PETROPHYSICAL AND ROCK PHYSICS ANALYSES FOR CHARACTERIZATION OF COMPLEX SANDS IN DEEPWATER NIGER DELTA, NIGERIA

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ABSTRACT

Characterization of complex sand reservoirs in deepwater of Niger Delta was carried out through petrophysical and rock physics evaluation of well log data from three wells. Petrophysical analysis to determine clay volume, porosity, lithologies and hydrocarbon saturation were made. Rock physics was studied in velocity-porosity plane to analyze the influence of depositional and diagenetic features on the reservoirs. Cross-plots of different elastic parameters, using linear regression and cluster analysis, were generated for lithologic and fluid fill identification and to differentiate between the hydrocarbon bearing sands, brine sands and shale. Variance attribute was extracted on seismic time slice in order to image the complex sand distribution in the area. Three reservoirs of turbidite origin were identified within the upper fan to lower fan area. Petrophysical results revealed gas bearing reservoir units with less than 20% shale volume and porosity of 25-31%. Lambda-Mu-Rho (LMR) cross-plots for the reservoirs show gas saturated data cloud and trend. Ratio-Difference (R-D) cluster analysis of elastic rock properties shows a distinct trend and data cloud that represents lithofacies units and fluid fills. The study concludes that the reservoirs simulated contact cement and friable models with properties that ranged from highly porous, well sorted and poorly consolidated sand to fairly sorted and highly cemented sands. The results provide a model that increases the possibility of finding reservoir sand, while mitigating the risk involved in finding hydrocarbons.

Keywords: Rock Physics, Petrophysics, Deepwater, Reservoir, Niger delta, Cross-plot

1 INTRODUCTION

Deepwater and Ultra Deepwater exploration in Niger Delta was heralded in 1990 with the maiden acquisition of two dimensional seismic data offshore with the sole aim of investigating the hydrocarbon potential of the area [1]. The deepwater setting of the West African Offshore Basins has witnessed an intensive hydrocarbon exploration and field development for about 30 years. Although giant discoveries have been made in these basins, the success rate still remains lower than the failure rate in the deep and ultra-deepwater Niger Delta [2], [3], [4]. This may not be unconnected with the fact that deepwater clastics and turbidites systems in the deepwater Niger Delta are associated with diapiric structural evolution and complex sand distribution [5], [6], [7], [8]. The deepwater reservoir systems have been recognized for their complexity and variability in sand distribution and reservoir quality [9], [10]. It is therefore expected that this will have bearing on exploration and reservoir characterization. Consequently, prediction of lithofacies and reservoir characterization using conventional seismo-structural sedimentary analogs techniques has not been effective in this area. The study by [11] reported that sandstones and shales in siliciclastic formations have been observed to deform differently at specific burial depth. This implies that rock physics analysis of critical changes in the gross rock rigidity and incompressibility can be used to discriminate between lithofacies and fluid content in siliciclastic depositional setting like the deepwater Niger Delta[12] ,[13]. Based on the stress-strain relationship, quartz-rich wet sand, oil sand, gas sand, and clay-rich shale will deform differently and therefore characterized by distinct rock physics responses [14]. For these reasons, Rock physics is commonly utilized for reservoir property analyses [15], [16], [17], [18]. Rock Physics is a discipline that establishes the relationship between rock properties such as porosity, permeability and the elastic rock attributes: P- and S- wave velocities, impedances, etc. Rock Physics models are important for a quantitative seismic interpretation and reservoir characterization which increases the chances of success in hydrocarbon exploration [14]. Also, attribute analyses of seismic data have also been proved useful in mapping the morphology and architectural elements of deepwater clastics [19], [20]. This study is therefore focused on integrating petrophysical analysis, seismic attribute and rock physics responses for lithofacies identification and fluid fill discrimination in order to reduce geological risk and uncertainty associated with predicting complex deepwater reservoirs and lithofacies in the offshore Niger Delta. The results of this study will aid reservoir characterization and conceptual geological modelling of the study area which will in turn aid the direct prediction of hydrocarbon sands.

2 STUDY AREA AND GEOLOGICAL SETTING

The study area is an offshore field on the continental slope of deepwater Niger Delta in areas of water depth of about 1000 m (Figure 1). The Niger Delta basin is composed of overall regressive clastic sequence which

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reaches a maximum thickness of about 12000 m [21]. The geology is very complex, and is characterized by rapid deposition of prograding sands on over-pressured mobile shale of the Akata Formation. The sedimentary succession of the slope and basin floor deepwater setting, are considered to be dominated by pelagic and hemipelagic marine shales (>80%); with interbedded sandstone deposits of debris flow, turbidite and channel-levee complexes [22]. According to [2], the offshore Niger Delta has been subdivided into five structural zones with distinct depositional framework (Figure 2). These zones include the extensional province, shale diapirs, inner thrust belt, translational detached fold and outer and toe thrust zones.

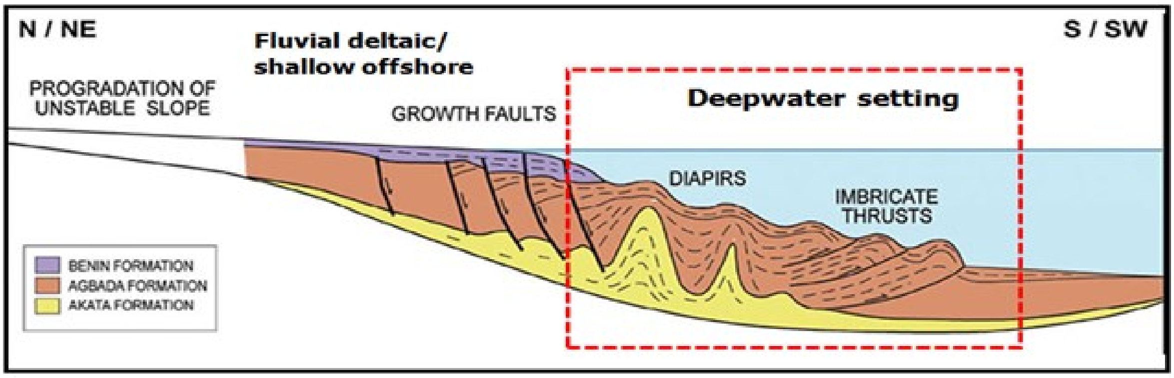

Figure 1. Geologic cross-section of the Niger Delta continental shelf and offshore setting (according to [2])

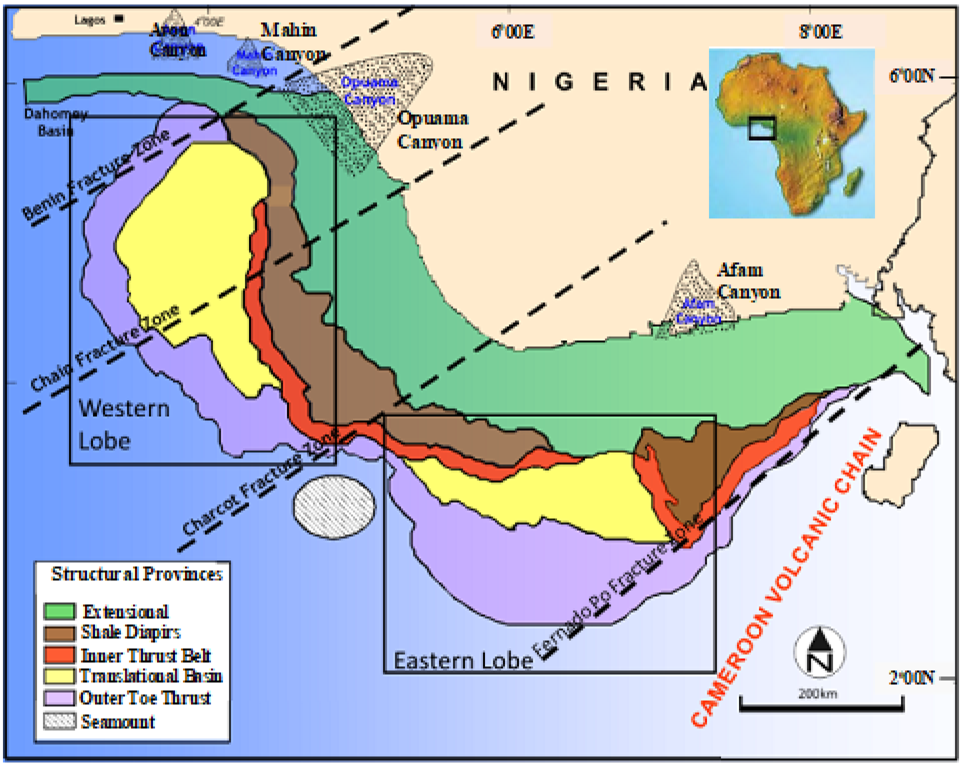

Figure 2. Map of Niger Delta showing the study location, and five offshore structural provinces (modified according to [2])

3 METHODOLOGY

Well log data of three wells (Figure 3): Freeman 003ST1, Freeman 004ST1, Freeman 005 obtained from Shell Nigeria Exploration and Production Company (SNEPCO) were used for the study. The well logs include the gamma-ray, resistivity deep, density, neutron and Primary sonic logs. Schlumberger's Petrel E&P software and Ikon Science's RokDoc software packages were employed for the data processing and interpretation.

3.1 Petrophysical analysis

To ensure quality interpretation, the input logs were quality-checked, and bad data edited through the processes of despiking and log normalizations. The wireline logs were then quantitatively analyzed using standard petrophysical equations [19], [23]. The reservoir fluid typing was achieved through density and neutron logs cross-plot. The separation between the density and neutron log motifs (gas effect) in a reservoir zone was used to indicate the presence of gas [23]. However, as in the case of [24], it was difficult to differentiate between oil and gas on the basis of the measured logs.

3.2 Rock Physics Modelling

There are many rock physics models which relate the constituent properties, texture and composition to the effective elastic properties of the rock [19]. Three Rock physics models (Contact Cement model [25], [14], Friable Sand model [26] and Hashin-Shtrikman Lower Bound Models [27] were employed to simulate the reservoir properties. The Rock physics analysis was made in the velocity-porosity plane on data from wells in which gas sands were encountered. Different depth intervals may have distinctively different velocity-porosity trends due to variations in depositional and diagenetic history. In building the rock physics model, P-velocities of each reservoir were cross-plotted with porosity values and compared with the three rock physics models (Contact Cement, Friable Sand, and the Hashin-Shtrikman Lower Bound models). This allowed a description of depositional and diagenetic features, such as cementation, grain size, sorting and clay content. For example, well-sorted grains with a small amount of intergranular cement may correspond to a high-energy stream, whereas deteriorating sorting is likely to be found in a low-energy depositional environment downstream. Cross-plots were carried out for Freeman 003ST1, Freeman 004ST1 and Freeman 005 Wells. For the Contact-cement and Friable sand models, a critical porosity of 0.4 and coordination number of 9 were used, at a constant effective pressure of 30 MPa was employed for the Friable sand model. Table 1 shows the general mineral and fluid properties used for the modelling.

Figure 3. Relief map of Nigeria and adjoining areas showing the areal distribution of Freeman Wells

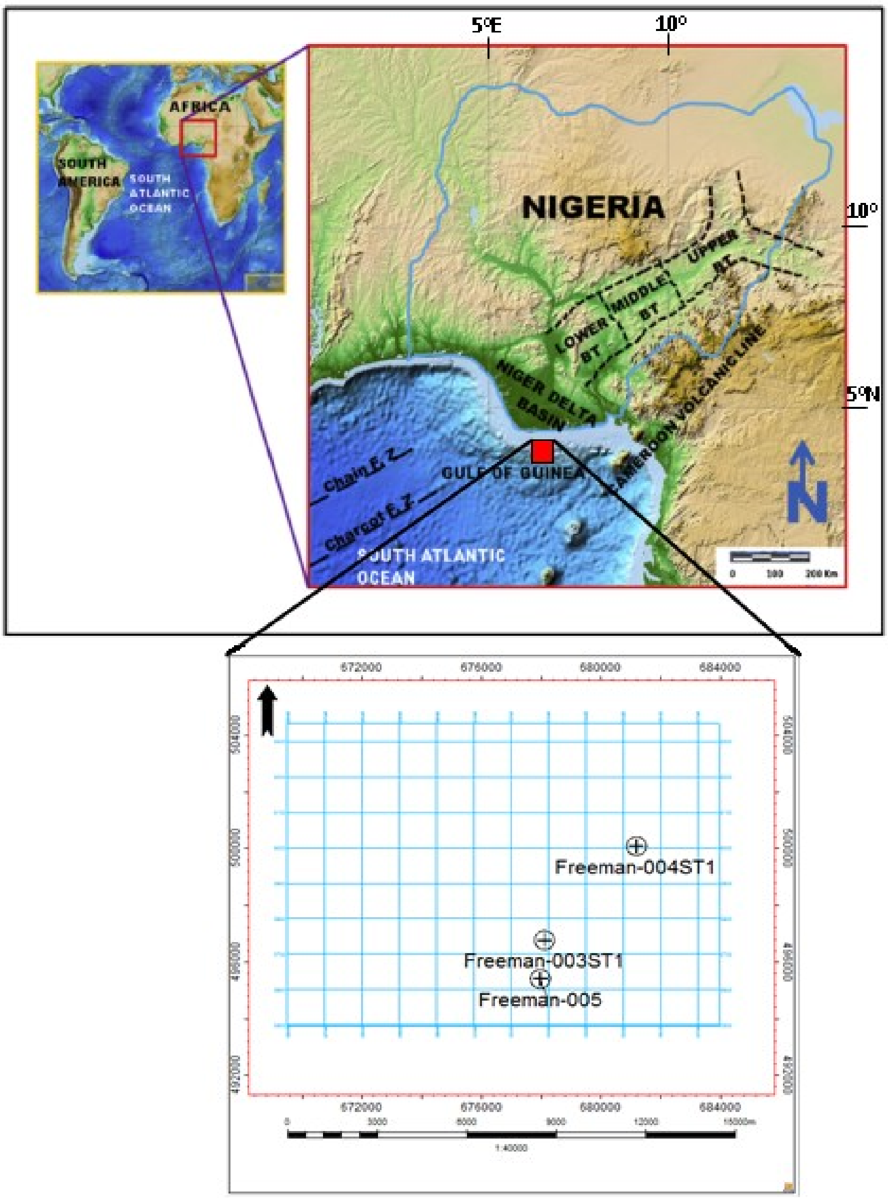

Table 1. Physical property of minerals and fluids used in rock physics modelling

	Bulk modulus (Gpa)	**Shear modulus** (Gpa)	**Density** (g/cm^3)
Quartz	36.60	45.00	2.65
Water	3.58	-	1.00
Gas	0.10	-	0.28

3.3 Reservoir Elastic Properties

The reservoir elastic properties were computed using standard rock physics equations [23], [19]. The input logs for the computation of the elastic rock properties include primary sonic velocity, shear sonic velocity and density. No measured shear sonic velocity was available for the three wells. Therefore, shear sonic velocities for the wells were estimated using empirical equations by [28] and [29], [30].

LambdaRho was calculated using the empirical formula:

$$\lambda\rho = (\rho V_P)^2 - 2(\rho V_S)^2 \qquad (1)$$

Where λ = incompressiblity, V_P is the P-wave velocity, V_S is S-wave velocity and ρ is density. Incompressibility is sensitive to pore fluids [31].

MuRho was calculated by squaring the S-wave impedance. It was calculated from the formula:

$$\mu\rho = (\rho V_S)^2 \qquad (2)$$

where μ represents rigidity which is responsive to lithology.

The estimated elastic parameters were cross-plotted using linear regression and cluster analysis to discriminate between the lithologies and fluid contents in the target reservoirs. In the hydrocarbon zones, the LambdaRho (incompressibility) values are expected to drop compared to a water zone because the density and velocity of water are higher than that of hydrocarbons. MuRho (Rigidity) will tend to increase in reservoir zones because sands (reservoirs) generally have higher acoustic impedance than shales. The LambdaRho – MuRho (LMR) were cross-plotted to provide lithological and fluid information. Petrophysical and rock physics results were integrated to characterize the reservoirs encountered in the wells. Variance attribute was extracted on seismic time slice in order to image the complex sand distribution in the area.

4 RESULTS AND DISCUSSION

Two lithofacies (three sandstone and shale layers) were delineated from Wireline logs of the three wells (Figure 4). The sandstones are deposited between thick layers of shale. The sandstones were not correlated because of the complex stratigraphic relationships in deepwater settings. The deep resistivity log, and neutron-density logs indicate that the sandstone lithofacies are hydrocarbon bearing. The large negative separation of the Neutron and Density log motifs indicates the presence of light hydrocarbon-gas. The sandstone lithofacies are characterized by cylindrical gamma ray log motifs in a manner characteristic of slope channel to Inner Fan Channel of a turbidite deposit.

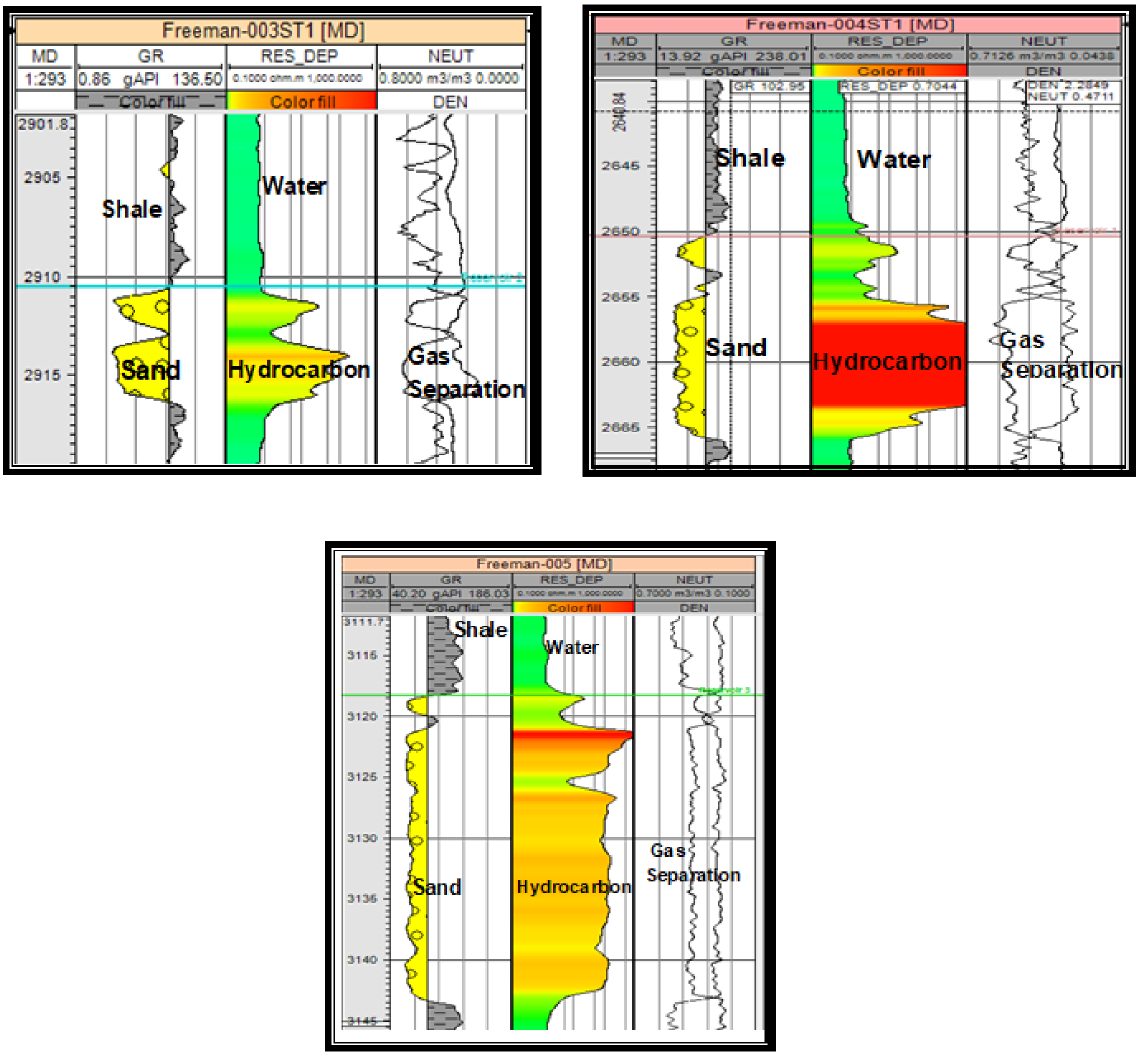

Figure 4. Well sections showing the potential reservoirs on the Freeman Wells

4.1 Reservoir Petrophysical Properties

Petrophysical interpretation of the wireline logs (Table 2) indicates quality reservoir sand units with shale volume generally less than 20% and quite high porosity average of 31%, 25%, and 31%, respectively for the interpreted sand units (Figure 4.2). Permeability and hydrocarbon saturation ranges from 2498.78 to 14425.01 mDarcy and 0.82 to 0.90 respectively.

Table 2. Petrophysical properties of the three studied reservoirs

Well name	Thickness (m)	V_{shale} (m/s)	Porosity	Effective porosity	Water saturation	Hydrocarbon saturation	Permeability (mDarcy)
004ST1	16	0.12	0.31	0.27	0.08	0.92	14425.01
003ST1	6	0.17	0.25	0.21	0.18	0.82	2498.78
005	25	0.05	0.31	0.29	0.10	0.90	14425.01

4.2 Velocity-Porosity Cross-Plots

Figure 5 shows the velocity-porosity cross-plot for the Reservoir 1 from Freeman 004ST1 Well. This reservoir simulates friable (very loose and unconsolidated) sand with a small amount of shale content. The friable nature of the reservoir may be explained by the fact that the reservoir was buried to a shallow depth where geochemical compaction has not commenced. This reservoir is characterized by low velocity (2250 - 2500 m/s) and porosity of up 0.31, which may be explained by its unconsolidated nature and good sorting. The low velocity value may imply a poorly developed quartz cementation which culminated into the unconsolidated sand. Because of the possible poor cementation and good sorting, the reservoir is expected to have high porosity and permeability values. These results are in good agreement with the estimated reservoir petrophysical properties (Table 2).

The velocity-porosity cross-plot for the Reservoir 2 on the Freeman 003ST1 (Figure 6) simulates friable (very loose and unconsolidated) sand with minimal shale content. The sands in this reservoir plot to the left of the Friable Sand model line with a slope approximately equal to that of the model line. This may be connected to a decreasing porosity due to poor sorting. Furthermore, Reservoir 2 is characterized by relatively high velocity (2500- 2710 m/s) and a reduced porosity (0.29), which may be explained by an increase in the degree of consolidation as a result of increase depth of burial. Moreover, these sands do not plot along the Contact Cement line in any way; indicating absence of quartz cementation. Nevertheless, there is a possibility of some cementation by clay minerals. Consequently, these sands would possibly have lower porosity compared to the sands in the Reservoir 1. It is concluded that the sand is poorly sorted and probably clay cemented. Therefore, this reservoir would have relatively lower porosity values and low permeability values. This result agrees with the porosity and permeability indicated by petrophysical study (Table 2). The velocity-porosity cross-plot for Reservoir 3 (Figure 7) of the Freeman 005 Well simulates model midway between Friable Sand and Contact Cement models. Some of the sands plot along the Contact Cement line with high velocity values (2500- 2750 m/s) indicating a high degree of quartz cementation, while a few plots along the Friable Sand model line suggest shaliness. The other points in between the two lines—with high velocity values—would possibly have varying amounts of quartz and clay cement. Therefore, this reservoir has a complex geology expected in a deepwater environment. The sands are probably cemented and have fair to good sorting. As a result of the complex geology of this reservoir, the porosity distribution is complex and permeability should be relatively low due to the cementation. However, the log calculated permeability indicates the same value of permeability for Reservoirs 1 and 3 (Table 2). This could be erroneous because the density porosity dependent formula of the permeability equation does not accurately account for the depositional and diagenetic factors of the reservoir—sorting and cementation. The permeability formula has probably overestimated the permeability of this reservoir.

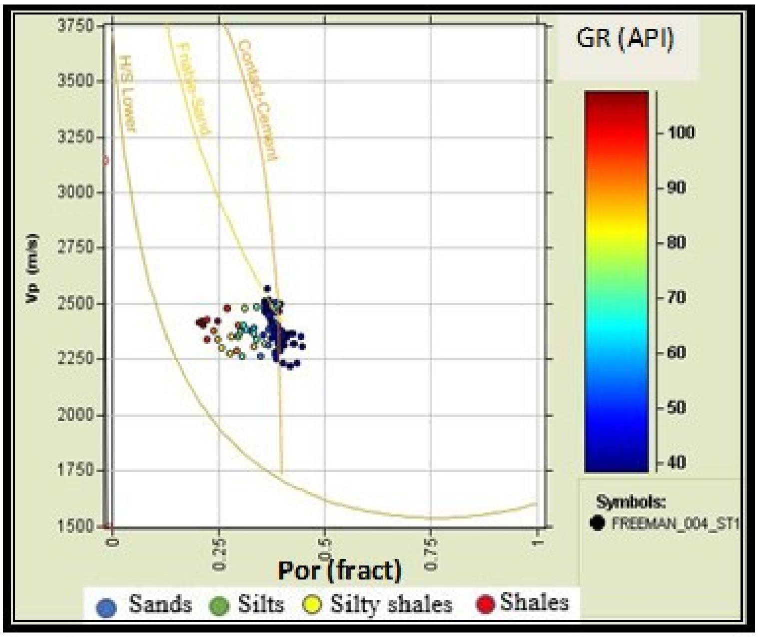

Figure 5. Velocity-porosity cross-plot for Reservoir 1 (Freeman 004ST1)

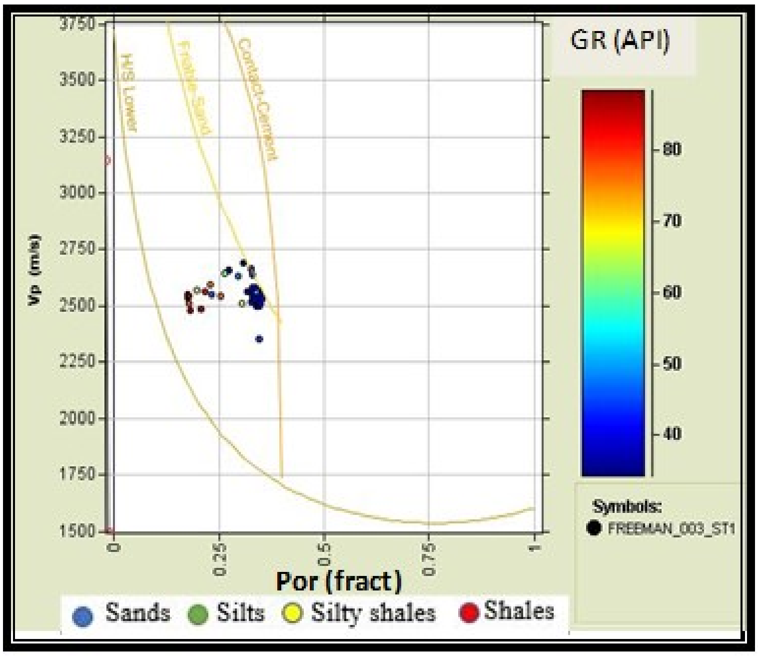

Figure 6. Velocity-porosity cross-plot for Reservoir 2 (Freeman 003ST1)

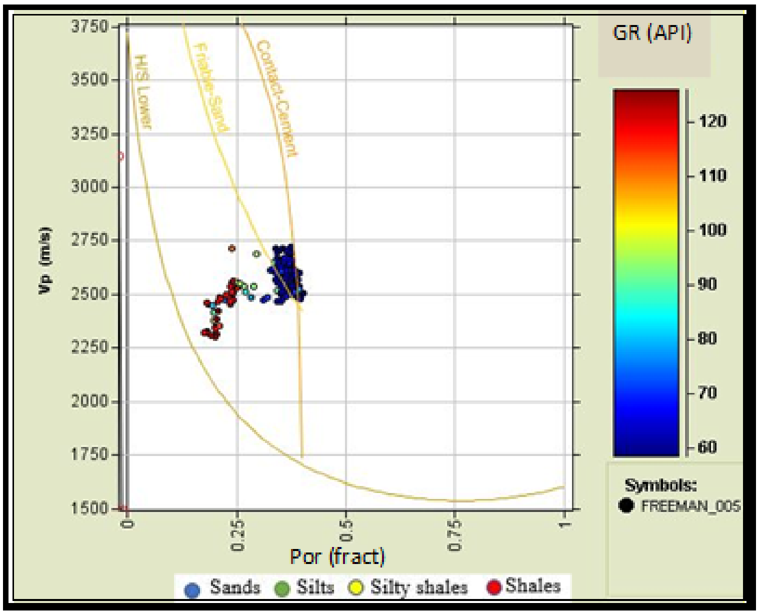

Figure 7. Velocity-porosity cross-plot for Reservoir 3 (Freeman 005)

4.3 Cluster Analysis of Reservoir Elastic Properties

Figures 8 - 10 show the responses of brine and gas filled sand in Lambda-Mu-Rho (LMR) cross-plots space for Reservoirs 1 to 3. The cross-plots show distinct brine filled sediment and gas saturated data cloud and trends. The LMR cross-plots confirm the presence of gas in these reservoirs. It should be noted that the gas filled sands occupies lower Lambda-Rho values signifying its low incompressibility. Also, the cross-plots brought to the fore the ability of rock physics to discriminate fluid fills in a reservoir.

Figure 11 shows the response of shale and gas filled sand in Ratio-Difference (R-D) cross-plot space. Cluster analysis of elastic rock properties shows distinct trend and data cloud on cross-plots.

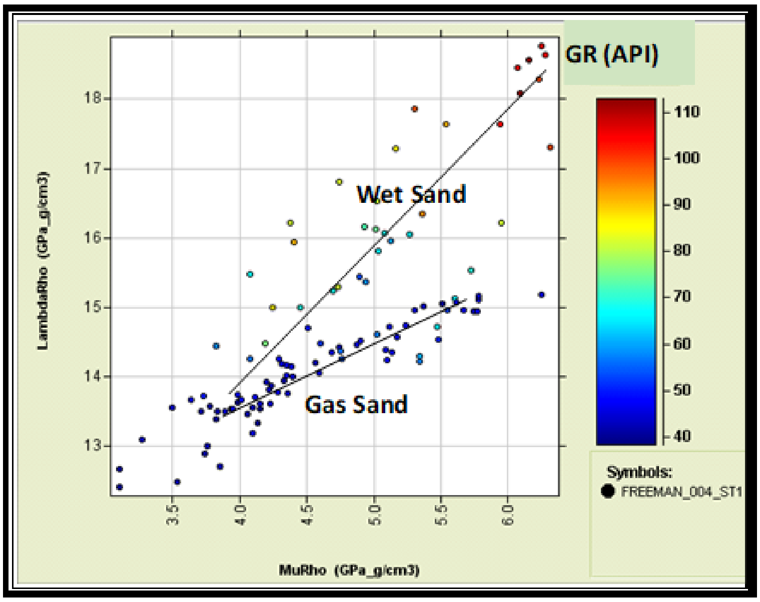

Figure 8. LambdaRho-MuRho Crossplot for Reservoir 1 (Freeman 004ST1)

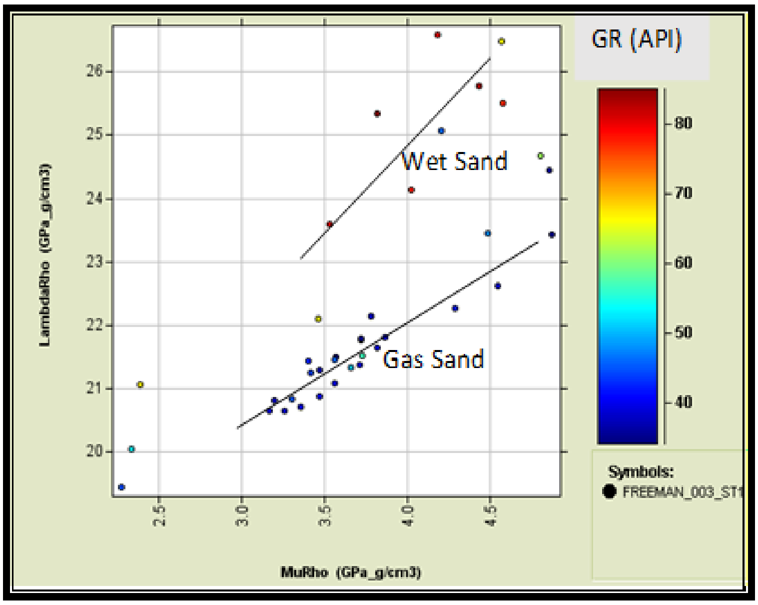

Figure 9. Lambda-Mu-Rho Cross-plot for Reservoir 2 (Freeman 003ST1)

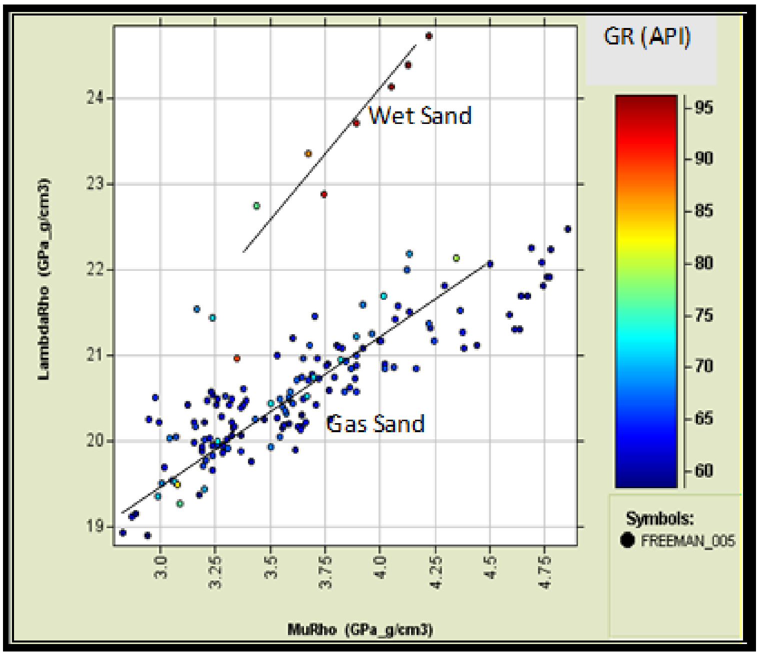

Figure 10. Lambda-Mu-Rho Cross-plots for Reservoir 3 (Freeman 005)

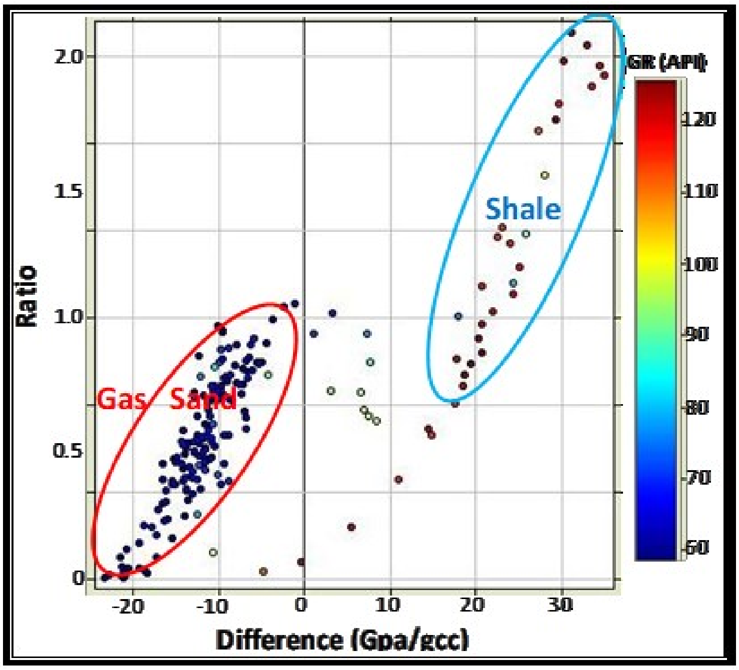

Figure 11. Ratio Difference cross-plot of reservoirs

These trends and data clouds represent distinct lithofacies units defined by characteristic elastic rock properties. The R-D cross-plot made sand identification possible which is in the lower left quarter, i.e. difference less than 0 and ratio less than 1. Cross-plots clearly separate the shale and gas-bearing sand clusters, which may not be possible through conventional petrophysical analysis.

4.4 Qualitative Description of Reservoir Characteristics

Table 3 shows a qualitative description of the studied reservoir characteristics based on the integration of petrophysics and rock physics. Reservoir 1 showed good sorting and poor cementation. Porosity and permeability of such a reservoir is expected to be high as confirmed by the petrophysics derived porosity. Reservoir 2, however, shows poor sorting and some possible clay cementation. The porosity and permeability of this reservoir is expected to be relatively low as evident from the petrophysical results. Reservoir 3 shows good sorting and well developed cementation as inferred from the relatively high velocity values. Despite the high porosity, the reservoir may have low permeability because of the cement.

Table 3. Qualitative characteristics of study reservoirs

Reservoirs	Sorting	Cementation	Porosity	Permeability	Fluid type
Reservoir 1	Good	Poor	High	high	gas
Reservoir 2	Poor	Fair (clay cement)	Low	low	gas
Reservoir 3	Good	Good	High	low	gas

Variance attribute extracted from time slice seismic data intersection (Figure 12) shows the position of the three wells on the turbidite deposit. The reservoir on Freeman 004ST1 Well falls within the upper fan sand deposit, while those on Freeman 003ST1 and 005 fall within the middle to lower fan area (Figure 12). It is therefore evident that the reservoirs cannot be simply correlated seeing that the wells fall in different sand intervals.

5 CONCLUSION

Petrophysical analysis integrated with rock physics analysis has been carried out for reservoir characterization in deepwater Niger delta basin, Nigeria, using a suite of well log data from three wells in the field. Petrophysical interpretations of mainly turbidite sand reservoirs indicated 5 -17% clay content, 0.82 - 0.92 water saturation and 0.21- 0.29 effective porosity. Hydrocarbon bearing zone showed cross over for neutron-density logs and is simultaneously supported by very high resistivity. However, it was difficult to differentiate between oil and gas on the basis of the measured logs. Cluster analyses of rock physics properties shows distinct trends and data clouds, which made sand identification possible and confirmed the fluid fill as gas. Cross-plots clearly separate the shale and gas-bearing sand clusters, which may not have been possible through a conventional petrophysical analysis. The results showed that the reservoirs properties ranged from highly porous, well sorted and poorly consolidated sand to fairly sorted and highly cemented sands. This study has demonstrated how Rock physics can be used in predicting reservoir lithology and fluid content. The results provide a model that increases the possibility of finding reservoir sand and mitigates the risk involved in finding hydrocarbons.

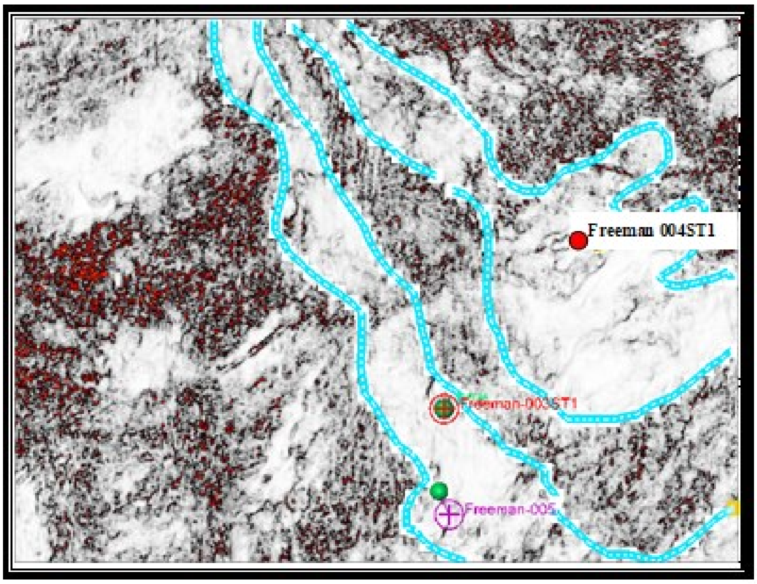

Figure 12. Variance attribute time slice showing the position of the study wells on the turbidite deposit

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