Demonstration of Clay Mineral Distribution and Its Effect on Porosity of Reservoirs in "Amo" Field in the Niger Delta Basin of Nigeria

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ABSTRACT

The wireline log responses are affected by clay depends on not just the proportion of shale and the physical properties of shale in the host rock but also on the distribution of clay types. The Thomas-Steiber model (1975) was used to interpret the clay distributions and their effects on total porosity of reservoirs in "Amo-Field". The model has unveiled laminated (pore filling), dispersed (pore filling), and structural clay (grain replacing) kinds of clay distribution in the "Amo-Field". Using Thomas-Steiber model equations, the total porosities for the laminated, dispersed, and structural clay distribution for reservoir A2 in well A are 0.015%, 0.06%, and 0.35%, respectively while in reservoir A3 in the same well, the total porosities are 0.009%, 0.048%, and 0.035% with laminated clay distribution in reservoir A3 having the highest porosity reduction.

For reservoir B2 in well B, their clay distribution types are structural (grain replacing) and dispersed (pore filling) while their total porosities are 0.010% and 0.30%. For reservoir B10, the true total porosity of this reservoir is 0.095% with dispersed (pore filling) clay distribution. Total porosities for reservoir were obtained from using laminated, dispersed (pore filling) and structural clay (grain replacing) distribution clay equations are 0.32%, 0.16%, and 0.40% for C1 reservoir while total porosity for reservoir C5 with structural (grain replacing) clay distribution is 0.28%. Clays in "Amo-Field" are distributed in the form of dispersed, laminated, and structural clay. The clay in the reservoirs accelerate the rate of total porosity loss in the reservoirs.

(Keywords: distribution of clay types, Amo-Field, porosities, dispersed clay, laminated clay, structural clay, Niger Delta)

INTRODUCTION

Clay minerals mask the high resistance property of hydrocarbon and significantly affect the following important reservoir properties: porosity, water saturation, and permeability (Ruhovelts and Fertl, 1982, Fozao, *et al*., 2019). Accurate prediction of clay distribution within reservoirs enables reliable estimation of the volume of producible hydrocarbons, thus reducing uncertainties and risks in heterogeneous sandstone reservoir production (Mode, *et al*., 2013).

The volume of shale of reservoir in "Amo-Field was evaluated to be within the limit that can affect the reservoir quality (Eze, *et al*., 2017). The layered structure of clays always has effect on logs. The conductivity and the porosity measurements are affected due to the water that is trapped between the layers (Mohammed, 2015). The presence of negative charges on the clay surface allows them to attract cations (Sondhi, 2011; Kale, *et al.*, 2010). Thus, the cation exchange coefficient (CEC) of clay determines the extent clay lowers the resistivity reading of a reservoir (Boyd, *et al.*, 1995). The CEC which is the ability of clays to exchange the cations, not only depend on the volume of clay mineral but also on how those clays are distributed in the formation (Ipek, *et al.*, 2005, Hafizh, *et al.*, 2022). The extent to which log evaluation and the resulting estimation of water saturation (Sw) is affected by clay or shale also depend on the type and volume, as well as the distribution of shales and clays with respect to the pay sand.

A reservoir sand can display any of these three modes of clay distribution: laminar, dispersed shale, and structural clay distribution (Siyamak Moradi, *et al*., 2016, Maeland, 2014). Clay distribution on the other hand is controlled by burial history, sedimentary environments and lithologies (Xiaolong, *et al*., 2019).

Having an adequate knowledge about the kind of clay minerals in the rock formation of an interested area help in choosing a suitable drilling mud (Mohammed, 2015). Shale can be distributed across a reservoir sand body as a combination of different modes: Therefore, the way log responses is affected by clay depends on the modes, that is the clay distribution pattern, the proportion of shale and the physical properties of shale in the host rock. According to Thomas-Steiber's model, the porosity behavior of any shaly sand depends on the amount of shale and the nature of shale/clay distribution in the sand. This work aims at demonstration of the clay distribution and estimation of total porosities of the delineated reservoirs using Thomas-Steiber's model.

CLAY DISTRIBUTION

I. Laminar Clays: Clay layers between sand layers. They make up significant percentage of low resistivity formations offshore. Laminar shales are formed during deposition, interspersed in otherwise clean sands (Boyd, *et al*., 1995). Laminated shales/clays replace porosity and matrix.

II. Dispersed Clays: Presence of Clays throughout the sand, coating the sand grains or filling the pore space between sand grains. Dispersed clays are formed during deposition of individual particles or masses of clay. Dispersed clays can result from post depositional processes, such as burrowing and diagenesis. In clay coated sand grains the irreducible water saturation of the formation increases, lowering the resistivity values. Dispersed shales/clays replace the porosity.

III. Structural Clays: Clay grains or nodules in the formation matrix. Structural clays occur when framework grains and fragments of shale or claystone occur with a grain size equal to or larger than the framework grains are deposited at the same time. Structural clays/shales replace only the matrix.

GEOLOGY OF NIGER DELTA BASIN

The opening of the southern Atlantic in late Jurassic led to the formation of the Niger Delta at the site of a rift triple junction (Tuttle, *et al*., 1999). From the Eocene to the present, the delta has prograded southwestward. The depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990) were formed from Eocene to the present progading southwestward (Doust and Omatsola). The thickness of sediments in the Niger Delta basin average 12 km and it covers a total area of about 140,000 km^2 (Obaje, 2009).

The following formations makes up the Niger Delta Basin. They are: Akata Formation, Agbada Formation and Benin Formation. Lithologically, the Benin formation is made up of continental sands and gravels. The Agbada formation consists of sand while the marine origin Akata formation is composed of shales sequences, turbidite sands potential reservoir, clays, and silts (Short and Stauble, 1967, Tuttle, *et al*.,1999). Akata formation deposition began in the Paleocene and through the Recent it formed during low stands when terrestrial organic matter and clays were transported to deep water areas (Stacher, 1995). Deposition of Agbada formation was from Eocene to Recent. This is the major petroleum-bearing unit. The Agbada Formation is overlayed the by the third formation the Benin Formation. It is a continental alluvial and upper coastal plain sands deposit aged latest Eocene to recent (Figure 1).

METHODOLOGY

This research was carried out using three suites of wire line geophysical well logs obtained from Elf Petroleum, Ltd. through the permission of Department of Petroleum Resources. The depth of well A is 4,245 meters, depth of well B is 4,413 meters while well C was drilled to 3,166 meters depth. These logs are Gamma ray, Neutron, Sonic, density, self-potential (SP), resistivity log (LLD and MSFL), and caliper log.

The productive reservoir units were delineated by analyzing the gamma ray log, resistivity, and neutron and Density logs. Total porosity versus volume of shale (Vsh) were plotted using the rhombus plot proposed by Thomas and Steiber (1975). This demonstration was used to interpret the type of shale-distribution in the reservoirs of the three wells.

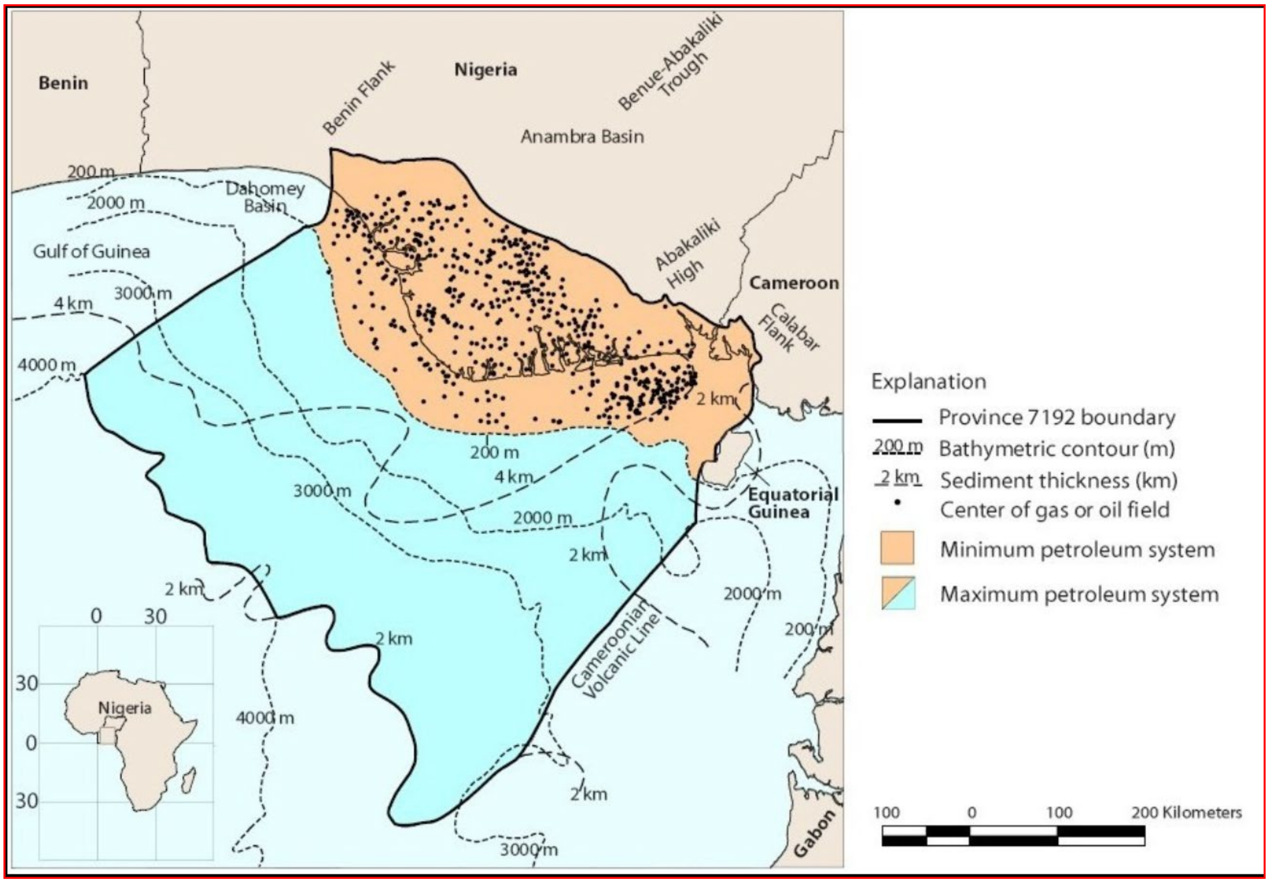


Figure 1: Map of Niger Delta showing Province outline (maximum petroleum system) and key structural features. Minimum petroleum system as defined by oil and gas field center points (data from Petroconsultants, 1996); 200,2,000, 3,000, and 4,000m bathymetric contours shown by dotted contours; and 2 and 4 km sediment isopach shown by dashed lines (from Tuttle, *et al.*, 1999).

The following model equations describing Total porosity as a function of Vsh for purely laminated, dispersed and structural distribution of shale by Thomas and Steiber (1975) were used to compute the total porosity for each case. They are as follows:

Laminated: $\Phi_T = \Phi_s V_{sh} * (\Phi_s - \Phi_{sh})$

Dispersed (Pore filling): $\Phi_T = \Phi_s - V_{sh} * (1 - \Phi_{sh})$ ……for $Vsh <= \Phi_s$

Dispersed (grain replacing): $\Phi T = V_{sh} * \Phi_{sh}$ .... for $V_{sh} > \Phi_s$

Structural (grain replacing): $\Phi T = \Phi_s + V_{sh} * \Phi_{sh}$ .....for $Vsh < 1 - \Phi_s$

Structural (Pore filling): $\Phi_T = 1 - Vsh * (1 - \Phi_{sh})$……for $Vsh > 1 - \Phi_s$

Where, Φ_T represent Total Porosity and V_{sh} represent volume of shale while the subscripts "Φ_{sh}" and "Φ_s" represent the porosities of ~100% shale and sand intervals respectively**.** Total porosity which is the total pore volume of the rock includes porosity filled with hydrocarbons, moveable water, capillary-bound water, and clay-bound water (Hook, 2003, Archie, 1942) was calculated using the following equation:

$$\phi_D = \rho_{\max} - \rho_b \big/ \rho_{\max} - \rho_{fl}$$

Where $Ø_D$ and ρ_{max} stand for total and matrix porosity respectively.

The value of matrix density (sandstone) = 2.65g/cm^3.

ρ_b stands for bulk density (log reading) and ρ_{fl} stands for fluid density = 1.0g/cm (for water), 0.7 (for gas) and 0.9 (for oil).

The shale volume was then calculated using the Larionov (1969) nonlinear response method.

$V_{sh} = 0.083\left(2^{3.71} I_{GR} - 1\right)$ for tertiary unconsolidated rocks, where V_{sh} represents volume of shale and I_{GR} is the gamma ray index and it was gotten using the following equation:

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

Where I_{GR} = Gamma ray Index,
$GR_{\log}$ = Gamma ray reading of formation, $GR_{\max}$ and $GR_{\min}$ are maximum gamma ray for shale and minimum gamma ray for clean sand, respectively.

RESULT AND DSCUSSION

Porosity value and shale volume from log data at each reservoir layer were imputed to Thomas and Steiber (1975) model for the determination of true total porosities of the reservoirs (Hafizh, *et al*., 2022). The position of each point inside the rhombical area of the plots determines the type of clay distribution in the field (see Figures 1, 2, and 3).

Clay Distribution for Well A

Figure 2 is a plot of total porosity versus volume of shale of two reservoirs A2 and A3 of well A. Reservoir A2 has sand porosity (Φ_s) of 0.32% and shale porosity (Φ_{sh}) of 0.13% and the volume of shale is 0.25%. Reservoir A3 has sand porosity (Φ_s) of 0.32% and shale porosity (Φ_{sh}) of 0.08% and the volume of shale is 0.12%. The plots reveals that the clay distribution in reservoir A2 is mixed-type clay distribution as the data plot within the lines that defined both laminated, dispersed (pore filling because $V_{sh} < \Phi_s$) and structural clay (grain replacing because $Vsh < 1- \Phi_s$) distributions.

Using laminated, dispersed (pore filling) and structural clay (grain replacing) distributions equations, the total porosities for the laminated, dispersed (pore filling), and structural clay (grain replacing) distributions are 0.015%, 0.06%, and 0.35%, respectively. Laminated and dispersed (pore filling) clay distribution have affected the reservoir more than the structural (grain replacing) clay distribution. Temporal variations in sediment supply and flow velocity result in shale lamination and lamination can be a key feature of shales in terms of porosity, permeability, and shale brittleness (Juhwan, *et al*., 2021). However, textural and compositional variations due to fluctuations in sediment type and transport, water chemistry, and biogenic activity are the environmental setting that preserve laminated fabric (Yawar and Schieber, 2017).

The plot reveals that the clay distribution in reservoir A3 (Figure 2) is also mixed-type clay distribution as the data plot within the lines that defined both laminated, dispersed (pore filling) and structural clay (grain replacing clay distributions). Using the preceding equations, the total porosities for the laminated, dispersed (pore filling) and structural clay (grain replacing) distributions are 0.009%, 0.048%, and 0.035%, respectively. The porosity of this reservoir is drastically affected by these clays and the highest porosity reduction is reduction due to laminated clay distribution in reservoir A3 (well A) (Table 1).

Clay Distribution for Well B

The clean sand and shale porosity for reservoir B2 are 0.29% and 0.08%, respectively, and the volume of shale is 0.12%. The plot in Figure 3 of Total porosity versus Vsh revealed that the clay distribution for reservoir B2 are structural (grain replacing) and dispersed (pore filling) because the data plotted mainly on the line that defined the dispersed clay (pore filling) distribution and structural (grain replacing). The total porosity for structural (grain replacing) clay distribution is 0.010% while the total porosity for dispersed (pore filling) clay distribution is 0.30% (Figure 3). The clean sand porosity for reservoir B10 is 0.24% and porosity of shale is 0.05% while the volume of shale is 0.14%.

Table 1: Clay Distributions and the Resultant Petro-Physical Parameters.

Well Types/Reservoirs		Clay Distributions	Volume of shale of the reservoir (Vsh)	Total Porosity (Ø) of the reservoirs	Clean sand Porosity (Øs) of the reservoirs	Shale porosity (Øsh) of the reservoirs
WELL A	Reservoir A2	Laminated, dispersed (pore filling) and structural (grain replacing) clay distributions.	0.25%.	0.015%, 0.06% and 0.35%	0.32%	0.13%
	Reservoir A3	Laminated, dispersed (pore filling) and structural clay (grain replacing clay distributions.	0.12%.	0.009%, 0.048% and 0.035%	0.32%	0.08%
WELL B	Reservoir B2	Structural (grain replacing) and dispersed (pore filling) clay distributions.	0.12%.	0.010% and 0.30%	0.29%	0.08%
	Reservoir B10	Dispersed (pore filling) clay distributions.	0.14%.	0.095%.	0.24%	0.05%
WELL C	Reservoir C1	Laminated, dispersed (pore filling) and structural (grain filling) clay distributions	0.11%.	0.32%, 0.16%, and 0.40%	0.30%,	0.18%
	Reservoir C5	structural clay distribution	0.10%.	0.28%	0.30%	0.20%

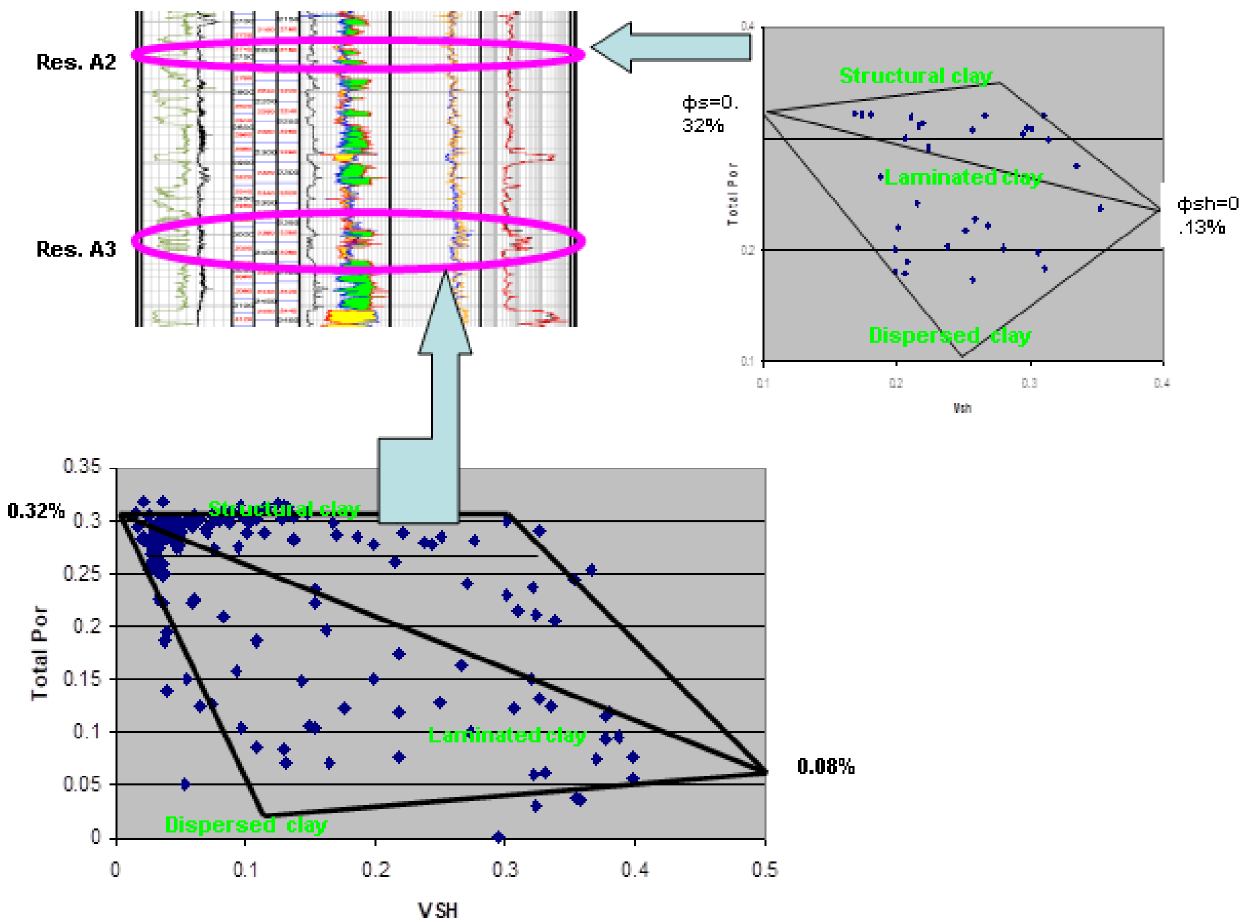
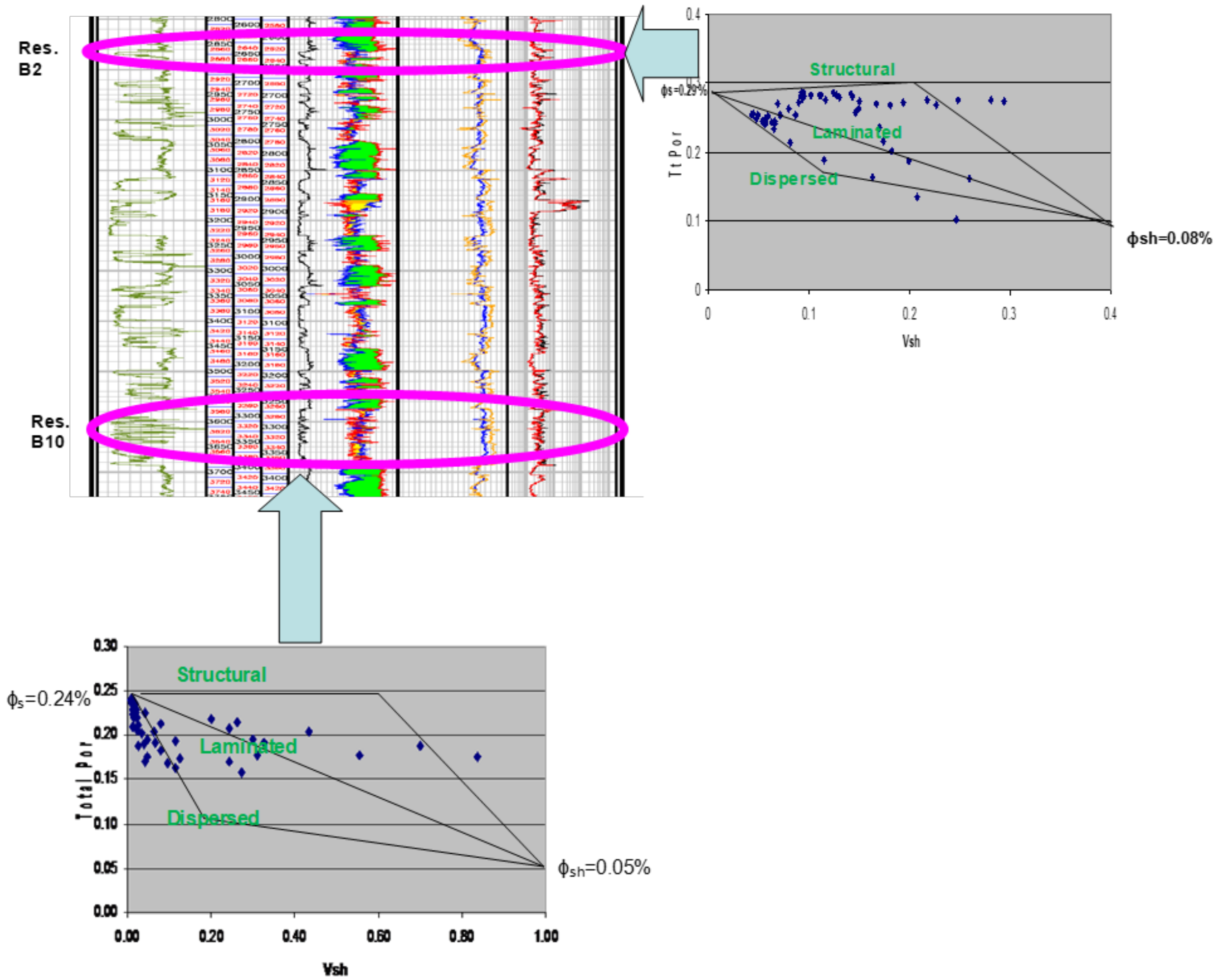


Figure 2: Thomas-Steiber's Triangle for Reservoir A2 and A3 of Well-A.



Fiure 3: Thomas-Steiber's Triangle for Reservoir B2 and B10 in Well B.

The log data for reservoir B10 plotted along the dispersed (pore filling) clay distribution line, using the equation for dispersed (pore filling) clay distribution above, the true total porosity of this reservoir is 0.095%. Pore-filling clay mineral distribution affects the pore connectivity (permeability) more than the pore spaces porosity (Ahmad, *et al.*, 2018).

Clay Distribution in Well C

Figure 4 is the volume of shale versus Total porosity (Thomas –Steiber's Triangle) plot for reservoir C1 and C5 of Well C. The clean sand porosity for reservoir C1 is 0.30%, the porosity of shale is 0.18%, and the volume of shale is 0.11%. Reservoir C5 has clean sand porosity of 0.30% and porosity of shale is 0. 20% with volume of shale of 0.10%. The clay distributions for reservoir C1 is mixed-type clay distribution as they plotted within the lines that defined laminated, dispersed (pore filling) and structural (grain filling) clay distributions, while data from the reservoir C5 plot on the line that define structural clay distribution. The Total porosities equations above for laminated, dispersed and structural (grain replacing) clay distributions were used in computing C1 porosities. Total porosities for reservoir gotten from using laminated, dispersed (pore filling) and structural clay (grain replacing) distribution equations for C1 are 0.32%, 0.16%, and 0.40% while Total porosity for reservoir C5 is 0.28% (Figure 4).

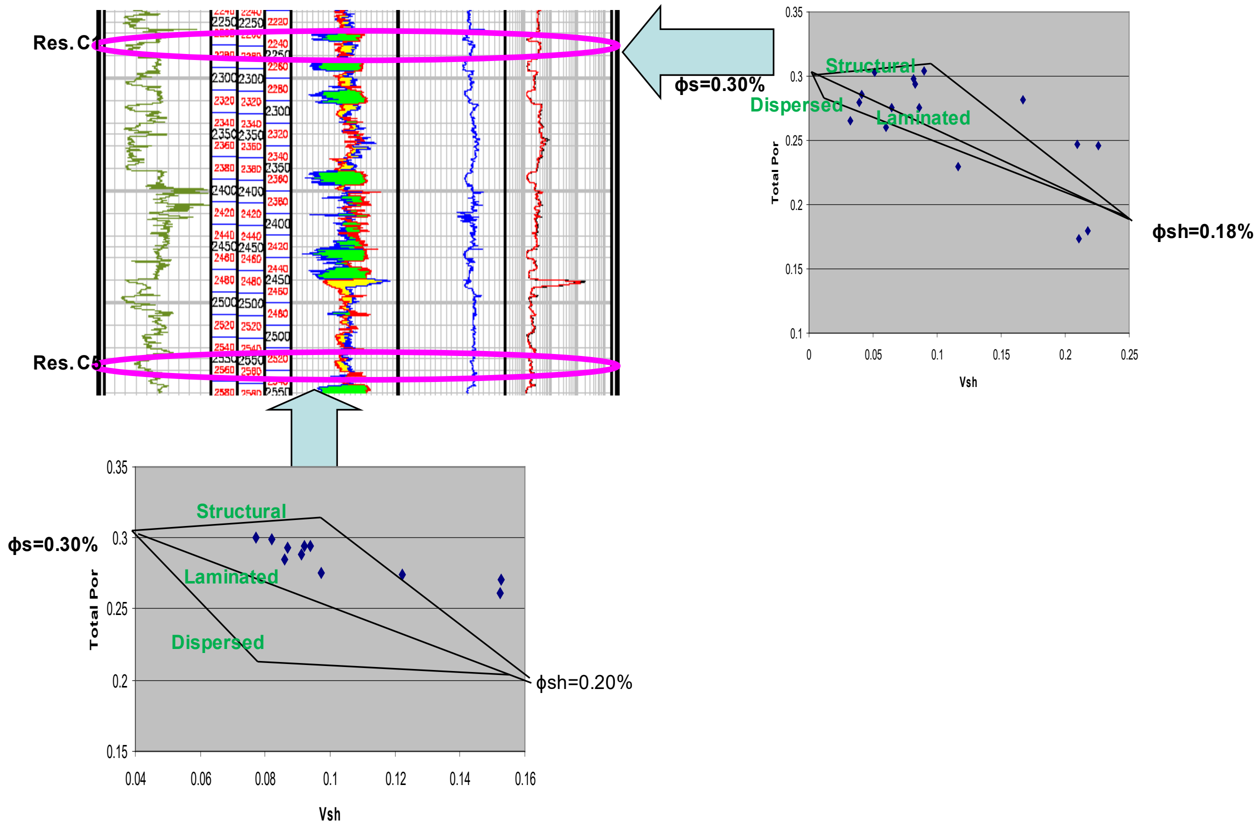


Figure 4: Thomas-Steiber's Triangle for Reservoir C1 and C5 in Well C.

CONCLUSION

The clay distribution studies carried out using the Thomas-Steiber's model, revealed that the clay in "Amo-field" are distributed in the form of dispereset, laminated, and structural clay distribution. The dispersed clay distribution in the field is mainly in form of pore filling while the structural clay distribution is mainly in form of grain replacing. The clay in the reservoirs accelerate the rate of total porosity loss in the reservoirs. The highest porosity reduction is reduction due to laminated clay distribution in reservoir A3.

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SUGGESTED CITATION

Eze, M.O. 2023. "Demonstration of Clay Mineral Distribution and Its Effect on Porosity of Reservoirs in "Amo" Field in the Niger Delta Basin of Nigeria". *Pacific Journal of Science and Technology*. 24(1): 131-139.