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Research Article

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Reservoir Characterization of Buma Field Reservoirs, Niger Delta using Seismic and Well Log Data

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Abstract

The reservoir characterization of Buma Field, Niger Delta using seismic and well log data is the focus of this research. Seismic data in SEG-Y format and suites of well logs have been used to achieve the aim and objectives of the research. Methodologies used in this work are standard methods used in this kind of research. Results of the analysis seismic data shows fifteen faults have been identified, nine trend NW-SE and are antithetic faults whereas the six trend NE-SW and are synthetic faults. These faults formed closures and could act as trapping mechanisms for hydrocarbon in the identified horizons/reservoirs. Two hydrocarbon bearing horizons D and F have been mapped on the seismic and analysis of the well logs showed that sand and shale are major lithologies in the studied wells. Well correlation showed similarities in geological properties such as lithology, reservoir tops and petrophysical properties. Volumetric estimation carried out on the two reservoirs showed Reservoir D having average thickness of 26.73 ft., area of 3784.89 acres, bulk volume of $4407x10^6$ ft^3, net volume of 4226x106 ft^3, pore volume of 216 $x10^6$ RB, hydrocarbon pore volume (oil) of $143x10^6$ RB and STOIIP of 77 MMSTB. Reservoir F has an average thickness of 41.55 ft., area of 2790.63 acres, bulk volume of 5051x106 ft3, net volume of $4769x1010^6$ ft^3, pore volume of $248x1010^6$ RB, hydrocarbon pore volume (oil) of $167x1010^6$ RB and STOIIP of 88 MMSTB. Integrating results of structural interpretation, well log analysis, petrophysical properties and volumetric estimation it is evident that both reservoirs have very good porosities and excellent permeability, good thicknesses of productive sand and reduced water saturation as to aid storage and easy flow of hydrocarbon pore fluids. Therefore, the two Buma Field Reservoirs D and F are prolific with hydrocarbon pore fluids (oil) which can be exploited economically.

Keywords: Reservoir Characterization, Trapping Mechanisms, Petro physical Properties.

Introduction

The petroleum industry is in dare need to maximize and increase hydrocarbon production, hence reservoir characterization is critical to determining the structures (fault traps), petrophysical properties and pore fluid contents of the reservoirs geared towards achieving efficiency. Reservoir characterization has to do with understanding the behavior of a reservoir by describing the reservoir characteristics and distributing the petro physical properties using available data to provide reliable reservoir models for accurate prediction of reservoir performance. The comprehension of the properties is essential in evaluating the productive capacity of a hydrocarbon bearing zone [1]. In characterizing a reservoir unit, well log and seismic information has may be used for its characterization [2]. The integration of well log and seismic information would give a high level of precision in evaluation of a given field [3,4]. In mapping hydrocarbon reservoirs, studies of geologic structures that can hold hydrocarbon in place is considered in addition to, combining rock properties that will keep oil and gas from migrating either vertically or laterally [5]. Buma Field is an Onshore field within the Niger Delta and is located between longitudes 60 0' 30" E and 60 7' 0" E and between latitudes 50 24' 0" N and 50 30' 0" N (Figure 1 - 2). The geology of the Niger Delta is well established in relation to the stratigraphy, structural framework, sedimentology and petroleum geology see Reijers [6-11]. A lot of works on reservoir modeling and reservoir characterization has been undertaken in the Niger Delta such as Omoboriowo [12-19]. See Figures 3-4.

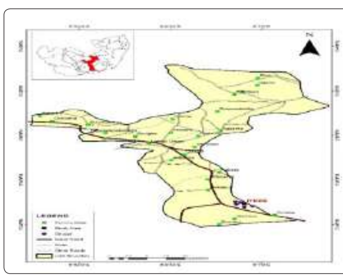


Figure 1: Location of the Study Area

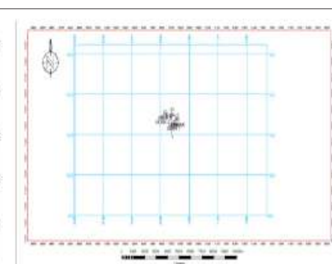


Figure: 2

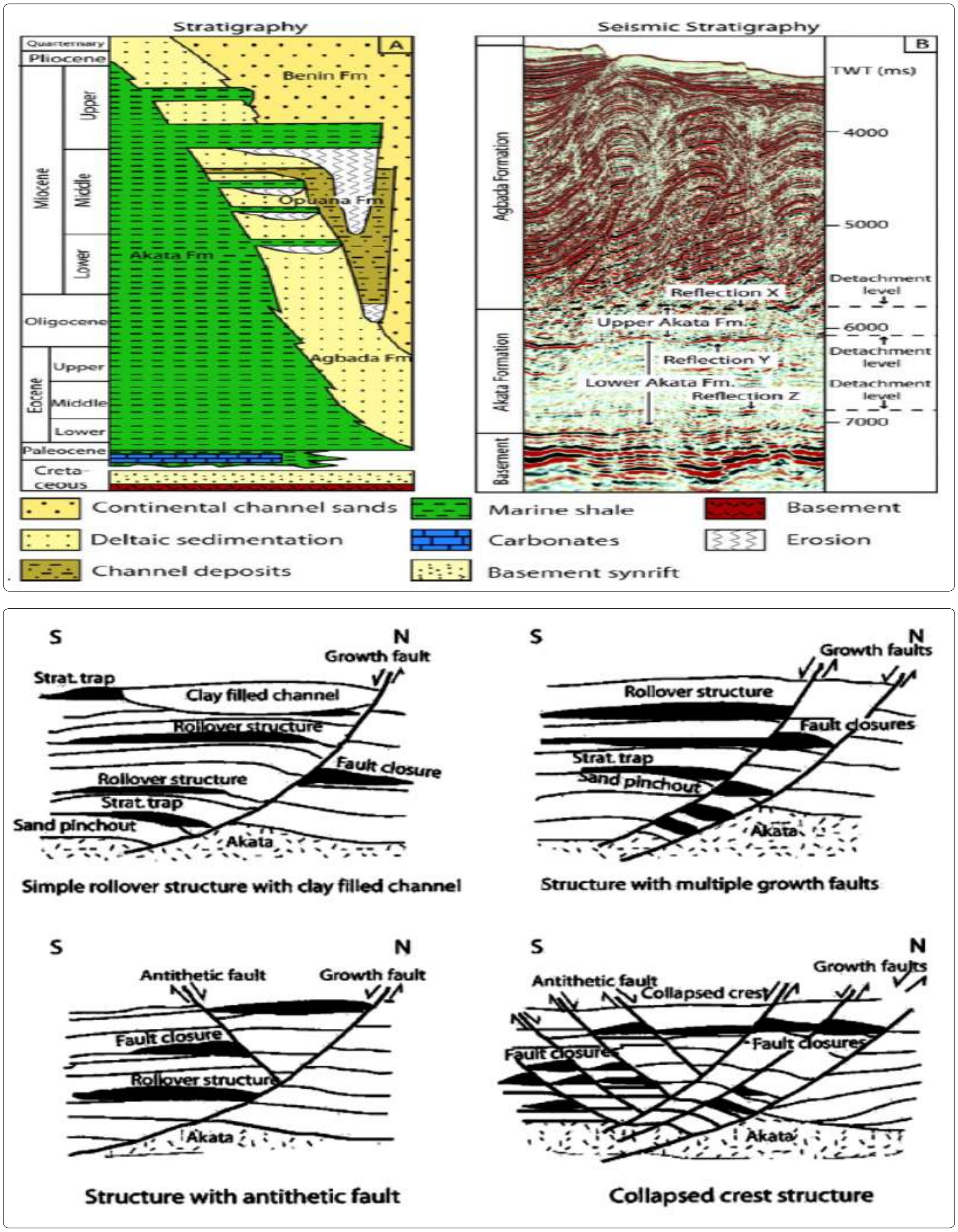


Figure 3: Niger trapping systems (Modified from Doust and Omatsola (1990)

Materials and Methods

Materials

Materials used in this research comprise a suite of well logs, seismic data in Seg-Y, Petrel Software and Workstation at the Department of Geology, University of Port Harcourt, Nigeria.

Methods

Suite of well logs and seismic data in Seg-Y were inputted into Petrel Software used in this research. See Figure 4.

Petrophysical Analysis

Petrophysical estimations were carried out for the six wells that penetrated the two reservoirs in the area of study. From the wire line logs, the petro physical empirical formulae were used to determine Net-to Gross (NTG), volume of shale (V_{sh}), porosity (Φ), permeability (K), water saturation (S_w) from the Petrel Software.

Net-To-Gross Ratio

This measures the potential productive part of a reservoir either as percentage producible (Net) part of the reservoir within the entire

(Gross) reservoir zone or sometimes as a ratio.

NTG = (h/H) x 100% (1)

Where;

NTG = Net to Gross

h = Net thickness and

H=Gross thickness

Volume of Shale

The volume of shale (V_{sh}) was calculated from gamma ray log using the linear method of estimation which requires determining gamma ray responses of clean sand associated with no shale (GR_{min}) and a zone of 100% shale (GR_{max}). Presence of shale in a flow unit makes the porosity logs to record high porosity, lower saturation values and thus, cause low resistivity readings. This however makes it challenging to control productive zones of a reservoir volume of shale in unconsolidated Tertiary Niger Delta. The formula is given by the linear equation below [20].

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad (2)$$

Where;

I_{GR} = gamma ray index

GR_{Log} = log reading

GR_{min} = minimum log value in clean sand and

GR_{max} = maximum log value in 100% shale

$$V_{sh} = 0.083*(2^{3.7*}{}_{IGR}-1) \qquad (3)$$

The I_{GR} formula is not very accurate and tends to give an upper limit to the volume of shale.

Porosity (Φ)

Porosity is described as the percentage of the pore spaces to total volume of the rock. Porosity is taken as the measure of the void space relative to the entire volume which shows the storage strength of the given reservoir. Denoted by Greek symbol, Phi (Φ), it is usually presented either as a fraction or in percentage and mathematically represented thus:

$$(\Phi) = \frac{\text{Bulk Volume - Grain Volume x 100}}{\text{Bulk Volume}} \qquad (4)$$

In measuring the total or the entire porosity, both the void spaces and the whole matrix are considered, regardless of whether effective or non-effective. The porosity was determined using the equation (Wyllie et al. 1958).

$$\Phi\text{Total} = \frac{\rho_{matrix} - \rho_{bulk}}{\text{Pmatrix} - \rho_{fluid}} \qquad (5)$$

Where;

Φ_{Total} = total porosity

Pmatrix = matrix density given as $2.65g/cm^3$

Pbulk = bulk density obtained from the density log

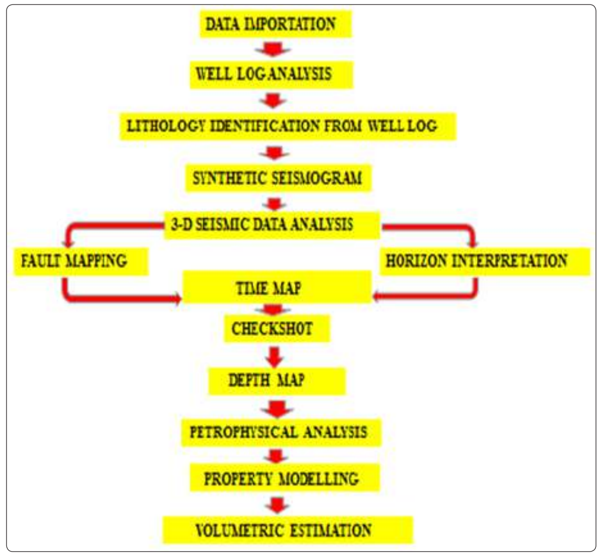


Figure 4: Flow Chat for Methodologies Used in this Research

Pfluid = fluid density of water given as $1g/cm^3$

When the pore spaces are relatively connected then it is described as an effective porosity which accounts for the free-flowing fluid.

$$(\Phi_{eff}) = (1-V_{sh}) * \Phi_{Total} \qquad (6)$$

Where;

Φ_{eff} = effective porosity

V_{sh} = volume of shale

Φ_{Total} = total porosity

Permeability (K)

Permeability is simply the degree or a measure of the ease of flow through a medium via its interconnected pores, capillaries or fractures. In order to determine the permeability of the given formation, several factors must be known. To start with, the fluid properties must be well understood, the Formation geometry (in terms of the shape and size which the Formation assumes), the amount of fluid flow or flow rate as well as the amount of flow should be put into account. Flow rate is enhanced by the amount of pressure the Formation exerts. Thus, it is clear to say that the higher the pressure the more or higher the rate of flow. Very empirically, it is observed that very few rocks have a 1 Darcy value of permeability. In computation of permeability, it is often given in millidarcies or expressed as a fraction in 1/1000 of a Darcy.

Usually, increased porosity could imply a higher permeability prospect although porosity is not directly related to permeability. Pore size, shape and continuity (Pore geometry) with porosity generally influence the permeability of a Formation. The Tixier model, 1949 is given as [21]:

$K = 250 \times \Phi_{eff}^{3} / S_{wirr}$ (7)

Where;

K = permeability

Φ_{eff}^{3} = effective porosity

S_{wirr} = irreducible water saturation

Water Saturation

It is a pore volume occupied by formation water, expressed in either percentage or as a fraction. It is expected that water saturation should be equal to one (1).

Water saturation is usually obtained using the Archie's formula given below [22]:

$$Sw = \frac{n\ aRw}{\Phi mRt} \quad (8)$$

Where;

S_w = Water saturation

n = Saturation exponent

Φ = Porosity

R_T = True Formation resistivity

m = Cementation exponent

a = Empirical constant

R_w = Resistivity of Formation water

Water saturation can also be obtained using the equation [23].

$S_w = 0.082/\ \Phi$ (9)

Where;

S_w = water saturation

Φ = effective porosity

Property Modelling Delineation

Structural, facies and fluid distribution models of the two reservoirs were generated. Also generated were models of their petro physical properties such as NTG, porosity and permeability. These models were generated by distributing the estimated properties (geologic and petro physical properties) estimated along well paths across the entire reservoir structure or grid using geo-statistical technique. The geo-statistical algorithm applied in distributing the facies is the Sequential Indicator Simulation (SIS) algorithm. The geo-statistical algorithm applied in distributing the petro physical properties such as porosity, NTG, water saturation and permeability is the Sequential Gaussian Simulation (SGS) algorithm.

Volumetric Estimation

The volumetric calculations were done using the formulae as stated by [24].

Calculation of Bulk Volume

The bulk volume is calculated with the formula below;

Bulk volume = A*H (10)

Where;

A = Area

H = Gross thickness

Net Volume Estimation

Net volume is estimated with the formula below;

Net volume = A*H*NTG (11)

Where;

A = Area

H = Gross thickness

NTG = Net thickness

Calculation of Pore Volume

Pore volume = A*H*NTG* Φ (12)

Where;

A = Area

H = Gross thickness

NTG = Net thickness

Φ = Porosity

Calculation of Hydrocarbon Pore Volume (HCPV)

$HCPV = Area*H*\Phi*NTG*(1-S_w)$ (13)

Where;

Area = Hydrocarbon-bearing area of the reservoir

H = Gross thickness

Φ = Porosity

NTG = Net thickness

$(1-S_w)$ = 1-water saturation (hydrocarbon saturation)

Calculation of Stock Tank Oil Initially In Place (STOIIP)

$STOIIP = 7758*A*h*\Phi*(1-S_w)*1/B_o$ (3.19)

Where;

7758 = Acre-feet conversion for oil

A = Area in acres

h = Net Pay thickness in feet

Φ = Porosity

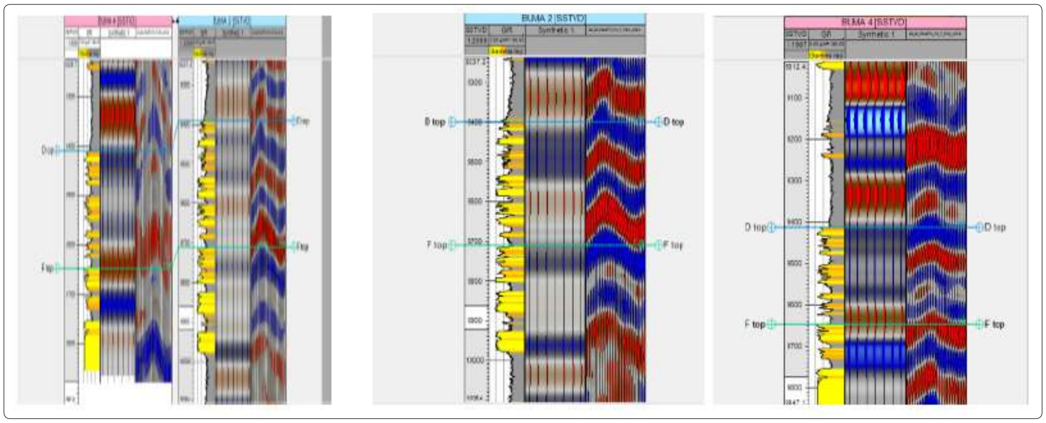
S_w = Water saturation

B_o = Formation volume factor.

Results and Discussion

The results of this research are presented in Figures 5 – 17 and Tables 1 -5

The results of seismic analysis are presented in Figures 5 – 9. Synthetic seismograms generated using sonic and density logs have been used to create a well to seismic tie. Top of reservoir D -Well 2 from well log was tied to seismic at 9400 ft. whereas top of reservoir F -Well 2 from well log was tied to seismic at 9710ft. For Well 4, the tie was at 9410ft. at the top of reservoir D whereas at the top of reservoir F, the tie was done at 9650ft see Figure 4. The seismic to well tie demonstrates the relationship between the tops of horizons D and F and the seismic reflections as well establishes the depth/time model. Fifteen (15) faults have been mapped on the seismic, they comprise normal faults, nine (9) trend Northwest-Southeast and are antithetic faults while six (6) trend Northeast-Southwest and are synthetic faults (Figure 5). These faults are believed to be the trapping mechanism for the hydrocarbon in Buma Field reservoirs. Two horizons were mapped - horizons D and F respectively (See Figure 6). Time maps were generated for horizons D and F, showing early arrivals of reflections at the upper parts of the maps as compared to the values of the lower parts which show late arrivals of the seismic reflections (Figures 7 and 8) and time maps converted to depth maps using check-shot (Figures 9 and 10). From the seismic interpretation, the area is associated with fault structures. These faults are typical of the structural faults in the Niger Delta which may have contributed to the trapping of the hydrocarbon pore fluids in reservoirs D and F respectively. The results of the property modelling and petrophysical analysis are presented in Figures 11 - 16 and Tables 1 - 4. Structural models for reservoirs D and F show well positions and faults coupled with the superimposition of the two reservoirs (Figures 11 -13). Fluid distribution models for reservoirs D and F show parts of the reservoirs containing oil and that containing water (that is the contact between oil and water). See Figures 14 and 15). Facies models of the two reservoirs D and F in the studied wells show the portions that have sand; fine sand and shale see Figure 13.



(a) (b)

Figure 5: (a) Before Well-To-Seismic (b) After Well-To-Seismic Tie for Wells 2 and 4)

Petrophysical logs were generated for the six wells in the show the lithology and facies type (from Gamma ray log, GR), resistivity log (LL9D), neutron (NPHI)-density (RHOB) logs were used to evaluate the petrophysical properties such as net-to-gross NTG, volume of shale V_{sh}, total and effective porosities, water saturation and permeability. Petrophysical evaluation of reservoirs involves evaluating the following parameters porosity (which aids the storage of appreciable quantity of pore fluids), permeability (for good and easy flow of the pore fluids), the thickness of the productive sand in the overall reservoir (NTG), and water saturation. Petrophysical models are used displaying the petrophysical properties evaluated such as NTG, porosity and permeability models generated for reservoirs D and F (Figures 14 - 16). The mean reservoir properties across the six wells used in this research is as follows porosity (26.32%), permeability (224.87mD), S_w (31.60%) and NTG (0.89) for Reservoir D while for Reservoir F it is as follows porosity (28.78%), permeability (195.38mD), S_w (33.51%) and NTG (0.90). The range of values for the petrophysical for the studied wells are as follows for Reservoir D porosity is (0.00 – 31.15%), permeability (0.00 – 499.74mD), S_w (0.00 - 48.40%) and NTG (0.00 – 1.00) while for Reservoir F it as follows porosity is (23.95 – 33.15%), permeability (28.97 – 512.51mD) and NTG (0.00 – 1.00). These results are typical for the Niger Delta [12]. The volumes of fluids were computed for reservoirs D and F (Table 5). Reservoir D, the average thickness is 26.73ft., area (3784.89acres) and for reservoir F, the average thickness is 41.55ft., area (2790.63acres). See Table 5. The average thickness of Reservoirs D and F is 34.14ft (3287.76 acres), Reservoir bulk volume is 4729 x 10^6 ft^3, two hydrocarbon bearing zones (horizons D and F) comprise mainly of sand bodies with intercalations of shale beds mapped on the seismic section. Structural models of the two reservoirs D and F as well as their fluid distribution models showed areas occupied by oil and water. The petrophysical properties of the studied reservoirs showed similarities typical of the Agbada Formation in the Niger Delta Basin and is hydrocarbon bearing. Integrating the structural interpretation (the fault traps) with analysis of the well logs including their petrophysical properties and volumetric estimation suggest that the reservoir sand units of Buma Field (Reservoirs D and F) are economically viable and can be exploited beneficially.

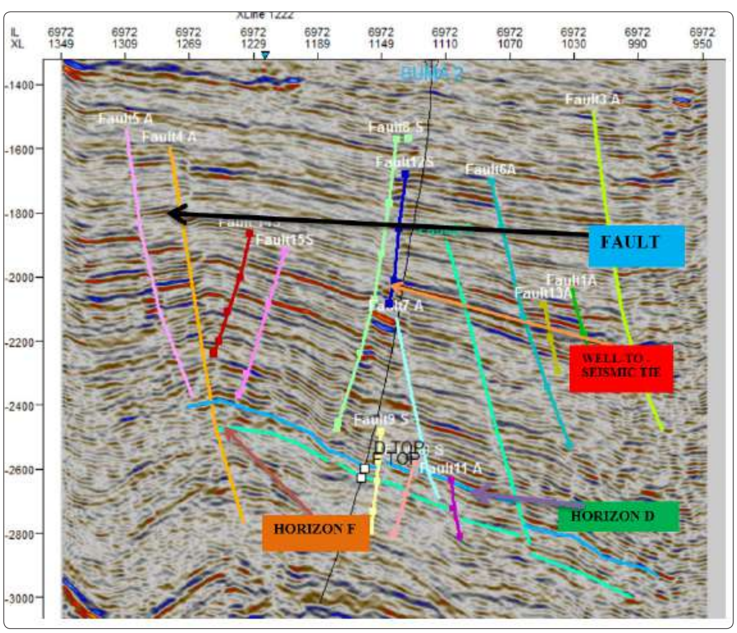


Figure 6: Faults and Horizon Interpretation on Seismic Section (mapping)

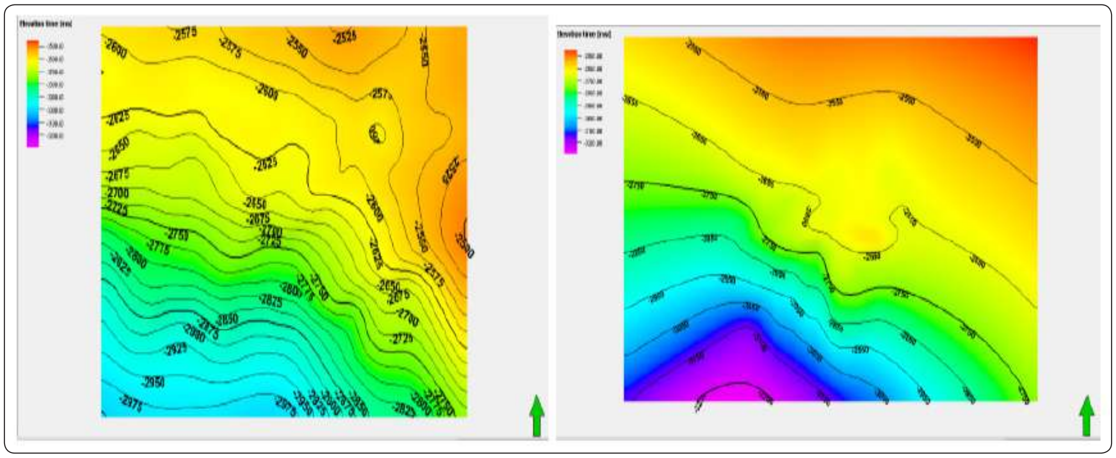


Figure 7: (a) Horizon/Time Map for reservoir D (b) Horizon/Time Map for reservoir F

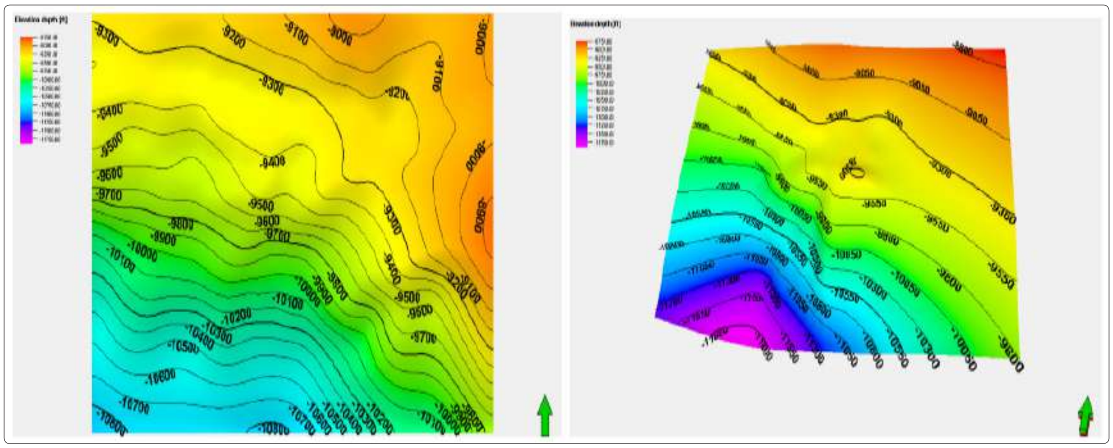


Figure 8: (a) Horizon/Depth Map for Reservoir D (b) Horizon/Depth Map for reservoir F

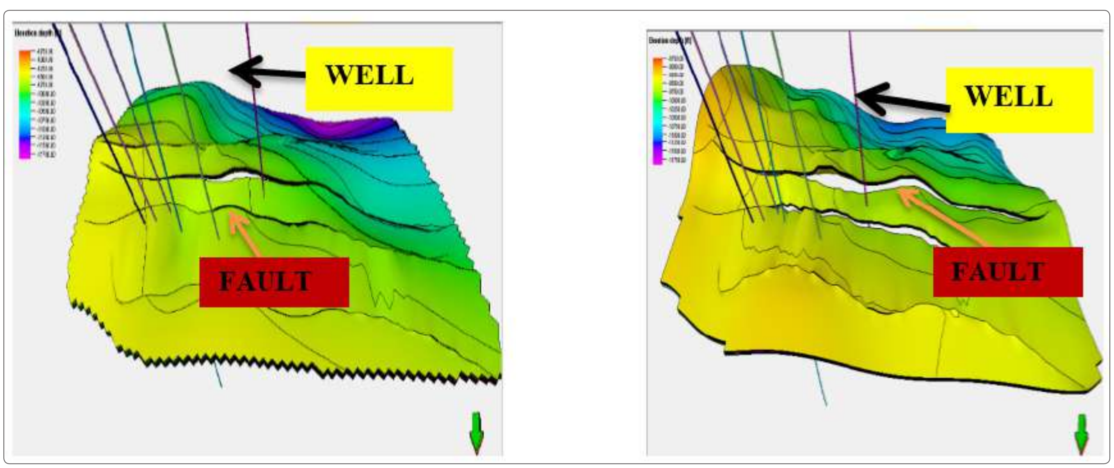


Figure 9: (a) Fault model of reservoir F (b) Fault model of reservoir F.

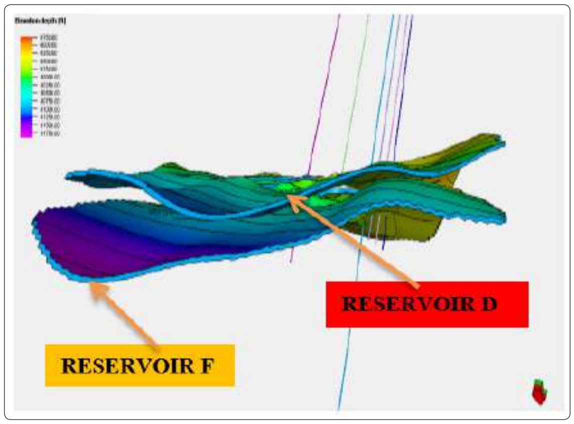


Figure 10: Reservoirs D and F Structural Models

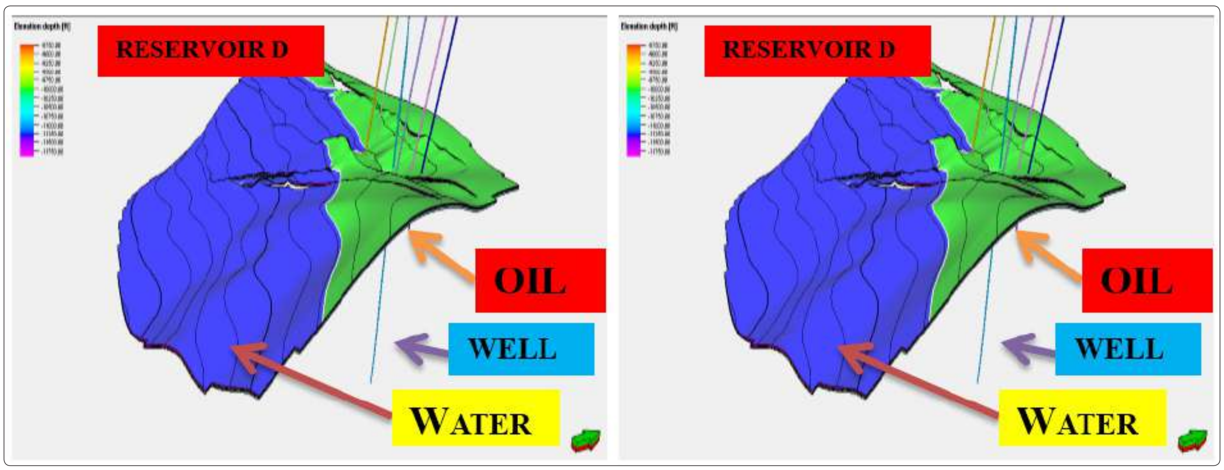


Figure 11: (a) Reservoir D Fluid Distribution Model (b) Reservoir F Fluid Distribution Model

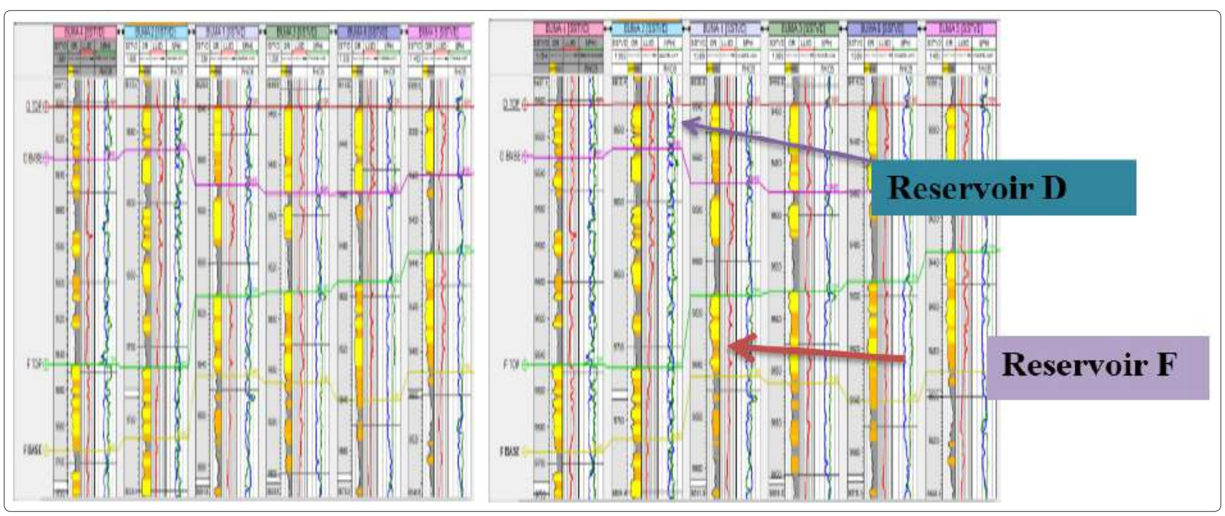


Figure 12: Sand Lithology identifications of Reservoirs D and F of Buma Field

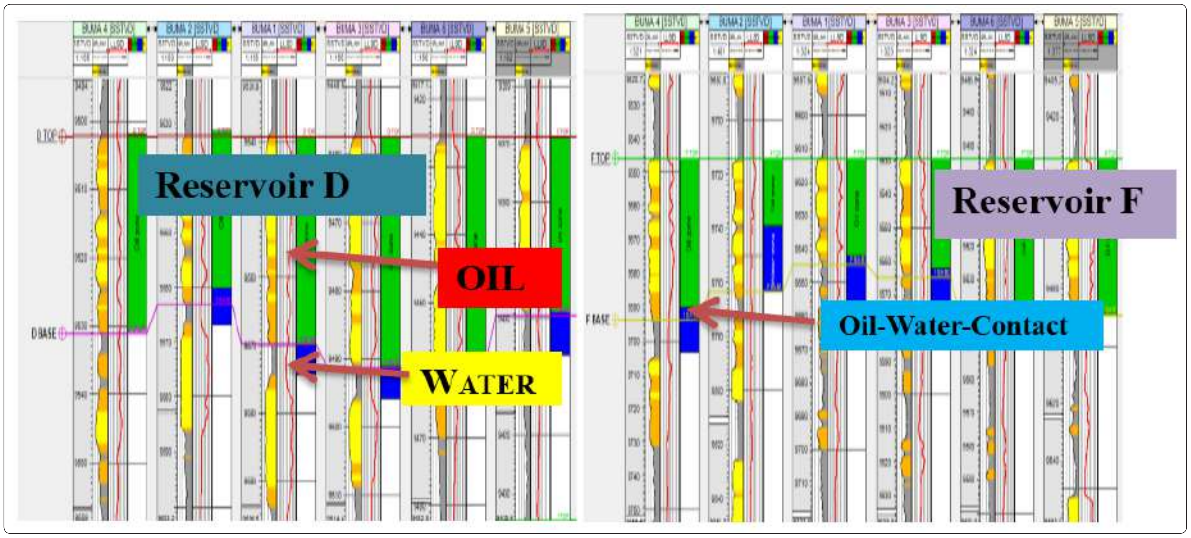


Figure 13: Fluid Contact Distribution Plot for Reservoirs D and F

Table 1: Petrophysical Characteristics of Reservoir D (Mean values)

Well Name	Porosity %	Permeability mD	Water Saturation (S_w) %	Net-To-Gross (NTG)
Buma 1	23.98	193.91	29.09	0.8571
Buma 2	27.98	255.15	35.08	0.9426
Buma 3	24.80	249.66	27.47	0.8600
Buma 4	28.23	192.72	34.94	0.9384
Buma 5	27.57	181.31	35.63	0.9345
Buma 6	25.34	276.44	27.44	0.8121
Mean	26.32	224.87	31.60	0.8908

Table 2 Petrophysical Characteristics of Reservoir D (Range of values)

Well Name	Porosity %	Permeability mD	Water Saturation (S_w) %	Net-To-Gross (NTG)
Buma 1	0.00 – 30.65	0.00 – 319.50	0.00 – 42.39	0.00 – 1.00
Buma 2	21.26 – 32.11	51.70 – 499.74	27.59 – 48.40	0.58 – 1.00
Buma 3	0.00 – 31.57	0.00 – 420.54	0.00 – 39.16	0.00 – 0.00
Buma 4	24.93 – 31.49	107.93 –261.48	31.31 – 39.93	0.75 – 1.00
Buma 5	23.11 – 30.03	51.70 – 249.89	30.22 – 42.00	0.75 – 1.00
Buma 6	0.00 – 32.01	0.00 – 457.56	0.00 – 37.82	0.00 – 1.00
Mean	0.00 – 31.57	0.00 – 499.74	0.00 – 48.40	0.00 – 1.00

Table 3: Petrophysical Characteristics of Reservoir F (Mean values)

Well Name	Porosity %	Permeability mD	Water Saturation (S_w) %	Net-To-Gross (NTG)
Buma 1	27.11	127.58	37.73	0.8203
Buma 2	28.41	231.20	32.99	0.9835
Buma 3	29.47	190.46	33.52	0.7727
Buma 4	28.40	194.72	31.94	0.9354
Buma 5	29.50	218.30	32.19	0.9839
Buma 6	29.80	210.03	32.70	0.9215
Mean	28.78	195.38	33.51	0.9028

Table 4 Petrophysical Characteristics of Reservoir F (Range of values)

Well Name	Porosity %	Permeability mD	Water Saturation (S_w) %	Net-To-Gross (NTG)
Buma 1	25.11 – 28.33	28.97 – 276.60	33.92 – 44.03	0.00 – 1.00
Buma 2	23.95 – 30.42	93.05 – 433.58	30.66 – 40.25	0.92 – 1.00
Buma 3	25.63– 31.40	116.57 – 29.50	29.61 – 38.36	0.00 – 1.00
Buma 4	26.43 – 31.48	109.43 –361.48	31.31 – 39.93	0.75 – 1.00
Buma 5	27.19 – 33.15	55.87 – 512.51	27.33 – 39.38	0.92 – 1.00
Buma 6	25.86– 31.78	63.40 – 277.78	29.20 – 40.13	0.33 – 1.00
Range	23.95 – 33.15	28.97 – 512.51	27.33 – 40.13	0.00 – 1.00

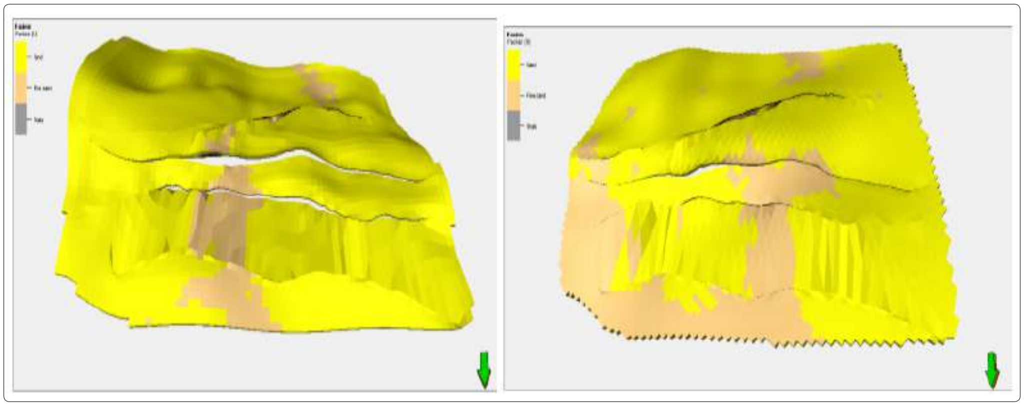


Figure 14: Reservoirs D and F Facies Model; the position of the arrow points to the north

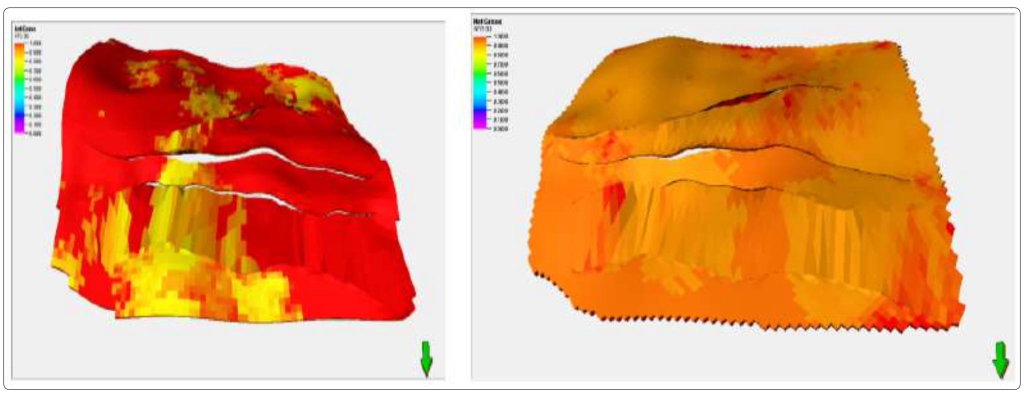


Figure 15: Reservoir D and F NTG Model; the position of the arrow points to the north

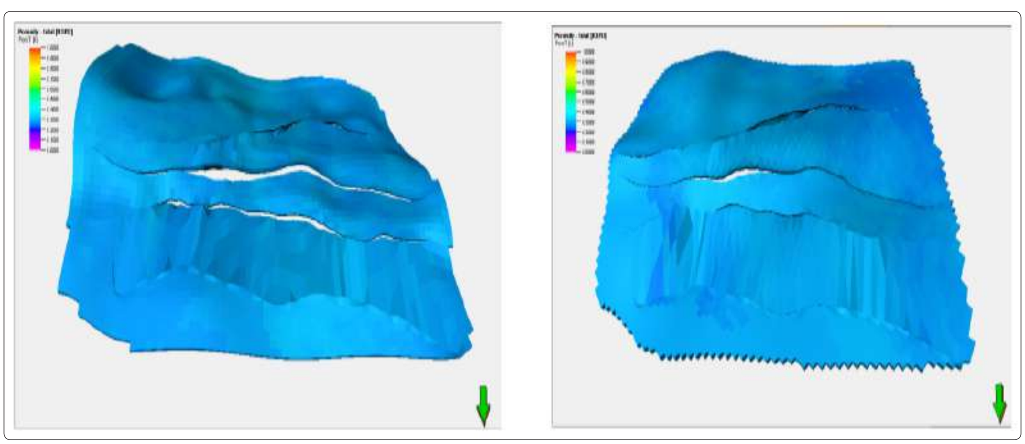


Figure 16: Reservoirs D and F Porosity Model; the position of the arrow points to the north

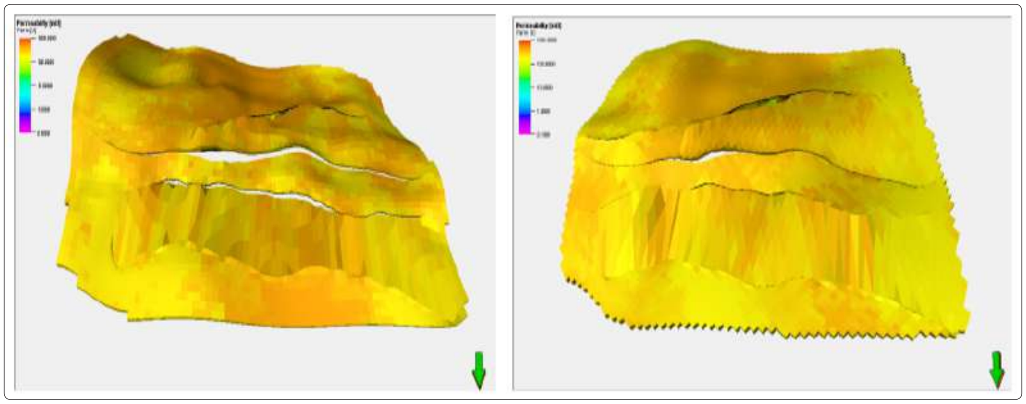


Figure 17: Reservoirs D and F Permeability Model; the position of the arrow points to the north

Table 5: Volumetric Estimation of Reservoirs D and F

RESERVOIR	AVERAGE THICKNESS (ft.)	AREA (ACRES)	BULK VOLUME ($x10^6 ft.^3$)	NET VOLUME ($x10^6 ft.^3$)	PORE VOLUME ($x10^6$ RB)	HCPV (($x10^6$ RB)	STOIIP ($x10^6$ MMSTB)
D	26.73	3784.89	4407	4226	216	143	77
F	41.55	2790.63	5051	4769	248	167	88
Average	34.14	3287.76	4729	4497.5	232	155	82.5

Conclusion

The characterization of reservoirs D and F of Buma Field has elucidated their productive capability by containing hydrocarbon pore fluids (from petro physical properties and volumetric estimation) based on the analysis and interpretation of the seismic and well log data. Showed the economic viability of the reservoirs (Reservoirs D and F) of Buma Field [25-30].

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