid contents and contacts within the reservoir

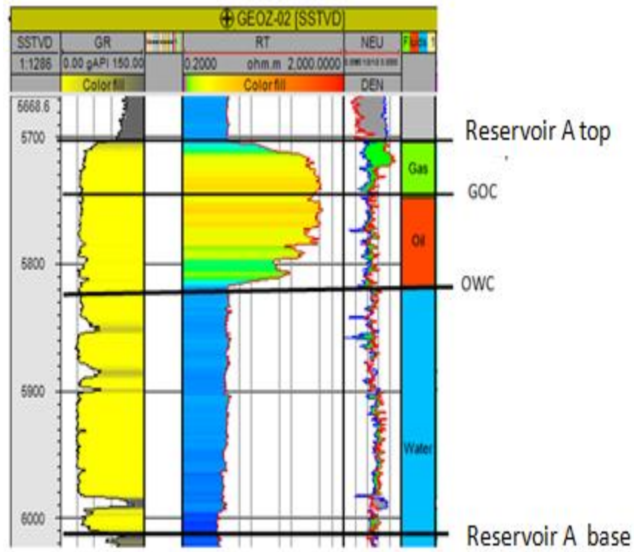


Fig b. Geoz 02 well log for Reservoir A, describing fluid contents and contacts within the reservoir

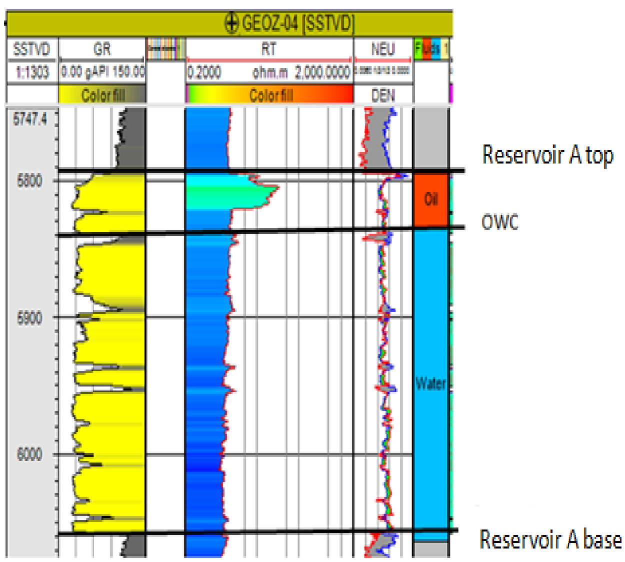


Fig c. Geoz 04 well log for Reservoir A, describing fluid contents and contacts within the reservoir

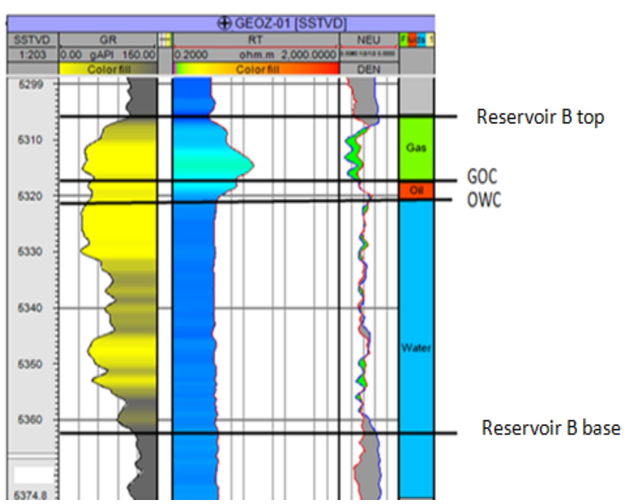


Fig d. Geoz 01 well log for Reservoir B, describing fluid contents and contacts within the reservoir

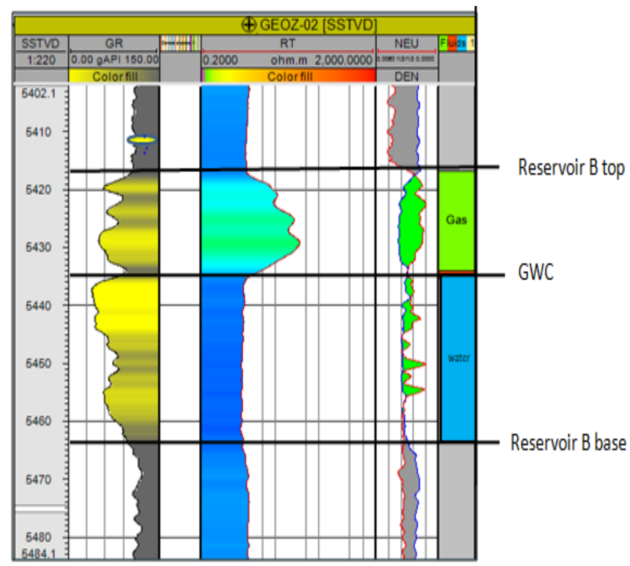


Fig e. Geoz 02 well log for Reservoir B, describing fluid contents and contacts within the reservoir.

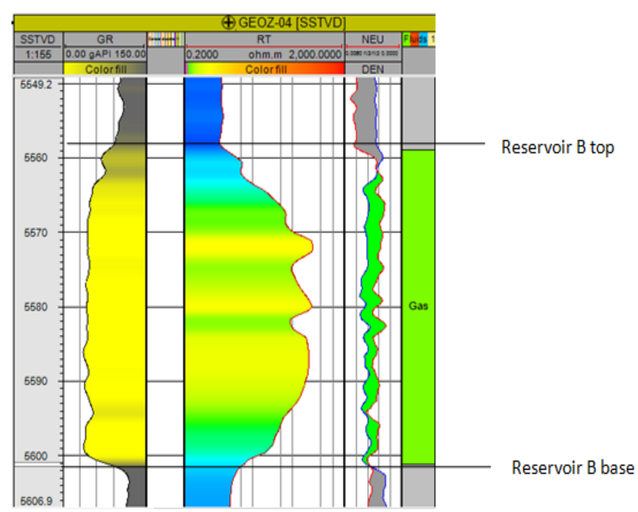


Fig f. Geoz 04 well log for Reservoir B, describing fluid content and contacts within the reservoir

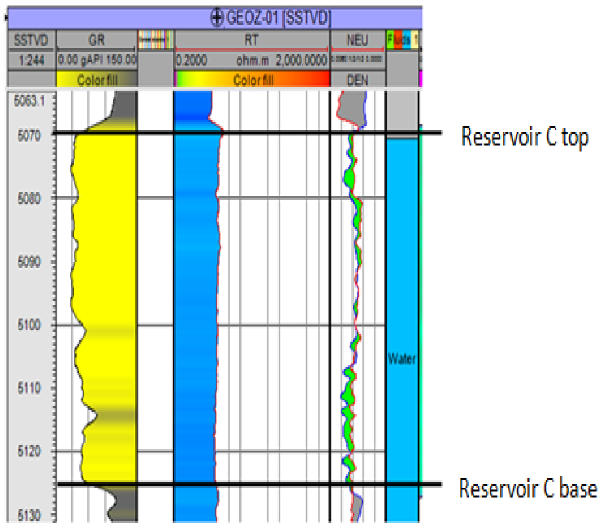


Fig g. Geoz 01 well log for Reservoir C, describing fluid content and contacts within the reservoir.

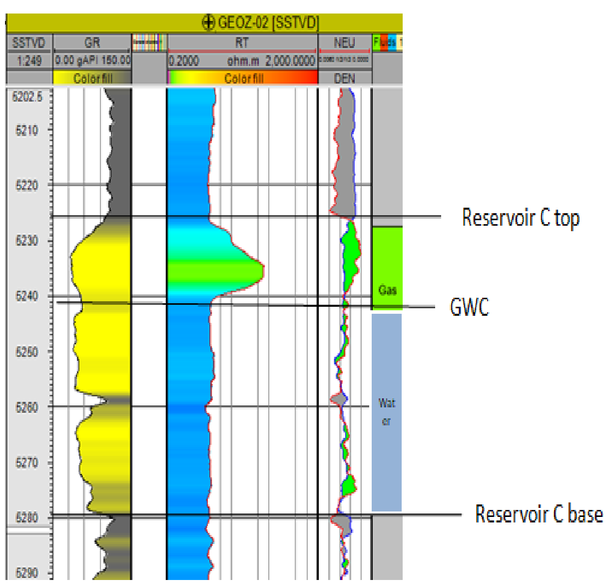


Fig. h. Geoz 02 well log for Reservoir C,describing fluid content and contacts within the reservoir.

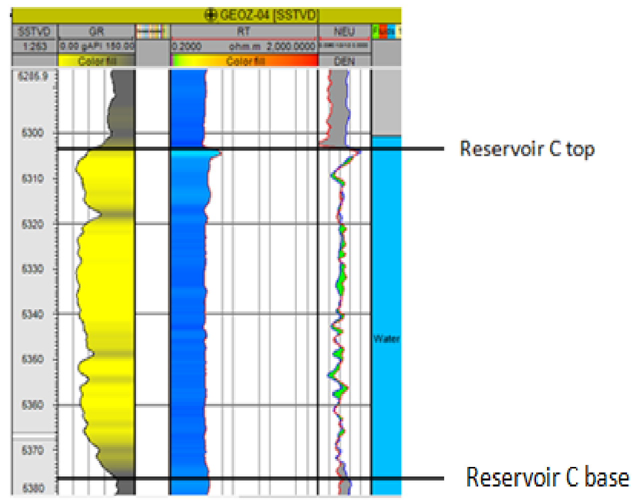


Fig i. Geoz 04 well log for Reservoir C, describing fluid content contacts within the reservoir.

The following tables shows the description of the reservoir and the average values of petrophysical parameters in the Geoz Field (Table1,2,3 and 4).

Table 1. Reservoir intervals and thickness in the Geoz Field

Reservoir	**Hydrocarbon Type**	**Geoz 04**			**Geoz 02**			**Geoz 01**		
		Top (ft)	Base (ft)	T (ft)	Top (ft)	Base(ft)	T(ft)	Top (ft)	Base(ft)	T(ft)
Reservoir C	Gas	5306	5370	64	5229	5276	47	5074	5123	49
Reservoir B	Gas	5550	5604	54	5410	5474	64	5305	5369	64
Reservoir A	Gas & Oil	5795	6055	260	5700	6000	300	5523	5863	340

Table 2. Calculated ranges of petrophysical parameters in the Reservoirs A, B and C.

Wells	**Reser-voirs**	**Ø% Min-Max**	**K(mD) Min-Max**	**Vsh % Min-Max**	**Sw(%) Min-Max**	**Sh(%) Min-Max**	**BVW(%) Min-Max**	**Swirr(%) Min-Max**	**Depth (ft) Min-Max**	**Thick-ness (ft)**
Geoz 01, 02 & 04	C	2.0-34	624-7427	4.0-53	1.0-31	63-97	0.009-0.36	0.115-0.72	5123-5306	53
Geoz 01, 02 & 04	B	3.0 -34	404-8344	1.0-58	5.0-23	61-98	0.002-0.37	0.052-0.132	5369-5550	64
Geoz 01, 02 & 04	A	15.0-37	1344-8277	2.0-40	8-27	73-99	0.002-0.059	0.091-0.108	5863-5795	300

Table 3. Calculated average petrophysical parameters of the Reservoirs A,B and C

Wells	**Res-er-voirs**	**H/C Type**	**Gross Thick-ness (ft)**	**Net Thick-ness (ft)**	**N/G %**	**Ø%**	**K (mD)**	**Sw (%)**	**Sh (%)**	**Vsh (%)**	**Swirr (%)**	**BVW (%)**
Geoz 01, 02 & 04	C	Gas	53	13.00	27.65	29.0	4015.61	6.0	94	23.0	6.8	1.8
Geoz 01, 02 & 04	B	Gas	64	29.70	36.23	31.0	4039.80	8.0	92	30.0	6.3	2.5
Geoz 01, 02 & 04	A	Gas & Oil	300	65.00	22.17	29.0	3894.47	9.0	91	23.0	6.8	2.4

Table 4. Fluid contents and contact in the Geoz Field.

Wells	Reservoirs	Fluid types	Gross Thickness (ft)	Net thickness (ft)	N/G (%)	GOC Depth (ft)	OWC depth (ft)	GWC depth(ft)
Geoz 04	Reservoir C	Water	5304 – 5370 (64)	Nil	Nil	Nil	Nil	Nil
Geoz 02	Reservoir C	Gas & Water	5229 – 5276 (47)	5227 – 52240 (13)	27.65	Nil	Nil	5240
Geoz 01	Reservoir C	Water	5072 – 5124 (52)	Nil	Nil	Nil	Nil	Nil
Geoz 04	Reservoir B	Gas	5550 – 5604(54)	5550 – 5604 (54)	54.00	Nil	Nil	Nil
Geoz 02	Reservoir B	Gas & Water	5410- 5474 (64)	5416– 5435 (19)	29.68	Nil	Nil	5435
Geoz 01	Reservoir B	Gas & Oil	5305 – 5369 (64)	5305-5321 (16)	25.00	5317	5321	Nil
Geoz 04	Reservoir A	Oil & Water	5795 – 6055 (260)	5795 – 5840 (45)	17.30	5840	Nil	Nil
Geoz 02	Reservoir A	Gas & Oil	5700 – 6000 (300)	5700 – 5830 (130)	43.33	5735	5830	Nil
Geoz 01	Reservoir A	Oil & Water	5523 – 5863 (340)	5540-5560(20)	5.88	Nil	5560	Nil

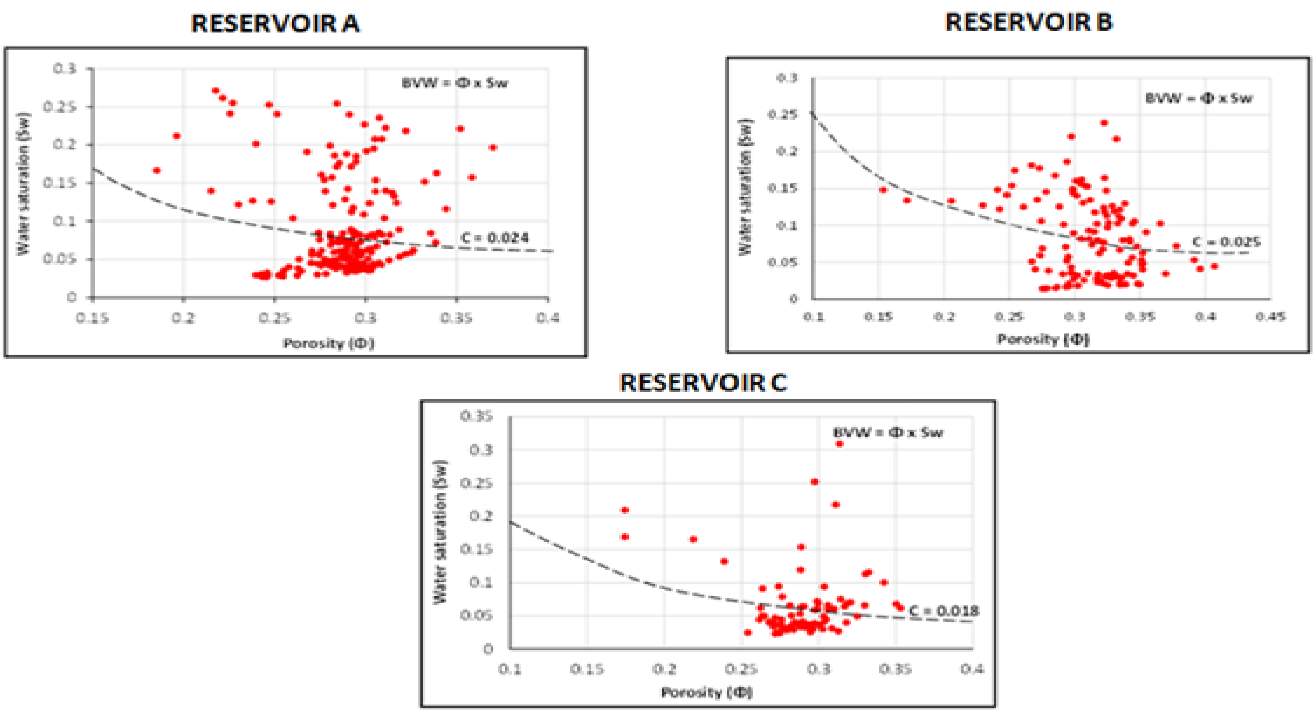
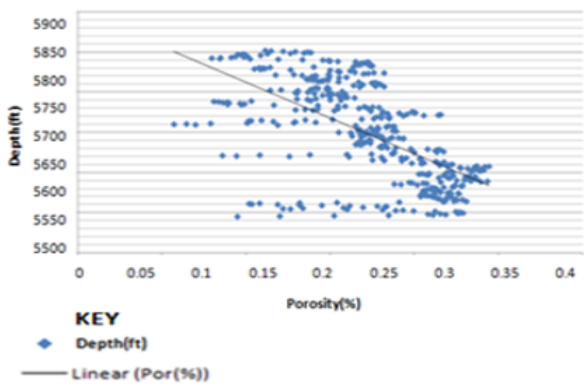
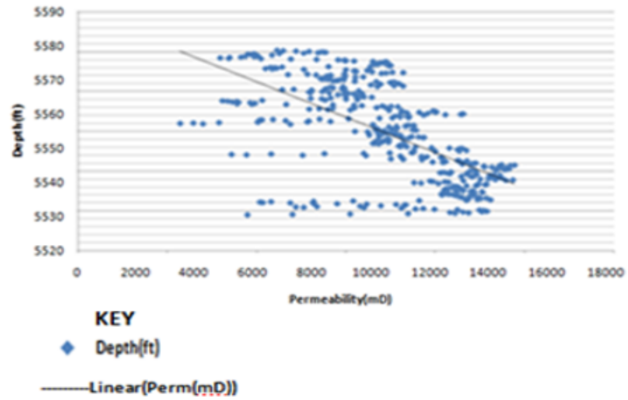


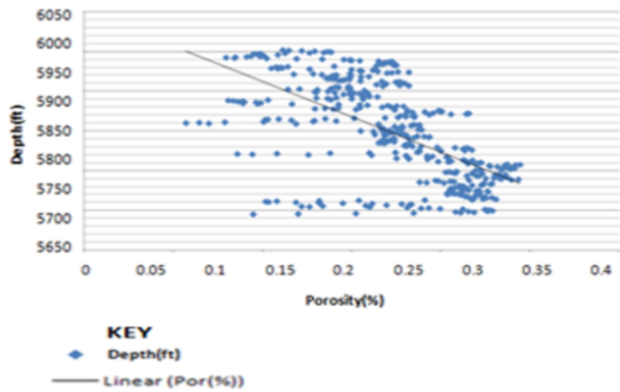
Fig. 5 Bulk volume water (BVW) cross plot for Reservoirs A, B and C in Geoz Field.



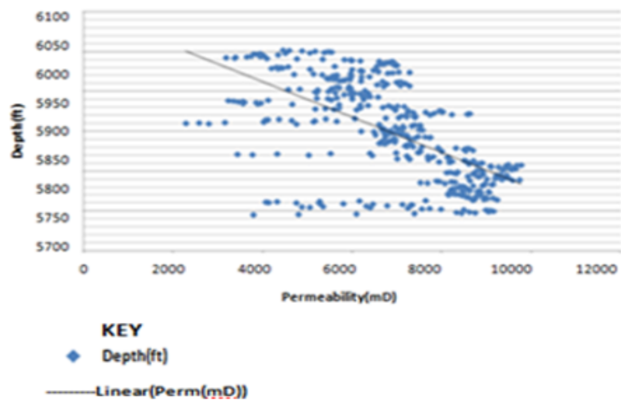
a. Plot showing depth against porosity Geoz 01, Reservoir A



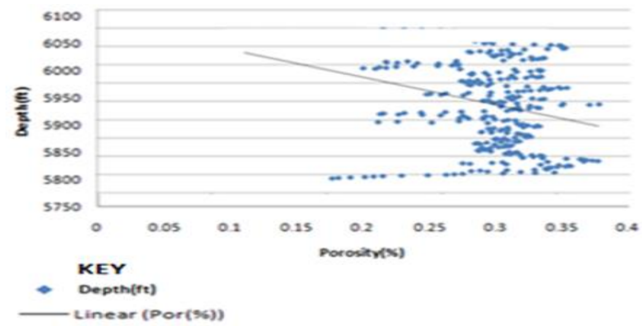
b. Plot showing depth against permeability Geoz 01, Reservoir A



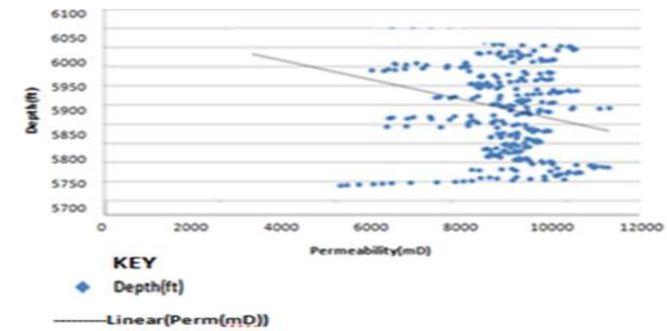
c. Plot showing depth against porosity Geoz 02, Reservoir A



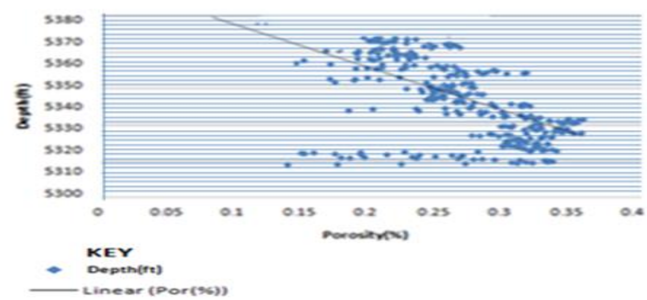
d. Plot showing depth against permeability Geoz 02, Reservoir A



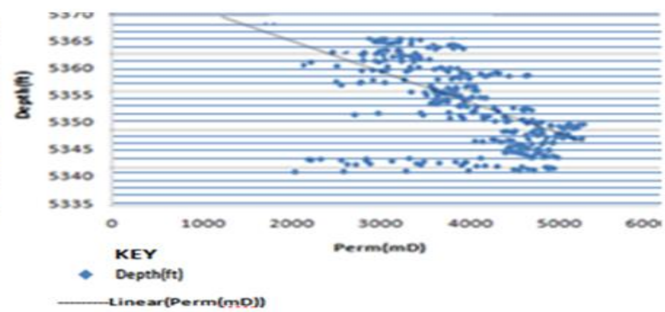
e. Plot showing depth against porosity Geoz 04, Reservoir A



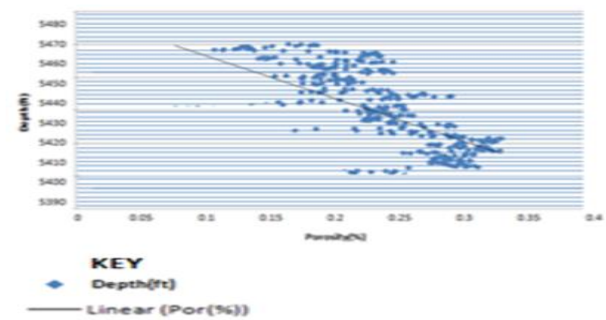
f. Plot showing depth against permeability Geoz 04, Reservoir A



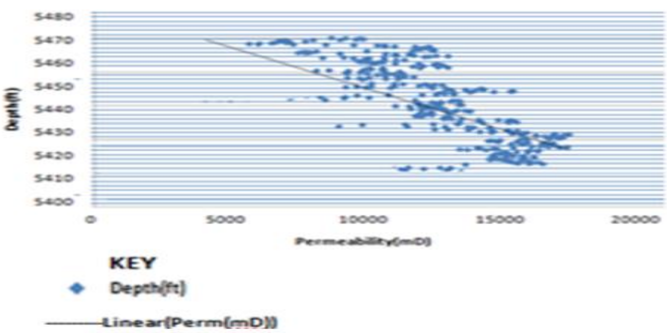
g. Plot showing depth against porosity Geoz 01, Reservoir B



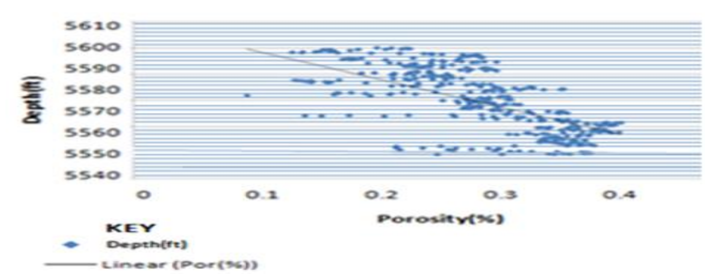
h. Plot showing depth against permeability Geoz 01, Reservoir B



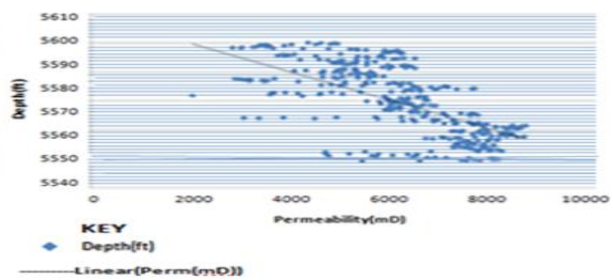
i. Plot showing depth against porosity Geoz 02, Reservoir B



j. Plot showing depth against permeability Geoz 02, Reservoir B



k. Plot showing depth against porosity Geoz 04, Reservoir B



l. Plot showing depth against permeability Geoz 04, Reservoir B

Fig 6. Cross plots of depths against porosity and permeability of the Geoz Field.

DISCUSSION

Lithology Identification and Correlation

The lithologies penetrated by the three wells (Geoz 01, 02 and 04) were identified as alternating thick blocky sands with few interbedded shales according to the log signatures. A total of nine sand units (Sands 1-9) and eleven shale units (Shale A-I) were identified. From the correlation of the lithologic units, it was observed that five (5) sand units (Sands 1-5), in all the wells were correlatable.

Reservoir Identification and Delineation in the Geoz Field

The nine sand units were analyzed and delineated across the field by combining readings of low gamma ray together with high resistivity logs. Only five of the sand units (Sand 1-5) exhibited high resistivity and porosity. However, these five sand units have been classified into three potential reservoir rocks namely: Reservoirs A, B and C. Reservoir A comprises two sand units (Sands 1 and 2), Reservoir B consist of two sand units (Sand 2 and 3), while Reservoir C is made up of two sand units (Sand 4 and 5). It was revealed that the correlatable reservoirs are genetically related and laterally continuous, (Fig.7) thereby suggesting that they were probably deposited in the same depositional environment under similar hydrodynamics conditions

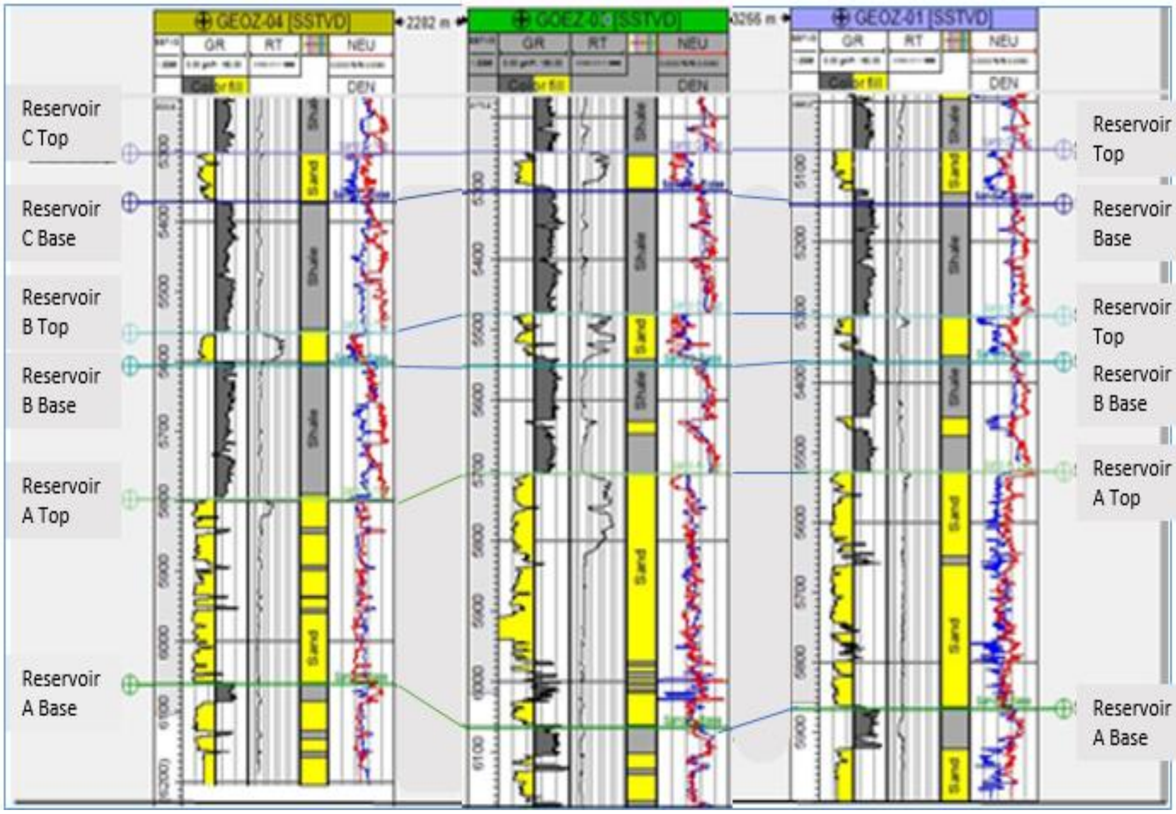


Fig.7. Lithostratigraphic correlation of hydrocarbon bearing sands in wells (Geoz 01, 02 and 04) in Niger Delta Basin.

Porosity of the potential Reservoirs of the Geoz Field

The porosities of Reservoirs A, B and C were ascertained on the basis of the neutron and density logs. Lateral variations were observed in the porosity of various reservoir units across the wells Geoz 01, 02 and 04.The average porosity values estimated revealed that reservoir B in the Geoz Field has the highest porosity of 31.1 % , compared to Reservoirs A and C which have an average porosity of 28.9 % and 28.8 % respectively(Table 3), indicating very good porosity in general.

Permeability of the potential Reservoirs of the Geoz Field

The reservoirs A,B, and C were observed to have variable permeability across the Geoz Field. Reservoir B exhibited the greatest average permeability of 4039.80 mD, compared to Reservoirs A and C which have average permeability of 3894.47 mD and 4015.61 mD respectively (Table.3). According to Rider (1986), these permeability values suggested that the three reservoirs (A,B and C) are of excellent permeability for hydrocarbon accumulation. The implications of the cross plots of permeability against depth shown in (Fig.5) revealed that the permeability decreases with depth. The Bulk Volume Water cross plot indicates that the porosity variations in Reservoir A , B and C in Geoz 01, 02 and 04 were relatively homogenous across the Geoz Field and are near irreducible water saturation (Fig.4) which may suggest that the reservoirs may not produce wet hydrocarbons (Asquith and Gibson, 1982).The permeability trends with porosity though there are some fluctuations from one reservoir to another reservoir.

Hydrocarbon Saturation and Water Saturation

Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbons. Water saturation is the percentage of pore volume in a rock which is occupied by formation water (Archie, 1942). Hydrocarbon saturation of Reservoir A, varies from 73 to 99 % with an average of 91% while Reservoir B and C, ranged from 61 to 98%(average of 92%) , and 73% to 99% (average of 94%)respectively. These imply that the reservoirs (A, B and C) have good hydrocarbon saturation. The water saturation ranged from 8 to 27% (average of 9%) for Reservoir A , while Reservoir B and C values vary from 5 to 23% with an (average of 8%, and 1.0 to 31% (average of 6%) respectively(Table.3).The water saturation value show that Reservoir A has the highest water contents while Reservoir C has the least water contents. Reservoir A and C in Geoz 01, 02 and 04 are not at irreducible water saturation and therefore may not produce water-free hydrocarbon during production , while Reservoir B is at irreducible water saturation and therefore, may produce water-free hydrocarbon during production (Tiab and Donaldson, 2016).

Bulk Volume Water(BVW)

The BVW cross plot indicates that the porosity variations in Reservoir A , B and C in Geoz 01, 02 and 04 are relatively homogenous across the Geoz Field and are near irreducible water saturation. These imply that the reservoirs may not produce wet hydrocarbons (Asquith and Gibson, 1982). However, the average BVW for Reservoirs A,B and C are 2.4, 2.5 and 1.8 % respectively (Table 3).

Net to Gross Thickness Ratio

The porosity logs (resistivity, neutron and density logs) revealed that Reservoirs A,B and C have average net thickness estimated in the Geoz Field as 65.00 ft (20 m), 29.70 ft (9 m) and 13 ft(4 m) respectively (Table 3). Their average net to gross thickness across the Geoz Field have been estimated as; 22.17 %, 36.23 % and 27.65 % respectively (Table 2). These Net to Gross values therefore suggests high hydrocarbon potentials for the three Reservoirs (A, B and C).

Volume of Shale

The volume of shale (Vsh) contained in the Reservoir sandstones varies. Reservoir B in Geoz 01, 02 and 04, has the highest volume of shale ranged 1.0% to 58 % with an average of 30%, compared to Reservoirs A and C which has 2.0 % to 40 % with an average of 23% , and 4.0 % to 53 % with an average of 23% respectively.

Fluid contents and their contacts

The signature responses for oil and gas thickness ranged at 20 ft(6 m) , 25ft (8 m), 105 ft(32 m)and 45 ft(13.7 m) respectively, for Reservoir A. Reservoir B responses for gas thickness ranged from 4 ft(1.2 m) ,12 ft(4 m) , 64 ft(20 m) and 54 ft(17 m), while Reservoir C response for gas thickness range from 21 ft(6.4 m), for oil and gas intervals respectively. Hence, different units were delineated in vertical succession that represent the reservoirs lithologic attributes of the wells. In Geoz 02, the Neutron Density logs showed good responses with clear separation in the signatures where gas occurs(Fig.4b). This indicates that the reservoirs are of good responsive attributes with well-defined and clear dissociation for oil and gas.

CONCLUSION

The three wells (Geoz 01, 02 and 04) investigated revealed that they consist of sandstones and shaly-sands in alternating sequence. The wells indicated high porosity with corresponding high permeability. The cross plots of the reservoirs A, B and C indicate a decrease of porosity with depth. This can be attributed to compaction and change in different phases. Low compaction results in high porosity. Reservoir B was observed to have the highest porosity value of 31% which is very good to excellent (Rider, 1986) and the highest permeability value of 4039.80 mD which was excellent (Rider, 1986). Although all reservoirs are viable, it can be concluded from the results that Reservoir A is more viable compared to Reservoirs B and C on the basis of hydrocarbon prospects. This study therefore revealed that the Geoz Field has good prospect for hydrocarbon production and exploration as a result of the high amount of hydrocarbon saturation in the reservoirs.

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