ISSN: 2639-7536

Research Article

Petroleum and Chemical Industry International

Reservoir modeling and petrophysical evaluation of kanga field onshore Niger delta.

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Submitted: 28 July 2021; **Accepted:** 05 Aug 2021; **Published:** 12 Aug 2021

Citation: *Okolie O., Ideozu R.U., Chiazor F.I. (2021). Reservoir modeling and petrophysical evaluation of kanga field onshore Niger delta. Petro Chem Indus Intern, 4(2), 43- 48.*

Abstract
Reservoir sands from seven wells in Kanga Field in the Onshore Niger Delta was subjected to both petrophysical evaluation and reservoir modeling. Methodologies used are standard methods used in reservoir modeling and petrophysical evaluation. Results from reservoir modeling, shows that six synthetics and four antithetic faults have been identified and these faults are the main structural closure for hydrocarbon accumulation in Kanga Field. Petrophysical analysis showed porosity ranging from (25-27%), (16-27%) and (11-17%) for J100, K100 and L100 respectively. Modeled porosity showed high porosity in J100 and the central part of K100 reservoir. While, low porosity/; is recorded in L100. Water saturation ranges from 20 to 90% in the J100 reservoir, the lowest water saturation value was at the NE, NW and central part of the reservoir. Oil water contact reveals pockets of hydrocarbon in J100 and L100 reservoir. The bulk volume of hydrocarbon saturation closure is (21,954.37) arceft, (209,613.7) acreft and 46,025.51) acreft for J100, K100, and L100 reservoirs respectively. The estimated volumetric for P90 are (4,648,755.06) STB, (16,545,452.38) STB and (9,976,551.38) STB respectively. This study de that the field is viable for hydrocarbon exploration.

Keywords: *Reservoir, Modeling, Petrophysical evaluation and Facies*

Introduction

The high energy demand globally, especially in Nigeria has necessitated the use and search for advanced and better ways to improve oil field development. Investigating the spatial variability of saturating reservoir fluids (hydrocarbon) is a significant aspect of oil and gas production. Hence, the need to integrate reservoir modeling techniques to identify bypassed hydrocarbon prospect and increase prognosis with petrophysical analyses. Modeling helps in recognition and prediction of reservoir, seal and source-rock facies, in addition to reducing uncertainties at the exploration stage and improving correlation of reservoir exploitation; (Opdal, 2000). The application of modeling to study the lateral variation in terms of fluids in reservoirs may be useful as it helps measure the lateral continuity or extent of the reservoir when seismic data is not available and thus reduces loss in oil/gas exploration (Adeoye and Enikanuselu, 2009)

This paper aims at using reservoir modeling and petrophysical evaluation to identifying major compartments of a reservoir fluid volumes and fluid movement during production. This will contribute to a better understanding of the resources for optimal production.

Geology of the Niger Delta

The Niger Delta Basin is situating within the Gulf of Guinea, Equatorial West Africa and occupies an area of about 75.000km with average thickness of 12,000m. It is located within Latitudes 30 N and 6 0N and Longitudes 50 E and 80 E (Reijers et al, 1996). The Niger Delta is bounded to the northwest by the subsurface continuation of the West African Shield, and the Benin Flank. The eastern edge of the basin coincides with the Calabar Flank to the south of the Oban Masif (Murat, 1972). On the west, the delta it is separated from the Dahomey basin by the Okitipupa Basement High, and on the east, by the Cameroun Volcanic Line. Its northern margin transects several tectonic elements. The delta has prograded southwest-ward, forming depobelts which represent the most active portion of the delta at each stage of its development from the Eocene to the present, (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of about 300,000 km2 (Kulke, 1995)

The tertiary deltaic complex was divided into three depositional lithofacies identified as the Akata Formation, Agbada Formation and Benin Formation respectively (Short and Stauble, 1967). Agbada Formation constitutes the main reservoir of hydrocarbon in the Niger Delta.

Location of the Study Area

The Study Area is located within the Central Swamp Depobelt, Onshore Niger Delta., The field lies between Longitudes 5˚00'00'' N and 8˚00'00'' N and Longitudes 4˚00'00'' E and 6˚00'00'' E. See Figure 1

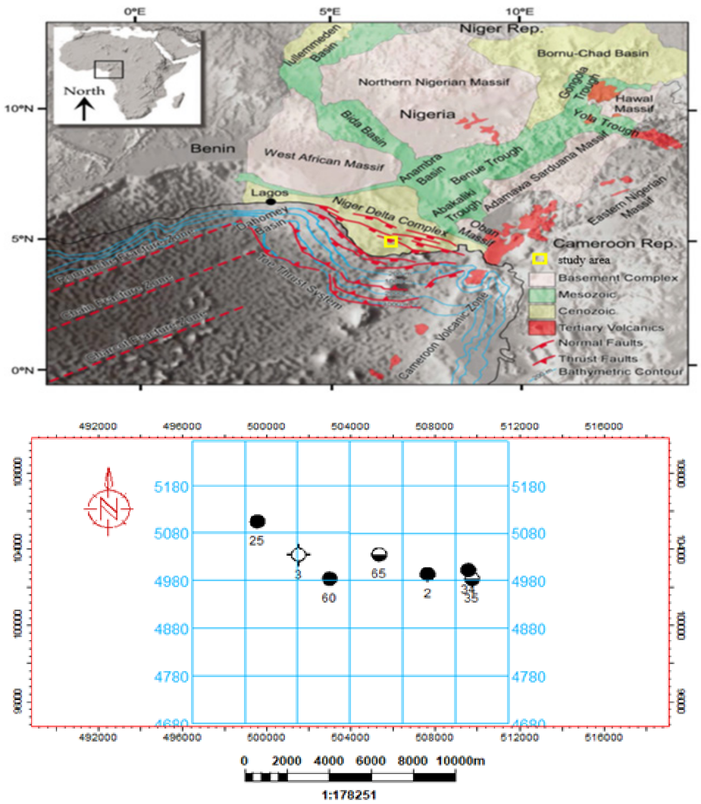


Figure 1: Location of the study area, onshore Niger Delta region (modified after, Corredor et al., 2005)

Materials and Methods

Materials

3-D Seismic data, Well log data and Side Wall Samples across seven wells was used for this study. Suite of wire line logs: gamma ray, neutron, density and sonic logs were used to evaluate the petrophysical properties of the reservoir.

Methods

The suite of well logs has been used to correlate the reservoir sands, estimate the volume of shale and calculate the net-to-gross ratio as well as the porosity and permeability (see equations 1 – 6). The first step in Reservoir modelling is Seismic interpretation which involves fault picking, synthetic seismogram generation, well tie, horizon mapping and generation of structural maps. The next stage is the building of structural, stratigraphic framework and building of a geocellular grid for distributing reservoir properties. This is followed by building the facies model which act as constraints for the distribution of other petrophysical properties (models). In the process hydrocarbon volume estimates and uncertainty analysis was carried out. The models generated include fault model, facies model and property models.

Shale Volume Estimation

Shale volume (Vsh) is the amount of shaliness contained within a reservoir unit. To calculate the shale volume, the gamma ray index (IGR) was first computed using Saputra, (2008) equation as follows;

$$IGR = \frac{GRlog - GRmin}{GRmax - GRmin} \qquad 1$$

Where,
IGR = Gamma ray index
GRlog = Gamma ray log reading
GRmax = Gamma ray reading in 100% shale
GRmin = Gamma ray reading in 100% sand
Shale volume was calculated using Larinov (1969) equation for Tertiary sands as follows;

$$Vsh=0.083[2^{((3.7\times IGR)}) - 1.0] \qquad 2$$

Net to Gross (NTG)

The NTG was calculated after defining the top and base of the reservoir sand bodies. The difference between the top and base was calculated as the gross reservoir thickness. After applying a cutoff of 65gAPI on the GR log, the net sand was determined by deflections to the left of the GR tract. The net sand is an estimate of the productive reservoir interval. Thus, NTG was defined as the total net sand divided by the entire reservoir gross thickness.

Porosity determination

Porosity was determined from the logs using Wyllie's equation (1963) see Equation 3

$$\emptyset = \frac{\rho ma - \rho log}{\rho ma - \rho fluid} \qquad 3$$

Where;
*P*ma = density of the rock matrix (2.65g/cm^3)
*P*log=Density reading from log
*P*fluid =Density of fluid (water =1g/cm^3)

Water saturation (Sw)

Water saturation (S_w) was estimated from the derived porosity using the equation developed by Udegbunam and Ndukwe (1988) as follows;

$$Sw = \frac{0.082}{\emptyset} \qquad 4$$

Where,
Sw = water saturation and Φ = Total porosity
The hydrocarbon saturation (S_H) was calculated by subtracting the water saturation from 1.

$$S_H=1-S_w \qquad 5$$

The hydrocarbon volume was determined for the three identified reservoirs J100, K100 and L100 using Udegbunam (2008) equation as follows;

$$STOIIP = \frac{7758 \times A \times h \times \emptyset \times NTG \times (1 - Sw)}{Boi} \quad 6$$

Where;
STOIIP (mmstb) = stock tank oil initially in place
Sw = water saturation
NTG = net – to – gross ratio
Boi = formation volume factor (1.25 for Niger Delta reservoir)

RESULTS AND DISCUSSION

Petrophysical Analysis

Petrophysical properties was a key input for reservoir property modeling, these include net to gross, (NTG) porosity and water saturation. The results of Petrophysical evaluation for J100, K100 and L100 reservoir identified in the study area is presented in Tables 1-4.

Table 1: Results of petrophysical analysis of J100 reservoir

Wells / Parameters	Top (ft.)	Bottom (ft.)	OWC (ft.)	Thickness (ft.)	Pay Thickness (ft.)	NTG	Ø	Sw
Well 25	5958	6040	-	82	-	0.77	0.26	0.98
Well 03	6077	6131	-	54	-	0.31	-	0.81
Well 60	6163	6203	-	40	-	0.24	-	-
Well 65	5939	5991	-	52	-	0.33	-	0.99
Well 02	5921	5970	-	49	-	0.24	-	0.82
Well 58	5841	5897	5891	56	50	0.41	0.27	0.43
Well 35	5865	5919	5897	54	32	0.41	0.25	0.75
Average				**55.29**	**41**	**0.39**	**0.26**	**0.80**

Table 2: Results of petrophysical analysis of K100 reservoir

Wells / Parameters	Top (ft.)	Bottom (ft.)	OWC (ft.)	Thickness (ft.)	Pay Thickness (ft.)	NTG	Ø	Sw
Well 25	7579	7746	-	167	-	0.82	0.21	0.99
Well 03	7570	7700	-	130	-	0.47	-	0.79
Well 60	7628	7724	-	96	-	0.64	0.27	0.99
Well 65	7313	7365	7326	52	13	0.65	-	0.66
Well 02	7382	7460	7406	78	24	0.38	-	0.54
Well 58	7270	7331	7329	61	59	0.53	0.18	0.38
Well 35	7308	7373	7378	65	70	0.39	0.16	0.42
Average				**92.71**	**41.5**	**0.55**	**0.21**	**0.68**

Table 3: Results of petrophysical analysis of L100 reservoir

Wells / Parameters	Top (ft.)	Bottom (ft.)	OWC (ft.)	Thickness (ft.)	Pay Thickness (ft.)	NTG	Ø	Sw
Well 25	9011	9121	-	110	-	0.75	0.11	0.91
Well 03	8484	8594	-	110	-	0.74	-	0.79
Well 60	8854	8976	-	122	-	0.74	0.17	0.85
Well 02	8392	8463	-	71	-	0.55	-	0.79
Well 58	7998	8099	8095	101	97	0.29	0.18	0.36
Well 35	8035	8122	8111	87	76	0.59	0.15	0.51
Average				**100.17**	**86.5**	**0.61**	**0.153**	**0.70**

Table 3: Results of petrophysical analysis of L100 reservoir

Case	J100		K100		L100	
	STOIIP (STB)	P value	STOIIP (STB)	P value	STOIIP (STB)	P value
1.00	4648755.06	90.00	60735463.80	75.00	8922162.03	10.00
2.00	3858246.34	55.00	53302785.81	15.00	9215497.89	35.00
3.00	3937183.62	15.00	57248202.03	25.00	9742640.59	65.00
4.00	4016697.22	35.00	60309586.06	55.00	10687194.57	95.00
5.00	3867830.12	25.00	60317188.24	65.00	9976551.38	90.00
6.00	3981281.65	50.00	58686521.82	50.00	9304623.90	55.00
7.00	4295579.89	65.00	52386022.26	10.00	9233035.04	50.00
8.00	4317246.94	75.00	61967971.93	95.00	9887313.16	75.00
9.00	3392249.72	10.00	57734262.60	35.00	9063622.35	15.00
10.00	5120791.02	95.00	61545452.38	90.00	9182595.86	25.00

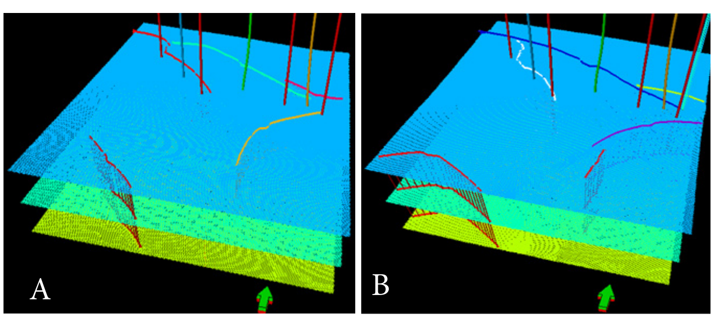
Rider (1986), classified porosity as follows; 0-5% (negligible), >5-15 (poor), >15-20 (good) >20-30 (very good), >30 (excellent). Based on this classification, average porosity in J100 and K100 reservoirs are classed as very good and good in L100 reservoir.

The result of the estimated water saturation ranges from 43 to 99% in J100, 38 to 99% in K100 and 36 to 91% in L100 reservoir. This shows an equivalent hydrocarbon saturation of 1 to 57% in J100, 1 to 62% in K100 and 9 to 64% in L100 reservoir. On average, the hydrocarbon saturation is 20%, 32% and 30% in J100, K100 and L100 reservoirs.

Reservoir Modeling

Structural Modelling

The results of fault modelling of the identified reservoir intervals are presented in Figure 2. Five faults were identified and modelled on J100 depth structure map, six on K100 structure map and seven on L100 depth structure map. This shows that the number of faults increases with depth in the field. All faults at shallow intervals were significant at deeper intervals; In addition, new faults were also introduced at deeper horizons. As an addition, a skeleton framework was created during the pillar gridding process, which is a grid consisting of a top, mid and base skeleton grid, each attached to the top, mid and base points of the key pillars generated in the fault modelling process (Figure 2).



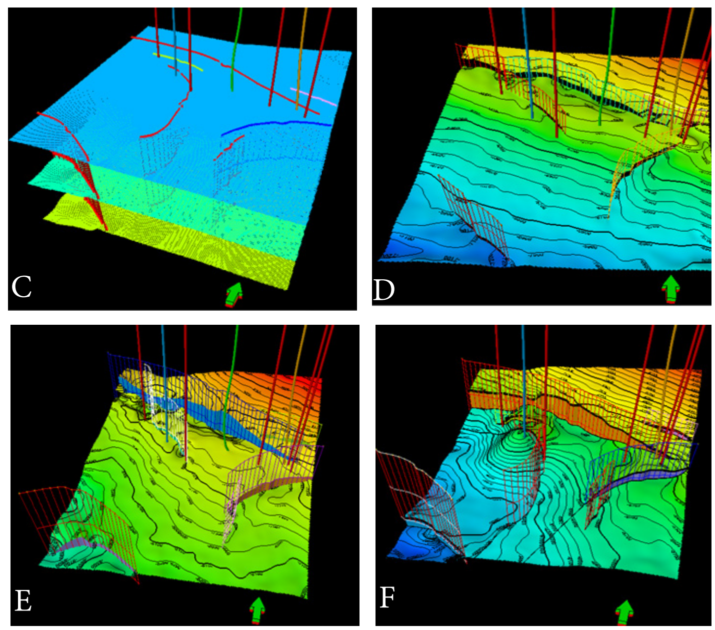


Figure 2: (a) J100 reservoir showing key pillars and reservoir tip, mid and base skeleton, (b) K100 reservoir showing key pillars and reservoir tip, mid and base skeleton, (c) L100 reservoir showing key pillars and reservoir tip, mid and base skeleton (d) Stratigraphic model generated for J100 horizon along with modelled faults, (e) Stratigraphic model generated for K100 horizon along with modelled faults, (f) Stratigraphic model generated for L100 horizon along with modelled fault

Stratigraphic Modelling

The reservoir framework was completed by incorporating stratigraphic levels represented by seismically interpreted horizons and geologically significant surfaces identified in well data: where the levels are identified in both data sets, the mapped seismic horizons are constrained by the well picks. The J100, K100 and L100 top reservoir horizons and base reservoir horizons were used to build the stratigraphic reservoir framework. The results of the stratigraphic models generated are presented in Figures 2 (d –f). To capture reservoir heterogeneities, the stratigraphic models were sub-divided into two zones. These zones were created to account for facies vertical variation in the reservoirs.

Facies Modelling

Based on the environment of deposition, four lithofacies were identified and used for facies modeling. These facies include; Channel sands (CH), Upper Shoreface (US), Lower Shoreface (LS) and Shale (SH). The facies identified on well logs were up-scaled through a blocking process. The results of facies modelling for the three reservoir intervals are presented in Figures 3, 4 and 5. The facies models were generated for the identified reservoir zones to constrain the petrophysical reservoir properties. The objective was to incorporate the medium-scale reservoir heterogeneity represented by the sedimentology into the architecture of the stratigraphic framework. The resulting facies model was used stochastic property modelling. The facies maps for the three reservoir intervals reveals that the volume of shales decreases from the shallow to the deeper reservoirs. Zone 1 of reservoir J100 shows a predominance of shore face sands and fewer channel sands in significantly high shale coverage area. The shales are predominantly found around the fault lines. In addition, the lower section of J100 reservoir (zone 2), shows a predominance of shales in the North-East and South-East part of the reservoir. Lower shore face sands are prevalent compared to upper shore face sands and channel sands are low in total areal coverage. These results show that the upper part of J100 reservoir has better quality than the lower part of the reservoir. In K100 reservoir, channel sands and shore face sands are predominant across the entire surface. The upper section of K100 reservoir (zone 1) shows some volume of shales at the NE, NW, and SW, while, the shale content is reduced at the lower part of the reservoir (zone 2). The channel sands are significantly very high in K100 reservoir when compared with J100 reservoir.

In reservoir L100, upper shore face and channel sands are significantly higher than lower shore face sands and shales, especially at the shallow part (zone 1). There is a significant increase in shaliness at the lower portion of the L100 reservoir. The channel sands trend NW-SE in zone 1 and 2, with few scattered patches in zone 2. Generally, zone 1 has better reservoir quality in J100 and L100 reservoirs while zone 2 has better quality than zone 1 in K100 reservoir.

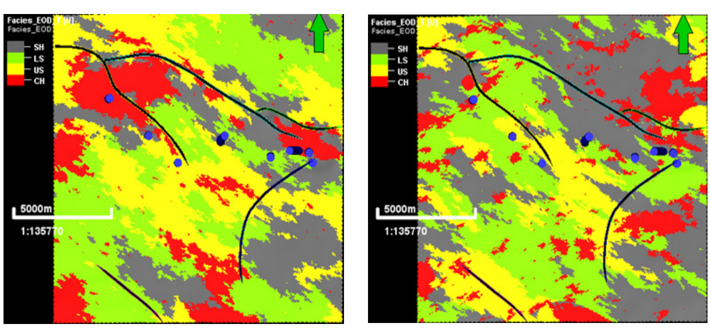


Figure 3: Environment of Deposition facies model for J100 reservoir (a) Zone 1, (b) Zone 2

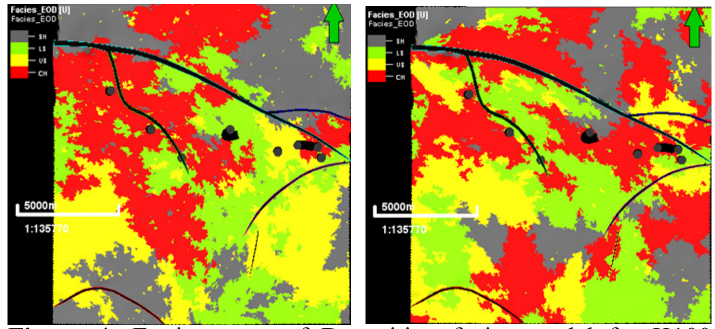


Figure 4: Environment of Deposition facies model for K100 reservoir (a) Zone 1, (b) Zone 2

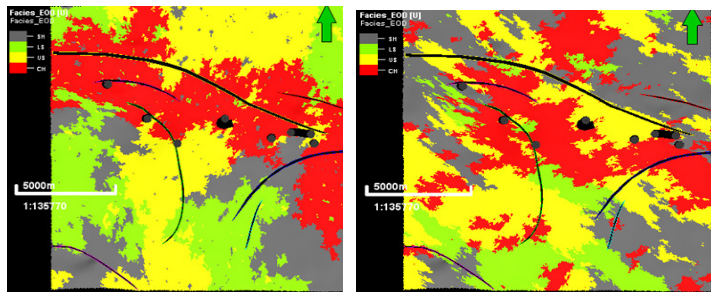


Figure 5: Environment of Deposition facies model for L100 reservoir (a) Zone 1, (b) Zone 2

Fluid Content

The presences of hydrocarbon in the reservoirs were established with the use of resistivity logs. Reservoirs J100 and L100, have hydrocarbon identified in Well-58 and Well-35. In K100 reservoir, hydrocarbon was found in Well-65, Well-02, Well-58 and Well-35 respectively. In the wells under study, the resistivity log revealed the presence brine (salt water). Average pay thickness which is the thickness of the reservoir containing hydrocarbons are 41ft, 41.5ft and 86.5ft in J100, K100 and L100 reservoirs respectively. In the absence of pressure data to differentiate the type of contained hydrocarbons, the neutron and density logs was used to determine the presence of a gas cap, and no gas was identified in any of the reservoir intervals. The result of the estimated water saturation ranges from 43 to 99% in J100, 38 to 99% in K100 and 36 to 91% in L100 reservoir. This shows an equivalent hydrocarbon saturation of 1 to 57% in J100, 1 to 62% in K100 and 9 to 64% in L100 reservoir. On average, the hydrocarbon saturation is 20%, 32% and 30% in J100, K100 and L100 reservoirs.

The oil water contact (OWC) determined from the deepest well at the various reservoir intervals were posted on the depth structure maps to delineate structural highs containing hydrocarbon deposits. The maps revealed closures with hydrocarbon in prospective areas. See Figures 6 which shows oil water contacts posted on stratigraphic models for J100, K100 and L100 reservoirs. The faults identified were the major structural controls on hydrocarbon accumulation across the surfaces as revealed by the depth structure maps for the various reservoir intervals. Pockets of hydrocarbons were found in reservoir J100 while a very large area occupied by hydrocarbons was identified in K100 reservoir. In L100 reservoir, a small area occupied by hydrocarbons was identified on the eastern part of the reservoir surface. All hydrocarbon accumulations were found within fault supported closure systems.

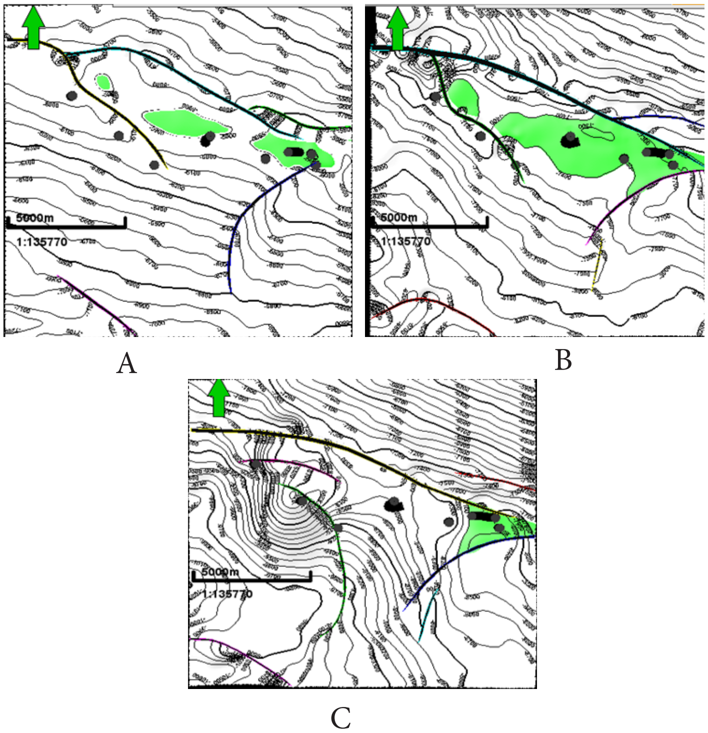


Figure 6: Oil Water Contact overlain on depth structure modelled surface (a) J100 surface, (b) K100reservoir, (c) L100 reservoir

Risk assessment

To account for production risk and uncertainty, 10 realizations were generated for the petrophysical models which have been facies-constrained. These realizations were used to compute the hydrocarbon volumes using Equation 6. Afterward, the associated probabilities were determined. The relevant probabilities of significance are P10, P50, and P90 which represents a worst-case scenario, base-case scenario, and best-case scenarios. P10 means that there is a 10 percent chance of success and a 90% chance of failure. P50 means that there is a 50-50 chance of success or failure while P90 means that there is a 90% chance of success and a 10% chance of failure. Most oil producing companies adopt P50 because it gives results that are quite similar to results generated through a deterministic approach.

Conclusion

The integration of seismic volume and well logs provided a useful and important technique in structural mapping and interpretation, and these where was used in defining the subsurface geometry, and determining the fault closures, these closures act as faults acted traps for hydrocarbon. In this research, it was seen that seismic trait frames an amazing method to spot hydrocarbon, although, they do not often conform to structures. It revealed that seismic resolution gives the lateral and vertical resolution of the subsurface but resolution diminishes at greater depth. Results from Geomodelling and risk assessment show that the field is good for hydrocarbon exploration. However, it is necessary to integrate Multi-attribute, Spectral decomposition and Core data analyses in exploration and evaluation in other to enhance productivity.

Acknowledgement

The authors acknowledge Department of Petroleum Resources (DPR) Nigeria, for the data and Schlumberger for the Petrel Software donated to the Department of Geology, University of Port Harcourt which was used in the work.

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