

PETROPHYSICAL AND STRUCTURAL ANALYSIS OF MAITI FIELD, NIGER DELTA, USING WELL LOGS AND 3-D SEISMIC DATA

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Abstract

Well logs, checkshot and 3-D seismic data have been evaluated to delineate oil bearing sand reservoirs, to determine the petrophysical parameters and to analyze the geologic structures within Maiti field. Three wells were evaluated and three hydrocarbon reservoirs were delineated. petrophysical parameters for the reservoir sands have porosity, ϕ range of 0.28 – 0.35, permeability $k(mD)$ range of 68-168, hydrocarbon saturation, S_h range of 0.65 to 0.68 and volume of shale V_{sh} range of 0.02 – 0.15. The average values of these petrophysical parameters were used to rank the three reservoirs R1, R2, R3. It was deduced that reservoir R1 is the most prolific reservoir while R2 is the least. The structural analysis shows a fault assisted anticlinal structure known as structural trap within Maiti field, Niger delta, Nigeria.

Keywords: hydrocarbon sand reservoir; petrophysical analysis; reservoir ranking; structural analysis; Niger delta.

1. Introduction

Reservoir rock contains connected pore spaces used to reserve quantity of fluids (oil, gas and water). To be commercially productive it must have sufficient thickness, area extent and interconnected pore spaces (permeable) [1].

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. It is therefore necessary to delineate the hydrocarbon reservoirs and evaluate them because they are the zone of interest for hydrocarbon exploitations.

Petrophysical parameters such as Porosity, permeability, Water Saturation, hydrocarbon saturation, net pay thickness and volume of shale are critical elements in interpretation. Estimation of these reservoir properties is best done using appropriate well logs.

Potentiality of oil reservoirs can be determined using the results of the petrophysical analysis. Good reservoir must be porous, permeable, oil saturated and relatively high thickness. It is therefore necessary to map reservoir sands and rank them using the petrophysical parameters because not all reservoirs are prolific. Detail structural analysis will reveal the trapping mechanism of the oil field and this will help to avoid drilling of dry hole.

2. Location and geology of the study area

Maiti field is located in the onshore depobelt of the Niger Delta Basin figure (1), where thick Late Cenozoic Clastic sequence of Agbada Formation were deposited in a deltaic fluvio-marine environment.

The Niger Delta Basin covers an area of about 75,000Km² and is composed of an overall regressive clastic sequence that reaches a maximum thickness of 9,000 to 12,000m (29,500 to 39,400 ft). The Niger Delta is divided into three formations, figure (2) representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios. [2-3]

The Akata formation composed of shales and silts at the base of the known delta sequence. They contain a few streaks of sand, possibly of turbiditic origin and were deposited in holomarine

environment. The thickness of this sequence is not accurately known; but may reach 7000 m in the central part of the delta.

The Agbada Formation forms the hydrocarbon-prospective sequence in the Niger Delta [4] It is composed of sands, silts and shales in various proportions and thicknesses, representing cyclic sequences of off-lap units. It reaches a maximum thickness of more than 3050 m.

The Benin formation is the uppermost unit. it consists of massive freshwater bearing continental sands and gravel deposited in an upper deltaic plain environment and extends from the West across the whole Niger Delta area and southward beyond the existing coastline. The thickness of the formation ranges from 305m in the offshore to 3050m onshore.

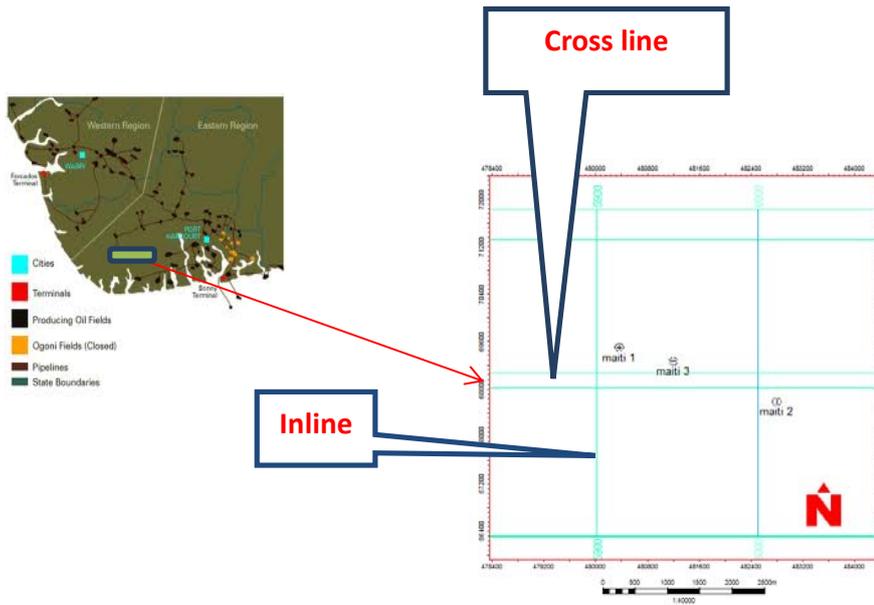


Figure 1 Location and base map of the study area showing seismic lines and well

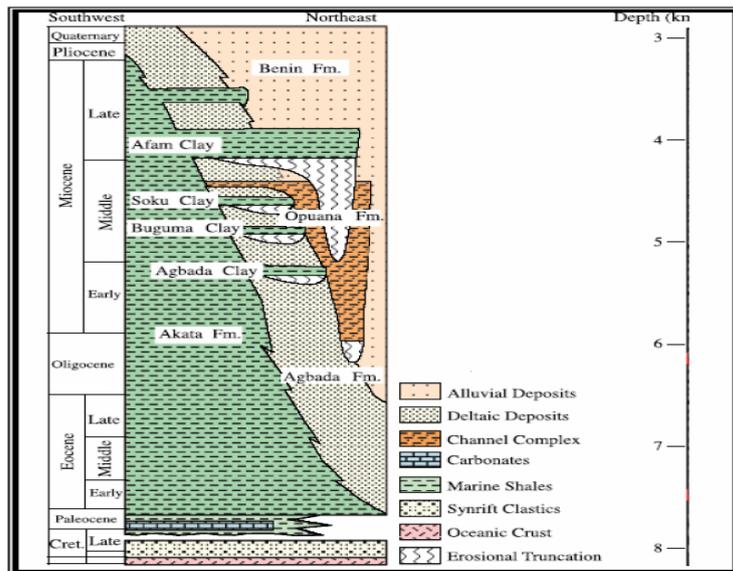


Figure 2 Niger Delta stratigraphy. (Modified from Shannon and Naylor [2]) and Doust and Omatsola [3]).

3. Methodology

3.1 Well logs and petrophysical analysis

Suites of well logs including gamma ray log, resistivity log, water saturation log, density log and neutron log are used to carry out both well logs and petrophysical analysis.

3.1.1 Lithology identification

Gamma ray log was used to delineate lithology (sand and shale bodies). Sand bodies were identified by deflection to the left due to the low concentration of radioactive minerals in sand while deflection to the right signifies shale which is as a result of high concentration of radioactive minerals in it. Gamma ray log was set to a scale of 0-150 API, central cut off of 65 API units in which less than 65API was interpreted to be sand while greater than 65API was interpreted to be shale. Resistivity log was used with Gamma ray log to delineate potential reservoirs.

3.1.2 Identification of reservoirs

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and deep resistivity logs. Intervals that have high resistivity are considered to be hydrocarbons while low resistivity zones are water bearing intervals.

3.1.3 Porosity(ϕ)

Porosity is defined as the percentage of voids to the total volume of rock. The formation density log was used to determine formation porosity. The formation porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation below:

Porosity from density log

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (1)$$

where: ρ_{ma} is the matrix density = 2.65gm/cm³ (sandstone); ρ_f is the fluid density= 1.1g/cm³ (fluid density); ρ_b = formation bulk density

3.1.4 Estimation of water saturation, hydrocarbon saturation and permeability

Determination of the water saturation for the uninvaded zone was achieved using the Archie's equation [5], given below:

$$S_w = \left(\frac{R_w}{R_{wa}} \right)^{\frac{1}{n}} \quad (2)$$

where n is the saturation exponent, R_{wa} is water resistivity in the zone of interest, S_w is water saturation of the uninvaded zone, R_o is resistivity of formation at 100% water saturation, R_t is true formation resistivity.

Hydrocarbon Saturation, S_h is the percentage of pore volume in a formation occupied by hydrocarbons. It can be determined by subtracting the value obtained for water saturation from 100% i.e. $S_h = (1 - S_w)$ in fraction

Permeability, K of each identified reservoir is calculated using equation [6]

$$K = \sqrt{\frac{250\phi^2}{S_{wir}}} \quad (3)$$

Where, S_{wir} is the irreducible water saturation

3.1.5 Volume of Shale (V_{sh}).

The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step used to determine the volume of shale from a gamma ray log was the calculation of the gamma ray index using the equation below:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (4)$$

where: I_{GR} = Gamma ray index; GR_{log} = Gamma ray reading of the formation; GR_{min} = Minimum gamma ray (clean sand); GR_{max} = Maximum gamma ray (shale).

All these values were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated using the Dresser Atlas formula below,

$$V_{sh} = 0.083(2^{3.7 \times I_{GR}} - 1.0) \quad (5)$$

3.2.3 D Seismic Interpretation

3.2.3.1 Seismic to well tie

In order to ensure the continuity of events both on the seismic section and wells, well to seismic tie was done using checkshot data. On a 3D window, the Maiti 3 with the reservoir tops and bases was displayed on the seismic section figure (8).

3.2.3.2 Mapping of Horizons and faults

A horizon is a surface separating two different rock layers. The surface is identified by distinctive reflection pattern that can be observed over a layer with relatively large extent. Three horizons representing the top of the three reservoirs were mapped figure (9). The two major faults observed from the section were mapped as well figure (9).

3.2.3.3 Generation of time structure maps

The three horizons mapped across both crosslines and inlines were used with fault polygon to generate time structure maps for the top of the three reservoirs.

4. Discussion of results

Well logs study revealed three hydrocarbon sand reservoirs R1, R2 and R3 at depth of 9,474 ft, 10,480ft and 11,107ft respectively within Maiti 1 as shown in Figures 3, 4 and 5.

Hydrocarbon sand reservoir petrophysical parameters calculated from these reservoirs are shown in Tables 1, 2 and 3. Reservoir R1 revealed effective porosity, hydrocarbon saturation, permeability, and net thickness varied from 0.30 to 0.35, 0.65 to 0.68, 90(mD) to 168(mD) and 12(ft) to 75(ft) respectively. Reservoir R2 revealed effective porosity, hydrocarbon saturation, permeability, and net thickness varied from 0.30 to 0.31, 0.58 to 0.62, 90(mD) to 103(mD) and 44(ft) to 58(ft) respectively. Reservoir R3 revealed effective porosity, hydrocarbon saturation, permeability, and net thickness varied from 0.28 to 0.31, 0.50 to 0.66, 68(mD) to 103(mD) and 73(ft) to 103(ft) respectively.

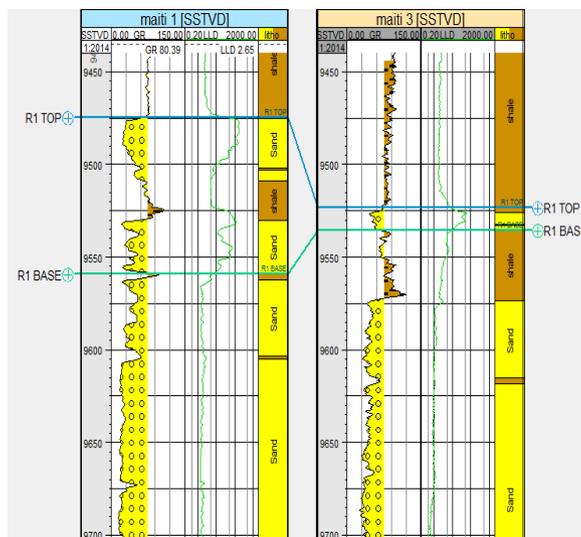


Figure 3 Lithostratigraphic correlation panel showing for reservoir 1

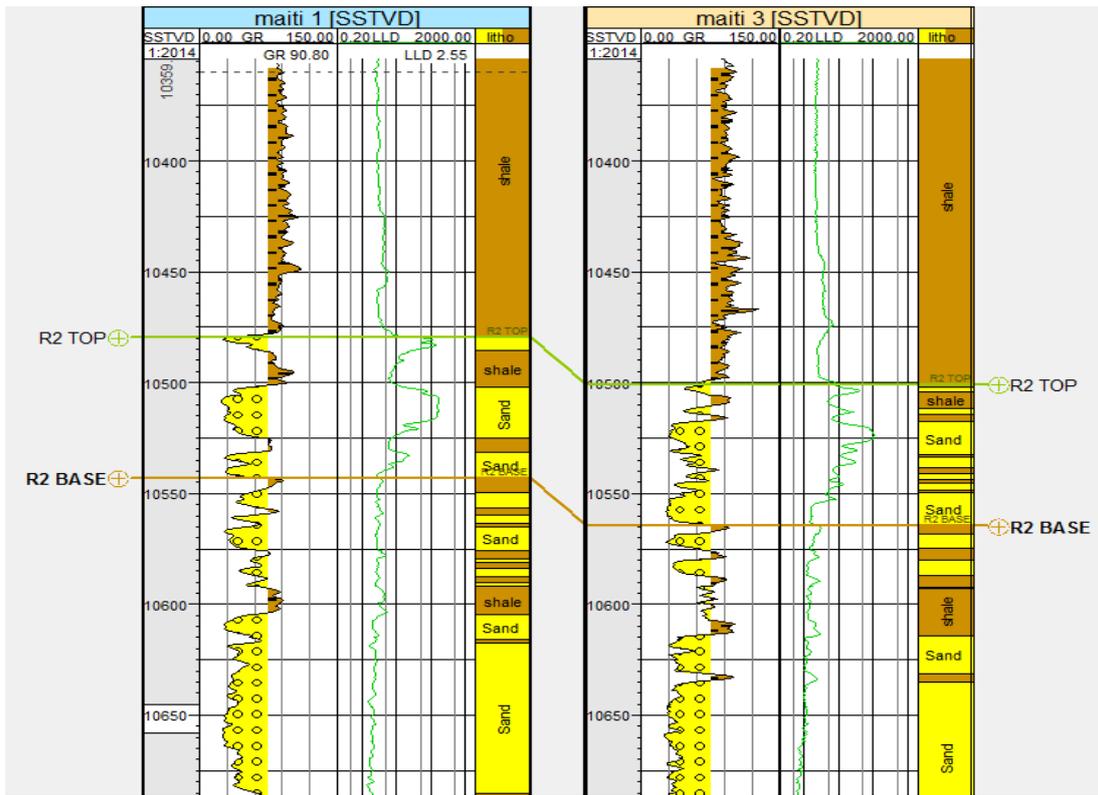


Figure 4 Lithostratigraphic correlation panel showing for reservoir 2

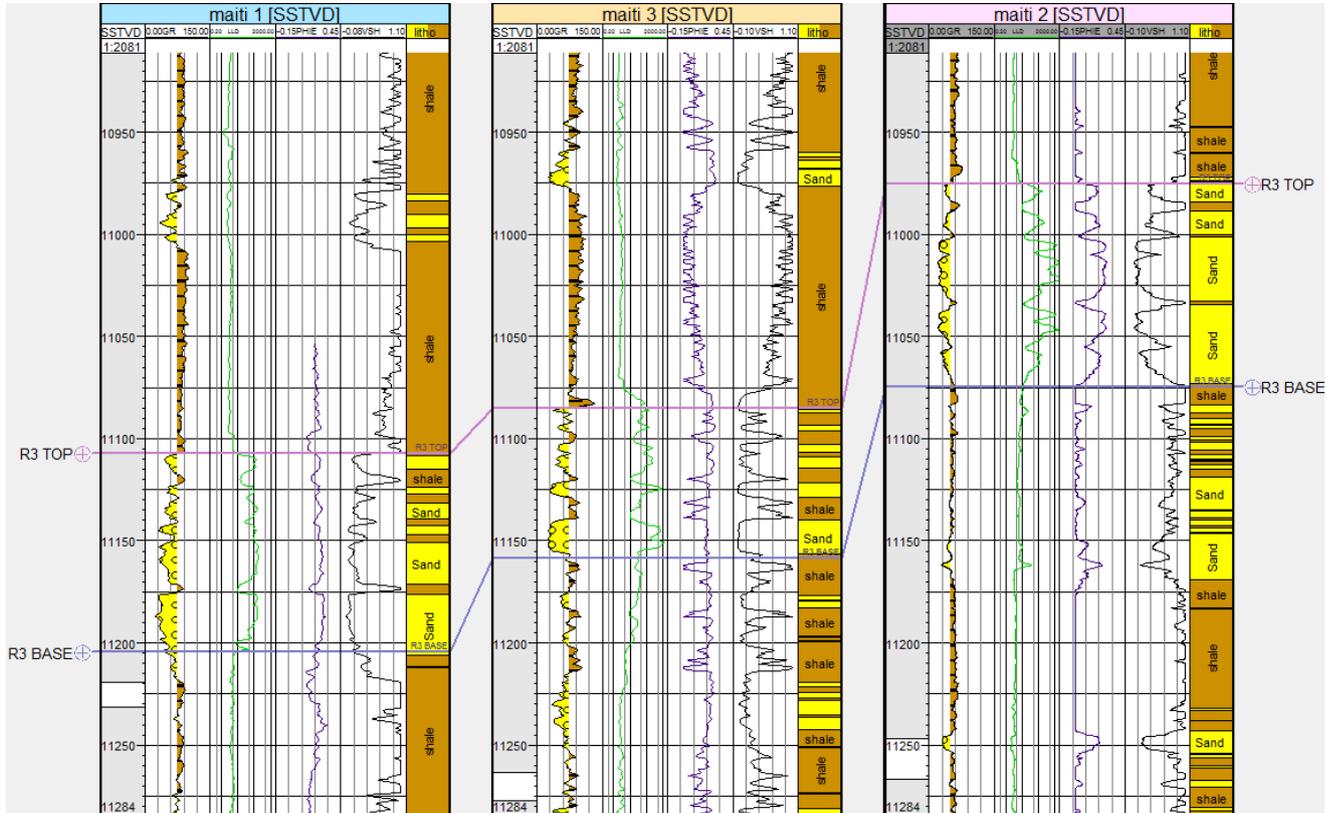


Figure 5: Lithostratigraphic correlation panel showing for reservoir 3

Table 1 Summary of petrophysical analysis (Reservoir 1), Maiti field.

wells	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G (fraction)	Porosity effective	S _{wirr}	Permeability (mD)	S _w (fraction)	S _h (fraction)	V _{shale} (fraction)
Maiti 1	9474	9560	86	75	0.87	0.35	0.064	168	0.42	0.68	0.07
Maiti 2	9523	9535	12	12	1	0.30	0.074	90	0.35	0.65	0.02

Table 2 Summary of petrophysical analysis (Reservoir 2), Maiti field.

wells	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G (fraction)	Porosity effective	S _{wirr}	Permeability (mD)	S _w (fraction)	S _h (fraction)	V _{shale} (fraction)
Maiti 1	10480	10542	64	44	0.69	0.31	0.072	103	0.42	0.58	0.07
Maiti 2	10500	10565	65	58	0.89	0.30	0.074	90	0.38	0.62	0.08

Table 3 Summary of petrophysical analysis of (Reservoir 3), Maiti field.

wells	Top (ft)	Bottom (ft)	Gross (ft)	Net (ft)	N/G (fraction)	Porosity effective	S _{wirr}	Permeability (mD)	S _w (fraction)	S _h (fraction)	V _{shale} (fraction)
Maiti 1	11107	11204	103	98	0.95	0.31	0.072	103	0.38	0.62	0.15
Maiti 2	11085	11158	73	55	0.75	0.28	0.079	68	0.35	0.65	0.11
Maiti 3	10957	11072	97	85	0.87	0.28	0.079	68	0.32	0.68	0.15

Average petrophysical parameters were calculated on each of the reservoirs, table 2 and these results were used to rank the reservoirs, figures 6 and figures 7.

The time structure maps of the tree horizons that correspond to the top the three reservoirs (figures 9-11) showed a fault assisted anticlinal structure at the central part of the field which is a structural trap. The time range for horizon 1 is from 1941 ms to 2210 ms, for horizon 2 it is from 2130 ms to 2310 ms, for horizon 3, it is from 2170 ms to 2510 ms.

Table 4 Average petrophysical parameters for each reservoir across the Maiti Field

reservoir	Gross (ft)	Net (ft)	N/G (fraction)	Porosity effective	S _{wirr}	Permeability (mD)	S _w (fraction)	S _h (fraction)
1	49	44	0.94	0.33	0.069	129	0.34	0.66
2	65	51	0.79	0.31	0.073	97	0.40	0.50
3	91	79	0.86	0.29	0.076	86	0.35	0.65

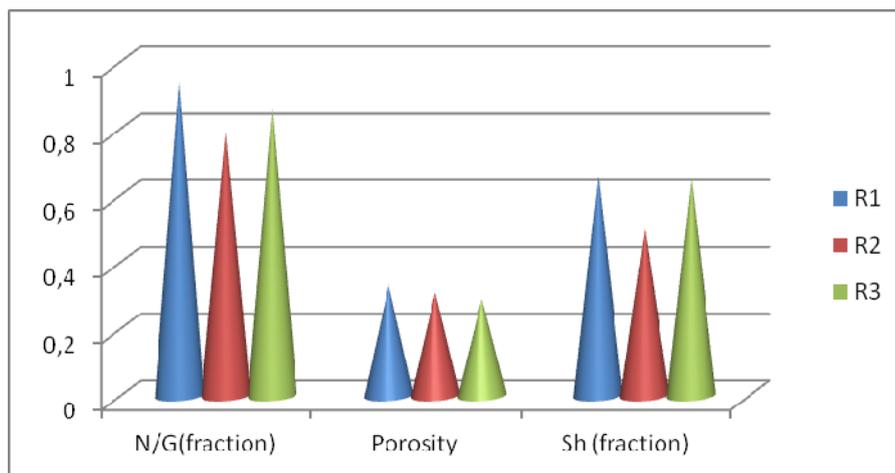


Figure 6 Reservoir ranking using N/g, effective porosity and Sh

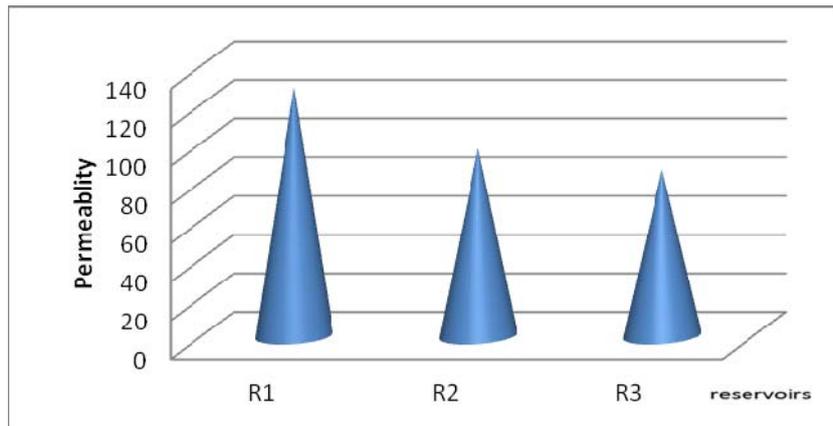


Figure 7 Reservoir ranking using permeability.

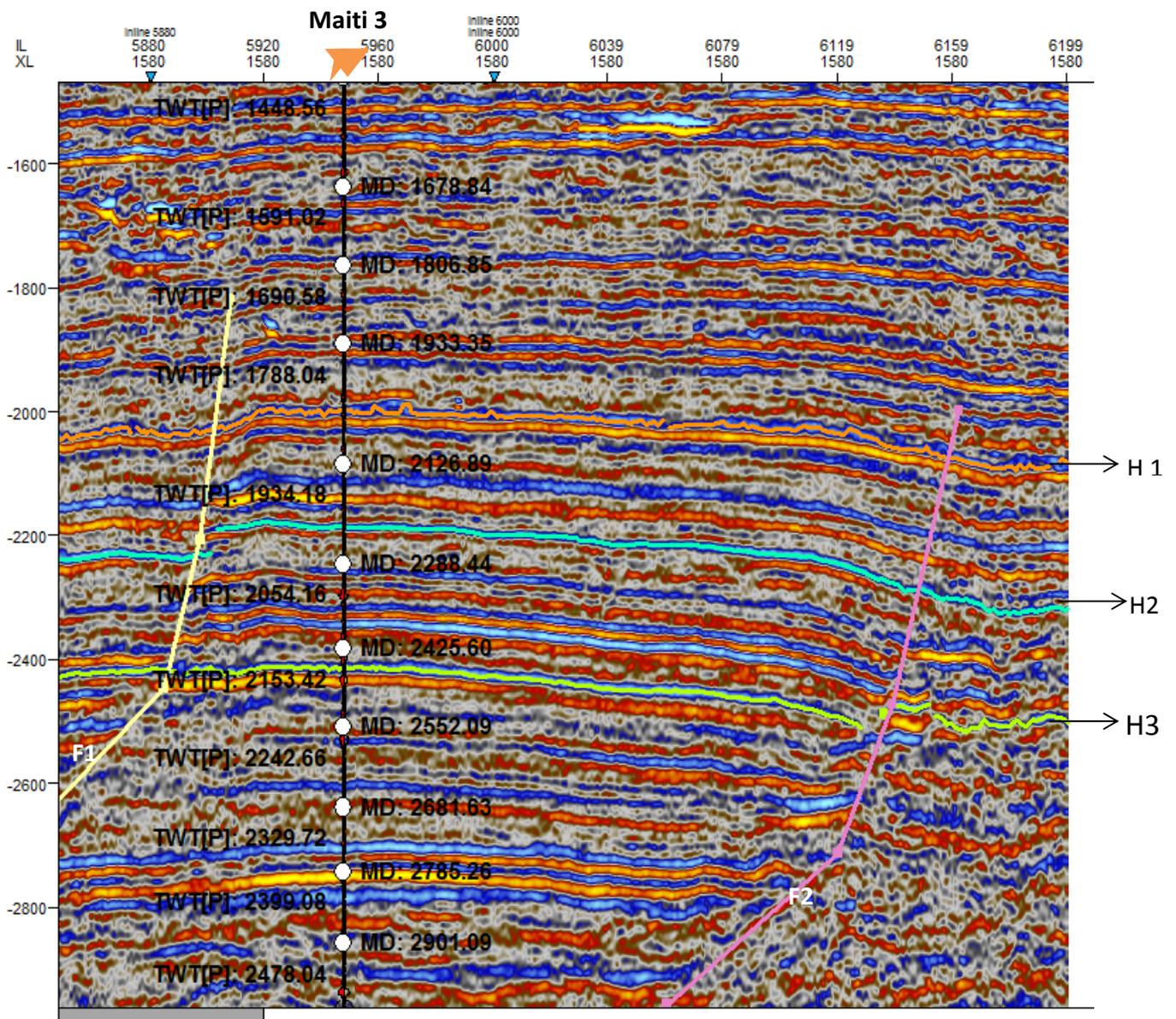


Figure 8 Tying of well to seismic showing the three horizons (H1, H2 and H3) and faults (F1 and F2) at Xline 1580

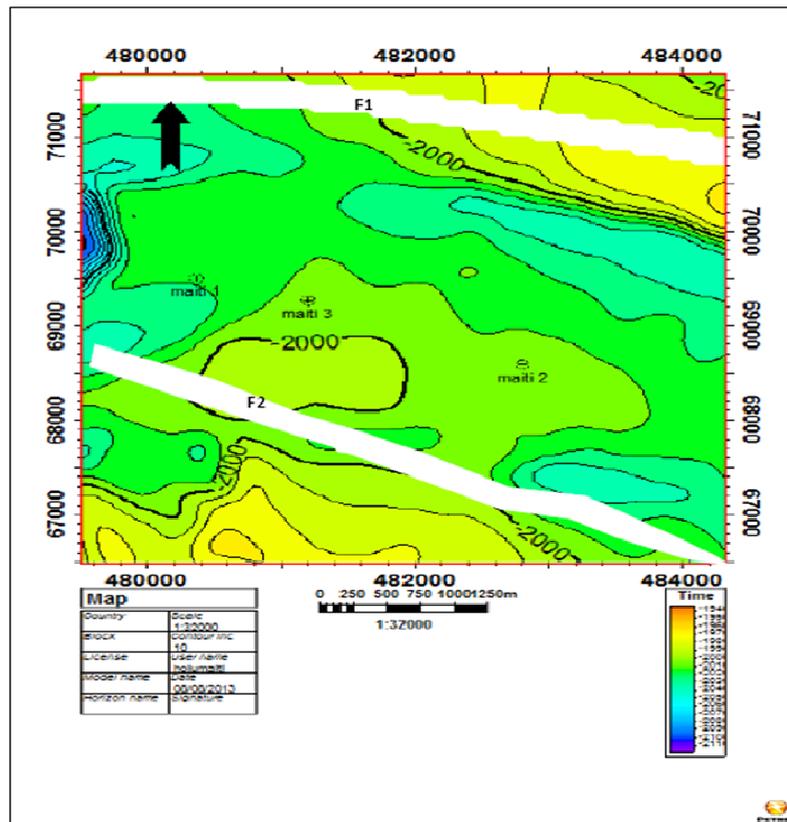


Figure 9 Time structure map for horizon 1

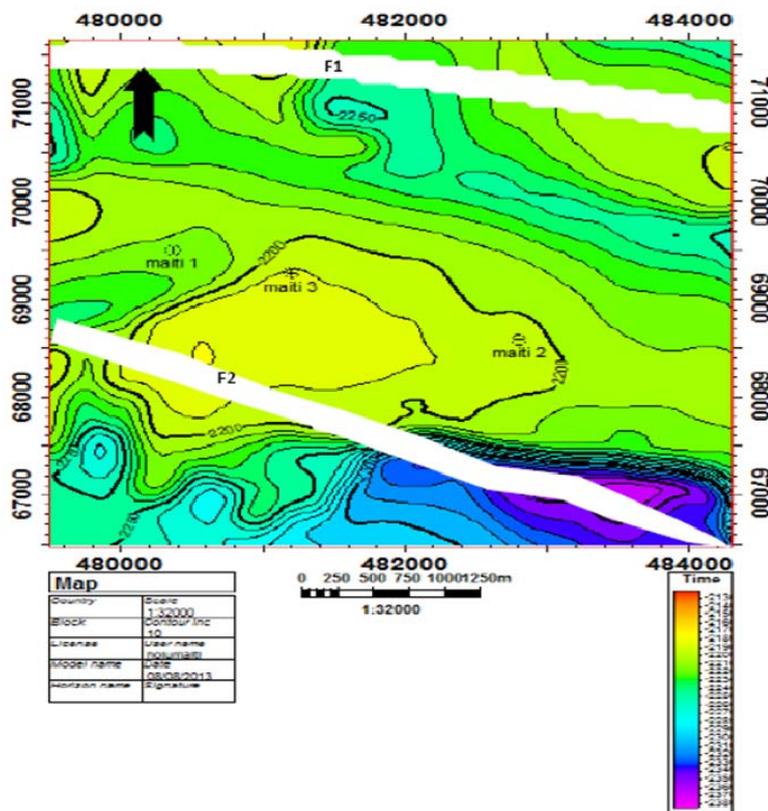


Figure 10 Time structure map for horizon 2

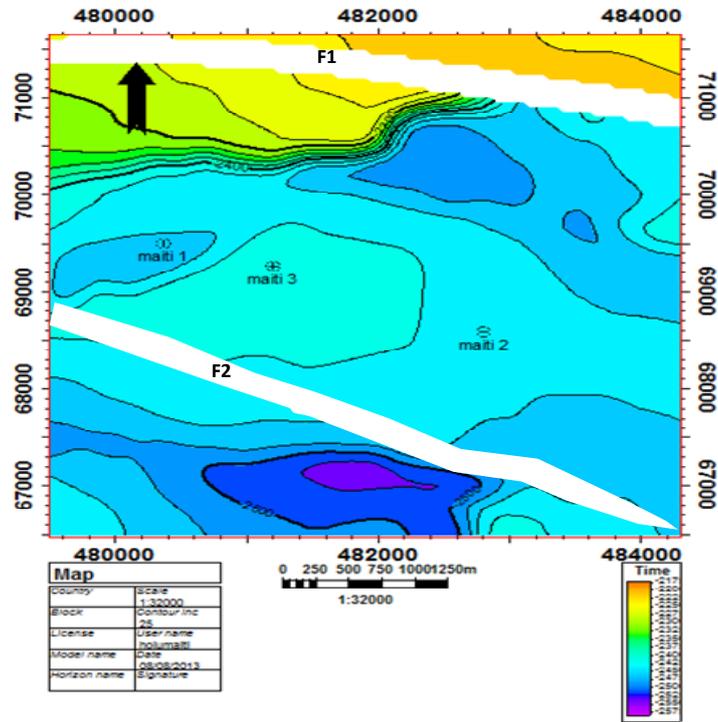


Figure 11 Time structure map for horizon 3

5. Conclusion

The hydrocarbon reservoir sand delineation, the petrophysical analysis, reservoir ranking and structural analysis performed on Maiti field reveals that Maiti field is a prolific hydrocarbon zone. Three hydrocarbon reservoirs were delineated. petrophysical parameters for the reservoir sands have porosity, ϕ range of 0.28 – 0.35, permeability $k(mD)$ range of 68-168, hydrocarbon saturation, S_h range of 0.65 to 0.68 and volume of shale V_{sh} range of 0.02 – 0.15. The average values of these petrophysical parameters were used to rank the three reservoirs R1, R2, R3. It was deduced that reservoir R1 is the most oil prolific reservoir while R2 is the least within Maiti field.

The time structure maps of the top the three reservoirs showed a fault assisted anticlinal structure known as structural trap within Maiti field, Niger delta, Nigeria.

6. References

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