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Petrophysical Characterization of Reservoirs in parts of Northern Ughelli Depobelt of Niger Delta, Nigeria

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***Abstract*—Determination of petrophysical characteristics, using well logs data, in reservoir rock in parts of the Northern Ughelli depobelt in the Niger Delta, has been performed. A total of five (5) wells were evaluated. The evaluated parameters are porosity, permeability, density, shale and sand volumes, shear and compressional velocities, hydrocarbon and water saturations, using Petrel and Excel software. The results reveal the occurrence of three stacked Sand A, Sand B and Sand C reservoirs in each well, and correlated across the five wells. Topmost reservoir is at 8328ftss (2,538.4m) and deepest reservoir base is at 11215ftss (3,418.3m). The computed petrophysical parameters are highly variable in the entire field. The reservoirs' density, wave velocities and shale volume increase with increase in depth, which result in the observed very low porosity and permeability at depth. Reservoir thickness varies between 63ft. (19.2m) and 328ft (99.97m) with an average of 162.3ft (49.47m); permeability varies between 4.34 and 66.12mD with average of 32.2mD; porosity varies between 0.09 and 0.25 with average of 0.26; water saturation varies between 0.20 and 0.73 with average of 0.40; hydrocarbon saturation varies between 0.27 and 0.80 with an average of 0.60; net-to-gross varies between 0.16 and 0.70 with an average of 0.45 which infers the reservoirs rocks are productive. These parameters across the field are good and exploitable reservoirs.**

***Index Terms*—Petrophysics, Hydrocarbon, Porosity, Permeability, Saturation, Net-to-Gross.**

I. Introduction

The principal goal of the petroleum industry is to produce oil and gas which are very difficult to discover due to being situated thousands of kilometres in the subsurface [1]. As a result, proper planning, delineation and development of potential fields become very necessary and challenging as the demand for maximum possible turnover and returns of investment becomes more challenging in a high cost industry with increasing competition, technological advancement and demand.

Defining Petrophysical properties is very vital to the oil and gas industry [2, 3]. Petrophysics is regarded as the process of characterising the physical and chemical properties of the rock-pore-fluid system through the integration of the geological environment, well logs, rock and fluid sample analyses and their production histories [4]. A reservoir is a subsurface layer or a sequence of layers of porous rock that contain hydrocarbon. Depending on their geological origin, these layers are usually sandstone rock or carbonate rock [5]. The hydrocarbon resides in the open spaces in the rock matrix called pores [6].

To properly define complete reservoir architecture, some of the key properties to evaluate are lithology, porosity, water saturation, permeability, density [7, 8]. These parameters when combined with geological and geophysical data give a complete picture of the reservoir, which includes the internal and external geometry, its model, as well as the distribution of the reservoir properties. The aim of this research work is to determine the petrophysical characteristics of reservoirs in parts of Northern Ughelli depobelt in the Niger Delta using well log data. Petrophysical properties are sources of valuable information essential in locating and extracting mineral resources, and in the design and construction of any structure on the rock. The results from the work will also add to the accumulation of reservoir petrophysical parameters in the Niger Delta.

II. Location, Geology of Niger Delta and the Study Area

The field of study is located in the Northern Ughelli depobelt in the Niger Delta Basin (Fig 1). The Delta is included amongst the largest provinces that produces hydrocarbons. The latitudinal and longitudinal dimensions of Niger Delta lie along the coordinates (4°N - 9°N and 4°E - 9°E) and is globally one of the main hydrocarbon regions [9]. Only one petroleum system has been identifed to be associated to the Niger Delta basin and it is known as the (Akata-Agbada) petroleum system [10, 11].

The geological structure of the basin is composed of three major stratigraphic units or "formations": Akata, Agbada and Benin. Figure 2 shows a schematic section across the Niger Delta basin, indicating the inferred stratigraphic relationships between the Benin, Agbada and Akata formations, which form the bulk of the deltaic sediments. The Benin formation is of continental fluviatile environment and consists mainly of sands, gravels and backswamp deposits. Due to its high sand percentage, few minor shale streaks and absence of brackish water and marine fauna in the formation is recognized delta wide [12-14]. A typical example shows shale content increasing toward the base. Sands and sandstone are coarse to fine and commonly of granular texture [11, 15].

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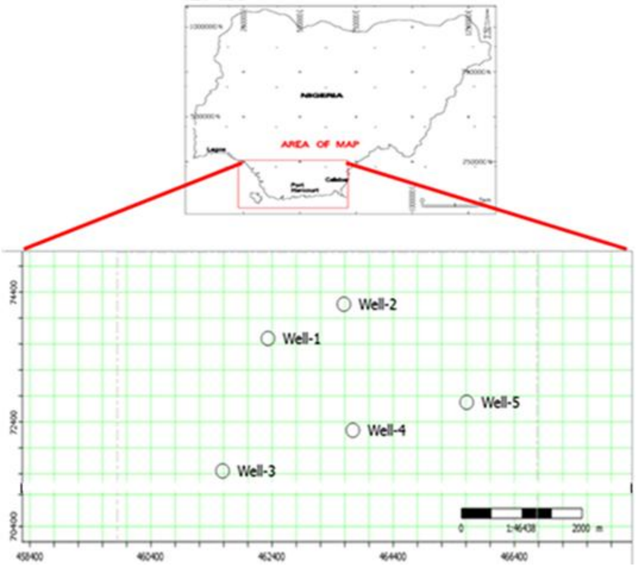

Fig. 1: Map of Nigeria Showing theStudyArea.

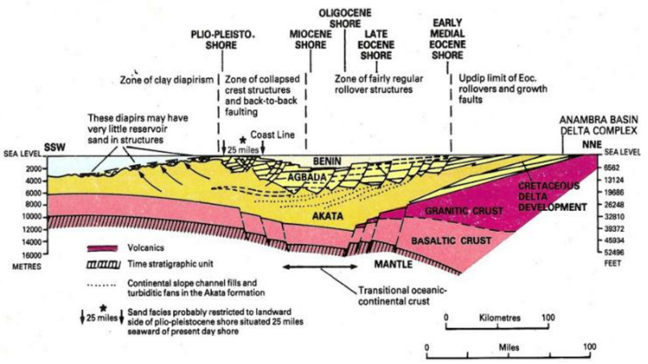

Fig. 2: Structural section of the Niger DeltaComplex showing Benin, Agbada and Akata Formations [16]

The sands can be partly unconsolidated. Limonitic coating is often described. Cross bedding and pebbles are common. Lignite occurs in thin streaks or as finely dispersed fragments. Hematite and feldspar are common. Benin shales are sandy to silty and often contain plant remains and dispersed lignite. They form a small part of the sequence (less than 30%) [12]. Benin Formation was laid down in continental, probably upper deltaic environment. Sands were deposited as point bars or channel fills, while finer grained deposits and shales were laid down in backswamps and oxbows. The Agbada formation overlies the Akata and consists mainly of alternations of sands, sandstones and siltstones. The Agbada sands constitute the main hydrocarbon reservoirs of the delta. The sandstones are often poorly sorted and their grain size varies from fine to coarse. They are generally unconsolidated but can be slightly consolidated with calcareous cement. Lignite streaks and limonite are common; shell fragments and glauconite occur. The shaliness increases downward as the formation passes gradually into the Akata shales. Due to normal processes of compaction the shales are denser at the base [17, 18].

The Agbada formation generally consists of a series of offlap rythms which range in thickness from 50 to 330 ft. [12-14] Rythms begin with onlap marine sands laid down during a marine transgression. They are followed by marine shales as the offlap stage begins. Laminated fluviomarine sediments, follow, Barrier bar and fluviatile sediments succeed. They are often truncated by the next marine transgression deposits. The Akata formation is mainly composed of marine shales with locally sandy and silty beds thought to have been laid down as turbidites and continental slope channel fills. This formation is said to be the main source rock for the Niger Delta complex. Its thickness depends on shale diapirism and flowage which the formation has been subjected to. The faunal content clearly indicates a shallow marine shelf and slope. Deep water deposits as fans and turbidites may have developed from time to time as the Niger Delta prograded. The upper boundary of the formation has been structurally deformed while diapirs and high pressure zones developed on large scale [12-14].

III. Material and Method

A. Source of Data

The materials used in this research include a suite of Wireline well-log data; Work station (computer); LAS tools pro 4.3 and Excel software; software. The well-log data for this research was provided by SPDC in Excel format (.xlsx), comprising measurements for: Gamma Ray, Sonic, Porosity, and Resistivity logs. The digital data was provided in.xlsx format files at different runs across the wells. The logs were loaded into Excel software and a database was created for the research.

B. Well Log Data Conditioning

The aim of wireline logging is to measure and record a given formation’s properties in its undisturbed state to evaluate it Petrophysical parameter. However, the objective is rarely achieved because the drilled hole where the logging operation is performed is not perfect and the logging environment also is often affected by drilling mud type, mud salinity, that need to be removed in order to get the actual response of the logs. The raw log data were therefore quality-checked. Log editing is basically a form of log interpretation aimed at removing or correcting problems that affect logs and provides the best possible presentation of the in-situ properties measured and recorded by logs.

The process of de-spiking is an editing that involves removing of unwanted signals in form of cycle skip, noise and spike that is associated with sonic logs. This research manually filtered the data using special techniques of observing unambiguous readings and edit unwanted noise. Care was taken in editing noise because some of the noise may be as a result of thinly bedded porous layers. When spikes are removed, the quality of the sonic log data was improved. Log splicing or merging is a process of bringing together all the runs logged in a well to form a continuous LAS file. The logs run at different depths were spliced or merged into a continuous log using a LAStools pro. software.

C. Delineation of Reservoir and Well correlation

Lithology identification was achieved with the aid of the gamma ray log. The sand baseline and the shale baseline were determined for each of the wells. The sand baseline was selected as the highest mode GR occurrence at the lower spectrum while the shale baseline was selected as the highest mode GR occurrence at the higher spectrum. The sand/shale cut-off was selected as the mid-point between the sand baseline and the shale baseline for each well. Gamma ray values which deflects to the left-hand of the established cut-off indicated clean sand while deflections to the right-hand of the cut-off indicated shales. On this basis, lithology was identified across all the wells. Higher positive GR values (API units) signifies shalier portions of a formation while lower values indicate the sandy portions. The American Petroleum Institute (API) values ranges from sandstone line 0 to shale line 150. As the signature of the log move towards the higher values, the formation becomes shalier. The maximum value is the shale baseline while the minimum value is the sand line.

D. Determination of Petrophysical Properties

After well-log conditioning, the digital data was loaded in to Excel software, where all the Petrophysical properties were computed and evaluated using different empirical relations. These relations are discussed below.

i. *Determination of Shale Contents (Shaliness)*: The volume of shale was computed from the Larionov[19] formula for tertiary sediments from Gamma ray index (IGR)

$$V_{sh} = 0.083\left(2^{2.3*I_{Gr}} - 1\right) \tag{1}$$

Where;

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \tag{2}$$

ii. Determination of Porosity: Porosity was computed from Sonic log using Wyllie time-average empirical equation;

$$\phi = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \tag{3}$$

where ϕ = fractional porosity of the rock, Δt_f is the acoustic transit time of interstitial fluids (218µsec/ft.) and Δt_{ma} is the acoustic transit time of the rock matrix (55.6µsec/ft.); assuming that the interstitial fluid is fresh water and the lithology is semi-consolidated sandstone [20].

iii. *Determination of Bulk Density*: Gardner's equation (Gardner *et al.*, 1974) was used to compute the bulk density

$$\rho = 0.23V_p^{0.25} \tag{4}$$

Where V_p is seismic p-wave velocity and ρ is density in kg/m^3.

iv. *Determination of Permeability*: For permeability estimation, this study used the empirical relation model developed by Coates and Dumanoi [21];

$$K = 100\% \times \frac{\phi^2 \times \left(1 - S_{wirr}\right)}{S_{wirr}} \tag{5}$$

Where ϕ = Porosity; S_{wirr} = irreducible water saturation, which is the minimum water saturation that a formation with a given permeability and porosity can hold without producing water [22].

v. Determination of Water/Hydrocarbon Saturations: Using Archie equation [23];

$$S_w = \sqrt{\frac{aR_w}{\phi^m R_t}} \tag{6}$$

Where Φ is the porosity of the formation, R_t is the true resistivity of the formation, R_w is the formation water resistivity at formation temperature, a is the constant tortuosity of the formation which is taken as 0.62 and m is the cementation exponent which is 2 for sands [22].
Hydrocarbon saturation S_h is given as;

$$S_w = 1 - S_w \tag{7}$$

vi. Determination of Net-to-Gross Thickness: Net/gross ratio is used to define the proportion of the intervals that are reservoirs and it help in the understanding of the formation [24]. The net/gross ratio reflects the overall quality of a zone not minding its thickness. Reservoir gross thickness is defined as the zones where reservoir beds occur; these beds includes both productive and non-productive zones [25]. The Net/Gross Reservoir thickness is given as;

$$h/H = \frac{H - h_{shale}}{H} \tag{8}$$

Where *h/H* is the net/gross thickness, *H* is the Gross reservoir thickness, *h* is the net reservoir thickness and h_{shale} is the shale thickness.

IV. Results

The results are presented in Tables 1 - 4, and Figs 1 - 6.

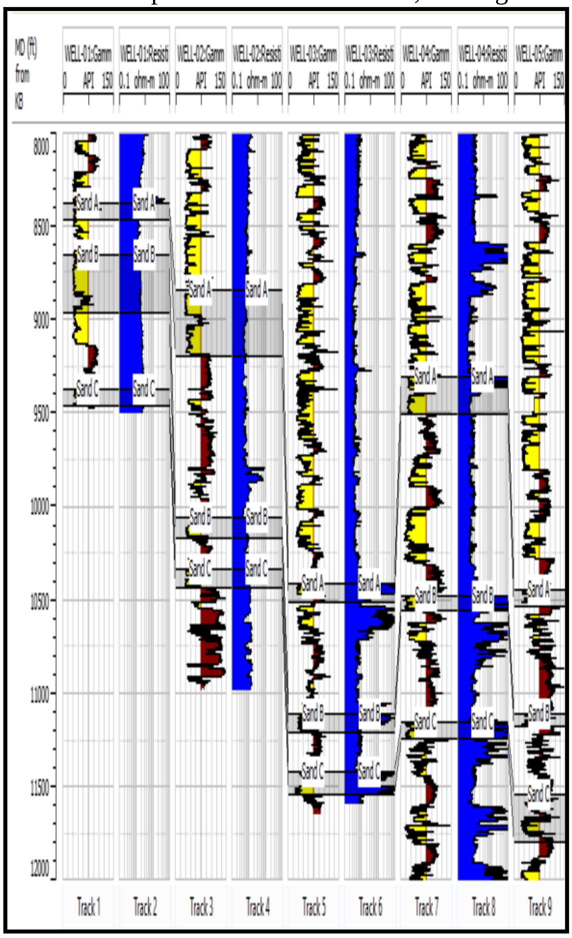

Fig. 3: Panel showing sand bodies and reservoirs across the study area

Table 1: Reservoirs for Wells-01 - 05 for Sand A, Sand B and Sand C

Wells	Reservoir Name	Top (ft)	Base (ft)	Reservoir Thickness (ft)	Reservoir Thickness (m)
Well-01	Sand A	8328	8426	98	29.87
	Sand B	8591	8919	328	99.97
	Sand C	9312	9410	98	29.87
Well-02	Sand A	8820	9148	328	99.97
	Sand B	10001	10133	132	40.23
	Sand C	10264	10395	131	39.93
Well-03	Sand A	10362	10493	131	39.93
	Sand B	11018	11150	132	40.23
	Sand C	11346	11543	197	60.06
Well-04	Sand A	9247	9443	196	59.74
	Sand B	10428	10559	131	39.93
	Sand C	11084	11215	131	39.93
Well-05	Sand A	10399	10488	89	27.13
	Sand B	11062	11125	63	19.20
	Sand C	11500	11750	250	76.20

Table 2: Summary of Petrophysical Parameters for Sand A Reservoir

Petrophysical parameters	Unit	Well 1		Well 2		Well 3		Well 4		Well 5	
		Top	Base	Top	Base	Top	Base	Top	Base	Top	Top
		8328	8426	8820	9148	10362	10493	9247	9443	10399	10488
Gross Thickness	ft	98		328		131		196		89	
Shale Volume	%	50.10		12.95		33.15		42.37		41.33	
Net Thickness	ft	49.90		87.05		66.85		57.63		58.67	
Net to Gross	Frac.	0.51		0.27		0.51		0.29		0.66	
Eff. Porosity	Frac.	0.33		0.33		0.28		0.43		0.25	
Water Sat	Frac	0.35		0.54		0.26		0.34		0.31	
Hydrocarbon Saturation	Frac.	0.65		0.46		0.74		0.66		0.69	
Permeability	mD	23.12		26.49		26.18		43.00		66.12	
Density	g/cc	1.32		1.21		1.25		1.01		0.90	

Table 3: Summary of Petrophysical Parameters for Sand B Reservoir

Petrophysical parameters	Unit	Well 1		Well 2		Well 3		Well 4		Well 5	
		Top	Base	Top	Base	Top	Base	Top	Base	Top	Top
		8591	8919	10001	10133	11018	11150	10428	10559	11062	11125
Gross Thickness	Ft	328		132		132		131		63	
Shale Volume	%	27.10		7.33		67.37		51.58		55.88	
Net Thickness	ft	72.90		92.67		32.63		48.42		44.12	
Net to Gross	Frac.	0.22		0.70		0.25		0.37		0.70	
Eff. Porosity	Frac.	0.13		0.23		0.29		0.42		0.09	
Water Sat	Frac.	0.51		0.73		0.20		0.49		0.55	
Hydrocarbon Saturation	Frac.	0.49		0.27		0.80		0.51		0.45	
Permeability	mD	4.34		12.66		28.15		41.88		66.12	
Density	g/cc	1.38		1.32		1.14		1.00		0.89	

Table 4: Summary of Petrophysical Parameters for Sand C Reservoir

Petrophysical parameters	Unit	Well 1		Well 2		Well 3		Well 4		Well 5	
		Top	Base	Top	Base	Top	Base	Top	Base	Top	Top
		9312	9410	10264	10395	11346	11543	11084	11215	11500	11750
Gross Thickness	ft	98		131		197		131		250	
Shale Volume	%	35.56		8.56		68.20		35.55		33.78	
Net Thickness	ft	64.44		91.44		31.80		64.45		66.22	
Net to Gross	Frac.	0.66		0.71		0.16		0.49		0.26	
Eff. Porosity	Frac.	0.13		0.21		0.33		0.30		0.15	
Water Sat	Frac.	0.66		0.50		0.27		0.25		0.46	
Hydrocarbon Saturation	Frac.	0.34		0.50		0.73		0.75		0.54	
Permeability	mD	4.36		10.12		38.42		30.19		62.11	
Density	g/cc	1.37		1.33		1.07		1.17		0.93	

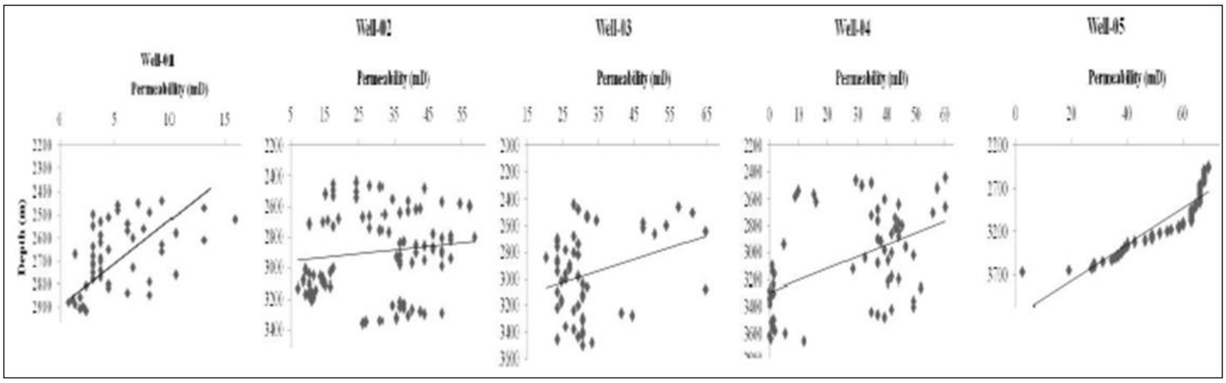

Fig. 4: Combined depth-permeability relations for all wells

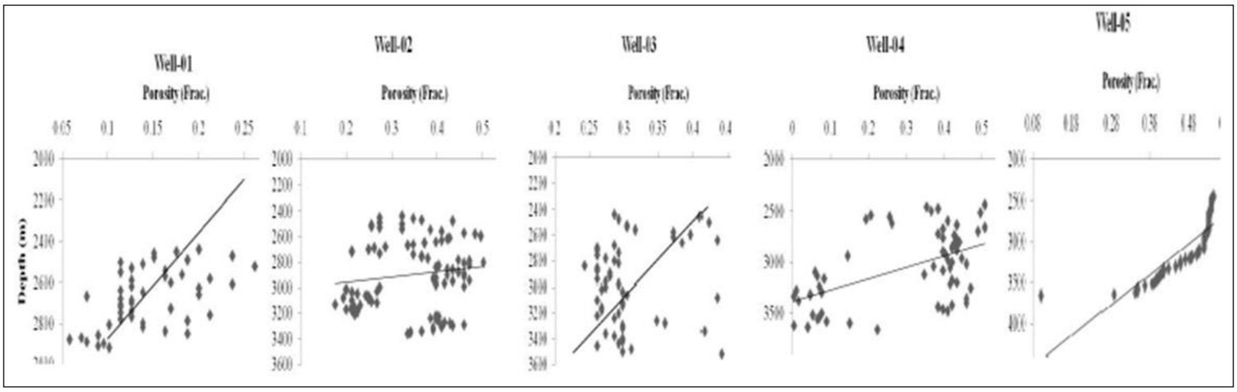

Fig. 5: Combined depth-effective porosity relations for all wells

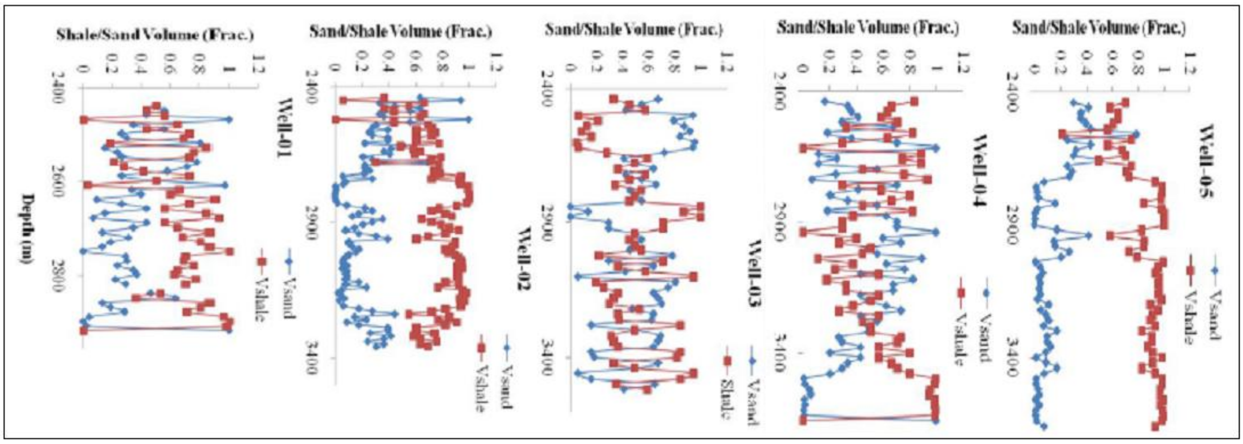

Fig. 6: Combined depth-sand/shale volume relations for all wells

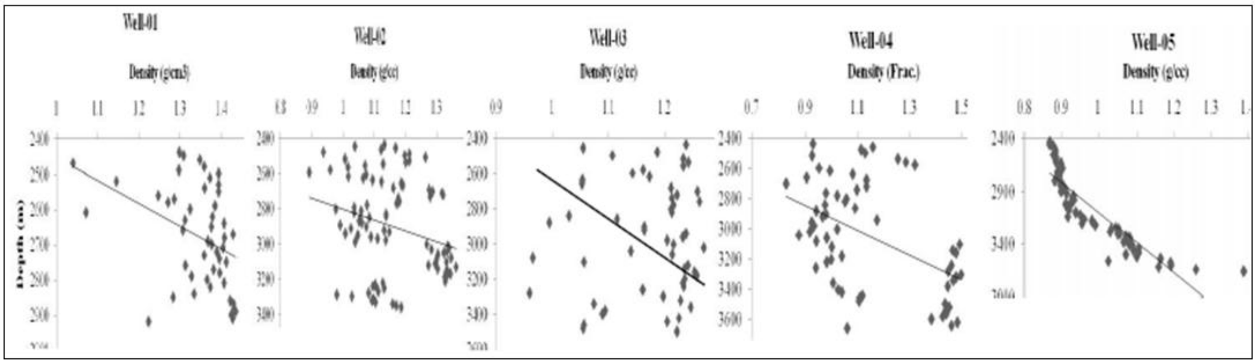

Fig. 7: Combined depth-density relations for all wells

V. Discussion

A. Well Correlation and Delineated Reservoirs

Low gamma ray and high resistivities are sand lithologies. Shale lithologies were defined by the high gamma ray value [26]. Well correlation which provides a knowledge of the general stratigraphy of the study field is shown in Fig.3. Fifteen sand bodies marked Sand A, Sand B and Sand C were correlated across the five wells in the field as the reservoirs (Table 1).

B. Petrophysical Parameters for Reservoir Sand A

Table 2 shows the summary of the average petrophysical parameters for Sand A reservoir correlated across Wells 01 - 05. The volume of shale ranges from 12.95% to 50.10% with average of 35.98% indicating that the fraction of shale in the reservoirs is quite low. This means the reservoir has a large volume (64.02%) of sand deposit than shale, therefore, hydrocarbon has much sand space to be saturated in. The reservoirs effective porosity ranges from 0.25 to 0.43 with average of 0.32 indicating a very good reservoir quality and reflecting well-sorted coarse grained sandstone reservoirs with minimal cementation. The permeability of the reservoirs range was from 23.12 to 66.12mD, with average of 36.98mD. This implies that the reservoir has poor throat connectivity for hydrocarbon flow. For a reservoir to be exploitable without stimulation, its permeability must be greater than or approximately 100mD. However, depending on the nature of the hydrocarbon - gas reservoirs with lower permeabilities are still exploitable because of the lower viscosity of gas with respect to oil[27]. These results imply that the reservoir is highly porous and permeable. It also contains high hydrocarbons that is very viable for production. The hydrocarbon saturation of the reservoirs ranges from 46.0% to 74.0% with average of 64.0% indicating that the proportion of void spaces occupied by water (36%) is low consequently high hydrocarbon saturation and high hydrocarbon production. The net-to-gross ranges from 0.27 to 0.66 with average of 0.45, which implies the reservoir is contains less sands than shale.

C. Petrophysical Parameters for Reservoir Sand B

Table 3 shows the summary of the average petrophysical evaluation for Sand B reservoir correlated across Wells 01 - 05. Average volume of shale values ranges from 7.33% to 67.37% with average of 41.85%. Low volume of shale signifies that the fraction of shale in the reservoirs is quite low, which means large volume of sand (58.15%) deposit than shale. Porosity values ranges from 0.09 to 0.42 with average of 0.23 indicating a very good reservoir quality. The permeability of the reservoir range was from 4.34 to 66.12mD with average of 30.63mD. This implies that the reservoir has poor throat connectivity for hydrocarbon flow.The water saturation of the reservoirs ranges from 0.20 to 0.73 having average of 0.50. High value of water saturation were observed in Well-02 (0.73). This implies Well-02 reservoir contain low hydrocarbon saturation and low hydrocarbon production. The net-to-gross ranges from 0.22 to 0.70, with average of 0.45 which implies the reservoir contains less sands than shale. It also contains high hydrocarbons that is very viable for production.

D. Petrophysical Parameters for Reservoir Sand C

Table 4 shows the summary of the average petrophysical parameters for Sand C reservoir correlated across Wells 01 - 05. Average volume of shale values ranges 8.56% to 68.20% with average of 36.33%. Low volume of shale signifies that the fraction of shale in the reservoirs is quite low, which means large volume of sand (63.67%) deposit than shale. Porosity values ranges from 0.13 to 0.33, with average of 0.22 indicating a very good reservoir quality. The permeability of the reservoir ranges was from 4.36 to 62.11mD having average of 23.04mD. This implies that the permeability variation is poor. The hydrocarbon saturation of the reservoirs ranges from 34.0% to 75.0% with average of 57.0% indicating that the proportion of void spaces occupied by water is low. But Well-01 contains little concentration of hydrocarbons (34.0%). However, the other wells in this reservoir have high hydrocarbon saturation and high hydrocarbon production. The net-to-gross ranges from 0.16 to 0.71 with average of 0.46, which implies the reservoir is contains less sands than shale. It also contains high hydrocarbons that is very viable for production.

E. Petrophysical Parameters Variation with Depth

In Figs. 4 to 7, variation of permeability, porosity, sand/shale volume, density compressional and shear velocities are plotted with depth. The reservoirs' density, and shale volume increase with increase in depth due to rock compaction resulting from over burden pressures. It was observed that porosity and permeability decrease with increase in depth. Permeability decreases with increase in depth. Permeability is porosity-dependent; hence it decreases with decrease in porosity.

The depth-porosity plot (Fig. 5) shows a normal trend of porosity with depth. Olowokere and Ojo [28] stated that, in the Niger Delta, the decrease of porosity with depth is linear and estimated from about 35% at 5000ft to around 15% at 14,000ft. At the surface when sediments are deposited their porosity is high, but when these sediments are deeply buried, they undergo normal and Shear compressional stresses due to the overburden load thereby subjecting the formation or layer to high overburden pressure, which causes compaction that gets rock porosity reduced with depth [29, 30].

From Fig. 6, it is observed that it is sandy at surface and shalier deeper in the reservoir. This is very typical of reservoir rocks as they get shalier at greater depths [16, 31, 32]. From the plot of density against depth in Fig. 7, there is increase of bulk density with depth. According to Telford et al. [33], the density of sedimentary rocks is also influenced by their age, previous history and depth below surface. A porous rock buried under a heavy load will be compacted and consolidated to a degree, which depends on the size and duration of the load. The density thus increases with depth and time. This effect is more pronounced in clays and shales than in sandstones [34, 35].

VI. Conclusion

This research was carried out to petrophysical characterize a sandstone reservoir from the Niger Delta region. To this end, dataset from five (5) well logs obtained from reservoirs in parts of Northern Ughelli depobelt in the Niger Delta were analyzed. The following conclusions were arrived at;

i. There are three stacked Sand A, Sand B and Sand C reservoirs in each well, and the same are correlated across the five wells, and across the field.
ii. The computed petrophysical parameters are highly variable in the entire field. The reservoirs' density, wave velocities and shale volume increase with increase in depth, which result in the observed very low porosities and permeabilities at depth.
iii. The topmost reservoir is at 8328ftss (2,538.4m) and deepest reservoir base is at 11215ftss (3,418.3m).
iv. Reservoir thickness varies between 63ft. (19.2m) and 328ft (99.97m) with an average of 162.3ft (49.47m); permeability varies between 4.34 and 66.12mD with average of 32.2mD; porosity varies between 0.09 and 0.25 with average of 0.26; water saturation varies between 0.20 and 0.73 with average of 0.40; hydrocarbon saturation varies between 0.27 and 0.80 with an average of 0.60; net-to-gross varies between 0.16 and 0.70 with an average of 0.45 which infers the reservoirs rocks are productive.
v. These reservoirs are good and exploitable reservoirs.

Acknowledgment

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