Petrophysical Properties and Reservoir Modeling of Kala Field, Eastern Niger Delta, Nigeria

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Abstract: - **This research is focused on Petrophysical properties of Kala Field Eastern Niger Delta and reservoir modeling. Data used for this research include 3-D Seismic in Seg-Y and suites of well logs. Normal faults trending NW-SE has been delineated on the seismic data of Kala Field. The lateral extent of reservoirs E and F have also been delineated in blocks (A, B and C) and modeled with the results of the petrophysical analysis. The results of the average petrophysical values of Reservoirs E and F in the delineated blocks are as follows porosity (25% for Block A, 25% for Block B, and 23% for Block C), permeability 291md for Block A, 300 md for Block B, 1990 md for Block C), Net-to-Gross ratio (for Block A is 0.74, for Block B is 0.80 and for Block C is 0.66 respectively), water saturation (for Reservoir A is 45%, , for Block B is 39%, and Block C is 37% respectively) and the Stock tank oil initially in place for Reservoirs E and F in Block A is 54.71 mm stb, B is 26.83 mm stb , and C is 15.47mm stb respectively. The results of the petrophysics petrophysical analysis shows that the porosity and permeability values within the Reservoirs E and F indicate significant accumulation of hydrocarbon in the studied reservoirs.**

Key Words: **Petrophysical properties, Reservoir Modeling, Niger Delta**

I. INTRODUCTION

Investigations are routinely carried out to evaluate and improve on knowledge of source and habitat of hydrocarbon such as in the Kala Field, Niger Delta. The various levels of investigation vital to understanding source and habitat of hydrocarbons can be derived from the information generated from the sedimentary basin, petroleum systems analysis, play, and prospect evaluations. In the petroleum industry, static modeling is required to create a computer model of petroleum reservoirs to increase the assessment of reserves and take necessary steps to improve field development. (Stephen, 2007). Petrophysics play an import role in characterizing and evaluating reservoirs of a permeable and porous unit (reservoir rock), the rock fluid properties in situ, which could aid the rate of recovery and quantity of oil produced. The study area is located in the eastern part of the Niger Delta (Figures 1 -2). The geology, stratigraphy, structural geology, sedimentology and petroleum geology of the Niger Delta is well established. See the works of Orife and Avbovbo (1982), Corredo *et al* (2005), Burke *et al* (1971, 1972), Heinio and Davis (2006), Cohen and McClay (1996), Whiteman (1982), Olade (1975), Murat (1972), Doust and Omatsola (1989, 1990), Ekweozor and Daukoru (1994), Ejadawe *et al* (1984), Evamy *et al* (1978), Haack *et al* (1997), Iheaturu and Ideozu (2017), Ideozu *et al* (2018), Akpan *et al* (2016), Selley (1978), Reijers, 1996; Kulke, 1995; Webber (1971) and Webber and Daukoru (1975). Stratigraphically, the Niger Delta sequence comprises Akata, Agbada and Benin Formations. See Figure 3-4.

Figure 1 Map of Study area

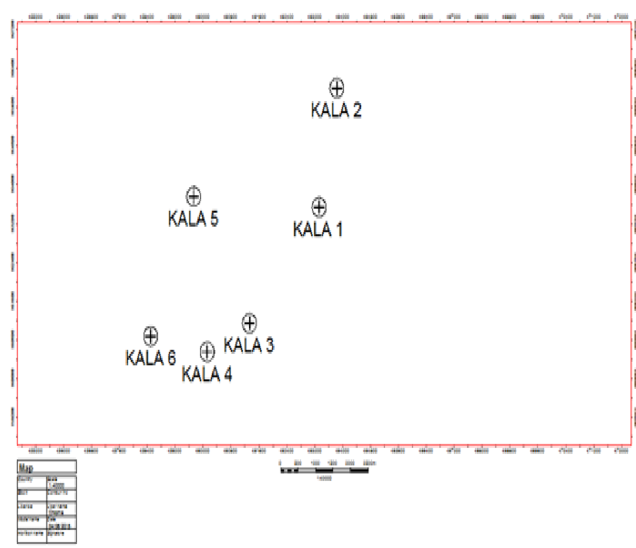

Figure 2 Distribution of wells within Study area.

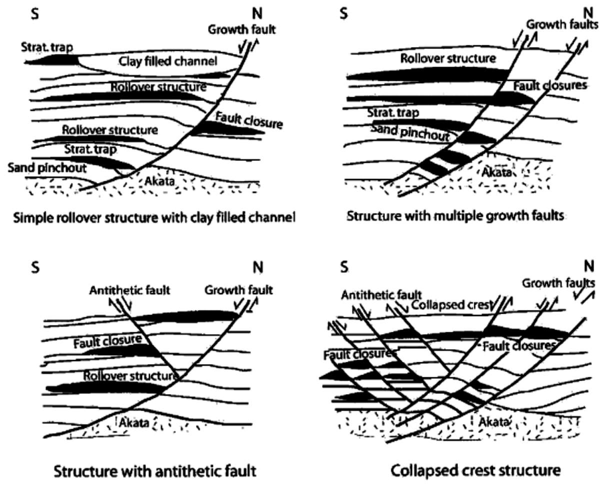

Figure 3 Niger trapping systems

(Modified from Doust and Omatsola (1990)

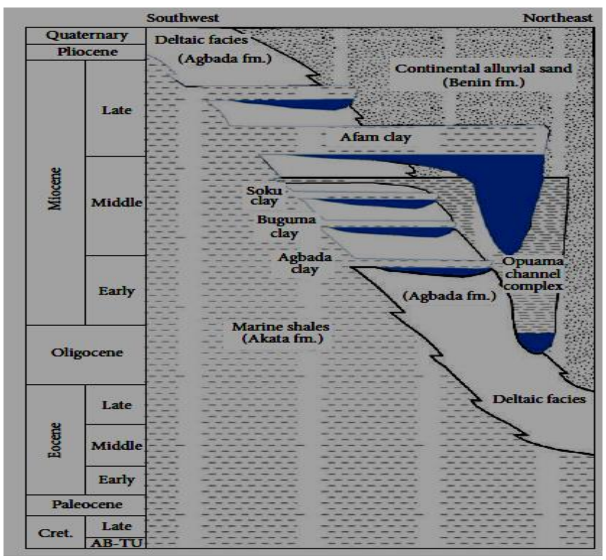

Figure 4 Stratigraphic structure of the Niger Delta

(Shanon and Naylor 1989; Doust and Omatshola (1990) and Stacher (1995).

II. MATERIALS & METHODS

Materials

Materials used in this research comprise well log and seismic data in Seg - Y

Methods

The methods used in this research is illustrated in in the flow chart below Figure 5.

Well Log Analysis and Well Correlation

Well log information was available for six wells in the field. The well header was created and the well logs for the wells were imported. Colour filling was done and the baseline for shale was set. Well correlation was done across the six wells kala 1, kala 2, Kala 3, kala 4, kala 5 and Kala 6. Log signatures from GR log, deep resistivity logs were utilized to correlate the wells

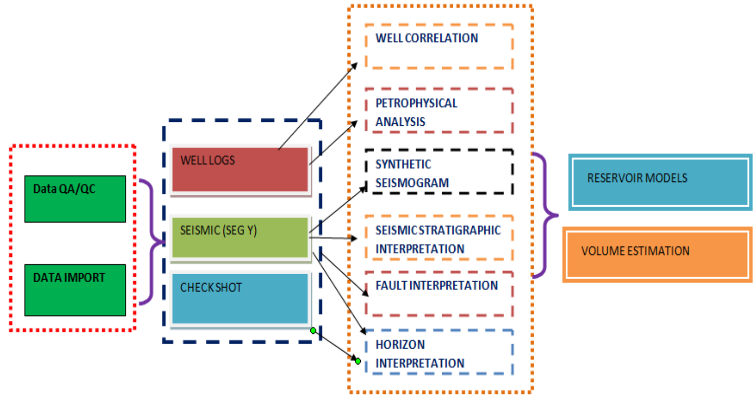

Figure 5 Workflow used in this research.

Seismic Data Analysis

The seismic volume is imported into the Petrel Software, cropping and realization has been done, to reduce the processing time stipulated for the seismic information, in addition to chopping away areas that are not required for the research, leaving only the regions of interest. From the crop-realized volume, inline and crossline and time slice are inserted. A 3D window and an interpretation window were opened to view and map the faults. The faults were mapped on the crosslines and the continuity viewed on the inlines.

Structural Analysis

The fault mapping carried out on the cross lines and the continuity viewed on the inlines.

An anomaly is a continuity division of any geological unit, which involves lateral or vertical displacement of a part of a rocky unit resulting from different geological processes.

The conditions for the fault mapping used are, (a) A sudden cessation of reflection (b) Displacement or distortion of the reflection. Normal faults trending NW-SE were picked from seismic and mapped.

Well To Seismic Tie

Tearpock and Bischke (1991), stated that once the well position is annotated on seismic, the information stemming from the well log were analyzed, geologic tops were recognized and noted on the seismic section. Well to seismic tie was carried out with the check shot data, Well-seismic ties allow well data usually measured in units of depth, and compared side by side with seismic data usually measured in units of time. These processes enable one to correlate horizon tops delineated on a well with a particular reflection on seismic section and this is done with the aim of recognizing how the events continue on both the seismic and the well. The different wells, reservoir peaks and troughs were visualized on a three dimensional window. This is superimposed over the seismic line to ensure correct seismic event and well linking. One of the key needs when tying logs to seismic is having a method of converting from depth to time units.

Petrophysical Evaluation

The following petrophysical parameters have been determined from each reservoir; Porosity (ϕ), Permeability (K), Water Saturation (Sw), Hydrocarbon Saturation (Sh), Gamma Ray Index (I_{GR}), Formation Factor (F), Volume of Shale (Vsh), Bulk Volume Water (BVW), Irreducible Water Saturation (Swirr), Net-to-gross and STOIIP of the formation were utilized to evaluate the reservoirs.

Porosity

Reservoir Porosity (ϕ) can be estimated directly with the availability of cores and indirectly using logs. The formation logs were utilized to determine the porosity (Frank et al., 2001). The porosity was determined by putting in the values of the bulk density read out from the density log in different reservoirs into the following equation (Dresser Atlas, 1979). Density derived porosity can be calculated with the equation below

$$\phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

(ϕ_{den}) = density derived porosity

ρ_{ma} = density of matrix (2.65g/cm^3 for sandstone)

ρ_b = bulk density

ρ_f = fluid density= 1.1gm/cm3 (fluid density),

The criteria used to classify porosity given by Schlumberger, 1985 is:

Ø < 0.05 = Negligible

0.05 < Ø <0.1 = Poor

0.1 Ø< 0.15 = Fair,

0.15 < Ø < 0.25 = Good

0.25 < Ø <0.30 = Very good

Ø > 0.30 = Excellent.

Permeabilty (K)

It is very vital in estimating well productivity, performance of the reservoir and hydrocarbon recovery (Frank et al., 2001). Owolabi et al. (1994) equation was used in determining permeability in this research. It is shown in the formula below.

Permeability $K = 307 + 26552\phi^2 - 34540(\phi \text{ x } S_w)^2$ (Owolabi et al., 1994)

Where, K = Permeability (millidarcies)

Swirr = irreducible water saturation

ϕ = porosity

Volume Of Shale (Vsh)

Shale volumes in the reservoirs were estimated with the use of the GR log. The gamma ray index is calculated using the equation below:

$$Gamma\ Ray\ Index\ (IGR) = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad \text{(Owolabi et al., 1994)}$$

Where:

IGR = GR index,

GRlog = GR value of the reservoir

GRmin =Lowest gamma ray value (for clean sand),

GRmax = Highest gamma ray value (shale).

After calculating the GR index, the value obtained is the substituted in the equation below to estimate shale volume in the reservoir (Dresser Atlas, 1979).

$V_{sh=}\ 0.083(2^{3.7\times IGR} - 1.0)$ (Tertiary consolidated sand)

Water Saturation (Sw)

Water saturation (S_w) estimation is the most demanding of all petrophysical calculations. The hydrocarbon saturation,

$S_{h,}$ $(1 - S_w)$.

$S_{w\,=}$ 0.082 (Udegbunam et al., 1988)

Hydrocarbon Saturation

Hydrocarbon saturation can defined as that fraction of pore space that contains hydrocarbons. It is depicted by symbol Sh.

$S_h = (1 - S_w)$.

Where Sh = hydrocarbon saturation,

Sw = water saturation

1 = unity

Formation Factor

Formation factor is a function of porosity and the type of rock. The formation factor within the target depth interval was calculated with the Humble's formula of best averages for sandstones and unconsolidated formations.

$F = \frac{0.62}{\phi^{2.15}}$

Where F = formation factor

(ϕ) = porosity

Irreducible Water Saturation (Swi)

This is the water that is occupied in the pore spaces by forces known as the capillary forces. For most reservoir rocks, "Swi" ranges from less than 10% to greater than 50% (Schlumberger, 1989). It was determined from the equation given by Asquith and Gibson (1982)

$$S_{wi} = \sqrt{\frac{F}{2000}}$$

Estimation of the Pore Volume of Hydrocarbon (HCPV)

This is the portion (represented in fractions) of the reservoir volume occupied by

hydrocarbon. It is estimated with the formula below

$$HCPV = \emptyset_{den} \times (1 - S_w) \times V$$

Where ϕden is the average porosity obtained from density log, the volume (V) is the product of the area of the closure obtained from depth structure map and the reservoir thickness

Net-To-Gross

It is the ratio of the productive sand body thickness to the gross thickness observed in the reservoir. Net-to-gross can be estimated by using the wire line gamma ray logs. . Shales are usually non-productive can be differentiated from clean or non-shaly formations by measuring and differentiating natural radioactive levels along the borehole (Frank et al., 2001). For this research work, N/G was calculated with the aid of PETREL using:

$$N/G = \frac{\Sigma h_i}{H} = \frac{\text{Net reservoir}}{\text{Gross reservoir}} \quad \text{(Asquith 2004)}$$

Hydrocarbon Water Contact

Hydrocarbon water contact shows the elevation above which fluids usually not water can be found in the rock pores. The resistivity log has been used to delineate the hydrocarbon/water or gas/water contacts.

Volume Estimation

Volume estimations shows the quantity or how much hydrocarbon exists in an accumulation. Stock-tank oil initially in place (N_f) is the volume of hydrocarbon in a reservoir prior to production. (Frank et al., 2001). For this research work, STOIIP was calculated using:

$$STOIIP = \frac{A \times H \times \emptyset(1 - S_w) \times 7758 \times NTG}{\beta_o}$$

Where; STOIIP = Stock Tank Oil Initially in place.

7758 = barrels per area foot

A = drainage area in acres

H = reservoir thickness in ft.

$\emptyset$ = porosity in decimal

S_H = (1-Sw) hydrocarbon saturation in decimal

NTG= Net to Gross

B_o =oil formation volume factor

$$B_o = 1.05 + 0.5 \times \frac{GOR}{100}$$

$$\text{GOR (gas-oil ratio)} = \frac{\text{Gas in cubic feet}}{\text{oil in barrels}}$$

III. RESULTS AND DISCUSSION

The results of this research is presented in Figures 6 -36 and Tables 1 -3.The approach used in this research is focused on prospect evaluation of the reservoirs in Kala Field using seismic stratigraphy, petrophysical and reservoir modeling techniques. The reservoir sands in Kala Field were mapped for closures or structures that may have an efficient trapping system appropriate for hydrocarbon buildup, development and production. These are necessary for predicting the horizons into areas where well control may be lacking. The identification of various facies using the Gamma Ray Log was carried out based on recognition of well logs responses. The identification of faults and mappable horizons was identified on the well logs.

Well Log Interpretation

Well correlation of Wells in Kala Field wells was based on the use of Gamma Ray and resistivity logs. Reservoir sands and shale sequences were established, in addition to identifying the well tops and bases See Figures 7 -8. The overall stratigraphic framework of the wells shows of alternations of sand and shale layers. There is an increase in shale layer with depth and a corresponding decrease in sand layer with depth is an indication of transition from Benin to Agbada Formation.

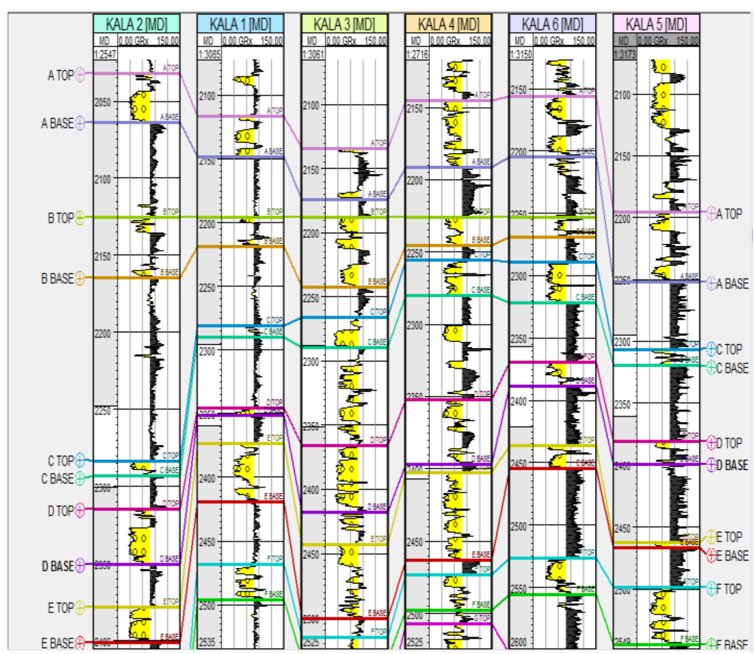

Figure 6: Well correlation of sands A to E

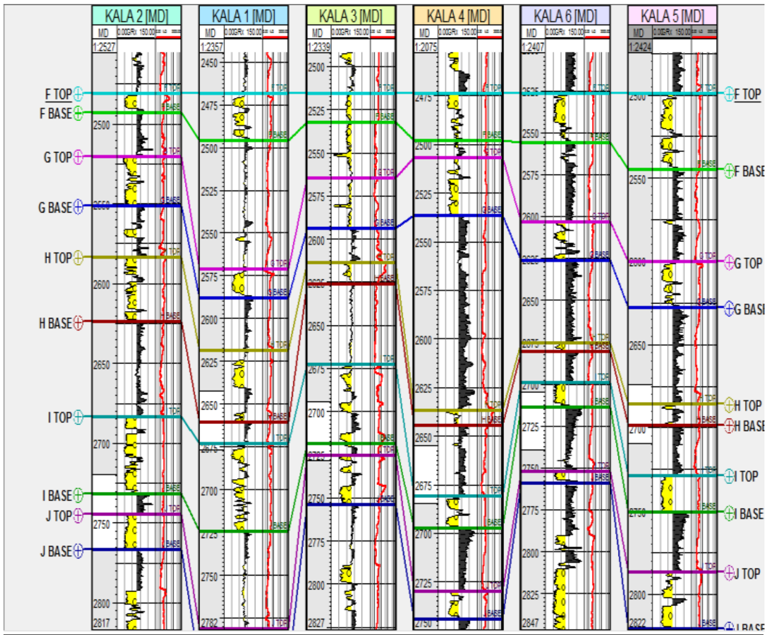

Figure 7: Well correlation of sand F to J

Fault Interpretation and Horizon Interpretation

Normal faults in Kala Field trend NW-SE and have been identified on seismic section. Four faults have been mapped and shows that Kala Field is a complex south-west dipping anticlinal closure. See Figures 8 - 9). The horizons of reservoir tops were picked and ensured that the interpretation process is consistent. Two horizons with hydrocarbon bearing reservoirs E and F were delineated and mapped. Horizons E and F were identified at the time levels of 1900ms and 2000ms on the seismic section. The depth equivalents of these horizons are 2350m and 2460m respectively. See Figure 10 - 11.

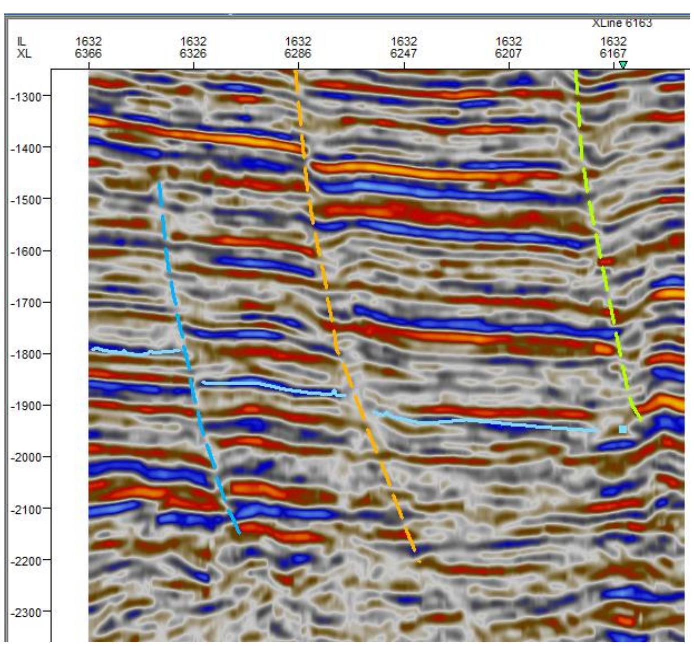

Figure 8: Interpreted Faults

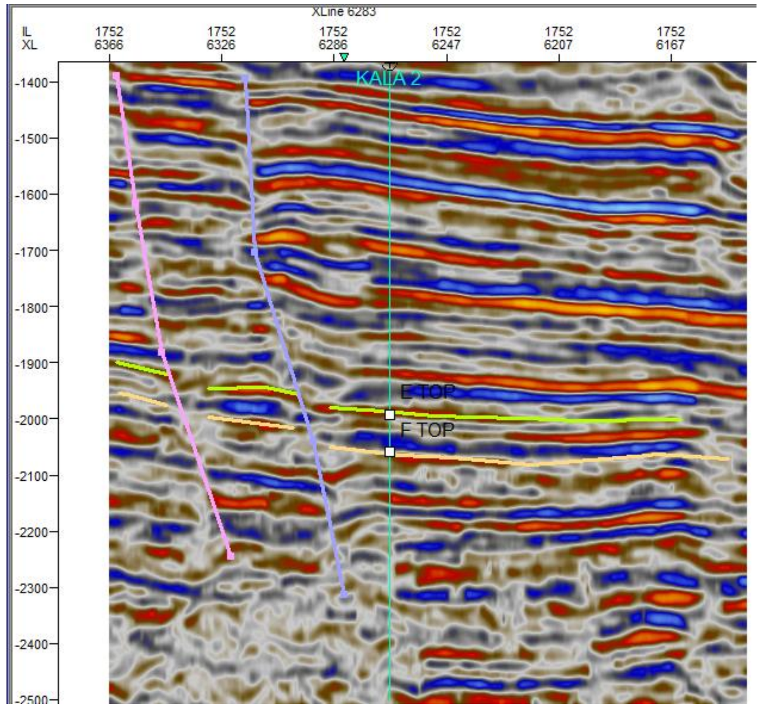

Figure 9: Interpreted horizon E and F

Time and Depth Map

Time and depth structural maps were produced for the two horizons defined on top of sand bodies, namely, Horizon E and F (Figure 8 and 9). Both types of structural contour maps show similar structural relationship. Figure 14 shows the representation of depth structural map of horizon-E. The depth map revealed the crest of the anticline at the depth of 1,900ft, which tied with what was obtained on the well logs. The anticline dip closure establishes the trap for this reservoir. The throw of the fault range indicate that these faults are sealing based on (Whiteman , 1982) which postulated that faults are still conductive as long as their throw is less than or equal to 500ft. Since it is less than 500ft it is adjusted sealing because it will be justaposed by shale which is impermeable and will prevent the migration of hydrocarbon. The overall depth at which the reservoir is located from the depth map ranges from 1500ft to 2500ft. Figure 12 – 15 shows the depth structural map of horizon F. Horizon F has similar features with horizon E. On the depth structural map the up dip areas were seen with closure signifying probable anticlinal structures where hydrocarbon could be trapped. This can serve as potential location where wells can be penetrated to improve development of the sands in the reservoir within the field using the reservoir models generated.

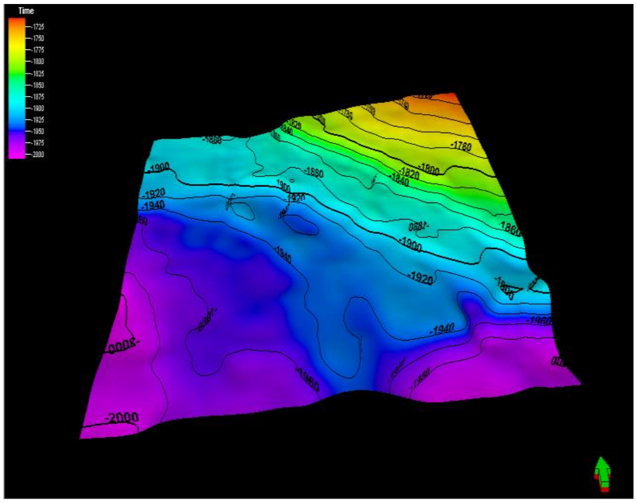

Figure 10: Reservoir E time surface map

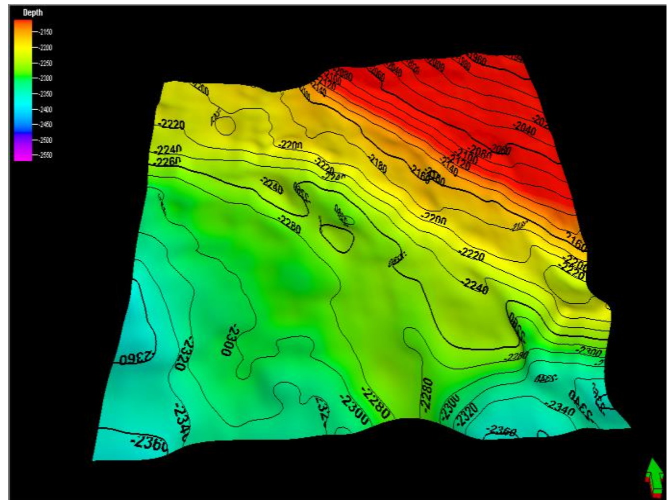

Figure 13: Reservoir F depth map

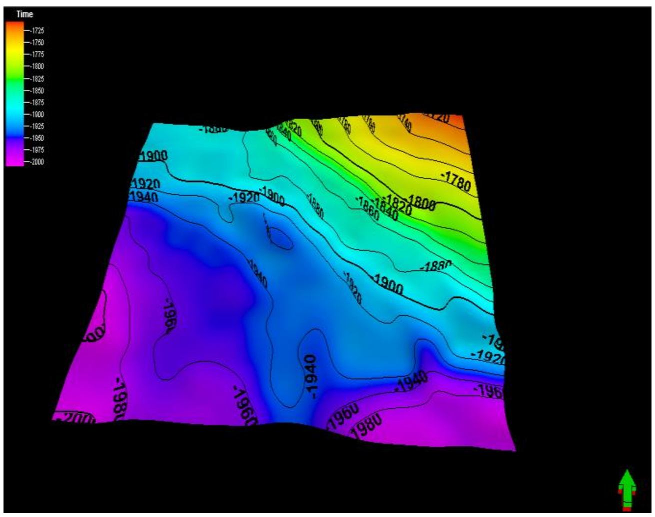

Figure 11: Reservoir F time surface map

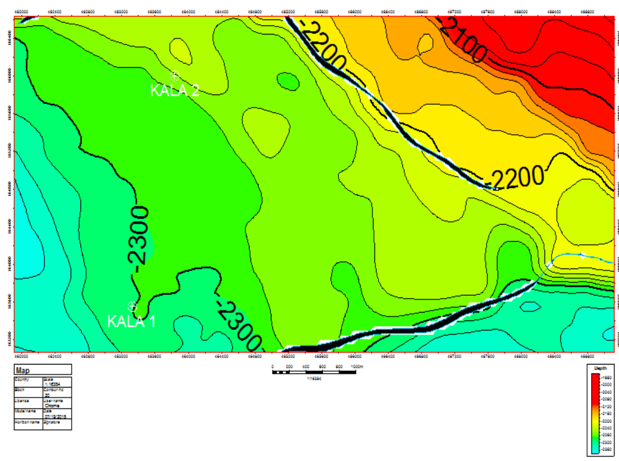

Figure 14: E top Structural map

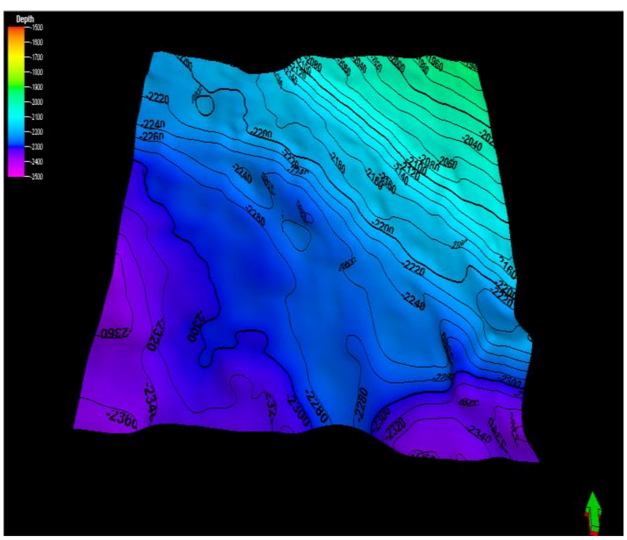

Figure 12: Reservoir E depth map

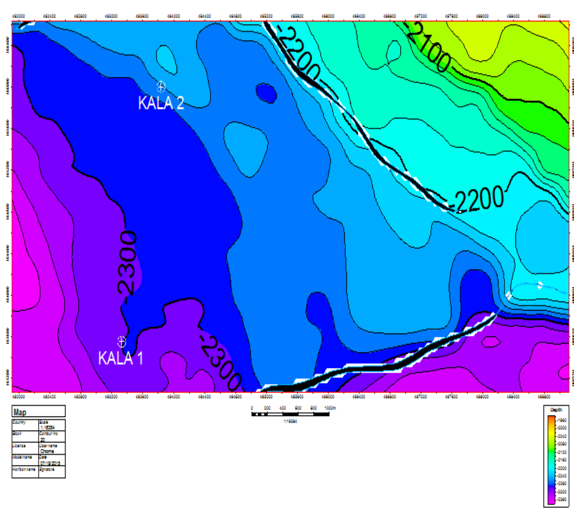

Figure 15: F top Structural map

Reservoir Models

The modeling reservoirs in the oil and gas industry helps to facilitate assessments of the field. The modeling Kala Field depends on the state of the input data, the quality of the geophysical and petrophysical interpretations of the field and the profit potential of the field. Reservoir models was generated for petrophysical parameters such as porosity, permeability, Net-to-gross, and water saturation. The two horizons interpreted were grouped into three blocks A, B and C. Block A and C showed good petrophysical values (Figure 16 - 17).

The Oil water contact and the distribution of fluid was delineated using the resistivity log and the results shows that block B in both Reservoir E and F is predominantly water, while block A and C in both reservoirs contain hydrocarbon of commercial importance. (Figure 18 -24).

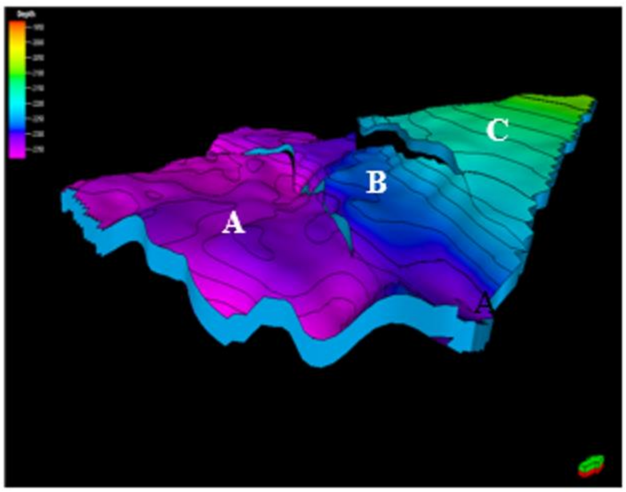

Figure 16: E Reservoir Model

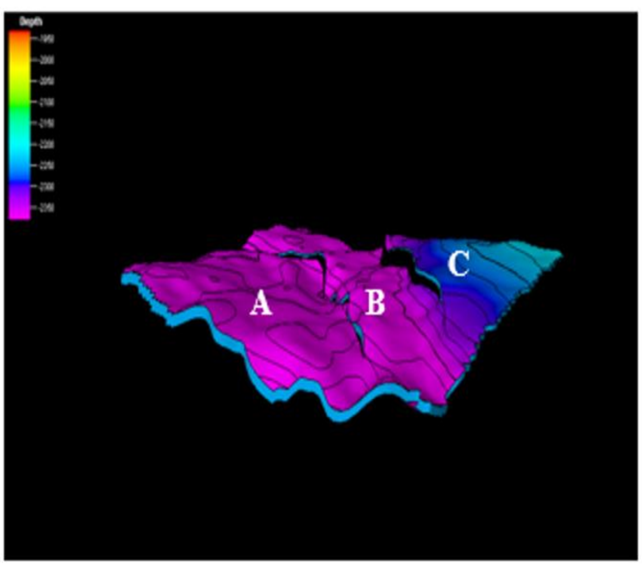

Figure 17: F Reservoir Model

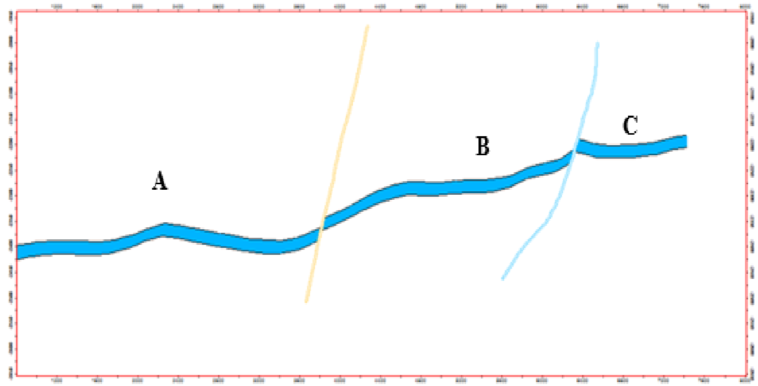

Figure 18: Cross section of E Reservoir

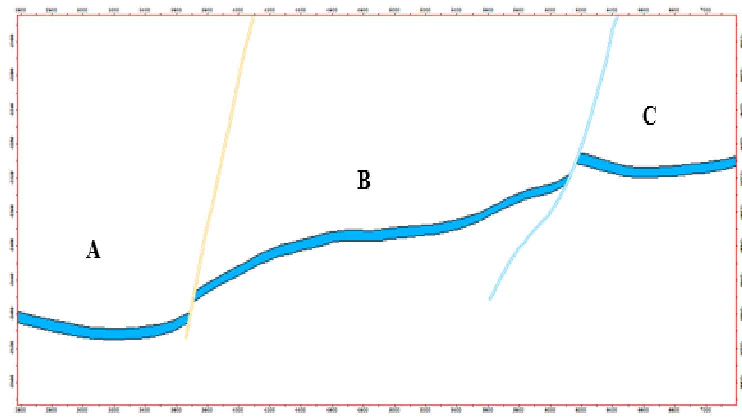

Figure 19: Cross section of F Reservoir

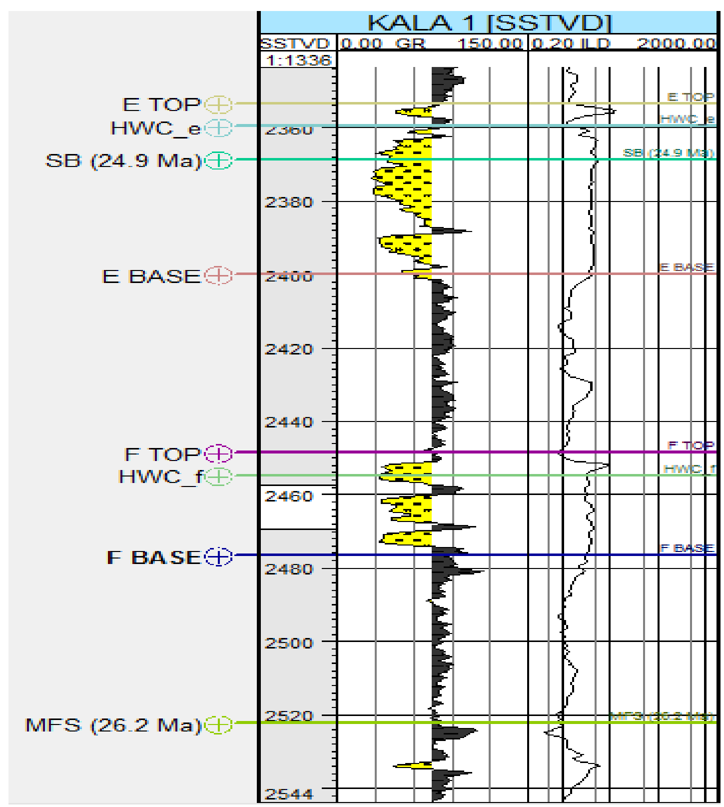

Figure 20: Contact delineation for Reservoir E and F

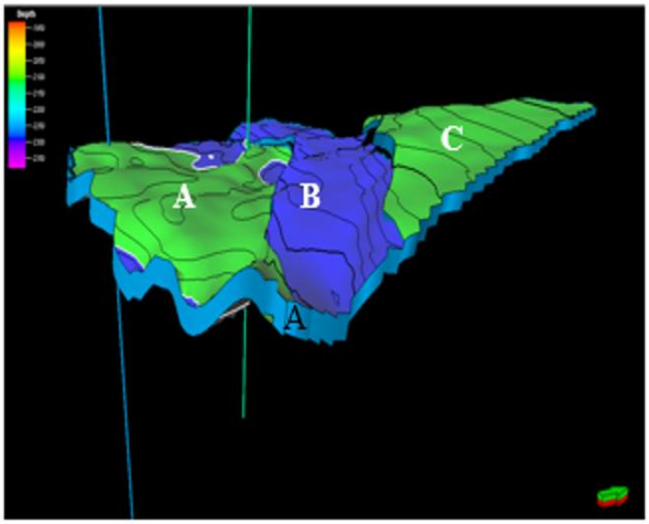

Figure 21: Reservoir E fluid distribution

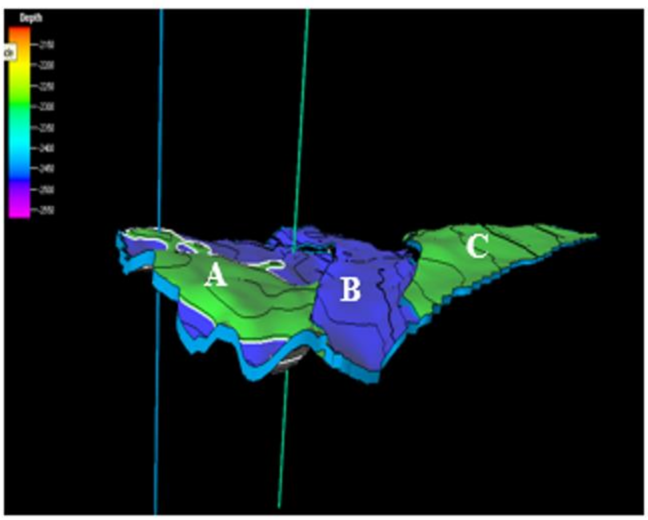

Figure 22: Reservoir F fluid distribution

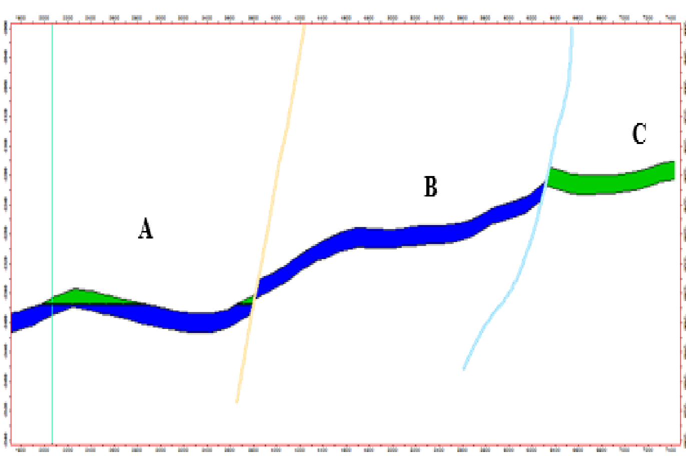

Figure 23: Cross section of fluid distribution for Reservoir E

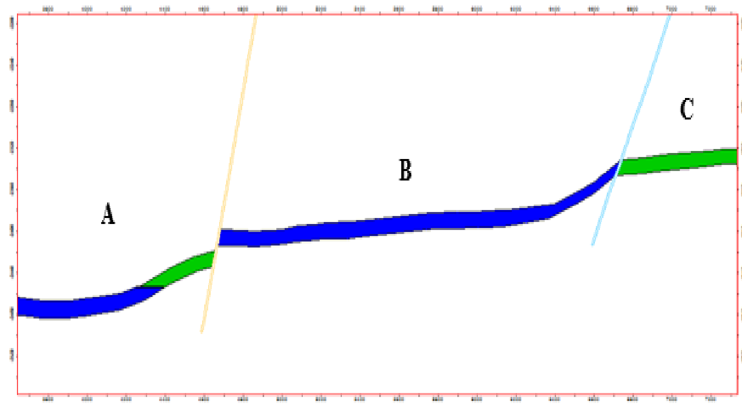

Figure 24: Cross section of fluid distribution for Reservoir

Petrophysical Interpretation

A reservoir is a rock in the subsurface with excellent petrophysical properties like porosity and permeability and can also contain appreciable quantity of hydrocarbon of good economic value. Characterizations of the reservoirs were carried out to ascertain and predicts its hydrocarbon possibilities. Characterizing a reservoir deals with the determination of reservoir properties/parameters such as porosity (Φ), permeability (K), fluid saturation, Net-to-gross among others. The petrophysical curves of two wells "Kala 1" and "Kala 2" was done and it indicated that reservoir E and F petrophysical attributes are economically viable (Figure 25 - 26).

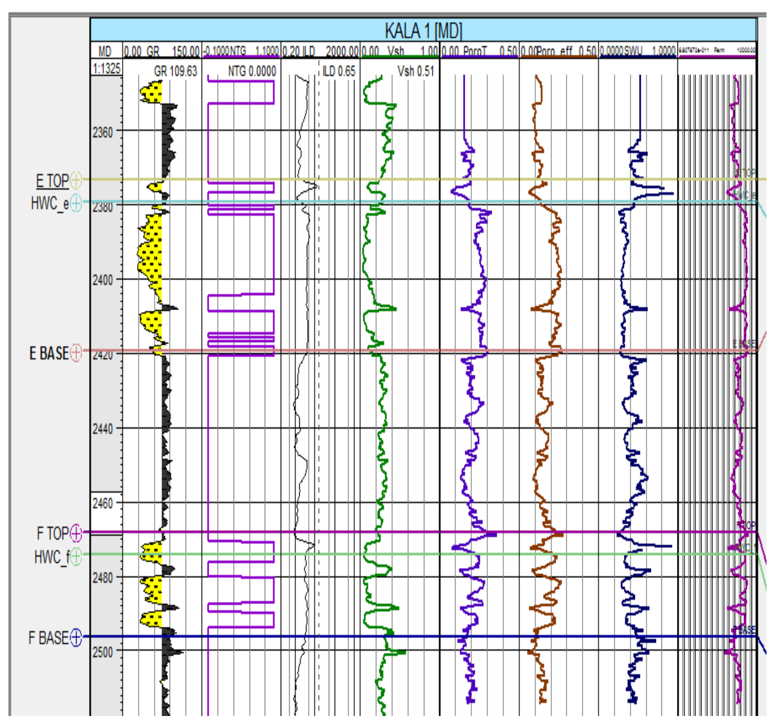

Figure 25: Petrophysical curves for Kala 1

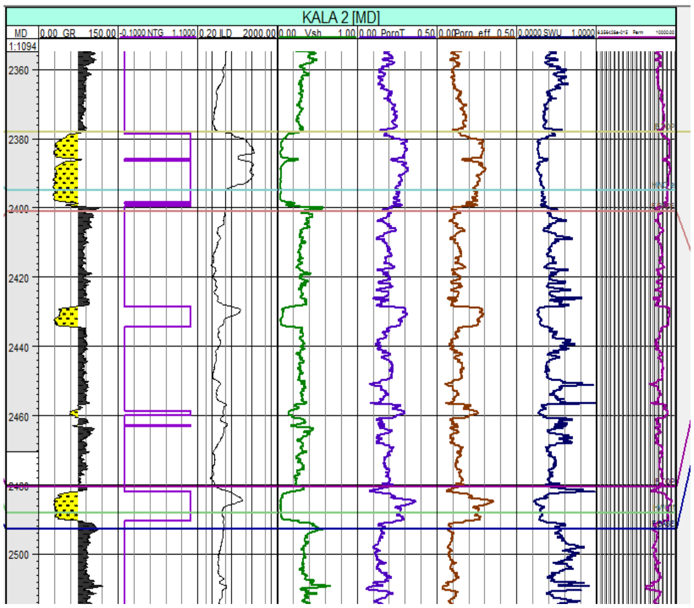

Figure 26: Petrophysical curves for Kala 2

Porosity Model

Porosity is a measure of free space in a reservoir. It is defined as a fraction of the volume of the void space above the total volume between 0 and 1 as a percentage, which is between 0 and 100%. The porosity of the rock plays a fundamental role in assessing the hydrocarbon or potential hydrocarbons in the reservoir. Blocks A and C in Reservoirs E and F have porosity values of 25%, 25%, 22% and 23% respectively. These porosity values indicated that the reservoirs have excellent porosities to accommodate appreciable quantity of hydrocarbon. See Figures 27-28.

Permeability Model

One important parameter generated in reservoir modelling is the permeability model is used in dynamic simulation of permeability. It may define the dynamic flow character of the model in the reservoir. The model below shows that the permeability values of block A and C of both reservoir E and F are 291md, 300md, 1850md and 1990md respectively, indicating it is a good reservoir. See Figures 29-30.

Net-To-Gross Model

The Net-to-Gross is the portion of the reservoir volume that is filled with hydrocarbon. It is determined based on the volume of shale in the reservoir. The Net-To-Gross of Kala Field was modeled using the Petrel software and displayed between 0 and 1, or as a percentage between 0 and 100%. Large quantities of hydrocarbon bearings, the A and C blocks of reservoir E and F represent a strong likelihood that is evident in the high net-to-total value. See Figures 31-32.

Water Saturation Model

The water saturation model in blocks A and C of the Kala Field suggests a low water saturation which in turn indicates a high hydrocarbon saturation, Block B having high water saturation was not captured in the water saturation model. Areas with 100% water saturation were cut off. See Figures 33-34.

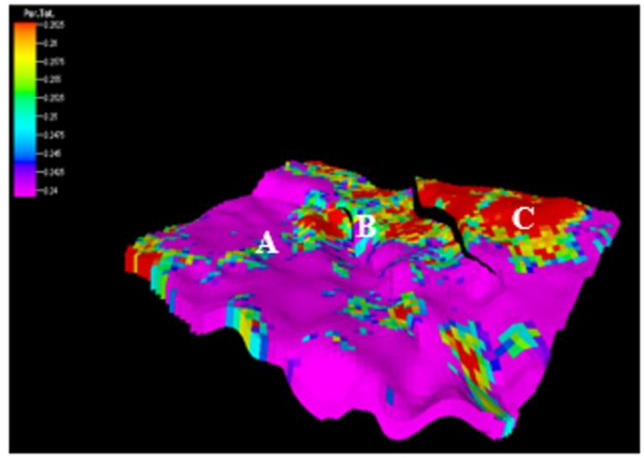

Figure 27: Reservoir E porosity Model

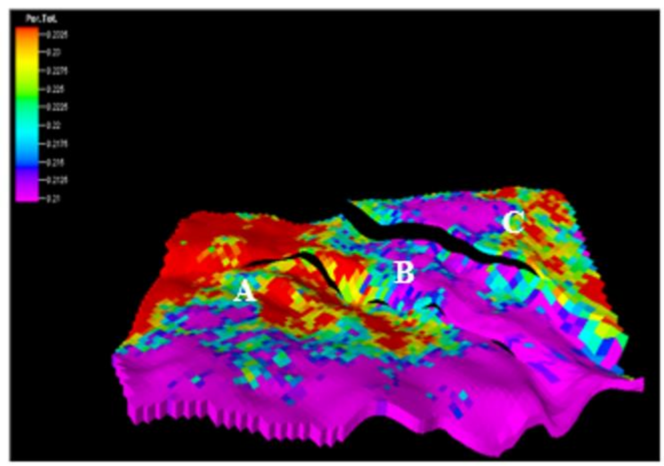

Figure 28: Reservoir F porosity Model

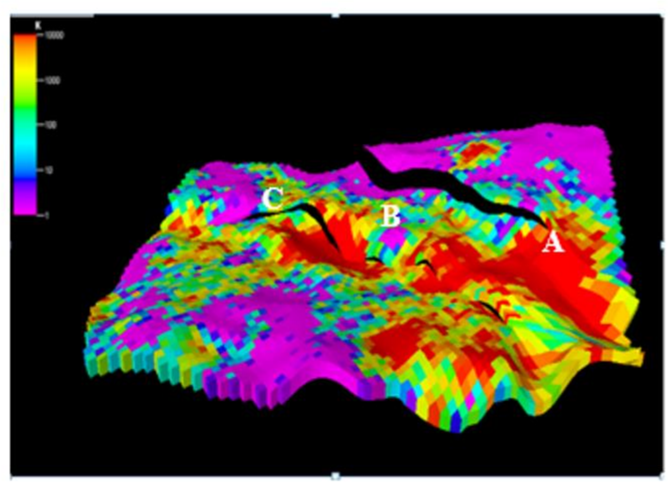

Figure 29: Reservoir E Permeability Model

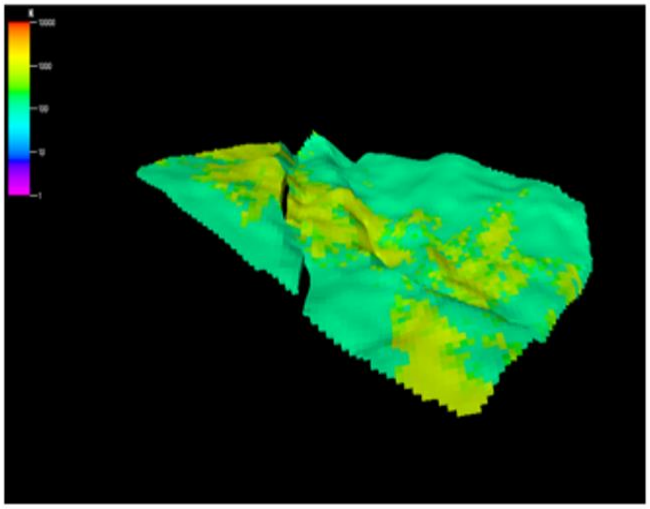

Figure 30: Reservoir F Permeability Model

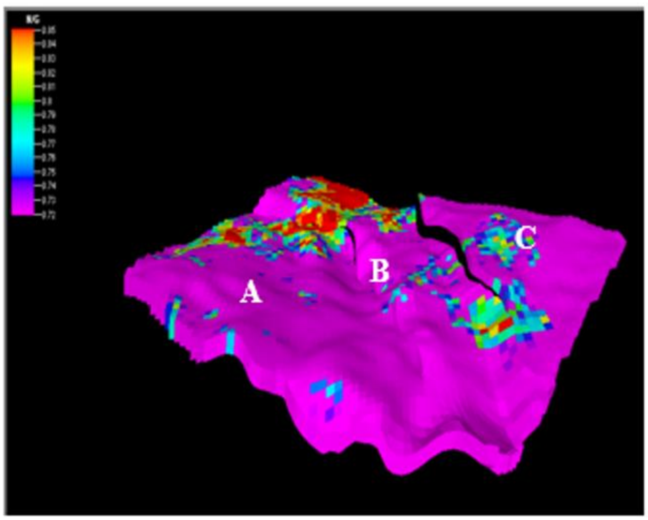

Figure 31: Reservoir E NTG Model

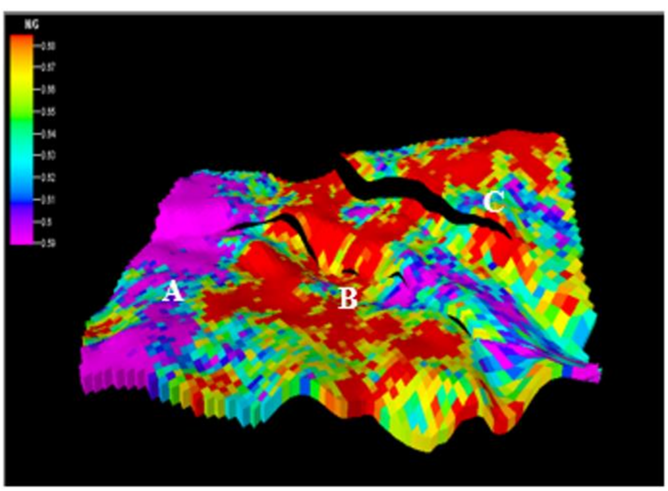

Figure 32: Reservoir F NTG Model

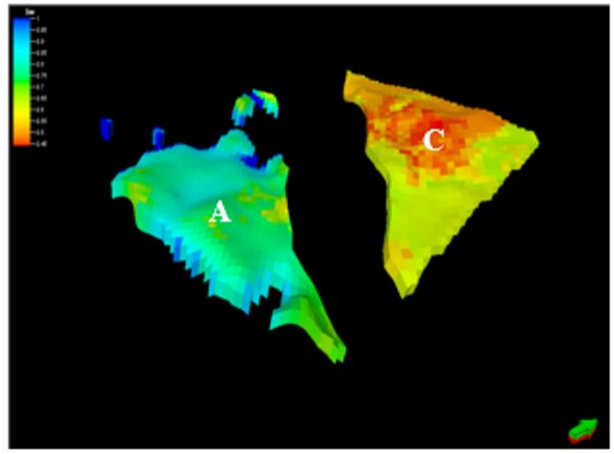

Figure 33: Reservoir E Water Saturation Model

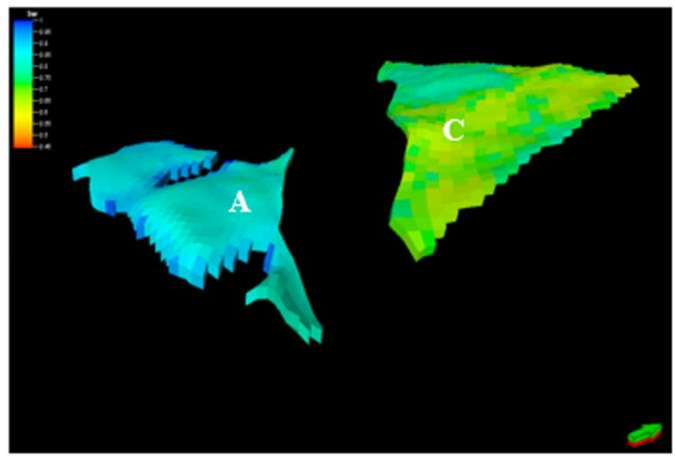

Figure 34: Reservoir F Water Saturation Mode

Prospect Evaluation of Kala Field.

Table 1: Average Petrophysical values for block A and C

Properties Reservoir	**NTG %**	**Porosity %**	**Permeability (MD)**	**Water Saturation %**
RESERVOIR E (Block A)	74	25	291	0.45
RESERVOIR E (Block C) Prospect 1	**80**	**25 (Very Good)**	**300 (Very Good)**	**0.34**
RESERVOIR F (Block A)	64	22	1850	0.39
RESERVOIR F (Block C) Prospect 2	**66**	**23 (Very Good)**	**1990 (> 1000- Excellent)**	**0.37**

Table 2: Reservoir E Volume Estimation

Case	Bulk volume	Net volume	Pore volume	HCPV oil	HCPV gas	STOIIP (in Oil)
CASEF	418	303	74	48	0	81.54
Zones						
Zone 1	418	303	74	48	0	81.54
Segments						
BLOCK A	284	205	50	32	0	54.71
BLOCK B	0	0	0	0	0	0.00
BLOCK C **Prospect 1**	**134**	**98**	**25**	**16**	**0**	**26.83**

Table 3: Reservoir F Volume Estimation

Case	Bulk volume	Net volume	Pore volume	HCPV oil	HCPV gas	STOIIP (in Oil)
CASEF	161	106	23	14	0	23.55
Zones						
Zone 1	161	106	23	14	0	23.55
Segments						
BLOCK A	107	70	15	9	0	15.47
BLOCK B	0	0	0	0	0	0.00
BLOCK C **Prospect 2**	**55**	**36**	**8**	**5**	**0**	**8.08**

Table 4: Volume Comparison

Reservoir	STOIIP (*10^6STB)
RES E (Block A)	**54.71**
RES E (Block C) Prospect 1	**26.83**
RES F (Block A)	**15.47**
RES F (Block C) Prospect 2	**8.08**

IV. CONCLUSION

Reservoirs E and F are two hydrocarbon bearing horizons delineated and mapped and has been identified at time levels of 1900ms and 2000ms on the seismic section with depth equivalents of these horizons being 2350m and 2460m respectively. Structural traps have partitioned Reservoirs E and F into blocks A, B and C. Blocks A and C are hydrocarbon bearing while B is water bearing. The petrophysical values of the reservoir E and F have indicated large accumulations of hydrocarbon pore fluid. Whereas the stock tank oil initially in place showed economic viability. These methods provide a basis for elucidating those geological factors that directly influence the areal distribution of reservoirs, facies, geometries, qualities and eventually the establishment of petroleum trapping mechanism in prospect area

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