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Improved Sand characterization of Mafe Field of Niger Delta by integrated well logs information and 3D seismic data

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Abstract

Well log rock physics and seismic facies analysis was carried out with a view to enhancing reservoir sand characterization of Mafe Field of Niger Delta**.** Lithofacies were identified using suites of well logs and correlated across the block. Rock properties were estimated from wireline logs using empirical methods. Vp-porosity crossplot was used to characterize the delineated sandstone reservoirs by comparing observed clusters and trends with various rock physics models. Seismic attribute analysis was employed to detect lateral changes in lithology across the field. Reservoir A is a relatively clean sand, with low average volume of shale of 0.4, average thickness of 55m, good average porosity of 0.26 and average water saturation of 0.45. Reservoir B is also a relatively clean sand with low average volume of shale of 0.35, average thickness of 85m, high average porosity of 0.27 and average water saturation of 0.54. Reservoir C has an estimated volume of shale of 0.21 average total porosity of 0.23, and an average thickness of 70m with average water saturation of 0.65. Reservoir A conforms to the friable sand model while Vp-porosity crossplot cluster trend for both reservoir B and C show trend and properties imitating the contact cement model. The time slices extracted at different time intervals from the envelope and instantaneous frequency cubes show lateral variation in lithofacies across the delineated sandstones. Instantaneous frequency decreases from southwest to northeast which corresponds to decrease in shalines. Reservoir quality information can be predicted or even derived from the estimated petrophysical 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.

Keywords: Niger Delta, facies, rock physics.

INTRODUCTION

The Niger Delta basin is one of the most prolific hydrocarbon provinces in the world, comprising of many depobelts and has been the key area for exploration since 1960 [1]. The basin covers an extensive area both onshore and offshore with exploration activities progressively shifting to deep offshore where oil and gas are predominantly trapped in sandstones and unconsolidated sands in the Agbada formation [1]. A good understanding of the stratigraphic architecture is imperative in hydrocarbon exploration.

Porosity and permeability of Niger Delta is high in some fields due to very good to excellent sand quality [2], but low in other areas due to poor sand quality arising from the intercalation of sand and shale. Some of the shallow reservoirs of the field are not economically viable [3]. Because of the continuous deltaic progradation which commenced since Early–Tertiary, the stratigraphic unit in the Niger Delta is strongly diachronous and difficult to subdivide, [4].

The sand-shale intercalation of Niger Delta is associated with high degree of uncertainty in reservoir predictability. Because of this lithologic inhomogeneity, it is still a challenge to accurately

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delineate the sand bodies because depositional trend is not always consistent from one point to another within the same field. This uncertainty in reservoir sand arrangement has long been the bane of hydrocarbon explorationists; it has contributed in flawed reservoir predictability which poses dire economic.

The degree of reliability and precision of the mapping can be greatly enhanced by integrating seismic data (because it gives large scale pictures of subsurface strata) with well logs (due to its high resolution). This research integrates the principles of rock physic and seismic facies analysis to discriminate sandstone bodies in Mafe field of Niger Delta for an improved reservoir predictability and well positioning.

Regional Geologic Setting

The Niger Delta basin Figure-1 is located at the continental margin of the Gulf of Guinea in equatorial West Africa consisting a thick clastic fill of variable thickness extending more than 300km [5]. It is ranked among the largest subaerial basins in Africa with subaerial area of about 75,000 km^2, a total area of 300,000 km^2, and a sediment fill of about 500,000 km^3 [6].

The Delta complex evolved at the meeting point of the three arms of a triple junction formed during the fragmentation of the African and South American plates in the Albian [7].

The true delta development commenced only in the Paleocene times when sediments began to accumulate in the troughs between basement blocks of the northern flank of the present delta area, The progradation of the Niger Delta first occurred during the Eocene, probably in response to epeiorogenic movements along the Benin and Calabar flanks, [8] and this continued to the present time.

The Niger Delta developed through phases of sedimentation over an oceanward-dipping continental basement into the Gulf of Guinea from the Cenozoic to Middle Miocene, progradation subsequently took place over a landward-dipping oceanic basement [9].

The Niger Delta basin consists of three major formations; a basal thick and extensive marine shale called Akata Formation typically over 7,000 meters thick [10] which grades upward into a younger interbedded shallow marine fluvial sands, silts and clays, which forms the typical paralic portion of the delta called Agbada Formation (over 3700 meters thick). This is then overlain by the youngest and uppermost part of the sequence, a massive continental sand unit named Benin Formation (over 200 meters thick) [11].

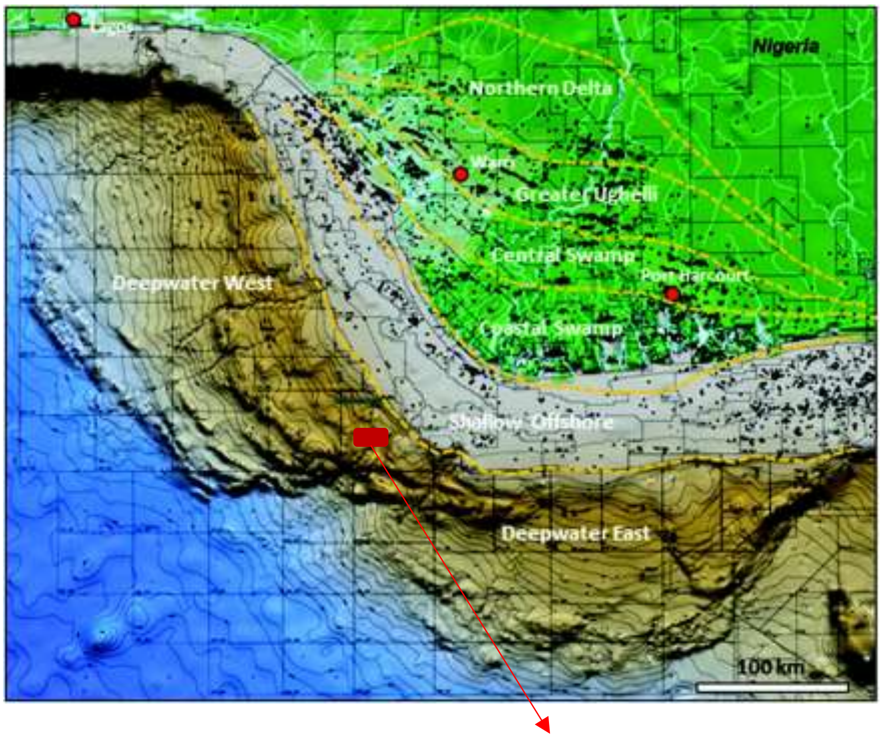

Figure 1-Google Map of Niger Delta showing the location of Mafe Field.

METHODOLOGY AND DATA INVENTORY

Four spatially distributed offset wells with composite suites of wireline logs and 3D time migrated Post-Stacked seismic data were available for this research work.

Lithofacies field were identified using suites of gamma ray log and resistivity log. High gamma and low resistivity was taken to indicate shale while low gamma and high resistivity were used to identify sand. The delineated sandstones units were correlated across the block. Shales were used as time reference because they are laterally and extensively deposited during different stages of shoreline shift. Rock properties such as porosity, (net/gross) and volume of shale were estimated from wireline logs by 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 by gamma ray index (linear method) (equation 2).

$$\Phi_{corr} = \frac{\rho ma - \rho b}{\rho ma - \rho f} \qquad \text{Davis [12]} \qquad (1)$$

Where,

ρma = matrix density (g/cc)

ρb = log reading (g/cc)

ρf = density of mud filtrate (g/cc)

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

$$Vclay = (\mathrm{GRlog - GRmin})/(\mathrm{GRmax - GRmin}) \qquad \text{Asquith and Krygowski [13]} \qquad (2)$$

Elastic parameters including Vp, Vs and density were used to characterize the delineated sandstone reservoir in terms of sedimentary parameter such as porosity. Vp-porosity crossplots were used to characterize the delineated sandstone reservoirs by comparing observed clusters and trends with various rock physics models, Figure-2.

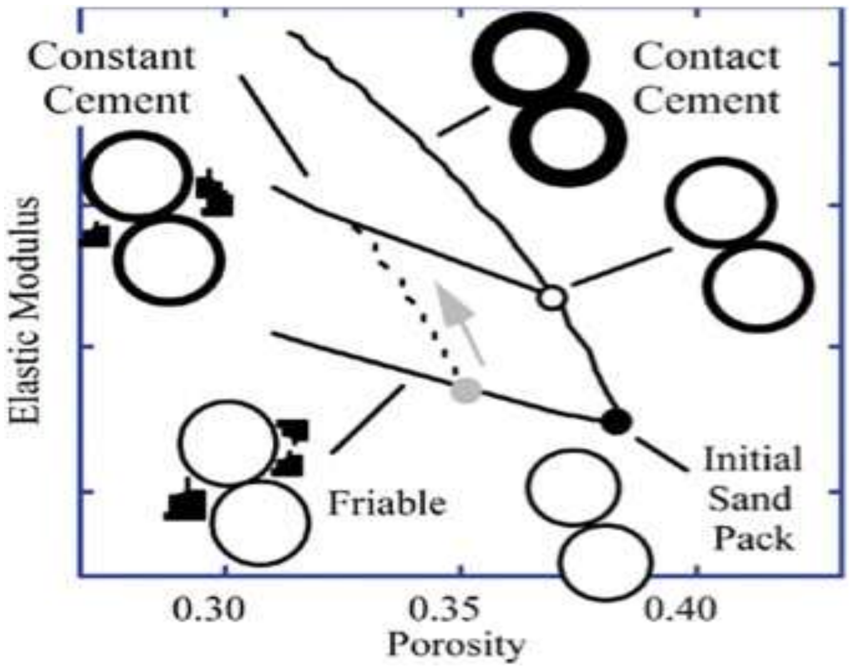

Figure 2- Schematic Representation of the Friable, Contact Cement and Constant Cement Sand

Models [14]

Seismic attribute was extracted to show vertical variation in instantaneous frequencies which corresponds to vertical changes in lithofacies of the mapped sands intervals. Sandstone units were identified by high seismic amplitude and low frequency and shale have low seismic amplitude and higher frequency.

The envelope attribute analysis was used to detect major lithological changes that are caused by strong energy reflections and sequence boundaries. The attribute clearly shows subtle lithological changes that may not be apparent on the seismic data.

Instantaneous frequency which is independent of phase and amplitude [15], was used to determining lateral changes of the lithology across the field.

RESULTS AND DISCUSSION

I have rephrased it to "Figure-3 shows the southwest to northeast correlation of reservoir sand tops of Mafe Field. The Thicknesses of the delineated reservoir sands vary across the three wells due to the effect of the mobile shale from the underlying Akata Formation of the Niger Delta. The shape of each of the gamma ray (log motif) between the sand tops are similar across the three well.

The upper horizon is relatively at the same depth across the four wells. The basal horizon is shallowest in Mafe-04 and occur deepest in Mafe-07

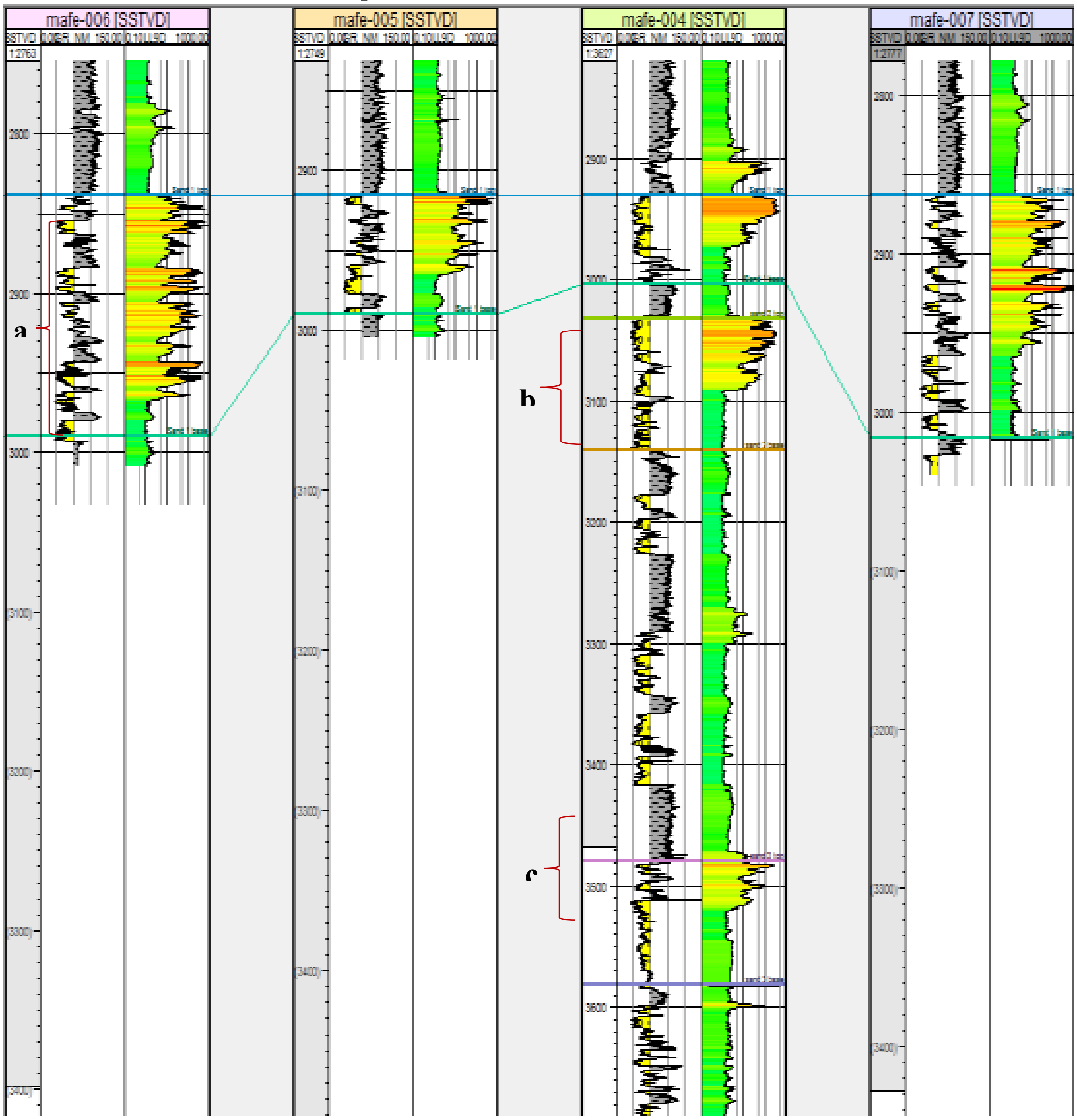

Figure 3-Well Log Interpretation and Reservoir Correlation of Mafe Field

The petrophysical estimations of the delineated sandstone lithofacies in terms of strorativity, fluid saturation and volume of shale is shown in table 1. Basically, reservoir quality information can be predicted or even derived from the estimated petrophysical 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.

Reservoir A is a relatively clean sand, with low average volume of shale of 0.4, average thickness of 55m, good average porosity of 0.26 and average water saturation of 0.45. Reservoir B is also a relatively clean sand with low average volume of shale of 0.35, average thickness of 85m, high average porosity of 0.27 and average water saturation of 0.54. Reservoir C was penetrated only by mafe004 and has an estimated volume of shale 0.21, average total porosity of 0.23, and an average thickness of 70m with average water saturation of 0.65 from this single well.

Table 1-Estimated Petrophyical Parameters for Mafe Field of Niger Delta

Well name	Reservoir	Porosity	Ntg	Vshale	Sw
Mafe 006	A	0.29	0.45	0.55	0.35
Mafe 005	A	0.23	0.55	0.45	0.41
Mafe 004	A	0.25	0.79	0.21	0.35
	B	0.27	0.77	0.23	0.50
	C	0.26	0.79	0.21	0.64
Mafe 007	A	0.20	0.77	0.23	0.50

Figure-4 is the crossplot of Vp against porosity of reservoir A sand interval. This gives rise to a Friable Unconsolidated Sand Model. The uppermost sandstone unit from the Vp-porosity crossplot has a data cluster trend similar to the unconsolidated or friable sand model. This is similar to the unconsolidated sand that characterize the youngest formation (Benin Formation) of the Niger Delta Basin. Unconsolidated sand 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.

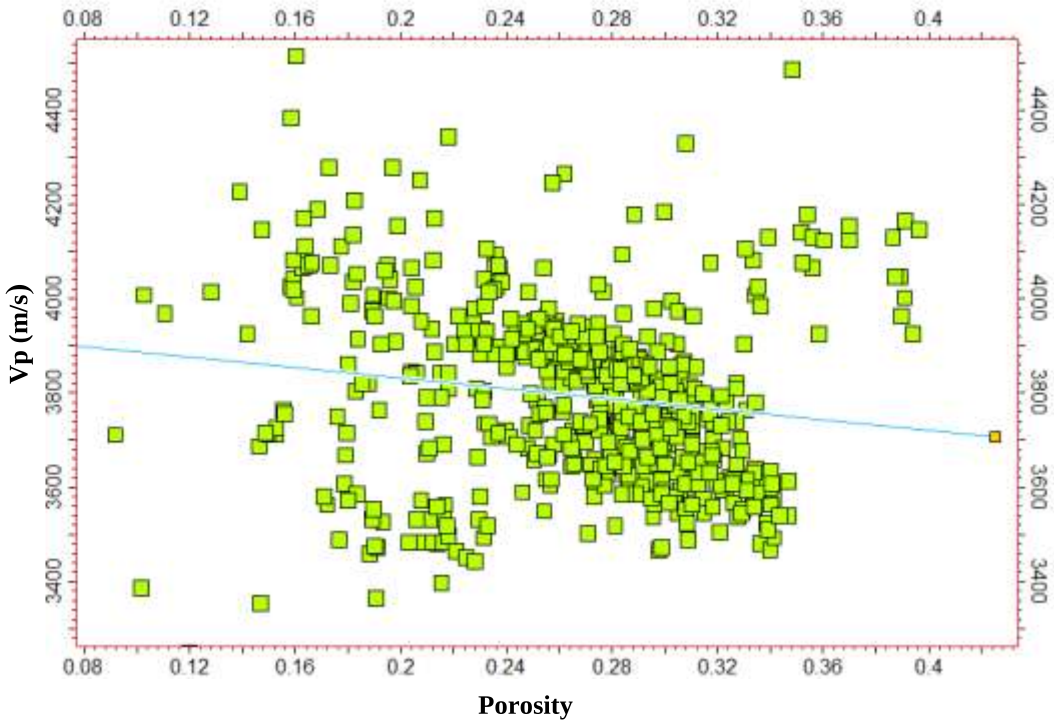

Figure 4-Crossplot of P-Velocity against Porosity from within Reservoir A Interval indicating a Friable Sand Model Trend

Figure-5 (a and b) show the crossplots of Vp against porosity in the reservoir sand B and C respectively. These mirrors are the Contact Cement Model. In this case, clay particles were deposited at the crack spaces near the grain contacts, so the stiffness of rock rapidly increases with very little change in porosity.

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

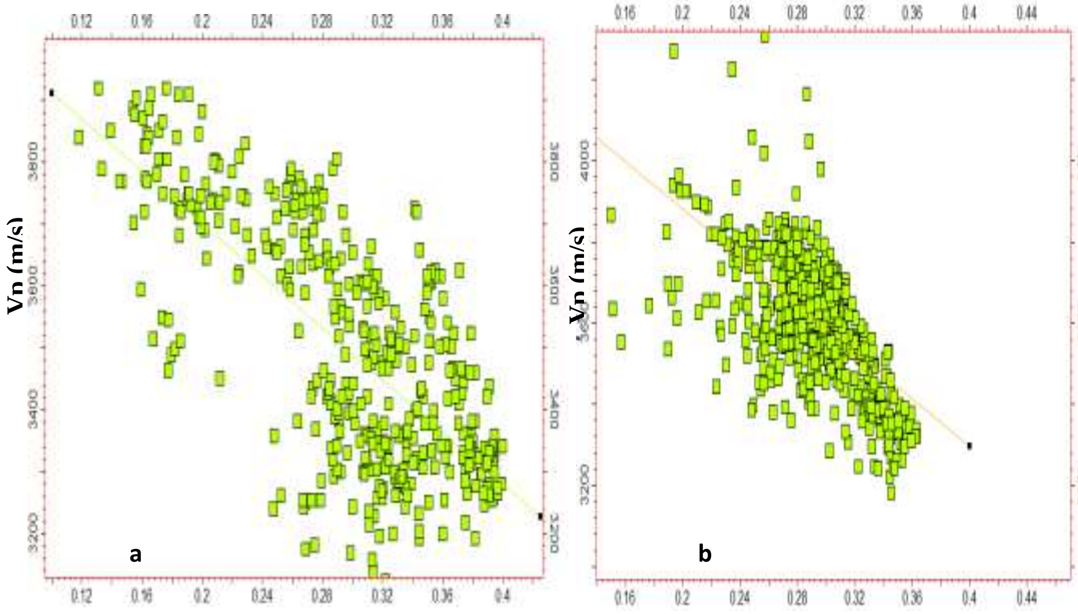

Figure 5-Crossplot of P-velocity against porosity of reservoir B and C intervals indicating constant cement model trends.

Figures-6 is the extracted seismic attribute that shows the vertical variation in amplitude within the Mafe Field which parallels the vertical lithofacies variation across the mapped sandstones intervals. High amplitude indicates sandstone while low amplitude indicates fine grained facies such as clay content.

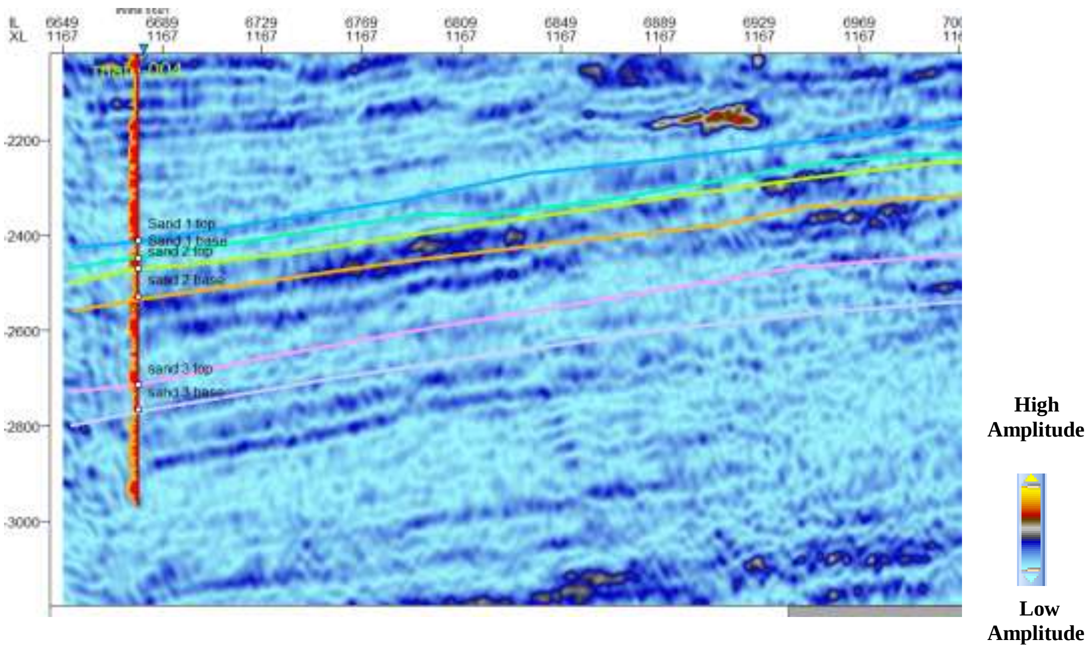

Figure 6-Crossline 1167 overlain with Extracted Envelope Attribute Cube and GR Log from Mafe-004. Note Amplitude Variations within the Delineated Reservoir Intervals.

Figure-7 is the extracted seismic attribute showing the vertical variation in instantaneous frequencies which corresponds to vertical changes in lithofacies the mapped sands intervals. Low frequency indicates sands and high frequency indicates shales.

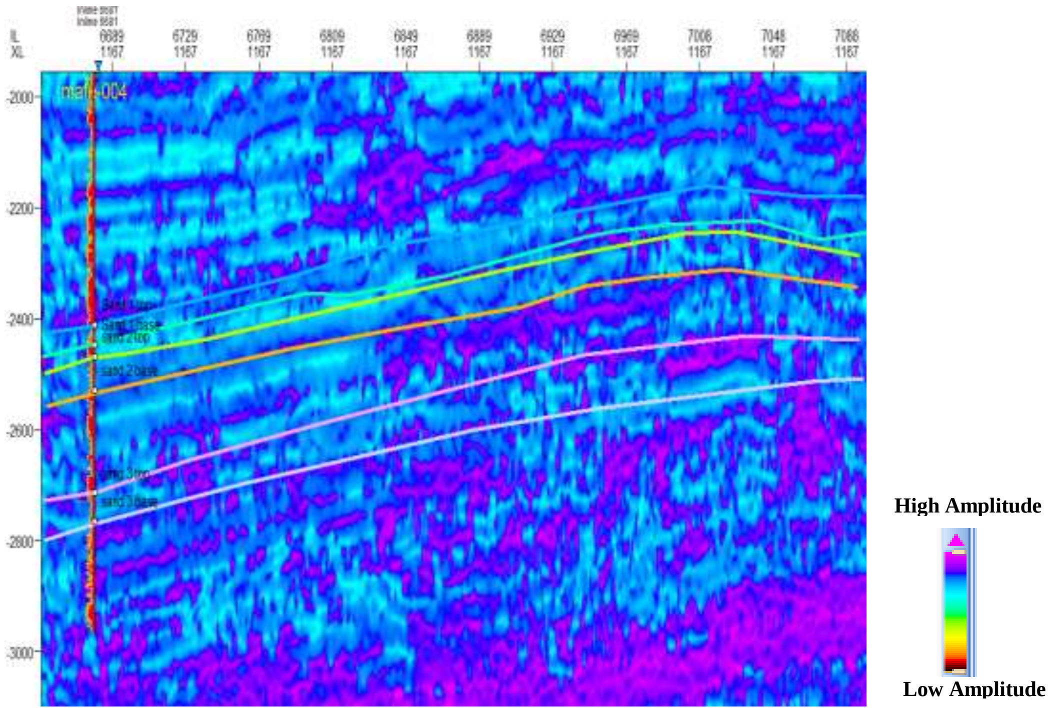

Figure 7-Crossline 1167 overlain with Extracted Instantaneous Attribute Cube Overlain and GR Log from Mafe-004. Note amplitude Variations within the Delineated Reservoir Intervals

Figure-8 shows the time slices extracted at 2445ms, 2515ms and 2770ms within the reservoir intervals from the envelope cubes, highlighting lateral variation in amplitude which corresponds to lateral variation in lithofacies across the delineated sandstone reservoirs and hence varying proportions of clay contents.

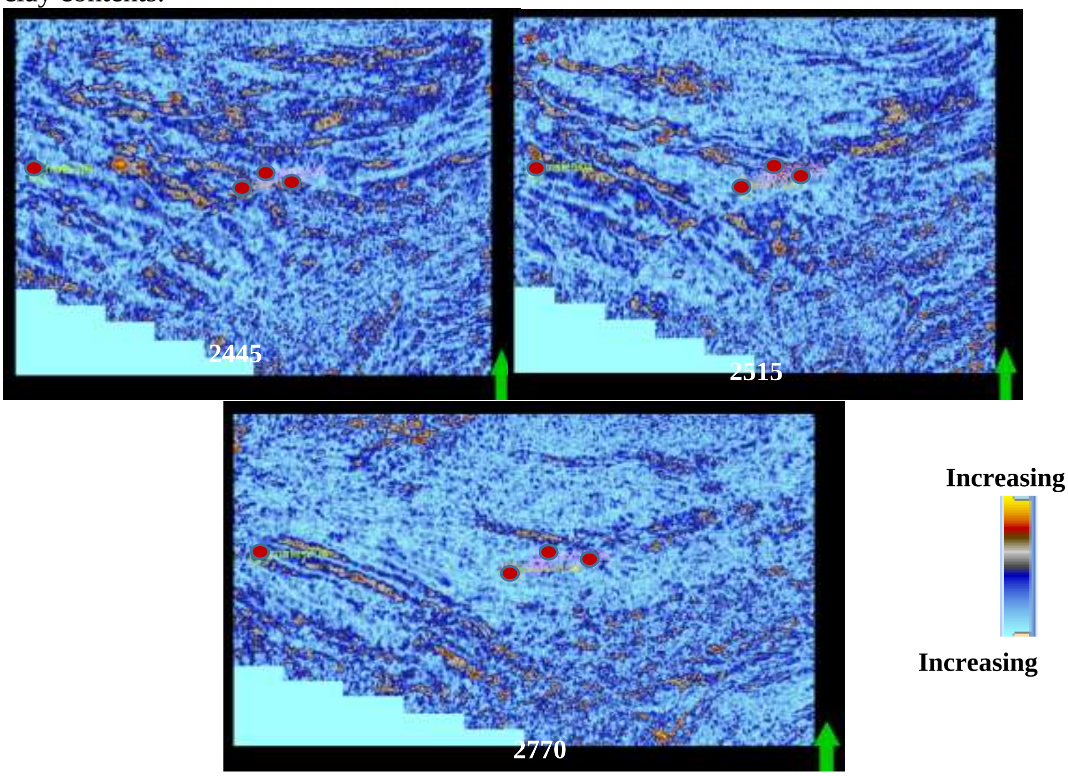

Figure 8- Time Slice Cut at 2445ms, 2515ms and 2770ms from the Envelope Volume Attribute Showing Lateral Variation in Lithofacies. Red circles show the locations of the wells

Figure-9 shows the time slices extracted at 2445ms, 2515ms and 2770ms within the reservoir intervals from the instantaneous frequency cubes indicating lateral variation in lithofacies across the delineated sandstone reservoirs.

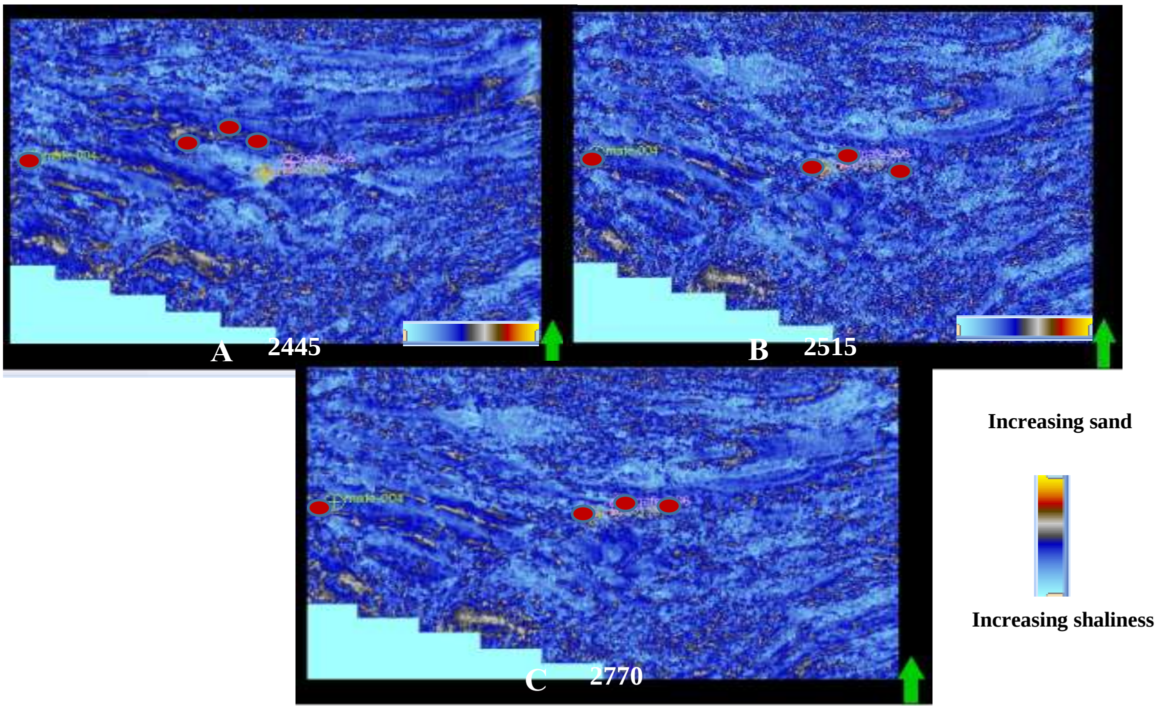

Figure 9- Time Slices Cut at 2445ms, 2515ms and 2770ms from the Instantaneous Volume Attribute Showing Lateral Variation in Lithofacies. Red circles show the locations of the wells

CONCLUSION

The petrophysical estimation was employed to delineate sandstone lithofacies in terms of strorativity, fluid saturation and volume of shale. Reservoir quality information was derived from the estimated petrophysical 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.

Reservoir A is found to be a relatively clean sand, with low average volume of shale of 0.4, average thickness of 55m, good average porosity of 0.26 and average water saturation of 0.45. Reservoir B is also a relatively clean sand with low average volume of shale of 0.35, average thickness of 85m, high average porosity of 0.27 and average water saturation of 0.54. Reservoir C has an estimated volume of shale of 0.21 average total porosity of 0.23, and an average thickness of 70m with average water saturation of 0.65.

The uppermost sand unit from the Vp-porosity crossplot exhibits a cluster conforming to the friable sand model, Vp-porosity crossplot cluster trend for the two lower sandstone reservoirs show trend and properties imitating the contact cement model. There is moderate-low amplitude anomaly and moderate-low frequency anomaly across reservoir A and B intervals there is low amplitude and high frequency anomalies across the reservoir C interval. The time slices shows lateral variation in lthofacies across the delineated sandstone reservoirs with increase in shaliness from southwestern to northeastern part of the Field. The moderate-low amplitude anomaly and moderate-low frequency anomaly across reservoir A and B is an indication of low shale content and hence high porosity. The observed low amplitude and high frequency anomalies across the reservoir C interval indicates a high presence of shale with corresponding low porosity relative to A and B interval. The studied well positions in relation to the amplitude and frequency of the extracted attributes indicates the consistency of the integration of both the well information and seismic attributes information with the seismic attributes given more lateral and vertical reservoir quality information and lithofacies information.

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