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Seismic Attributes Mapping and 3D Static Modeling of Reservoirs within "OYA" Field, Offshore Depobelt, Niger Delta Sedimentary Basin, Nigeria

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Authors' contributions

This work was carried out in collaboration between both authors. Author OAE accepted and designed the study, provided the workspace, read, supervised and corrected the final draft manuscript. Author OYA conceptualized the study, performed the statistical analysis, wrote the protocol, managed the analyses of the study, managed the literature searches and wrote the first draft of the manuscript under the supervision of author OAE. Both authors read and approved the final manuscript.

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ABSTRACT

An integrated 3D seismic data, checkshot data and suite of well logs for nine wells in "OYA" field, Offshore, Niger Delta were analyzed for reservoir characterization, 3D static modeling and volumetric analysis. This study is majorly in two folds: the first focuses on the application of 3D static model by incorporating all the geologic characteristics within subsurface volume that are relatively stable over long periods of time for optimization and development of hydrocarbon potentials in "OYA" field while the use of seismic attributes to map and identify new prospects that can be possibly explored in the same field. Geological structural and property models (net to gross, porosity, permeability, and water saturation) were distributed stochastically within the constructed 3D grid using the method of Sequential Gaussian Simulation algorithms. Depth structural maps and seismic attribute maps generated shows the trapping mechanisms to be a fault assisted anticlinal closure and four way closures while new hydrocarbon prospects were delineated respectively. The

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result (output) of the 3D static model was used to carry out volumetric analysis which divided the three reservoirs (Sand 1, 2 and 3) into two zones; the first zone [sand 1- sand 2(surface depths)] with a STOIIP of 4.93344*10^6 Stock tank barrel of recoverable oil while the second zone [sand 2- sand 3 (surface depths)] have a STOIIP value of 500369*10^6 Stock tank barrel of recoverable oil. This research work has demonstrated how new hydrocarbon prospects can be further explored in the field. 3D static geologic models and volumetric analysis of evaluated reservoirs in the already drilled wells shows evidence of good hydrocarbon yield in the field of study.

Keywords: Seismic attributes mapping; 3D static modeling; reservoirs; sedimentary basin.

1. INTRODUCTION

In the exploration and production business, which is the petroleum exploration industry is cost intensive and required detailed risk and economic evaluation of prospective areas to promote adequate investment. Companies carry out a series of risk and economic analysis to determine the viability of a prospect because geologic concepts are uncertain with respect to structure, reservoir, seal, and hydrocarbons. In other words by far the largest component of geophysical spending is driven by the need to characterize (potential) reservoirs. The simple reason is that better reservoir characterization means higher success rates and fewer wells for reservoir exploitation [1].

Reservoir characterization includes determination of reservoir limits, structure, volume and reservoir properties such as porosity, permeability, net pay thickness, and heterogeneity [2] Reservoir characterization as defined by [3] is the entire germane and valuable information requisite for the effective description of a reservoir.

Seismic attributes have come a long way since their introduction in the early 1970s and have become an integral part of seismic interpretation projects, for example, amplitude, average reflection strength and spectral decomposition are useful tools for locating reservoir quality, outlining their geometry and possibly displaying lateral changes in thickness [4].

Hydrocarbon resources remain very vital to the economy of many nations of the world. Niger Delta province of Nigeria has large commercial accumulation of hydrocarbon. The production of oil and gas is from the accumulation in the pore spaces of reservoir rocks usually sandstone, limestone or dolomite [5]. In Niger Delta, petroleum is majorly produced from the sandstone reservoirs which are the unconsolidated sands of Agbada Formation.

Subsurface studies (integrated reservoir characterization) carried out during this research typically incorporates all the available well data integrated with 3D seismic data so as to establish a 3D static geological model and volumes of hydrocarbon in the reservoirs established. Meanwhile seismic attributes were used extensively to identify new hydrocarbon prospects in the seismic volume.

1.1 Geology of the Study Area

OYA field is located within the offshore area of Niger delta in Nigeria (Fig. 1). The Tertiary Niger Delta covers an area of approximately 75,000 sq km and consists of a regressive clastic succession, which attains a maximum thickness of 12,000 m [6]. The Niger delta is located in the Gulf of Guinea, Central West Africa, at the culmination of the Benue Trough and is considered one of the most prolific hydrocarbon provinces in the world [7].

Lithostratigraphy (geologic Formations) of the Tertiary Niger Delta is sub-divided into three major units namely: Akata, Agbada and Benin Formations, with depositional environments ranging from marine, transitional and continental settings respectively. The Akata Formation is the basal sedimentary unit of the delta, it consists of uniform dark grey over-pressured marine shales with sandy turbidites and channel fills and age ranges from Late Eocene to Recent [6]. The Agbada Formation is characterized by paralic to marine-coastal and fluvial-marine deposits mainly composed of sandstone and shale organized into coarsening upward off-lap cycles [7].

Onshore and in some coastal regions, the Benin Formation overlies the Agbada Formation. The Benin Formation consists of Late Eocene to Recent deposits of alluvial and upper coastal plain deposits that are up to 2000 m (6600 ft) thick [8].

(A)

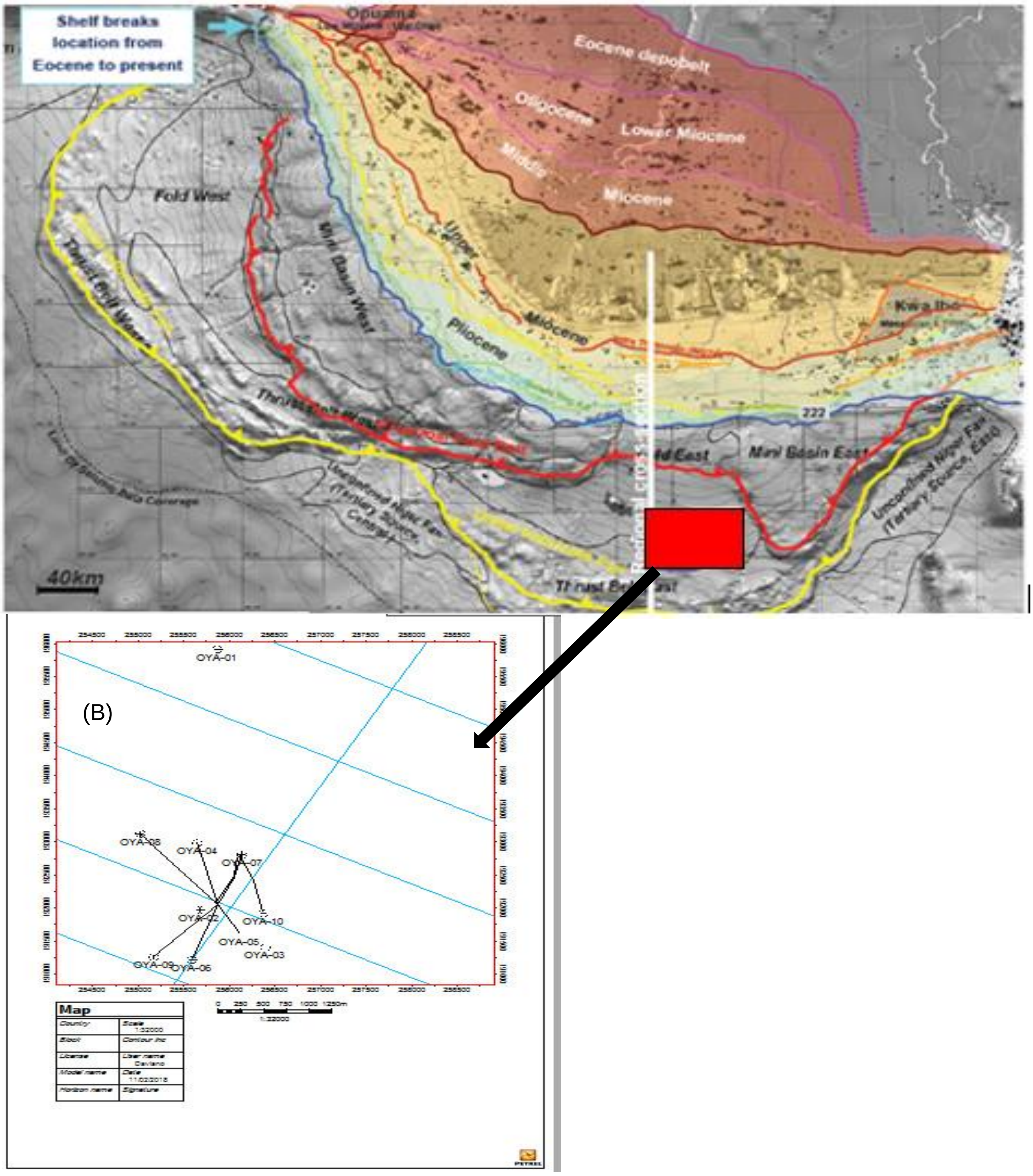

Fig. 1. (A) Location of the study area, modified by [9] and (B) base map showing the seismic lines and wells

2. MATERIALS AND METHODS

2.1 Data Acquisition

The data set used for this research were provided by Chevron Nigeria Ltd through the Department of Petroleum Resources (DPR). The data provided include; 3D Post stack seismic data and well log data. The logs provided are; Gamma ray, deep resistivity, sonic, neutron porosity and density logs of selected wells. Ten wells were drilled in “OYA” field and are labeled OYA-01, 02, 03, 04, 05, 06, 07, 08, 09 and 10. Fig. 1 shows the base map of “OYA” Field.

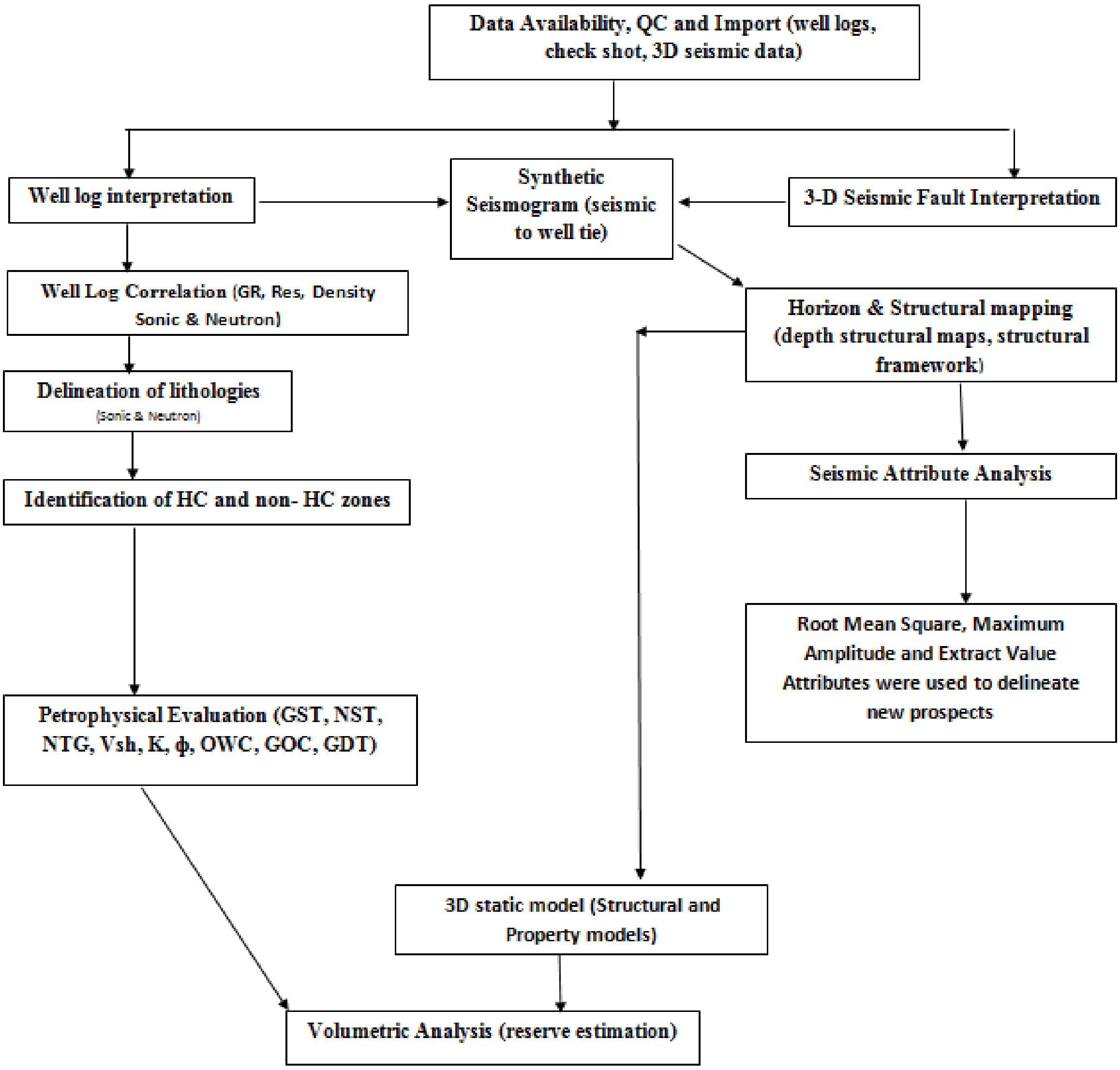

Fig. 2. Workflow adopted to characterize 'OYA' Field, Niger Delta

2.2 Data Processing and Interpretation

Well and seismic dataset were uploaded in Petrel 2014 software and used to generate curves. Gamma ray curve was in track 1, resistivity curve in track 2, neutron curve in track 3 and density in track 4. The datasets were used for stratigraphic correlation, seismic interpretation, geo-modeling and volumetric analysis. Interactive Petrophysics software was used extensively for petrophysical interpretation of the well logs.

2.2.1 Petrophysical interpretation and evaluation

Detailed petrophysical interpretation was conducted for the OYA wells namely OYA 02, 03, 05, 08 and 09. The interpretation of the logs in general was performed using a deterministic approach and generated output curves and values for shale volume, net to gross, effective porosity, effective water saturation and permeability amongst several other parameters being derived [5].

The following equations represent the methods adopted for evaluating the geological Formation as related to petrophysics.

2.2.1.1 Gamma ray index (I_{GR})

$$I_{GR}=\frac{GRlog-GRmin}{GRmax-GRmin} \quad (1)$$

Where, I_{GR} = the gamma ray index, *GRlog* = the gamma ray reading of formation from log, *GRmin* = the minimum gamma ray (clean sand), *GRmax* = the maximum gamma ray (shale).

Well log correlation was carried with the aid of Petrel 2014 software by picking shale markers to delineate between reservoir rocks and non-reservoir rocks with the aid gamma ray and resistivity logs. Shale volume was determined from gamma ray log. Porosity and hydrocarbon type were estimated using the available porosity logs (Density and Neutron). The effective porosity was calculated from the total porosity corrected for shale fraction.

2.2.1.2 Formation Factor (f)

This was achieved using the Achie's equation

$$\phi D = \frac{\ell \mathrm{ma} - \ell \mathrm{b}}{\ell \mathrm{ma} - \ell \mathrm{fl}} \quad (2)$$

Where, ɸD= density derived porosity, ℓma= matrix density (2.65 gm/cm^3 for sandstone), ℓb = formation bulk density, ℓfl= fluid density (1.1 gm/cm^3 for water, 0.74 gm/cm^3 for gas and 0.9 gm/cm^3 for oil).

Water saturation was estimated using [10] model:

$$F = \frac{a}{\phi m} \quad (3)$$

Where, F=Formation factor, a = tortuosity factor = 0.62, Ø = porosity, m = cementation factor.

$$Sw^2 = (F \times Rw) / Rt \quad (4)$$

$$But; F = Ro/Rw \quad (5)$$

$$Thus; Sw^2 = Ro/Rt \quad (6)$$

Where, Sw = the water saturation = uninvaded zone, Ro=resistivity of formation at 100% water saturation, Rt = true formation resistivity, F=formation factor

2.2.1.3 Irreducible water saturation

This is the water held in the pore spaces by capillary forces. In this study, it was determined from the equation of [11].

$$Swirr = \sqrt{F}/2000 \quad (7)$$

Where $Swirr$ = irreducible water saturation. F= formation factor

2.2.1.4 Permeability

It is the ability of a rock to transmit fluid and is related to porosity but it is not always dependent on it. It is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in Darcies or Millidarcies. The permeability of each reservoir was determined from the equation by [12].

$$K = 250 \, x \, \phi 3/Swirr \quad (8)$$

Where $Swirr$ = irreducible water saturation

Baker [13] classified porosity values as follows (guide to porosity calculation): ɸ < 0.05 = Negligible, 0.05< ɸ <0.1 = Poor, 0.1 ɸ< 0.15 = Fair, 0.15 < ɸ < 0.25 = Good, 0.25 < ɸ <0.30 = Very good ɸ> 0.30 = Excellent. Baker, 1992 classified permeability based on the following threshold: poor to fair =1.0 to 14 md, moderate = 15 to 49 md, good = 50 to 249 md, very good = 250 to 1000 md, >1 darcy = excellent.

2.3 Seismic Interpretation

2.3.1 Fault interpretation and well tie to seismic

The structures identified during the cause of fault mapping are majorly growth fault with rollover anticlines which is typical of the structures found in the Niger delta basin. These growth faults mapped are found to have associated synthetic and antithetic faults which are listric in nature. Major and minor faults were identified and interpreted on the seismic sections (Fig. 3). Well to seismic tie was carried out using OYA-03 well data and checkshot survey data for OYA-03. The logs were corrected for possible spikes (despiked) and subsequently convolved with butterworth wavelet to generate synthetic seismogram, hence, tying the seismic to the wells was achieved. Synthetic match with seismic was quite good in OYA-03 and enabled the seismic events to be picked for horizon interpretation as represented in Figs. 4 and 5.

2.3.2 Horizon mapping

Horizon interpretation was based on synthetic processes as shown in the Fig. 5, with three horizon surfaces corresponding to the top and base of the reservoirs being mapped as sand 1, sand 2 and sand 3 (reservoir tops) respectively. The horizon surfaces were picked on both in-lines and cross-lines.

The key seismic amplitude reflections which corresponded to tops of main reservoir sands were identified and interpreted on seismic volume as represented in the seismic interpretation section (Fig. 6).

Sedimentary section can be subdivided into three distinct intervals based on general seismic reflection character, regional studies and the uniformly blocky, low-value gamma-ray patterns, some low to high amplitude, parallel and discontinuous reflection pattern, was observed [5]. Upper Agbada section with thick shale on the sandy sequence and lower Agbada formation characterized by thick shale, parallel and high amplitude followed by sand shale intercalation, [5]. Although, a chaotic and low amplitude re-flections interpreted as the Akata formation was also observed as defined by [5].

2.3.3 Time-depth conversion

Time-depth function (Fig. 7) was used to convert time structural maps into depth structural maps in order to know the geologic structures that houses hydrocarbon in the subsurface.

2.3.4 Seismic attribute

Seismic attributes such as Root Mean Square, Maximum Amplitude and Extract Value attributes were generated in the seismic volume across Sand 1, Sand 2 and Sand 3 respectively with the aim of identifying sweet and bright spots as indicated with areas with very high amplitude coinciding with structural closures.

2.4 Static Geological Model

It was necessary to build a static geological model of the reservoirs established in the field so as to understand the subsurface architecture better which will also optimize production performance of the wells. A 3D static geologic model is achieved by integrating all the available subsurface data sets as inputs towards managing the reservoirs delineated in the well.

The static geological model of Sand 1, 2 and 3 for the entire "OYA" Field in the Agbada Formation of the Niger delta was built by integrating relevant sub-surface data; 3D seismic structural interpretation, porosity, permeability and water saturation from petrophysical analyses. Petrel (2014) software was used in building the static model. The structural model (interpreted faults and horizon surfaces) and property model (porosity, permeability, net to gross and water saturation and) were used for the static modeling.

2.4.1 Structural model of sand 1, 2 and 3

Depth converted seismic interpretation surfaces and faults were used to build the structural model in OYA field. The following data set were inputted into the Petrel 2014 workflow for constructing a geologic structural model: Sands 1, 2 and 3 depth surfaces, polygons and interpreted fault surfaces.

Fault modeling was the first step adopted in building the structural model with petrel workflow tools which is done by first defining the faults through the process of generating key pillars. The next step adopted was pillar gridding which is simply a way of making a grid based on the defined faults in the studied area. Pillar gridding resulted to a skeleton grid which defined extensively all the faults and pillars created. Layering was the final step adopted in creating the structural model of the field by inserting the interpreted horizon surfaces into the 3d fault grid which was attached to corresponding depth maps. The resultant output is a fault model which is enhanced to make the final scale layering suitable for property models of the reservoirs in OYA field.

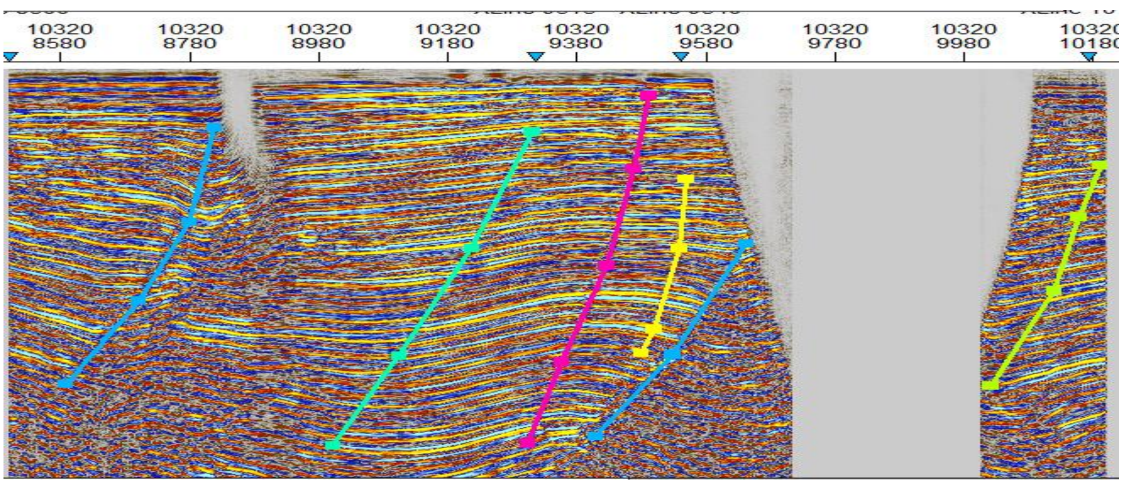

Fig. 3. Fault mapped on Inline 10320 displayed on Relative acoustic impedance attribute

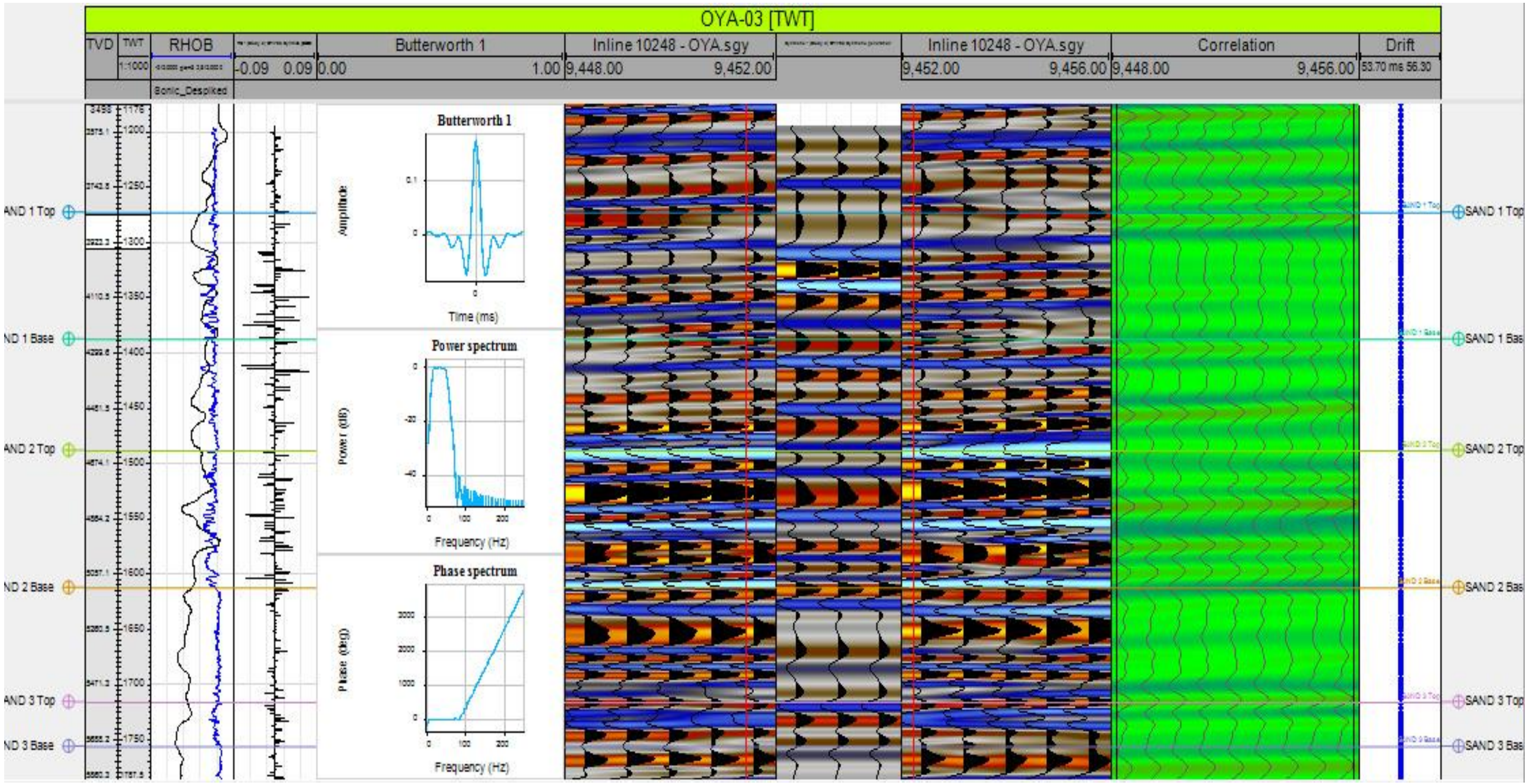

Fig. 4. Calibration plate showing synthetic seismogram

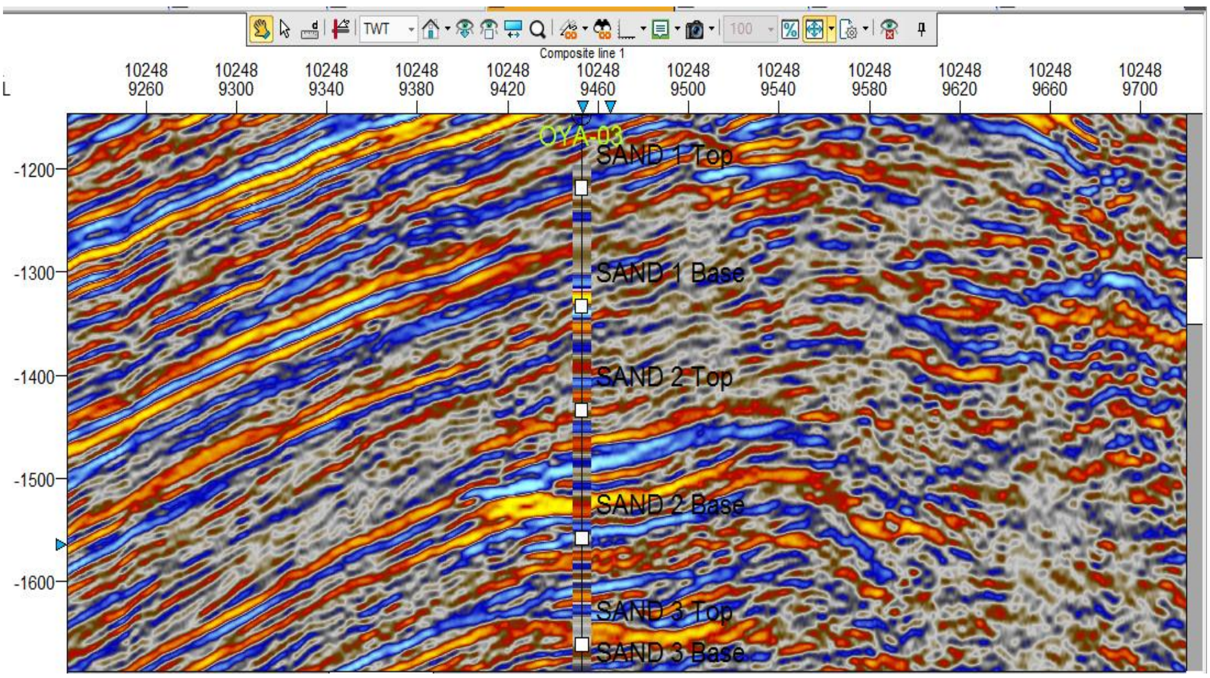

Fig. 5. Synthetic seismogram displayed on an interpretation window

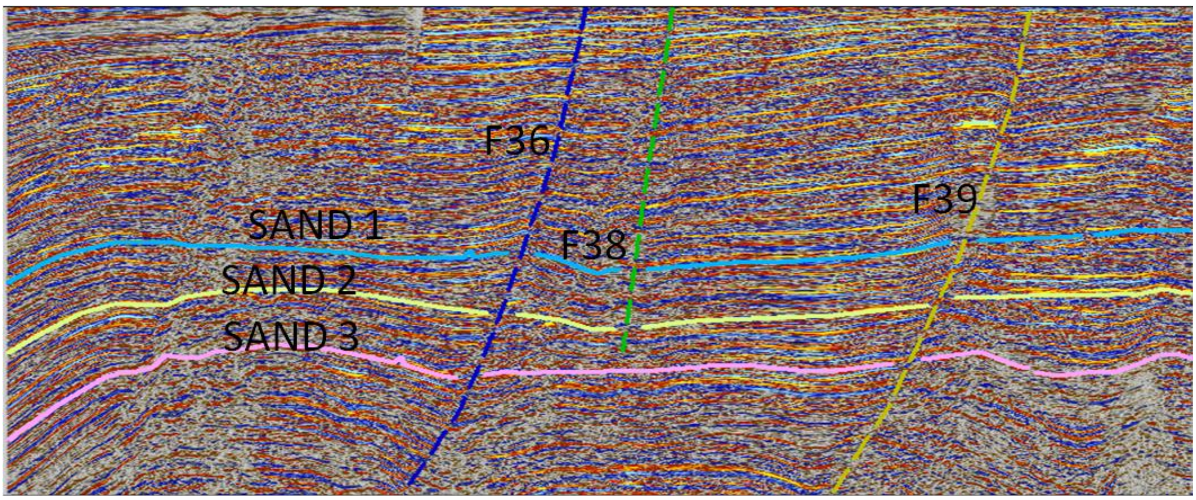

Fig. 6. Faults (F36, F38 and F39) and Horizon surfaces on random seismic section

2.4.2 Property modeling

The property modeling entails filling the cells in the grid earlier created with petrophysical properties. Property modeling in petrel is differentiated into separate processes: geometrical, facies and petrophysical modeling. This research work used the petrophysical modeling which involves simulation of porosity, permeability, net to gross and water saturation in building the property models of the delineated reservoirs. Sequential Guassian Simulation algorithm was used to build the model. The resultant static model was then used for volumetric distribution of the field.

2.4.3 Reservoir volumetric

It uses static geologic models to estimate the volume of hydrocarbons in a reservoir.

$$STOIIP = NRV \times ɸ \times S\,((oil))/\,Bo \qquad (9)$$

Where, $\boldsymbol{NRV}$ = net rock volume, $\boldsymbol{\Phi}$ = porosity, $\boldsymbol{S(oil)}$ = oil saturation, $\boldsymbol{Bo}$ = oil formation value factor.

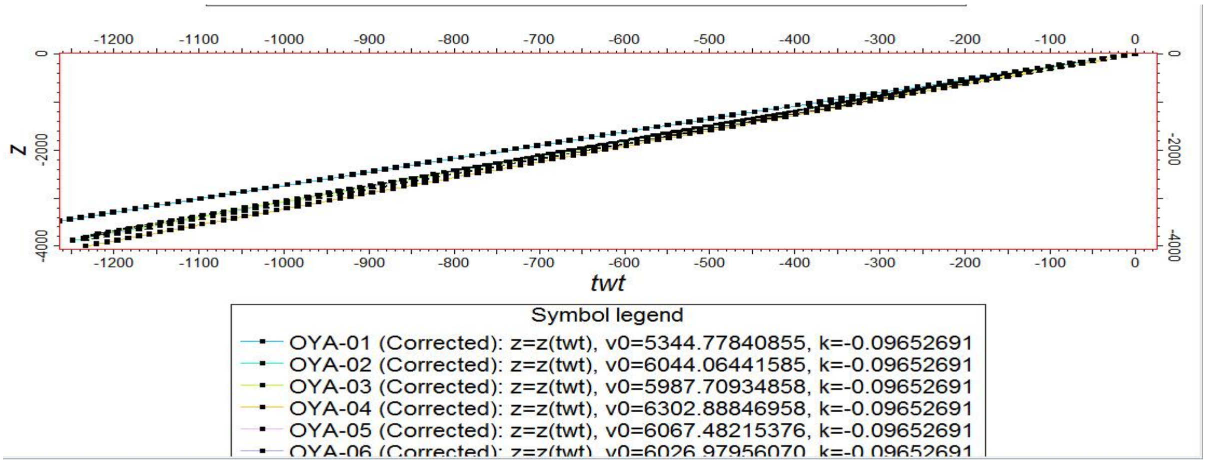

Fig. 7. Time depth function

3. RESULTS AND DISCUSSION

3.1 Results

Correlation of five well logs in OYA field is displayed in Fig. 8. Petrophysical evaluation of reservoirs in wells 02, 03, 05, 08 and 09 are represented in Table 1, 2, 3, 4, and 5 respectively. The display of the top of sand 2 depth and time structural maps is shown in Fig. 9. The RMS, Maximum amplitude and Extract value attribute maps for sand 2 is presented in Fig. 10. Fig. 11 represent 3D fault interpretation of the field of study. Fig. 12 shows the 3D component of the structural model of the reservoirs. The NTG (net to gross) and porosity models are presented in Fig. 13 while permeability and water saturation models are shown in Fig. 14. Results of volumetric obtained using the model based approach is shown in Table 6.

3.2 Discussion

3.2.1 Petrophysical analysis

Five wells out of the nine wells were used basically for petrophysical evaluation. Wells 02, 03, 05, 08 and 09 has depth range of 2941.91 to 3017.11 m, 2923.72 to 2998.62 m, 3038.38 to 3108.00 m, 2979.30 to 3055.71 m, and 3002.88 m to 3078.10 m respectively. Fig. 8 shows correlation of five wells depicting five reservoirs with reservoir sand 2 cutting across them.

Sand 2 reservoir (most promising) in OYA field was picked between depth of 1543.96 m – 1587.94 m (TVDSS) in well 02, well 03; 1411.85 m – 1557.47 m (TVDSS), well 05; 1537.05 m – 1601.7 m (TVDSS), well 08; 1662.84 m – 1715.3 m (TVDSS), well 09 1670.7 m – 1720.28 m (TVDSS). All the established reservoirs were correlated across the wells to see their lateral continuity which gives a better description of the reservoirs.

Generally reservoir sand 1 is a wet reservoir as it contains over 90% of water on the average across the five wells being evaluated.

The reservoir sand 2 contain hydrocarbon saturation of 0.36, 0.44, 0.82, 0.51, 0.15, porosity values; of 0.29, 0.25, 0.19, 0.27, and 0.25, water saturation of 0.64, 0.56, 0.18, 0.49, and 0.85 all at wells; OYA-02, OYA-03, OYA-05, OYA-08 and OYA-09 respectively. In other words sand 2 have an average porosity of 0.25 across the five wells which are in accordance with [13] classification of porosity; porosity value of 25% is represented as very good for a hydrocarbon reservoir. The reservoir has an average hydrocarbon saturation of 45.6% and average water saturation of 54.4% across the five wells. It is worthy to conclude that reservoir sand 2 is a very good hydrocarbon reservoir.

Reservoir sand 3 has an average porosity of 0.26 across the five wells which are in accordance with [13] classification of porosity; porosity value of 26% is represented as very good for a hydrocarbon reservoir. The reservoir has an average hydrocarbon saturation of 14.2% and average water saturation of 86% across the five wells.

Table 1. Petrophysical parameters for well 02

Reservoirs	Top (MD) (M)	Bottom (MD) (M)	Gross thickn (M)	Net thickn (M)	Net Pay (M)	NTG	PHIEϕ	SW	K (mD)	SH	F	Vsh	S_{wirr}	Fluid type	Contacts
Sand 1	1209.04	1287.44	78.4	16.17		0.21	0.32	1	16477	0	7.18	0.1	0.06	Water	Wet
Sand 2	1543.96	1587.94	43.98	24.4	11.29	0.56	0.29	0.64	7773	0.36	8.76	0.08	0.07	Gas, Oil	GOC
Sand 3	1705.99	1762.67	56.69	19.22		0.34	0.3	0.95	12323	0.05	8.25	0.09	0.06	Water	Wet
Sand 4	2228.09	2331.27	103.12	87.47	39.04	0.85	0.24	0.68	2539	0.32	13.33	0.12	0.08	Oil, Water	OWC
Sand 5	2644.81	2862.27	271.47	110.41	86.92	0.52	0.2	0.38	716	0.62	19.73	0.09	0.1	Gas, Oil	GOC

Table 2. Petrophysical parameters for well 03

Reservoirs	Top (MD) (M)	Bottom (MD) (M)	Gross thickn (M)	Net thickn (M)	Net Pay (M)	NTG	PHIEϕ	SW	K (mD)	SH	F	Vsh	S_{wirr}	Fluid type	Contacts
Sand 1	1170.26	1298.01	127.75	42.17		0.33	0.28	0.94	6637	0.06	9.57	0.13	0.07	Water	Wet
Sand 2	1411.85	1557.47	145.62	43.92	27.76	0.3	0.25	0.56	3052	0.44	12.21	0.07	0.08	Gas	GDT
Sand 3	1689.85	1743.62	53.78	45.76	13.73	0.85	0.3	0.75	12323	0.25	8.25	0.07	0.06	Gas, Oil	GOC
Sand 4	2215.86	2307.39	91.54	88.15	58.87	0.96	0.27	0.42	5635	0.72	10.35	0.05	0.07	Gas, Oil,	GOC

Table 3. Petrophysical parameters for well 05

Reservoirs	Top (MD) (M)	Bottom (MD) (M)	Gross thickn (M)	Net thickn (M)	Net Pay (M)	NTG	PHIEϕ	SW	K (mD)	SH	F	Vsh	S_{wirr}	Fluid type	Contacts
Sand 1	1206.03	1222.79	16.75	9.01		0.54	0.32	0.85	16477	0.14	7.18	0.08	0.06	Water	Wet
Sand 2	1537.05	1607.7	64.01	17.23	17.08	0.27	0.17	0.18	239	0.82	28	0.05	0.12	Gas	GDT
Sand 3	1728.28	1788.35	60.07	40.7	21.88	0.68	0.25	0.62	3640	0.38	11.23	0.06	0.08	Gas, Oil	GOC
Sand 4	2281.55	2390.55	109.27	83.04	55.82	0.76	0.2	0.4	716	0.6	19.7	0.07	0.1	Gas, Oil,	GOC

Table 4. Petrophysical parameters for well 08

Reservoirs	Top (MD) (M)	Bottom (MD) (M)	Gross thick n (M)	Net thick n (M)	Net Pay (M)	NTG	PHIEϕ	SW	K (mD)	SH	F	Vsh	S_{wirr}	Fluid type	Contacts
Sand 1	1205.34	1274.72	69.39	33.7		0.49	0.34	0.94	21644	0.06	6.13	0.13	0.06	Water	Wet
Sand 2	1662.84	1715.3	52.45	43.92	24.48	0.84	0.27	0.49	5636	0.51	10,35	0.07	0.07	Gas, Water	GWC
Sand 3	1943.13	2003.52	60.39	32.03		0.53	0.22	0.99	1356	0.01	16.08	0.09	0.09	Water	Wet
Sand 4	2281.55	2390.55	109.27	83.04	55.82	0.76	0.2	0.4	716	0.6	19.7	0.07	0.1	Gas, Oil,	GOC

Table 5. Petrophysical parameters for well 09

Reservoirs	Top (MD) (M)	Bottom (MD) (M)	Gross thick n (M)	Net thick n (M)	Net Pay (M)	NTG	PHIEϕ	SW	K (mD)	SH	F	Vsh	S_{wirr}	Fluid type	Contacts
Sand 1	1207.23	1230.13	22.9	14.79		0.65	0.37	0.9	45600	0.1	5.26	0.08	0.05	Water	Wet
Sand 2	1670.7	1720.28	49.58	39.51	6.84	0.8	0.25	0.85	3051	0.15	12.21	0.08	0.08	Oil, water	OWC
Sand 3	1967.76	1976.73	8.97	8.21		0.92	0.23	0.99	1657	0.02	14.61	0.07	0.09	Water	Wet

Table 6. Volumetric obtained after modeling

Case	Bulk volume [*10*6ft3]	Net volume [*10*6 RB]	Pore volume [*10*6 RB]	HCPV oil [*10*6 RB]	STOIIP (in oil) [*10*6 STB]	STOIPP[*106 STB]	Recoverable oil[*10*6 STB]
Total	13348218	13348218	2464284	563713	563713	993713	$9.937138*10^6$
Sand1surface(depth1)-Sand 2 surface (depth)	6924802	6924802	123360	493344	493344	493344	$4.93344*10^6$
Sand2surface(depth1)-Sand3 surface (depth)	7023416	7023416	1250924	5000369	5000369	500369	$5.00369*10^6$

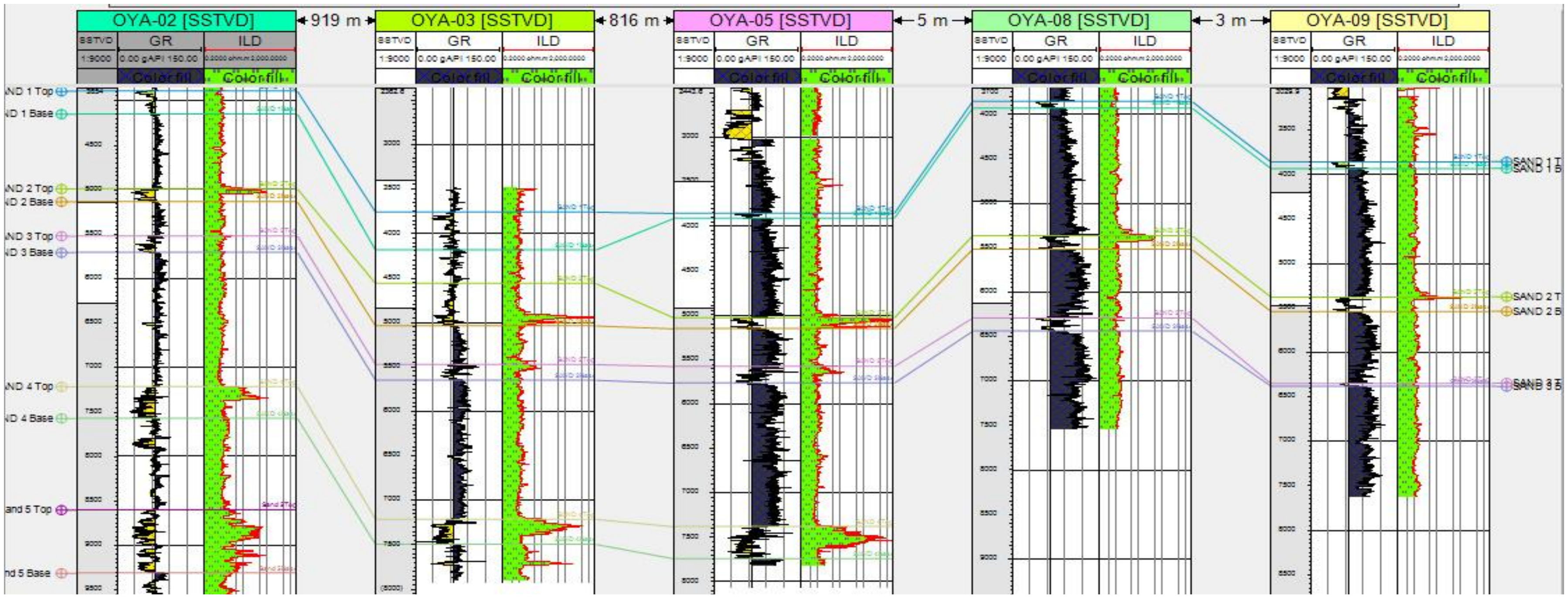

Fig. 8. Well correlations across the five evaluated wells

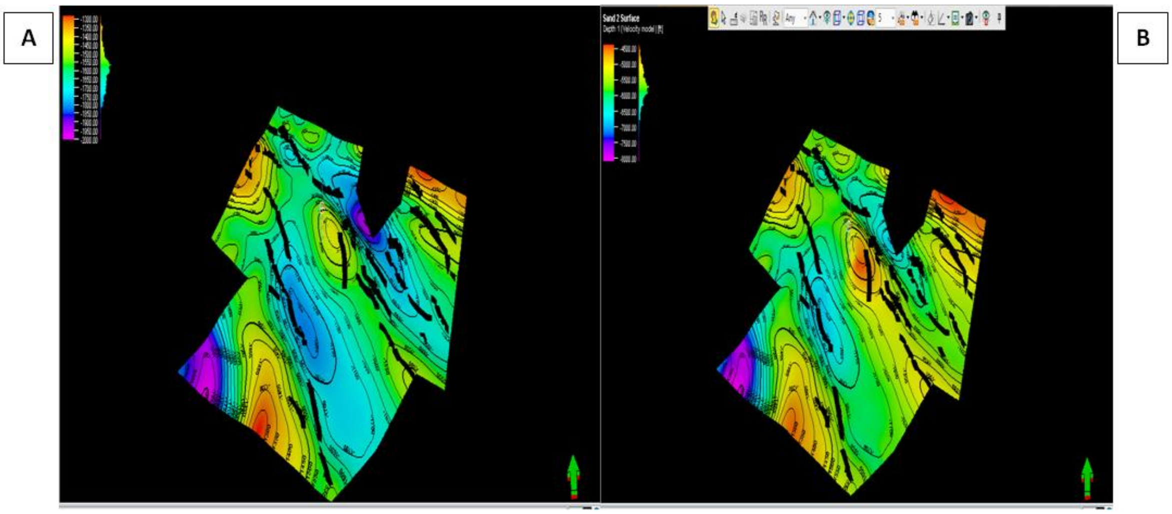

Fig. 9. Top showing (a) time structural map, (b) depth structural map for Sand 2

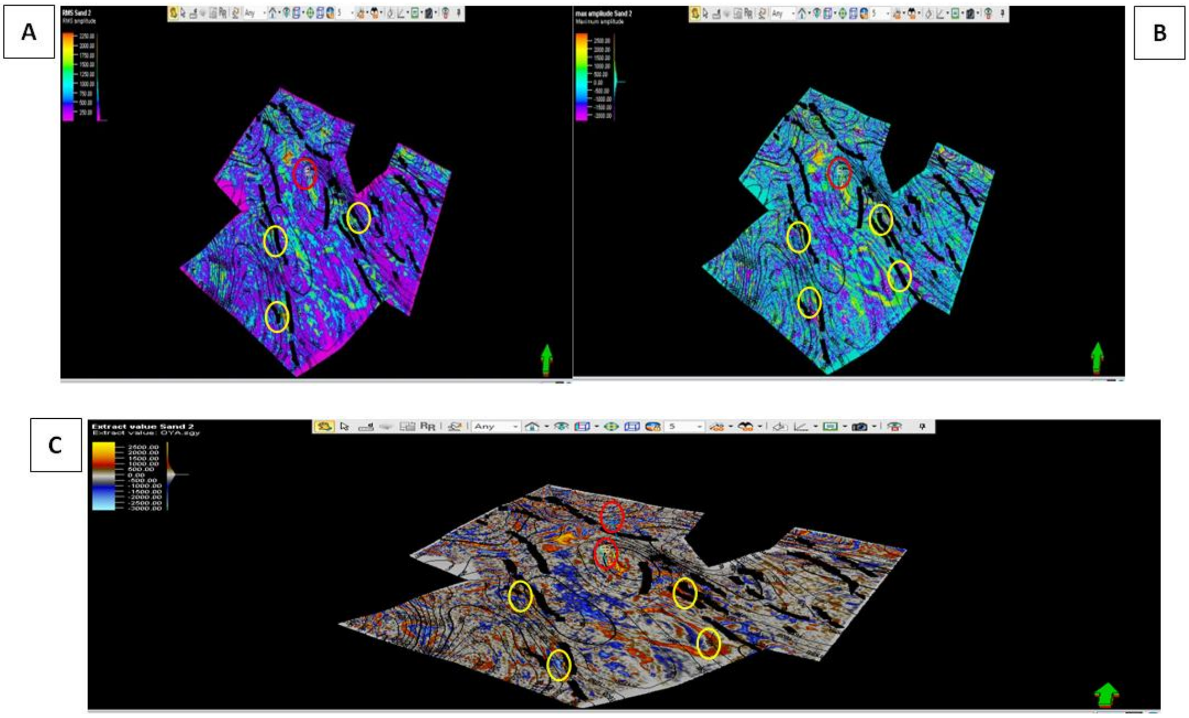

Fig. 10. Top showing (a) RMS amplitude (b) Maximum amplitude and (c) Extract value attribute maps for Sand 2 with wells in red point and yellow impact points as new prospects

3.2.2 Seismic analysis

The structural framework (interpretations) were integrated to derive a time structural map of reservoirs (sand 1, sand 2 and sand 3) in OYA field, after which time depth function (Fig. 7) was used to convert the time structural map to depth structural map. The depth structural map (Fig. 10) above is the geologic subsurface interpretation of each horizon surfaces which shows the various structural highs, lows and the binding faults. The structural maps shows that the field is composed of rollover structures with multiple growth faults, fault dependent hydrocarbon trapping mechanism and likewise some four way dip closures were observed. The mapped growth faults serves as the structural trap that impede seepage of hydrocarbon which is typical of the Niger delta petroleum system. These structures are proven to contain hydrocarbon by using the depth structural maps to create polygon around the prospective zone highlighted by the RMS amplitude, Maximum amplitude and Extract value attributes. The attribute maps (Fig. 10) were used to identify new prospective zones (Fig. 10) aside the wells already drilled in the field. Petrel software was then used to calculate the area and thickness was estimated from the well log, and porosity values also being calculated.

3.2.3 Static modeling

3.2.3.1 Structural model for the reservoirs

The structural model of the field shows the rollover anticlinal growth fault; typical of the Niger delta which is responsible for hydrocarbon trapping mechanism of the field. The three mapped horizon surfaces were seen to form anticlines. This model further buttresses the information gathered from the depth structural maps.

3.2.3.2 Permeability model

The model (Fig. 14) depicts good permeability values which ranges from 100 mD to 1000 mD within zones in proximity to the wells in OYA field. The values are reflective of good interconnectivity of pore spaces and transmisivity of the fluids in the reservoir sands. In contrary, the region farther away from the well location in the southern part and some parts in the south-west direction indicate poor to fair permeability which ranges from 1 mD to 20 mD. This support the methodology adopted by [5].

3.2.3.3 Porosity model

The map shows evidence of excellent porosity distribution (0.30 - 0.50) within locations around the wells in OYA field. This indicates the pore spaces having sufficient space to accommodate fluid while the region farther away from the well locations in the northern part and some parts in the south-west direction indicate porosity range from 0 – 0.1 which indicate poor porosity.

3.2.3.4 Net to gross model

The Map shows good net to gross which falls between 0.6 and 1 within the well locations of the OYA field while the region farther away from the well location is indicative of low net to gross which is between 0 and 0.3.

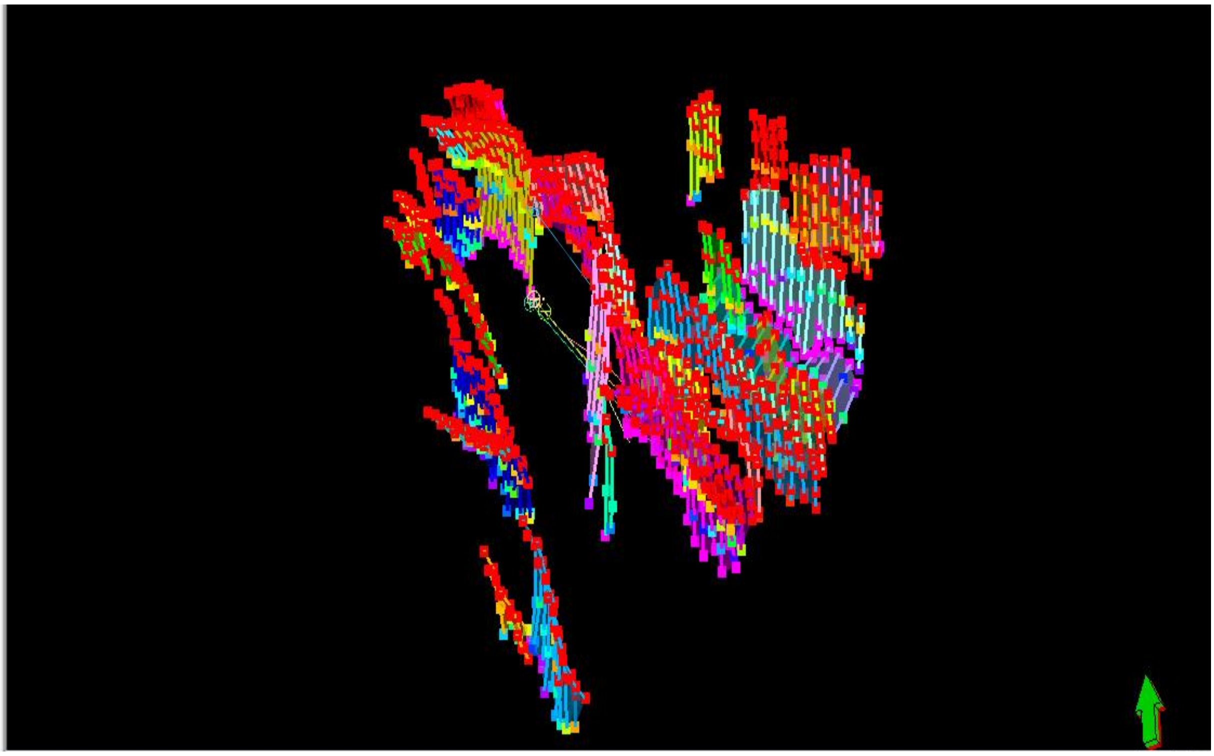

Fig. 11. Fault interpretation incorporated into the structural model

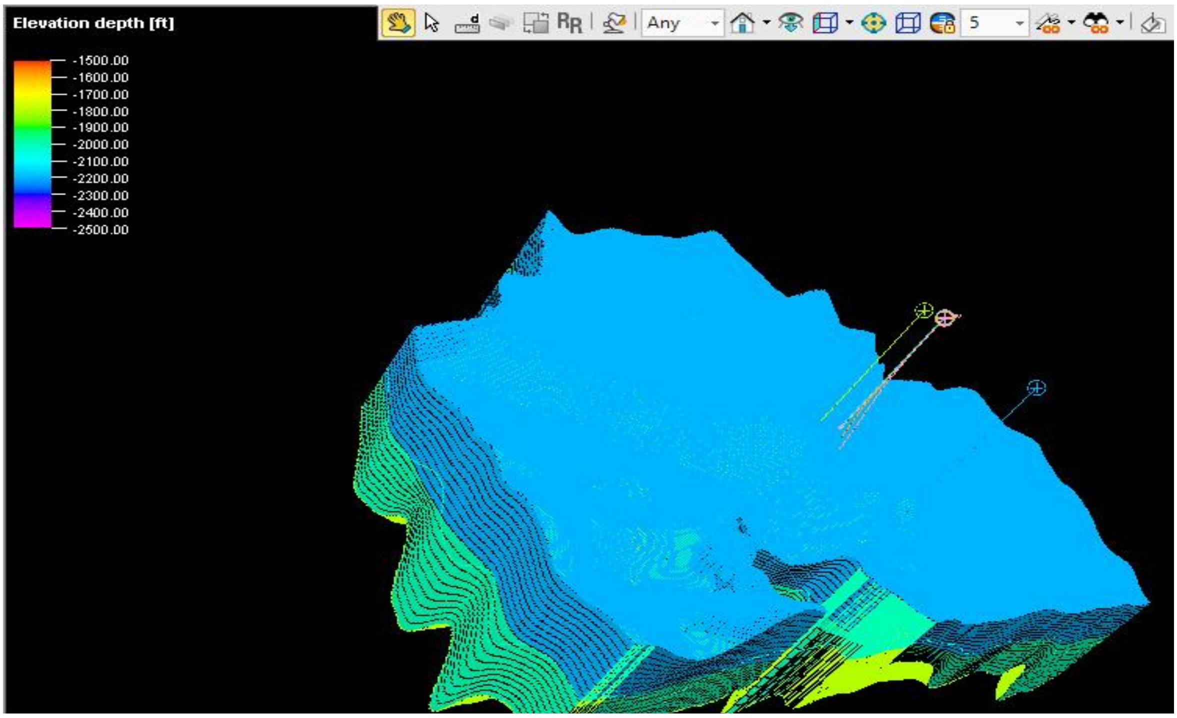

Fig. 12. Top showing 3D view components of the structural model of the reservoirs

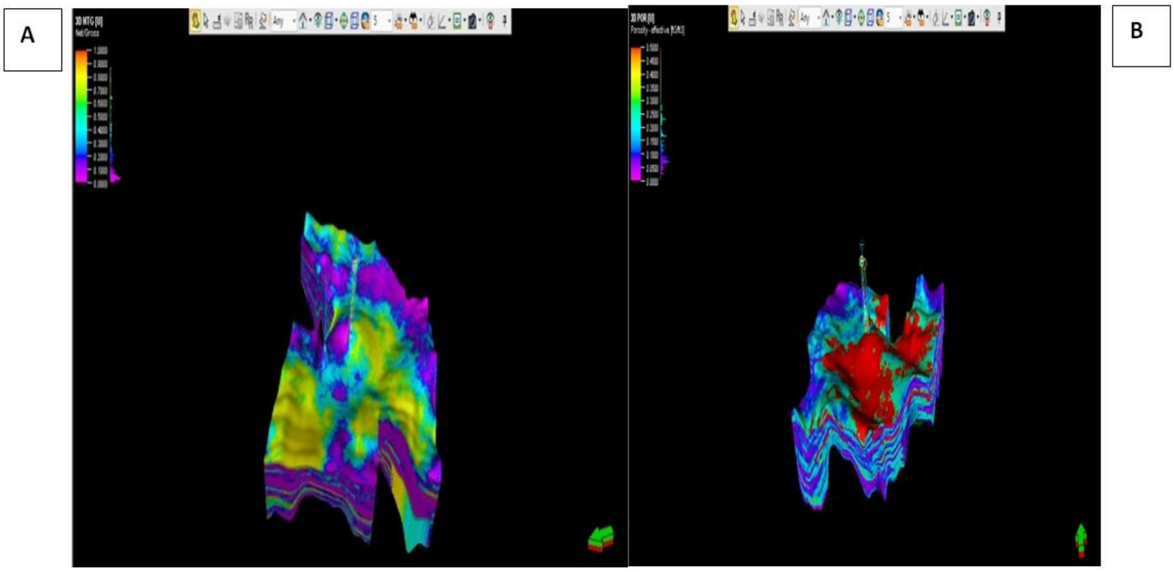

Fig. 13. Showing (a) NTG model and (b) Porosity model of the mapped surfaces

3.2.3.5 Water saturation model

The map reveals that water saturation distribution within the well locations of the OYA field varies from 0.6 to 1.00. This is indicative of more of water than hydrocarbon. In general the reservoirs has higher fraction of water than hydrocarbon.

3.2.3.6 Reservoir volumetric

Two zones of hydrocarbon accumulation have been identified from the volumetric analysis as shown in the Table 1 above. Total amount of recoverable oil from the two zones amount to $9.937138*10^5$ STB.

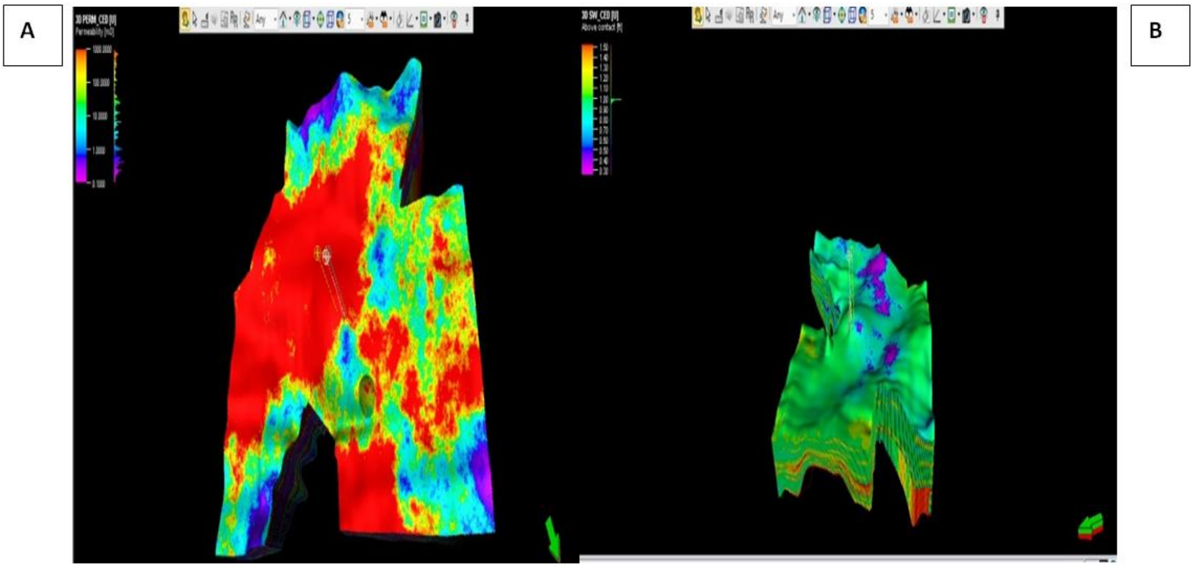

Fig. 14. Showing (a) Permeability model and (b) Water saturation model of the mapped surfaces

4. CONCLUSION

This research work help to understand the versatility of integrating 3D seismic reflection data and well log data for reservoir characterization, attributes analysis and modeling. Static geologic model generated aid in understanding the structural framework and property distribution of the designated reservoirs in "OYA" field, Offshore Depobelt, Niger Delta Sedimentary Basin. Results of petrophysical analysis shows that the reservoirs in the wells are of good porosity, permeability and moderate net-to-gross. The accumulation and trapping of hydrocarbon in this field is as a result of the rollover structures due to faulting. The trapping mechanisms include fault assisted and four way closures. Seismic attributes maps also aid in identifying new hydrocarbon prospects in the field, which can be subjected to further seismic analysis and integrated with well logs in order to ascertain the volumes of hydrocarbons within these prospects.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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