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Petrophysical Analysis of Sand Reservoirs in F-Field Using 3D Seismic Data and Well Logs, Niger Delta

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Abstract-The study entails the petrophysical evaluation of reservoir sand bodies in F-Field, offshore Niger Delta, using seismic and well logs data sets. 3D seismic data and well log data were analysed with a view to identify potential hydrocarbon reservoirs in the study area. Structural and stratigraphic interpretation was done on seismic sections while lithologic interpretation and petrophysical analysis was done with well log. Four major faults were mapped on the seismic section. Two hydrocarbon bearing sands were identified with good porosity ranging from 0.3765 to 0.37035. Reservoir 2 was a single phase reservoir containing oil and gas while Reservoir 1 was a double phase reservoir containing mainly oil. Result shows that the two reservoirs harbor considerable volumes of hydrocarbon enough to make an affirmative business decision.

Keywords- *Petrophysical Analysis, Sand Reservoirs, F-Field*

I. INTRODUCTION

Tapping residual hydrocarbon reserves in many fields in the Niger Delta has become increasingly difficult and costly. The “easy wells” in producing fields have been drilled. It can only get harder and more challenging as drill well opportunities located in declining fields and the search for bypassed pay is very risky. Reservoir characterization and simulation are used as part of an integrated workflow to identify bypassed opportunities even as drilling through depleted reservoir zones stretches current available technologies, (Andrew, 2010). One of the major challenges in hydrocarbon exploration and development is the proper delineation of reservoir extent for volumetric computation and optimization of well placement. Therefore adequate petrophysical analysis should be carried out on promising fields using well data and seismic data for optimal results.

Understanding reservoir characteristics, most importantly porosity, permeability, water saturation, thickness and area extent of the reservoir are crucial factors in quantifying producible hydrocarbon (Schlumberger, 1989). Petroleum in the Niger Delta is predominantly produced from sandstone and unconsolidated sands in the Agbada formation. It is necessary to delineate the hydrocarbon reservoirs and evaluate them because they are the zones of interest for hydrocarbon exploitations (Adewoye et al., 2013). Based on reservoir geometry and quality, the lateral variation in reservoir thickness is strongly controlled by growth faults; with the reservoirs thickening towards the fault within the down-thrown block (Weber and Daukoru, 1975).

The analysis of F-Field using well logs and seismic data will be achieved by the identification of the reservoirs and estimating the petrophysical parameters from the well logs, generating time structure of mapped horizons from structural analysis, carrying out a volumetric analysis in order to estimate the hydrocarbon in place. This study is expected to enhance knowledge of the subsurface geology and structural setting of the study area and enable an evaluation of the hydrocarbon extracting potential of the field.

II. LOCATION OF THE STUDY AREA AND GEOLOGY OF THE NIGER DELTA BASIN

F-Field is located within the offshore area of Niger delta in Nigeria (Fig1) and belongs to an active oil producing company in Nigeria. The field is coded F-Field in this study for confidential and propriety reasons. The Niger Delta is located in southern Nigeria, between longitudes 3˚ and 9˚E, and between latitudes 4˚ and 7˚N (Klett et al., 1997).

The Niger Delta Basin is the sedimentological product of two main hydrological elements, the Rivers Niger and Benue which drain into the Atlantic Ocean at the Gulf of Guinea through multiple distributaries. The Niger Delta Basin consists of three diachronous formation of which the Akata, Agbada and Benin Formations are of main interest to the oil explorationist. The Akata Formation consists of shale and subordinate sand content (Short and Stuable, 1967; Whiteman, 1982). It occurs as the bottom set, unconformably overlain by the Agbada Formation characterized by sand and shale interbeds (Short and Stuable, 1967; Whiteman, 1982), and exists as the foreset of the delta. The Niger Delta is capped by the Benin Formation which consists of mainly sands of fluvial origin (Short and Stuable, 1967; Whiteman, 1982), and exists as the topset of the delta.

III. WORK FLOW

Figure 2 summarizes the work flow adopted for this study. Geophysical well log data (the TOMBOY data) which includes gamma ray, resistivity, density, neutron logs (fig. 2), from four offshore wells were utilized in this study. The sequence of data import begins with the well heads and logs.

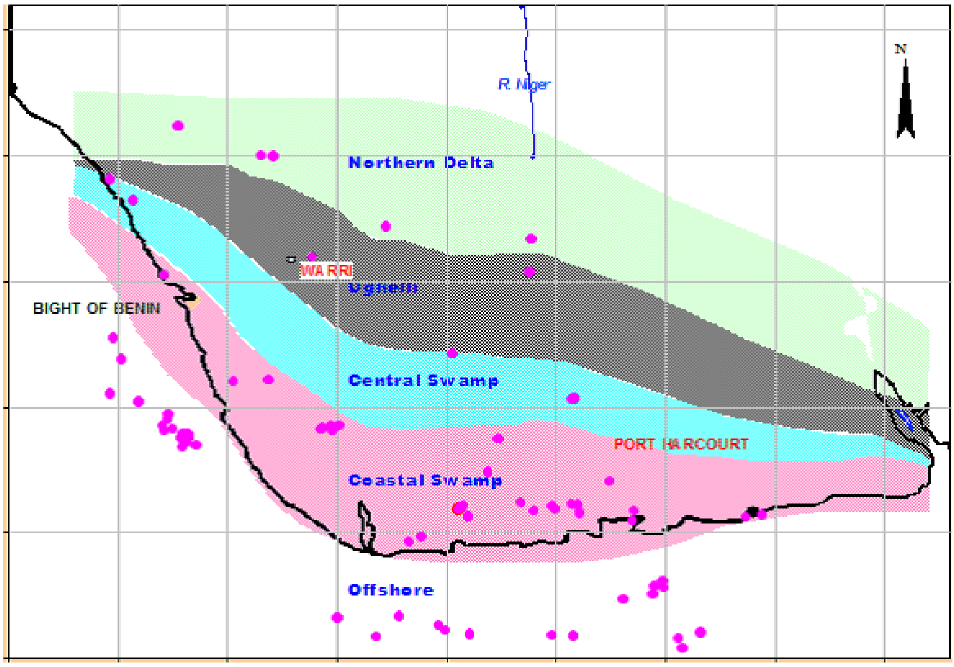

Figure 1. Map of Niger Delta showing the depobelts (Emudianughe et al 2014 modified from Doust and Omatsola 1990)

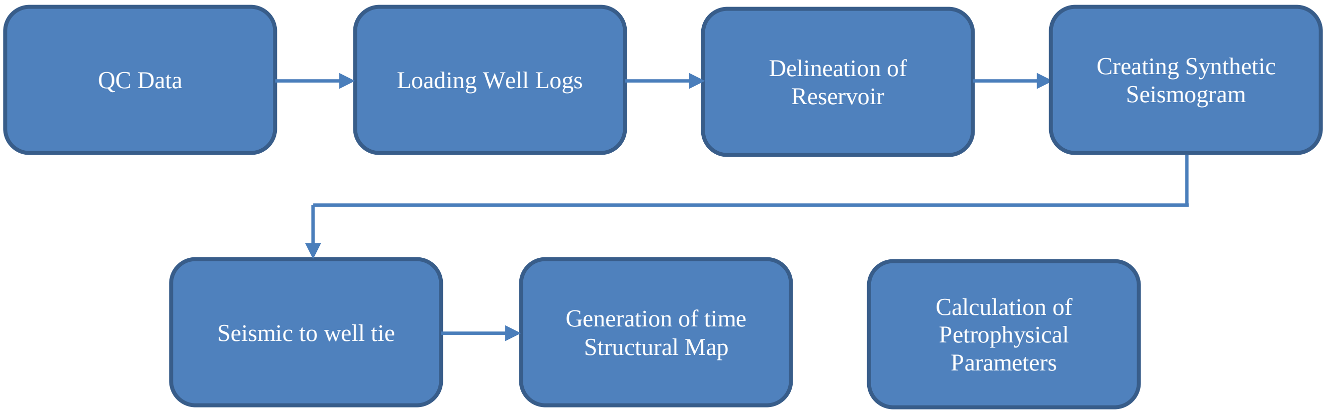

Figure 2. Research workflow

IV. DELINEATION OF RESERVOIR

The potential reservoir for this study was identified by picking sands (top and base, fig. 3) of low gamma ray log with a corresponding high resistivity log signature. In this way, hydrocarbon reservoir were delineated and their boundaries mapped using direct indicators from 3-D seismic data.

In order to ensure the continuity of events on both seismic section and well sections, well to seismic tie was done. On a 3-D window, the wells with the reservoir tops and bases were displayed (fig. 3). This was superimposed on the seismic lines to ensure that there was accurate tie between the well and seismic event.

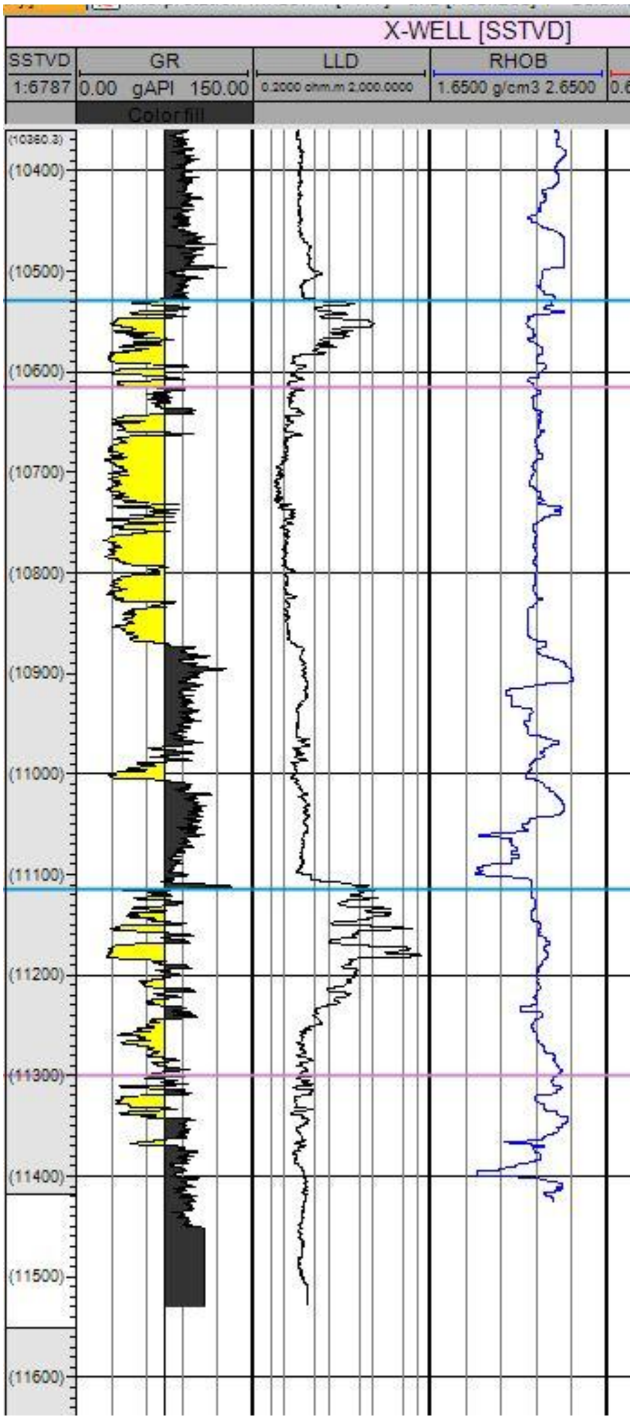

Figure 3. Delineation of Reservoirs

Most of the faults seen on the seismic section were discontinuous across the seismic volume, but major and minor faults that were continuous were mapped. Fault planes and fault polygons using the variance attribute time slice were generated. The faults were posted on the surfaces using the fault polygons. A horizon surfaces of different rock layers were identified by distinctive reflection pattern that can be observed over a layer with relatively large extent. Identification of prospective sand was achieved from the composite logs available. In areas without well control, strong reflections on the seismic section were selected for mapping. Time to depth conversion was done, and the corresponding depth structure map was produced. Mapped horizons and the generated fault polygons were then used to generate time structural map for the reservoirs (fig. 5)

V. RESULTS AND DISCUSSION

Two lithologies (sand and shale) were identified using the Gamma ray log. From the lithology log, the interval colored yellow is sand, while the interval colored grey is shale.

X-WELL was correlated with three (3) other wells across the field (fig. 4). The results obtained from this study are based on both the petrophysical analysis and seismic interpretation. The well correlation panel shows the tops and bases of the reservoirs within the F-Field. Horizon 12,13 and 14 are reservoir of interest (fig. 4).

The analysis of all the well section revealed that each of the sand units extends across the field and varies in thickness with some unit occurring at greater depth than adjacent unit; possibly an evidence of faulting. The frequency of occurrence and thickness of shale intervals (beds), was observed to increase with depth, with a corresponding decrease in the frequency of occurrence and thickness of associated sand beds/intervals. A pattern observed to characterize formational transition from Benin to Agbada Formation. From the analysis, particularly the resistivity log, all delineated reservoirs were identified as hydrocarbon bearing units across the wells.

VI. TIME STRUCTURAL MAP

Mapped horizons and the generated fault polygons were used to generate time structural maps for the reservoirs, (fig. 5). An anticlinal structural element is displayed at the southwestern part of the area. Although a time map is compressed in its deeper parts and stretched out in its shallow areas because of the general increase in velocity with depth, the highs and lows are normally in the right places.

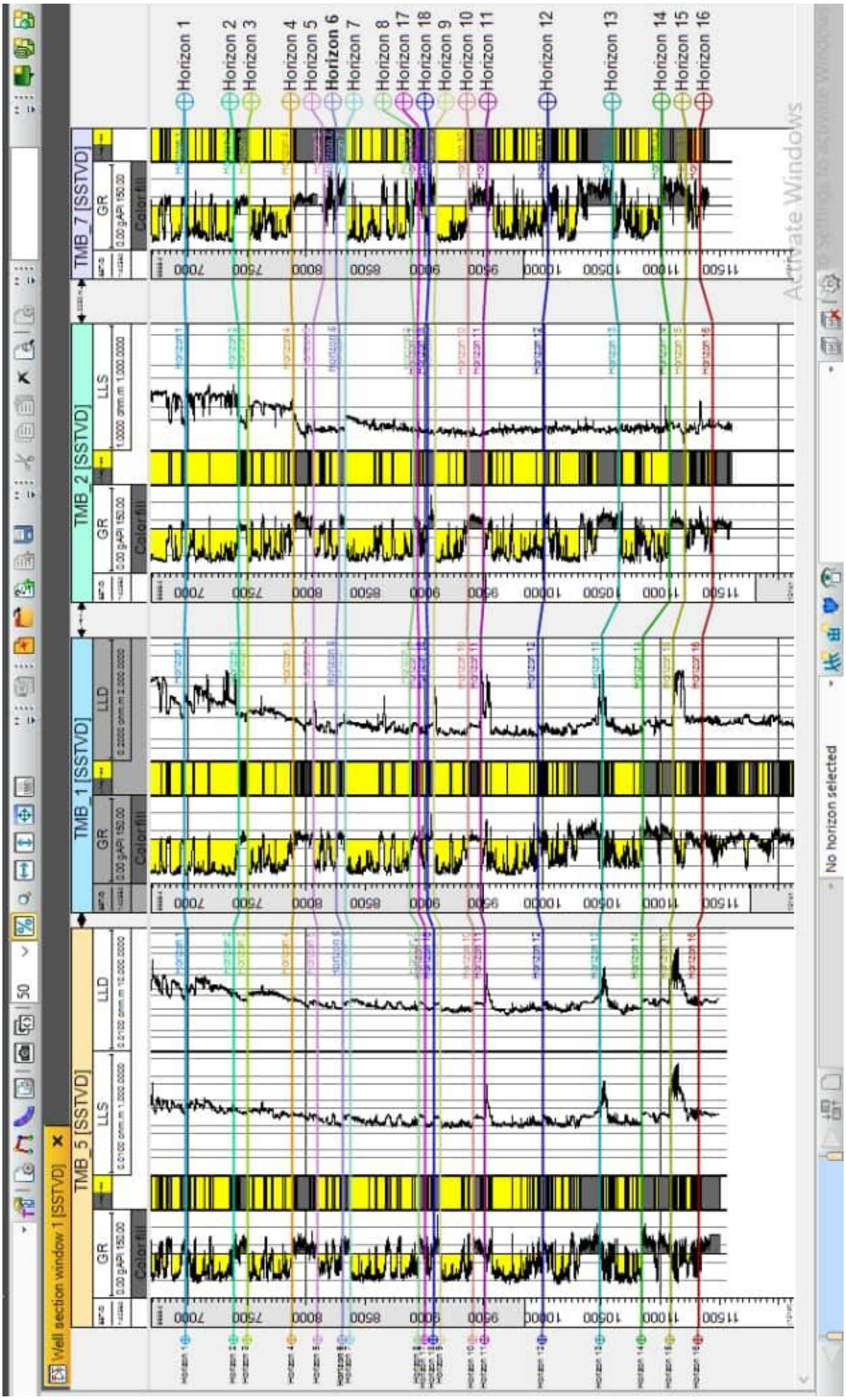

Figure 4. Well correlation panel across F-Field showing the tops & base of the reservoirs

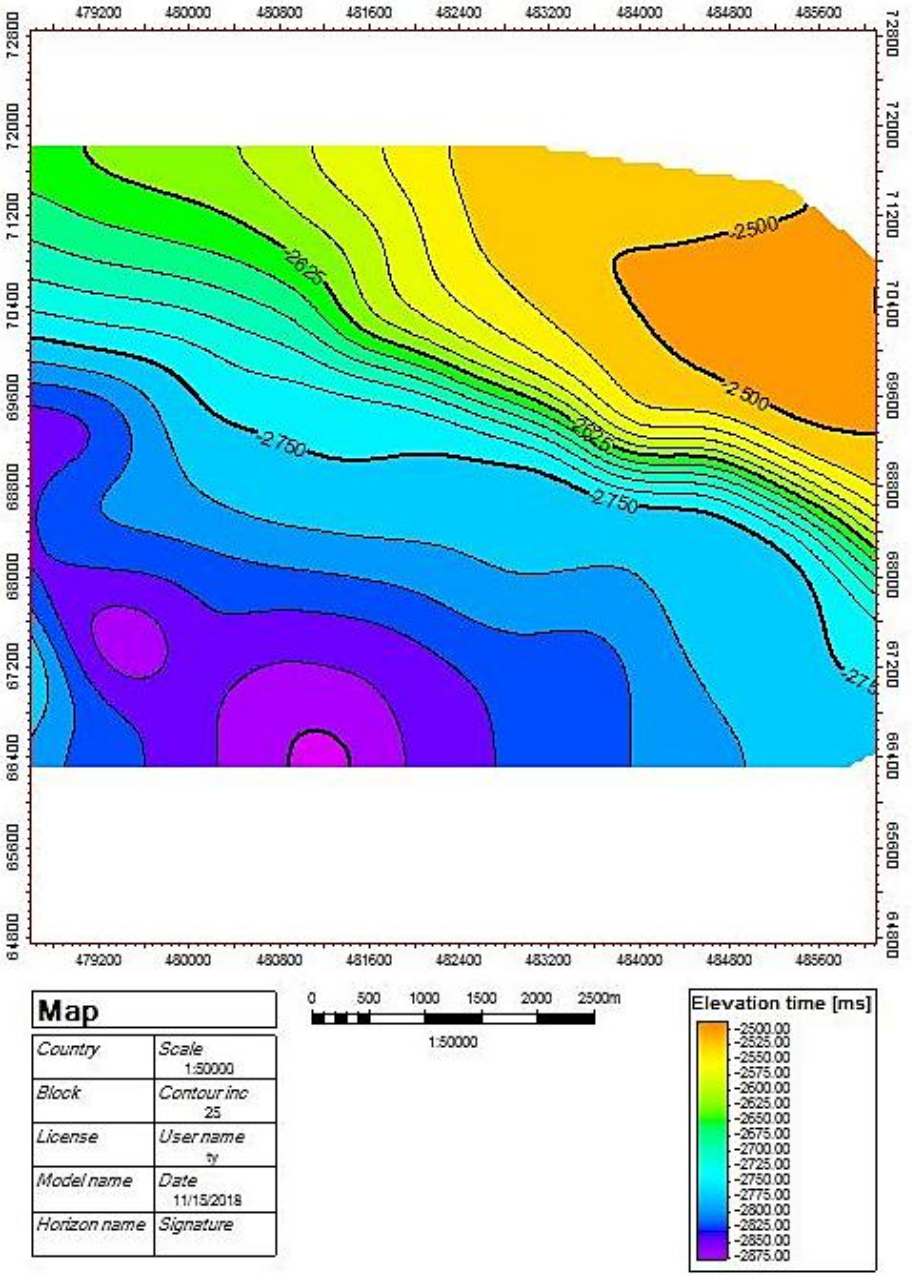

Figure 5. Time structural map

VII. SEISMIC TO WELL TIE SHOWING WELL TOPS

Tying wells usually involves forward modeling a synthetic seismogram from sonic and density logs, then matching that synthetic to the seismic reflection data, thus producing a relationship between the logs (measured in depth) and the seismic (measured in travel time).

The synthetic seismogram is generated by convolving the reflectivity derived from digitized acoustic and density logs with the wavelet derived from seismic data. By comparing marker beds or other correlation points picked on well logs with major reflections on the seismic section, interpretations of the data can be improved. The quality of the match between a synthetic seismogram depends on well log quality, seismic data processing quality, and the ability to extract a representative wavelet from seismic data, among other factors. Figure 6 shows the well to seismic tie. Some of the reservoir tops and bases coincide with the peaks and troughs on the seismic section.

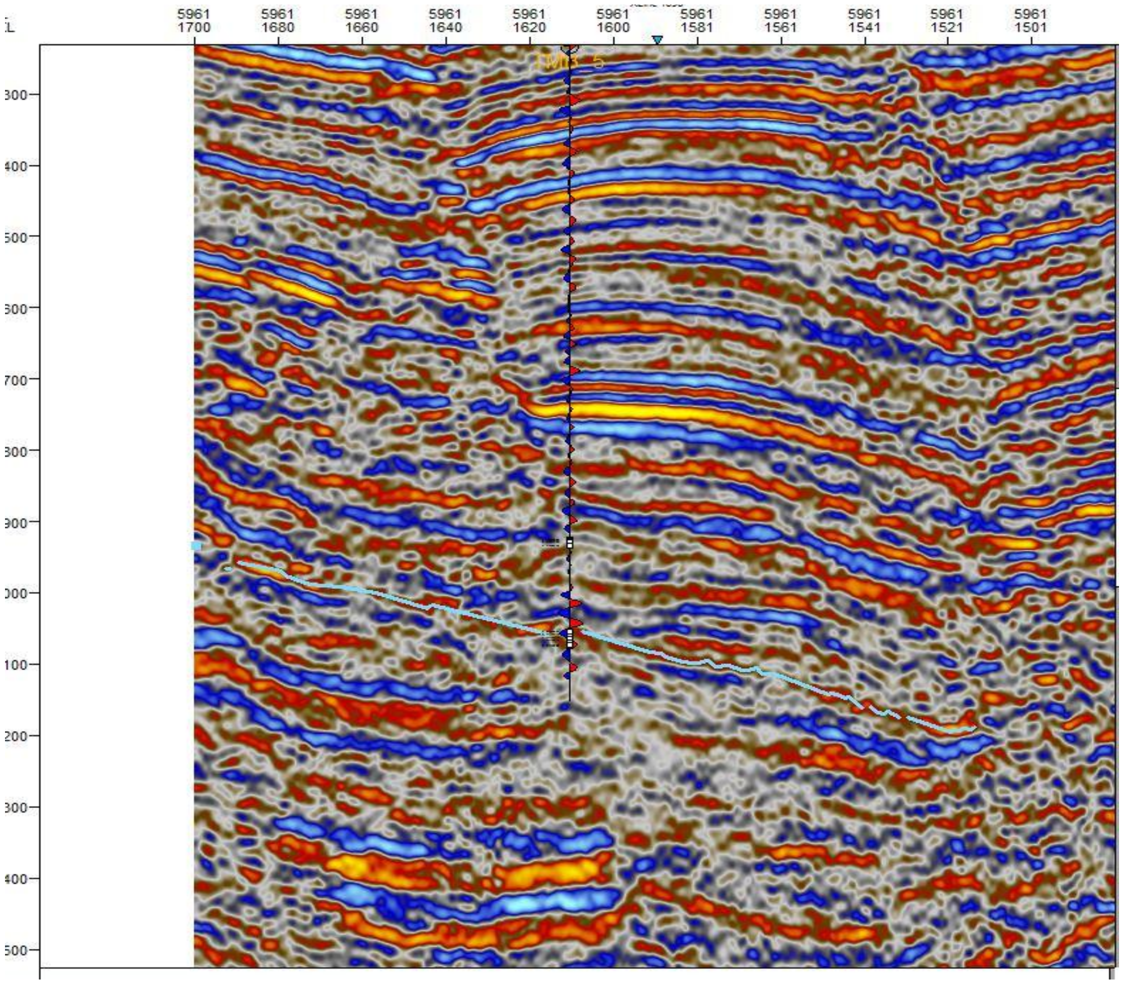

Figure 6. Showing Well to Seismic tie

Three horizons corresponding to the tops and bottoms of the two reservoirs and four major faults were mapped as fault 1, fault 2, fault 3 and fault 4 respectively across the seismic section for these analyses.

VIII. LITHOFACIES

Two lithofacies [sand (yellow) and shale (grey)] were differentiated based on gamma ray log signatures constrained with neutron logs.

IX. VOLUMETRIC ESTIMATION

Volumetric estimates of original oil in place (OOIP) and original gas in place (OGIP) are based on a geological model that geometrically describes the volume of hydrocarbon in the reservoir. However, due mainly to gas evolving from the oil as pressure and temperature are decreased, oil at the surface occupies less space than it does in the subsurface. Conversely, gas at the surface occupies more space than it does in the subsurface because of expansion. This necessitates correcting subsurface volumes to standard units of volume measured at surface conditions as shown below:

$$STOIP = (7758 \times A \times H \times \Phi eff \times Sh)/Boi \quad (1)$$

Where:

STOIP = Storage Tank Oil In Place (STB: stock tank barrels)

7758 = conversion factor from acre-ft to bbl barrels

A = area of reservoir (acres) from map data

NOTE:

A = 4935.03 Acres from map data

h = height or thickness of pay zone (ft) from log and/or core data (height is same as thickness of facie of sand)

Φeff = Effective porosity (decimal) from log and/or core data

Sh = Hydrocarbon saturation

Boi = formation volume factor for oil at initial conditions (reservoir bblbarrels/STBstock tank barrels)

Another basic volumetric equation is

$$STGIP= (43560 \times A \times H \times \Phi eff \times Sh)/Bgi \quad (2)$$

where:

G = OGIP original gas in place (SCF standard cubic feet)

43560 = conversion factor from acre-ft to ft 3

Bgi = formation volume factor for gas at initial conditions

X. RESERVOIR 1

Table 1 and 2 shows the result of some computed petrophysical parameters for reservoir 1 (Fig3) which cut across X-WELL in the F-Field. The first reservoir was penetrated at depths of 10541.46 - 10628.4 feet in X-WELL. It has a gross sand thickness of 86.94m, net sand thickness of 62.41m, and a net to gross thickness (N/G) ranging from 0.38 – 0.94 with average value of 0.717.

Reservoir 1 also has an average porosity value of 0.3765 with permeability value of 6527.196 mD. The water and hydrocarbon saturation have average values of 31% and 69% respectively.

The porosity value obtained within reservoir 1 shows a good to excellent rating, while the high permeability value obtained indicate an excellent value that permit the free flow of fluid within the reservoir. The hydrocarbon saturation indicates a high proportion of hydrocarbon to the quantity of water within the reservoir. Hence reservoir 1 is a hydrocarbon saturated reservoir.

XI. WELL TOPS 2/RESERVOIR 2

The petrophysical parameters for reservoir 2 are displayed in Table 2. It has a gross sand thickness of 185.71m, net sand thickness of 83m, Net to Gross (N/G) ranging from 0.28-0.57, with average value of 0.4469, average porosity of 0.37035. The water saturation (Sw) and hydrocarbon saturation (Sh) have average values of 16 % and 84 % respectively with average volume of shale (Vsh) being 22 %.

TABLE I. ANALYZED PETROPHYSICAL PARAMETERS FOR RESERVOIR 1

Depth (ft)	Zone log	GR (API)	Rt (Ohm-m)	RHOB (g/cm^3)	Porosity	Vsh1	Effective Porosity
10541.46	Zone 1	70.91	13.0851	2.3193	0.3211	0.2535	0.2356
10558.76	Zone 2	43.51	43.6969	2.2159	0.4215	0.0752	0.3901
10579.78	Zone 3	44.15	5.4366	2.2553	0.3832	0.0858	0.3494
10604.92	Zone 4	55.44	1.921	2.2584	0.3802	0.1595	0.3204
10628.40							

Permeability K (mD)	Formation Factor F	Water saturation Sw (frac)	Hydrocarbon saturation Sh (frac)	STOIIP	STGIIP	Gross sand thickness	Net Sand Thickness	Net To Gross
175.1687	11.16969	0.119013	0.880987	20661298	116010070.1	17.3	6.5	0.38
18306.99	4.074176	0.035639	0.964361	1.14E+08	639852215.6	21.02	19.78	0.94
5379.087	5.078622	0.286447	0.713553	80714848	453201698.4	25.14	21.14	0.84
2247.541	6.039579	0.810672	0.189328	13925463	78189373.97	23.48	14.99	0.64

TABLE II. ANALYZED PETROPHYSICAL PARAMETERS FOR RESERVOIR 2

Depth (ft)	Zone log	GR (API)	Rt (Ohm-m)	RHOB(g/cm^3)	Porosity	Vsh1	Effective Porosity
11126.92	Zone 1	61.56	112.6602	2.2402	0.3979	0.1818	0.3256
11171.88	Zone 2	63.19	179.3481	2.2877	0.3517	0.2224	0.2716
11214.89	Zone 3	76.44	15.2623	2.2431	0.395	0.2933	0.2787
11259.85	Zone 4	63.6	3.0276	2.3031	0.3368	0.1849	0.278

Permeability K(mD)	Formation Factor F	Water saturation Sw (frac)	Hydrocarbon saturation Sh (frac)	STOIIP	Gross sand thickness	Net Sand thickness	Net To Gross
2628.248	5.848209	0.013823	0.986177	1.18E+08	44.96	24	0.53
517.5358	8.404892	0.008683	0.991317	68033964	43.01	16.5	0.38
640.8115	7.982111	0.102036	0.897964	47907731	44.96	12.5	0.28
627.4542	8.022359	0.514368	0.485632	62025900	52.78	30	0.57

TABLE III. AVERAGE PETROPHYSICAL PARAMETERS FOR RESERVOIR 1 AND 2

Reservoirs	Φeff	ΦT	SW (frac)	Sh (frac)	K (mD)	STOIIP	STGIIP	Net To Gross
Reservior 1	0.323875	0.3765	0.312943	0.687057	6527.196	57314690	321813339.5	0.717
Reservoir 2	0.288475	0.37035	0.159727	0.840273	1103.512	73996523	-	0.44
Average Values	0.306175	0.373425	0.236335	0.763665	3815.354	65655606		0.58

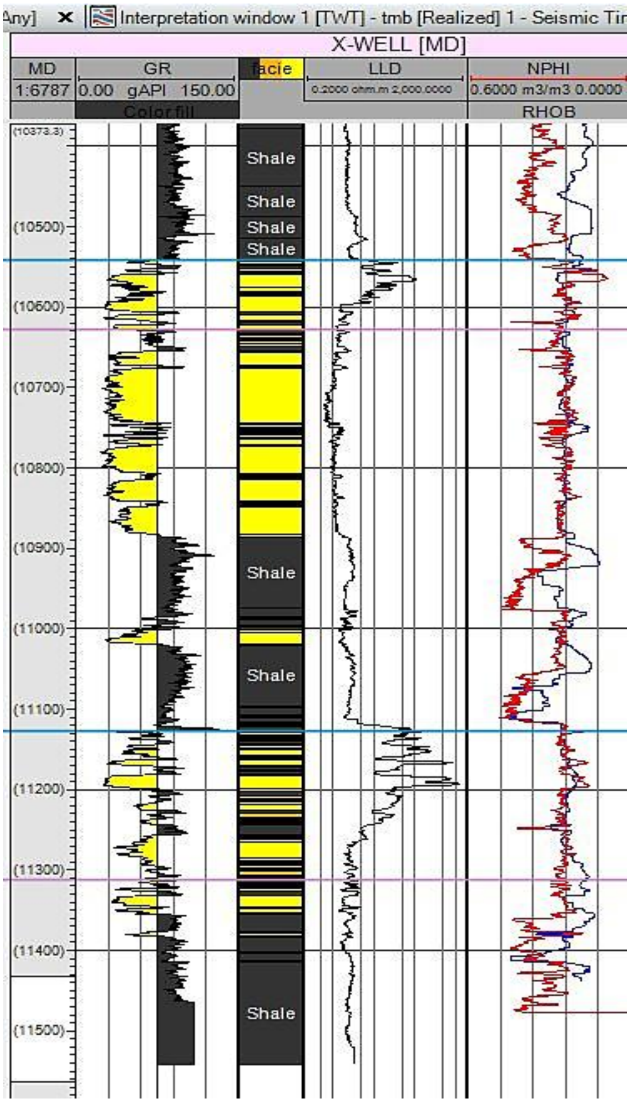

Figure 7. Well Log Showing Reservoir Phase

The two reservoirs were ranked using average results of petrophysical parameters. R1 is said to be double phase reservoir while R2 is a single phase reservoir within F-Field. Volumetric study of the hydrocarbon in place shows that the reservoirs are of appreciable areas and thicknesses. The volume of hydrocarbon originally in place was estimated to be 57314690 barrels of oil and 321813339.5 cubic ft of gas in reservoir 1 and 73996523 barrels of oil in reservoir 2. From these results, we can infer that the F-Field has exploitable potential hydrocarbon.

XII. CONCLUSION

Petrophysical analysis of F-field Niger Delta has been carried out using well logs and seismic data. The integration of well log and seismic data in the assessment of the potential occurrence of residual hydrocarbon in the field studied proved positive as it enabled the identification of potential reservoirs and structural trapping elements in which hydrocarbon substantial amounts of hydrocarbon were contained.

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