Formation Evaluation and Its Implication on Hydrocarbon Production in Imoye Field, Niger Delta

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Abstract

This project was carried out using two dimensional seismic reflection data of five (inline and crossline) seismic sections and one composite log to determine the trapping style and estimate hydrocarbon reserve in M field, Niger Delta. Two hydrocarbon bearing horizons appraised were selected by well log to seismic correlation. Two growth faults and closures (simple rollover anticlines and closures against faults), which serve as reservoirs, characterized the field.

The wireline log facilitated the determination of the field's petrophysical attributes which were used for the volumetric estimation of the hydrocarbon in the reservoirs. The first reservoir has estimated original oil in place of 120.8million barrels, original gas in place (proved) of 407million cubic feet and estimated original gas in place (possible) of 668.2million cubic feet. The second reservoir has original oil in place of 29.2million barrels and original gas in place (proved) of 2.8million cubic feet. The crest of the closures trapping the hydrocarbon was recommended for possible drilling. Integration of three dimensional seismic data and artificial neural networks is however desirable to better understand the fault communication, hydrocarbon reservoir lithofacies and their heterogeneities in the field.

Keywords: Petrophysics, seismic, prolific, production, gas cap.

1. Introduction

Examples of oil field structures and associated trap types in the Niger Delta have been described by (Evamy et al. 1978, Doust and Omatsola 1990, Weber et al 1978, Ojo 1996). Trapping styles that have been delineated in the Niger delta include anticlinal dip closures, upthrown fault (footwall closures) and downthrown fault (hanging wall closures). Anticlinal dip closures are of three types – unfaulted simple dip rollovers, dip closures where faults contribute less than 15m (50ft) to the closure and faulted anticlinal closure where a dip closure is dissected by non-sealing faults. The trapping in these closures is largely by means of simple closure independent of faults. In footwall closures, trapping is by combined dip/fault closure on the upthrown side of a sealing fault, where the fault plane and the sediments dip in opposite directions. For hanging wall closures, the trapping relies on combined dip/fault closure on the downthrown side of a sealing fault, here, the fault plane and the sediments dip in the same direction.

Most petroleum producing fields in the Niger Delta consist of a number of individual reservoirs that are often stacked and containing common gas cap of varying oil gas ratio. Reservoir thickness ranges from less than 15 meters to 10% having greater than 45 meters thickness (Evamy et al., 1978). The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990). Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. However, in the outer portion of the delta complex, deep-sea channel sands, low-stand sand bodies, and proximal turbidites create potential reservoirs (Beka and Oti, 1995). Edwards and Santogrossi (1990) described the primary Niger Delta reservoirs as Miocene paralic sandstones with 40% porosity, 2 Darcy's permeability, and a thickness of 100 meters. The lateral variation in reservoir thickness is strongly controlled by growth faults. In most cases the reservoir thickens towards the fault within the down-thrown block (Weber and Daukoru, 1975). Many reservoirs are over pressured making primary production to be mainly from gas expansion (Kulke, 1995). Common oil production issues in the Niger delta include water coning, unconsolidated sands, wax deposition and high gas/oil ratios, leading to ultimate recovery rates of up to 30% (Kulke, 1995). Optimizing reservoir development requires a model capable of realistically predicting the dynamic behavior of an oil field in terms of fluid recovery and production rate for different operating conditions. Some of the parameters for constructing such a model using geological, geophysical, and well data are touched in this study.

This project is carried out to determine the trapping style and volume of hydrocarbon in this field, to throw more light on the fundamental characteristics of reservoirs of typical oil fields in the Niger delta and suggest ways for efficient draining of oil from them. This research work was done manually without the aid of any geophysical software. Also, only one well was made available for control in this project.

2. Synopsis of the geology

M field is situated in the Cenozoic Niger delta (figure 1), at the apex of the Gulf of Guinea on the west Coast of Africa, which covers an area of about 75 000 km^2. Several workers (Short and Stauble, 1967; Weber, 1971; Weber and Daukoru, 1975; Weber et al., 1978; Evamy et al., 1978; Doust and Omatsola, 1990) have given detailed reports on the geology of this province. The Niger delta is composed of regressive sequence of clastic sediments developed in a series of offlap cycles demonstrating a tripartite lithostratigraphic succession (figure 2) of a massive monotonous marine shale (Akata Formation) below a paralic sequence of alternation of sand and shale in the middle (Agbada Formation) and capped by thick sequence of fresh water sand (Benin formation). The Akata Formation likely extends to the basement rock. These three sedimentary environments, typical of most deltaic environments, extend across the whole delta and ranges in age from early Tertiary to Recent. Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. The most striking structural features of the Cenozoic Niger Delta complex are the synsedimentary structures which deform the delta largely beneath the Benin sand facies. These structures, regarded as the product of gravity sliding during the course of deltaic sedimentation, are polygenic in origin and their complexity increases generally in down delta direction (Merki, 1972). The synsedimentary structures, called growth faults, are predominantly trending northeast to southwest and northwest to southeast (Hosper, 1971). Associated with these growth faults are rollover anticlines, shale ridges and shale diapers which are caused by shale upheaval ridges. Mud diapers are the most common and occur on the landward side of the growth faults restricting sedimentation on the up-thrown side of the faults and enhancing sedimentation on the down-thrown side. Oil and gas are predominantly trapped by roll over anticlines and fault closures. Stratigraphic traps of paleo-channel fills, regional sand pinch-outs and truncations, crestal accumulations below unconformity surfaces, canyon-fill accumulations above unconformity surfaces, incised valley and low-stand fans have been recognized (Orife and Avbovbo, 1982; Kruise and Idiagbor, 1994).

3. Methodology

The 2-D seismic reflection data used for this study consists of five (inline and crossline) seismic sections (figure 3) in conjunction with one composite well log from the field. The well logs were those of caliper, gamma ray, resistivity, neutron and density porosity. Interpretation of the log was carried out first by gridding the well log at 1 ft interval. Two hydrocarbon bearing sands were identified on the log and named sand M-01 and sand M-02. Depth structure maps were generated for these horizons, first by posting the faults on the basemap (figure 2) and then mapping the horizons using contour interval of 20ms on seismic data. Petrophysical parameters of the reservoirs were derived from the log (figure 7) which includes:

3.1 Volume of shale**:** This was derived from the gamma ray log first by determining the gamma ray index I_{GR} (Schlumberger, 1974):

$$I_{GR} = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min}) \quad (1)$$

Where I_{GR} = gamma ray index; GR_{log} = gamma ray reading of the formation; GR_{min} = minimum gamma ray reading (sand baseline); GR_{max} = maximum Gamma ray reading (shale baseline).

For the purpose of this project work, Larionov's (1969) volume of shale formula for tertiary rocks was used.

$$Vsh = 0.083(2^{3.7*IGR} - 1) \quad (2)$$

3.2 Net-to-gross ratio (NTG): This refers to the proportion of clean sand to shale within a reservoir unit. The gross sand is the whole thickness of the reservoir; the non-net sand is the shaly sequences within the whole reservoir thickness; the net sand is thus obtained by subtracting the non-net sand from the gross sand. The Net-to-gross ratio reflects the quality of the sands as potential reservoirs. The higher the NTG value, the better the quality of the sand.

$$NTG = \text{Net sand} / \text{Gross sand} \quad (3)$$

$$\text{Net sand} = \text{gross sand} - \text{shaly intervals} \quad (4)$$

3.3 Total porosity (ϕ_T): This was calculated from the density porosity log using the equation below:

$$\phi_T = (\rho_{ma} - \rho b)/ (\rho_{ma} - \rho_f) \quad (5)$$

Where ρ_{ma} = matrix density which is taken to be 2.65g/cc for sandstone (Reference), ρb = the bulk density read directly from the log, ρ_f = the fluid density which is taken to be 1 for gas and 0.87 for oil (reference).

3.4 Effective porosity: This is usually based on an adjustment of total porosity by means of an estimated shale volume.

$$\Phi_{eff} = \Phi_{total} - (\Phi_{sh} * Vsh) \quad (6)$$

Where Φ_{eff} = effective porosity, Φ_{total} = total porosity, Φ_{sh} = log reading in a shale zone, Vsh = volume of shale

3.5 Water and hydrocarbon saturation: The water and hydrocarbon saturation are much related. In this research work, water saturation was derived using Archie's (1942) equation for water saturation in uninvaded zone (Archie, 1942):

$$Sw = [(a * R_w)/ (R_t * \Phi^m)^{1/n} \quad (7)$$

$$Sh = 1 - Sw \quad (8)$$

Where Sw = water saturation; R_w = resistivity in the water leg (that is resistivity of formation water); R_t = true formation resistivity derived from the deep induction resistivity log; Φ = porosity; n = saturation exponent usually taken as 2.0; m = cementation factor; a = tortuosity.

3.6 Irreducible water saturation: sometimes called critical water saturation. It defines the maximum water saturation that a formation with a given permeability and porosity can retain without producing water.

$$S_{wirr} = (F/2000)^{1/2} \quad (9)$$

$$F = 0.81/\Phi^2 \text{ (in most sandstone reservoirs)} \quad (10)$$

Where F – Formation factor

3.7 Bulk volume of water (BVW): This is the product of water saturation and porosity corrected for shale (Adepelumi et al, 2011):

$$BVW = Sw * \Phi e$$

(Asquith and Krygowski, 2004) (11)

Where BVW = bulk volume of water; Sw = water saturation; Φe = effective porosity

If values for BVW calculated at several depths within a formation are coherent, then the zone is considered to be homogeneous and at irreducible water saturation. Therefore, hydrocarbon production from such zone should be water free (Morris and Biggs, 1967).

3.8 Permeability: measure of the ease with which a fluid (gas, oil or water) flows through connecting pore spaces of reservoir rock. It is very important in predicting the rate of production from a reservoir.

$$k = 0.136 (^{4.4} / S_{wirr}^{2}) \text{ – Timur, 1968} \quad (12)$$

Where K = permeability (millidarcy; Φ = porosity; S_{wirr} = irreducible water saturation)

3.9 Fluid type: Delineation of fluid type contained within the pore spaces of formation is achieved by the observed relationship between the Neutron and Density logs. Presence of hydrocarbon is indicated by increased Density log reading which allows for a cross-over. Gas is present if the magnitude of cross-over, that is, the separation between the two curves is pronounced while oil is inferred where the magnitude of cross-over is low (Asquith and Krygowski, 2004).

After the petrophysical attributes were estimated, the reserves for the two horizons mapped were estimated. The parameters used were derived from both the logs and the seismic sections as follows:

3.10 Volumetric Equation = Area*thickness*(1-Sw)* Ø*NTG (13)

3.11 OOIP = (7758*area*thickness of oil column*S_H* Ø*NTG) (14)

Where OOIP = original oil in place, S_H = hydrocarbon saturation

3.12 STOOIP = (OOIP*FVF_{oil}) (15)

Where STOOIP = stock tank original oil in place, FVF_{oil} = formation volume factor (oil)

3.13 Reserve (oil) = (STOOIP/RF) (16)

Where RF = recovery factor

3.14 OGIP = (43,560* area*thickness of oil column*S_H* Ø*NTG) (17)

Where OGIP = original gas in place

3.15 STOGIP= (OOIP*FVF_{gas}) (18)

Where STOGIP = stock tank original gas in place, FVF_{gas} = formation volume factor (gas)

3.16 Reserve (gas) = (STOGIP/RF) (19)

4. Results and discussion

Two hydrocarbon bearing horizons were delineated in the M field. The depth structure maps (Figure 5a and 6a) produced for each of the two horizons studied revealed one major and a minor fault (figure 3b). The major fault had a larger throw than the minor one. The two horizons interpreted also revealed existence of simple rollover anticlinal structures. The rollover structures terminated against the downthrown side of the minor normal growth faults. The throw of the fault increases along the downthrown block which is so evident from the cross section shown (figure 5b & 6b). The structure maps of top sand M-01 and M-02 (Figure 5a & 6a) respectively, revealed that the horizons dip southeast. Table 1 shows the average petrophysical parameters for the two reservoirs studied.

4.1 Sand M-01

Sand M-01 is the first trough on the seismic section (figure 3b). The reservoir (figure 4a) is a viable one with a thick column of oil below a thick gas cap. The reservoir started out with very clean sand from 5394ft – 5414ft (20ft thick) to very shaly sand from 5415ft – 5424ft (9ft thick) and then to moderately clean sand from 5425ft – 5435ft (10ft thick), hence, the total thickness of the reservoir is 41ft. The resistivity of the reservoir varies between 6 - 2000 Ωm which is considered very high and depicts hydrocarbon bearing zone. Below the reservoir is very thick fresh water in very shaly sand with the resistivity of the water varying between 2-6 Ωm. The gas column is from 5394ft – 5412ft and the oil column is from 5413ft – 5436ft.

Volumetric estimation of hydrocarbon in this reservoir was estimated using the calculated petrophysical parameters (Table 1.) and data derived from the depth structural map (Figure 9a). The estimated original oil in place is 120.7 million barrels, estimated original gas in place (proved) is 407 million cubic feet and estimated original gas in place (possible) is 668.2 million cubic feet.

4.2 Sand M-02

Sand M-02 is the fourth trough on the seismic section (figure 3b). From wireline log (Figure 4b), the reservoir interval is shaly sand all through the reservoir column from 6100 – 6140 ft. The total thickness is 40ft. The resistivity within this reservoir is lower than that of the first reservoir but still wraps around 92 Ωm. Hydrocarbon saturation parameter calculated within this reservoir show range of values well above 90% from 6100 – 6106 ft. This suggest that the reservoir has a thin gas cap implies that there may be no abrupt change in the reservoir pressure during production. The thick column of fresh water (as a result of resistivity values) below the hydrocarbon column suggest that the reservoir has a strong water drive mechanism which would help in the oil recovery up to about 30% (kulke, 1995). Using the calculated petrophysical parameters (Table 1) and data derived from the depth structural map (Figure 10a), the estimated original oil in place is 29.2 million barrels while the estimated original gas in place (proved) is 2.8 million cubic feet.

4.3 Structural style and hydrocarbon trap

Structural styles often provide a broad context for understanding the pattern of faulting that may be expected in a region. Its basic utility lies in identifying certain basic patterns of deformation that are repeated in geologic provinces. They are different across the major depobelts in the Niger delta and have direct implication on the hydrocarbon distribution (Doust and Omatsola 1990). From the 2-D seismic section (figure 3b), two NE-SW trending listric fault systems were identified. The major fault shows a soling out at the base of the section with a rollover anticlinal structure located on the minor fault which happened to have occurred later than the major fault. The faulted rollover anticline bounded by a major northwest-southeast trending growth fault system constitutes the hydrocarbon trap in this field. Just like in the other parts of the Delta, the interbedded shale of the Agbada Formation constituted the seal. Hydrocarbon leakage through the fault plane must probably have been prevented by shale smearing along the fault plane (Weber & Daukoru, 1975).

4.4 Implications of reservoir characteristics on production

Optimizing reservoir development requires a model capable of realistically predicting the dynamic behavior of an oil field in terms of fluid recovery and production rate for different operating conditions. The situation in the two reservoirs under study within 'M' field in the Niger delta varies and is discussed individually.

4.4.1 Sand M-01

Two production wells would help in maximally recovering the oil in reservoir M-01 because of the estimated large volume of oil in place. This proposition is made considering several factors especially the fluid content and reservoir pressure. As a result of the large gas cap within this reservoir, a high pressure is expected. A radius of 400m was considered a very good drainage ring (figure 5a) for the wells to avoid interference between wells. The well should be perforated very close, at about 4ft below the Gas-oil-contact (since the expected reservoir drive is water driven) so as to recover most of the oil while still giving space for gas expansion which according to Kulke (1995) mainly accounts for primary production in the Niger Delta. The reservoir structure has a very thick gas cap with a thick column of oil which suggests that the oil likely has a high API gravity as a result of gas dissolution in the oil. This reservoir would most likely yield a high gas/oil ratio. It is therefore envisaged that the high gas/oil ratio coupled with the strong water drive should lead to ultimate recovery efficiency of well over 30%. The reservoir should not need an enhanced oil recovery (EOR) technique except in the mature phase of production. The trends of the result for bulk volume of water in the sands M-01 is shown in figure 7a which shows the trend for the interval to be inhomogeneous. Production from this reservoir interval would likely not be water free according to Morris & Biggs (1967). This reservoir has high porosity and permeability values (table 1) which would aid economic flow of the fluids.

4.4.2 Sand M-02

This reservoir has a thin gas cap suggesting that there may be no expected abrupt change in the reservoir pressure during production. The reservoir is expected to operate under a strong water drive mechanism which would help in the oil recovery of up to about 30% recovery efficiency. The reservoir would most likely not need an enhanced oil recovery (EOR) technique except in the mature phase of the reservoir. The bulk volume of water in this reservoir (figure 7b) shows the trend to be fairly homogenous; therefore production from this reservoir interval would most likely be water free (Morris & Biggs, 1967).

5. Conclusion

The two faults identified in M field are growth faults which are evidenced by the increase in throw and thickness on the downthrown block. These growth faults trend northeast to southwest which further supports the work by Hosper (1971). Simple rollover anticlinal structures, terminating against the downthrown side of the normal growth faults acts as trap for hydrocarbon. Oil and gas are predominantly trapped by roll over anticlines and fault closures. The trapping style delineated on this field is a structure with multiple growth faults (Doust and Omatsola 1990). Petrophysical analysis revealed the reservoir sands to be shaly sands having high porosity and permeability values. Bulk volume of water for reservoir M-01 is inhomogeneous while for reservoir M-02, it is fairly homogenous which suggests that production from reservoir M-02 should be water free. The first reservoir (M-01) has estimated original oil in place of 120.8million barrels, original gas in place (proved) of 407million cubic feet and the estimated original gas in place (possible) of 668.2million cubic feet. The second reservoir (M-02) has original oil in place of 29.2million barrels and original gas in place (proved) of 2.8million cubic feet. The crest of the closures trapping the hydrocarbon was recommended for possible drilling. Integration of three dimensional seismic data, artificial neural networks and amplitude versus offset (AVO) is however desirable to better understand the fault communication, hydrocarbon reservoir lithofacies and their heterogeneities in M field.

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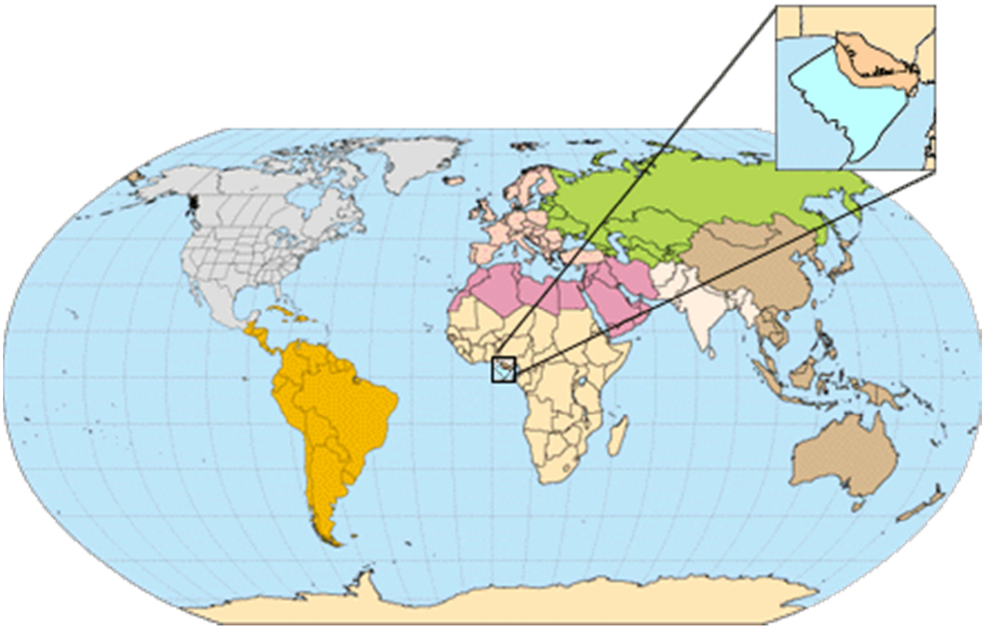


Figure 1: Niger delta in the Gulf of guinea West Africa (modified after Michele et al 1999)

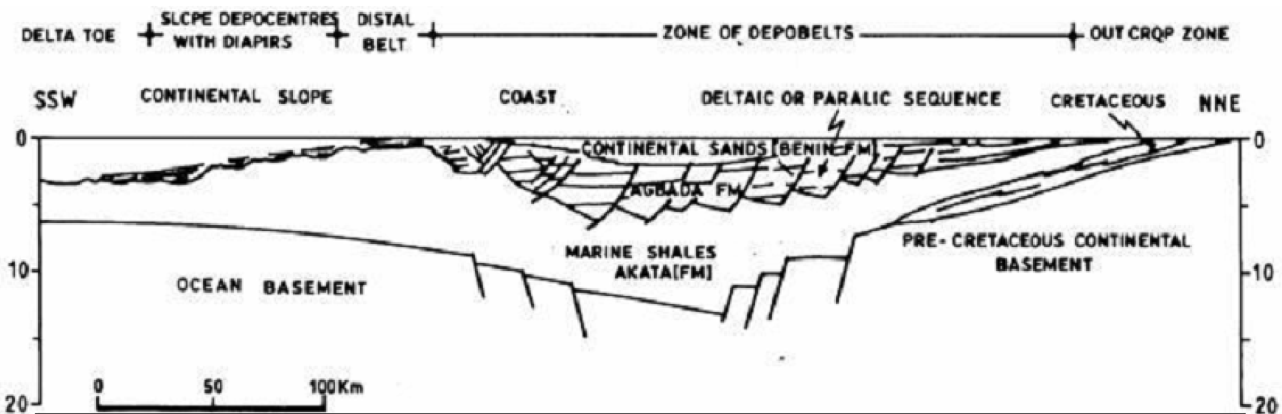


Figure2: Schematic section through the axial portion of the Niger Delta showing the relationships of the tripartite division of the tertiary sequence to basement (Doust and Omatsola, 1990)

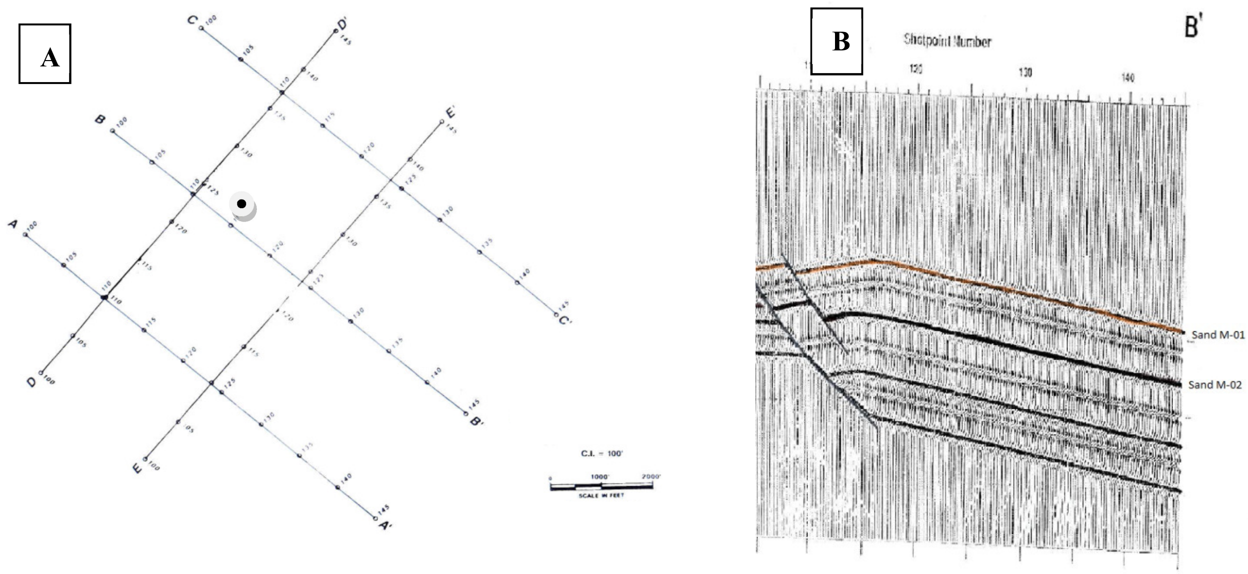


Figure 3: Basemap and typical seismic section of the study area

(a) Basemap showing the location of the well in the study area

(b) Interpreted seismic section along B-B[I]

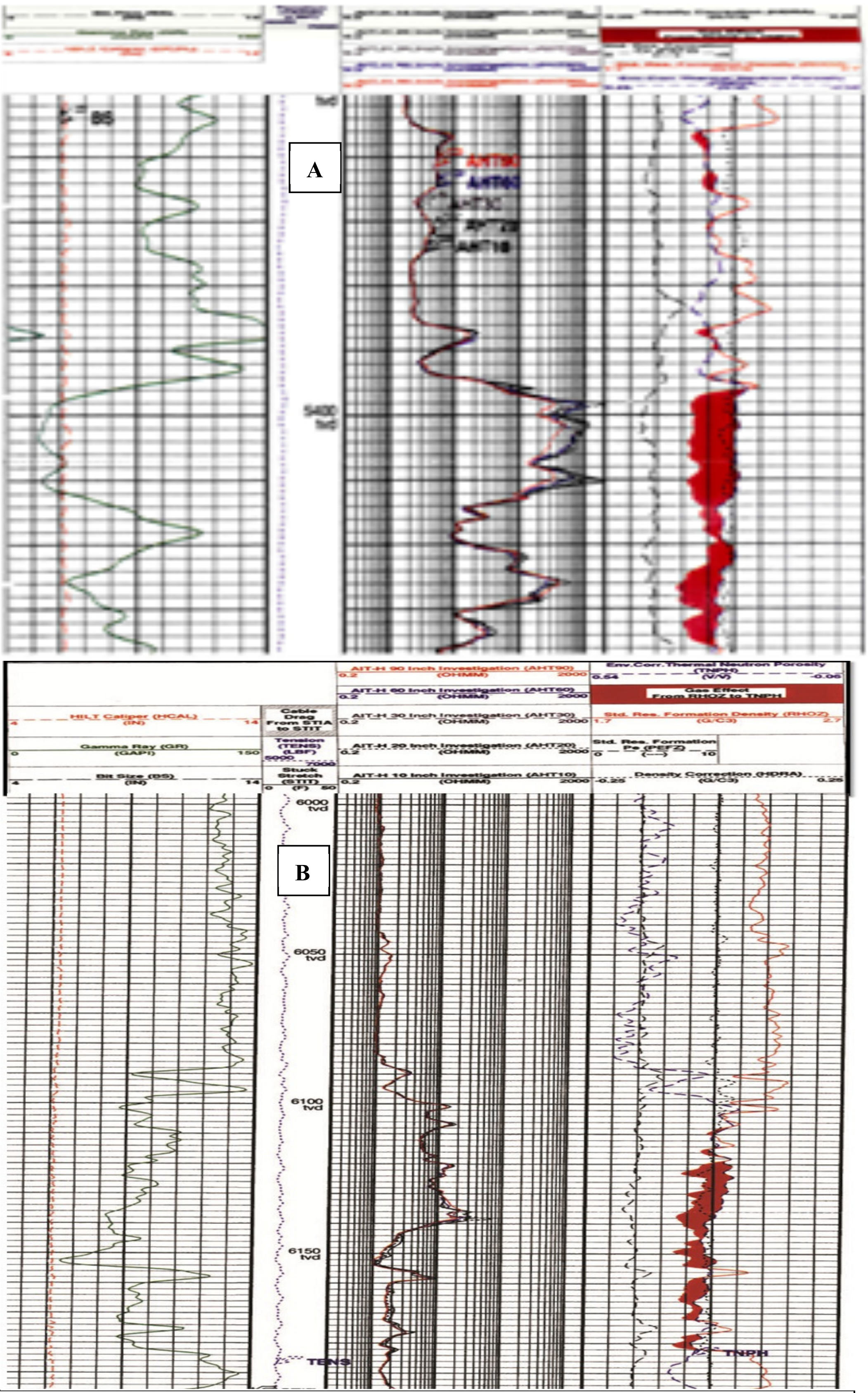


Figure 4: Wireline log of the well in M field showing the hydrocarbon bearing sands
(a) Sand M-01 (b) Sand M-02

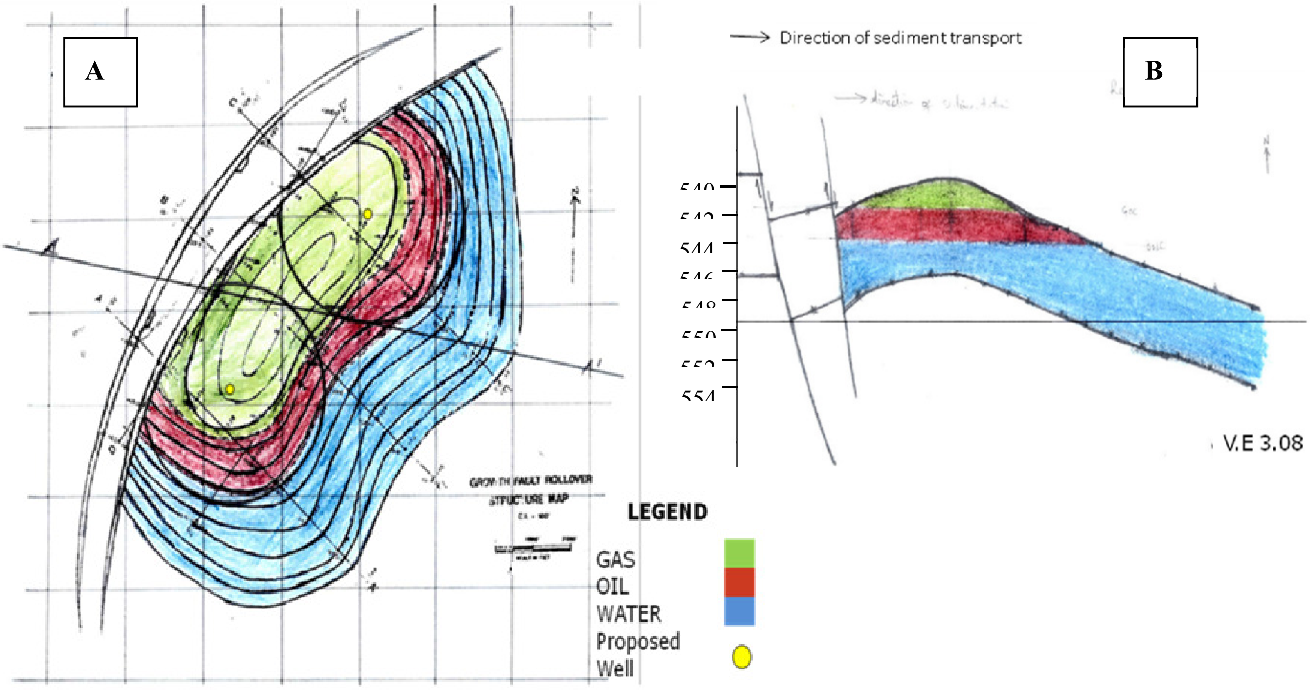


Figure 5: Depth structure map and cross section for Reservoir

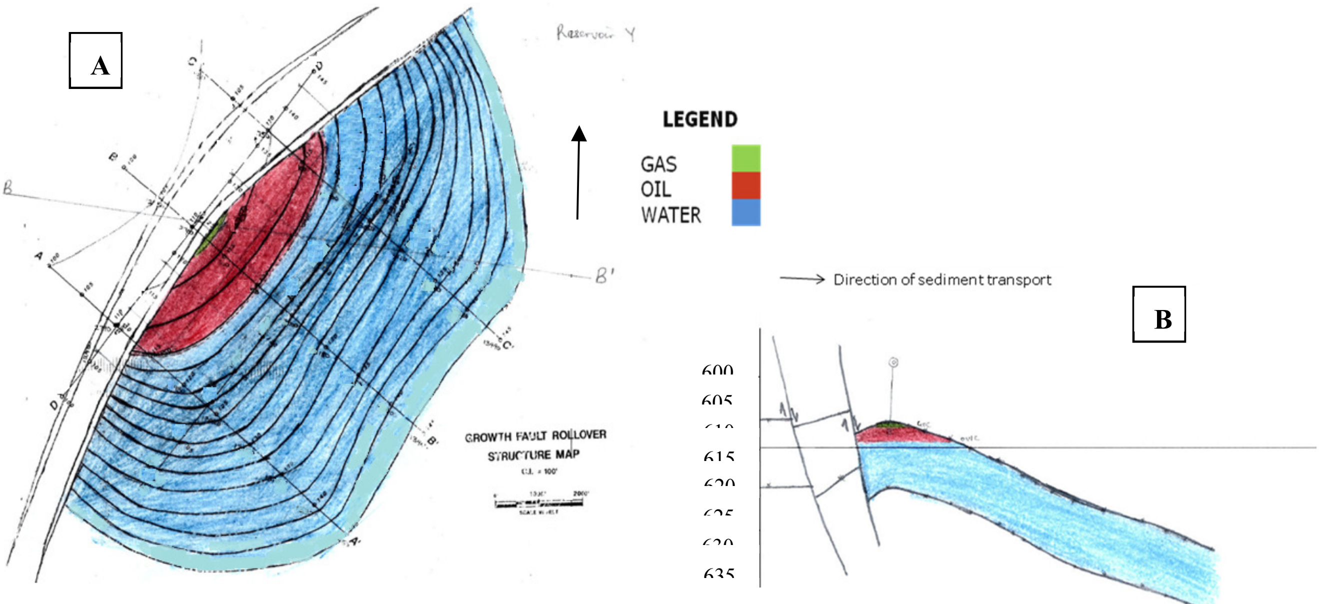
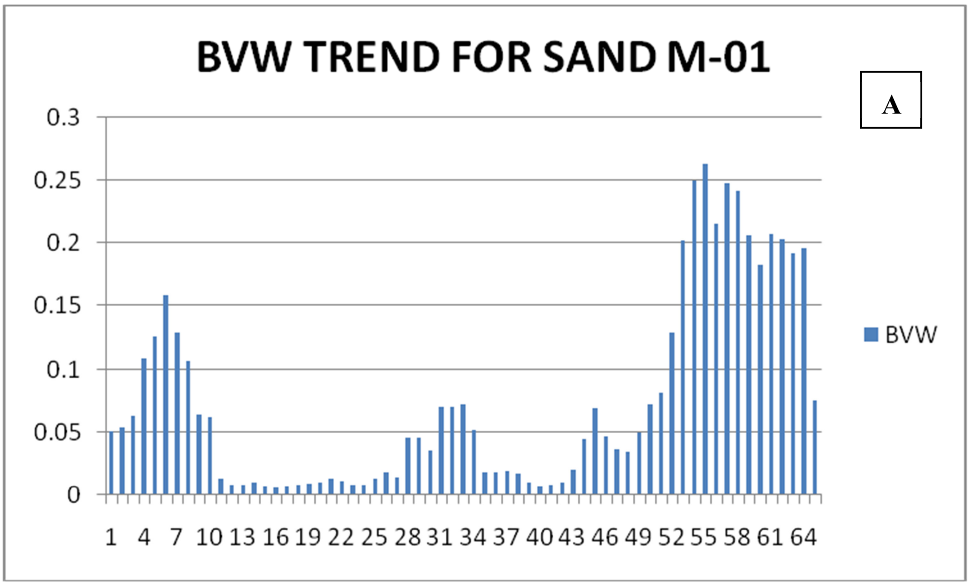


Figure 6: Depth structure map and cross section of reservoir



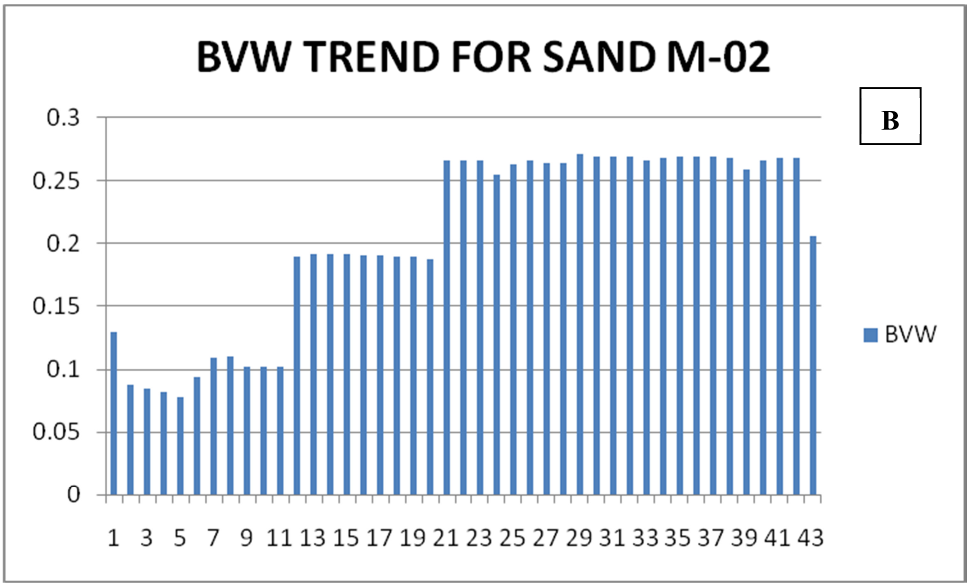


Figure 7: Bulk volume of water histogram showing the trend of data in sand M-01 and M-02

Table 1: Petrophysical data (average) derived from the wireline logs of a well in M field

Reservoir Sands	Thickness (ft)	NTG (%)	Vshale (%)	S_w (%)	S_H (%)	BVW	PHIE (%)	K (mD) Oil	K (Md) gas
Sand M-01	41	85.14	21.03	31.29	68.71	0.08	30.53	596	52
Sand M-02	40	81.36	48.12	43.29	56.71	0.21	31.69	304	32

NTG – Net to gross, **Vsh** – Volume of shale, $\mathbf{S_w}$ – Water saturation, **BVW** – bulk volume of water, $\mathbf{S_h}$ – hydrocarbon saturation, **PHIE** – effective porosity, **K -** permeability