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An Integrated Geophysical Approach for Porosity and Facies Determination: A Case Study of Tamag Field of Niger Delta Hydrocarbon Province

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Abstract

Petro physics, rock physics and multi-attribute analysis have been employed in an integrated approach to delineate porosity variation across Tamag Field of Niger Delta Basin. Gamma and resistivity logs were employed to identify sand bodies and correlated across the field. Petro physical analysis was undertaken. Rock physics modelling and multi-attribute analysis were carried out. Two hydrocarbon reservoir sands (A and B) were delineated across the field. Reservoir A is a relatively clean sand, characterized with high average porosity of 0.28 while Reservoir B is also a relatively clean sand with lower average porosity of 0.24. Reservoir A is a replica of Friable Sand Model while reservoir B mirrors the Constant Cement Model. Acoustic impedance attributes serve as good predictors of lateral changes in porosity across the reservoirs. The internal fabric of Reservoir sand A is that of a clean high porosity sands implying that there are few or no diagenetic cement and the stiffness of the rock is weakly affected. This reservoir is relatively good quality due to its good porosity and sorting even at deeper depths. This unconsolidated sandstone reservoir is associated with high permeability but highly susceptible to sand production, which causes severe operational problem for oil and gas explorers. Reservoir B has good porosity but relatively lower that of Reservoir A. This conforms to the results of the petro physical analysis which shows that reservoir sand A with average porosity 0.28 is more porous than reservoir sand B with average porosity 0.24.

Keywords: Petro physics; Multi-attribute; Friable.

Introduction

The geophysical and geologic studies of the Niger Delta hydrocarbon province by several authors have proven that the basin constitutes an enormous sedimentary formation and significant petroleum geological features favorable for hydrocarbon exploration across various terrains that constitute the basin. Several techniques have been employed for improved understanding of facies and porosity distributions for successful exploration. An effective and efficient characterization of reservoirs necessitates

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the integration of different data types and different techniques to define reservoir model.

Alao and Oludare (2015) [1] employed seismic attributes to estimated reservoir properties, classified the reservoir sand-facies distribution and identified potential hydrocarbon pay zones with a view to optimizing placements of wells in "Bigola" Field of Niger Delta Alao and Oludare (2015) [1] analyzed 3D seismic volume and well logs using multi-attribute Probabilistic Neural Networks to generate target reservoir property (Porosity and Resistivity). The comparison of the target reservoir properties was based on the general criteria that; low acoustic impedance, has high Porosity and high shale resistivity typify hydrocarbon-bearing sand facies.

Multi-attributes prediction of lithology and porosity from seismic data over Tomboy Field, NOyeyemi and Aizebeokhai (2015) described some commonly utilized seismic attributes that are of complementary value to the information acquire through traditional methods of seismic interpretation. Seismic attributes extraction have proven to offer new information into structural and stratigraphic mapping interpretations of Niger Delta Basin. Seismic attributes are great tools in delineation of hydrocarbon leads and prospects which afterwards help to reduce exploration and development risk (Oyeyemi and Aizebeokhai, 2015).

Srivastava et al. (2013) [8] analyzed a number of reservoir properties (Porosity, Resistivity and Vshale) and optimize the restricting conditions for each of the property in with a view to delineating the hydrocarbon bearing sands from those of the water bearing sands and shales. Srivastava et al. (2013) [8] suggest that multiple reservoir properties taken together may be employed to corroborate the objective to define the hydrocarbon bearing reservoir sands and their aerial distribution over the study area.

Multi-attribute seismic analysis and strata slicing had proved very useful in the detection of near-surface deep-water channels and depositional facies. The integration of deep-water channel morphology and facies architecture with modern fluvial systems and ancient Tertiary outcrops has improved our understanding of the eastern offshore Niger Delta deep-water sedimentology and reservoir distribution Ebere *et al.* (2013) [7].

Ajisafe and Ako (2013) [2] carried out an integrated interpretation of seismic and well log data over "Y" Field in the Niger Delta area of Nigeria. This was carried out with the aim of characterizing reservoir rocks using quantitative seismic attributes and petro physical properties.

Aminu and Olorunniwo (2009) [3] employed the technique of multi-variate linear transforms to predict reservoir properties for the Agbada Formation of the Tomboy Field, Niger delta. Petrophysical from analysis over a horizon of the Agbada Formation revealed clean hydrocarbon-bearing sand at the target with shale volume ranging from porosity 20-25% and average hydrocarbon saturation of 77%. Petrophysical studies of Tomboy Field of Niger Delta by Aminu and Olorunniwo (2009) [3] indicates that the lithofacies are distinguishable from their physical properties (namely: P-wave impedance, porosity, and shale volume and water saturation).

In this research work, both seismic and well logs were integrated using various techniques such as rock physics, petrophysics and multi-attibute analysis to investigate the variation of porosity across Tamag Field of Niger Delta. Due to the non-uniqueness of all geophysical techniques, integration of the various techniques is necessary so that the strength of a given technique can compensate for the weakness of another. The agreement of various geophysical techniques also validates a given model.

Three rock physics models for sandstone reservoir response to coacyton and diagenesis were used to describe the sandstone delineated (Fig. 1).

The friable (unconsolidated) sand model: This describes the velocity-porosity behaviour versus sorting at a specific effective pressure. The velocity for the well sorted, high-porosity member (normally selected to be around 0.4) is determined by contact theory, and intermediate (poorly sorted) porosities are "interpolated" using a lower bound (Dvorkin and Nur, 1996) [6].

The contact-cement model: This model describes the velocity-porosity behaviour versus cement volume at high porosities. The contact cement fills the crack-

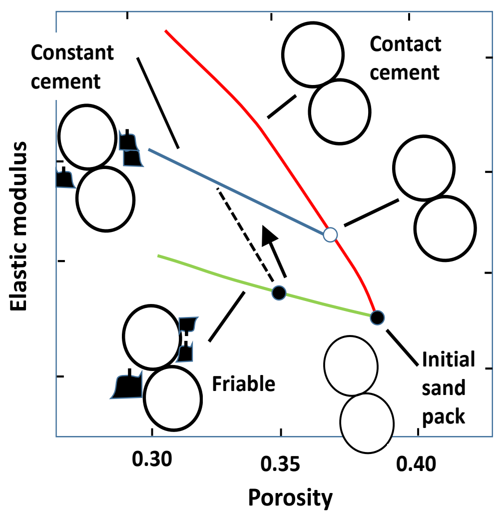

Figure 1. Rock Physics Reservoir Models (Dvorkin and Nur, 1996) [6].

like spaces near the grain contacts. This has the effect of very rapidly stiffening the rock with very little change in porosity. This cement tends to eliminate further sensitivity to effective pressure in the model. The high-porosity member is the critical porosity, which can vary as a function of sorting. For practical purposes, we assume this porosity to be equal or close to the well-sorted end member of the friable-sand model.

More poorly sorted cemented sandstones are then modelled using the constant-cement model (Dvorkin and Nur, 1996) **[6]**.

The constant-cement model: This describes the velocity-porosity behaviour versus sorting at a specific cement volume, normally corresponding to a specific depth. The high-porosity member is defined by first applying the contact-cement model and calculating the velocity-porosity for a well-sorted sandstone with a given cement volume. A lower bound interpolation between this well-sorted end member and zero porosity will then describe more poorly sorted sandstones with the constant-cement volume (Dvorkin and Nur, 1996) **[6].**

Geology of Niger Delta

The Niger delta, reputed as one of the most prolific petroleum province in the world is found in the Gulf of Guinea on the west coast of Central Africa. It is found between latitudes 4^0 00'N and 6^0 00'N and longitudes 30 00'N and 90 00'N and is located at the south-southern part of Nigeria. It is bounded in the south by the Gulf of Guinea and in the North by older (Cretaceous) tectonic elements which include the Anambra Basin, Abakaliki uplift and the Afikpo syncline. In the east and west respectively, the Cameroon volcanic line and the Dahomey Basin mark the bounds of the Delta (Fig. 2). The delta is considered one of the most prolific hydrocarbon provinces in the world, and recent giant oil discoveries in the deep-water areas suggest that this region will remain a focus of exploration activities (Corredor *et al.*, 2005) [4].

Geomophology of the Tamag Field

Tamag Field is located at the southern part of the Tertiary Shallow Offshore Niger Delta, which is ranked among the most prolific hydrocarbon provinces in the world. The geologic province is situated at the point of triple junction which evolved during the separation of South American and African Continental plates. Fig. 3 represents the map of Niger Delta and location of the Field.

Materials and Methods

The available dataset include 3-D seismic data (Fig. 2) containing 3-D seismic reflection lines (546 cross-lines and 865 in-lines). The inline length and interval include 401 and 25 respectively while the crossline length and interval include 221 and 25 respectively. The data has been processed to improve the resolution and the details of the structure interest.

Also, there are a total of four spatially distributed

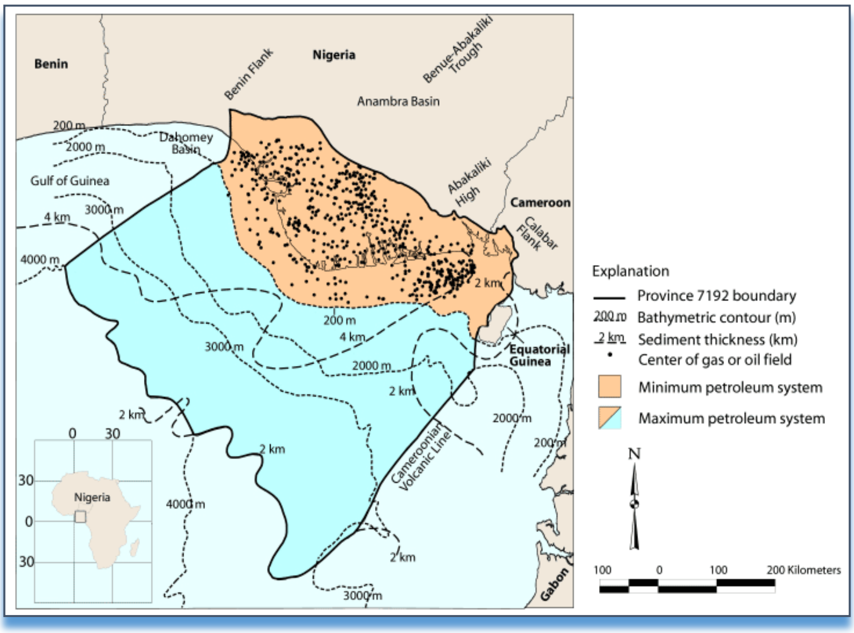

Figure 2. Index Map of Nigeria and Cameroun (Doust And Omatsola, 1990)[5].

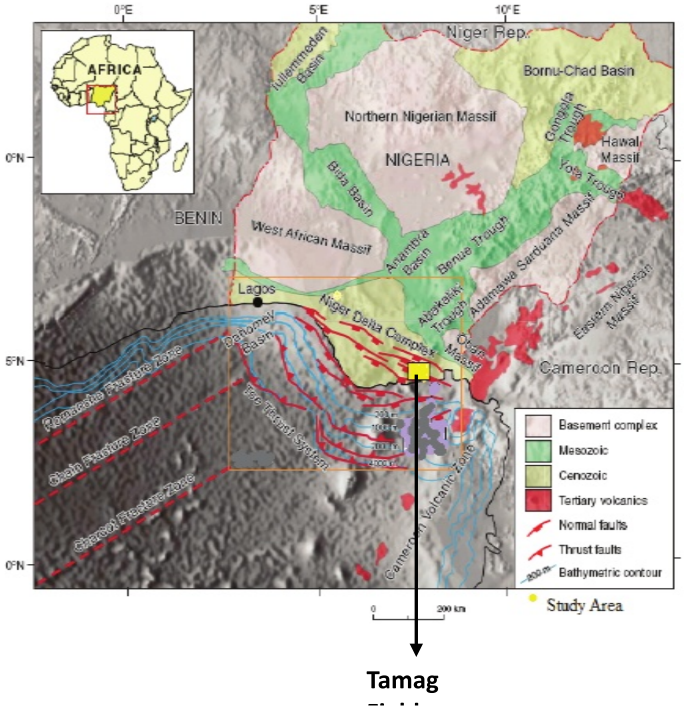

Figure 3. Map of Niger Delta (Doust and Omatsola, 1990) [5] showing the Base Map of Tamag Field.

offset wells (Fig. 4) available for this study namely Tamag-1, Tamag-2, Tamag-3 and Tamag-4. Table 1 is the summary of the wireline logs available in each well and Table 2 is the list of available well logs in the field.

Delineation and correlation of reservoir sand

This was carried out on both inline and crossline seismic sections by mapping the continuous and strong seismic reflections which marks the top of the sandstone reservoirs. The synthetic seismogram enabled the identification of the events that indicate the top of the sandstone reservoirs.

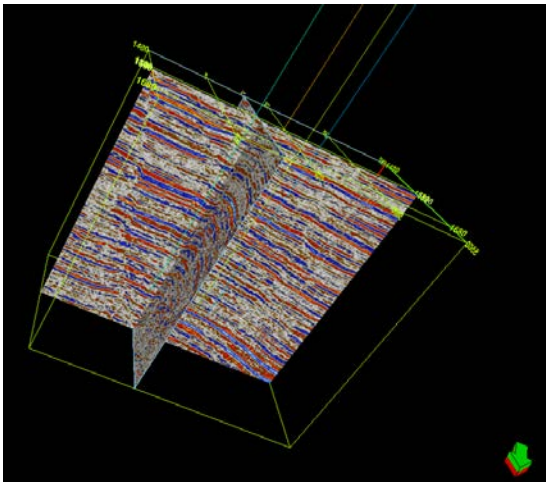

Figure 4. 3D View of the Available Seismic Data and the Drilled Wells.

Reservoir sand was identified by marking point of low gamma and high resistivity on the log within the subdivided system tracts and correlating the points across the other wells within the study area.

Petrophysical analysis

Rock properties including porosity, net/gross and volume of shale were estimated from wireline logs using empirical methods. Porosity was calculated using bulk density (equation 1), net/gross was estimated from the thickness of sand units intervals to gross thickness of the reservoir while the volume of shale was estimated using gamma ray index (linear method) (equation 2).

$$\Phi_{corr} = \frac{\rho ma - \rho b}{\rho ma - \rho f} \quad (1)$$

Where,

ρma = matrix density (g/cc)

ρb = log reading (g/cc)

ρf = density of mid filtrate (g/cc)

Volume of shale was estimated using gamma ray index (i.e linear method)

$$V_{clay} = (GR_{log}-GR_{min})/(GR_{max}-GR_{min}) \quad (2)$$

Rock physics analysis

Elastic parameters including Vp, Vs and density were used to characterize the delineated sandstone reservoir

Table 1. Summary of the Wireline Logs Available in Each Well of Tamag Field of Niger Delta.

WELL NAME	X(m)	Y(m)	KB(ft)	TD(ft)
Tamag-8	479289.8	180979.2	76.6	9922
Tamag-2	478119	182206	80	9700
Tamag-3	480068.3	180757.5	79	8741
Tamag-4	480721.5	181230.2	74.8	8840

in terms of sedimentary structures such as mineralogy, sorting and overall reservoir quality. Vp was extracted from sonic log. Vp-Porosity crossplot (Avseth *et al.*, 2003*)* was used to characterize the delineated sandstone reservoirs by comparing observed clusters and trends with various rock physics models.

Muliti-attributes analysis and porosity prediction

Several attributes were compared with reservoir parameters through crossplots and correlation analysis to determine physical relationship between the attributes and porosity/lithofacies. Since seismic attributes in terms of amplitude tends to give a gross lateral variation and distribution of rock properties away from well locations, to reduce uncertainties, determination of correlation coefficients between the derived attributes and reservoir properties was done to determine the most suitable attribute combinations that are good indicators and predictors of porosity and lithofacies variations across the reservoir. The correlation coefficients between the computed attributes and reservoir properties were summarized in Tables 4 and 5.

Results and Discussion

Figure 5 is the display of the lateral arrangement of reservoirs across the Tamag Field. Variation in well tops and depth of the reservoir sands across the wells are indicative of faulting (i.e. relative displacement) within the field. This suggests that available wells were likely drilled within fault blocks. The correlation across the wells also laid the groundwork for calibrating the mapping of horizons and petro physical analysis at different wells.

The petro physical estimation of the delineated sandstone lithofacies in terms of porosity, fluid saturation and volume of shale is shown in Table 3. Basically, reservoir quality information can be predicted or even derived from the estimated petro physical properties since these parameters such as porosity and volume of shale are sometimes closely associated with rock properties such as sorting, lithofacies and grain maturity.

From Table 3, reservoir A is a relatively clean sand, characterized with low average volume of shale of 0.12, average thickness of 55m, high average porosity of 0.28 and average water saturation of 0.46. Reservoir B is also a relatively clean sand with low average volume of shale of 0.13, average thickness of 85m, high average porosity of 0.24 and average water saturation of 0.50.

Figure 6 is the cross plot of P-velocity and Porosity of Reservoir A Sand of Tamag Field. The result is a replica of friable sand model or unconsolidated line rock physics model, which indicates that the internal fabric of the delineated sandstone facies is that of a clean high porosity sands. The implication of a friable sand model cluster space trend is that there are few or no diagenetic cement and the stiffness of the rock is weakly affected. Though porosity and underlying sorting deteriorates with influx of fine grain materials, friable sandstone reservoirs are of relatively good quality since they tend

Table 2. Available Well Logs from each Well of Tamag Field.

WELL NAME	Well Logs Available
Tamag-8	Gamma, Resistivity (shallow and deep), Effective porosity, Neutron log
Tamag-2	Gamma, Resistivity (shallow and deep), neutron, Effective porosity,
Tamag-3	Gamma, Resistivity (shallow and deep), Effective porosity, Neutron log
Tamag-4	Gamma, Resistivity (shallow and deep), Effective porosity, Sonic, density log

Table 3. Estimated Petrophyical Parameters for Tamag Field of Niger Delta.

Well name	Reservoir	Porosity	Ntg	Vshale	Sw
Tamag 08	A	0.27	0.45	0.11	0.35
	B	0.23	0.48	0.12	0.43
Tamag 02	A	0.28	0.55	0.12	0.41
	B	0.25	0.64	0.13	0.52
Tamag 03	A	0.28	0.79	0.12	0.35
	B	0.24	0.77	0.13	0.50
Tamag 04	A	0.29	0.77	0.14	0.50
	B	0.25	0.67	0.15	0.56

to have few grain-grain cements, good porosity and sorting even at deeper depths. Unconsolidated sandstone reservoirs are associated with high permeability but are highly susceptible to sand production, which caused severe operational problem for oil and gas explorers. Most reservoirs in the Niger-Delta fall in this category.

The cross plot of VP against Porosity in Tamag-4 well within Reservoir Sand B (Fig. 7). This gives rise to a Constant Cement Model by comparing the cluster trends observed within the well and the model in figure 7. In this case clay particles have been deposited at the crack spaces near the grain contacts, so the stiffness of rock rapidly increase with very little change in porosity.

This sandstone reservoir shows trend and properties similar to contact cement model. Contact cement model is associated lower porosity than those obtainable in the friable cement model.

Figure 8 shows the cross plot of porosity versus acoustic impedance of Tamag Field of Niger Delta. The correlation coefficient of acoustic impedance versus porosity is -0.66. The variation of this acoustic impedance across the field is an indication of the variation of porosity across the field. High acoustic impedance corresponds to high velocity.

Figure 9 is the cross plot of porosity versus acoustic impedance of Tamag Field of Niger Delta. There is an observable negative correlation coefficient of -0.10 between the acoustic impedance and facies. From the cross plot analysis, it is observed that acoustic impedance of both sands and shales overlaps and hence acoustic impedance has low correlation coefficients with lithofacies. The variation of this acoustic impedance across the field is an indication of the variation of porosity across the field because high acoustic impedance is associated with high density which corresponds to low porosity.

Table 4 shows the relationship between seismic attributes and lithofacies. The table presents the physical relationship between the listed seismic attributes and lithofacies. RMS, average energy and envelop are positively correlated with lithofacies with correlated coefficients of 0.16, 0.20 and 0.34 respectively. Acoustic impedance is negatively correlated with lothofacies with correlated coefficient of -0.10. Seismic attributes in terms of amplitude tends to give a gross lateral variation and distribution of rock properties away

Table 4. Relationship between Computed Seismic Attributes and Lithofcaies.

Seismic attribute	Reservoir property	Correlation Coefficients
Acoustic impedance	Lithofacies	-0.10
Rms amplitude	Lithofacies	0.16
Average energy	Lithofacies	0.20
Envelope	Lithofacies	0.34

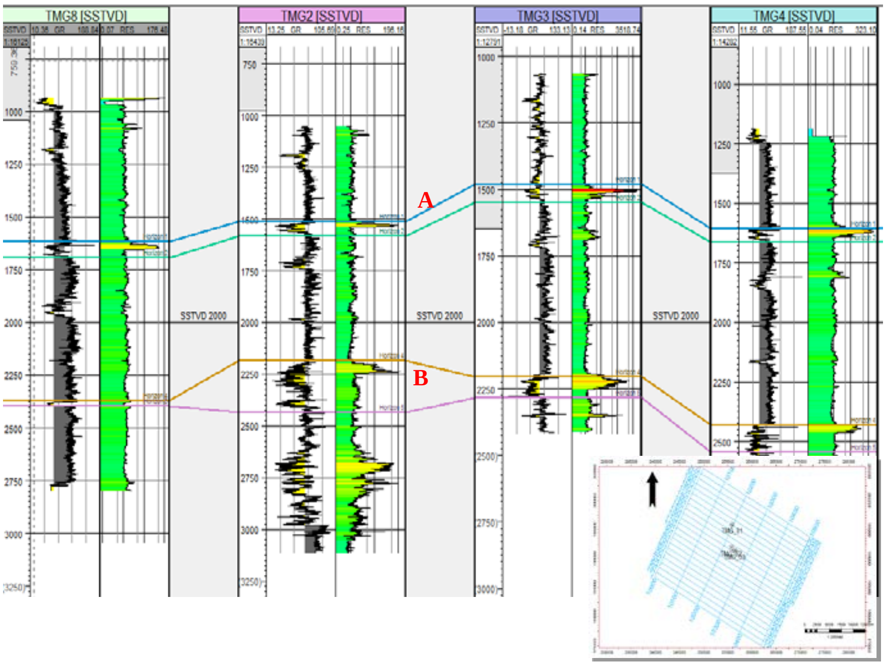

Figure 5. Well Log Interpretation and Reservoir Correlation of Tamag Field showing the Morphology of the Two Mapped Reservoir Sands.

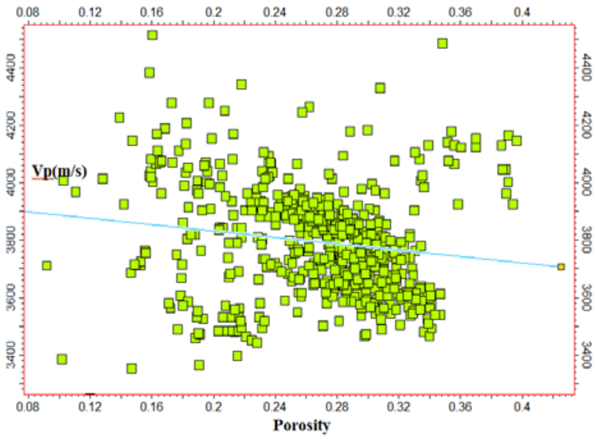

Figure 6. Crossplot of P-Velocity against Porosity from the Uppermost Part of Tamag-4 Well within Reservoir Sand A Interval indicating a Friable Sand Model Trend.

Table 5. Relationship between Computed Seismic Attributes and Porosity.

Seismic attribute	Reservoir property	Correlation Coefficients
Average energy	Porosity	-0.511
RMS amplitude	Porosity	0.75
Acoustic impedance	Porosity	-0.66
Envelope	Porosity	0.68

from well locations which helps to reduce uncertainties. The correlation coefficients between the derived attributes and reservoir properties is significant in the determination of the most suitable attribute combinations that can serve as indicators and predictors of porosity and lithofacies variations across the reservoir. The correlation coefficients between the computed attributes and lithofacies are summarized in Table 4.

Table 5 shows the summery of relationship between selected seismic attributes and porosity describing the physical relationship between the seismic attributes and lithofacies. Average energy and acoustic impedance are negatively correlated with porosity with correlation coefficients of -0.51 and -0.66 respectively. Rms and envelop are positively correlated with porosity. The correlated coefficient of RMS and envelop with porosity are 0.75 and 0.68 respectively. The correlation coefficients between the derived seismic attributes and reservoir properties is significant in the determination of the most suitable attribute combinations that can serve as indicators and predictors of porosity and lithofacies

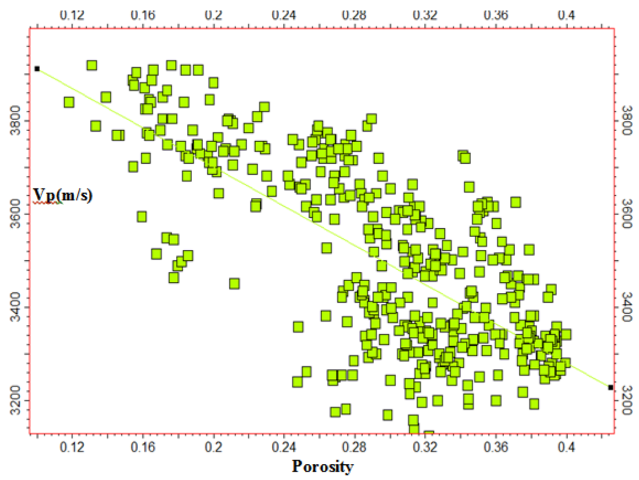

Figure 7. Crossplot of P-Velocity against Porosity from Tamag-4 Well within Reservoir Sand B Interval Indicating a Constant Cement Model Trend.

variations across the reservoir. Seismic attributes in terms of amplitude tends to give a gross lateral variation and distribution of rock properties away from well locations, to reduce uncertainties. The correlation coefficients between the computed attributes and porosity are summarized in Table 5.

Figure 10 shows the extracted envelop attribute of Reservoir A indicating the lateral variation of porosity across the Tamag Fields of Niger Delta. The amplitude attributes i.e. RMS amplitude and acoustic impedance attributes show pockets of low and high amplitudes indicating region of low and high porosities which could serve as sweet spots for proposing future wells. The drilled wells overlies a region of moderate to high porosity areas. It can be deducted that apart from the vertical variation of porosity in the Niger Delta, there is also a lateral variation of porosity from one point to the other across the Tamag Field.

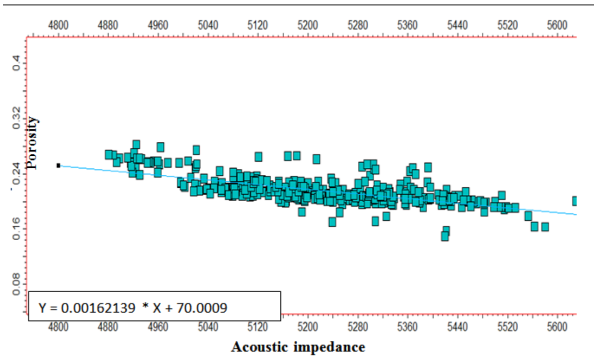

Fig. 8: Crossplot of Porosity with Acoustic Impedance Attribute.

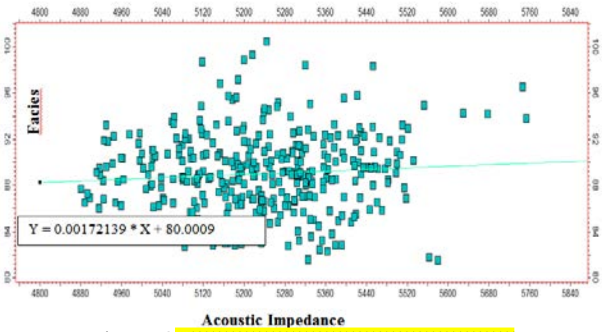

Figure 9. //

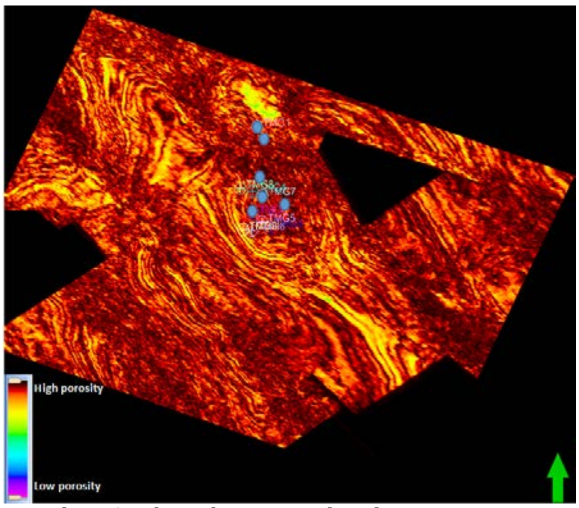

Figure 10. Envelope Attribute showing Predicted Porosities across Reservoir A.

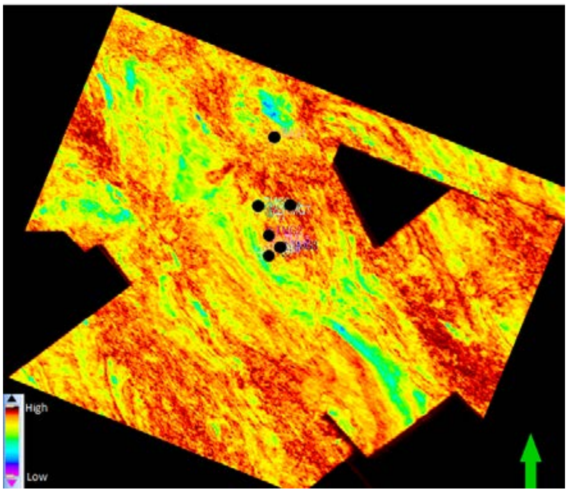

Figure 11. Envelope Attribute indicating Porosities across Reservoir B.

Figure 11 shows the extracted envelop attribute of Reservoir A indicating the lateral variation of porosity across the Tamag Fields of Niger Delta. The amplitude attributes and acoustic impedance attributes show pockets of low and high amplitudes indicating region of low and high porosities which could serve as sweet spots for proposing future wells. The drilled wells overlies a region of moderate to low porosity areas. It can be deducted that apart from the vertical variation of porosity in the Niger Delta, there is also a lateral variation of porosity from one point to other across the Tamag Field.

Conclusion

Two sandstone reservoirs A and B have been mapped and described in terms of porosity using rock physics, petro physics and multi-attribute analysis. The hydrocarbon type accumulated within the different reservoirs was identified to be gas for reservoir A and oil for reservoir B respectively.

Reservoir A is a relatively clean sand, characterized with low average volume of shale of 0.12, average thickness of 55m, high average porosity of 0.28 and average water saturation of 0.35. Reservoir B is also a relatively clean sand with low average volume of shale of 0.13, average thickness of 85m, high average porosity of 0.24 and average water saturation of 0.50.. Reservoir A is a replica of Friable Sand Model while reservoir B is a Constant Cement Model.

The cross plot analysis shows that acoustic impedance of both sands and shales overlaps. Acoustic impedance and amplitude attributes have low correlation coefficients with lithofacies and could not discriminate sand and shale lithofacies within the field. In effect, amplitude related attributes are not good indicators and predictors of lateral variation of sand and shale lithotypes across the reservoirs. This effect is closely linked to the diagenetic and sedimentology properties and behavior of sand and shales within the field. However, acoustic impedance separates zones of high and low porosities and the amplitude related attributes such as envelope, RMS amplitude and acoustic impedance attribute has high correlation coefficient with porosity and hence serves as good predictors of lateral changes in porosity across the reservoirs. The amplitude attributes and acoustic impedance attributes shows pockets of low and high amplitudes illustrating regions of low and high porosities which could serve as sweet spots for proposing future wells. The drilled wells overlies a region of moderate to low porosity areas.

Friable sand model of reservoir sand A indicates that the internal fabric of the delineated sandstone facies is that of a clean high porosity sand. This implies that there are few or no diagenetic cement and the stiffness of the rock is only weakly affected. Friable sand reservoirs are of relatively good quality since they tend to have few grain-grain cements, good porosity and sorting even at deeper depths. Unconsolidated sandstone reservoirs are associated with high permeability but are highly susceptible to sand production, which caused severe operational problem for oil and gas explorers. Most reservoirs in the Niger-Delta fall in this category.

In the case of constant cement model of reservoir sand B, clay particles have been deposited at the crack spaces near the grain contacts, so the stiffness of rock rapidly increases with very little change in porosity. Constant cement model is associated with lower porosity than those obtainable in the friable cement model. This conforms to the results of the petro physical analysis which shows that reservoir sand A with average porosity of 0.28 is more porous than reservoir sand B with average porosity of 0.24. Reservoir A has less average volume of shale of 0.12 compared to reservoir B with average volume of shale of 0.13. This difference in volume of shale in the two reservoir sands contributes in porosity variation between the two reservoirs.

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