Amplitude and Fluid Contact Mapping in Some Part of Niger Delta Using Seismic Attribute Analysis and Inversion.

M.T. Olowokere

Department of Applied Geophysics, Federal University of Technology, PMB 704, Akure, Nigeria.

E-mail: olowo_mt@yahoo.com

ABSTRACT

The 'Fuman' deep water Niger Delta environment contains large amounts of hydrocarbon reserves trapped inside turbidite channels deposited within predominantly shale sequences. One of the major challenges for deepwater exploration and development is the proper delineation of reservoir extent for volumetrics computation and optimization of well placement. The objective of this study was to predict the channel sand development and lateral continuity within a stratigraphic package identified between 3.2-4.0 seconds on a seismic reflectivity section. The study was also to determine if hydrocarbon is present within the package. This is with a view to determining optimal well location.

Compressional and shear impedance volumes were produced using Multi-stack simultaneous inversion. The volumes were later converted to a lithology cube using the well-established technique of rotating the P and S data around an axis defined along the shale points cluster. Individual channel interpretation was performed on the bases of the lithology volume.

Monte Carlo modeling was used for fluid identification, contact prediction and fluid probability mapping. The results showed the presence of amalgamated channel systems running North-East South-West from the proximal to distal part of the basin. The interpretation of the channel tops and bases showed appreciable sand thickening within an elongated structural closure trending roughly North-West South-East. There was a reduction in the uncertainty of the expected hydrocarbon volumes at the study area.

(Keywords: petroleum reserves, volumetrics calculations, Niger Delta, sand thickening)

INTRODUCTION

The Tertiary geologic section of the deep offshore Niger Delta is predominantly comprised of a mud dominated slope-basin depositional system. The area a prolific petroleum province, characterized with turbidite reservoirs derived from the beach and river dominated reservoirs of traditional area of oil operations in the onshore and shallow areas of the Niger Delta. Figure 1 is a location map of the Nigeria deep water environment with the location of the study area.

This study was carried out to determine the oil leg extent in the Fuman A-1 and B-1 reservoirs. A secondary objective of the study was to assist with time interpretation and provide a better understanding of the stratigraphy within the structure.

This study involved well to seismic tie, fluid probability analysis, contact prediction, seismic inversion, lithology volume generation, channel interpretation, amplitude extractions and shallow hazards identification.

BACKGROUND

A review of 3D seismic reflectivity data over the area Furman Field in the Niger Delta showed a prospective interval in the deep section between 3.1 3.8 seconds (13000-15500ftss). This new prospect is below an existing producing field with wells; it was penetrated by a well. The prospect is recognized from seismic based on the seismic reflection configuration and amplitude response as a stratigraphic wedge with a hanging wall closure. The aerial extent is estimated to range between 4-12 square kilometer

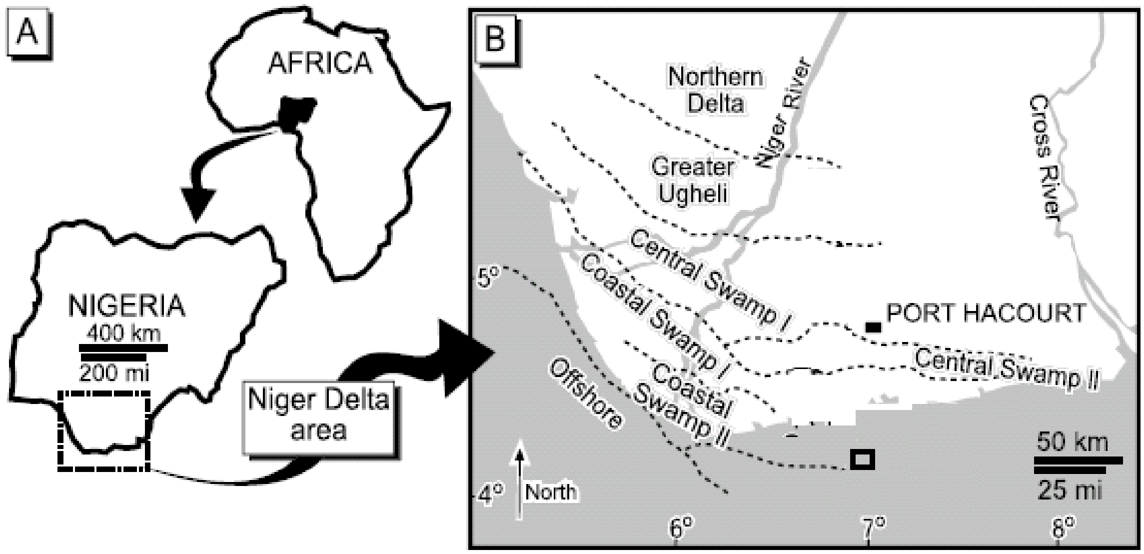


Figure 1: (A) Location of Niger Delta along the West Coast of Africa. (B) Location of Furman Field.

Regional correlation across several major faults showed that an equivalent stratigraphic interval was penetrated by a deep well (Well-2) some 18km to the north west of the Furman field. The penetrated stratigraphy was therefore considered to be a suitable analogue for calibrating the seismic response from the Furman prospect. Determination of sand development and continuity as well as presence of hydrocarbon within the package were critical factors for exploration success.

GEOLOGICAL SETTING

The continental slope of Nigeria extends from the shelf break to depths of 2000-3000m. The bathymetry is slightly complicated by the present active shale domes, the imbricated thrust toe and a zone of submarine canyons, which lie in the SW-NE direction and varied geographic directions. Extensive deformation of the slope by gravity-tectonic processes created numerous intraslope basins and diapers. The sea bottom expression of buried toe thrusts and related normal faults create high that are slightly oblique to the regional slope.

This phenomenon produces discrete sub-basins on the Upper slope, which are controlled by tectonic features. The slope has significantly given way to a more gentle continental rise, which continue seawards until it merges with the Guinea Abyssal Plain at depth in excess of 4,500m (Damuth, 1993).

Structures of this frontier basin as imaged in seismic profiles have developed as a result of such gravity instability of a large, rapidly deposited prism of unlithified and partially lithified sediments. The downslope movement has been attributed to the presence of the major overpressured mobile prodelta shale intervals inducing shale flowage and diaprism in the lower Tertiary (Miocene-Pliocene age).

Modern day channel-levee systems incise into the Slope and individual channels have been mapped for at least 80km in length and can be up to 1.5km wide and 500m deep. Moreover, active listric faults, thrusts with associated folds, rollovers and shale domes/diapers occurred in varied proportions. Figure 2 is a generalized geological setting of the Niger Delta.

The growth fault systems developed beneath the Niger Delta and adjacent inner continental shelf have been mapped in detail in conjunction with prolific hydrocarbon exploration and production (Weber and Daukoru, 1975, Evamy et al., 1978 and Whiteman, 1982).

In the Deep offshore area, The Niger Delta Basin stretches and progrades seawards from the continental Shelf, through the Continental slope to the Continental Rise. At about 300m water depths, the slope merges into a lower gradient continental rise (Average gradient 1 in 350).

DATA AVAILABILITY AND QUALITY CHECK

The data available for this study are seismic reflectivity runsum data (near, mid, far, ultra far and full stack); well logs (Well-1, Well-2 and Well-3); and interpreted horizons (A-1, B-1 and C-1). The seismic and well log data are of relatively good quality.

Checkshot data is available for Well-1, Well-2 and Well-3. The Checkshots generally follow the same trend indicating that there are no significant lateral variations in seismic velocities across the field (Figure 2).

METHOD OF STUDY

Well-to-seismic tie was carried out to tie the seismic events to well data. Following a successful tie, seismic inversion was done to produce inverted P-impedance and S-impedance. The inverted P- impedance and S-impedance volumes were used to produce a mudrock (lithology) volume, which formed the basis for detailed sand body (channel) interpretation. Channel top and base interpretation were done on the mudrock volume using a positive cut-off value from zero and above for the sands. Bodycheking on the modeled lithology volume was used to properly identify the channel bodies. It should be noted here that this interpretation method was very different from the container approach that had been performed in previous studies in the area. Arguably it was this technique of interpreting individual bodies that yielded the greatest benefits from the current work.

Seismic amplitude extraction and analysis was carried out on the lithology volume as well as on the far stack reflectivity data. The amplitude extraction was done using the interpreted channel tops and bases as window for extraction. Fluid identification, probability mapping and contact prediction were done using the Monte Carlo technique.

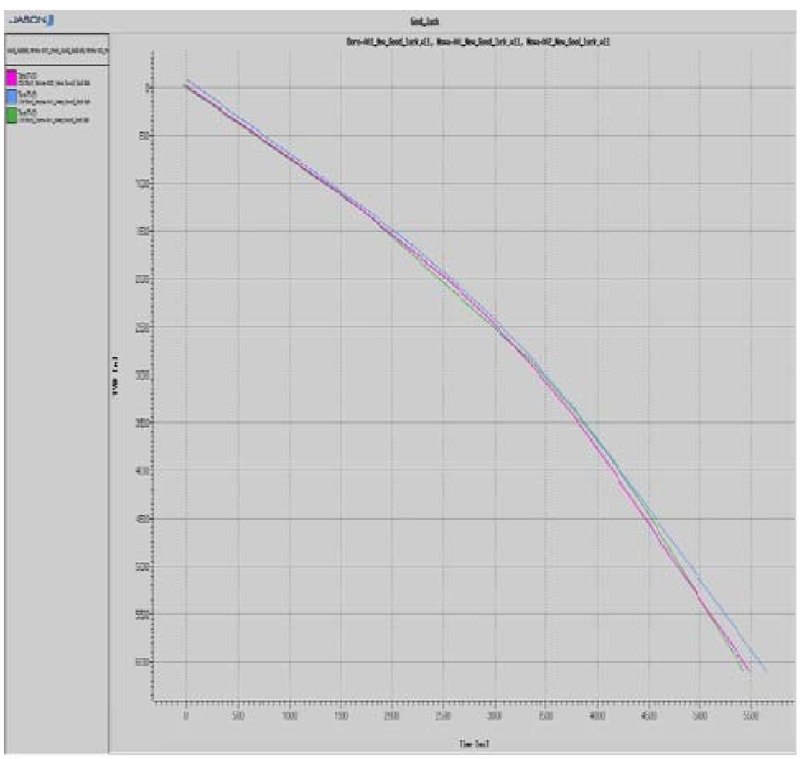


Figure 2: Well-1, Well-2, and Well-3 Checkshots.

RESULTS AND DISCUSSION

Amplitude and Fluid Contact Analysis

A-1 Channel: The A-1 amplitude crossplot of the eastern channel shows a sharp amplitude change at 3550ms TWT (3116m TVDSS). The detected depth is much higher than the known Gas Down To (GDT) and therefore it cannot be considered as contact related. The amplitude change is either due to lithology or overburden effects. The amplitude map also shows a sharp amplitude change (circled in red), which could coincide with the expected GOC in Well-1 based on pressure data (Figure 3).

B-1 Channel: The amplitude extraction from the Far Seismic between top and base B-1 complex are similar to those estimated from other studies.

Hydrocarbon contact analysis was performed using amplitude cross-plots. Figure 4 shows a sharp break at 3921ms has been interpreted as GOC, there is a possibility that the amplitude change is due to stratigraphy rather than fluid.

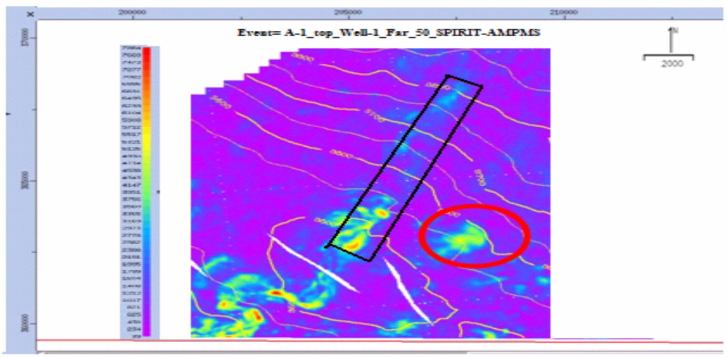


Figure 3a: Amplitude Map for A-1 Level.

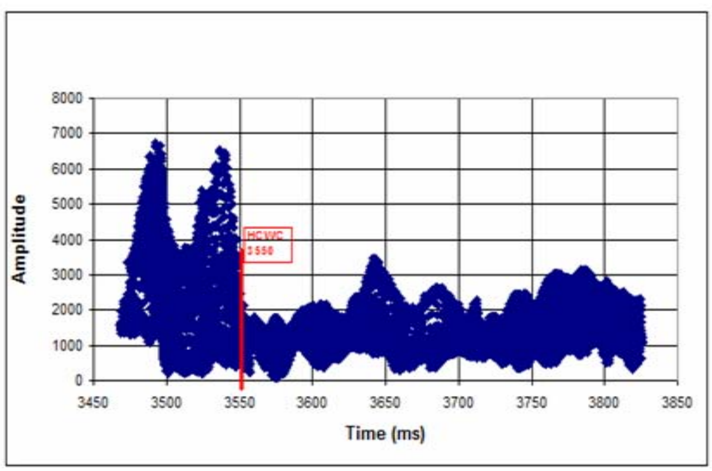


Figure 3b: A-1 Contact Analysis using Amplitude Crossplots.

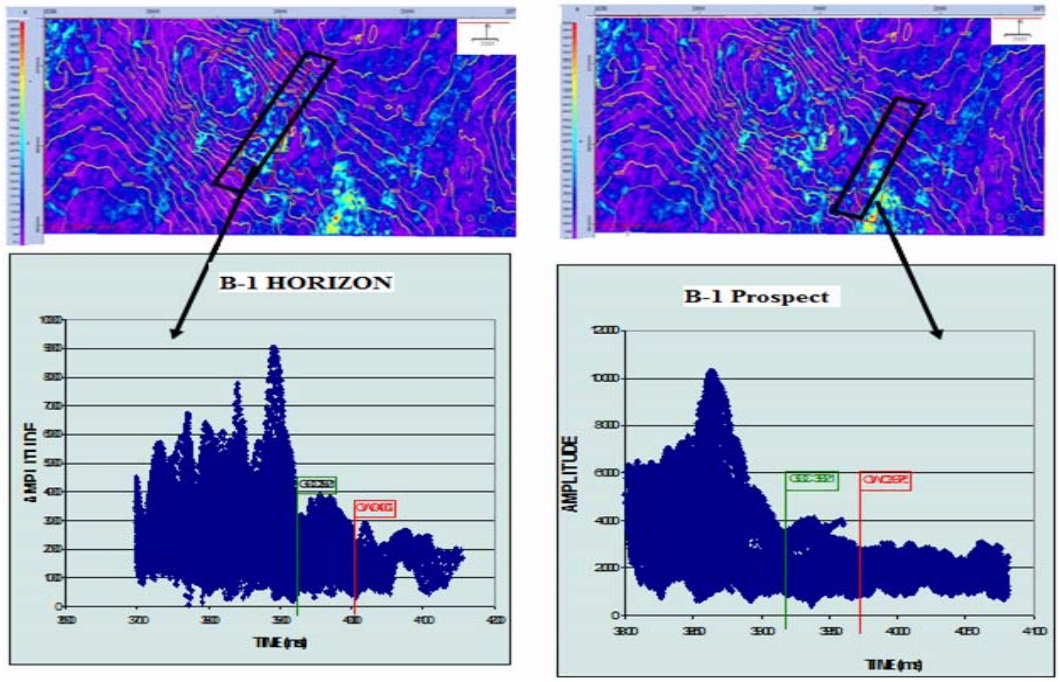


Figure 4: B-1 Contact Analysis using Amplitude Crossplots.

The B-1 windowed amplitude map between channel top and base showed a possible contact observed at 4,000 ms.. The contact value agrees with observations from the amplitude crossplot. An optically stacked (11 traces) north-east to south-west section across the prospect, also highlights the expression of the flat spot on the seismic (Figure 5).

Using the Well-1 checkshot for depth conversion, the GOC is estimated to be at a depth of 3572m TVDSS. This appears to be higher than the contacts encountered by the wells. This error could be acceptable within the limits of the seismic resolution and noise levels. Despite that, another possible reason for this discrepancy could be that the depth conversion velocity function used may be incorrect.

The OWC is estimated to be at a depth of 3685m TVDSS, which lies within the estimated values from the pressure data. The contact is supported both by the crossplots and the observations on the seismic line. RMS amplitude extraction between the top and base of the B-1 channel was extracted from the near and far seismic substacks. A background fluid map was produced using the Near and Far amplitude maps and the slope from the Monte Carlo forward modeling.

The B-1 time contours are overlain on the background normal fluid map.

As expected the higher amplitudes are concentrated within the closure showing fluid presence (Figure 4).

Monte Carlo Forward Modeling

Monte Carlo forward modeling for A-1 with sensitivity tests using net-to-gross of 30% and 60% as reservoir quality scenarios showed that as expected fluid separation is better for a net-to-gross of 60%. In both cases, gas is clearly detectable. However, for a 30% N/G, oil is almost not detectable (Figure 6).

Monte Carlo forward modeling for B-1 shows that there is brightening with offset due to fluid effect. Also the histogram plot shows that the fluid could be separated on the bases of near and far stack. However, some overlap is observed between the gas and oil response. The histograms are created after rotation around the background normal axis, the line drawn along the brine cloud of the crossplots (Figure 7).

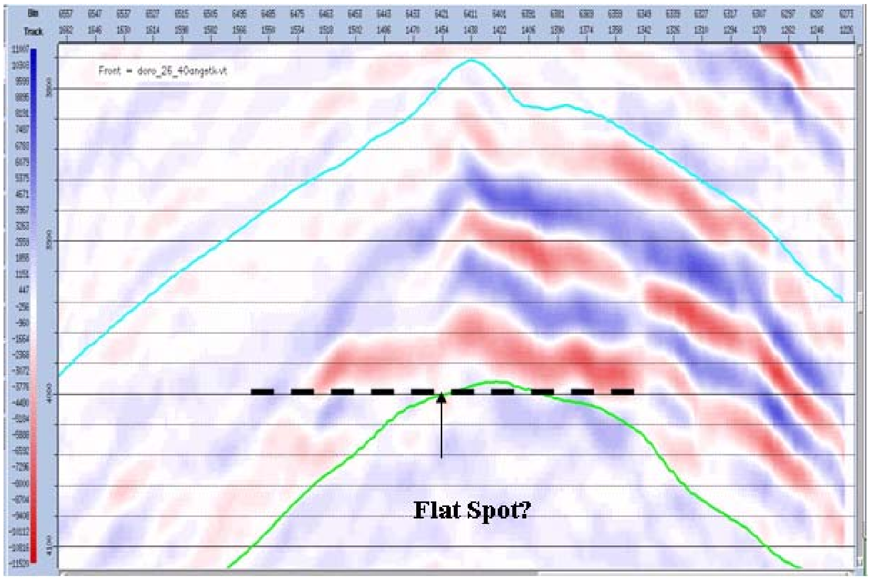


Figure 5: Possible Flat Spot on Seismic Line Across SE B-1 Level.

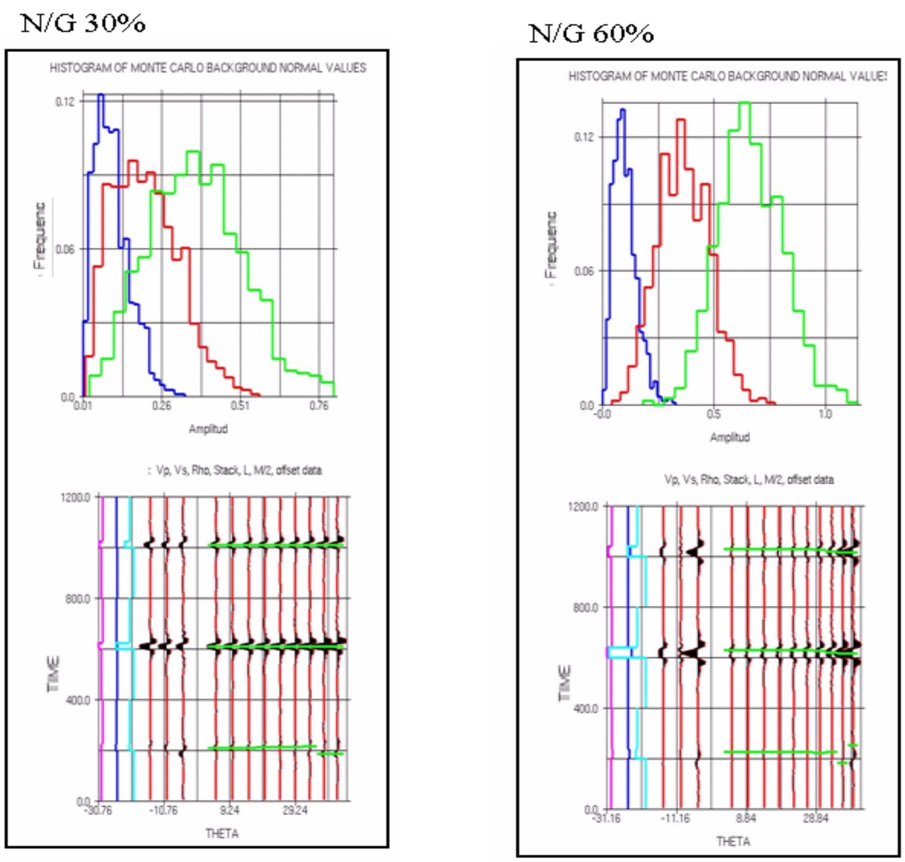


Figure 6: A-1 Forward Modeling using Monte Carlo Analysis.

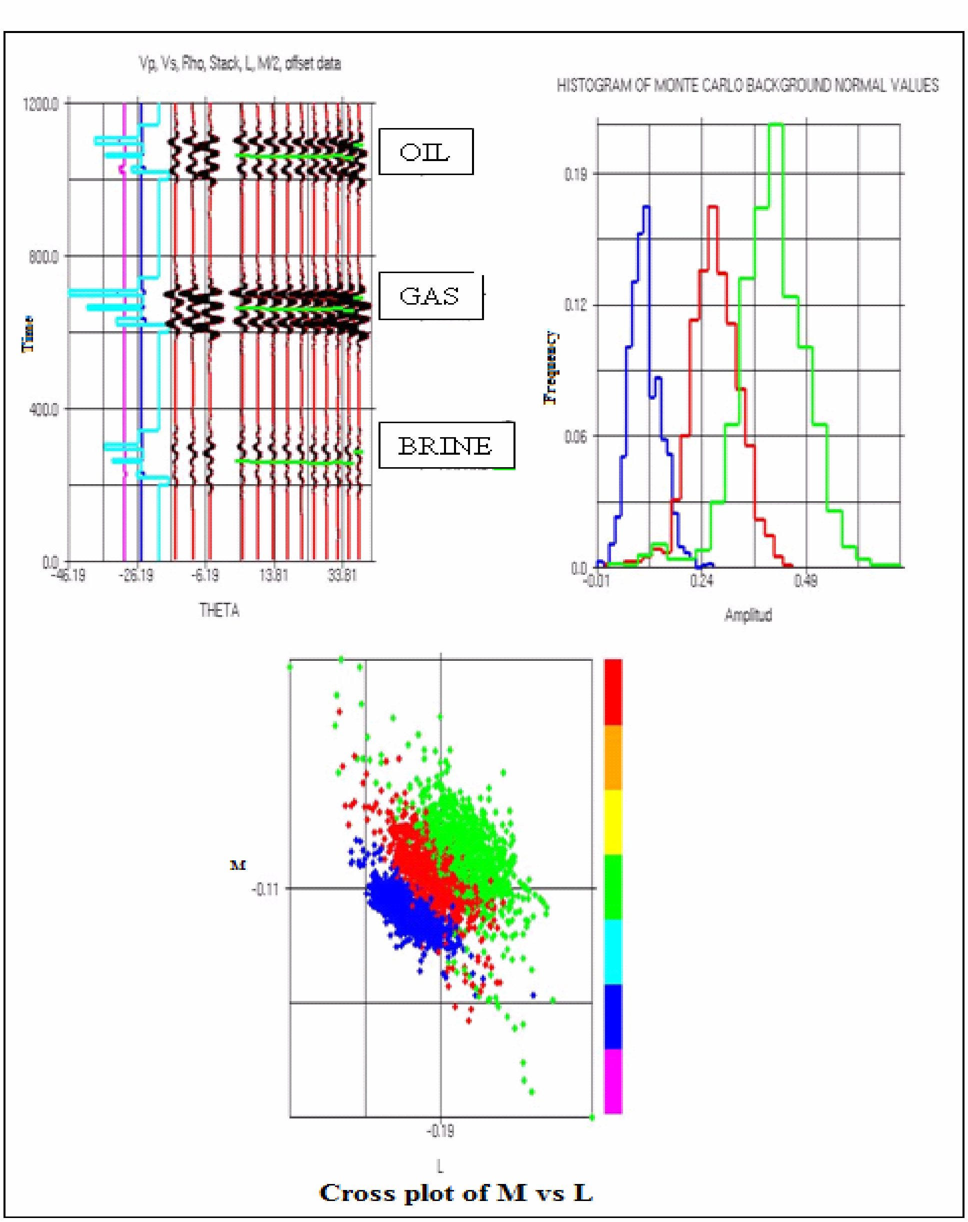
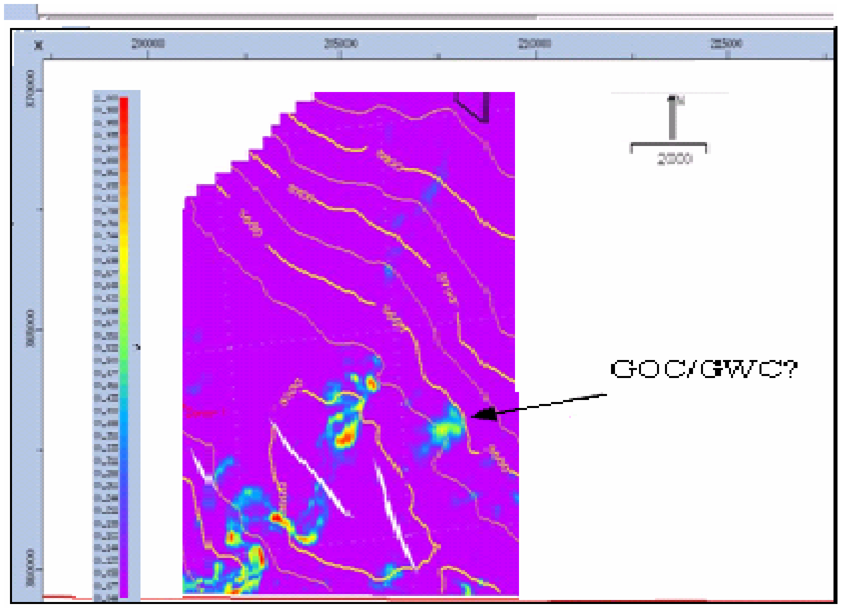


Figure 7: Forward Modeling using Monte Carlo Analysis.

The Monte Carlo Fluid Probability Map

The Monte Carlo fluid probability map shows that the oil probability is more constrained when the N/G is higher in A-1 channel. The oil probabilities are about 60% for both N/G scenarios. The gas probability is much higher and well constrained, while the oil probability has wider spread and lower value suggesting low reliability on these results (Figure 8).

The Monte Carlo probability map shows that the chance of finding oil in the area is about 65% in B-1 channel. This is consistent in all maps regardless the polygon selection. The current technique gives robust results, however it is important to note that the technique used here is more applicable for single fluid phase cases. Lithology and thickness changes may have an (overestimating) impact on probabilities (Figure 9).



(i) Gas Probability Map N/G 60% (Calibration Polygon 2)

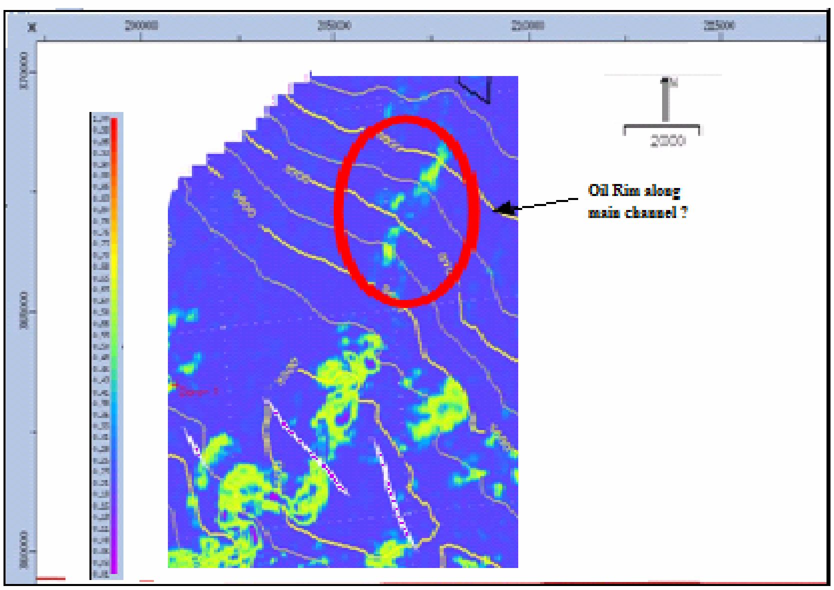
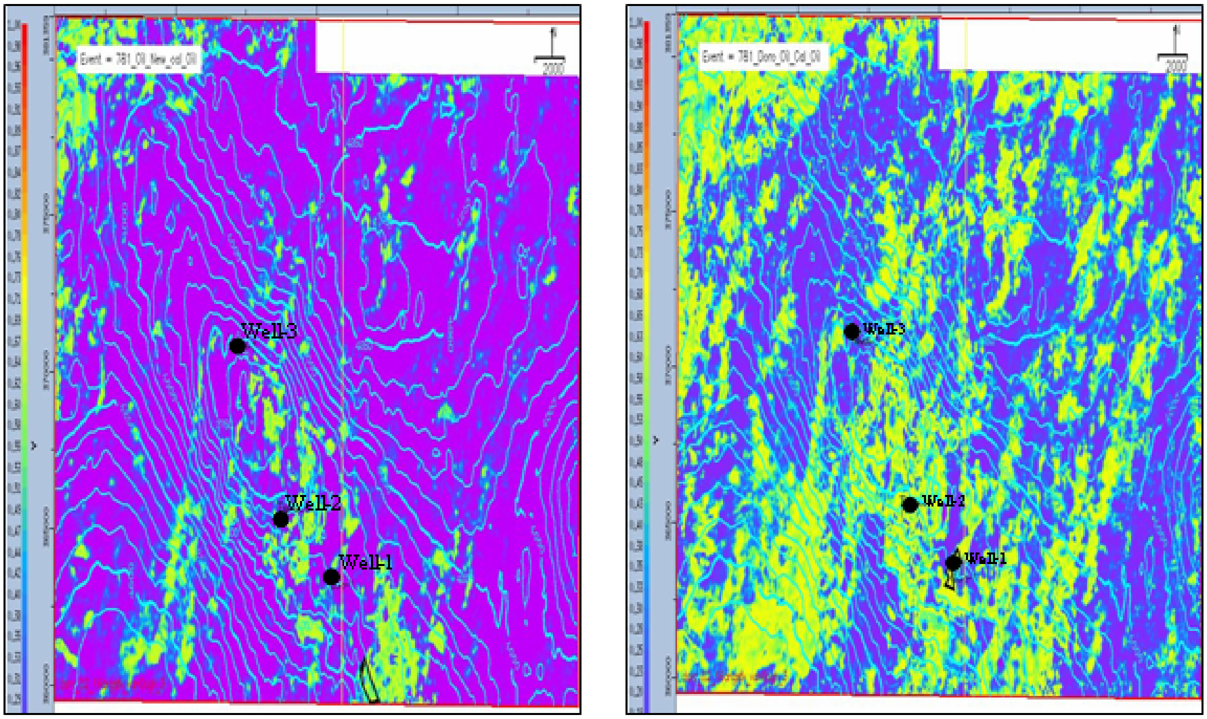


Figure 8: A-1 Oil Probability Maps.

Sand Body Interpretation

Body checking was done in Jason volume viewer to identify all the channel bodies. The v-sand evaluation results show that the Well-1 well penetrated the A-1 channel at the flank. There is better sand development towards the East of Well-1 (Figure 10).



(i) Polgon 1 captures the extend of the possible oil rim in the Southern flank

(ii) Polgon 2 captures Well-1 where the Oil rim is confirmed.

Figure 9: B-1 Oil Probability Map.

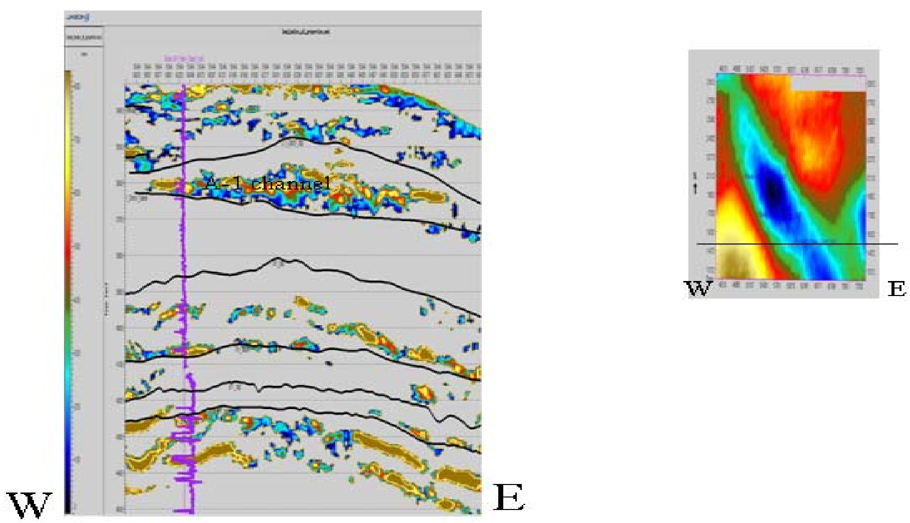


Figure 10: Inline Showing San Development Across Well-1.

In general, there are more sands deposited from B-1 level down below C-1. The sand development increases progressively towards the Eastern flank of the anticlinal structure. Figure 13.

A-1 Interval: There are two major channels on the A-1 level. The western channel was penetrated by Well-2 while the Eastern channel was penetrated by Well-1. The axes of both channels run in a North-East to South-West direction from the proximal to distal parts of the basin. The channels run perpendicular to a structural closure elongated in a North-West to South-East direction.

RMS amplitude extracted from the mud rock volume between the top and base of the A-1 channels showed areas where the good quality sands are accumulated.

According to the mudrock volume, most of the very good quality sands are accumulated at the crest of the structural closure. This raises the suspicion that the reservoir quality, highlighted by the inversion volume is partly distorted by the fluid presence. Despite that, in the western channel, the good quality accumulation is at the south-western flank of the structural closure. Interestingly, the amplitude on the western flank displays a sharp contrast parallel to contour line at 3710ms. It is believed to be the expression of hydrocarbon contact on the western channel (Figure 10).

B-1 Interval: The B-1 level has several amalgamated channels running from the North-east to the South-west with much of the sands accumulating within the structural closure. The amalgamated channels can roughly be separated into an upper and a lower stack of channels at the B-1 level. The amplitude map reveals the meandering axes of three of such channels running North-East to South West. Figure 11, 12 and 13.

The B-1 channel reservoir distribution from the mudrock volume evaluation indicates that the best sands are concentrated at the lower part of the container interval. This is the same interval where the oil rim is expected to be (Figure 13). This very observation is of great significance to the reserves estimates because it allows for higher net to gross input in the calculations.

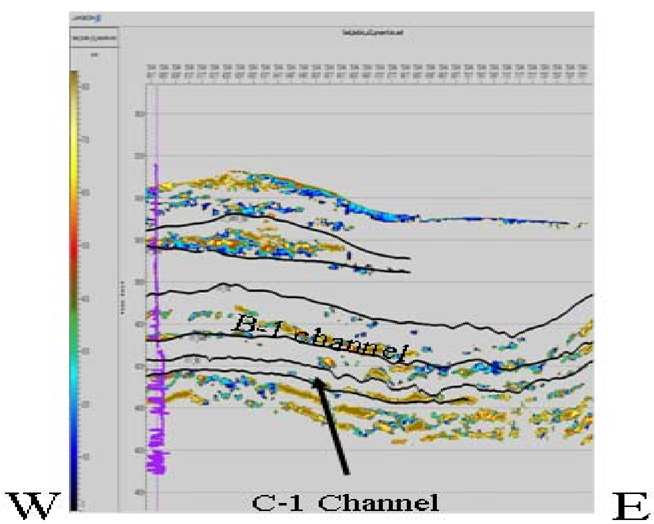


Figure 11: Sand Development across Well-1 Deep Intervals.

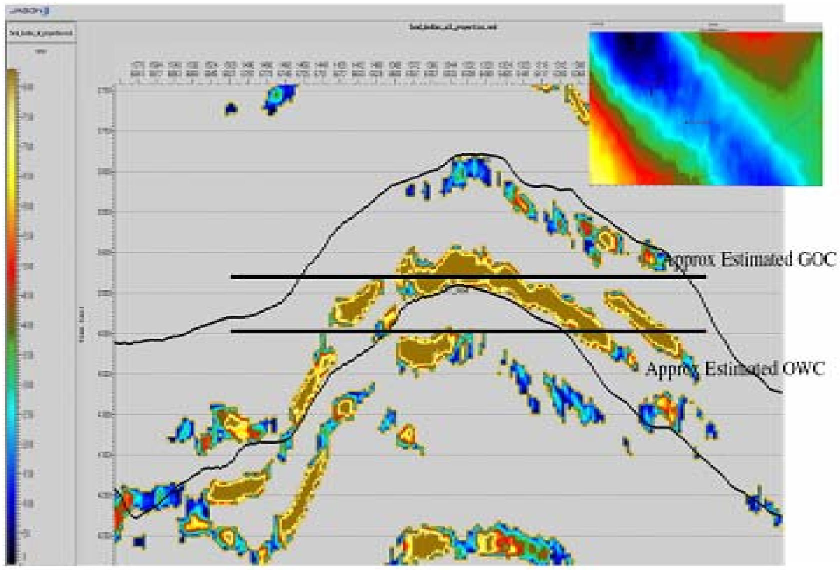


Figure 12: B-1 Sand Distribution.

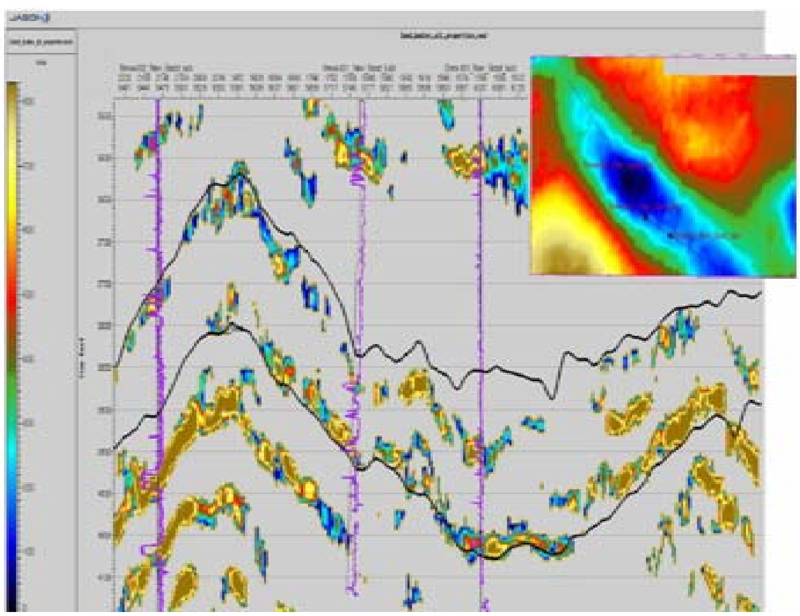


Figure 13: B-1 Sand Distribution along Structure/Wells (no colors indicate mainly shales; higher numbers indicate better sands).

CONCLUSIONS

There was high uncertainty in the determination of the oil column from the seismic at the A-1 level. Contact predictions would be unreliable. The estimated B-1 GOC from the analysis is at a depth of 3572m TVDSS. This depth is slightly shallower than well data.

The estimated OWC is at 3685m TVDSS, which falls within the range estimated from pressure data. It possible that the actual contact is deeper than the estimated value following the trend from the GOC. It could be as deep as 3706m TVDSS, the value estimated from Well-2 pressure data.

REFERENCES

1. Damuth, J.E. 1994. "Neocene Gravity Tectonics and Depositional Processes on the Deep Niger Delta Continental Margin". *Marine and Petroleum Geology*. 11(3): 320-345.

2. Evamy, B.D., Haremboure, J., Kamerling, P., and Knaap, W.A. 1978. "The Hydrocarbon Habitat of Tertiary Niger Delta". *Am. Assoc. Pet. Geol. Bull.* 62:1-39.

3. Weber, K.J. and Daukoru, E. 1975. "Petroleum Geology Aspects of the Niger Delta". *9th World Petroleum Congress*: 209-221.

4. Whiteman, A.J. 1982. *Nigeria: Its Petroleum Geology, Resources and Potentials . 1 & 2*. Graham and Tortman.

SUGGESTED CITATION

Olowokere, M.T. 2009. "Amplitude and Fluid Contact Mapping in Some Part of Niger Delta Using Seismic Attribute Analysis and Inversion". *Pacific Journal of Science and Technology.* 10(2):721-732.

Pacific Journal of Science and Technology