

**ORIGINAL ARTICLE**



# Percentile-Ogive Approach Determines the Textural Parameters of $X_a$ Field Lithology and the Suitable Technique for Porosity Estimates

Atat J. G.<sup>1</sup>, Akpabio I. O.<sup>2</sup>, Ekpo S. S.<sup>1</sup>

Corresponding Author: Atat J. G

**Abstract:** Assessment of textural parameters was carried out to decide on a better technique suitable for porosity estimates in the area of study. Data were obtained from wells A and B and used to generate suites of logs like gamma ray, density and sonic. Microsoft Excel was used for the analysis. The lithology was identified as sand for gamma ray information less than 75 API (or shale if this value is greater than 75 API). Three major Techniques (such as Techniques one, two and three) as deliberated in the subsection of the discussion were examined. Others are Techniques four and five for both wells A and B. The average result of porosity estimates for the three major Techniques are approximately 33%, 35% and 20% from one, two and three respectively for well A. also, 28%, 31% and 16% from one, two and three respectively for well B. With the result of semi-interquartile range, Technique three is seen with the lowest range of spread of the result (that is, 2.75 for well A and 3.00 for well B) and is strongly recommended as the best approach for porosity estimates. Where only sonic data is available, Technique one show better result and should be preferred over Technique two. The coefficient of variation shows that all the results obtained from these five approaches fall within low variance. The matrices making up the lithology are therefore, very poorly sorted, near symmetrically skewed and platykurtic for well A; extremely poorly sorted, coarse skewed indicating high energy environment and leptokurtic for well B. Moreso, the porosity information deduced for both wells from Technique three, categorised them into the good class.

**Keywords:** Mean, Median, Percentile, Porosity, Quartile, Skewness, Standard Deviation Technique, Textural Parameters, Variance

## 1. Introduction

To investigate the volume of hydrocarbon in place, porosity is an influential factor [1]. Porosity values could range about 5% to 45% [2]. The standards for categorising porosity include: value less than 0.05 is negligible, within 0.05 to 0.09 is poor, 0.10 to about 0.14 is fair, 0.15 to 0.24 is considered as good, 0.25 to almost 0.30 is very good and porosity values greater than 0.30 is excellent [3]. Porosity is therefore, the void existing in the rock which is significant for the build-up of fluids like oil, gas and water.

The use of statistical parameters for environmental reconstruction helps to discriminate ancient environments [4]. Textural parameter such as skewness is an environmental indicator [5-8]. Texture refers to the properties of sediment such as particle size, shape, roundness and sorting. A well sorted lithology (matrix) is one in which the grains are all about the same size. Poorly sorted sediment contains a disordered combination of different sizes of grain. One way to characterize sediment is to determine the sizes of grains in that sediment.

<sup>1</sup>Department of Physics, University of Uyo, Uyo, Nigeria.

<sup>2</sup>Department of Geoscience, University of Uyo, Uyo, Nigeria

Supplementary information The online version of this article contains supplementary material, which is available to authorized users. Evi Kurniawaty 2022; Published by Current Science, Inc. This Open Access article is distributed under the terms of the Creative Commons License (<http://creativecommons.org/licenses/by/4.0>), which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited

Matrix at rest will continue to be at rest and the one in motion with constant velocity will remain in motion with constant velocity except it is compelled to change that position by forces acting on it as contained in Newton's first law of motion. Sediment that was at rest begins to move in fluid (like water or oil) and the one that was in motion comes to rest. By his second law, this body will move in the direction in which the force acts [9]. A greater energy is needed for a greater force to be applied to move sediment and where this energy cannot supply the minimum required force, the coarser matrices are deposited [5]. In overall, coarser sediment are left behind by the transportation process and found closer to its source; fine ones are found farther away from the source.

Our aim is to carefully examine different Techniques proposed by different researchers or authors to recommend a most suitable approach that will result in a better and improve result of porosity estimates in different basins. This information will also aid the definition of the lithology characteristics in terms of the kinetic energy of the environment. The presence of Fine materials may not lead to a better porosity but coarser materials will certainly result in a better porosity and permeability.

## 2. Theoretical Background

### 2.1 Porosity/Techniques of Porosity Estimates

Porosity of the formation is important in evaluation of fluid content, potentiality of fluids flow and recaptures the amounts in a pool [10]. Two most frequently used methods of estimating porosity from sonic measurements are the Wyllie time average method [which requires an estimate of fluid interval time] as stated in Equation 1 and 2 [11] and the Raymer-Hunt-Gardner field observation method [which is an empirical approach developed from the statistical analysis of a database of sonic measurements and independently determined porosity]. The relationship is highlighted in Equation 4. Equation 2 is used for calculating

porosity in sandstones in which adjacent shale values ( $t_{sh}$ ) exceed 100  $\mu\text{sec}/\text{ft}$ ; otherwise, Equation 1 is preferred.

$$\emptyset = \frac{t - t_{ma}}{t_f - t_{ma}} \quad (1)$$

$t$  is the sonic response in  $\mu\text{sec}/\text{ft}$

$t_{ma}$  is the matrix travel time in  $\mu\text{sec}/\text{ft}$

$t_f$  is the fluid travel time in  $\mu\text{sec}/\text{ft}$

$\emptyset$  is the porosity

A fluid velocity ( $\Delta t_f$  of 189  $\mu\text{sec}/\text{ft}$ ) of 5,300 ft/sec is generally assumed for fresh drilling fluids. A slightly lower value, 185  $\mu\text{sec}/\text{ft}$ , is used for salt muds. The Wyllie equation represents consolidated and compacted formations. In poorly consolidated or unconsolidated rocks, a correction factor is necessary. Also, the presence of shale or clay within the sand matrix will increase  $t$  by an amount proportional to the bulk-volume fraction of the clay. The compaction correction factor can be evaluated using Equation 3.

$$\emptyset = \frac{t - t_{ma}}{t_f - t_{ma}} \times \frac{1}{C_p} \quad (2)$$

where  $C_p$  is the compaction correction factor, defined mathematically as

$$C_p = \frac{t_{sh}C}{100} \quad (3)$$

Where  $t_{sh}$  = specific acoustic transit time in adjacent shales ( $\mu\text{sec}/\text{ft}$ ), 100 = acoustic transit time in compacted shales ( $\mu\text{sec}/\text{ft}$ ). The shale compaction coefficient ( $C$ ) usually ranges from 1.0 to 1.3, depending on the regional geology.

$$\emptyset = \frac{C_r(t - t_{ma})}{t} \quad (4)$$

The value of  $C_r$  can vary between 0.625 and 0.700 depending upon local conditions. The most widely accepted value is 0.670; according to Standard-AAPG Wiki [12], the value is 0.60 for gas reservoirs.

Moreso, the porosity of a formation may also be estimated from density log. The volumetric

concentration of pore space can be determined using Equation 5.

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (5)$$

where  $\phi$  is the porosity;  $\rho_{ma}$  is grain matrix density;  $\rho_f$  is fluid density;  $\rho_b$  is bulk density of the formation [13]. We usually assume the fluid density is between 1.0 and 1.1. If gas is present, the actual fluid density will be  $< 1.0$  and the calculated porosity will be too high [14].

## 2.2 Textural Parameters

Statistical/textural parameters which include graphic mean, graphic standard deviation, graphic skewness and graphic kurtosis are needed for grain size and statistical spreading [15]. Textural parameters can be obtained from percentile deduction and statistical analysis of data. It relates with the velocity of the medium accountable for the transportation and deposition of sediment (or sand-shale lithology in this research) [5-6]. Table 1 highlights different interpretation of these parameters with their corresponding values. The mean (M) may be determination using Equation 6.

$$M = \frac{1}{3}(\phi_{16} + \phi_{50} + \phi_{84}) \quad (6)$$

Parameters such as standard deviation, sorting, skewness and kurtosis can be calculated by means of Equations 7 to 10 [4-6; 16]. Standard deviation is a measure of sorting. The sorting of a given population is a measure of the range of grain-size present and the magnitude of these sizes around the mean sizes [17]. Sorting can be homogenous [if it occurs when there is a very negligible level of deviation from the mean] or heterogeneous [if there is high deviation from the mean] [18]. SD and S

expressions are presented in Equations 7 and 8 respectively.

$$SD = \frac{1}{4}(\phi_{84} - \phi_{16}) \quad (7)$$

$$S = \frac{\phi_{84} - \phi_{16}}{4} + \frac{\phi_{95} - \phi_5}{6.6} \quad (8)$$

Skewness ( $S_k$ ) is another parameter. It measures the symmetry of a curve by marking the position of the mean in relation to the median [19]. A given size population that has a tail of excess fine particles is said to be positively skewed while one with tail excess is said to be negatively skewed. Equation 9 is the best relation for determining skewness. Negatively skewed (which is coarse skewed) defines high energy environment and positively skewed (which is finely skewed) corresponds to low energy environment.

$$S_k = 0.5 \left( \frac{\phi_{84} + \phi_{16} - 2\phi_{50}}{\phi_{84} - \phi_{16}} + \frac{\phi_5 + \phi_{95} - 2\phi_{50}}{\phi_{95} - \phi_5} \right) \quad (9)$$

The calculation of Kurtosis could be done using Equation 10. Kurtosis measures the sorting ratio at the extremes of the distribution [4]. If kurtosis is defined as platykurtic, its value is negative excess kurtosis (that is, opposite situation to the case of leptokurtic); if it is mesokurtic, kurtosis curve is observed to have uniform sorting in both tails and central position and finally leptokurtic, if its value is positive excess kurtosis (tail is better sorted than central portion) [20]. It is a quantitative measure used to describe the departure from normality of distribution. It signifies the ratio between sorting in tails and central portion of the curve.

$$K_s = \frac{\phi_{95} - \phi_5}{2.44(\phi_{75} - \phi_{25})} \quad (10)$$

**Table 1: Classification of textural parameters [4-6; 21-22].**

S/N	Parameters	Range of values	Interpretation/Classification
1	Sorting	Less than 0.35	Very well sorted
2	Sorting	0.35 to 0.50	Well sorted
3	Sorting	0.51 to 0.70	Moderately well sorted
4	Sorting	0.71 to 1.00	Moderately sorted
5	Sorting	1.01 to 2.00	Poorly sorted
6	Sorting	2.01 to 4.00	Very poorly sorted
7	Sorting	Greater than 4.00	Extremely poorly sorted

8	Skewness	Less than - 0.30	Very coarse skewed
9	Skewness	- 0.30 to - 0.11	Coarse skewed
10	Skewness	- 0.10 to +0.10	Near symmetrical
11	Skewness	+0.11 to +0.30	Fine skewed
12	Skewness	Greater than +0.30	Very fine skewed
13	Kurtosis	Less than 0.67	Very platykurtic
14	Kurtosis	0.67 to 0.90	Platykurtic
15	Kurtosis	0.91 to 1.11	Mesokurtic
16	Kurtosis	1.12 to 1.50	Leptokurtic
17	Kurtosis	1.51 to 3.00	Very leptokurtic
18	Kurtosis	Greater than 3.00	Extremely leptokurtic

### 2.3 Coefficient of Variation (CV)

This is also called Relative Standard Deviation (RSD) which is the standardized measure of dispersion of probability or frequency distribution. It is the ratio of the SD to the mean signifying the extent of variability in relation to the mean population [23]. If CV is less than one, it is low variance; if it is greater than one, it is high variance. It is mostly expressed in percentage.

### 3. Location and Geology

In the Eastern Niger Delta,  $X_A$  Field is located, South of Port Harcourt, Rivers State, Nigeria. Niger Delta basin is defined [24] between latitudes  $3^0N$  and  $6^0N$ ; longitudes  $5^0E$  and  $8^0E$  [25]. This region experiences wet and dry moments depending on the season in a year and the average rain in a month during wet season is about  $1.35 \times 10^2$ mm and reduces to  $6.50 \times 10^1$ mm while approaching dry

season [26-27]. The volume of sediment is nearly  $500000\text{km}^3$  [28-29]. The oil in the basin belongs to the category of Akata-Agbada [30-32]. More of marine shales made up the Akata formation with an expected width of up to  $7.0 \times 10^3$ m [33]. The Agbada formation is the major oil reservoir in the Niger Delta.

### 4. Methodology (Materials and Method)

Onshore  $X_A$  Field data was acquired from the Niger Delta Basin. These include well location and raw well data. With Microsoft Excel, data loading, processing, plots/curves, diagrams and other computations were obtained.

Two wells (A and B) were studied. Suites of log such as depth, gamma ray, density and sonic were generated from the available data. These data were analysed using Microsoft Excel. Figure 1 outlines the steps taken to arrive at the results.

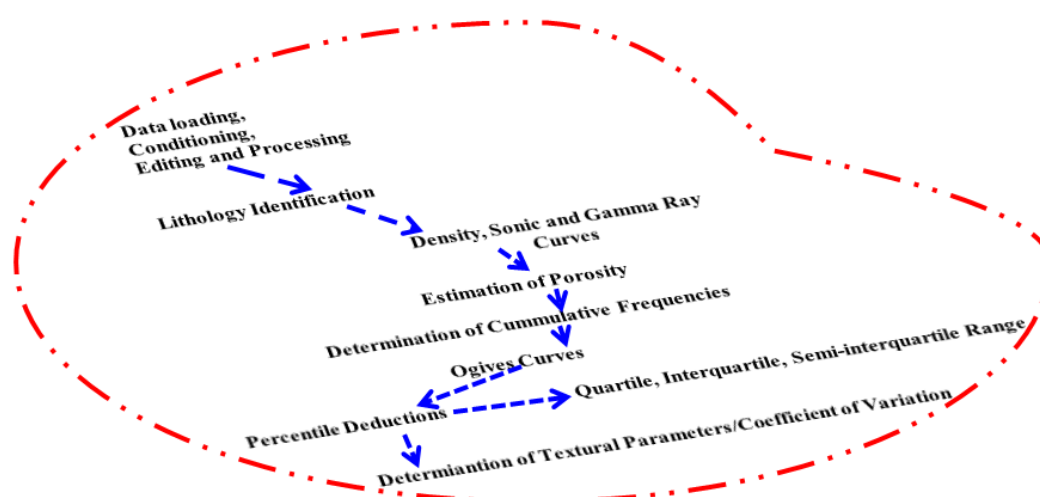


Figure 1: Workflow of the study.

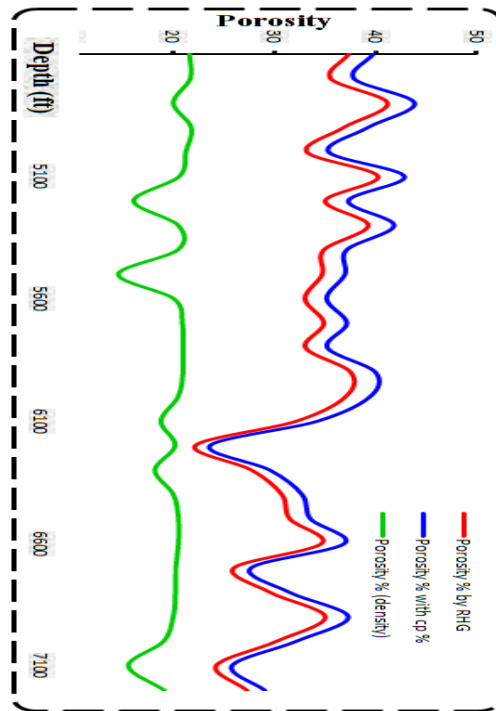
## 5. Results and Discussion

### 5.1 Result

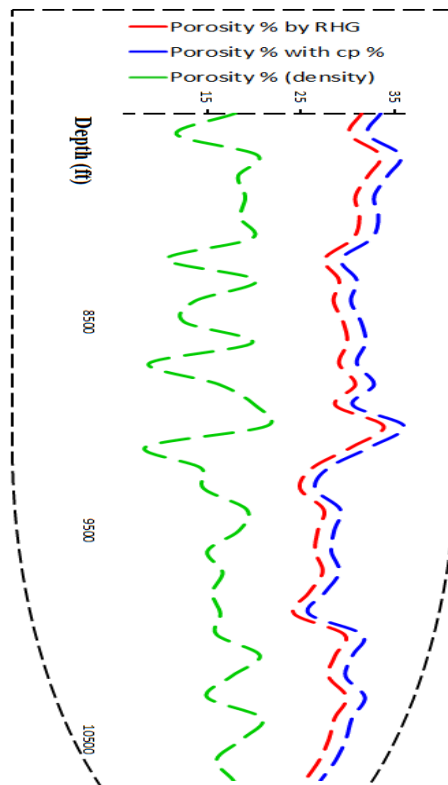
The results on porosity estimates obtained are shown in Figures 2 and 3. Figures 4 to 7 highlight

the cumulative frequency curves (the Ogive) used for percentile, quartile, and interquartile range results. Table 2 shows the percentile deductions and

other statistical results. Table 3 has information on the textural parameters obtained.



**Figure 2: Depth-Porosity curves estimated from different Techniques (red from one, blue from two and green from three) for well A.**



**Figure 3: Depth-Porosity curves estimated from different Techniques (red from one, blue from two and green from three) for well B.**

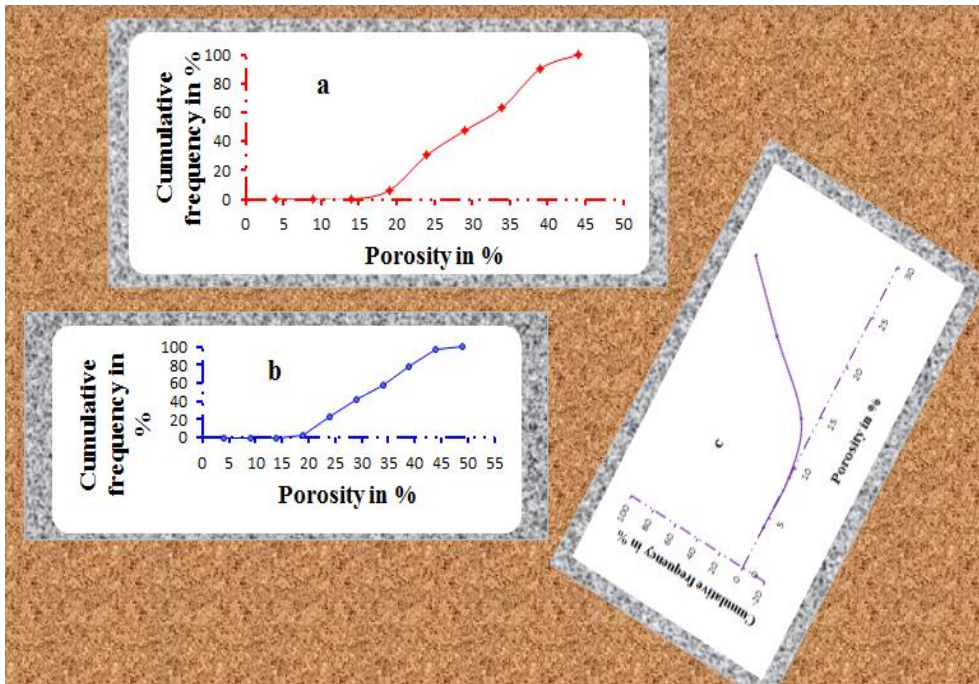


Figure 4: The Ogive resulting from Technique (a) one (b) two (C) three for well A.

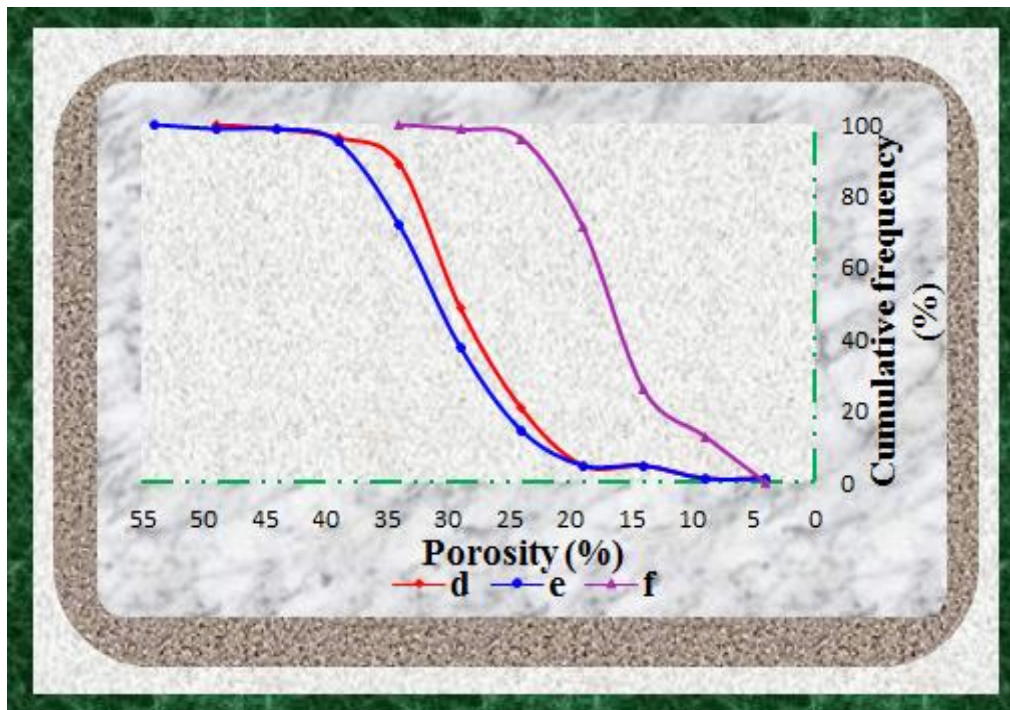


Figure 5: The Ogive resulting from Technique (d) one (e) two (f) three for well B.

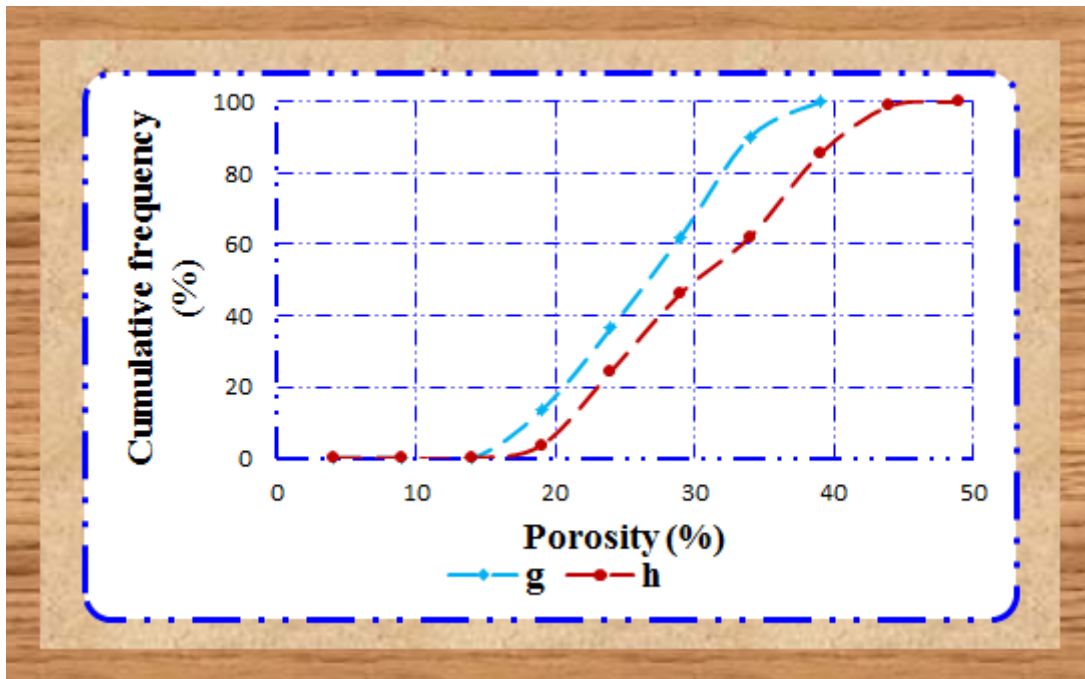


Figure 6: The Ogive resulting from Technique (g) four (h) five for well A.

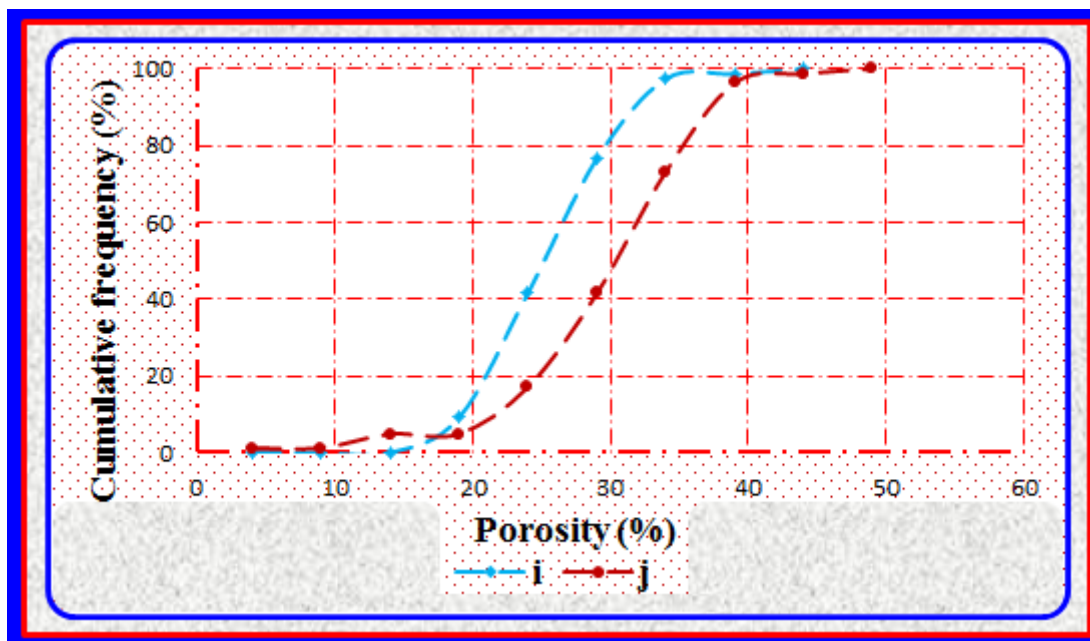


Figure 7: The Ogive resulting from Technique (i) four (j) five for well B.

Table 2: The Percentiles obtained from each Technique and other Statistical Results

Wells	Techniques	Percentiles							SD	Mean	CV (100%)
		$\phi_5$	$\phi_{16}$	$\phi_{25}$	$\phi_{50}$	$\phi_{75}$	$\phi_{84}$	$\phi_{95}$			
A	one	18.0	21.0	23.0	30.0	36.0	38.0	41.0	4.25	29.6667	14.3258
	two	19.5	22.0	24.5	31.5	38.0	40.5	43.0	4.50	31.3333	14.7606
	three	12.5	14.5	15.5	18.0	21.0	22.0	23.5	1.88	18.1667	10.3211
	four	16.0	19.5	21.5	26.5	31.5	33.0	36.5	3.38	26.3333	12.8165
	five	19.0	22.0	24.0	30.0	37.0	38.5	42.5	4.13	30.1667	13.6740
B	one	19.0	23.0	25.0	29.0	32.0	33.0	37.0	2.50	28.3333	8.8235

two	19.0	24.5	26.0	31.0	35.0	37.0	39.0	3.00	30.8333	10.1351
three	6.0	10.5	14.0	17.0	19.5	21.0	23.5	2.75	16.1667	16.2371
four	16.5	20.0	21.5	25.5	28.5	30.5	33.5	2.63	25.3333	10.3618
five	19.0	23.5	25.5	30.5	34.5	36.5	38.5	3.25	30.1667	10.7735

**Table 3: Result of textural parameters and interpretation**

Techniques	Sorting	skewness	Kurtosis	Interpretation
One for A	7.5833	-0.0294	0.6936	Extremely poorly sorted, Near symmetrical, Platykurtic
Two for A	8.1856	-0.0242	0.7134	Extremely poorly sorted, Near symmetrical, Platykurtic
Three for A	3.5417	0.0333	0.8197	Very poorly sorted, Near Symmetrical, Platykurtic
Four for A	6.4811	-0.0307	0.8402	Extremely poorly sorted, Near symmetrical, Platykurtic
Five for A	7.6856	0.0471	0.7409	Extremely poorly sorted, Near symmetrical, Platykurtic
One for B	5.2273	-0.1556	1.0539	Extremely poorly sorted, Coarse Skewed, Mesokurtic
Two for B	6.1553	-0.1200	0.9107	Extremely poorly sorted, Coarse Skewed, Mesokurtic
Three for B	5.2765	-0.2476	1.3040	Extremely poorly sorted, Coarse Skewed, Leptokurtic
Four for B	5.2008	-0.0532	0.9953	Extremely poorly sorted, Near Symmetrical, Mesokurtic
Five for B	6.2045	-0.1282	0.8880	Extremely poorly sorted, Coarse Skewed, Platykurtic

## 5.2 Discussion

Different methods have been recommended by good number of Authors for porosity estimates. Three of these methods have been studied so as to compare the deviation of their mean results from the median.  $X_A$  Field well data was obtained from the Niger Delta Basin and was analysed to identify the sandstone (less than 75 API) and the shale (greater than 75 API) lithologies using Gamma ray log after the data had been used to generate suites of log. Equations 1 to 5 were adequate for porosity estimates from Well A (Figure 2) and Well B (Figure 3) but with deviations. In order to effectively study these deviations, the porosity information obtained was subsequently considered as a grouped data to enable the findings of textural parameters using the Percentile-Ogive procedure. Equations 1 to 3 is the Wyllie approach called technique one. Equation 4 is the Raymer-Hunt-Gardner (RHG) called technique two. Equation 5 is one referenced by Serra in 1984 called technique three. The mean of the porosity estimates from these three approaches yielded technique four and lastly, technique five results from the mean of the two closest results which are the results from the methods using sonic data. The results are seen in Figures 4 to 7.

Figure 4a is the plot of cumulative frequency in percentage or relative cumulative frequency against porosity in percentage for well A, which was achieved by technique one. Figure 4b results from cumulative frequency (%) - porosity (%) curve for well A, which was achieved using technique two information. Figure 4c is the plot of cumulative frequency in percentage against porosity in percentage for well A, which was accomplished by technique three.

Figure 5d is the curve of cumulative frequency in percentage or relative cumulative frequency against porosity in percentage for well B, which was achieved by technique one. Figure 5e defines the curve of cumulative frequency in percentage against porosity in percentage for well B, which was achieved by technique two. Figure 5f results from cumulative frequency (%) - porosity (%) curve for well B, which was realized using technique three information.

Figure 6g and 6h are Ogives resulting from technique four and technique five respectively for well A. Figure 7i and 7j are Ogives resulting from technique four and technique five respectively for well B.

All these Figures (4 to 7) aided the determination of percentile results (Table 2). The standard deviation,

the mean and the coefficient of variation results are also presented in Table 2.

If the spread of values in the data set is large, the mean is not as representative of the data as if the spread of data is small because a large spread indicates that there are probably large differences between individual scores. So in the case of the mean presented in Table 2, technique three is recommended as the most suitable and adequate for porosity estimate in Niger Delta basin. In the case of standard deviation, it shows how varied the data spread out from the mean. Technique three yields better results for wells A and B, though Techniques one and four resulted in the least deviated values for well B. The resulting Coefficient of Variation (CV) indicates that the least varied result (10.3211%) for well A is from Technique three. For well B,

8.8235% is the lowest value of CV obtained from Technique One. The numerator with higher value increases the mean and the standard deviation, so these results could be misleading and as well influence the CV information obtained. This is explained in Equation 11.

$$\frac{W-X}{W+X} \neq \frac{Y-Z}{Y-Z} \quad (11)$$

Where  $W > X$ ,  $Y > Z$  and even if  $W - X = Y - Z$ .

The use of Interquartile Range (IQR) was employed to discuss the skewed distribution of the data set. The 75<sup>th</sup> quartile was considered as the upper quartile, the 50<sup>th</sup> or the middle quartile was taken as the median and the lower quartile corresponds to the 25<sup>th</sup> quartile.

**Table 4: The Interquartile Range and Semi-Interquartile Range result summary**

Well A Techniques	Well A					Well B				
	one	two	three	four	five	one	two	three	four	five
IQR	13.00	14.00	5.50	10.00	13.00	7.00	8.50	6.00	7.00	9.00
SIQR	6.50	7.00	2.75	5.00	6.50	3.50	4.25	3.00	3.50	4.50
Diff. M from Q3	6.00	7.00	2.50	5.00	7.00	2.50	3.50	3.50	3.00	4.00
Diff. M from Q1	7.00	7.00	3.00	5.00	6.00	4.50	5.00	2.50	4.00	5.00

A larger IQR (or Semi-Interquartile Range (SIQR)) from Table 3, shows the data values are widely spread. With this further analysis, Technique three is seen as the best approach for porosity estimates due to the reduced spread of the result. Where only sonic log data is available, Technique one is recommended as the most suitable.

However, to define the porous nature of the lithology (matrix), textural parameters from percentile results are required. Since the best method recommended in this research is Technique three, the matrices are very poorly sorted, near symmetrically skewed [that is, nearly zero but with a positive value, it is skewed positively] and platykurtic for well A. Also, for well B, they are extremely poorly sorted, coarse skewed [indicating high energy environment] and leptokurtic.

## 6. Conclusion

The textural parameters enable us to adopt a better

approach which is more suitable for estimation of porosity. However, from the analysis of coefficient of variation, it has been observed that none of these method results approaches or equal to unity [in fraction]; meaning all fall within the low variance. Among the three major Techniques studied, Technique three with least deviation as presented in the semi-interquartile range row of 2.75 and 3.00 respectively for wells A and B has been recommended. The matrices are very poorly sorted, near symmetrically skewed and platykurtic for well A; as well as extremely poorly sorted, coarse skewed indicating high energy environment and leptokurtic for well B. Where only sonic log data is available, Technique one is recommended over Technique two to improve the result. The average porosity estimates for each major Technique include 33.1977% from one, 35.3478% from two and 19.8678% from three for well A; also, 28.2475% from one, 30.0770% from two and

16.4962% from three for well B. Since our research is in support of Technique three, therefore, approximately 20% and 16% porous nature of the study area lithology for both wells A and B belong to the class of good porosity.

### 7. Conflict of Interest

There are non-conflicts of Interest.

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