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Well Logs and Seismic Data Analysis for Hydrocarbon Prospect in Kolo Creek, Niger Delta Nigeria

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Abstract
Hydrocarbon prospect, analysis and characterization are entailed in the processes used in identifying and delineating features/structures in the subsurface that are likely to be potential hydrocarbon reservoirs. The research was done by analyzing and interpreting well logs and seismic data obtained from Kolo Creek. Well logs were used to identify the lithologies present, sand and shale using the gamma ray log, potential hydrocarbon zones were interpreted using the resistivity log. These identified zones were taken into consideration for Petrophysical evaluation in which parameters such as porosity, permeability, water, and hydrocarbon saturation were obtained as details in the four wells. The lithologies were correlated across the four wells to define the continuity of the identified pay zones. Seismic-to-well tie was done using checkshot data obtainable in only Well-2. Three payzones were identified and the fluid types being gas, oil and water. Porosity values ranges from 20% to 34%, water saturation obtained were within the range of 24% and 40%, and hydrocarbon saturation (defined as whole minus water saturation) ranged from 60% to 76%. These values showed that the hydrocarbon was present in commercial quantity hence production can take place. Three horizons were picked, six faults labelled A-F, four synthetic and two antithetic were identified across the seismic sections. The horizons were studied in detail, for time, depth and attribute studies. Time structural map was generated,and it showed anticlinal structure present at its center. Depth map generated also depicted information as revealed by the time map thus validating the presence of hydrocarbon. An extracted attribute map indicated areas of high amplitudes and bright spots area being indicative of hydrocarbon accumulation present. The volumetric results showed that Reservoir A had OOIP of 467 x 10^6 STB and STOOIP of 389 x 10^6 STB.

Keywords*:* Kolo Creek, Hydrocarbon Reservoir,Channel Sands, Petrophysical Parameters.

1. Introduction

Hydrocarbon prospect, analysis and characterization is typically the processes employed in identifying and delineating features/structures within the subsurface that are likely to contain hydrocarbon. Two data sets, (seismic and well log data), are greatly utilized in exploration and exploitation of hydrocarbon and, they assist to effectively map subsurface structures and stratigraphic traps that are acceptable for economically exploitable accumulations, hence aiding in the delineation of findings in field assessments and development. Prediction of rock and fluid properties like porosity, clay content, and water saturation is crucial for exploration and development of hydrocarbon reservoirs. Rock and fluid property obtained from such predictions is employed in exploration, appraisal, or development of hydrocarbon reservoirs. Seismic data are usually the sole source of knowledge available throughout a field which will be used to predict the 3D distribution of properties with appropriate spatial resolution. (Emudianughe and Ogagarue 2018). Although some theories and laws appear to be approximately true in many samples of similar specific rock / field settings, it's very difficult to handle effects of all of micro-scale heterogeneity of rocks in any one set of petrophysical relationships.(Emudianughe et al 2017) In practice for any particular geological basin, petrophysical relations are therefore semi-empirical, they're calibrated with well logs and core data, and their theoretical uncertainty remains non negligible, (Bachrach, 2006).This studyused four (4) wells used from the study area code named GAMIN 2, GAMIN 7, GAMIN 9 and GARMIN 11, which assisted in achieving the aim of the research. Hydrocarbon within the Niger delta is principally produced from sandstones and unconsolidated sands within the Agbada Formation. The target of hydrocarbon exploration is to spot and delineate structural and stratigraphic traps suitable for economically exploitable accumulations and delineate the extent of discoveries in field appraisals and development.

Geological Setting, Stratigraphy and Petroleum System

Kolo Creek is located within Imiringi town area, situated about 10km east of Yenagoa, the capital city of present day Bayelsa State, Nigeria. It is located within longitudes 4’55’52.25N and 4’55’31.92N and latitudes 6’20’11.94E and 6’24’50.70E including the towns of Imiringi, Otuasega, Elebele, Orom and Ayon. (Figure 1) These areas as defined by this study are those communities within where oil exploration and exploitation activities are ongoing in Ogbia Local Government Area of Bayelsa State, Nigeria.

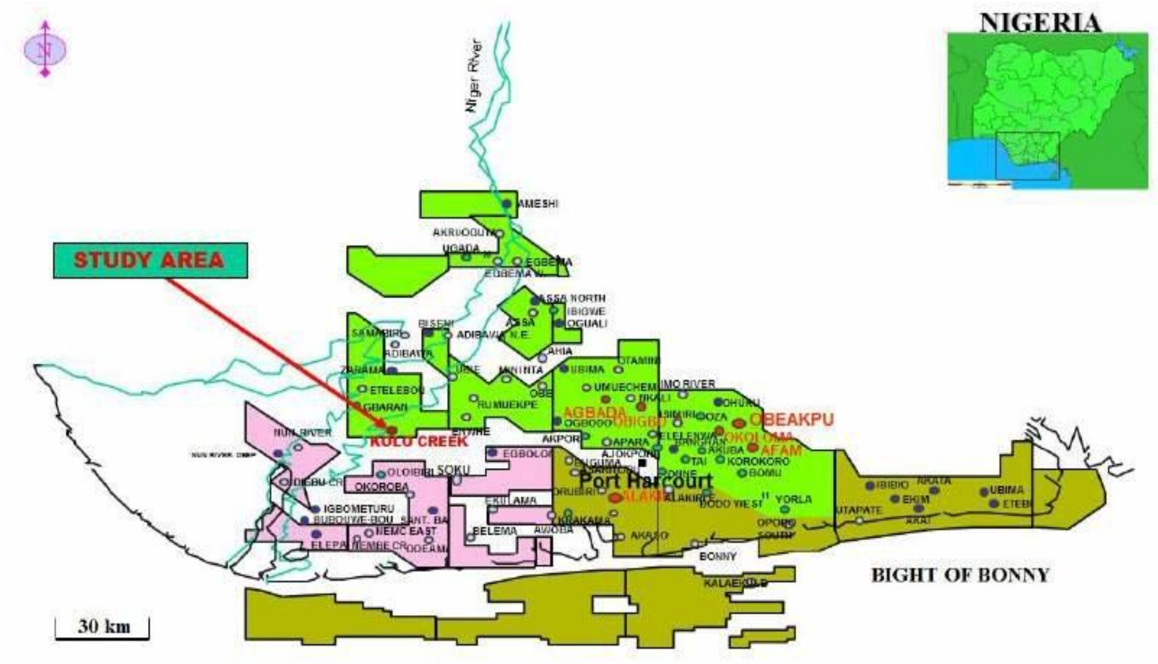

Figure 1: Location of Study Area

Kolo Creek oil field (Figure 1) is an onshore oil field with reservoir dated to the Middle Miocene using a palynomorph assemblage which is recognized as being deposited in the parasequence of shallow marine and deltaic plain deposit. The field is distinguished by several mostly E–W running growth faults; the reservoirs are Middle Miocene and of the Agbada formation (Oboh 1993). The Kolo Creek oil field has an aerial extent of about 5 by 10 kilometer, the main reservoir is oil bearing, located at a depth range of 3580 to 3670 meters with thickness of ranging from 50 to 60 meters. The sedimentary sequence is mainly of deltaic depositional sub-environments. The detected lithofacies are abundant in palynodebris, wood fragments, black debris, and amorphous organic materials.The palynomorph assemblage was used to date the reservoir to the early middle Miocene (14 to 15 Ma before present), which has been recognized as being formed in a parasequence of shallow marine and deltaic plain deposits (Oboho, 1995). The types of structures present are, simple non-faulted anticline rollover structures, faulted rollover anticline with multiple growth faults, or anticline faults and complicated collapse crest structures (Evamyet al., 1978). Others are sub-parallel growth fault (k-block structures) and structural closures along the back of major growth faults. Continental-margin collapse structures exert control on depositional and stratigraphic patterns within the Niger Delta clastic wedge (see Figure 2).

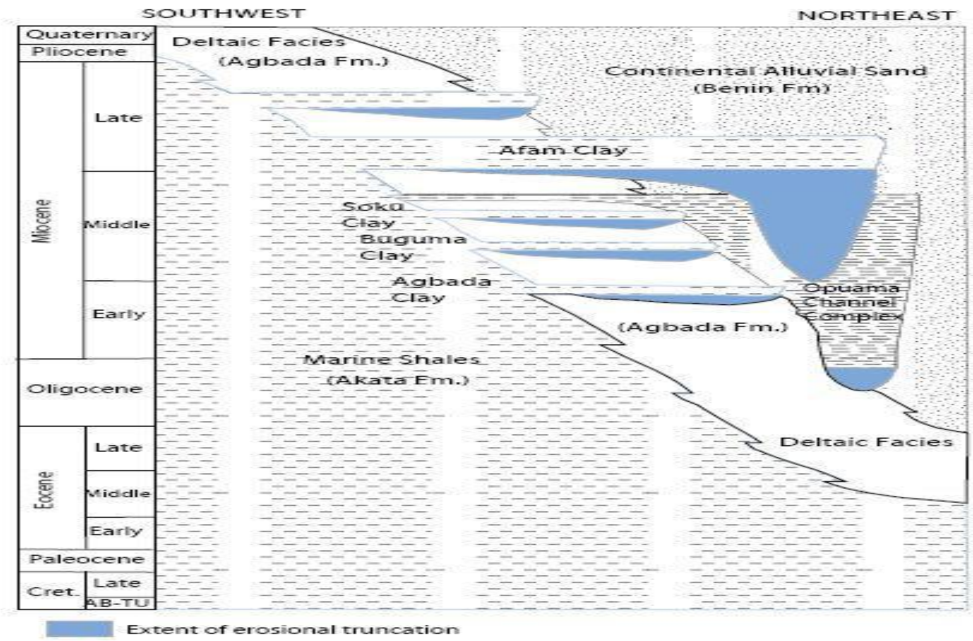

Figure 2: Stratigraphic Column Showing the three Formations of the Niger Delta (Tuttle et al.,1999).*Modified from Doust and Omatsola (1990).*

Only one petroleum system has been identified in the Niger Delta Province (C.M. Ekweozor and E.M. Daukoru, 1994). The Tertiary Niger Delta (Akata - Agbada) petroleum system is the name given to this system. The petroleum system's maximum extent corresponds to the province's borders. The majority of the petroleum is found in onshore or continental shelf fields in waters less than 200 meters deep, and it is mostly found in massive, relatively simple structures. The Niger Delta's Tertiary section is separated into three formations, each exhibiting a prograding depositional facies differentiated mostly by sand/shale ratio.A.A. Avbovbo, 1978, K.C. Short and A.J. Stäuble, 1967 describe the type sections of these formations. The thick shale sequences (possible source rock), turbidite sand (potential reservoirs in deep water), and tiny amounts of clay and silt make up the Akata Formation at the delta's base. (See Figure 2)

The Akata formation originated during lowstands from the Paleocene to the Recent, when terrestrial organic materials and clays were transported to deep water locations defined by low energy conditions and oxygen shortage. During the delta's development, turbidity currents most likely deposited deep sea fan sands inside the upper Akata Formation. The primary petroleum-bearing block, the overlying Agbada Formation, began forming in the Eocene and continues into the Recent. The formation is made up of 3700 meters of paralic siliciclastics and comprises the deltaic phase of the series.

In delta front, delta topset, and fluviodeltaic environments, clastics accumulated. Shale and sandstone strata were deposited in equal quantities in the lower Agbada Formation, but the top section is predominantly sand with relatively tiny shale interbeds. The Agbada Formation is overlain by the Benin Formation, a Continental deposit of alluvial and upper coastal plain sands up to 2000m thick that dates from the late Eocene to the recent (A.A. Avbovbo, 1978)

2. Material and Methods

Data for this research include composite geophysical well logs, seismic sections, check shot data, and a base map of the seismic lines as acquired.The well logs were as obtained from four wells (GAMIN 2, 7, 9 and 11). The data includes gamma ray log, resistivity and sonic logs, density logs. Two seismic profiles were interpreted, one on an arbitrary line running NW-SE and the other on an inline running E-W. The base map of the seismic lines and the well locations are shown in ***Figure 3.*** The gamma ray and resistivity logs were used for the identification of lithology and hydrocarbon-bearing reservoirs. The logs were also utilized to correlate wells. Using check shot data from the wells, the determined reservoir tops of the wells were linked to the seismic sections for horizon identification and mapping. The Work flow for the methodology is as presented in Figure 4.

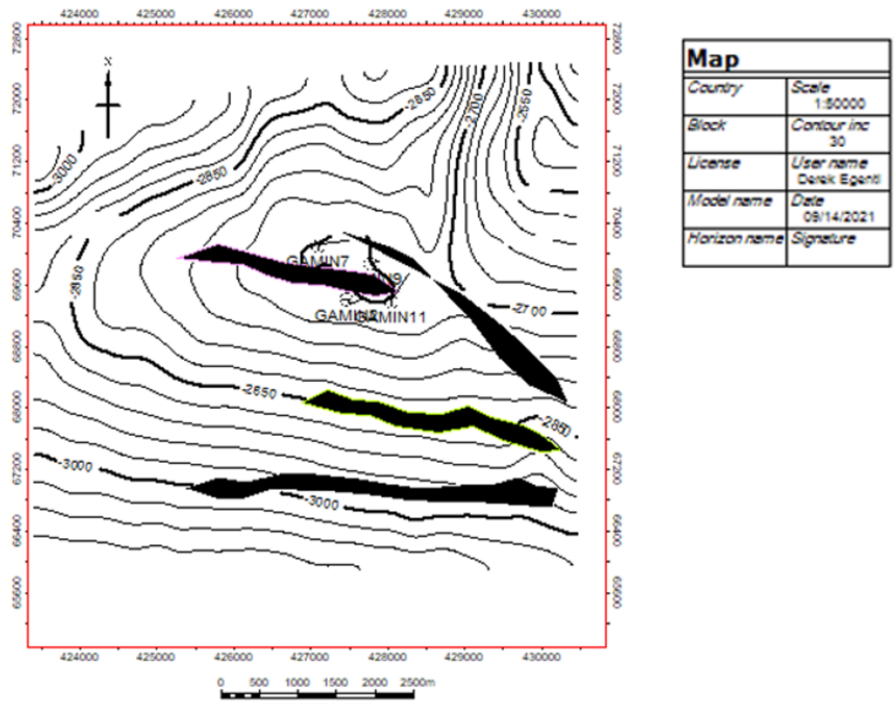

Figure 3: Base map of the Study area, showing well locations

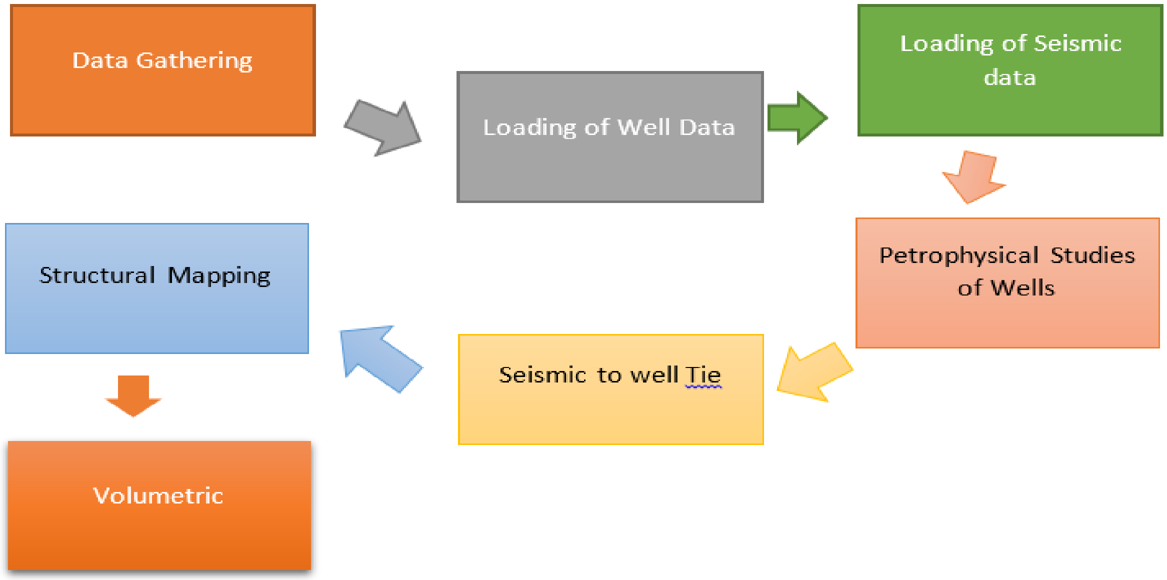

Figure 4: Workflow of Methodology

3. Results and Discussion

The data as obtained were analyzed using standard set parameters. First, was to delineate the various lithology, to identify the reservoirs and the source rocks in the data obtained across the wells. Three reservoir tops and bottoms were identified and labeled A, B,& C(See Figure 5, 6 and 7) respectively across the four wells. Other parameters such as porosity of the reservoirs (Por T), Water Saturation (S_w) Hydrocarbon Saturation (S_H), Volume of Shale (V_{sh}) and the Net to gross (NTG) as displayed on the logs for each of the wells presented below in this section were also determined.

Neutron porosity log when combined with density log was able to tell the fluid in place, showing that gas with very low density, oil with medium to high density and water with much higher density. Density log and gamma ray log combined was also placed on the same track for effective differentiation of the lithology as displayed. This is done since low Gamma Ray and High porosity values is an indication of a possible reservoir (sand body) while high gamma ray and low porosity is an indication of a possible source rock (shale body).

Neutron porosity Index (NPI) helped in determining the Hydrogen Index which was used to determine some reservoir properties such as Porosity, Water Saturation (S_W), Hydrocarbon Saturation (S_H), the Volume of Shale (V-shale) and the net to gross (NTG) to aid in the determination of the productive zone in addition with other logs for each of the reservoir zones of the wells. Figure 5 shows the displayed results as obtained.

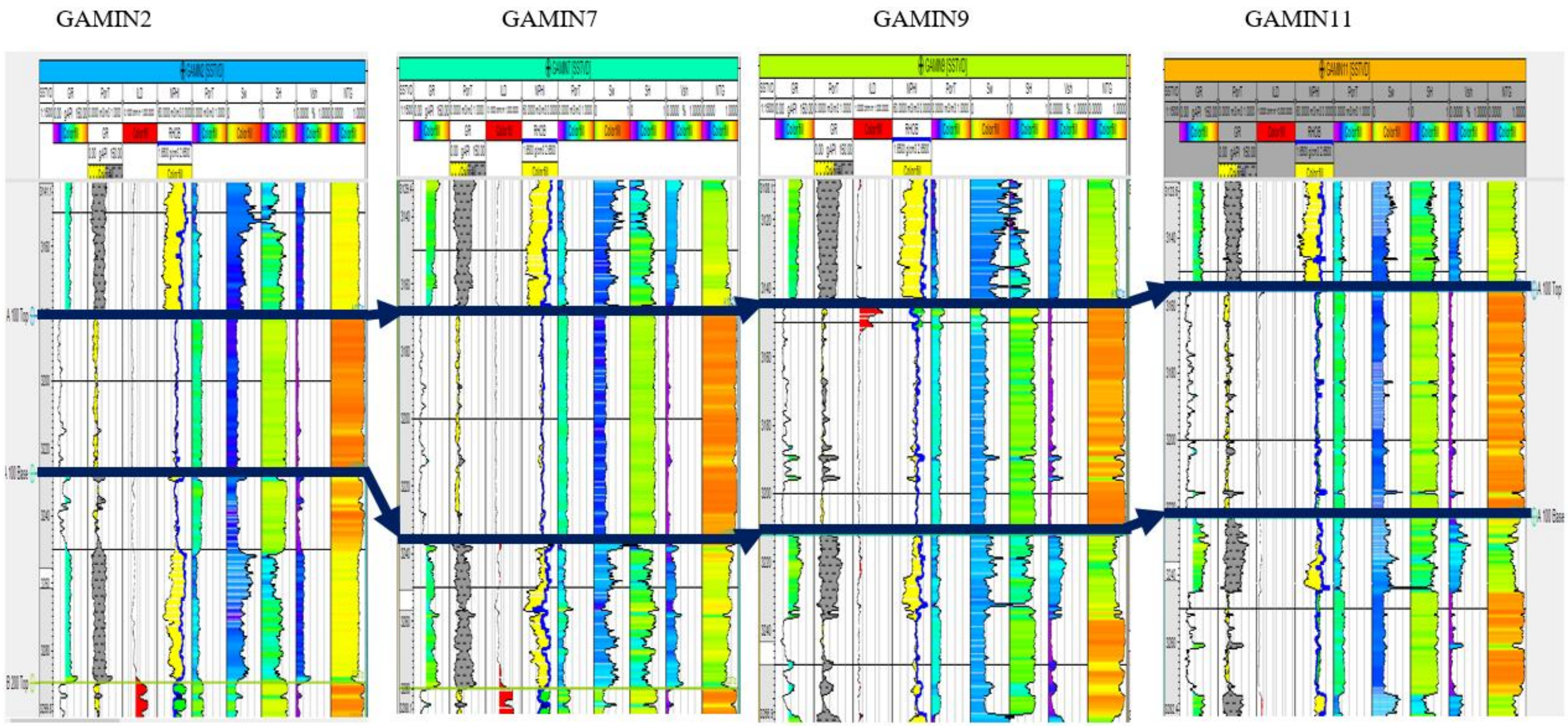

Figure 5: Correlation of Reservoir A across the wells

Correlation of Reservoir A across the wellsshowing continuity in stratigraphy for Reservoir A at different depth indicating a complex field.The wells (Gamin 2, Gamin 7, Gamin 9 and Gamin 11) were correlated for Reservoir A across tops at depthsof 3180m, 3168m, 3144m and 3156m and bottom 3226m, 3234m, 3210m, 3224m respectively (as shown in Figure 5 above). The differences in depths is as a result of the faults present in the study area as also shown in Figure 9.

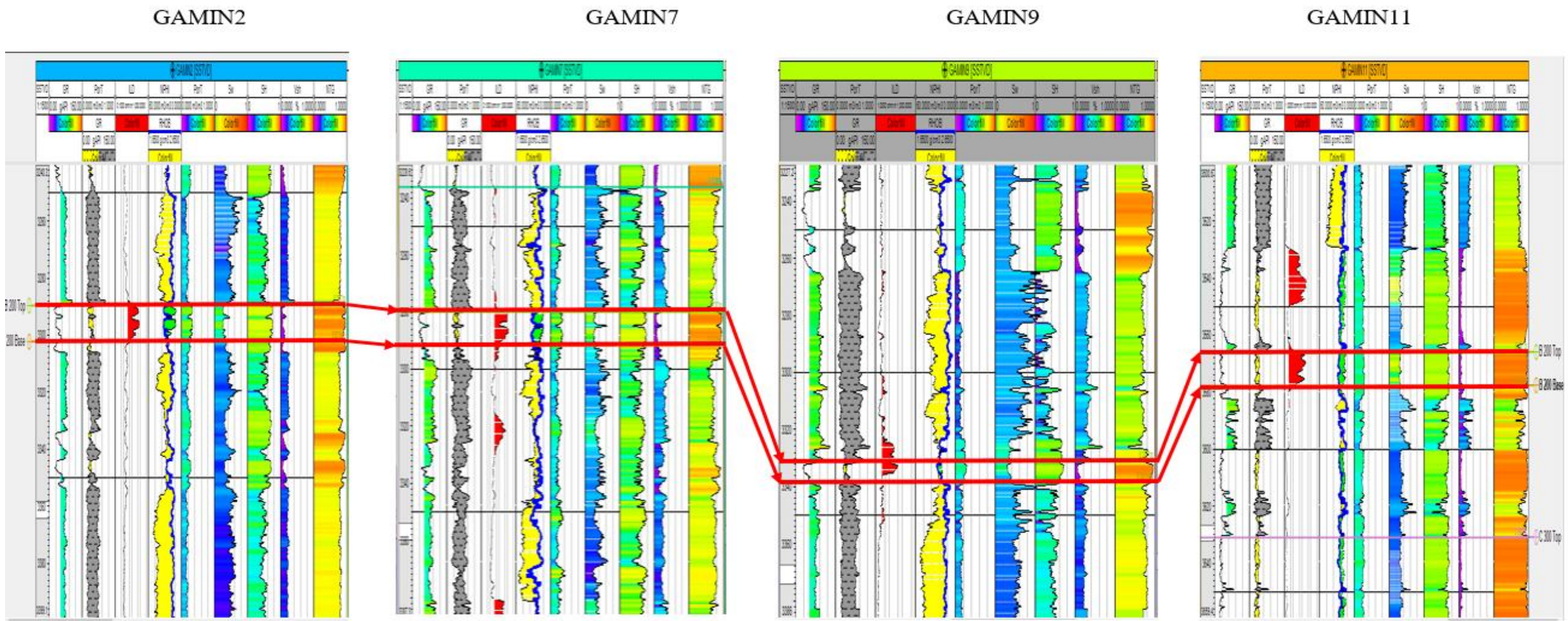

Figure 6: Correlation of Reservoir B across the wells

Correlation of Reservoir B across the wellsshowing continuity in stratigraphy at different depth.The wells (Gamin 2, Gamin 7, Gamin 9 and Gamin 11) were correlated for Reservoir B across tops at depths of 3290m, 3280m, 3332m and 3566m and bottom 3302m, 3292m, 3338m, 3578m respectively (as shown in Figure 6 above). The delineated formation for GAMIN7 with similar indices with GAMIN2 (shows high net-to-gross, low volume of shale, high porosity and high hydrocarbon). However the balloon shape of the Neutron-Density overlain logs, across the wells, with low density and low neutron indicates the hydrocarbon type as Gas.

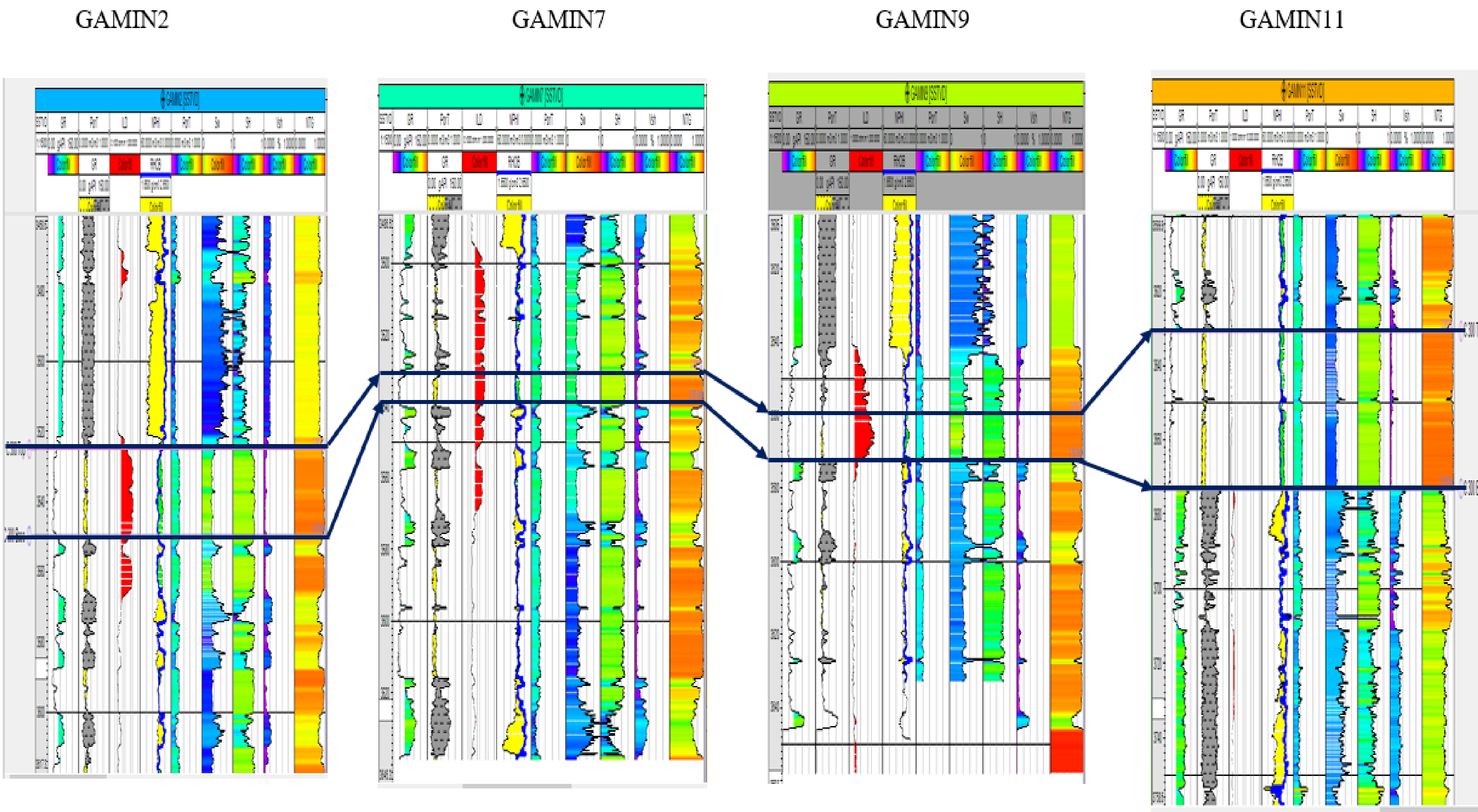

Figure 7: Correlation of Reservoir C across the Wells

Correlation of Reservoir C across the Wellsshowing continuity in stratigraphy at different depth.The wells (Gamin 2, Gamin 7, Gamin 9 and Gamin 11) were correlated for Reservoir C across tops at depths of 3525m, 3530m, 3559m and 3631m and bottom 3550m, 3539m, 3572m, 3673m respectively (as shown in Figure 7 above). This presents a petrophysical model of formation/Reservoir C for

GAMIN2, with high hydrocarbon recoverability (high Net-to-Gross, High porosity, low volume of shale) and Gas as the hydrocarbon type (balloon shape of Neutron-Density overlain logs).

Reservoir A, B and C confirmed that porosity, shale volume, net-to-gross, water saturation, and hydrocarbon saturation in the well logs as presented in Figures 5 to 7 indicates hydrocarbon potential of Kolo Creek. With high porosity and hydrocarbon saturation, all three reservoirs have good Well log characteristics. The proportion of the reservoir rock's pore volume that is filled with water is known as water saturation. The water saturation value ranges from 15% to 100%, while hydrocarbon saturation ranges from 0 to 85%. The constant 15% is called the irreducible water saturation. Unless otherwise stated, it is assumed that the pore volume that is not filled with water is filled with hydrocarbons. Four (4) well were used to determine the petrophysical parameters of the reservoir.

Table 1: A - Reservoir sand

Well	Fluid type	Porosity	Water saturation	Hydrocarbon saturation	Shale volume	Net-to-Gross
Well 2	Brine	0.27	0.30	0.70	0.04	0.96
Well 7	Brine	0.24	0.34	0.66	0.06	0.94
Well 9	Gas/Oil/Brine	0.23	0.35	0.65	0.08	0.92
Well 11	Brine	0.27	0.30	0.70	0.04	0.95

For reservoir A, the net-to-gross of the reservoir ranges from 0.92 to 0.96, and thus giving a volume of shale range of 0.04 – 0.08. The volume of shale in the reservoir had a direct effect on the porosity and the zones with high volume of shale had a reduced porosity. The porosities had values ranging from 0.23 – 0.27 (very good). Reservoir A has a water saturation range of 0.3 – 0.35, hence, its hydrocarbon saturation ranges from 0.65 – 0.7. The pay zones were fairly homogenous.

Table 2: B - Reservoir sand

WELLS	Fluid type	Porosity	Water Saturation	Hydrocarbon Saturation	Shale Volume	Net-to-Gross
Well 2	Gas/Brine	0.32	0.25	0.75	0.05	0.95
Well 7	Gas/Brine	0.34	0.24	0.76	0.05	0.95
Well 9	Oil/Brine	0.27	0.30	0.70	0.05	0.94
Well 11	Oil/Brine	0.28	0.30	0.70	0.04	0.96

For reservoir B, the reservoir sand is relatively very clean, with the volume of shale being between 0.04 and 0.05 and the net-to-gross ranging from 0.94 to 0.96. Well log analysis of this reservoir indicated reservoir Sand B to be the most feasible. The range of porosities are from 0.27 – 0.34 (from very good to excellent). Since the reservoir has hydrocarbon saturation more than 0.65 and good porosity values, the results indicate that it is producibl

Table 3: C - Reservoir sand

	Fluid type	Porosity	Water saturation	Hydrocarbon saturation	Shale volume	Net-to-Gross
Well 2	Oil/Brine	0.26	0.31	0.69	0.06	0.95
Well 7	Oil/Brine	0.28	0.30	0.70	0.05	0.94
Well 9	Oil/Brine	0.20	0.40	0.60	0.04	0.95
Well 11	Oil/Brine	0.29	0.30	0.70	0.05	0.95

For reservoir C, All the sands within the pay zones of this wells were satisfactorily homogenous. The volume of shale had values ranging from 0.04- 0.06. Porosities had values ranging from 0.2 – 0.29 (very good). The results also show hydrocarbon saturations range of 0.6 to 0.7. Seismic structural interpretation of the field revealshorizons showing various discontinued faults with 4-synthetic faultsand 2 antithetic faults (Figures 8 and 9), with continuity of the reservoir as shown in Figure 8. Computed petrophysical attributes (tables 1, 2 and 3) for the three delineated reservoirs favours the optimal prospectivity of the reservoir with very good quality and high porosity and hydrocarbon saturation.In the structural interpretation of inline 5714, three horizons were picked as seen in Figure 8. Synthetic faults shown in Figure 9 labelled Fault A, B, E and F (dipping downwards) and two antithetic faults were identified on the section. In other to ensure a good well-to-seismic tie is achieved, well tops of GAMINI-2 (the only well having a check-shot data) was superimposed on the seismic sections, hence intersecting each other. The two antithetic faults (FaultsC and D), synthetic, cut across the picked horizons as shown in Figure 8 and 9 below.

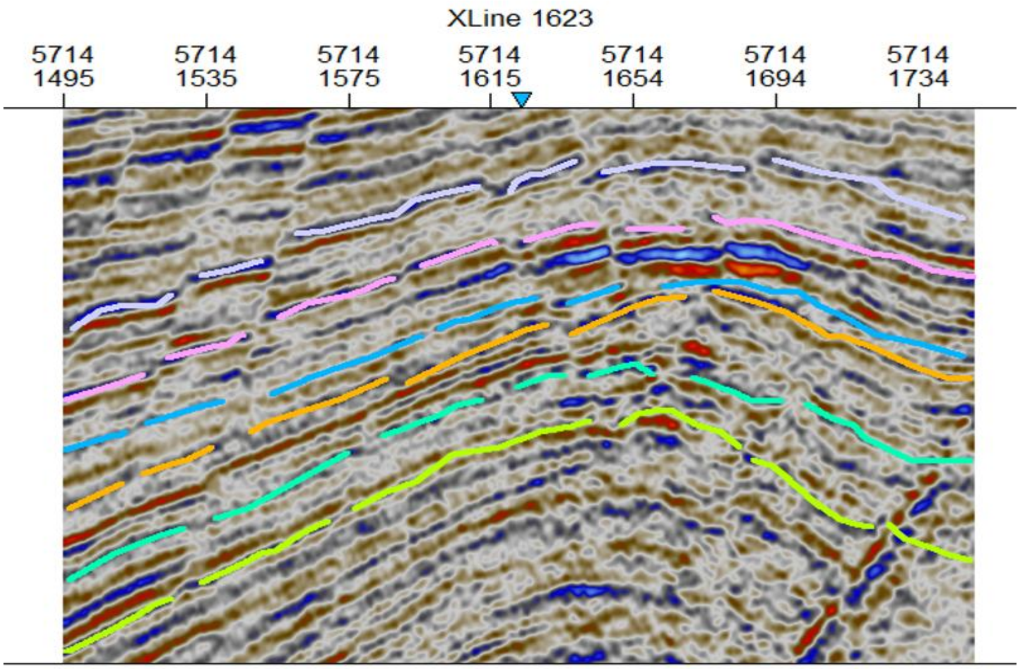

Figure 8: Mapped Horizons on the seismic section

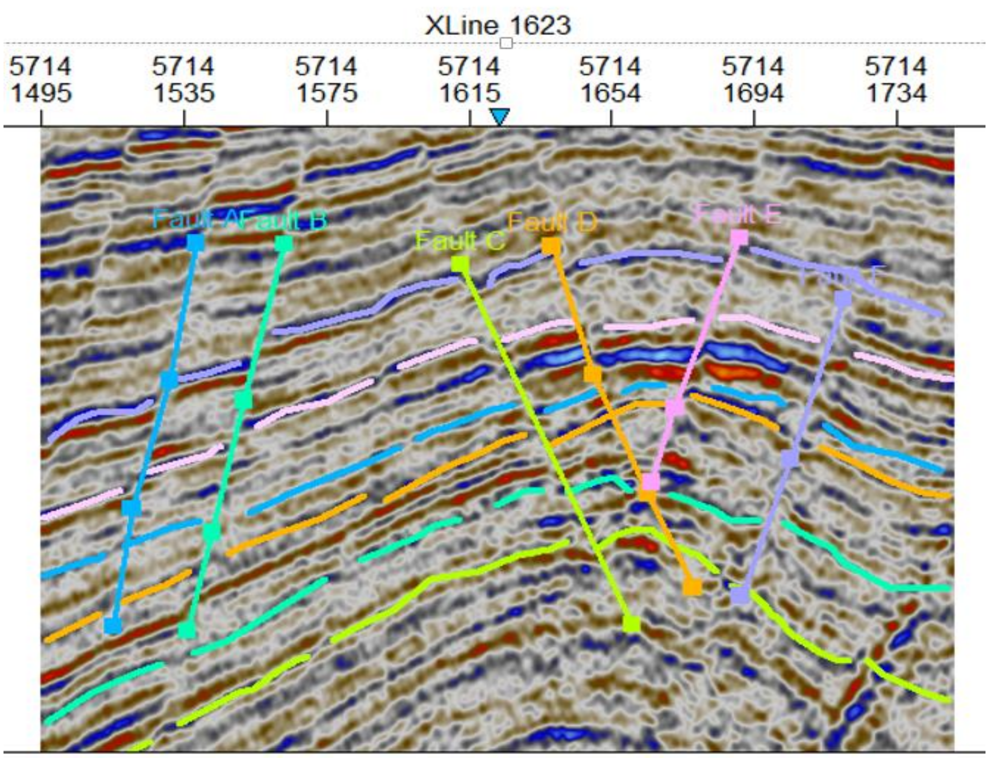

Figure 9: Mapped Discontinuity (faults) on the seismic section

Conclusion And Recommendation

Evaluation of the Kolo Creek, Niger Delta basin was done using well logs and seismic data volume. Well log correlation and petrophysical analysis was carried out using log suites from wells GAMINI 2, GAMINI 7, GAMINI 9 and GAMINI 11. The petrophysical parameters of Reservoir C showed that it had good reservoir characteristics to accumulate hydrocarbon (S_h>70%), Reservoir A contained more of brine, whilst Reservoir B, contained more hydrocarbon than brine. Petrophysical study conducted aided in accurately qualifying and quantifying identified hydrocarbon reserve which is applicable to well control studies.

The integration of seismic data and well logs proved to be a useful and valid tool in structure and stratigraphic mapping. From the well logs analysis three major reservoirs were identified.Theformation evaluations and reservoir characteristics of Kolo Creek revealed that the two major lithological units in the area to be sand and shale. Seismic interpretation showed that the field is highly faulted with faults forming structures for hydrocarbon entrapment and accumulation which is a confirmation of the fault types associated with the Niger Delta Basin as earlier described in chapter two. Seismic amplitude attribute map extracted from the top of the mapped Reservoir A showed that the reservoir is characterized by relatively high amplitudes in some areas. Further studies is thus recommended due to insufficiency of the available data especially for reservoir B and C to ascertain the actual volume of Oil in place which is also occasioned by none availability of check shot data on three out of the four of the wells used. This would aid in estimating volume for the entire area as covered in this research.

Acknowledgement

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