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Overpressure Identification and Petrophysical Evaluation of DIAG Field, Offshore Niger Delta, Nigeria

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Abstract
An accurate prediction of the sub-surface pore pressures is a necessary requirement for safety, economics and efficiency in the drilling of wells for exploration and production of oil and gas. The study therefore is aimed at determining overpressured zone(s) and the lateral extent from seismic and well log data and to evaluate petrophysical parameters of diverse sand units within DIAG Field. Qualitative evaluation of four sand bodies within three wells was determined. The identified sand horizons were correlated across the studied wells and tied to the seismic section. The depth structural maps and the isochore maps of the sand horizons were generated. The results show five over-pressured zones within the study wells which occurred at depth range from 1793.88 m (5919.68 ft) to 2119.62 m (6994.76 ft) and were tied to seismic section.The depth structured map of the overpressured zones were generated. The identified reservoir Sand 1, Sand 2 and Sand 4 can produce both oil and gas with Sand 3 producing only oil. From the petrophysical parameters, it was evident that all the reservoirs are highly prolific. The Movable Hydrocarbon Index for the entire hydrocarbon reservoir is lower than 0.7 indicating a high mobility of the hydrocarbon within the reservoir.

Key words: Overpressure, Seismic section, Porosity, Permeability, DIAG Field, Hydrocarbon saturation.

Introduction

Pore pressures in most deep sedimentary formations are not hydrostatic rather they are overpressured and elevated even to more than double of the hydrostatic pressure. If the abnormal pressures are not accurately predicted prior to drilling, catastrophic incidents, such as well blowouts and mud volcanoes, may take place. Abnormal pressured rocks are typical of many sedimentary basins worldwide [1 – 4]. Prediction of over/ high pressures in the sedimentary sequences in any sedimentary basin is indeed a challenging problem.

In the Tertiary Niger Delta basin of Nigeria, serious challenges are still been experienced in terms of over-pressure predictions despite many years of petroleum exploration. Deposition in the basin is largely controlled by extensive contemporaneous growth faults associated with shale diapiric structures. This situation has resulted in over pressuring at depth, which influences many related aspect of the basin. With growing interest in deeply buried reservoirs, understanding the role of tectonics in pressure distribution is becoming of utmost importance, making the evaluation of its impact on seal retention and hydrocarbon trapping a key to successful petroleum exploration [1 – 4]. Pre-drill pore pressure prediction allows for appropriate mud weight to be selected and drill casing program to be optimized, thereby enabling safe and economic subsurface drilling.

For exploration, where empirical relationships are available from well logs and drilling reports, and where information is available on a large scale, a more general, quantitative approach is desirable [5]. Thus, the knowledge of formation pore pressure is not only essential for safe and cost-effective drilling, but also critical for assessing exploration risk. This study therefore intends to delineate the lithology and determine the various petro-physical parameters (effective

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porosity, fluid saturation, formation thickness) of the well logs used. It shall also identify the possible overpressure zones and the depth at which they occur via well log; determine the lateral extent and correlate it on a larger scale using seismic data set from the field of study.

Location of the Study Area

The study area is within DIAG Field belonging to Chevron Nigeria Limited. It is located offshore depobelt of the Niger Delta (Figs. 1 and 2).

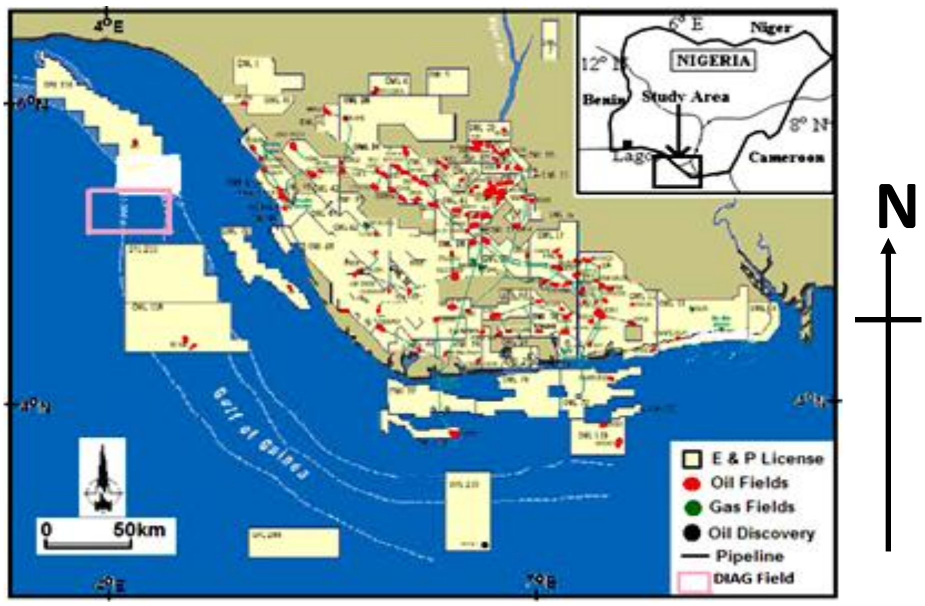

Fig. 1: Concession map of Niger Delta showing study area (modified from Doust and Omatsola 1990).

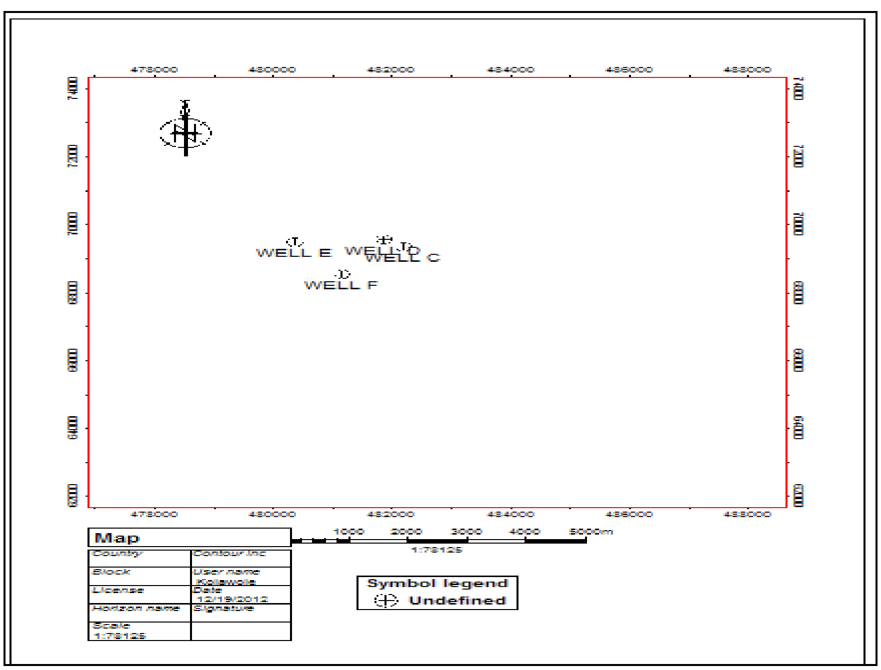

Fig. 2: DIAG Field showing the well locations.

Previous Work

The Niger Delta has been a subject of where research and exploration for its hydrocarbon potentials. Focus had been on the stratigraphy, petrophysics, sedimentology, as well as organic geochemistry of the sedimentary sucession of the delta. Short and Stauble [6] discussed the stratigraphy, subsurface sedimentary sequence, paleo-geography, structure, petroleum occurrence and other aspects of the Niger delta and suggested that the source rocks in the Niger delta are the shales of the Akata and Agbada Formations. Ekweozor and Okoye [7] also evaluated the petroleum source bed of the Niger delta, supporting the conclusion of Weber and Daukoru [8] that the source rocks are the shales of the Akata Formation. Merki [9] discussed the structures in the delta and how the delta sequence is deformed by synsedimentary faulting and folding.

Selly [10] interpreted the environments of the sand bodies using a combination of log shapes and detrital mineral components. He used gamma ray log shapes to identify facies of the deltaic, fluvial, marine and deep-sea environments. Orife and Avbovbo [11] studied structural and seismic sections of the Niger Delta and observed that hydrocarbons are trapped in stratigraphic traps. The causes of overpressure has been and characterized by porosity values being higher than expected, and the bulk density being correspondingly lower [12]. Krusi observeded the rate of overpressure increase is related to the proximity of the Akata Shales and that over-pressure is identified in wireline logs by a reversal in trend at the zone of occurrence suggesting that undercompaction could be a major cause of overpressure in the Niger delta [13].

Hottman and Johnson [14], and Pennebaker [15] used deviation of P-wave velocity from normal compaction trends to detect pore pressure and estimate pressure using empirical calibration curves. Eaton [16], relates the change in pore pressure to change in P-wave velocity. His assumption is that a ratio of P-wave velocity obtained from regions of normal and abnormal pressure is related to the ratio of normal and abnormal pressure for the region through an exponent that may be determined empirically [17]. Bradley [18] reported that the larger pore pressures are more likely encountered where the processes that formed them are recent or still active and seal efficiency is still very high. Swarbrick and Osborne [19] proposed that the major mechanisms for large magnitude over pressure in most extensional sedimentary basins are compaction disequilibrium. Mann and Mackenzie [20] proposed that compaction disequilibrium was the dominant mechanism for observed fluid overpressure between overpressure gradient, permeability and deposition rate.

Luo and Vasseur [21] proposed that excess pressure is so great that it cannot be explained by compaction alone in some areas. Ichara and Avbovbo [22] established that in Niger Delta, overpressuring cannot be accounted for by a single factor but the interplay of several factors operating in the basin.

Stratigraphy of the Niger Delta

The Niger Delta constitutes an advance of terrrestrial deposits into a high energy marine environment. At present, deposition occurs simultaneously under fully terrestrial and marine conditions, under conditions, where there is an interplay between terrestrial and marine influence (i.e parallic) and under fully marine conditions [23]. As the sediments prograded south, coast lines became markedly convex seaward with the present delta sedimentation still being wave dominated. Short and Stauble [6] defined formations within the Niger Delta as clastic wedge based on sand/shale ratios estimated from subsurface well-logs. The three major litho-stratigraphic units defined in the subsurface of Niger Delta (Akata, Agbada and Benin Formations) reflect a gross upward-coarsening clastic wedge (Fig. 3). These Formations were deposited in dominantly marine, deltaic and fluvial environments respectively [8].

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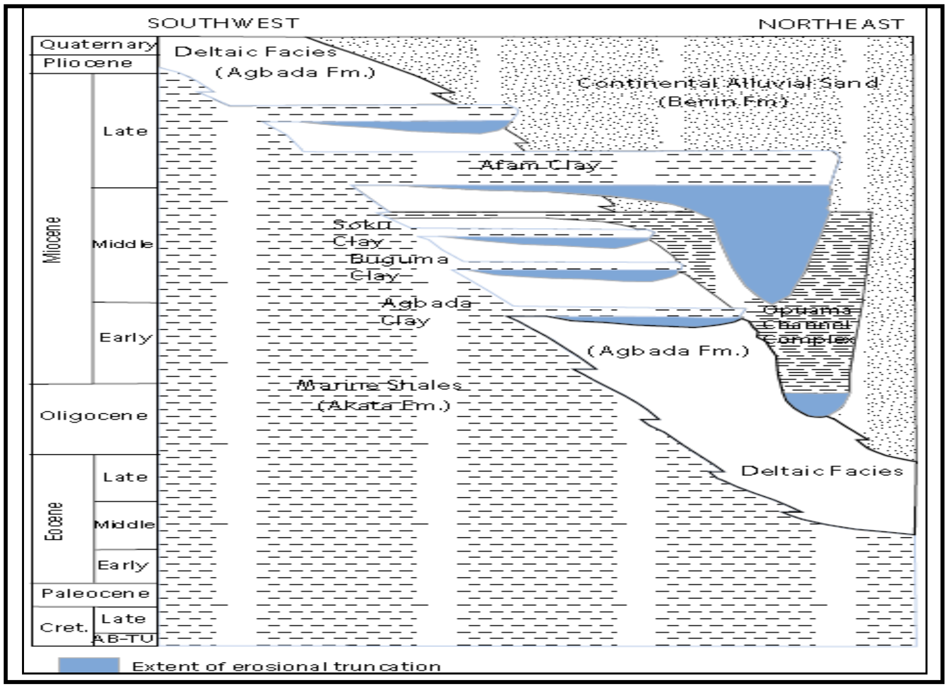

Fig. 3: Stratigraphic column showing the three formations of the Niger Delta (modified from Doust and Omatsola 1990).

Depobelts

Five off lapping siliciclastic sedimentation cycles have been postulated as being responsible for the deposition of the three subsurface Niger Delta formations (Akata, Agbada and Benin Formations). According to Stacher [24], these cycles (depobelts) are 30-60 kilometers wide and prograde southwestward 250 kilometers over Oceanic Crust into the Gulf of Guinea where they are defined by synsedimentary faulting that occurred in response to variable rates of subsidence and sediment supply.

The variations of subsidence and supply rates resulted in deposition of distinct depobelts. When further crustal subsidence of the basin could no longer be accommodated, the focus of sediment deposition shifted seaward, forming a new depobelt [25]. Each depobelt is a separate unit that corresponds to a break in regional dip of the delta and is bounded landward by growth faults and seaward by large counter-regional faults or the growth fault of the next seaward belt [25, 26]. Five major depobelts are generally recognized, each with its own sedimentation, deformation, and petroleum generation history [25] (Fig. 4).

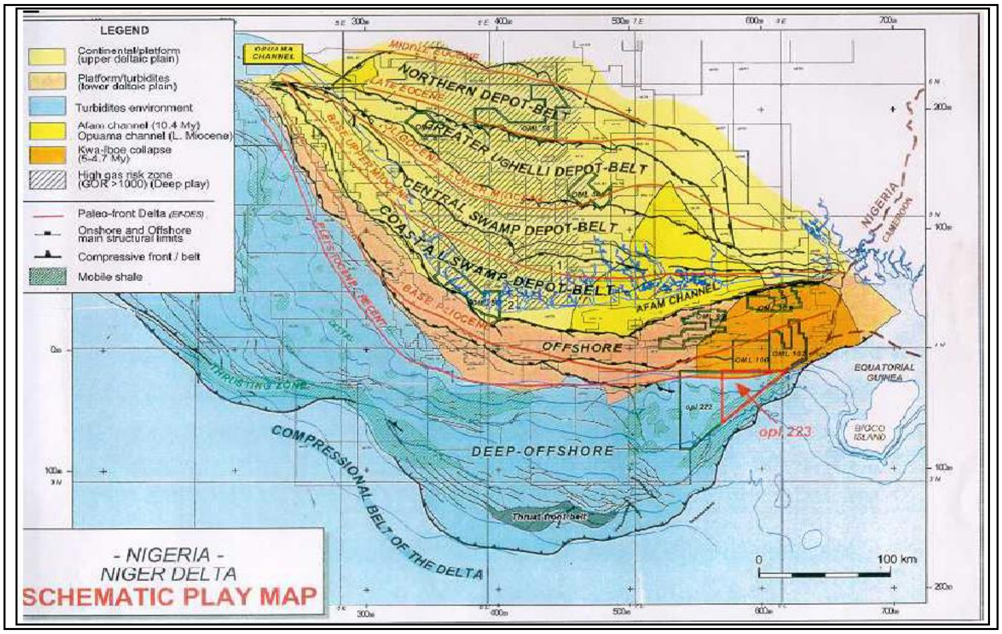

Fig. 4: Niger Delta depobelt (after Whiteman 1982).

The oldest is the northern delta province which overly relatively shallow basement. It has growth faults that are described as the oldest, generally rotational with increase in seaward steepness. The second is the Greater Ughelli Depobelt. The third is the central delta province swamp depobelt, it has well defined structures such as deeper rollover crest that shift seaward for any growth faults. The fourth depobelt is the Coastal swamp Depobelt, it is found in the distal delta province. It is the most structurally complex onshore depobelt due to internal gravity tectonics on the modern continental slope. The fifth is the Offshore Depobelt.

Materials and Methodology

The data set for this study was provided by Chevron Nigeria Limited. The data set include 3-D seismic survey, a composite log of four wells (Wells C, D, E and F) and a check shot data. The data set was analyzed using Petrel 2009 and RokDoc 5.6.3 softwares. Logs used for the study include the Lithology log (Gamma Ray), Resistivity log and Porosity logs (Density, Neutron and Sonic log).

Correlation, interpretation of well data and generation of maps were achieved using PETREL 2009 software. The data were validated, imported and edited to minimize errors. After validation of the available well data, the data which was in the LAS data format was imported into PETREL 2009 software in three stages. First, the well header information which consist of the name and coordinates of the wells, followed by the deviation data for deviated wells (Well C and Well F) and the different log siuts.The 3-D seismic data which was in the SGY data format was also imported into PETREL 2009. Necessary steps was duly followed in the importation of the data so as to avoid errors. The seismic data is a migrated data with in-line ranging from 5800 to 6200 and cross line ranging from 1480 to 1700.

The evaluation of reservoir rocks in terms of their petrophysical parameters such as porosity, permeability, water saturation and hydrocarbon saturation enhances the ability to predict abnormally pressured zones within the shale body, determine the reservoir bed thickness, and to distinguish between gas, oil and water bearing zones within the field. The method used for detection of over-pressure exploit the deviation of formation properties from an expected or normal trend in the area of interest. The identified overpressured zones from the well logs with the aid of check-shot data are picked on the seismic data and a lateral extent of the overpressure surfaces is mapped throughout the study area. Petrophysical parameters were also evaluated to obtain qualitative information of the identified reservoirs.

Results and Interpretation

Overpressured Zones

Five major overpressured zones (OPZ) were identified based on gamma ray, sonic and the density logs signatures (Fig. 5). These zones were correlated across wells D, E and F, but only OPZ 4 and OPZ 5 were observed in well C, due to the logging of well C which started at a depth of 6610ft (2003.03m). From the results presented in Table 1, the overpressured shale occurs at subsea depth ranging from 5119.68ft (1551.42m) to a depth of 7002.72ft (2122.04 m). The gross thickness of the intercalated overpressured shale range from 14.15ft (4.29m) to about 35ft (10.61m) thick (Table 1).

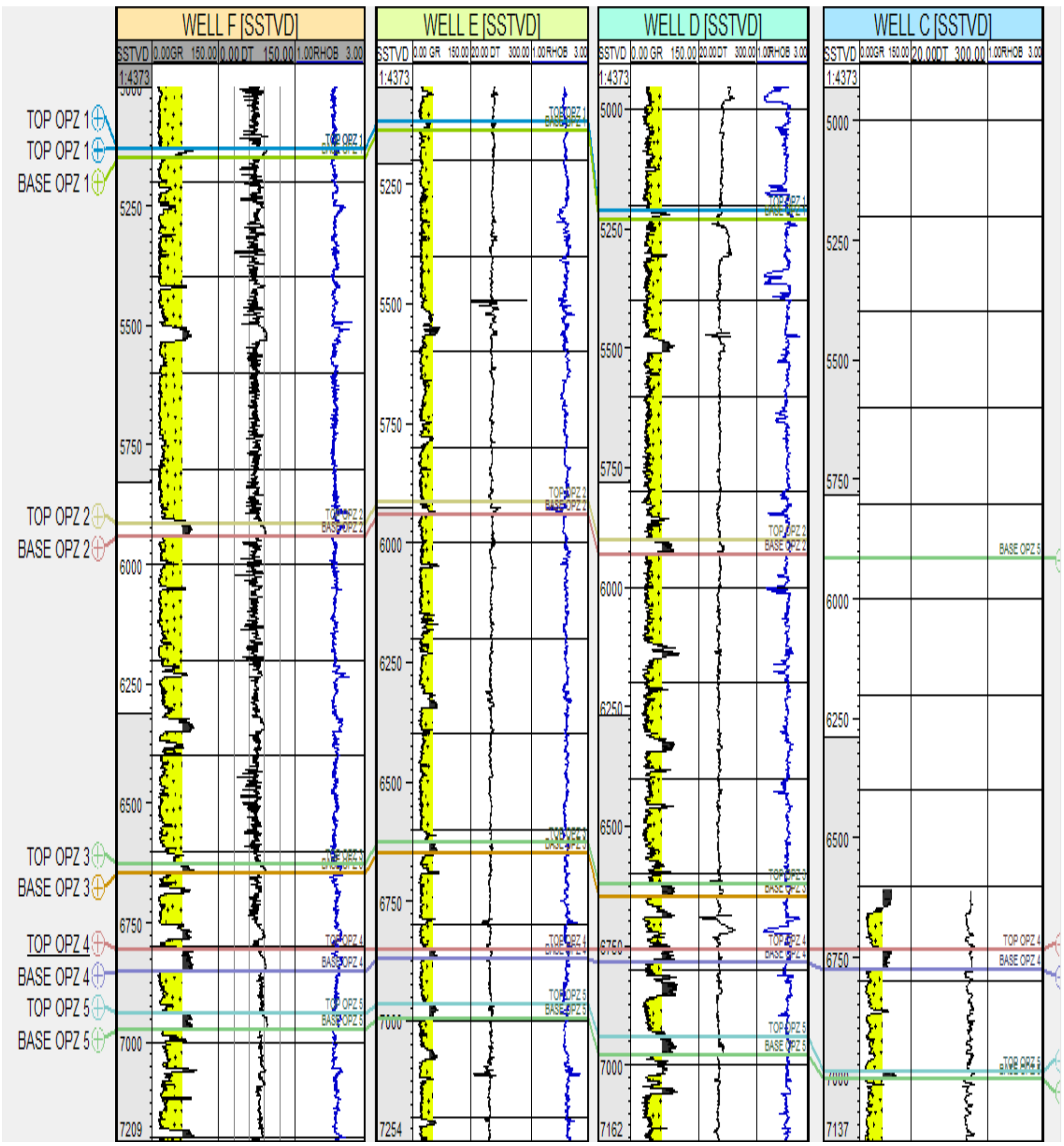

Fig. 5: Correlation of identified overpressured zones across the studied wells.

Table 1: Measured Depth (MD) and Stratigraphic Thickness of the identified Overpressured Shale Horizones

		OPZ 1 (Ft)	OPZ 2 (Ft)	OPZ 3 (Ft)	OPZ 4 (Ft)	OPZ 5 (Ft)
Well E	Top	5119.68 1551.42(m)	5916.29 1792.82(m)	6623.94 2007.26(m)	6849.05 2075.47(m)	6965.92 2110.89(m)
	Base	5133.83 1551.71(m)	5940.94 1800.29(m)	6650.56 2015.32(m)	6871.51 2082.28(m)	6994.76 2119.62(m)
	Thickness	14.15 (4.29m)	24.65 (7.47m)	26.62 (8.07m)	22.46 (6.81m)	28.84 (6.32m)
Well F	Top	5129.36 (1560.67m)	5916.38 (1792.84m)	6629.79 (2009.02m)	6802.74 (2061.44m)	6938.87 (2102.69m)
	Base	5150.21 (1560.67m)	5941.08 (1800.33m)	6649.05 (2014.86m)	6849.14 (2075.50m)	6974.10 (2113.36m)
	Thickness	20.85 (6.32m)	24.7 (7.48m)	19.26 (5.84m)	46.4 (14.06m)	35.23 (10.68m)
Well D	Top	5211.42 (1579.22m)	5904.54 (1789.26m)	6622.13 (2006.71m)	6756.66 (2047.47m)	6939.96 (2103.02m)
	Base	5232.28 (1585.54m)	5931.76 (1797.50m)	6649.38 (2014.96m)	6786.51 (2056.52m)	6981.34 (2115.56m)
	Thickness	20.86 (6.32m)	27.22 (8.25m)	27.25 (8.26m)	29.85 (9.05m)	41.38 (12.54m)
Well C	Top	-	-	-	6732.16 (2040.05m)	6988.35 (2117.68m)
	Base	-	-	-	6778.78 (2054.18m)	7002.72 (2122.04m)
	Thickness	-	-	-	46.62 (14.13m)	14.37 (4.36m)

OPZ = Overpressured Zone

Velocity relationship generated from the check-shot data was used to convert the time map of the overpressure horizons into depth map which was contoured using an interval of 30ft (9.1m). The depth structure map of the overpressured shale has minimum and maximum subsea contour values of -1550m and -1600m for OPZ1, -1660m and -1750m for OPZ 2, -1800m and -1875m for OPZ 3, -1800m and -1850m for OPZ 4 and -1850m and 2050m for OPZ 5 (Figs. 6 - 10).

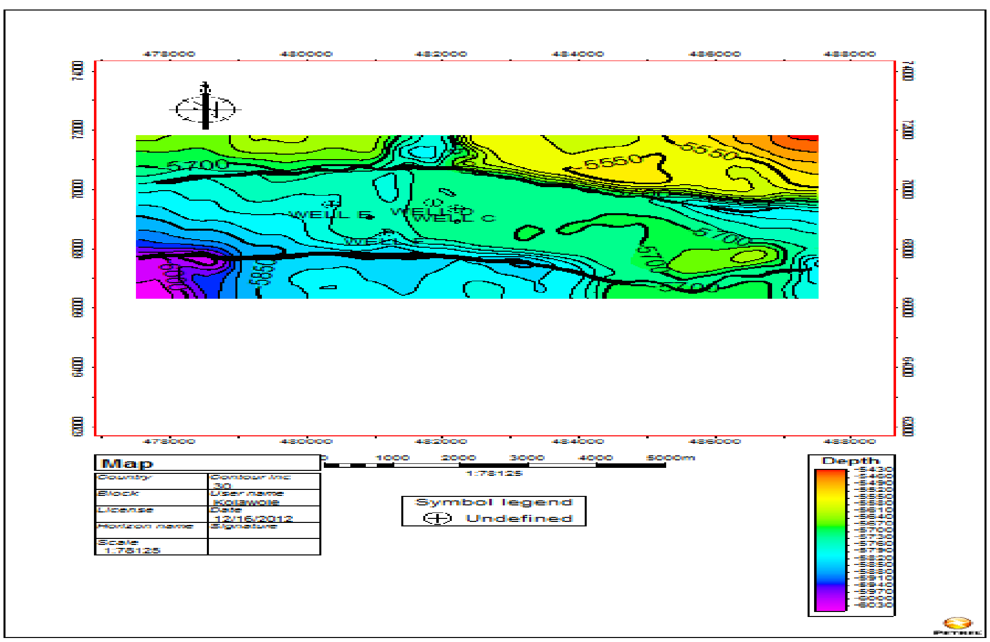

Fig. 6: Structural (Depth) Map showing the Top of OPZ 1.

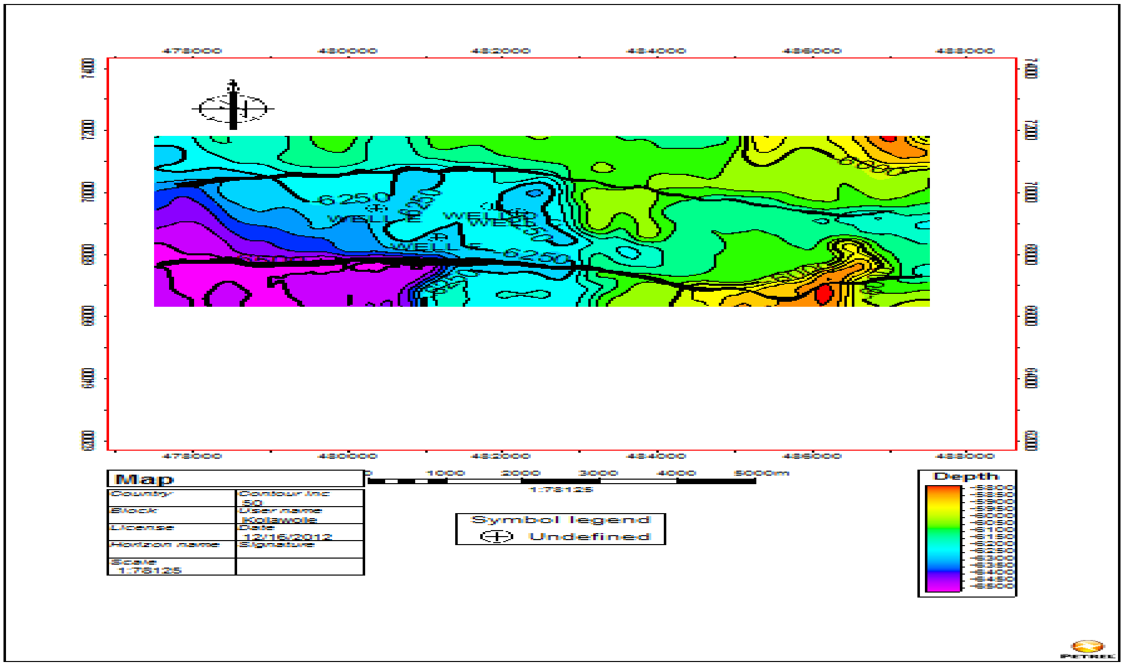

Fig. 7: Structural (Depth) Map showing the Top of OPZ 2.

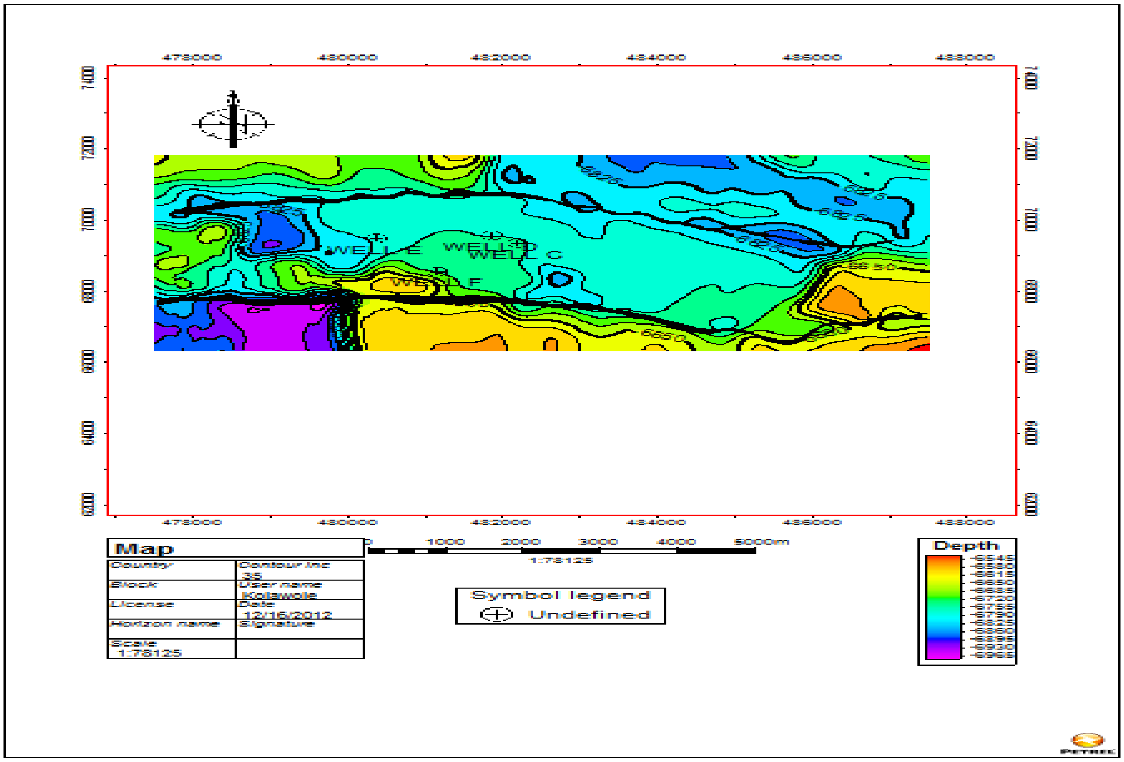

Fig. 8: Structural (Depth) Map showing the Top of OPZ 3.

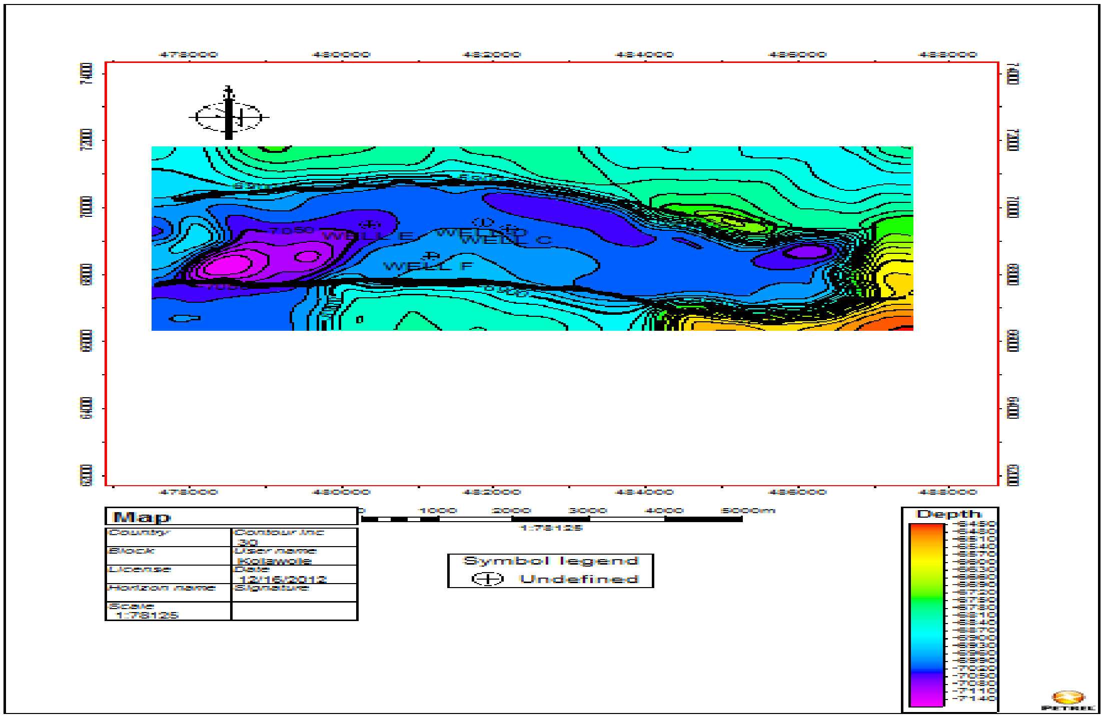

Fig. 9: Structural (Depth) Map showing the Top of OPZ 4.

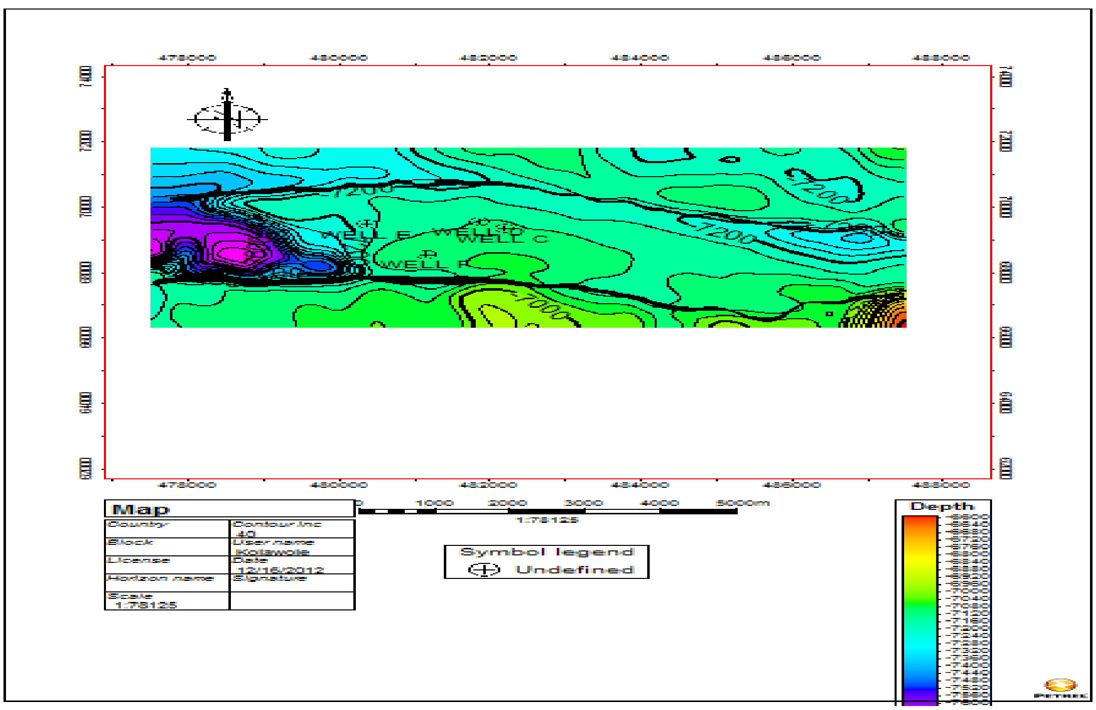

Fig. 10: Structural (Depth) Map showing the Top of OPZ 5.

Petrophysical Evaluation

Based on well log information, three of the wells (Well E, Well F and Well D) were analyzed for petrophysical parameters. From these wells, four major sand bodies identified are Sand 1, Sand 2, Sand 3 and Sand 4 (Fig. 11). The sand bodies were correlated across the wells and formation top and bottom were assigned to these sand bodies (Table 2). The gross thickness of the reservoirs ranged from 91.22ft (27.80m) to 251.39ft (76.62m) (Table 2). Contact observed within the reservoirs are; the Oil Water Contact (OWC) and Gas Oil Contact (GOC), (Table 3). Depth of Oil Water Contact within Sand 1 ranged from 6518.39ft (1975.24m) to 6556.42ft (1986.79m), in Sand 2 it ranged from 6813.78ft (2064.78m) to 6759.59ft (2048.36m), Sand 3 ranged from 6868.33ft (2081.31m) to 6757.80ft (2047.82m) and in Sand 4 it ranges from 7132.24ft (2161.29m) to 7183.80ft (2176.91m) respectively. Gas Oil Contact (GOC) within SAND 1 ranged from 6429.47ft (1948.32m) to 6487.26ft (1965.84m), in the Sand 2 reservoir, it ranged from 6688.33ft (2026.77m) to 6757.80ft (2047.82m), in Sand 3, it occurs only within Well D at a depth of 6897.87ft (2090.26m) while it ranged from 7041.68ft (2133.84m) to 7079.39ft (2145.27m) in Sand 4.

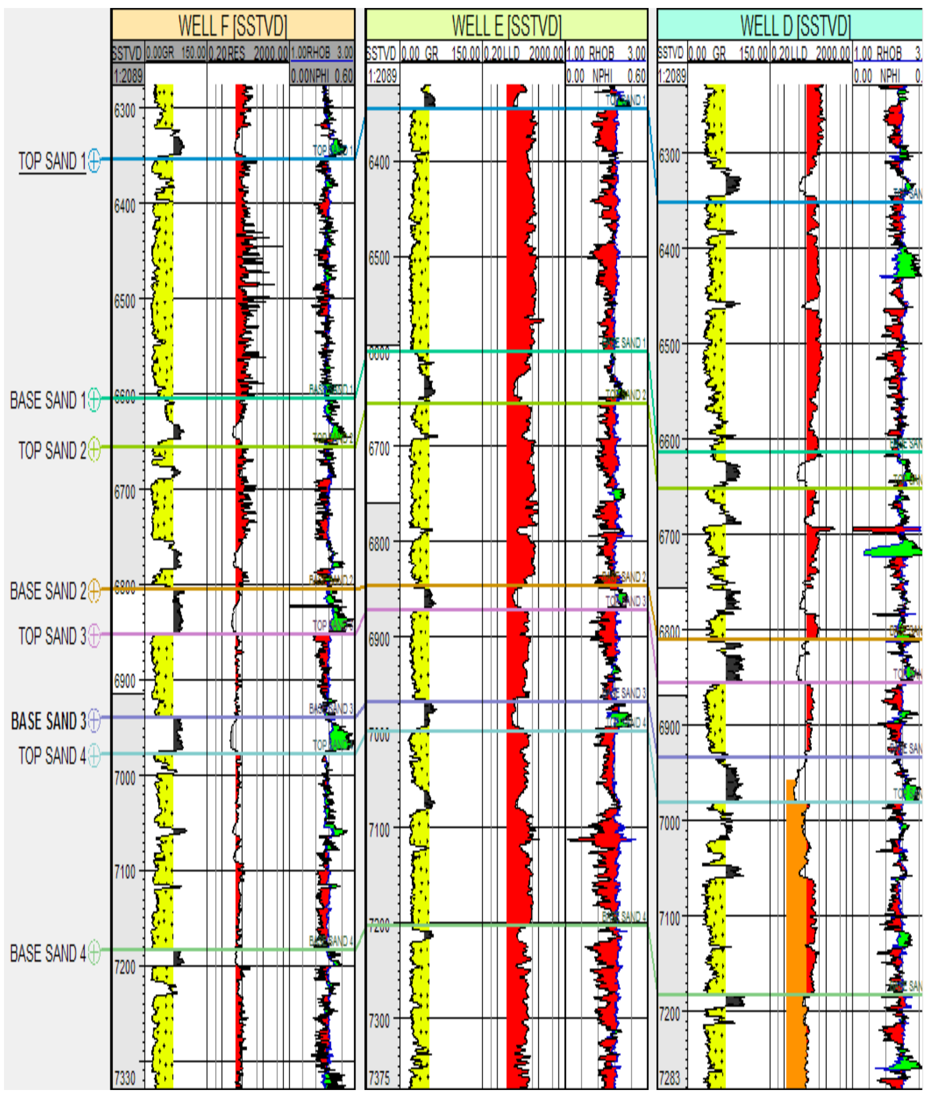

Fig. 11: Correlation of sand units across the studied wells.

Table 2: Measured depth (MD) and Stratigraphic Thickness of the identified Sandhorizons

		Sand 01 (ft)	Sand 02 (ft)	Sand 03 (ft)	Sand 04 (ft)
Well E	Top	6346.83 (1923.28m)	6652.61 (2106.85m)	6870.38 (2081.93m)	6998.52 (2120.76m)
	Base	6598.22 (1999.46m)	6844.83 (2074.19m)	6968.08 (2111.54m)	7202.00 (2182.42m)
	Thickness	251.39 (76.18m)	190.22 (57.64m)	113.25 (34.32m)	203.48 (61.66m)
Well F	Top	6351.71 (1924.76m)	6654.41 (2016.49m)	6849.71 (2075.70m)	6976.16 (2113.99m)
	Base	6603.10 (2000.94m)	6804.90 (2062.09m)	6940.93 (2103.31m)	7182.93 (2176.65m)
	Thickness	251.29 (76.15m)	150.49 (45.54m)	91.22 (27.64m)	206.77 (62.66m)
Well D	Top	6350.44 (1924.38m)	6658.14 (2017.62m)	6854.83 (2077.22m)	6979.79 (2115.09m)
	Base	6611.52 (2003.49m)	6808.43 (2063.16m)	6934.98 (1919.69m)	7181.66 (2176.26m)
	Thickness	261.08 (79.12m)	150.29 (45.54m)	80.15 (24.29m)	201.87 (61.17m)

Table 3: Summary of Petrophysical Parameters

Reservoir Sand	Net to Gross		Water Saturation		Porosity (ø)		Permeability (mD)		Fluid Contacts
	Min	Max	Min	Max	Min	Max	Min	Max	
Sand 01	0.02	0.08	0.12	0.13	0.168	0.302	140.05	8865.6	GOC,OWC
Sand 02	0.07	0.34	0.11	0.44	0.034	0.28	0.1	8285.3	GOC,OWC
Sand 03	-	-	0.14	0.45	0.02	0.27	1.4	7665.3	OWC
Sand 04	0.07	0.22	0.04	0.46	0.06	0.39	0.1	87210	GOC, OWC

The seismic section record of DIAG field is characterized by series of sub-parallel reflection patterns. The sub-parallel reflection pattern is typical of sediment deposited at a uniform rate of sedimentation in a stable basin. Sequel to the well log information from petrophysical evaluation, four horizons are considered to be of interest. The results show that the identified reservoir sand bodies occur at subsea depth of -6625ft (-2007.58m) to depth of -7750ft (-2348.48m). The seismic section showed that the field was highly faulted which is, a prominent feature of the Niger Delta Basin (Fig. 12). The faults identified in the section are F_1, F_2, F_3, F_4 and F_5. The major structure building faults are $F_1$and F_2 which almost cut through the entire survey area and the presence of only normal faults in the field indicates an extensional deformational phase during subsidence and uplift associated with instability of the overpressured late Cretaceous shale.

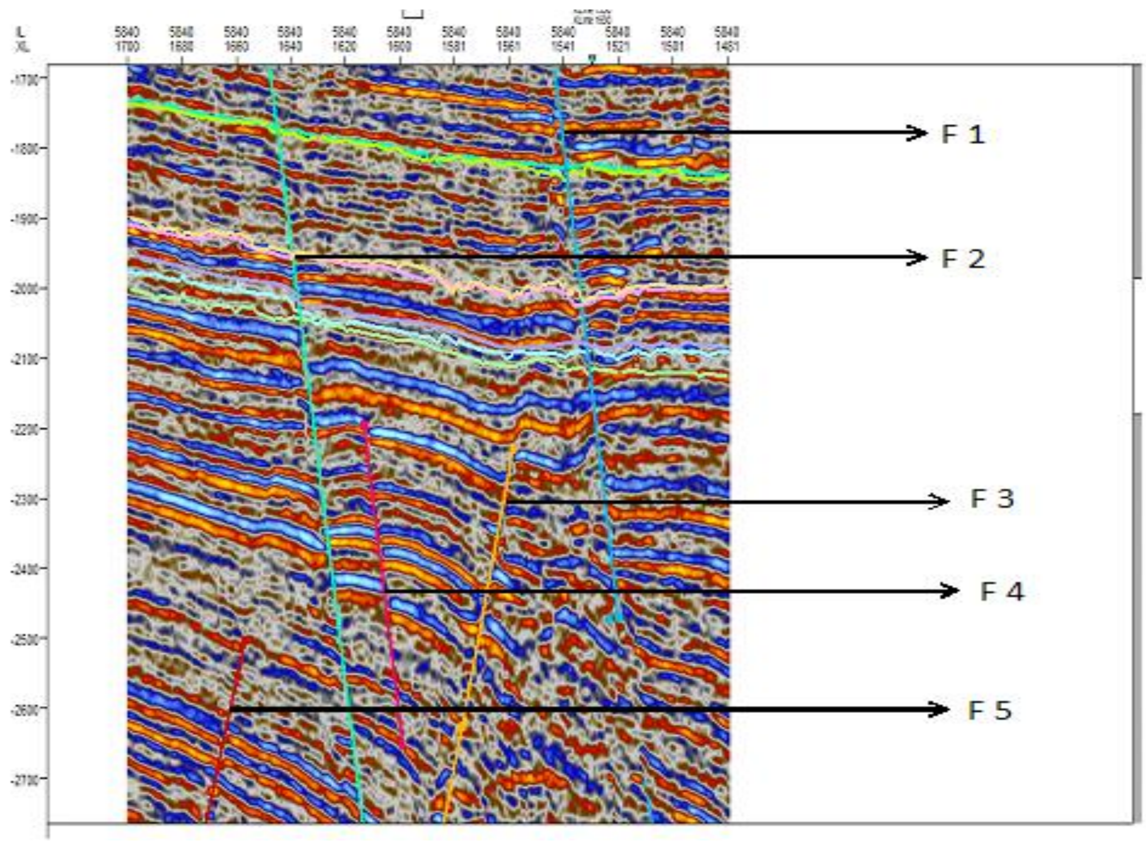

Fig. 12: Seismic cross section showing the normal and reverse faults (along inline 5840).

Depth maps as well as the thickness maps of the top and base of the reservoir sands identified were produced. The depth map was calibrated with a contour interval of 30ft (9.1m), while the thickness map was calibrated with a contour interval of 10ft (3.03m).

The minimum and maximum contour values of the reservoir sands top are; -6375ft (-1931.82m) to -6625ft (- 2007.58m) for Sand 1, -6600ft (-2000m) to – 6800ft (-2060.61m) for Sand2, -7000ft (-2121.21m) to -7500ft (-2272m) for Sand 3 and -7000ft (-2121.21m) to -7750ft (-234849m) for Sand 4 (Figs. 13 - 16).

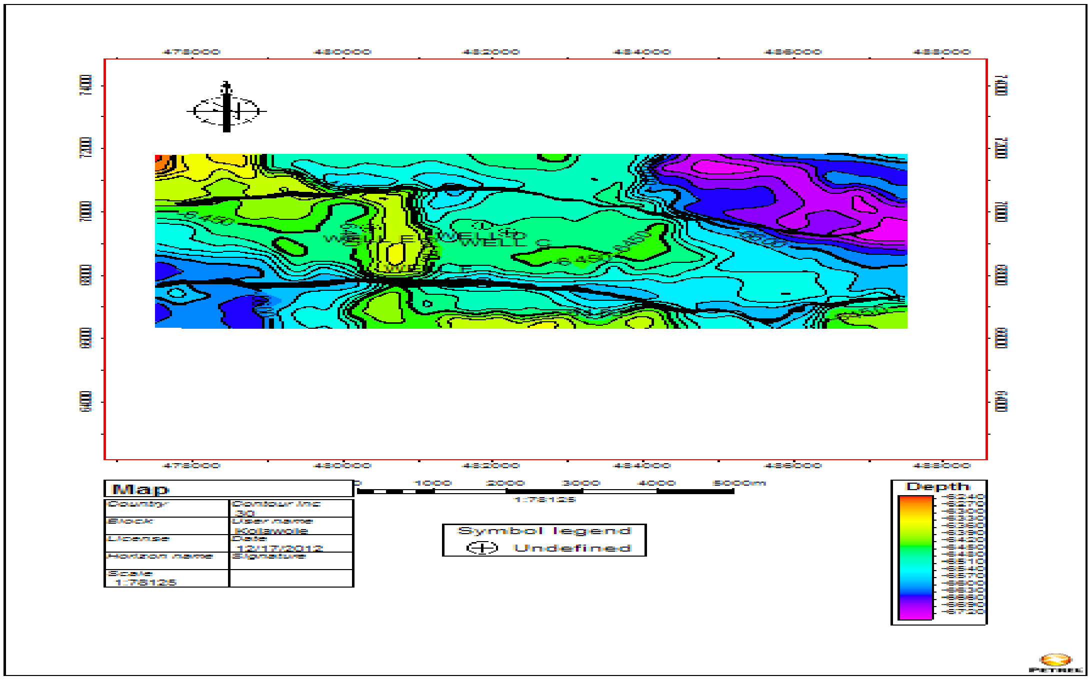

Fig. 13: Depth map showing the top of Sand 1.

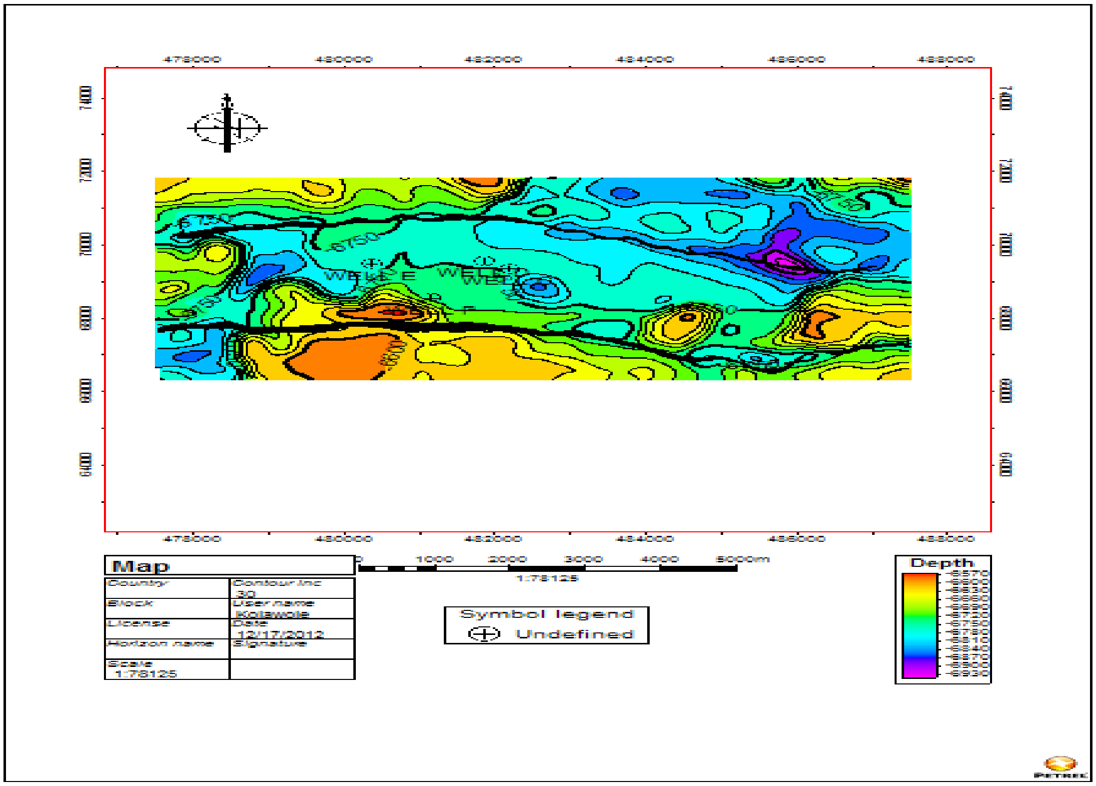

Fig. 14: Depth map showing the top of Sand 2.

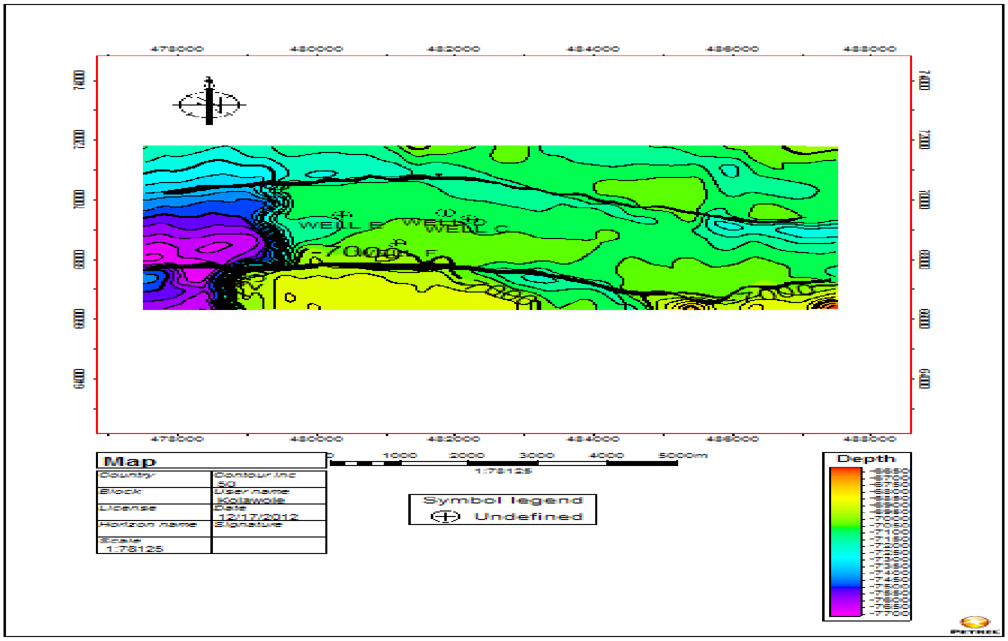

Fig. 15: Depth map showing the top of Sand 3.

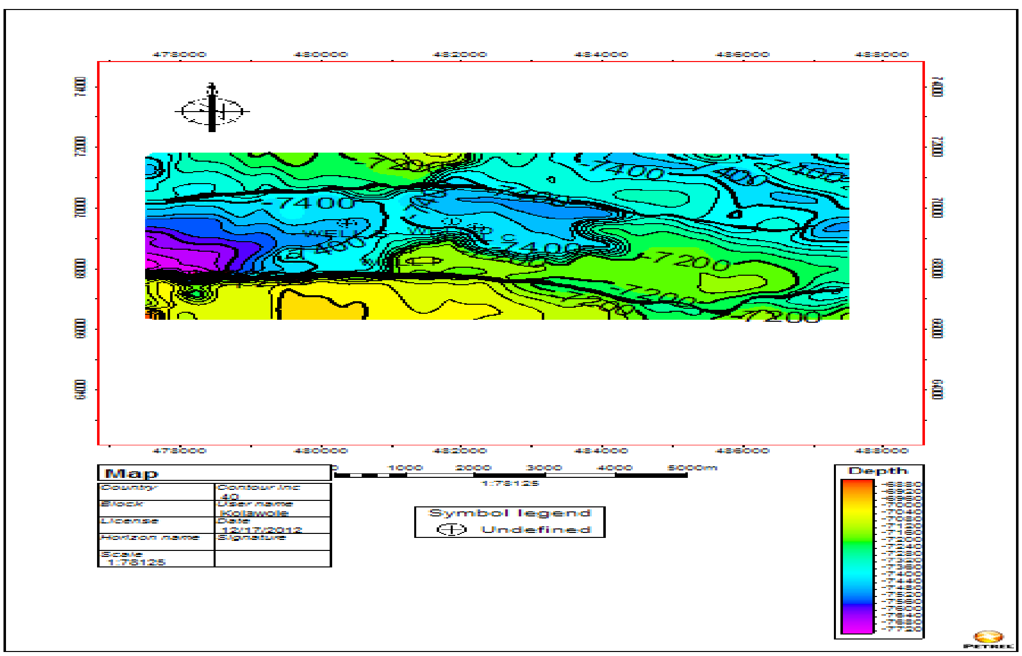

Fig. 16: Depth Map showing the top of Sand 4.

Interval transit time under normal pressure condition generally decreases with depth. At overpressure zone, there is a sudden increase in the interval transit time. Sonic velocities which is the inverse of interval transit time was calculated from the sonic logs, interval velocities were also computed from check shot data to establish an expected compaction trend and to confirm the identified overpressured zone (Figs. 17, 18, 19 and 20).

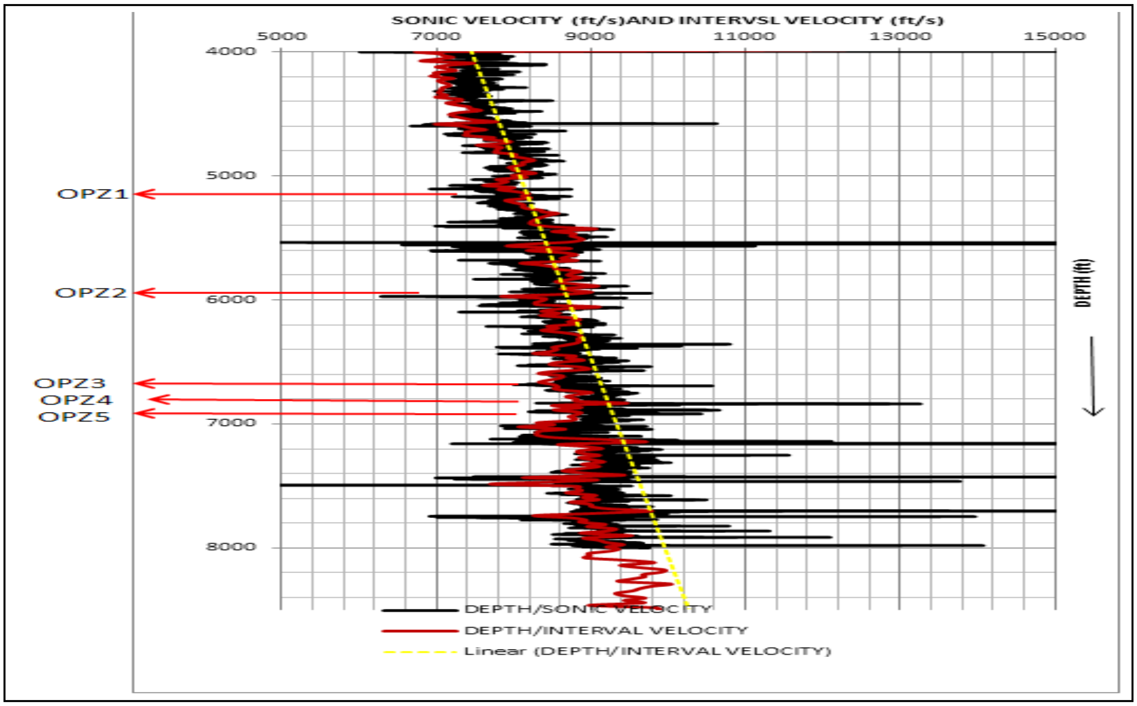

Fig. 17: Plot of sonic velocity and interval velocity against depth showing compaction trend across well E.

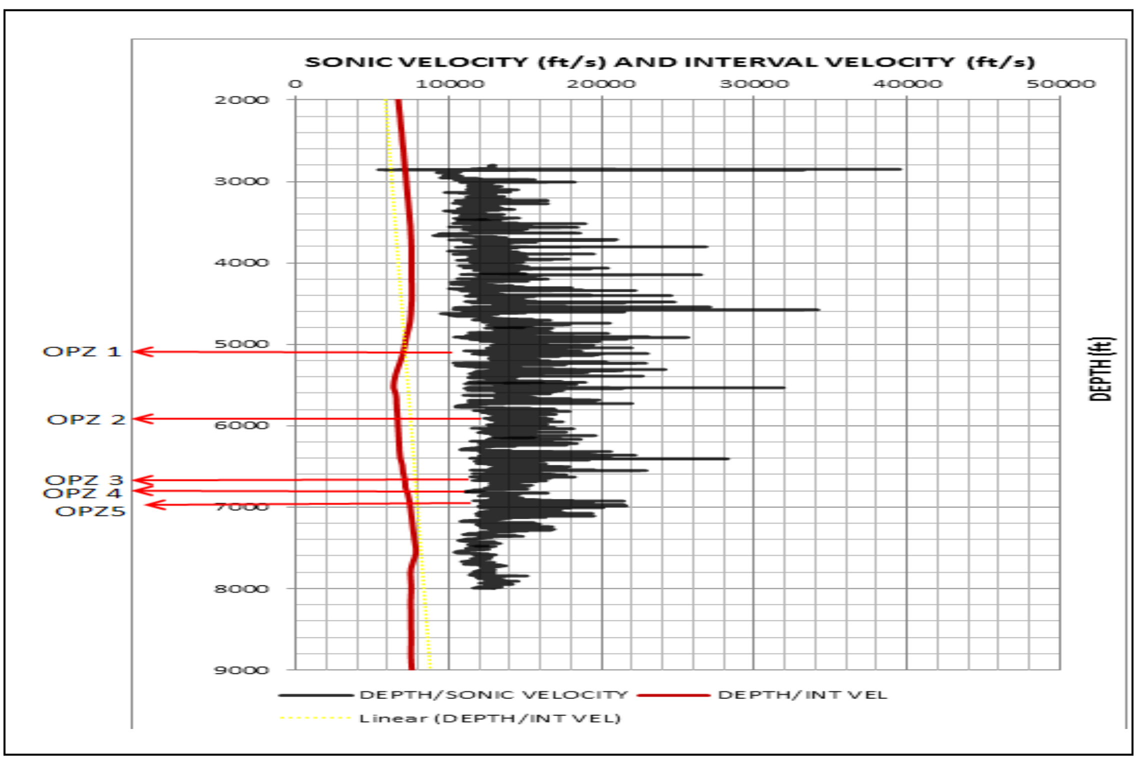

Fig. 18: Plot of sonic velocity and interval velocity against depth showing compaction trend across well F.

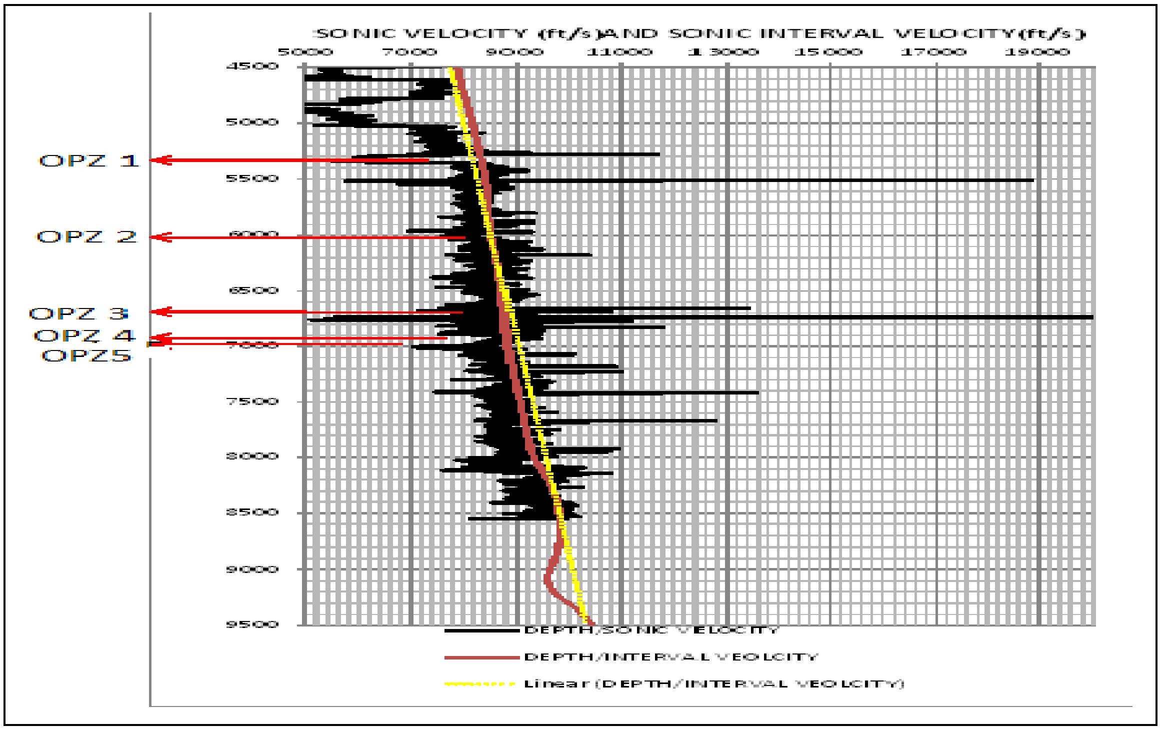

Fig. 19: Plot of sonic velocity and interval velocity against depth showing compaction trend across well D.

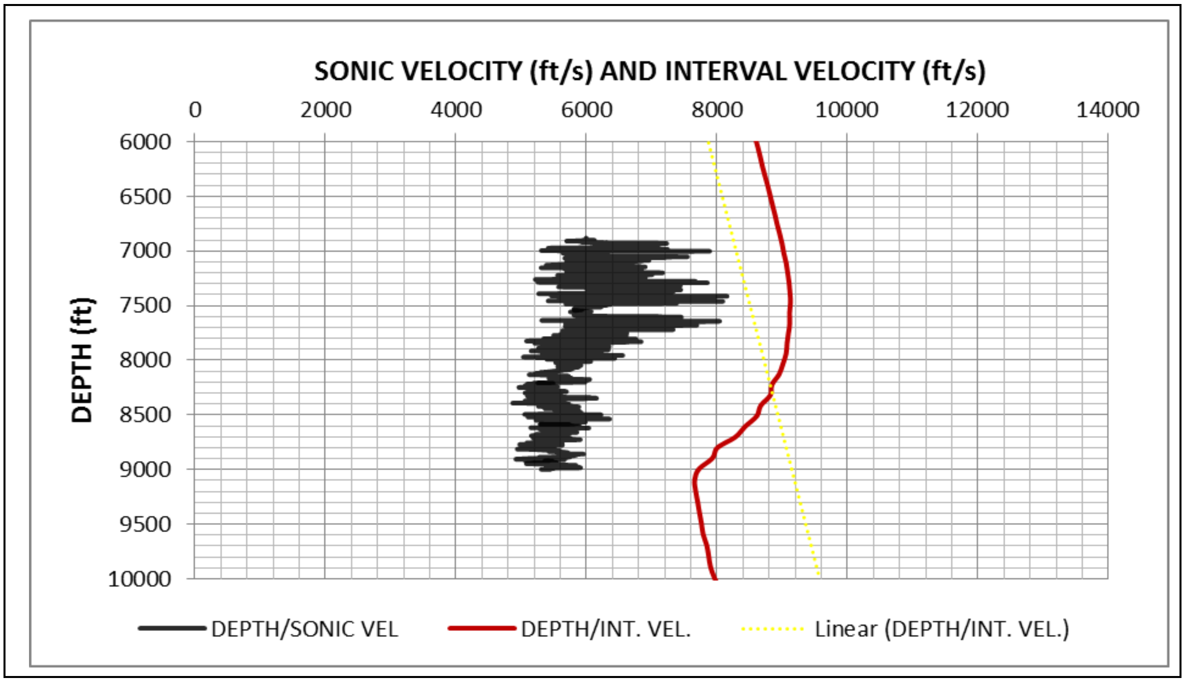

Fig. 20: Plot of sonic velocity and interval velocity against depth showing compaction trend across well C.

From these plots it was observed that interval velocity and sonic velocity values show increased with increasing depth. The sonic velocity log however shows decrease at some depths within the subsurface in the wells, thus indicating an abnormal compaction. From the cross plot of measured depth against formation density, there is a general increase with depth, but at identified overpressured zones, bulk density were observed to decrease (Figs. 21, 22, 23 and 24). This trend which is probably due to the effect of compaction and other post depositional processes is very much pronounced up to a depth of 7002ft (2134.20m) with an average density of 2.12g/cm^3. This suggests that compaction (or under compaction) could be the cause of overpressure in the area study.

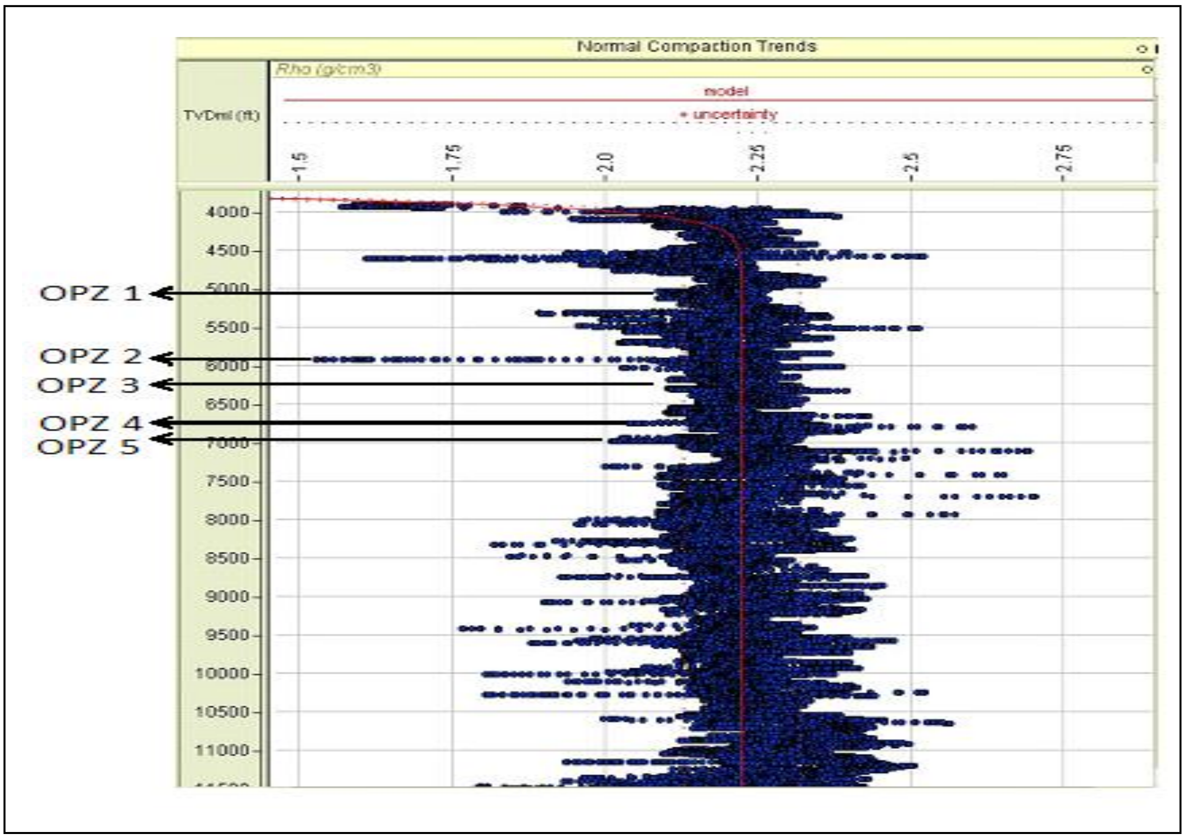

Fig. 21: Plot of formation bulk density against depth showing the normal compaction trend across well E.

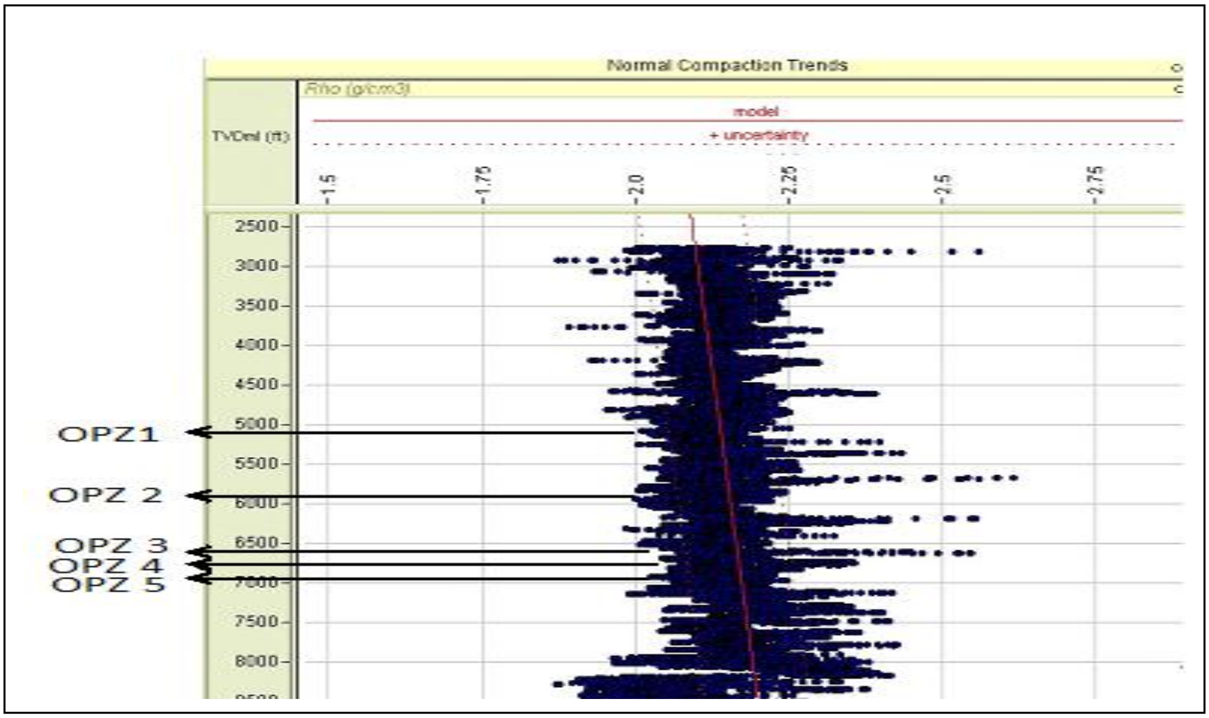

Fig. 22: Plot of formation bulk density against depth showing the normal compaction trend across well F.

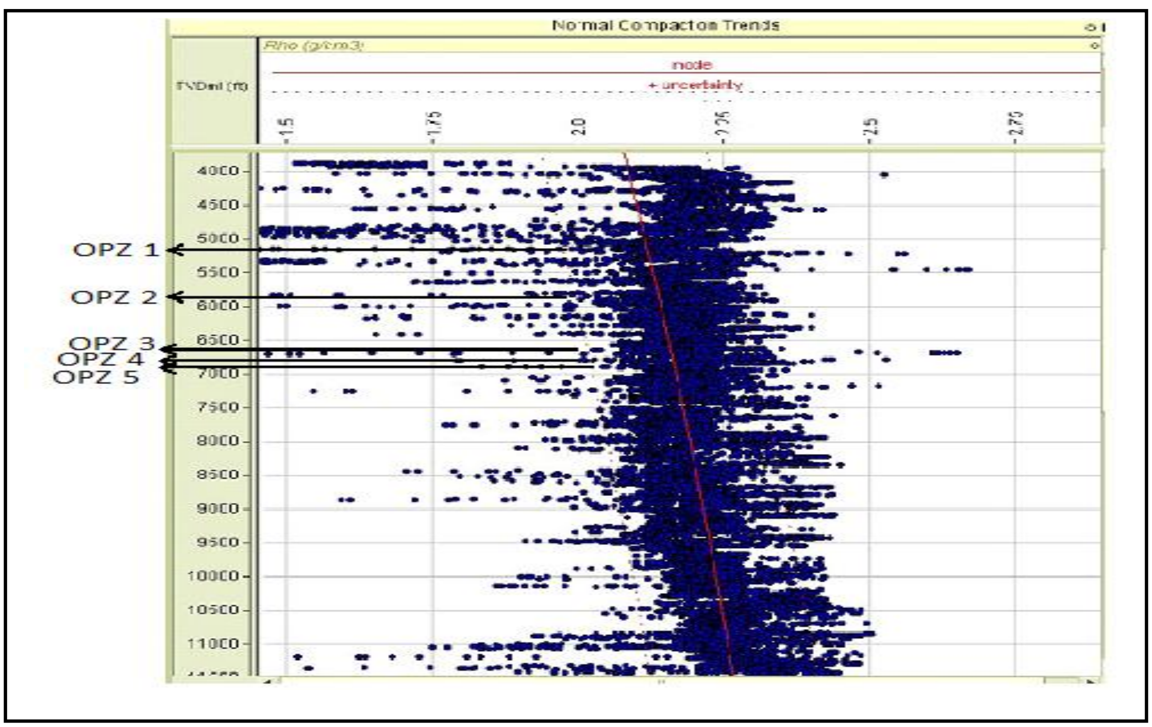

Fig. 23: Plot of formation bulk density against depth showing the normal compaction trend across well D.

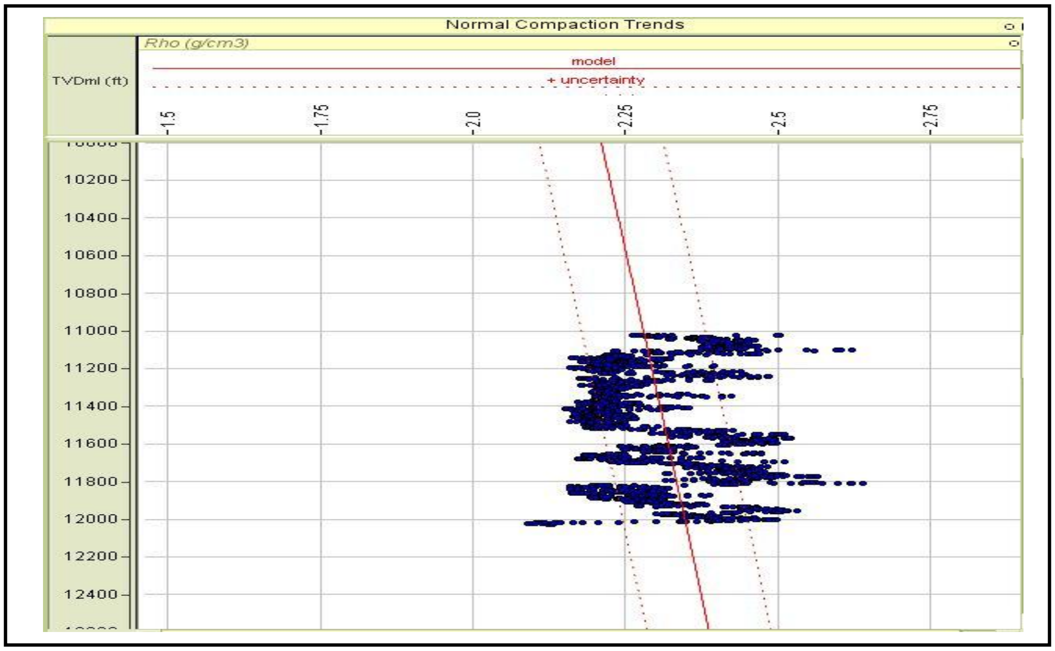

Fig. 24: Plot of formation bulk density against depth showing the normal compaction trend across well C.

Reservoir Sands Characterization

Reservoir SAND 1

Sand 1 is the first and the shallowest of the four sandstone reservoirs. The reservoir extends from a subsea depth of -6346.83ft (-1923.28m) to a depth o -6611.52ft (-2003.49m) with minimum stratigraphic thickness of 251.29ft (76.15m) to a maximum thickness of 261.08ft (79.12m) across the wells (Fig. 25).The reservoir is characterized by intercalation of shale which is typical of the Agbada Formation with a net to gross ratio of 0.02 to 0.08.

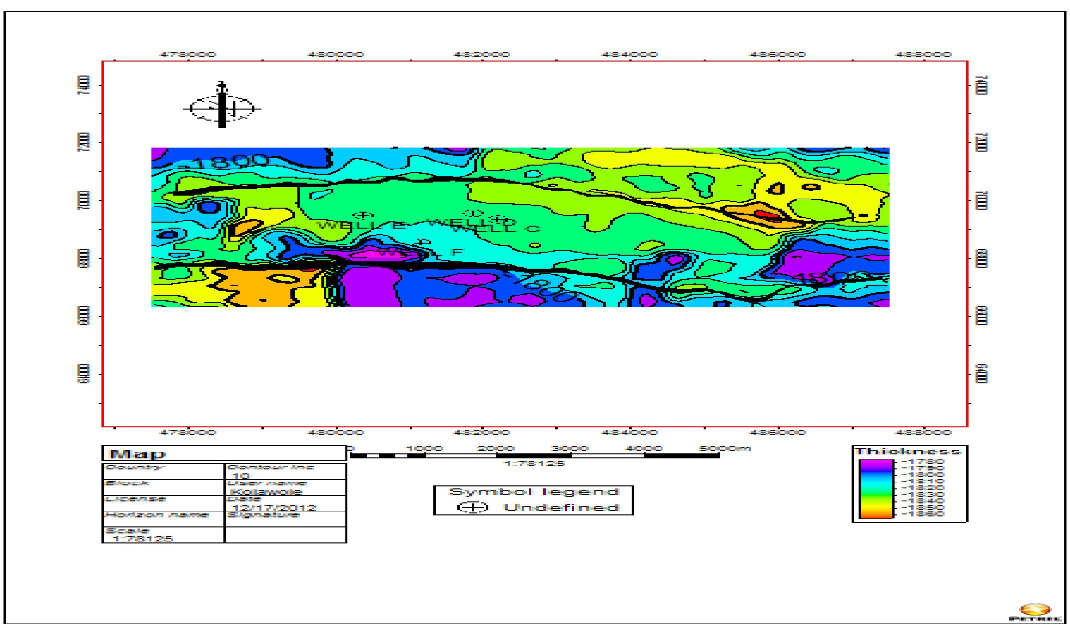

Fig. 25: Isochore map of reservoir sand 1.

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Porosity values within Sand 1 ranged from 19% to 31% with an average value of 27%. The presence of shale within the reservoir has a negative effect on the reservoir porosity. Increase in shale within the reservoir reduced the reservoir quality. From the porosity depth relationship, porosity is observed to decrease with depth except at depths containing porous sand and intercalation of shale which could be as a result of overpressures (Fig. 26).

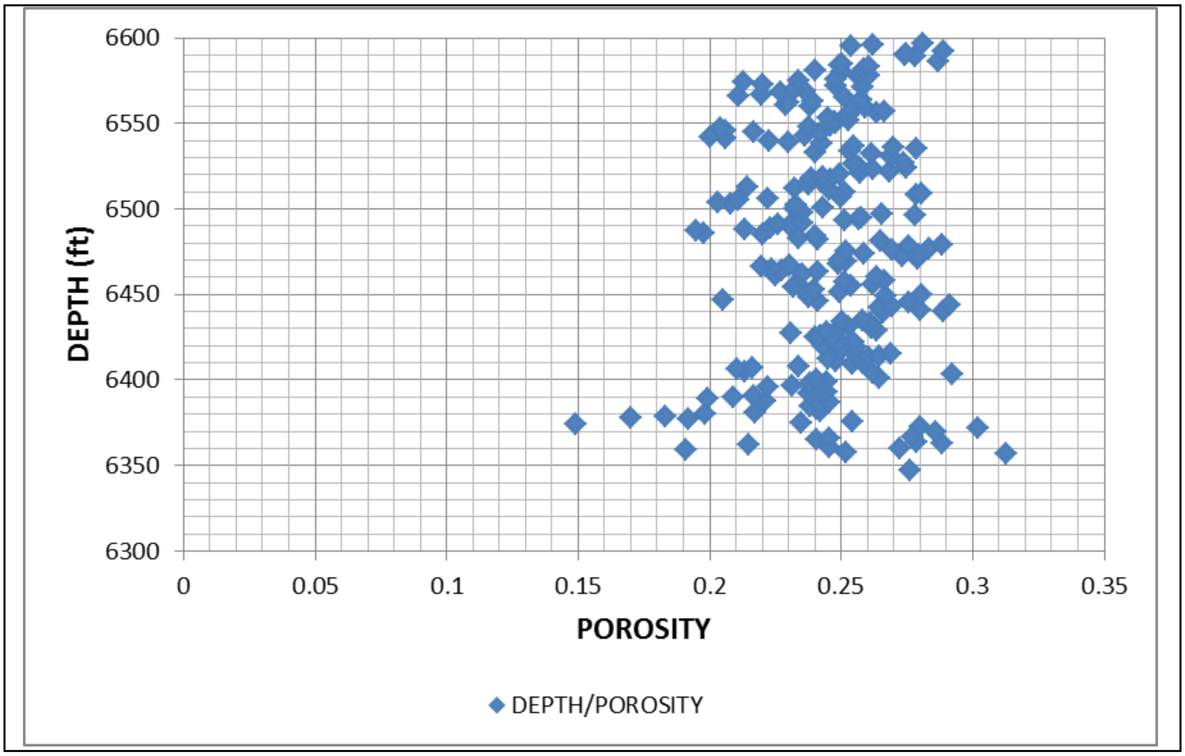

Fig. 26: Plot of depth against porosity in reservoir sand1 showing porosity trend with increasing depth.

Permeability values for this reservoir range between 373.1mD to about 8865.6mD with an average value 5601mD. Relative permeability to oil ranged from 0.29 to 0.75 with average value of 0.65. Asquith and Gibson [27] noted that data points with relative permeability to oil (Kroof 1.0), represents zones that should produce 100% hydrocarbon. The lower the value of Kro, the greater the amount of water that will be produced. Also, data points with zero relative permeability to water represent zones from which water-free production can be expected. A plot of permeability against porosity shows a parabolic relationship between the two parameters, this implies that with increasing porosity permeability increases (Fig. 27).

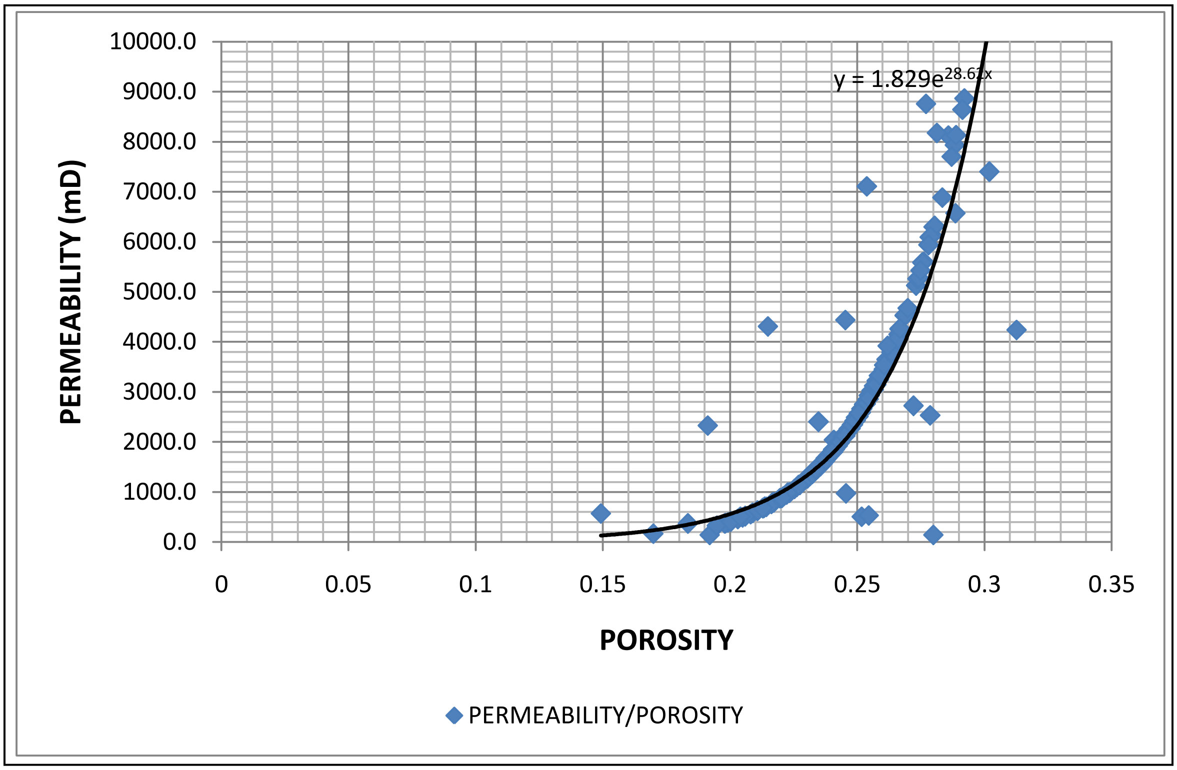

Fig. 27: Plot of permeability against porosity in sand 1.

Shale volume ranged from 0.05 (5%) to about 0.72 (72%) within the reservoir with an average value of 19%. The reservoir is generally characterized by shaly intervals. A cross-plot of Neutron porosity against Bulk density shows a distinct clustering of points which is indicative of a fairly clean reservoir. Outside this clusters are points considered to be shale present within the reservoir. This implies that under same overburden pressure, shale undergo more compression than sand (Fig. 28).

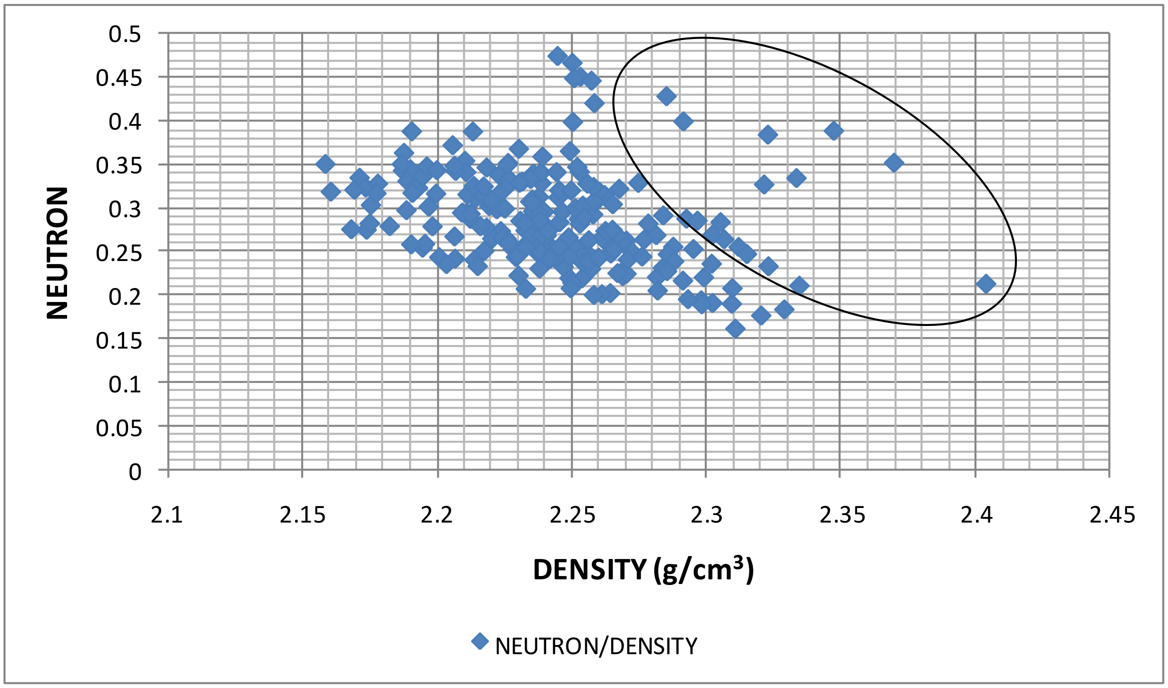

Fig. 28: Plot of neutron against formation bulk density in sand 1 reservoir.

Water saturation ranged from 13% to about 46.5% with an average value of 0.25%. Reservoir pore spaces are usually occupied by hydrocarbon and water, therefore, low water saturation, high porosity values are indicative of high hydrocarbon saturation and vice versa. The minimum and maximum water saturation values obtained are presented (Table 3). Hydrocarbon saturation values within the reservoir ranged from 19% to about 85% with an average value of about 60%. This high value indicated that SAND 1 is a probable prospect zone for hydrocarbon generation.

Reservoir SAND 2

This reservoir occurs at subsea depth of -6652.61ft (-2015.94m) to a depth of -6844.84ft (-2074.19m). The lowest and highest points are shown by a minimum and maximum contour value of -6600ft (-2000m) to -6800ft (-2060.60m) (Fig. 29). The reservoir has a net thickness of at least 150.29ft (45.54m) in all the wells producing both oil and gas. The reservoir is characterized by intercalation of shale which is typical of the Agbada Formation with a net to gross ratio of 0.07 to 0.34.

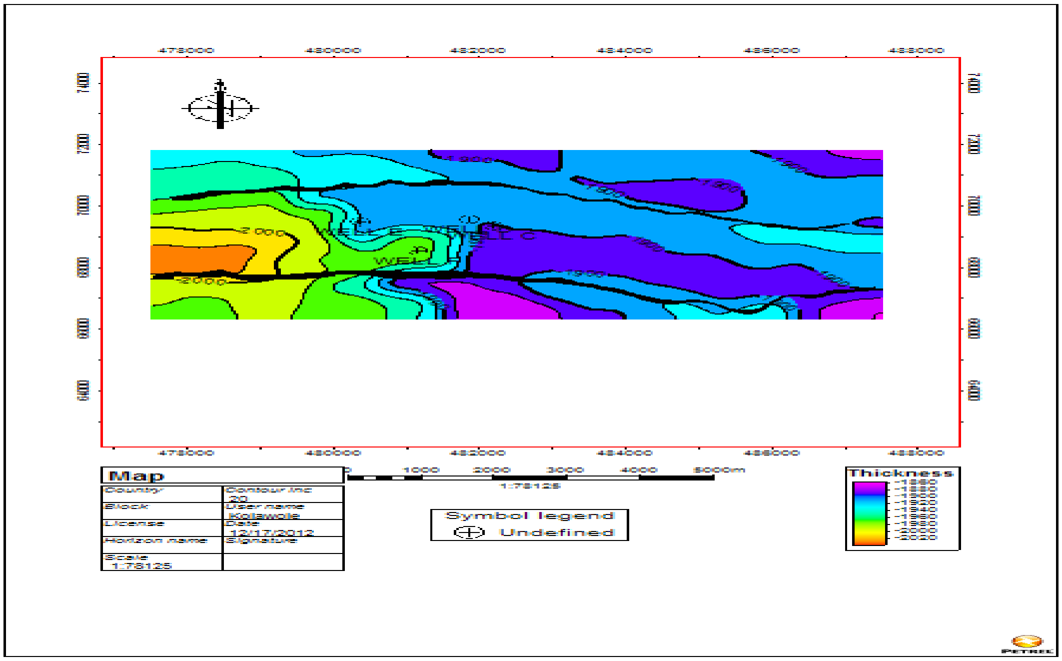

Fig. 29: Isochore map of sand 2.

Porosity within this reservoir ranged from about 6% to about 27% with an average value of 20%. From the porosity depth relationship, porosity is observed to generally decrease with depth. At some depth, an increase in porosity is observed this could be as a result of increase in pressure within intercalation of shale within the reservoir (Fig. 30).

Permeability values within this reservoir ranged from 0.1mD to 8653.3mD with an average value of 3011mD. The relative permeability to oil (K_{ro}) ranged from 0 to 1 with an average value of 0.77 and the relative permeability to water (K_{rw}) ranged from 0 to 0.053 with an average value of 0.023.

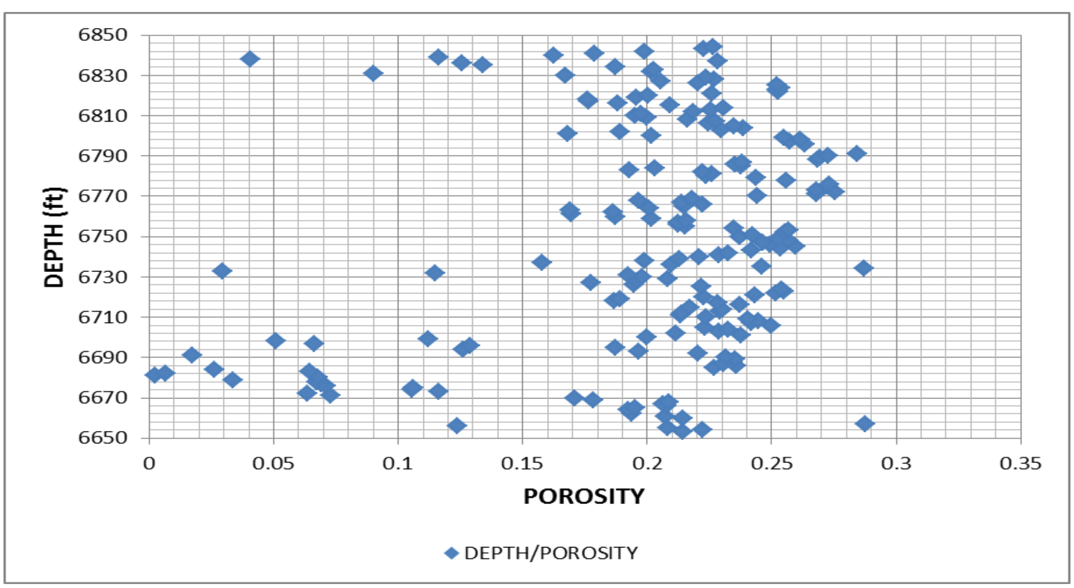

Fig. 30: Plot of depth against porosity for sand 2 reservoir showing porosity trend with increasing depth.

High relative permeability to oil and low value of relative permeability to water is an indication of the presence of hydrocarbon within the reservoir. A plot of permeability against porosity indicates that permeability increases with increasing porosity (Fig. 31).

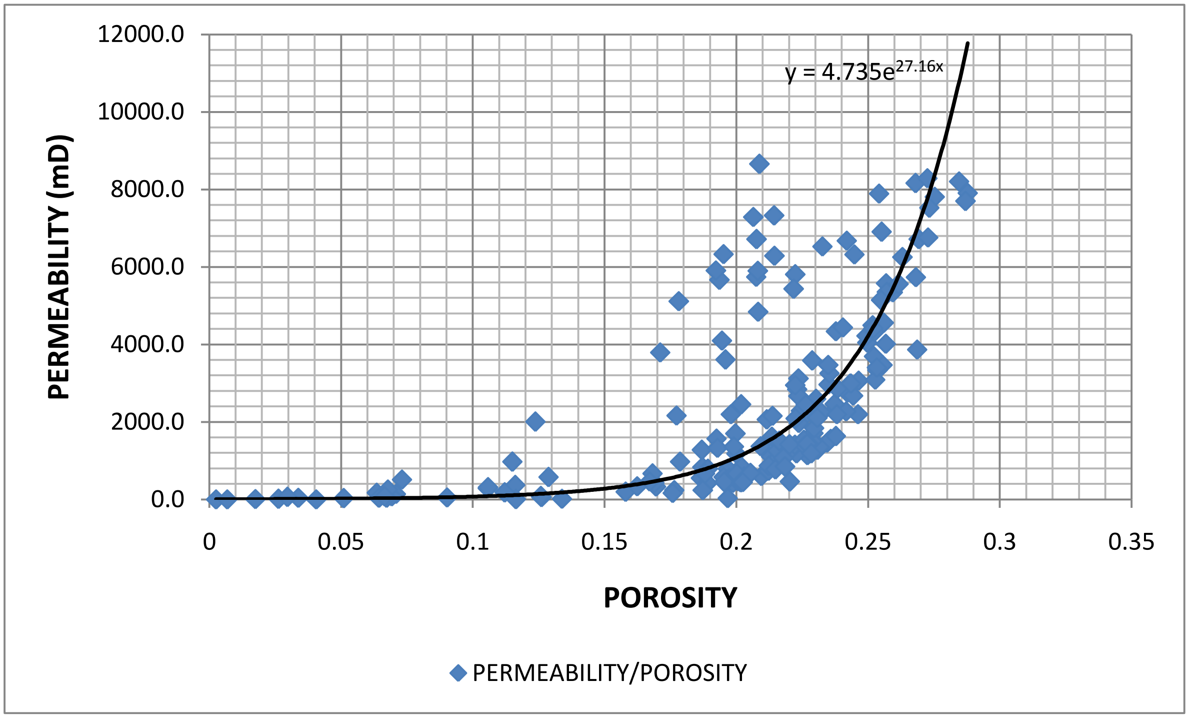

Fig. 31: Permeability against porosity plot for sand 2 reservoir.

Volume of shale within the reservoir ranged from 0.03 (3%) to 1 (100%) with an average value of 0.28 (28%). The reservoir is generally characterized by shaly intervals. A cross-plot of Neutron porosity against Bulk density indicate fairly clean reservoir. This implies that under same overburden pressure, shales undergo more compression than sand (Fig. 32). Water saturation within the reservoir ranged from 0.12 (12%) to 0.42 (42%) with an average value of 0.22 (22%). Hydrocarbon saturation is very high and fairly uniform. Values range from 0.58 (58%) to 0.89 (89%) with an average value of 0.78(78%). This high value indicates that Sand 2 is a probable prospect zone for hydrocarbon generation.

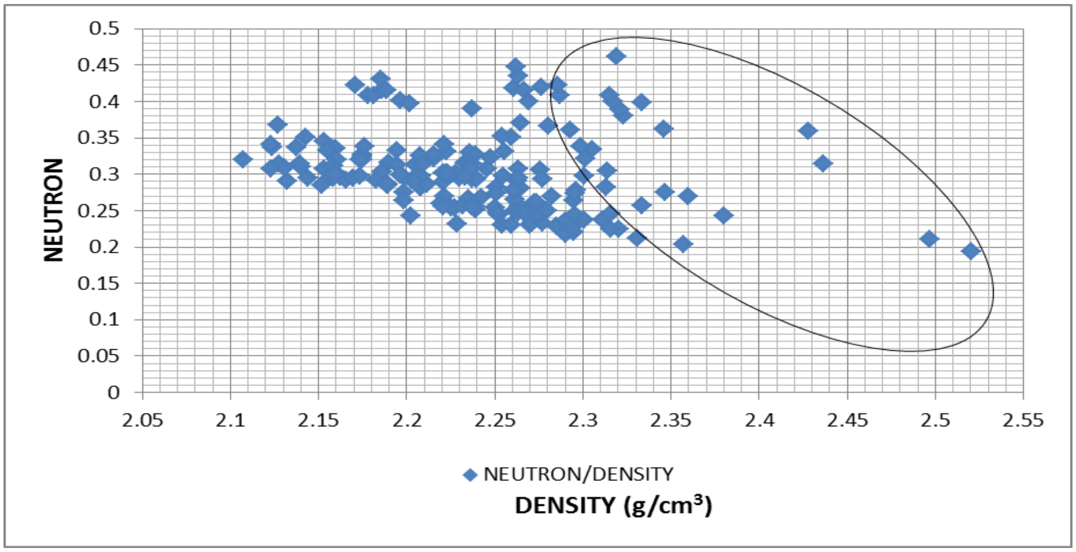

Fig. 32: Neutron against formation bulk density plot for sand 2 reservoir.

Reservoir SAND 3

This reservoir occurs at subsea depth of -6854.83ft (-2077.22m) to a depth of -6968.08ft (-2115.39m) (Fig. 19). The lowest and highest points are shown by a minimum and maximum contour value of -7000ft (-2121.21m) to -7500ft (-2272.73m) (Fig. 33). The reservoir has a net thickness of at least 80.15ft (24.29m) with the wells producing only oil (Table 2). Porosity is fairly uniform within this reservoir sand. Porosity values ranged from 0.2 (20%) to about 0.27 (27%) with an average value of 0.23 (23%) (Fig. 34).

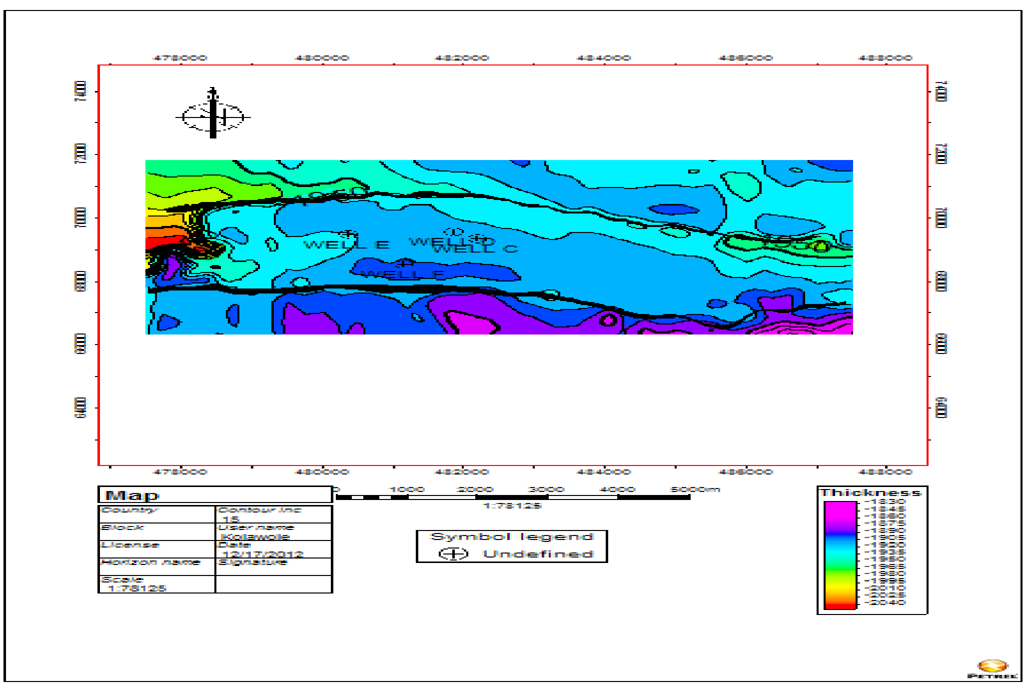

Fig. 33: Isochore map of sand 3.

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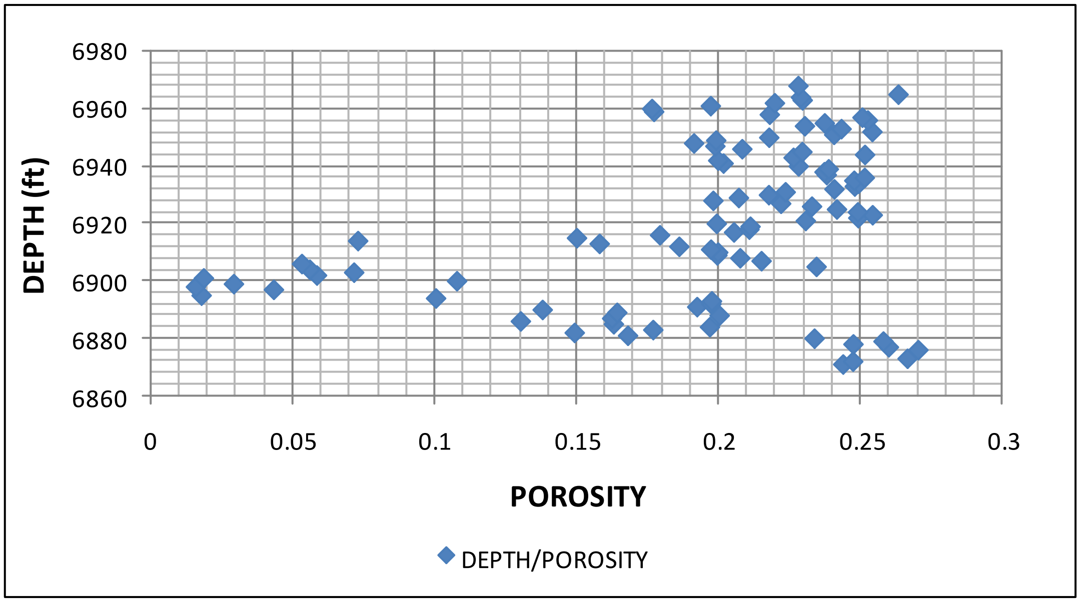

Fig. 34: Plot of depth against porosity for sand 3 reservoir showing porosity trend with increasing depth.

Permeability values within this reservoir ranged between 1.6mD and 7655.5mD with an average value of 2032mD. The relative permeability to oil (K_{ro}) value ranged from 0.37 to 1 with an average value of 0.72 and the relative permeability to water (K_{rw}) value ranged from 0 to 0.05 with an average value of 0.01. A plot of permeability against porosity shows a parabolic relationship between the two parameters, this implies that with increasing porosity permeability increases (Fig. 35).

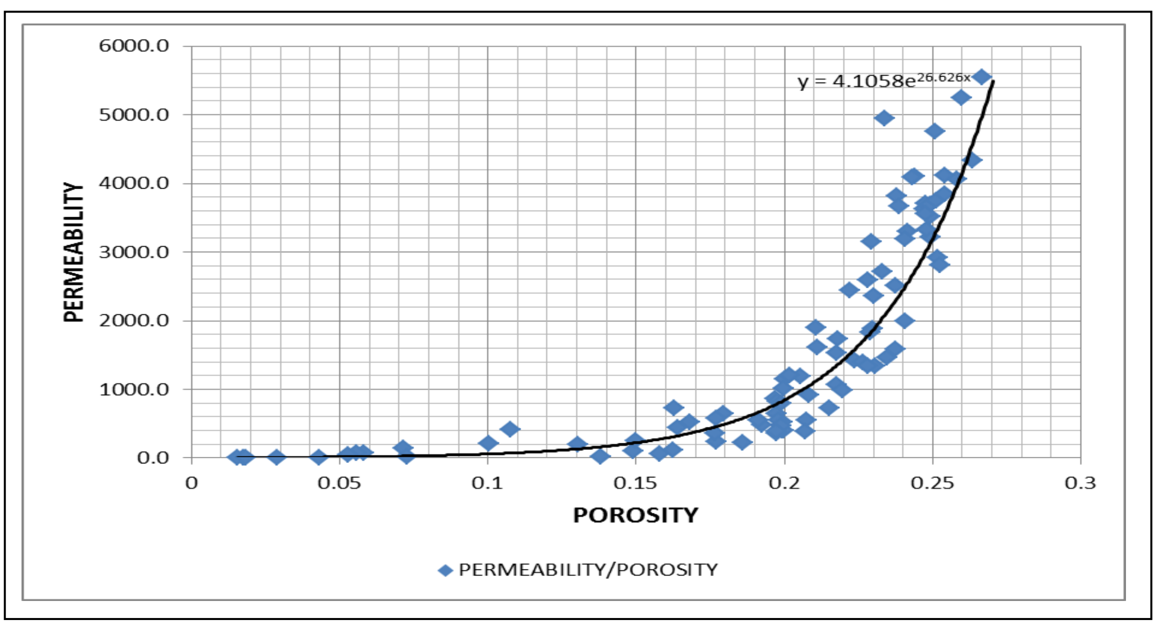

Fig. 35: Plot of permeability against porosity plot for sand 3 reservoir.

Volume of shale within the reservoir ranged from 0.04 (4%) to as high as 1 (100%) at very few interval with average value of 0.26 (26%). The reservoir is generally characterized by shaly intervals. The Neutron porosity against Bulk density plot a fairly clean reservoir (Fig. 36). The reservoir water saturation ranged from 0.13 (13%) to 0.44 (44%) with an average value of 0.25 (25%). Hydrocarbon saturation is very high and fairly uniform within this reservoir with values ranged from 0.56 (56%) to 0.86 (86%) with an average value of 0.75 (75%) indicating that Sand 3 is a probable prospect zone for hydrocarbon generation.

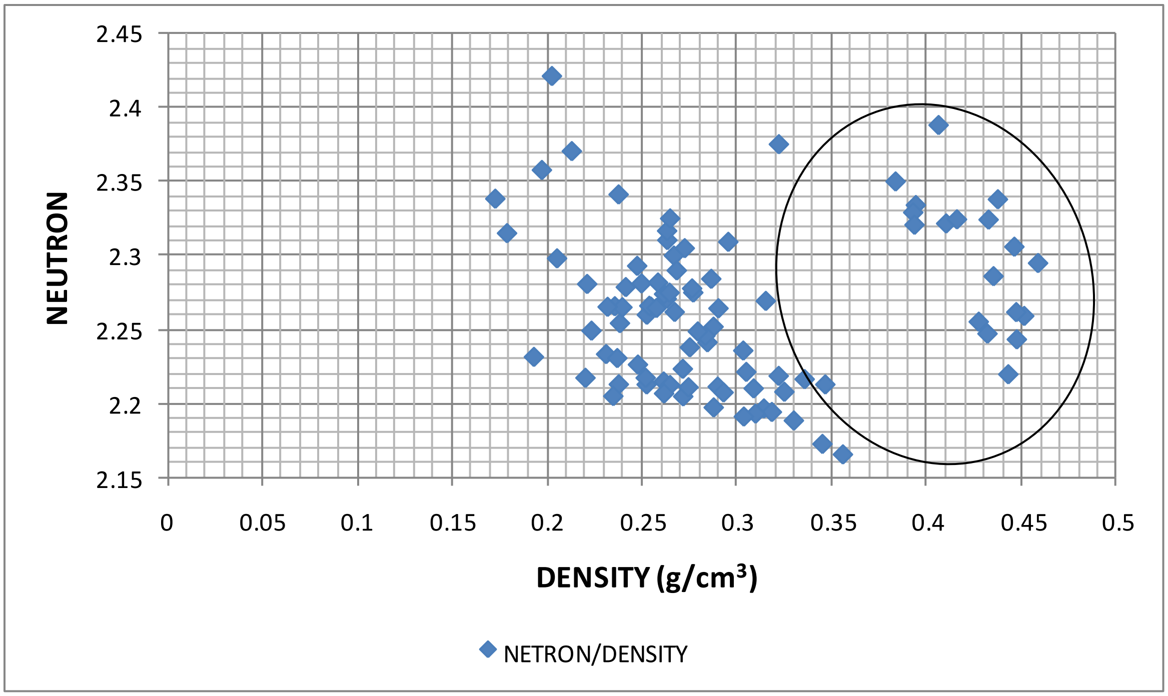

Fig. 36: Plot of neutron against formation bulk density for sand 3 reservoir.

Reservoir SAND 4

Sand 4 is the last and the deepest of the reservoirs analyzed in this field. It occurs at a subsea measured depth ranging from -6976.16ft (-2113.99m) to -7200.2ft (-2181.88m). The depth map of this reservoir unit has a minimum and maximum contour value of -7000ft (-2121.21m) to -7500ft (-272.73m) for the top of the reservoir and minimum and maximum contour value of -7000ft (2121.21m) to -7750ft (2348.49m) for the base of the reservoir. It has the second highest stratigraphic thickness of 203.48ft (61.66m) (Fig. 37) (Table 2).

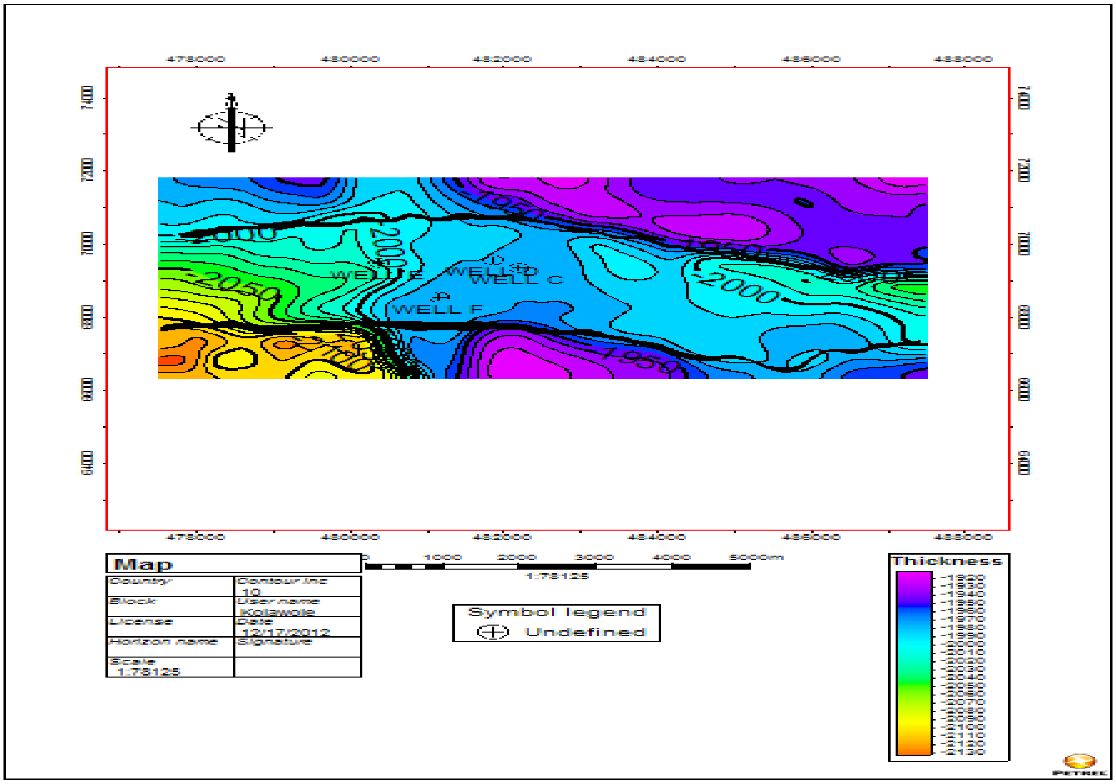

Fig. 37: Isochore map of sand 4.

Porosity values within this reservoir ranged from 0.11 (11%) to 0.47 (47%) with an average value of 0.25 (25%). From the porosity depth relationship, porosity is observed to generally decrease with depth. At some depth, an increase in porosity is observed this could be as a result of increase in pressure within intercalation of shale within the reservoir (Fig. 38). Permeability values within this reservoir ranges from 4.6mD to 92158 with an average value of 3379mD. The relative permeability to oil (K_{ro}) value ranges from 0.4 to 1 with an average value of 0.67 and the relative permeability to water (K_{rw}) value ranges from 0 to 0.04 with an average value of 0.03. A plot of permeability against porosity shows a parabolic relationship between the two parameters, this implies that with increasing porosity permeability increases (Fig. 39).

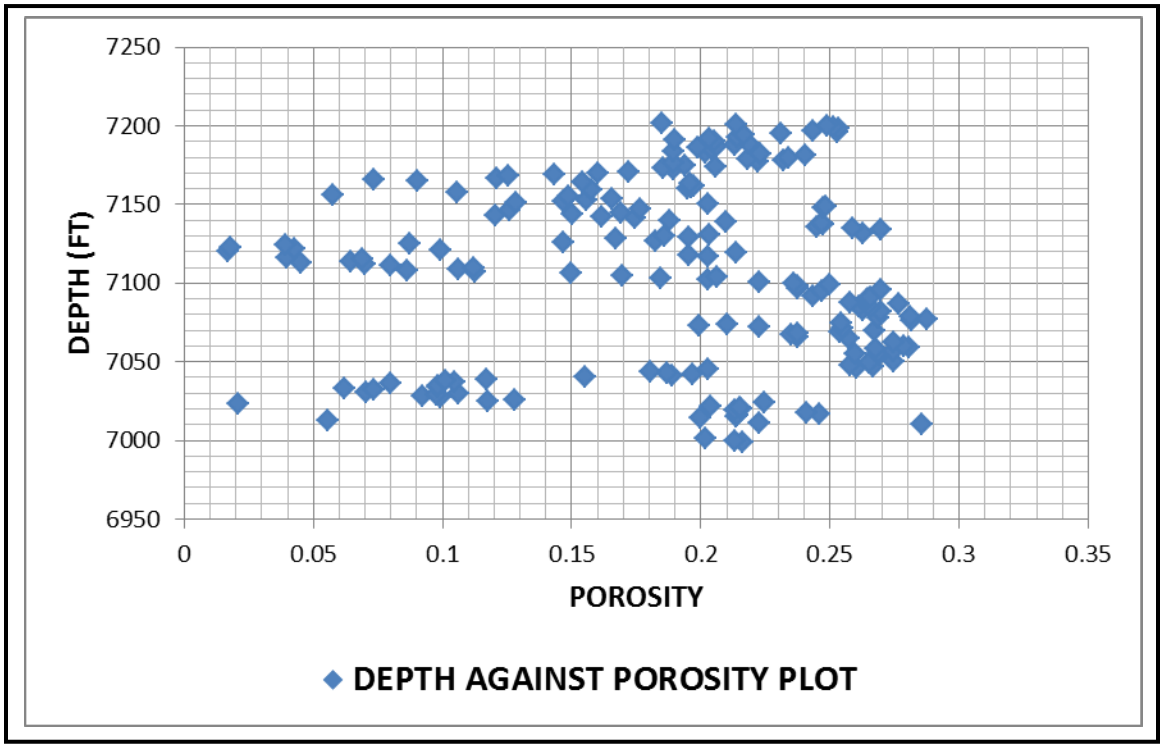

Fig. 38: Plot of depth against porosity for sand 4.

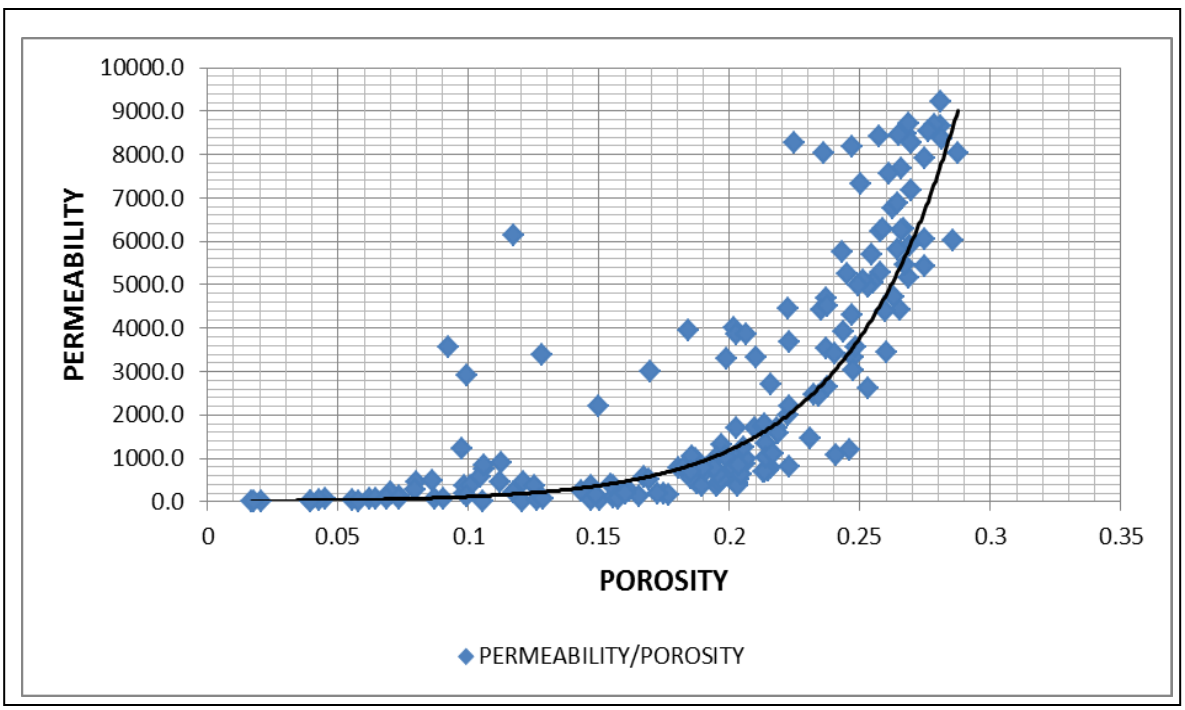

Fig. 39: Permeability against porosity plot for sand 4 reservoir.

Volume of shale present in the reservoir ranges from 0.03 (3%) to about 1 (100%) with an average value of 0.29 (29%). The plot of Neutron porosity versus Bulk density shows a distinct clustering suggesting that under same overburden pressure, shale undergo more compaction than sand (Fig. 40). The reservoir water saturation ranges from 0.06 (6%) to as high as 0.45 (45%) with an average value of 0.27 (27%).The reservoir hydrocarbon saturation values ranges from 0.51 (51%) to as high as 0.96 (96%) with an average value of 0.73 (73%). This high value indicates that Sand 4 is a probable prospect zone for hydrocarbon generation.

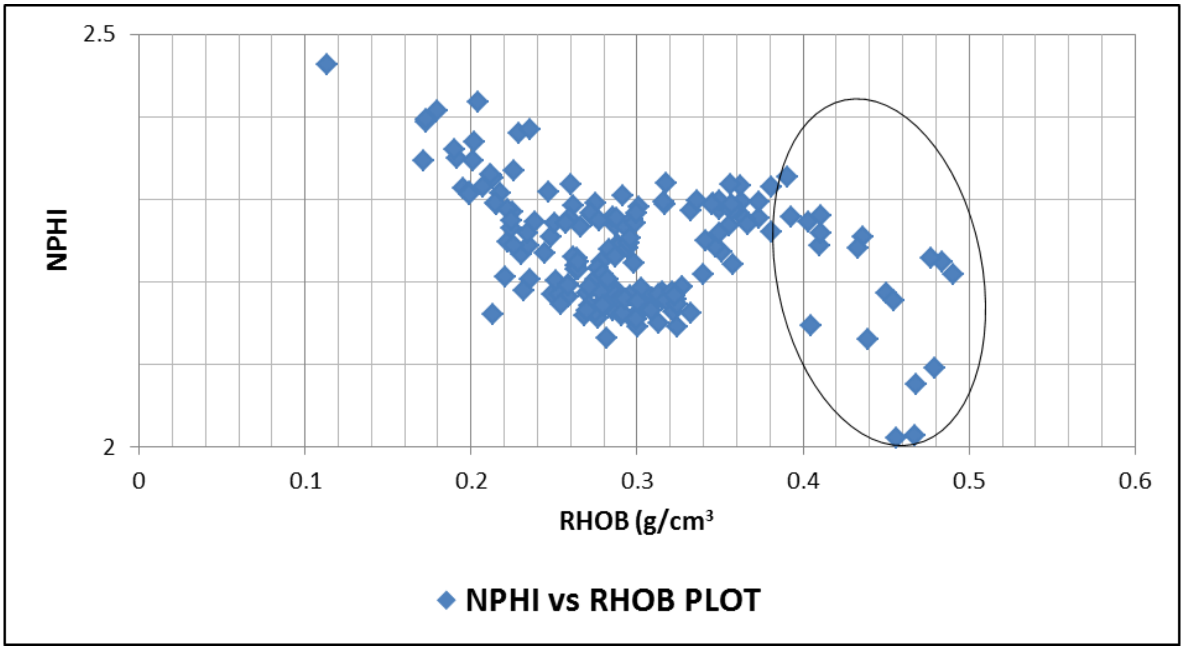

Fig. 40: Plot of neutron against formation bulk density for sand 4.

Conclusions

DIAG Field is an offshore field located off the coast of Niger Delta in the Gulf of Guinea. Integration of the available well log data (Gamma ray, Sonic log and Density log) together with the acquired seismic data were used to study and predict the overpressured shale zones present within the area of study.

Five overpressured zones were identified, these occur at various depths ranging from 5119.68ft (1551.4m) to 7002ft (2121.8m) and the gross thickness of this overpressured zone ranged from 14.15ft (4.3m) to about 35ft (10m) thick. The origin of these possible overpressure zones has been attributed to under-compaction which is known to characterize the Niger Delta region. The horizons of the overpressured zones were picked on the seismic and a depth structural maps of the overpressured zones were generated which shows the lateral extent across the field. The depth structure map of the overpressured shale has minimum and maximum subsea contour values of -5115ft (-1550m) and- 5280 ft (-1600m) for OPZ1, -5478 ft (-1660m) and -5775 ft (-1750m) for OPZ 2, -5940 ft (-1800m) and -6187.5 ft (-1875m) for OPZ 3, -5940 ft (-1800m) and - 6105ft (-1850m) for OPZ 4 and - 6105ft (-1850m) and - 6765ft (-2050m) for OPZ 5.

Plot of sonic velocity against depth, interval velocity against depth and the bulk density against depth showed a normal compaction trend in which there is a general increase in values with depth. At over-pressured zones, it was observed that there was an abrupt decrease in the sonic velocity, interval velocity and density values. In order to be able to put quantitative figures to the mapped prospects, petrophysical evaluation of the sand reservoirs were carried out. Four prospective sand reservoirs were identified from the gamma ray log with the aid of resistivity log, neutron log and the density log from the wells and a proper correlation of the sand units was carried out between the wells. The gross thickness of the reservoirs ranged from 91.22ft (27.64m) to 251.39ft (76.18m).

Petrophysical parameters determined from the log suite include hydrocarbon saturation with values ranging from 19% to about 85% (average value of about 60%) for Sand 1, for Sand 2, the values ranged between 58% and 89% (average value of 78%), for Sand 3 the values range between 56% and 86% (average value of 75%) and for Sand 4 the values ranged between 51% and 96% (average value of 73%) also, porosity values for Sand 1 ranged from 19% to 31% (average value of 27%), for Sand 2 the value ranged from 6% to 27% (average value of 20%), for Sand 3 the values ranged from 20% to 27% (average value of 23%) and for Sand 4 the value ranged from 11% to 47% (average value of 25%). Other parameters calculated include permeability, water saturation, movable hydrocarbon index, irreducible water saturation. The Movable Hydrocarbon Index for all the hydrocarbon reservoirs is lower than 0.7 indicating a high mobility of the hydrocarbon within the reservoirs.

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