IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 6, Issue 3 Ver. II (May. – June. 2018), PP 68-85
www.iosrjournals.org

Effects of Shale Volume Distribution on the Elastic Properties of Reservoirs in Nan tin Field Offshore Niger Delta Nigeria

Eje,E. O[1]and *Ideozu, R.U[2]
Department of Geology, University of Port Harcourt;
*Corresponding author:*Ideozu. R. U.

Abstracts:*Shale volume (Vsh) estimation has been carried out on three selected reservoirs (Nan.1, Nan.2, and Nan.4) distributed across four wells (01, 03, 06, and 12) in Nantin Field, using petrophysical analysis and reservoir modeling techniques with a view to understanding the reservoir elastic properties. Materials utilized for this research work include: Well Log data (Gamma Ray Log, Resistivity Log, Sonic Log, Density Log, Neutron porosity log), and a 3-D Seismic volume were used for the study. Sand and shale were the prevalent lithologies in NantinField. Normal and synthetic Faults were also mapped, the trapping system in the field includes anticlines in association with fault closures. The thicknesses and lateral extents of these reservoirs were delineated into three zones (1, 2, and 3) which were modeled appropriately. Petrophysical and some elasticity parameters such as Poisson ratio (PR), Acoustic Impedance (AI), and Reflectivity Coefficient (RC) were evaluated for the wells. The results from elasticity evaluation showed a high Poisson Ratio of 0.40 in Nantin 2 reservoir of Well 12 based on high shale volume distribution of 0.70 indicating high stress level and possible boundary to hydraulic fracture. The lowest Poisson Ratio was evaluated in Nantinreservoir of Well 1 with lowest shale volume of 0.18 which indicates weak zones and may not constrain a fracturing job. Results from Acoustic impedance showed a high AI value of 7994.3 in Nan 2 Reservoir compared to Nan.1 which has the least AI value of 7447.3 because of low shale volume. A higher Reflectivity Coefficient of 0.01 was recorded in Nan.2 reservoir indicating bright spot while a lower RC of -0.00023 was recorded in Nan.4 Reservoir indicating dim spot. Hydrocarbon volume estimate of the three reservoirs showed 163mmstb in Nan.1 reservoir, 169mmstb, in Nantin2 reservoir and 115mmstb in Nan. 4 Reservoir. The reservoirs encountered were faulted and laterally extensive. Nantin2 reservoir was more prolific with a STOIIP of 169 mmstb compared to Nan. 1 with a STOIP of 163 mmstb and Nantin.4 with a STOIP of 115 mmstb, because of its good petrophysical values, facies quality and low shale volume distributions.*

Key Words:*Shale Volume Distribution, Niger Delta, Acoustic Impedance, Poisson's Ratio*

Date of Submission: 02-06-2018 Date of acceptance: 18-06-2018

I. Introduction

Petroleum is one of the world's major sources of energy and is a key factor in the continued development of world's economy. It is essential that, the future planners, governments and the various stakeholders in the oil and gas industry have a clear assessment and management of already discovered reserves. To optimize production, shale volume distribution and elasticity of reservoir cannot be over emphasized. The presence of shale in reservoir reduces porosity permeability and net-to-gross (NTG) (tight reservoir) Siyamak*et al.,* (2016). Shalines is known to affect petrophysical values and logging tool response Adeoti*et al.,* (2009). The presence of shale in reservoir may also cause well bore instability. When these volumes of shale are correctly mapped and estimated, alternative methods of reservoir management can be employed to optimize productions. Some reservoirs have been abandoned in Nantin Field (Figure 1), due to decline in reservoir productivity over time because of variation in shale volume and erroneous description of reservoir elastics properties. These have resulted in hydrocarbon reserves, dropping in productivity with time. Thus, qualitative and quantitative shale volume estimation and the resultant effects on reservoir quality, play a great role in reservoir exploration/management.Reservoir elasticity varies significantly from reservoir to reservoir because of different properties that make up this important component of the petroleum system (Magoon*et al.,* 1991). One of these properties is the shale volume distribution which imposes an elastic property on the reservoir, other elastic properties are Poisson ratio, reflectivity coefficients, acoustic impedance etc. Reservoirs elasticity are strongly anisotropic in most

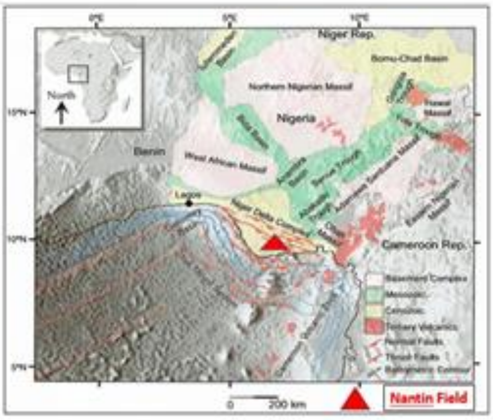


Figure 1a: Niger Delta Depobelt,
(Modified after Matchup and Watch, 2002)

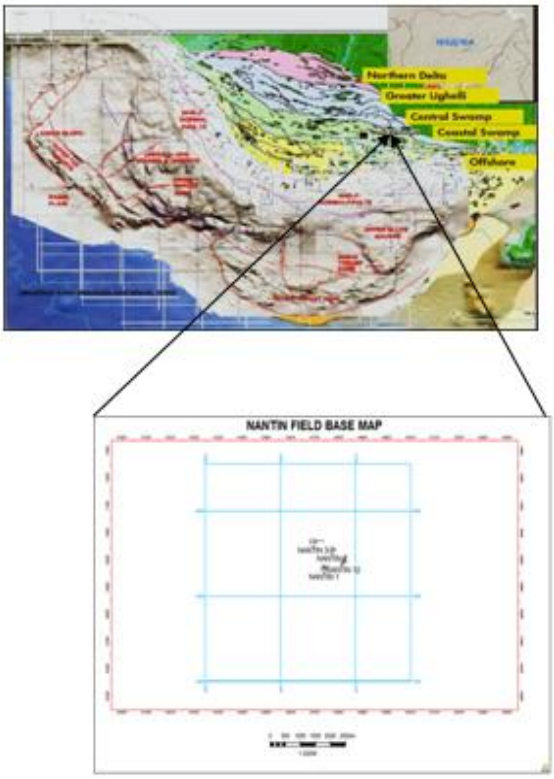


Figure 1.b: Niger Delta Depobelt, showing Distribution of Wells
Within the study area (modified after Matchup and Watch, 2002)

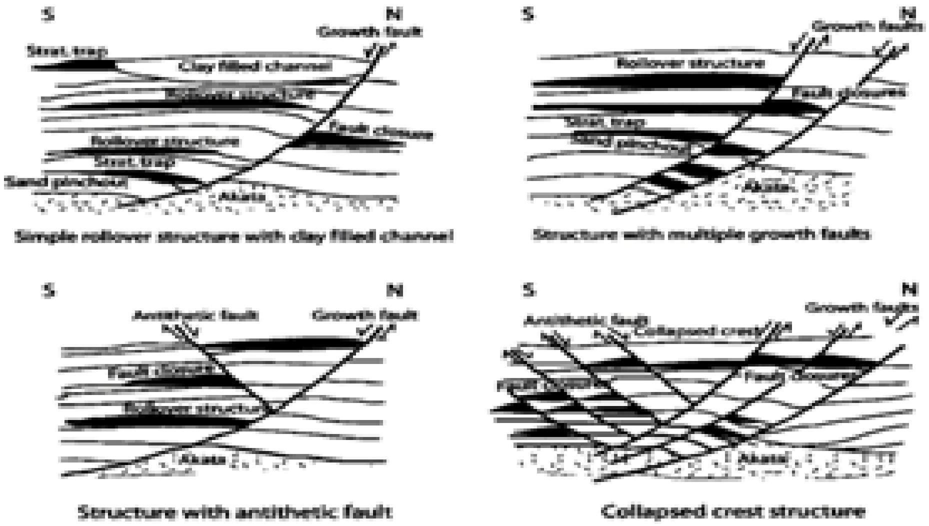


Figure 2 Niger Delta trapping system.
(After Doust *et al.*, 1990)

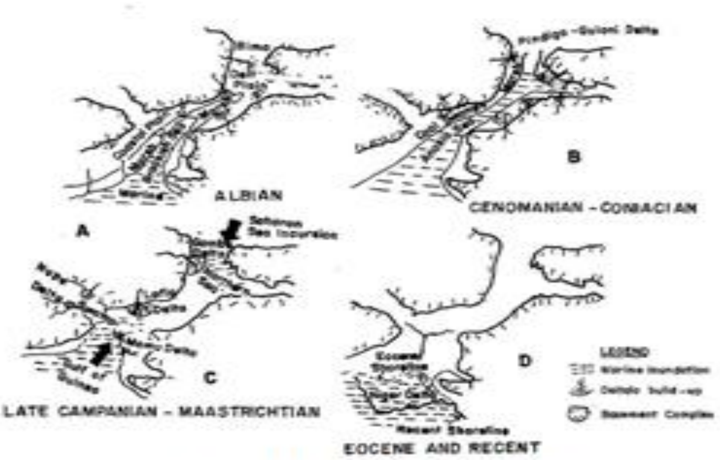


Figure 3Niger Delta lithostratigraphy.
(A) Generalized lithostratigraphy of Niger Delta
(B) Cretaceous to Recent pale geography of Niger
Delta (modified after Petters, 1978).

Cases and the degree of these anisotropy is because of the volume of shale, organic materials and the shale fabric. Shale is a fine grain heterogeneous sedimentary rock with different mineral composition. Siyamak*et al.,* (2016). Shale distribution in reservoir affects all petrophysical properties.

According to Cho and Perez (2014), Poisson's ratio is one of the many elastic moduli and it is related the material constitutive relations, Bahia *et al.,* (2015); suggested that Poisson ratio is relevant to clay content in shaly sand reservoirs by using Crain and Waxman- Smiths equation. Shale is a fine grained organic rich rock, which serve as source rock and reservoir rock in which shale gas can be found (Ross and Austine, 2007). Kennedy *et al.,* (2012) Identified that, shale has small pores with weak connection them and has low permeability. According to Tian et al., (2013), Shale gas exist as either free or absorbed gas. Free gas can fill opening in minerals which makes up the shale while absorbed gas is bonded to the clay particles and organic matter.Heidan*et al*., (2011), Quirein*et al.*, (2012) Sancifer*et al*., (2013) have characterized shale rich reservoir using well log data to analyze porosity, permeability, gas saturation, elasticity and Sarhi and Vargas- Murillo (2015) estimated water saturation in tight rock reservoir including those containing shale. Ahmad and Haghighi (2013) proposed a water saturation model appropriate for the range of total porosity in shale reservoir while Rickman *et al.*, (2008) identified, high deep resistivity values through depth as indicative of a less porous and pore containing hydrocarbon while,Dvorkins (2001) observed change of Poisson ratio in reservoir with different degrees of shale volume. In addition, anomalous high Poisson ratio values has observed in well data, he studied as most theories indicates that, PR in gas saturated sand lies within 0 to 0.255 range with typical values of about 0.15 while Dvorkins (2001). Perez (2013) investigated how changes in mineralogy and porosity affects elastic moduli and presented a chart to interpret the rock physics trends in Poisson's ratio. The geology, the stratigraphic, structural framework, petroleum geology and petroleum systems of the Niger Delta is well established (Doust and Omatsola, 1989, 1990; Reijers, 1996; Kulke, 1995; Ekweozor and Daukoru, 1994; Evamy*et al*, 1978:Mitchum and Wach, 2002; Stacher, 1995;Ejedawe, 1981; Weber, 1986; Doust and Omatsola, 1990; Haack *et al*., 2000 Short and Stauble, 1967 Beka and Oti, 1995; Burke *et al.,* 1972; Whiteman, 1982 Allen,1965 and OOmkens,1974). See Figures 2- 3). The Nantin Field is located within Coastal Swamp Depobelt region of the Niger Delta, between Longitudes 7^o to 8^o E and Latitudes 4^o to 4.5^oN. Available research has shown that, most of the reservoirs in NANTIN Field has experienced unprecedented decline in reservoir productivity and identifying the causative factors for this decline necessitated this research.

II. Materials and Methods

Materials

The Materials for this research work includethe following; (a) Base map of the study area (b) Petrelsoftware 2010 version (c) Wireline logs (Gamma rays, resistivity and density neutron combination) for four wells (d) 3D seismic data.

III. Methodology

The following procedure has been used in this research.The 3D seismic and well log data utilized for this research were imported into the Petrel (2010) software which generated correlation and petrophysical properties. The Zoning is importance in interpretation of well logs, which logs were split into potential reservoir zones and non-reservoir zones. Hydrocarbon bearing, and non-reservoir intervals were identified with in the appropriate logs (Table 3.0). The computation of shale volume from the Gamma Ray was derived from the Resistivity log and Gamma-Ray log first, by determining the Gamma-Ray index using the formula below;

$$\mathbf{IGR} = \frac{(GRlog-GRmin)}{(GRmax-GRmin)}$$ (Stieber 1970) Equation [1]

Larionox 1969 equation for Tertiary rock was used to evaluate Vsh
Vsh = 0.083(23.7 X IGR-1) Equation [2]
IGR = gamma ray index,
GRlog= gamma ray response in area of interest,
GRmin= gamma ray response in clean zone,
GRmax=gamma ray response in shale.

Total Porosity and shale corrected (effective porosity) was computed: the total and effective porosity was estimated from density, Neutron and sonic log using Archies Equation

$$\Phi\text{nd} = \frac{\Phi d + \Phi n}{2}$$ Equation [3]

For non-gas reservoir

$$\Phi\text{nd} = \sqrt{\frac{\Phi d^2 + \Phi n^2}{2}}$$

for gas reservoir Equation [4]

φd value:

$$\Phi\text{d} = \frac{\rho matrix - \rho log}{\rho matrix - \rho fluid}$$ Equation [5]

Where
ρmatrix is the matrix density (Table 4),
ρfluidis the fluid density (Table 5),
ρlog is the density log reading,
φd is the density-derived porosity,
φn is the neutron porosity (from neutron log reading), and
φnd is the combined porosity value

Water saturation;

This is the fraction of water in a pore space. It is express as volume/volume, percent or the saturation units. Water saturation (Sw) is the most demanding of all petrophysical calculation.

$$\mathbf{Sw} = \frac{0.082}{\emptyset}$$ (Udegbunam*et al*., 1988) Equation [6]

Hydrocarbon Saturation (S_h);

Hydrocarbon saturation is defined as that fraction of pore space that contain hydrocarbon. It is denoted by S_h

$S_{h} = (1-Sw)$ Equation [7]

Sh = hydrocarbon sat.
Sw= water sat.
1= Unity

Formation Volume factor

Formation Factor is a function of porosity and the type of rock. The formation factor within the target depth interval was calculated with the Humble formula of best average for sandstones and unconsolidated formations.

$$F = \frac{0.6}{\emptyset^{2.15}}$$ Equation[8]

Where F = formation factor
$\emptyset$ = porosity

Irreducible water saturation

This is the water that is occupied in the pore spaces by capillary forces. It was determined from the equation given by Asquit and Gibson (1982)

$$Swi = \sqrt{\frac{F}{2000}}$$ Equation [9]

Table 3 Functions of logs used.

NAME	USES
Gamma Ray (GR)	Reservoir Identification, Vsh estimation, permeability calculation, etc.
Spontaneous Potential (SP)	Sand Shale Identification, porous zone determination,
Deep Resistivity ILD	Lithology, Water, Hydrocarbon Saturation identification
Density (RHOB)	Elasticity Parameters such as (AI, SI, σ, etc.) calculation, etc
Neutron Porosity (NPHI)	Detection of Hydrocarbon
Sonic (DT)	Elasticity evaluation such (AI, SI, σ, etc.) calculation, etc

Table 4 Matrix density and fluid reference Table [Halliburton, 1991]

Lithology	**{gr/cm^3}**	**Fluid**	**(gr/cm3)**
Consolidated Sand	**2.645**	**Fresh Water**	**1.0**
Limestone	**2.710**	**Salt Water**	**1.5**
Dolomite	**2.877**	**Methane**	**0.423**
Anhydrite	**2.960**	**Oil**	**0.8**
Salt	**2.040**		

Permeability: Permeability defined as the rock's ability to transmit fluid, higher permeability shows that the rock can transmit fluid easily and it means that more fluids can be extracted.

$K = 387 + 265552\emptyset^2 - 34540(\emptyset x Sw)^2$ (Owolabi*et al*., 1994) Equation [10]

K = permeability,
Φis the porosity, and
Swi = water sat. (0.3 was used as for the variable).
Thus, if Sw. = 1, then the permeability will be zero

Elasticity: The following elasticity properties were calculated in this research work; Poisson Ratio (PR), Acoustic Impedance (AI) and Reflectivity Coefficient (RC).

Poisson Ratio: This is the vertical straindivided by horizontal strain. It can be calculated from well log using the formula below;

PR =0.125 X Vsh + 0.27 (Crane E.2 016) Equation [11]

Where
PR = Poisson ratio
Vsh = Volume of Shale

Acoustic Impedance

Acoustic impedance is the product of density and velocity. Theoretically, the AI of every rock should increase as it deposited in a deeper place, and by quick looking into the anomaly, it can be say that it is a zone of interest which can be used to detect hydrocarbon (direct hydrocarbon indicator

$AI = \rho \times Vp$ Equation [12]

Where; ρ = density, Vp = p wave velocity

Reflectivity Coefficient

The AI difference between every formation which shows the reflectivity coefficient (R) which shows the rock's ability to reflect wave to the surface, the formula is listed below.

$$RC = \frac{AI2 - AI1}{AI2 + AI1} \quad \text{Equation [13]}$$

The reflectivity coefficient is very related with seismic, it represents how good is the rock's ability to reflect seismic wave, if the reflectivity is high, then more seismic wave will be reflected to the surface which will be shown by the presence of bright spot, but if the reflectivity is very low and possibly minus, it is called dim spot, there are use for hydrocarbon indicator.)

Net to Gross

This is the ratio of the productive sand body thickness to the gross thickness observed in the reservoir. This can be estimated by using gamma ray logs. The N/G was calculated with the aid of PETREL using:

$$N/G = \frac{\sum hi}{H} = \frac{\text{Net reservoir}}{\text{Gross Reservoir}} \quad \text{Equation [14]}$$

Volume Estimation

Volume estimation was done in the three Zones of both Nan.1, Nan.2 and Nan.4 reservoirs using the following equations.

Bulk Volume (Bv) = Area x Thickness = reservoir thickness (m) x Area extent (m^2)

Where $1m^3$ = 6.29 oil barrels

Net Volume = NTG x Bv = Bulk volume x Net/Gross

Pore volume = Bv x ϕ x NTG = Bulk volume x Net/Gross x Porosity

HCPV = Hs x Pv = Bulk volume x Net/Gross x porosity x Hydrocarbon Saturation

$$STOIIP = \frac{A \times H \times \emptyset(1-Sw) \times 7758 \times NTG}{Bo}$$

Where;

STOIIP = Stock Tank Oil Initially in Place

7758= barrels per foot

H = Reservoir Thickness in ft

Sh = (1-Sw) hydrocarbon saturation in decimals

Bo = Oil formation volume factors

GOR (Gas oil Ratio) = $\frac{\text{Gas oil in cubic feet}}{\text{Oil in barrels}}$

A= Drainage area in acres

$$Bo = 1.05 + 0.5 \times \frac{GOR}{100}$$

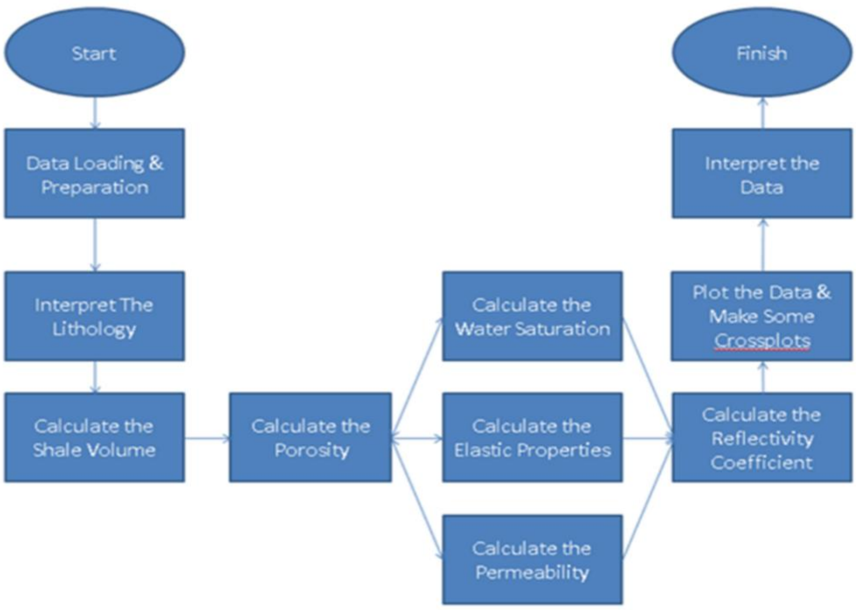


Figure 4.0 Flowchart for shale volume estimation and elastic properties of reservoir

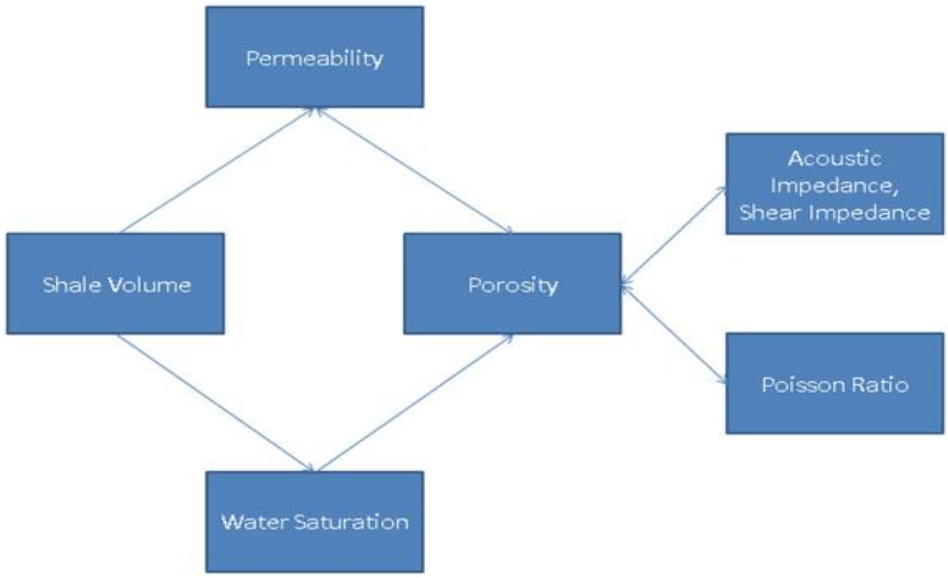


Figure 5.0. Figure shows shale volume estimation and elasticity properties.

IV. Results and Discussion

The results of this research are presented in Figures 6.0 to 22.0 and Table 5.0 to 15.0.

Well Correlation and Facies Analysis and Depositional Environment

Well correlation involves the identification of potential reservoir zones from non-reservoir zones and correlating across the field (Figure 6). Lithologic interpretation of the well logs indicates sand and shale as two principal lithologies predominant in Nantin Field. These identified lithologies vary both laterally and vertically across the field. Three reservoirs units (Nan. 1, Nan. 2 and Nan. 4) have been identified and were correlated across the Nantin Field based on SpontaneousPotential and Gamma Ray logs. Nan. 1 reservoir was thickest in Nantin well 12 (29.7ft), Nan. 2 Reservoir was thickest in Nantin well 12 (30.9ft) while Nan. 4 Reservoir was thickest in well 3 (72ft.Facies interpretation of the well logs (three log motifs recognized in the study area) shows that they are bell, cylindrical and funnel motifs which corresponds to a distributary channel,turbidite (submarine channel) and prograding Delta. The prograding Delta and the Delta distributary channel belong to the deltaic system and as interpreted as the reservoirs of Agbada Formation. The prograding submarine channels belonged to the deep marine setting which may be a deposit of upper Akata Formation (Doust*et al.,* 1990). The presence of submarine channels suggest that stratigraphic traps are inherent in NantinField apart from fault closures and whichfavour hydrocarbon accumulation (Pettingill and Weimer, 2002).

Nan. 1 Reservoir

The Nan. 1 Reservoir is at3290.3(ft) to 3306.9(ft) true vertical depth subsea (SSTVD) in Well 1. It isabout 16.6(ft) in Well 3- 3279.8(ft) to 3300.2(ft) (SSTVD). Sand thickness increases from Well 1 To Well 3 – an average thickness of about 20.4(ft). In Well 6 the reservoir is between 3237.2(ft) and 3264.3(ft) with a thicknessof 27.2(ft). However, in WELL 12, Nan. 1 Reservoir is at 3244.5(ft) to 3274.2(ft) true vertical depth subsea (SSTVD) with thickness measuring about 29.7(ft). Nan. 1 Reservoir was thickest in Well 12 andthinned eastward with Well 1 as the thinnest indicating a stratigraphic pinch out.

Nan. 2 Reservoir

The Nan. 2 Reservoir is at 3400.2(ft) to 3430.4(ft) true vertical depth subsea (SSTVD) in Well 1. -thickness is 30(ft). In WELL 3, Nan.2 Reservoir it is at 3381.7(ft) to 3408.2(ft) (SSTVD). The reservoir thickness decreases from Well 1 To Well 3 – average thickness of 26.5(ft).In Well 6, similar the reservoir is located between 3403.9(ft) and 3434.8(ft) with a thickness of 30.9(ft). However, inWell12, Nan. 2 Reservoir is at 3360(ft) to 3381.7(ft) true vertical depth subsea (SSTVD) with thickness of about 21(ft). Nan. 2 Reservoir was thickest in Well 6.

Nan. 4 Reservoir

The Nan.4 Reservoir is located between depths of 3524.3(ft) to 3564.2(ft) true vertical depth subsea (SSTVD) in Well1 - thickness is about 40(ft). In Well 3, Nan.4 reservoir ranges from 3496.3(ft) to 33568.3(ft) (SSTVD). Reservoir thickness increases from Well 1 To Well 3 with an average thickness of about 72(ft).In Well 6, the reservoir is located between 3546.7(ft) and 3590.6(ft) - thickness is about 44(ft). In Well 12, Nan.4 Reservoir is at 3529.1(ft) to 3581.0ft true vertical depth subsea (SSTVD) with thickness measuring about 52(ft). Nan.4 reservoir was thickest in Well 3 about 72(ft).

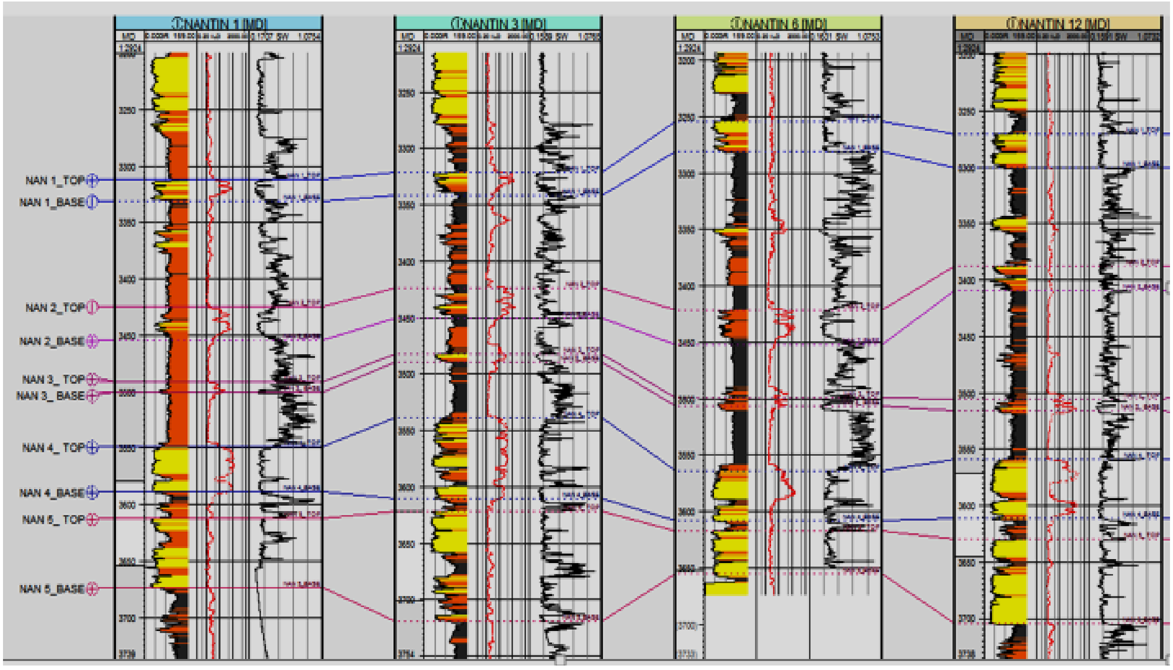


Figure6.0: Well correlation panel of NANTIN Field, Coastal Swamp, Niger Delta.

Seismic Interpretation

Well to seismic tie (Figure 8.0) was used to linkinformation from well logs to the seismic section. It involves forward modelling of a synthetic seismogram from sonic and velocity logs, then matching that synthetic to seismic reflection data thereby producing a relationship between the logs (measured in depth) (Figure 7.0) and the seismic (measured in time).Seismic horizon interpretation aimed at generating reservoir surfaces, exact horizons for the top of the reservoirs were identified and picked, ensuring that the interpretation process is

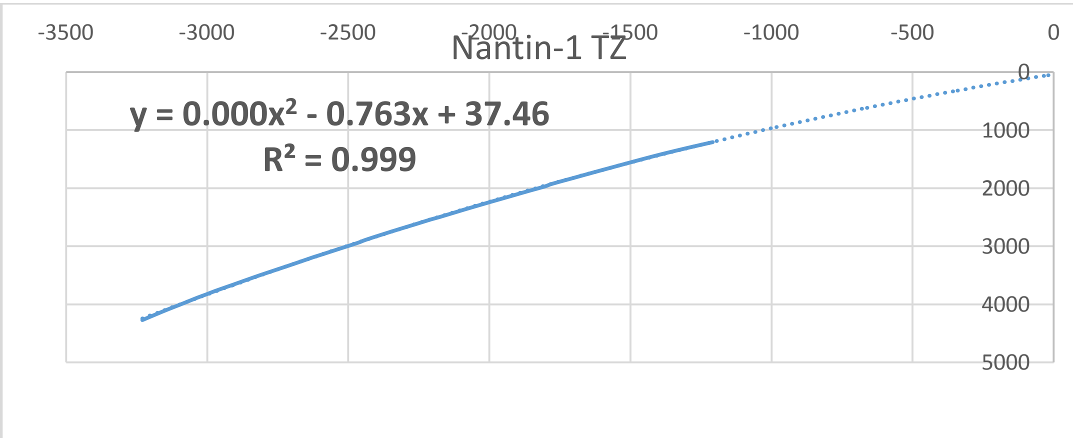
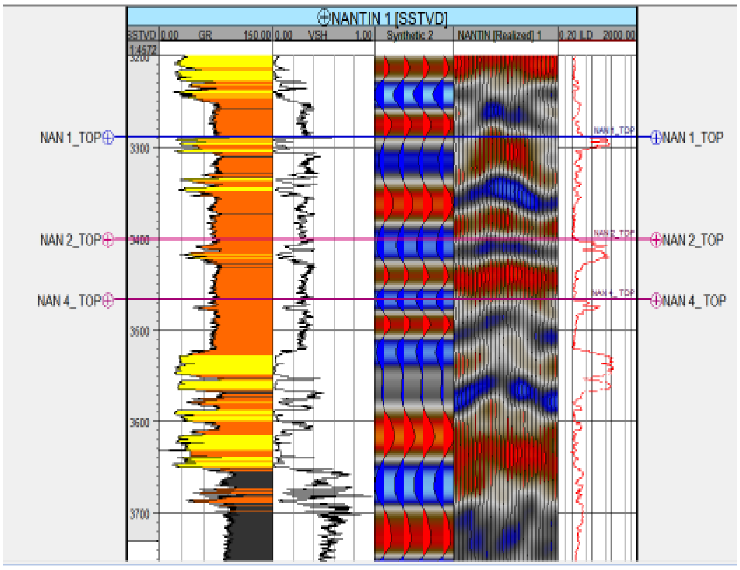
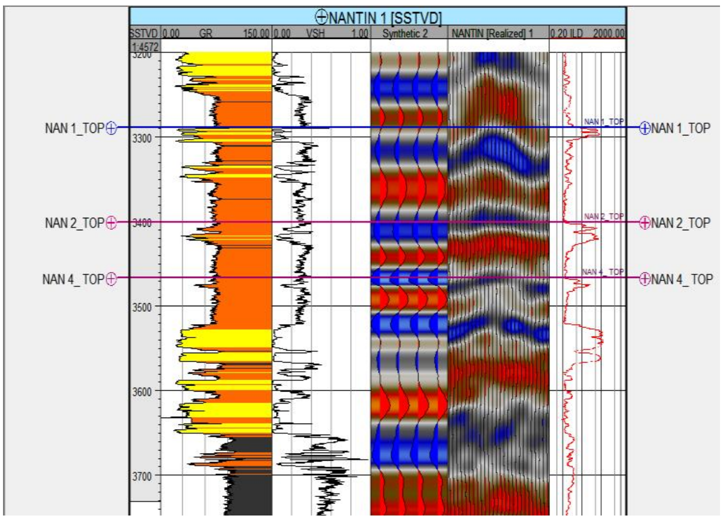


Figure 7.0. A plot of time versus depth of the checkshot



A



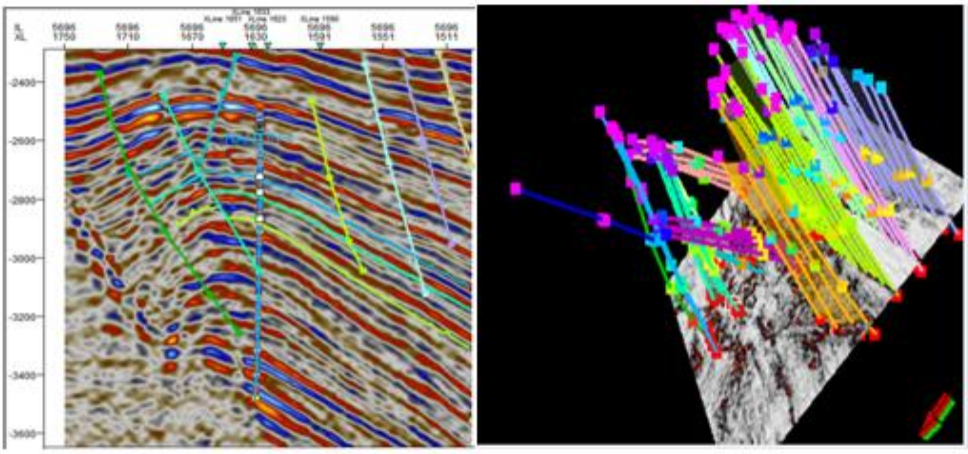
b

Figure 8.0 (a) Unmatched Synthetic Seismogram (b) Matched Synthetic Seismogram for Nantin Field -the red peak intervals depict the shale whereas the interval colored blue represents the trough (sand) according to Society of Exploration Geophysicists (SEG) standard**.**

Consistent. For this research, three (3) horizons of interest with hydrocarbon bearing reservoirs (Nan.1, Nan. 2 and Nan.4) has been identified in NantinField.Fifteen (15) faults has been mapped in Nantin Field trending NW/SE directions from the seismic section with series of colors. The Nantin Field has is a complex NW/SE dipping anticlinal structure with small scale antithetic and synthetic faults. (Figure 9.0). Time and depth maps have been produced for the three (3) horizons defined on top of sand bodies namely Nan. 1, Nan.2 and Nan. 4 though, there are slight variations in structural relationship depicting the complexities of the field. Nan 1 depth map revealed the crest of the anticline at a depth of 3290.3(ft), which correspond with what was obtained on the well logs. The dip closure of the anticline establishes the trap for the reservoir. The overall depth which the reservoir is located from the depth map ranges from 3290.3(ft) to 3306.9(ft). The depth structural map of horizon Nan.1 depicting similar features with Nan.2 and Nan. 4 horizons. On the depth structural map, the up-dip areas were seen with closure signifying probable anticlinal structures where hydrocarbon could be trapped (Figure 9.0 – 14.0).

Petrophysical Modelling and Reservoir Estimation

Reservoir modelling in the oil and gas industries is aimed at facilitating reserve estimation. Hence, a field evaluation is necessary only where it provides the most ideal model of the reservoir. In this research, reservoir models have been generated for petrophysical parameters such as porosity, permeability, Net-to-gross and water saturation. The three horizons interpreted were grouped into three (3) zones (Figure 6.0).



a b

Figure 9 (a) Interpreted faults and horizons reflecting Nan. 1, 2 and 4 reservoirs (b) Interpreted Faults on Z-Line (Realized)

Porosity is the measure of the void spaces in a rock (Efeotor 1997), it is between 0 and 100%. The porosity of a rock plays a fundamental role when evaluating the potential volume of water or hydrocarbon saturation in the reservoirs. Nan.1, Nan.2, and Nan.4 reservoirs has good to Very good porosity values (Table 5.0 – 12.0 and Figure 14.0). The models (Figure 15.0 and Table 5.0 – 8.0) show that, the permeability values in Nan.1. Nan 2 and Nan. 4 Reservoir have good to very good permeability with Nan.2 reservoir in well 3 having the highest permeability values of (1742Md) because of low shale volume distribution, while Nan. 4 Reservoir in Well 6 have the lowest permeability values of (1015Md) (Figure 15.0 and Table 5.0 – 8.0). This is the portion of reservoir volume filled with rocks that are hydrocarbon bearing. Petrel software was used to model the Net-to-gross along the reservoirs in the wells. It is expressed between zero (0) and one (1) or in percentage between 0 and 100%. High net to gross depict good prospect with Nan 1 reservoir in Well 1 having the highest values of 1.00 showing good prospect while Nan.2 Reservoir in Well 12 has the lowest value of 0.00 because of high shale volume (Figure 16). From the water saturation models (Figure 17.0) Nan. 4 reservoirs in Well 6 has higher water saturation values of 0.56, Nan. 1 Well 6, Nan.2 Well 6 Nan.1 Well 6, Nan. 1 Well 12 and Nan 4 Well 12 have water saturations of 0.40 respectively depicting low water saturation in turn high hydrocarbon saturation because of low shale volume distributions and good facies quality. The presence of shale in reservoir have severe effects on petrophysical properties, it reduces porosity and permeability of the reservoir. The shale volume distributions across the studied reservoirs in "NANTIN" Field (Figure 19.0), showed higher values of 0.67 (Table 13.0 – 15.0) in Nan.2 reservoir of well 12 which in turn reduces the NTG to zero (0). While, low shale volumes were estimated across the three reservoirs. Well 1 have high NTG of 0.9 to 1.00 and low Poisson Ratio of 0.30.

Table 5 Average Petrophysical values for NANTIN WELL 1

Reservoirs	Thickness(ft)	Vsh (Fract)	Poro T (Fraction)	Water Sat(Fract)	Permeability (MD)	NTG (Fraction)	F (Fract)	S_H
Nan. 1	16.6	0.30	0.18	0.45	1205.71	1.00	24.45	0.55
Nan. 2	30	0.29	0.17	0.51	1024.96	0.96	31.74	0.49
Nan. 4	40	0.18	0.18	0.53	3544.21	1.00	39.80	0.47

Table 6 Average Petrophysical values for Nantin Well 3

Reservoirs	Thickness (ft)	Vsh (Fract)	Poro T (Fract)	Water Sat. (Fraction)	Permeability (MD)	NTG (Fract)	F (Fract)	S_H
Nan. 1	20.3	0.39	0.19	0.44	1377.99	0.4	23.94	0.56
Nan. 2	26.5	0.39	0.23	0.38	1742.05	0.32	18.14	0.62
Nan. 4	72	0.35	0.20	0.46	1392.10	0.41	27.33	0.55

Table 7 Average Petrophysical values for Nantin Well 6

Reservoirs	Thickness(ft)	Vsh (Frac)	Poro T (Fract)	Water Sat. (Fract)	Permeability (MD)	NTG (Fract)	F (Fraction)	S_H
Nan. 1	27.2	0.41	0.19	0.45	1320.00	0.45	28.14	0.55
Nan. 2	30.9	0.51	0.18	0.49	1168.95	0.25	30.61	0.51
Nan. 4	44	0.26	0.16	0.55	1015.38	0.70	52.63	0.45

Table 8 Average Petrophysical values for Nantin Well 12

Reservoirs	Thicknes s (ft)	Vsh (Fract)	Poro T (Fract)	Water Sat. (Fract)	Permeability (MD)	NTG (Fract)	F (Fraction)	S_H
Nan. 1	29.7	0.47	0.22	0.39	11631.37	0.30	20.86	0.61
Nan. 2	21	0.68	0.19	0.45	1260.15	0.00	25.11	0.55
Nan. 4	52	0.38	0.21	0.40	1531.21	0.43	19.74	0.60

Table 9 Nan.1 Reservoir Volume estimation

Porosity:	PoroT					
Net gross:	NTG					
Properties in gas interval:						
Bg (formation vol. factor):	1.00000000	[rm3/sm3]				
Rv (vaporized oil/gas ratio):	0.00000000	[sm3/sm3]				
Recovery factor gas:	1.00000000					
Properties in oil interval:						
Sat. water:	SW					
Sat. oil:	1-Sw-Sg					
Sat. gas:	0.00000000					
Bo (formation vol. factor):	1.60000000	[rm3/sm3]				
Rs (solution gas/oil ratio):	0.00000000	[sm3/sm3]				
Recovery factor oil:	1.00000000					
Case	**Bulk volume[*10^6 m3]**	**Net volume[*10^6 m3]**	**Pore volume[*10^6 rm3]**	**HCPV oil[*10^6 rm3]**	**HCPV gas[*10^6 rm3]**	**STOIIP (in oil)[*10^6 STB]**
Case_NAN1	243	233	60	41	0	163
Totals all result types						
Zones						
Zone	52	51	14	10	0	38
Zone	68	68	18	12	0	48
Zone	89	81	21	14	0	56
Zone	35	34	8	5	0	20
Segments						
Segment 1	243	233	60	41	0	163

Table 10 Nan.2 Reservoir Volume estimation

General properties						
Porosity:	PoroT					
Net gross:	NTG					
Properties in gas interval:						
Bg (formation vol. factor):	1.00000000	[rm3/sm3]				
Rv (vaporized oil/gas ratio):	0.00000000	[sm3/sm3]				
Recovery factor gas:	1.00000000					
Properties in oil interval:						
Sat. water:	SW					
Sat. oil:	1-Sw-Sg					
Sat. gas:	0.00000000					
Bo (formation vol. factor):	2.20000000	[rm3/sm3]				
Rs (solution gas/oil ratio):	0.00000000	[sm3/sm3]				
Recovery factor oil:	1.00000000					
Case	**Bulk volume[*10^6 m3]**	**Net volume[*10^6 m3]**	**Pore volume[*10^6 rm3]**	**HCPV oil[*10^6 rm3]**	**HCPV gas[*10^6 rm3]**	**STOIIP (in oil)[*10^6 STB]**
Case_NAN2	599	408	93	59	0	169
Totals all result types						
Zones						
Zone	250	190	45	29	0	83
Zone	198	134	31	20	0	56
Zone	151	85	17	10	0	29
Segments						
Segment 1	599	408	93	59	0	169

Table 11 Nan.4 Reservoir Volume estimation

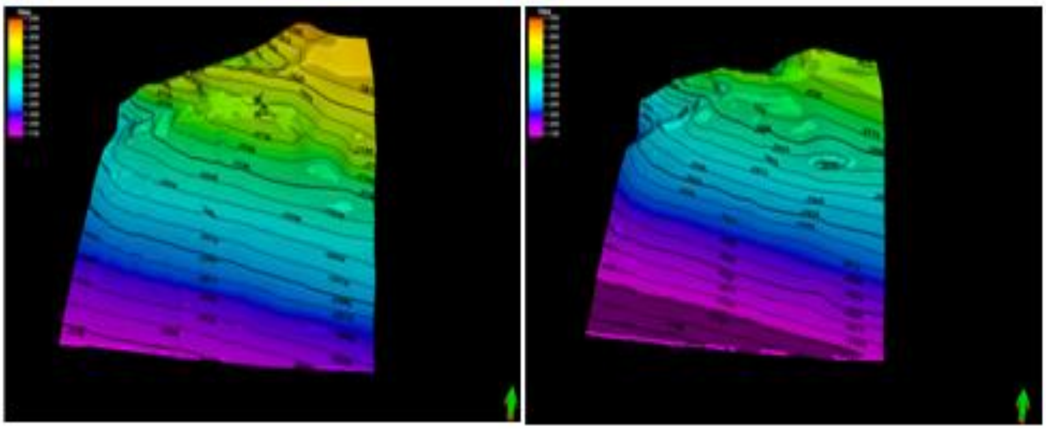
General properties						
Porosity:	PoroT					
Net gross:	NTG					
Properties in gas interval:						
Bg (formation vol. factor):	1.00000000	[rm3/sm3]				
Rv (vaporized oil/gas ratio):	0.00000000	[sm3/sm3]				
Recovery factor gas:	1.00000000					
Properties in oil interval:						
Sat. water:	SW					
Sat. oil:	1-Sw-Sg					
Sat. gas:	0.00000000					
Bo (formation vol. factor):	2.20000000	[rm3/sm3]				
Rs (solution gas/oil ratio):	0.00000000	[sm3/sm3]				
Recovery factor oil:	1.00000000					
Case	**Bulk volume[*10^6 m3]**	**Net volume[*10^6 m3]**	**Pore volume[*10^6 rm3]**	**HCPV oil[*10^6 rm3]**	**HCPV gas[*10^6 rm3]**	**STOIIP (in oil)[*10^6 STB]**
case_NAN4	312	279	64	40	0	115
Totals all result types						
Zones						
Zone	230	225	51	32	0	93
Zone	71	44	10	6	0	18
Zone	11	10	2	1	0	4
Segments						
Segment 1	312	279	64	40	0	115

Elastic Property Evaluation

The results from elasticity property evaluations shows a high Poisson Ratio of 0.40 in Nan. 2 Reservoir was recorded 12 because of the highest shale distribution of 0.70 in the field. This indicates ahigh stress level which in turnshows possibility of boundary to hydraulic fracture. The lowest Poisson Ratio was observed in Nan. 4 Reservoir of Well 1 with the lowest shale volume of 0.18 which indicate fragile area that might not fracture (Crane E., 2016)

Table 12 Volume Comparison

Reservoirs	**Zones**	**STOIIP (*10^6STB)**
Nan 1	**Zone 1**	**38**
	Zone 2	**48**
	Zone 3	**56**
	Zone 4	**20**
		163
Nan 2	**Zone 1**	**83**
	Zone 2	**56**
	Zone 3	**29**
		169
Nan 3	**Zone 1**	**93**
	Zone 2	**18**
	Zone 3	**4**
		115



a b

Figure 10(a) Nan. 1 reservoir time surface map (b) Nan. 2 reservoir time surface maps

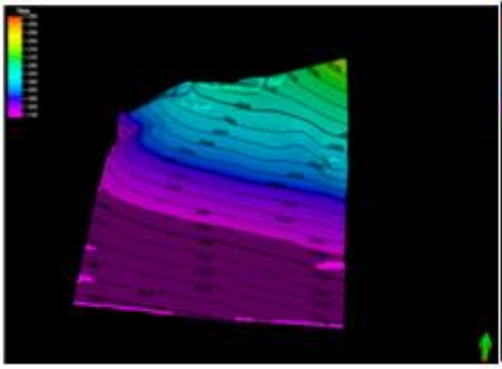
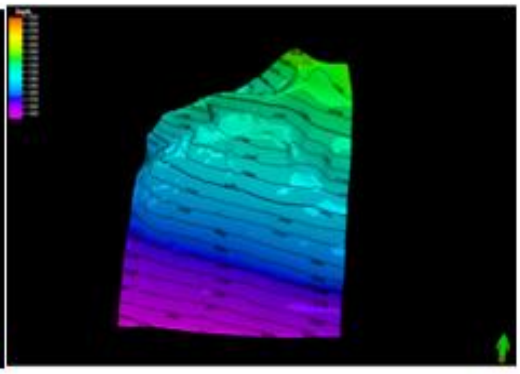



Figure 11c Nan. Reservoir 4 Time reservoir surface mapFigure12 (a) Nan 1 Reservoir Depth Surface Map

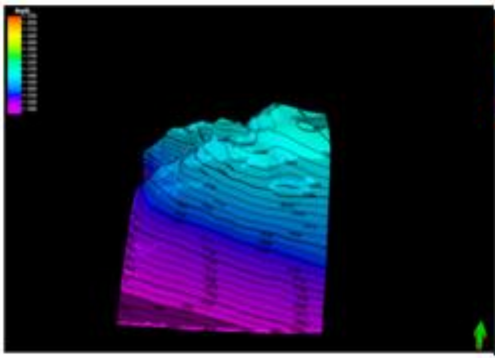
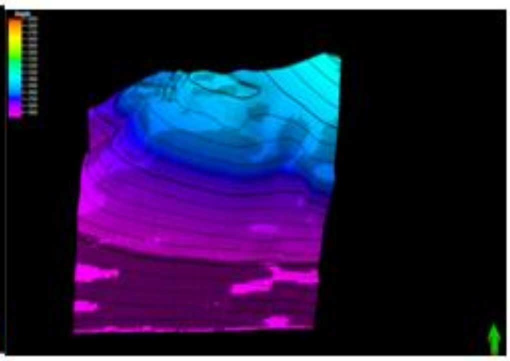
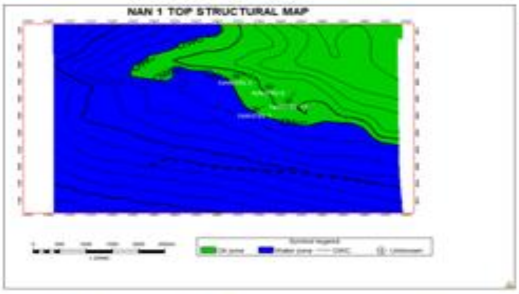



Figure 12 (b) Depth surface Map of Nan. 2 **Figure 12 (c) Depth Surface Map of Nan. 4**



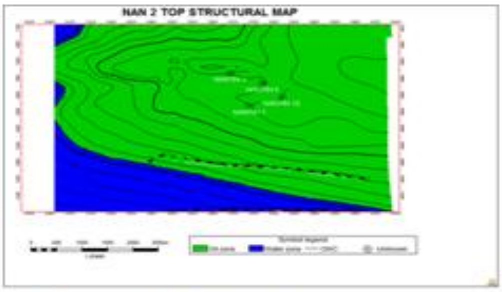
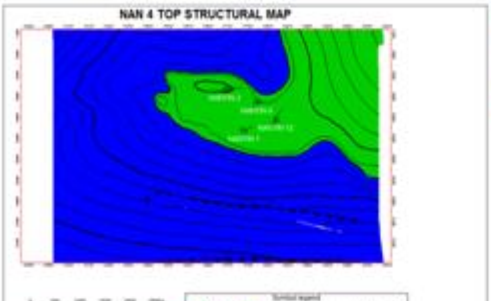
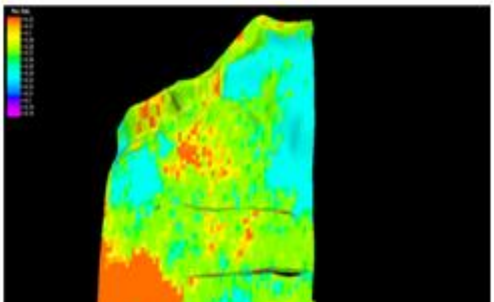
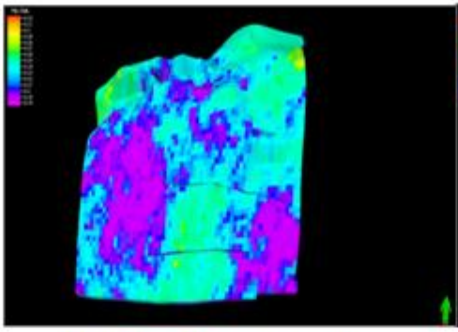


Figure 13 (a) Nan. 1 Top Structural Map **Figure 13 (b) Nan. 2 Top Structural Map**





(c) Nan. 4 Top Structural Map **Figure 14 (a) Nan.1 Porosity Model**



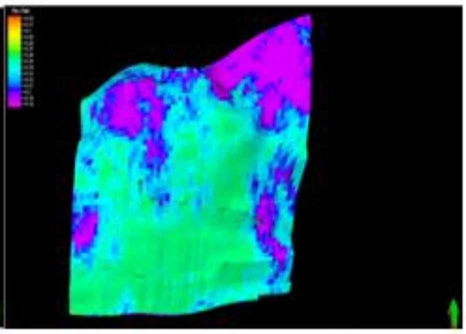
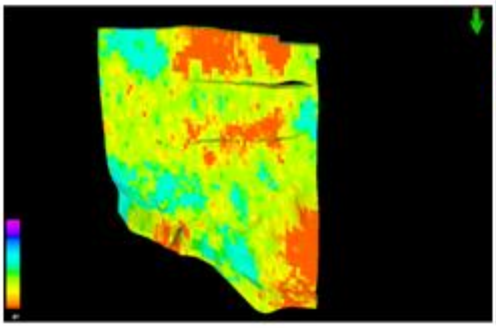


Figure 14 (b) Nan.2 Porosity Model **Figure 14 (c) Nan.4 Porosity Model**



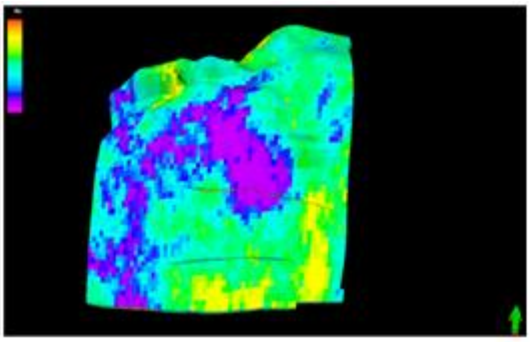
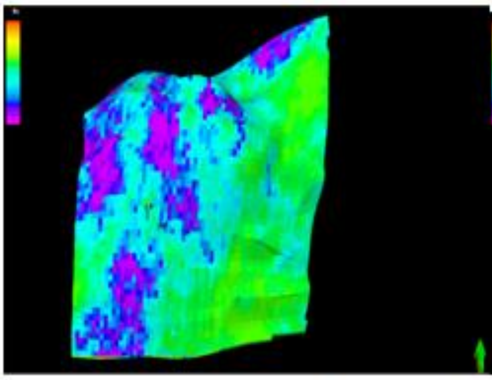


Figure 15 (a) Nan.1 Permeability Model **Figure 15 (b) Nan.2 Permeability Model**



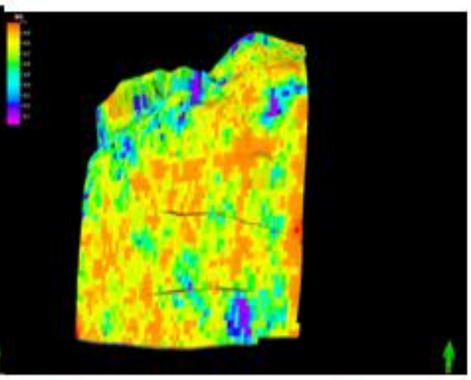
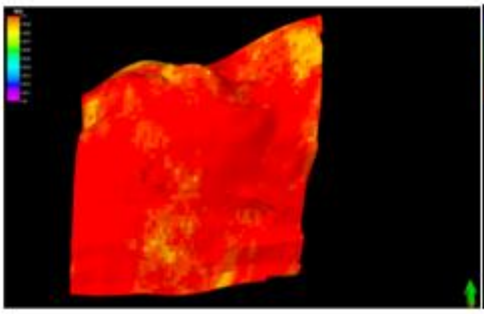


Figure 15 (c) Nan.4 Reservoir Permeability ModelFigure 16 (a) Nan.1 reservoir NTG Model



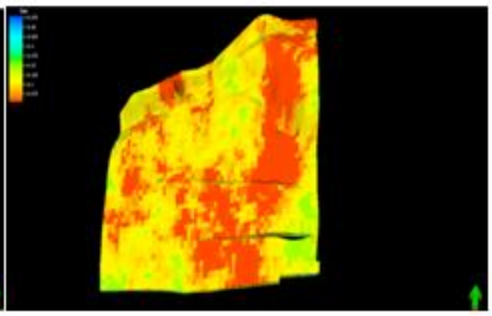
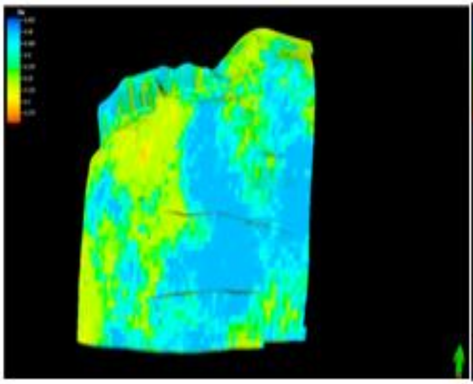


Figure 16 (b) Nan.2 reservoir NTG Model **Figure 16 (c) Nan.4reservoir NTG Model**



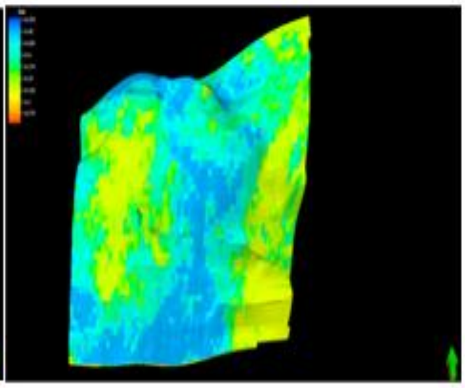
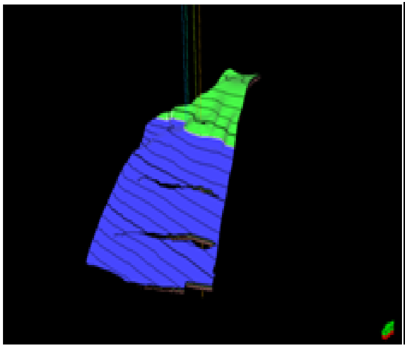


Figure 17 (b) Model of Nan.2 reservoirs Sw **Figure 17 (c) Model of Nan.4reservoir Sw**



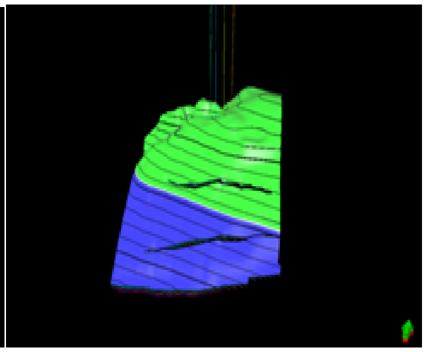


Figure18 (a) Nan.4 Fluid Distribution of Nan. 1 Figure 18 (b) Fluid Distribution of Nan. 2

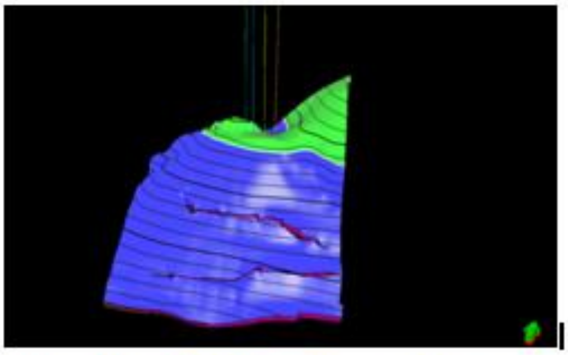


Figure 18 (c) Fluid Distribution of Nan.4

Results from Acoustic impedance showed that, Nan 2 Reservoir has higher acoustic impedance of (AI) of 7994.3 compared to Nan.1 which has the least acoustic impedance value of 7447.3. A higher Reflectivity Coefficient was recorded in Nan.2 reservoir indicating high bright spot while a lower RC of -0.00023 was recorded in Nan. Reservoir 4 indicating dim spot (Table 4.9)

The results in Table 4.5 to 4.9 shows that, reservoirs with high shale Volume distribution have increased the Poisson ratio and reduced the reflectivity coefficient as recorded in Nan. 4 Reservoir of well 12. (Table 4.9). This well has the least NTG and low volume of hydrocarbon compared to Well 2 which has low shale volume distributions and high reflectivity coefficient. The estimated volume of hydrocarbon in Well 2 is very high (169 mmstb) compared to (115mmstb) of well 12 due to variations in shale volume, Poisson ratio, Reflectivity Coefficient and Acoustic Impedance.

Figure 19 (a) Nan.1 Volume of Shale (Vsh) ModelFigure 19 (b) Nan.2 Volume of Shale (Vsh) Model

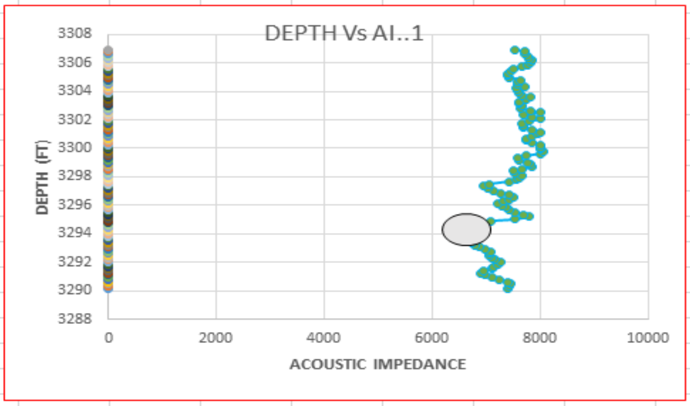


Figure 19 (c) Nan.4 Volume of Shale (Vsh) ModelFigure 20 Cross Plot between Depth Vs Acoustic Impedance (AI) for Nan. 1 Reservoir. The black circle shows the AI anomaly

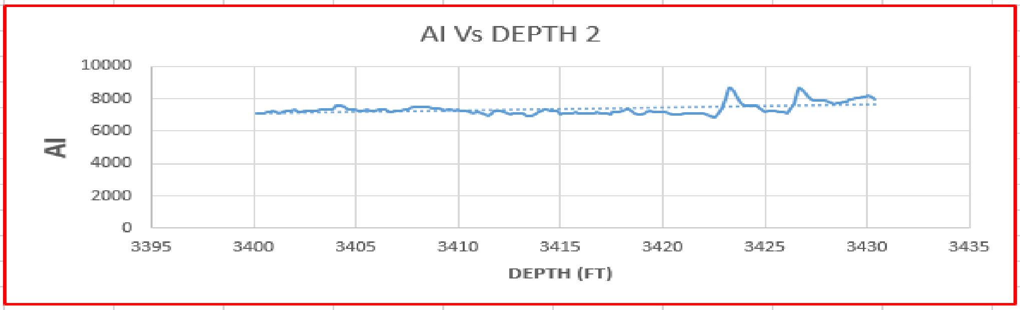


Figure 21. Depth Vs Acoustic Impedance for Nan. 2 Reservoir

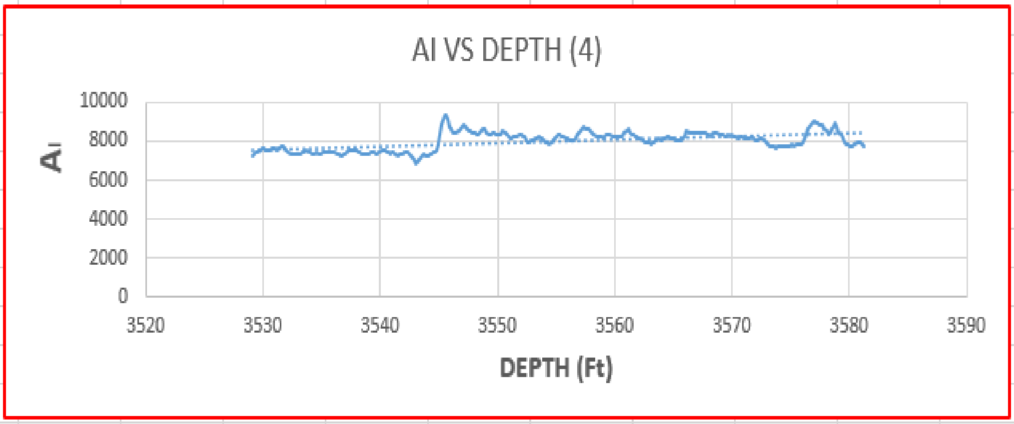


Figure 22. Depth Vs Acoustic Impedance for Nan. 4 Reservoir

Table 13. Average Comparison of Poisson Ratio and Shale Volume distribution for Nantin Well 1

Reservoir	Shale Volume Vsh	Poisson Ratio
Nan 1.	0.30	0.31
Nan2	0.29	0.31
Nan 4	0.18	0.29

Table 14. Average Comparison of Poisson Ratio and Shale Volume distribution for NANTIN WELL 3

Reservoir	Shale Volume Vsh	Poisson Ratio
Nan 1.	0.39	0.32
Nan2	0.39	0.32
Nan 4	0.34	0.31

Table 15 Average Comparison of Poisson Ratio and Shale Volume distribution for NANTIN WELL 6

Reservoir	Shale Volume Vsh	Poisson Ratio
Nan 1.	0.41	0.32
Nan2	0.51	0.33
Nan 4	0.26	0.30

Table 16 Average Comparison of Poisson Ratio and Shale Volume distribution for Nantin Well 12

Reservoir	Shale Volume Vsh	Poisson Ratio
Nan 1.	0.47	0.33
Nan2	0.68	0.35
Nan 4	0.38	0.32

Table17. Average AI and RC values IN Nantin Field

Reservoir	Vshale	RC	AI
Nan. 1	0.30	0.00089	7447.73
Nan. 2	0.29	0.01	7994.63
Nan. 4	0.18	-0.0002	80003.8

V. Conclusions

The Acoustic impedance has showed that, Nan 2 reservoir has high acoustic impedance of (AI) of 7994.6 due to low shale volume distributions of 0.03 compared to Nan.1 has the least acoustic impedance value of 7447.3 because of high shale volume distributions of 0.29. A high Reflectivity Coefficient of 0.01 recorded in Nan.2 reservoir indicate a bright spot while a lower Reflectivity Coefficient of -0.00023 recorded in Nan. 4 Reservoir with an estimated shale volume of 0.18, indicate dim spot in the field. The petrophysical attributes of the delineated reservoirs are good to very good except in well 12 which has high shale volume distribution of 0.70 with a resulting high Poisson ratio of 0.40 showing that a high Poisson ratio is related to high shale volume distributions. The STOIIP in this reservoir is 115 mmstb is the lowest in the fieldindicqting that the increased elastic properties in the Nantin reservoirs affect the petroleum yield in the field. Presence of shales in reservoirs affects both petrophysical (Porosity, Permeability, NTG, Water Saturation) and elasticity properties such as Poisson ratio, AI and RC, this has greatly impacted on the efficient economic production of hydrocarbon in the field. Estimating this property and factoring it in recovery plans would have save the IOC economic loss experienced and mitigate against it.

References

[1]. Ahmad, M., and Haghighi., M., (2013): Water Saturation Evaluation of Murteree and Roseneath Shale Gas Reservoirs, Cooper Basin, Australia Using Wire-line Logs, Focused Ion Beam Milling and Scanning Electron Microscopy. In: Society of Petroleum Engineers (ed.), Proceedings of the SPE Unconventional Resources Conference and Exhibition-Asia Pacific, 11–13th November 2013, Brisbane, Australia, pp. 1–20.

[2]. Allen, J.R., (1965): Late Quaternary Niger Delta, and Adjacent Areas Sedimentary Environment and Lithofacies: AAPG Bulletin, Volume 49, pp 547-600.

[3]. Archie, G. E., (1950): Introduction to Petrophysics of Reservoir Rocks. AAPG Bulletin, Volume 34(5), pp 943-961.

[4]. Asquit, G.B., and Gibson, S., (1982): Basic Well Log Analysis for Geologist; American Association of Petroleum Geologist, ISBN 0891816526, 9780891516522

[5]. Bahia., M., Ben Ghawar and Falhi S., Elburas., (2015): Poisson's Ratio, Deep Resistivity and Water Saturation Relationships for Shaly Sand Reservoir, SE Sirt ,Murzuq and Gadames Basins, Libya (Case Study). Journal of Geography and Geology, Vol. 7, No 1

[6]. Beka, F. T., and M. N. Oti, (1995): The Distal Offshore Niger Delta: Frontier Prospects of aMature Petroleum Province, in Oti, M.N., and G. Postma, eds., Geology of deltas:Rotterdam, A. A. Balkema, p. 237-241.

[7]. Biot, M. A., (1956): Theory of Propagation of Elastic Wave in a Fluid Saturated Porous Solid. Journal of Applied Geophysics 26, 182 (1955).

[8]. Burke, K., (1972): Longshore Drift, Submarine Canyons and Submarine Fans inDevelopment of Niger Delta: AAPG Bulletin, v. 56:1975-1983

[9]. Crain E., (2016):Petrophysical Handbook - Elastic Constants - Mechanical Properties

[10]. Doust, H., and Omatsola, E., (1990): Niger Delta "Divergent/Passive Margin Basins". AAPG Memoir 48: 239-24

[11]. Dvorkins J., M Prasad., (2001): Elasticity of Marine Sediments: Rock Physic Modelling Geophysical Research letters. 26 (12) 1789-1784
[12]. Egbia, J.C., and Aigbogun, C.O., (2012): Mathematical Modeling of Petrophysical Parameters for Reservoir Characterization Using Well Log Data. Advancement in Applied Science Research 3(2): pp 656-670.
[13]. Ejedawe, J.E., (1981): Patterns of Incidence of Oil Reserves in Niger Delta Basin, American Association of Petroleum Geologists, Volume 65, pp 1574-1585.
[14]. Emujakporue, Godwin O., and Ngwueke, Marcel L., (2013): Structural Interpretation of Seismic Data from XY Field, Onshore Niger Delta, Nigeria. J. Appl. Sci. Environ. Manage. 17 (1): 153-158.
[15]. Etu-Efeotor, J. O., (1997):Fundamentals of Petroleum Geology.Paragraphics: Port Harcourt.
[16]. Evamy, B. D., Haremboure, J., Kamerling, P., Knaap, W. A., Molloy, F. A., and Rowlands, P. H., (1978): "Hydrocarbon habitat of Tertiary Niger Delta".AAPG Bulletin. Volume 62, pp 277-298.
[17]. Fertl, W. H., (1981):OpenholeCrossplot Concepts: A Powerful Technique in Well Log Analysis. Journal of Petroleum Technology, 33(3): 535-549
[18]. Gassmann, F., (1951): Elastic waves through a packing of spheres, Geophysics, 16, 673-685.
[19]. Ghawar, B.M.B. and Elburas, F.S., (2015): Poisson's Ration, Deep Resistivity and Water Saturation Relationships for Shaly Sand Reservoir, SE Sirt, Murzuq and Gadames Basins, Libya (Case study). Journal of Geography and Geology, 7/1, 20. http:// dx.doi.org/10.5539/jgg.v7n1p20Guerin, G., and D. Goldberg, 1996, Acoustic and elastic properties of calcareoussediments across a siliceous diagenetic front on the eastern U.S. ContinentalSlope,Geophysics. Res. Lett., 23(19), 2697-2700.
[20]. Haack, R.C., Sundararaman, P., Diedjomahor, J.O., Xiao, H., Gant, N.J., May E.D., and Kelsch. (2000): Niger Delta Petroleum Systems, Nigeria, in M.R. Mello and B.J. Katz, eds., Petroleum Systems of the South Atlantic Margins: AAPG Memoir, Volume. 73, pp 213-231.
[21]. Halliburton (1991): Matrix density and fluid density reference table.
[22]. Kennedy, R.L., Knecht, W.N. and Georgi, D.T., (2012): Comparisons and Contrasts of Shale Gas and Tight Gas Developments, North American experience and trends. In: Society of Petroleum Engineers (ed.), Proceedings of the SPE Saudi Arabia Section Technical Symposium and Exhibition, 8–11th April 2012, Al-Khobar, Saudi Arabia, pp. 1–27.
[23]. Magoon, L.B., and Dow, W.G., (1991): The Petroleum System from Source to Trap. AAPG Memoir 60, Tulsa, Oklahoma, USA. pp 637.
[24]. Mitchum, R.M., Sangree, J.B., and Wach W.W., (2002): Recognizing Sequences and System Tracts from Well logs, Seismic Data and Biostratigraphy: Examples from the Late Cenozoic of the Gulf of Mexico, in P. Weimer and H.W. Postammentier, Eds,AAPGMemoir 58, Pp, 163-197.
[25]. Oomkens E., (1974): Lithofacies Relations in Late Quaternary Niger Delta complex Sedimentology, Volume 21, pp 195-222.
[26]. Owolabi, O. O., and Willis, B.J., T.F., Ajienka, J.A., (1994): An Empirical Expression for Permeability in Unconsolidated sands of Eastern Niger Delta: Journal of petroleum geology, volume 17, No. 1, pp 111-116.
[27]. Perez, R., (2013): Brittleness Estimation from Seismic Measurement in Unconventional Reservoir: Application to the Barnett Shale: Ph. D Dissertation, Conoco Philip School of Geology and Geophysics, University of OklahomaPetrel Software version,(2010)
[28]. Petters, S. W., (1978): Stratigraphic Evolution of the Benue Trough and its Implications forthe Upper Cretaceous Paleography of West Africa: Journal of Geology, v. 86, p.311-322
[29]. Rickman, R., Mullen, M.J., Petre, J.E., Grieser, W.V. and Kundert, D., (2008): A Practical Use of Shale Petrophysics for Stimulation Design Optimization: All shale plays are not clones of the Barnett Shale. In: Society of Petroleum Engineers (ed.), Proceedings of the SPE Annual Technical Conference and Exhibition, 21–24th September 2008, Denver, Colorado, USA, pp. 1–11.
[30]. Ross, D.J. and Bustin, R.M., (2007): Shale Gas Potential of the Lower JurassicGordondale member, Northeastern British Columbia, Canada. Bulletin of Canadian Petroleum Geology, 55/1, 51–75. http://dx.doi.org/ 10.2113/gscpgbull.55.1.51
[31]. Saneifar, M., Aranibar, A. and Heidari, Z., (2013): Rock Classification in the Haynesville Shale-Gas Formation Based on Petrophysical and Elastic Rock Properties Estimated from Well Logs. In: Society of Petroleum Engineers (ed.), Proceedings of the SPE Annual Technical Conference and Exhibition, 30th September–2nd October 2013, New Orleans, Louisiana, USA, pp. 1–12.
[32]. Sarihi, A. and Vargas-Murillo, B., (2015): A Method to Compute Water Saturation in Tight Rocks Accounting for Conductivity of Clay Minerals. In: Society of Petroleum Engineers (ed.), Proceedings of the Abu Dhabi International Petroleum Exhibition and Conference, 9–12th November 2015, Abu Dhabi, UAE, pp. 1–14
[33]. Schlumberger, (1996):Log Interpretation Principle/Application. Houston. Schlumberger Educational Services. Pp 20-30
[34]. Short, K. C. and J. Stauble, (1967): Outline of Geology of Niger Delta. American Association of Petroleum Geology Bulletin, Volume 51, pp 761-779.
[35]. Siyamak, M., Mohammad, M., Mohamad, K.G., and Elaheh, H., (2016): Determination of Shale Volume Distribution Patterns and Effective Porosity from Well Log Data Based on Cross-Plot Plot Approach for a Shaly Carbonate Gas Reservoir. Word Multidisciplinary Earth Science Symposium 44 (2016) 04202.
[36]. Stacher, P., (1995): Niger Delta Petroleum Habitat. NAPE Bulletin. 9/01: pp. 67-76.
[37]. Stieber, S., (1970): Pulsed Neutron Capture Log Evaluation - Louisiana Gulf Coast. Houston,Texas.
[38]. Tian Y., Kohn B.P., Gleadow A.J.W., Hu S., (2013): Peneplain formation in SouthernTibet predates the India-Asia collision and plateau uplift. Google Scholar e295, do:10.1130/G33617C.1.
[39]. Udegbunam, E.O., and Ndukwe, L, C., (1988): Rock Properties Correlation for Hydrocarbon Producing Reservoir Sands of the Niger Delta; Oil and Gas Journal Volume 86, no 6. Pp. 55-58.
[40]. Weber, K.J., and Daukoru., (1975): Petroleum Geology of the Niger Delta; Proceedings of the ninth World Petroleum Congress, Volume 2, Geology; London applied science publishers, Ltd., pp 210-221.
[41]. Whiteman, A., (1982): Nigeria: It's Petroleum Geology, Resources and Potential. Journal of African Earth Sciences, Volume1, pp 177-180.

Ejieh, E. O "Effects of Shale Volume Distribution on the Elastic Properties of Reservoirs in Nan tin Field Offshore Niger Delta Nigeria" IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) 6.3 (2018): 68-85.