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Determination of Reservoir Quality in Field "D" in Central Niger Delta, Using Well Log Data

Imikanasua, D.[1*], Tamunobereton-Ari, I.[2] & Ngeri, A.P.[3]

[1-3]*Department of Physics, Rivers State University, Port Harcourt, Rivers State, Nigeria.*
*Corresponding Author: Imikandaniel@gmail.com**

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ABSTRACT

Well log data was used in this study to assess reservoir properties of field "D" in the southern area of the Niger Delta. For successful petrophysical evaluation, three hydrocarbon-bearing reservoirs (reservoirs A, B, and C) were identified and correlated. The following metrics were tested to determine reservoir properties: porosity, permeability, shale volume, fluid saturation, and net pay thickness. The calculated reservoir property values indicate high reservoir quality. Porosity readings in well OTIG 2 are almost the same, averaging 20%, but values in wells OTIG 7 and OTIG 9 vary from 14-20%. The reservoirs' average permeability was greater than 100md. However, in wells OTIG 2 and OTIG 9, values steadily decline with depth due to compaction caused by the overburden pressure of the underlying rock. Hydrocarbon saturation values in well OTIG 2 are almost the same, averaging 60%, but vary from 60-70% in well OTIG 7 as well as 48-55% in well OTIG 9. Water saturation values in well OTIG 2 are almost the same, averaging 40%, but range from 30-40% in well OTIG 7 and 45-52% in well OTIG 9. The average bulk volume water values in well OTIG 2 are almost the same, averaging 8%, but range from 6-8% in well OTIG 7 and 7-9% in well OTIG 9. There is some evidence that reservoirs A, B, and C in well OTIG 2 are one continuous sand body. This is due to the fact that their porosity, bulk volume water, hydrocarbon saturation, and water saturation values are all roughly the same, and their depth values are all quite similar. The bulk volume water values support the hypothesis that these formations are homogeneous and near irreducible water saturation. The reservoirs found in the field contain hydrocarbons.

Keywords: *Hydrocarbon saturation, Petrophysical properties, Reservoirs, Water saturation.*

1.0. Introduction

In Nigeria, oil is the major source of revenue for national development and so it requires great effort from the government, research institutions, and oil companies to ensure that this non-renewable energy source is tapped (Adaeze et al., 2012).

Reservoir characterization is very important to oil companies since the beginning, around 1980 (Onuoha, 2011). It involves the use of all the available data, tools, discipline, and knowledge to describe a reservoir. The main purpose of reservoir characterization is to understand and identify the flow unit of the reservoir and predict the distribution of relevant reservoir properties such as porosity, permeability, fluid saturation, and net pay thickness (Onuoha, 2011). Understanding reservoir properties is very important in quantifying producible hydrocarbon (Schlumberger, 1989). It is, therefore, necessary to properly characterize a reservoir and determine the hydrocarbon in place in order to avert any loss or wastage of resources.

A reservoir rock has effective porosity, permeability and contains an exploitable quantity of hydrocarbon. Porosity and permeability are important properties that define reservoir quality. Determination of reservoir quality is concerned with the determination of reservoir properties or parameters such as porosity (Φ), permeability (K), fluid saturation, and Net Pay thickness (Amafule, 1998).

Accurate estimates on porosity and permeability values in certain stratigraphic intervals can be derived from well log types such as density, neutron, and sonic log. A good reservoir rock is one that is productive.

This study involved the employment of well log data to determinethe reservoir quality in the field "D" in the Central part of the Niger Delta.

2.0. Study Area

The Niger Delta is located in the Southern part of Nigeria boarding the Atlantic Ocean and extends from about longitude 30^0 00`E to $9^0$ 00`E and latitude 4^0 3`N to $5^0$ 20`N (Lambert, 1981).

It is the youngest sedimentary basin within the Benue trough system. The Niger development began after the Eocene tectonic phase, Niger and Benue rivers are the main supplier of sediments. The Niger Delta basin consists of three lithostratigraphic units, which are Benin formation, Agbada formation, and Akata formation. The Akata formation is predominantly marine Pro-Delta shale and overlain by the paralic sand/shale sequences of the Agbada formation. The uppermost section is the continental upper Deltaic plain sands which is the Benin formation. Hydrocarbon accumulation in the Niger delta occurs in the sands and sandstones of Agbada formation where they are trapped by rollover anticlines related to growth fault development (Ekweozor and Dankoru, 1994). Fig.1 shows the three stratigraphic formations in the Niger Delta.

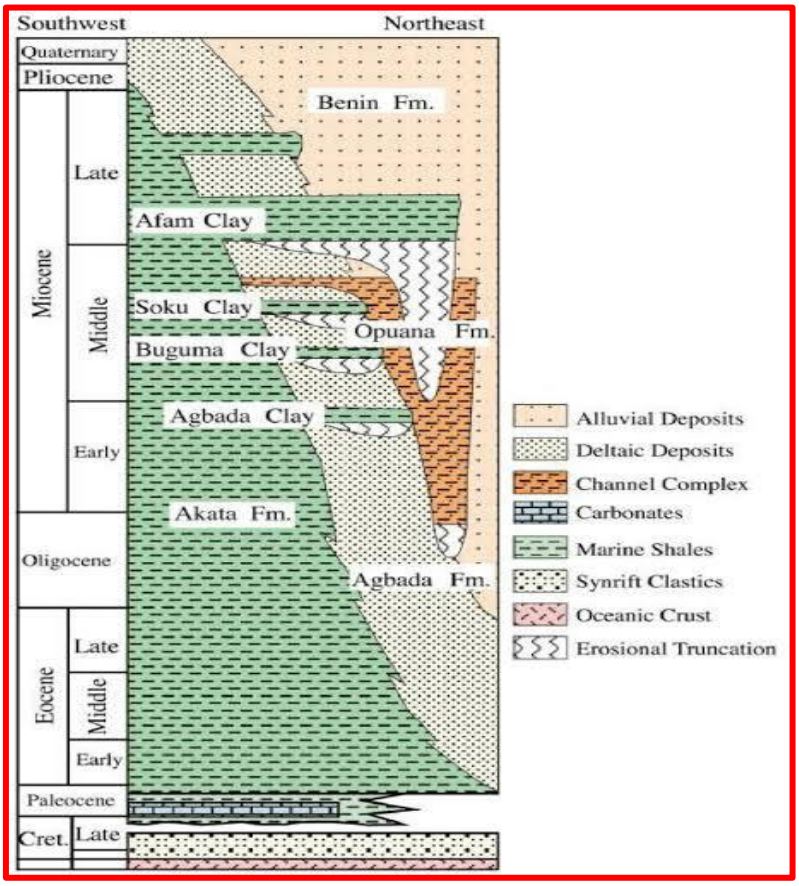

Fig.1. Stratigraphic column showing the three formations of the Niger Delta. (Modified from Shannon and Naylor, 1989; Doust and Omatsola, 1990)

3.0. Materials and Methods

The study was carried out in four stages. In the first stage, the data were gathered and loaded into the software used. In the second stage, the data were quality checked and edited, bad traces were removed to delineate the effects of error during the analysis of data. Cycle skipping, caused by spiky sonic logs often result in artificial events that can be mistaken for real reflectors that were corrected before they were used to calculate petrophysical parameters.

In the third stage, a stratigraphic correlation was carried out, this was done to pick the formation tops, and to delineate the reservoirs for the study. In the fourth stage, the petrophysical properties of the reservoirs were estimated using various empirical formulas. Fig.2 shows the workflow of the methodology.

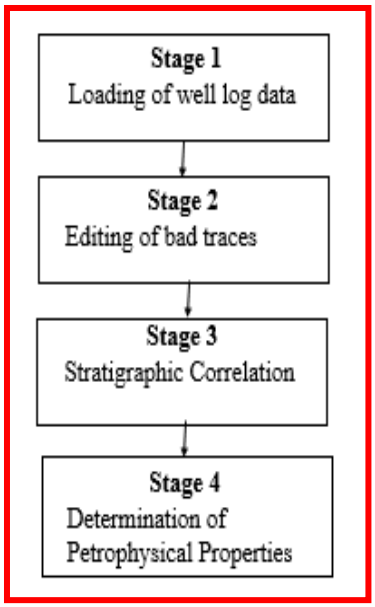

Fig.2. Workflow of the Methodology Process

3.1. Determination of Petrophysical Properties

The petrophysical properties used in this study are discussed below. Empirical equations were used to calculate some of these petrophysical properties, since they cannot be directly recorded on well log data, during data acquisition.

3.1.1. Determination of Gamma-ray index

A gamma-ray log was used for identifying lithologies and for correlating zones. Shale-free sandstones and carbonates have low concentrations of radioactive material and give low gamma-ray readings. As the shale content in a formation increases, the gamma-ray log response increases because of the high concentration of radioactive material in shale. The equation below was used to calculate the gamma-ray index (Schlumberger, 1974).

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad (1)$$

Where, GR_{log}= measured gamma-ray log reading at depth (z), GR_{min}= minimum gamma-ray log reading in clean sand, GR_{max}= maximum gamma-ray log reading in clean shale, IGR= Gamma-ray index.

3.1.2. Determination of Volume of shale

The volume of shale was calculated mathematically from the gamma-ray index (IGR) using Dresser Atlas (1979) formula:

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

Where, Vsh = volume of shale, IGR = gamma ray index.

3.1.3. Determination of Porosity

Porosity is the ratio of the pore volume to the bulk volume of rock, expressed as a percentage (%). It is calculated from density, sonic, or neutron logs.

Total porosity was determined from density log data which was the weighted average density of the rock and pore fluid using the equation below (Dresser, 1979):

$$\emptyset_t = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fl})} \qquad (3)$$

Where, $\emptyset_t$ = total density porosity, ρ_{ma} = density of rock matrix, ρ_b = measured density and ρ_{fl} = density of fluid.

The effective porosity was calculated using the equation below;

$$\emptyset_{eff} = (1 - Vsh) \times \emptyset_t \qquad (4)$$

3.1.4. Determination of Permeability

Permeability is defined as the ability of a reservoir to 'conduct' or 'transmit' fluids through the rock matrix: it is the flow capacity of a reservoir.

The empirical equation below was used to calculate the permeability of the reservoir.

Equation 5 is used when the reservoir is a gas reservoir, for an oil reservoir equation 6 was used.

$$K = \left(30.7 + 2655 \times {\emptyset_{eff}}^2\right) - 3454(\emptyset_{eff} \times S_{wirr})^2 \qquad (5)$$

$$K = 307 + \left(26552 \times {\emptyset_{eff}}^2\right) - (34540 \times \left(\emptyset_{eff} \times S_{wirr}\right)^2) \qquad (6)$$

Where, S_{wirr} is the irreducible water saturation, K is the permeability and $\emptyset_{eff}$ is the effective porosity.

3.1.5. Determination of Water saturation

Water saturation (S_w) is the measure of pore volume of the rock filled with water, the water in the rock may be mobile or capillary bound. The empirical equation below was used to calculate the water saturation,

$$S_w = \sqrt[n]{\frac{F.R_w}{R_t}} \qquad (7)$$

Where, R_t = the true formation resistivity, S_w = water saturation level, R_w = formation water resistivity, F = formation resistivity factor, n = saturation exponent.

The irreducible water saturation was calculated using the equation below,

$$S_{wirr} = \sqrt{\frac{F}{2000}} \qquad (8)$$

Where, F is the formation factor.

3.1.6. Determination of Hydrocarbon saturation (HS)

The hydrocarbon saturation was deduced from water saturation by the following empirical relationship:

$$HS = (1 - S_w) \qquad (9)$$

3.1.7. Determination of Bulk Volume Water (BVW)

If values of bulk volume water calculated at several depths in a formation are constant or very close to constant, they indicate that the zone is homogeneous and at irreducible water saturation.

The product of a formation water saturation and porosity is the bulk volume of water (Morris and Biggs, 1967).

$$BVW = S_w \times \emptyset_{eff} \qquad (10)$$

3.1.8. Determination of Transmissivity

Transmissivity is the product of reservoir thickness and permeability.

The equation below was used to calculate the fluid transmissivity.

$$T = Reservoir\ Thickness \times K \qquad (11)$$

Where, T is the Transmissivity and K is the permeability.

4.0. Results and Discussion

A display of the three reservoirs in the three wells is shown in Figs.3-6. Table 1 shows the petrophysical properties of Well OTIG 2 with the three reservoirs. Table 2 shows the petrophysical properties of Well OTIG 7, while Table 3 shows the petrophysical properties of Well OTIG 9.

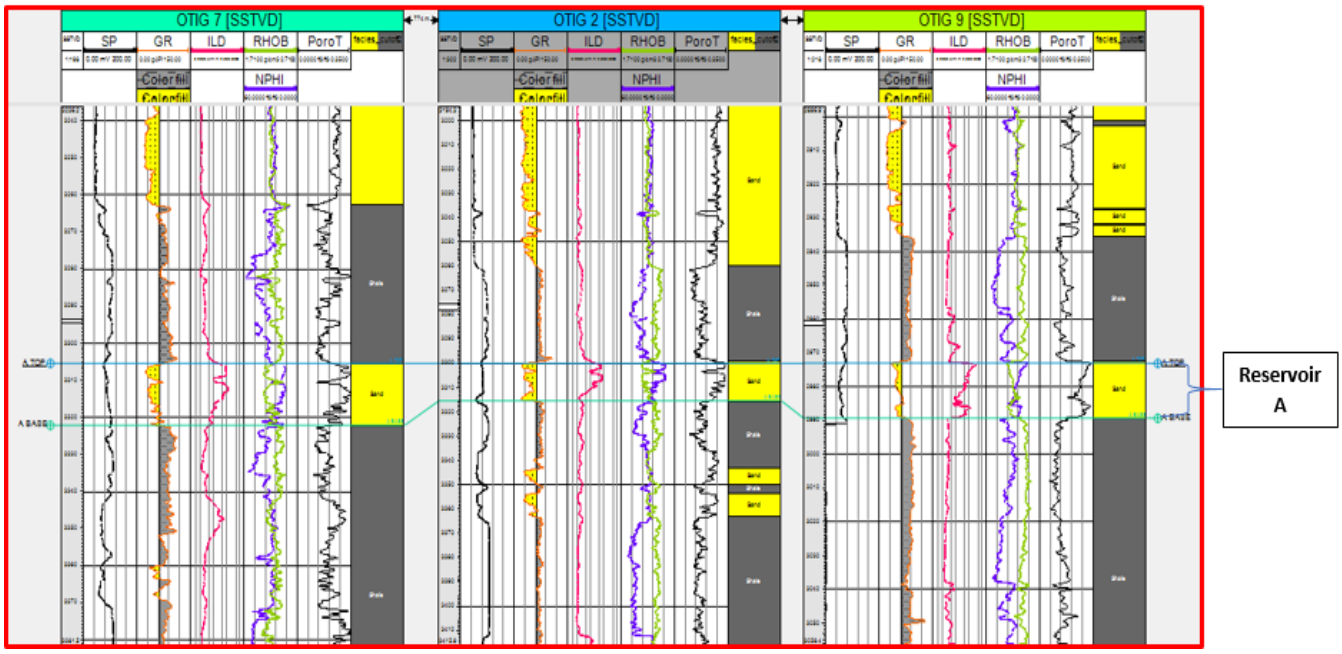

Fig.3. Well Logs from Well OTIG 2, OTIG 7, OTIG 9, Showing the Delineated Reservoir Sand A

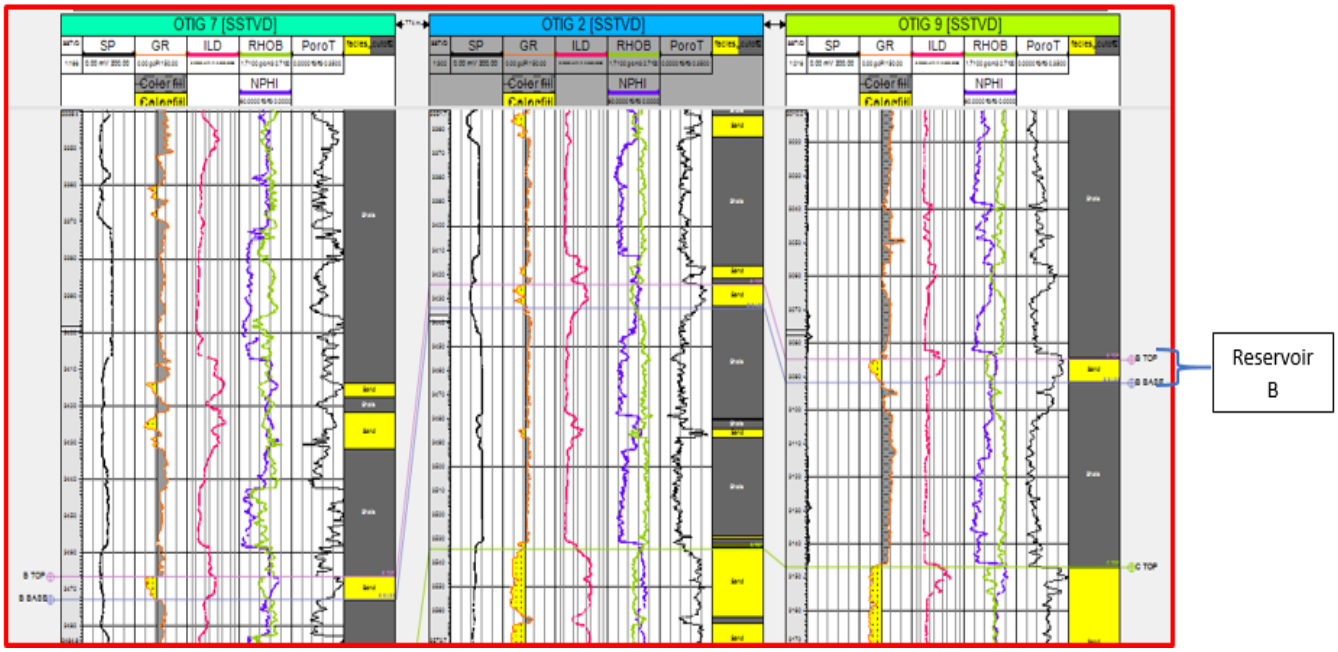

Fig.4. Well Logs from Well OTIG 2, OTIG 7, OTIG 9, Showing the Delineated Reservoir Sand B

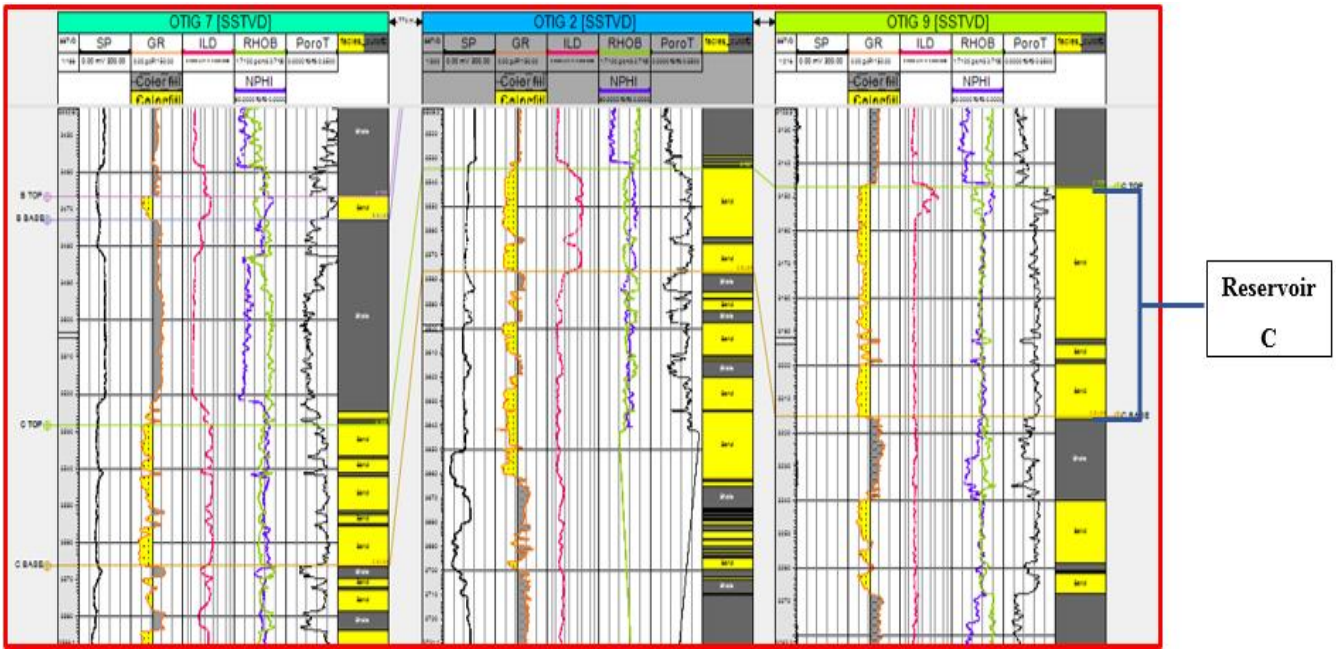

Fig.5. Well Logs from Well OTIG 2, OTIG 7, OTIG 9, Showing the Delineated Reservoir Sand C

Table 1. Petrophysical Properties of Well OTIG 2

Reservoir	Depth Top	Depth Bottom	Thickness (m)	Net thickness of sand (m)	Vsh	N/G Ratio	Ø (%)	S_{wirr}	Sw (%)	HS (%)	BVW	K (md)	T (mdft)
A	3300	3320	20	8	0.2	0.4	0.2	0.14	0.4	0.6	0.08	171	3420
B	3425	3445	20	15.6	0.2	0.78	0.2	0.14	0.4	0.6	0.08	152	3040
C	3530	3590	60	46.2	0.12	0.77	0.2	0.14	0.4	0.6	0.08	146	8760

Table 2. Petrophysical properties of well OTIG 7

Reservoir	Depth Top Bottom	Thickness (m)	Net thickness of sand (m)	Vsh	N/G Ratio	∅ (%)	S_{wirr}	Sw (%)	HS (%)	BVW	K (md)	T (mdft)
A	3305 3330	25	7.5	0.5	0.3	0.14	0.14	0.4	0.6	0.06	172	4300
B	3460 3485	25	5	0.4	0.2	0.2	0.12	0.3	0.7	0.06	241	6025
C	3525 3580	55	38.5	0.2	0.7	0.2	0.4	0.4	0.6	0.08	160	8800

Table 3. Petrophysical Properties of Well OTIG 9

Reservoir	Depth Top Bottom	Thickness (m)	Net thickness of sand (m)	Vsh	N/G Ratio	∅ (%)	S_{wirr}	Sw (%)	HS (%)	BVW	K (md)	T (mdft)
A	2970 3000	30	12	0.4	0.4	0.14	0.3	0.48	0.52	0.07	140	4200
B	3085 3105	20	8	0.4	0.4	0.14	0.3	0.52	0.48	0.07	127	2540
C	3140 3225	85	60.4	0.2	0.72	0.2	0.2	0.45	0.55	0.09	126	10710

4.1. Interpretation of the Reservoir Properties in Well OTIG 2

Reservoir A occurs at an interval of 3300 m - 3320 m. The thickness of reservoir A is 20 m, the net thickness of the sand is 8 m, the volume of shale value ranges from 0 - 0.39, with an average value of 0.2. The average net to gross ratio value is 0.4. The porosity values in the reservoir range from 0.09 - 0.33, with an average porosity of 0.2, indicating good porosity values. The permeability values range from 83 - 277 md, with average permeability values of 177 md, indicating good permeability values. The irreducible water saturation value is 0.14. The water saturation value ranges from 0.25 - 0.54, with an average water saturation value of 0.4. The hydrocarbon saturation values range from 0.46 - 0.75, with an average hydrocarbon saturation value of 0.6, indicating that the reservoir is productive. The bulk water volume value is 0.08 while the transmissivity value is 3420 mdft.

Reservoir B occurs at an interval of 3425 m - 3445 m. The thickness of reservoir B is 20 m, the net thickness of the sand is 15.6 m. The volume of shale values ranges from 0.03 - 0.31 with an average volume of shale value of 0.2. The average net to gross ratio is 0.78. The porosity in the reservoir ranges from 0.09 - 0.29 with an average porosity value of 0.2, indicating good porosity values. The permeability in the reservoir ranges from 69 - 233 md, with an average permeability value of 152 md indicating a good permeability value. The irreducible water saturation is 0.14. The water saturation values range from 0.28 - 0.46, with an average water saturation value of 0.4. The hydrocarbon saturation values range from 0.37 - 0.72, with an average value of 0.6 indicating that the reservoir is productive. The bulk water volume value is 0.08 while the transmissivity value is 3040 mdft. Reservoir C occurs at an interval of 3530 m - 3590 m. The thickness of reservoir C is 60 m, the net thickness of the sand is 46.2 m. The volume of shale values ranges from 0 - 0.35 with, an average volume of shale value of 0.12. The average net to gross ratio is 0.77. The porosity value ranges from 0.07 - 0.28 with an average porosity value of 0.2 indicating a

good porosity value The permeability value ranges from 57 - 210 md, with an average permeability value of 146 md indicating a good permeability value. The irreducible water saturation is 0.14. The water saturation value ranges from 0.29 - 0.75, with an average water saturation value of 0.4. The hydrocarbon saturation value ranges from 0.24 - 0.70, with an average hydrocarbon saturation value of 0.6 indicating that the reservoir is productive. The bulk volume water value is 0.08 while the transmissivity value is 8760 mdft.

4.2. Interpretation of the Reservoir Properties in Well OTIG 7

Reservoir A occurs at an interval of 3305 - 3330 m. The thickness of reservoir A is 25 m, the net thickness of the sand is 7.5 m. The volume of shale value ranges from 0.021 - 1 with an average volume of shale value of 0.5. The average net to gross ratio is 0.3. The porosity value ranges from 0.07 - 0.33 with an average porosity value of 0.14. The permeability value ranges from 77 - 297 md, with an average permeability value of 172 md, indicating good permeability values. The irreducible water saturation value is 0.14. The water saturation value ranges from 0.24 - 0.58, with an average water saturation value of 0.4. The hydrocarbon saturation value ranges from 0.42 - 0.72, with an average hydrocarbon saturation value of 0.6. The bulk volume water value is 0.06 while the transmissivity value is 3420 mdft. Reservoir B occurs at an interval of 3460 - 3485 m. The thickness of reservoir B is 25 m, the net thickness of the sand is 5 m. The volume of shale values ranges from 0.02 - 0.49, with an average volume of shale value of 0.4. The average net to gross ratio is 0.2. The porosity value ranges from 0.1 - 0.32, with an average porosity value of 0.2, indicating a good porosity value. The permeability value ranges from 123 - 461md, with an average permeability value of 241md, indicating a good permeability value. The irreducible water saturation is 0.12. The water saturation value ranges from 0.28 - 0.46 with an average water saturation value of 0.3. The hydrocarbon saturation value ranges from 0.59 - 0.81, with an average hydrocarbon saturation value of 0.7, indicating that the reservoir is productive. The bulk volume water value is 0.06 while the transmissivity value is 6025 mdft.

Reservoir C occurs at an interval of 3525 m - 3580 m. The thickness of reservoir C is 55 m, the net thickness of the sand is 38.5 m. The volume of shale value ranges from 0.001 - 0.66, with an average volume of shale value of 0.2. The average net to gross ratio is 0.7. Porosity value ranges from 0.04 - 0.28, with an average porosity value of 0.2, indicating a good porosity value. The permeability value ranges from 72 - 212 md, with an average permeability of 160 mdft, indicating a good permeability value. The irreducible water saturation is 0.14. The water saturation value ranges from 0.29 - 0.61, with an average water saturation value of 0.4. The hydrocarbon saturation value ranges from 0.39 - 0.71, with an average hydrocarbon saturation value of 0.6. The bulk volume water value is 0.08 while the transmissivity value is 8800 mdft.

4.3. Interpretation of the Reservoir Properties in Well OTIG 9

Reservoir A occurs at an interval of 2970 - 3000 m. The thickness of reservoir A is 30 m, the net thickness of the sand is 12 m. The volume of shale value ranges from 0.09 - 0.71, with an average volume of shale value of 0.4. The average net to gross ratio is 0.4. The porosity value ranges from 0.03 - 0.31, with an average porosity value of 0.14. The permeability value ranges from 61 - 278 md, with an average permeability value of 139 md, indicating a good permeability value. The irreducible water saturation is 0.3. The water saturation value ranges from 0.25 - 0.71 with

an average water saturation value of 0.48. The hydrocarbon saturation value ranges from 0.29 - 0.75, with an average hydrocarbon saturation value of 0.52. The Bulk volume water value is 0.07 while the transmissivity is 4200 mdft.

Reservoir B occurs at an interval of 3085 - 3105 m. The thickness of reservoir B is 20 m, the net thickness of the sand is 8 m, the volume of shale value ranges from 0.02 - 0.7, with an average volume of shale value of 0.4. The average net to gross ratio is 0.4. The porosity value ranges from 0.03 - 0.31, with an average porosity value of 0.14. The permeability value ranges from 61 - 256 md, with an average permeability value of 127 md indicating a good permeability value. The irreducible water saturation is 0.3. The water saturation value ranges from 0.26 - 0.71, with an average water saturation value of 0.52. The hydrocarbon saturation value ranges from 0.26 - 0.74, with an average hydrocarbon saturation value of 0.48. The bulk volume of water is 0.07 while the transmissivity value is 2540 mdft.

Reservoir C occurs at an interval of 3140 m - 3225 m. The thickness of reservoir C is 85 m, the net thickness of the sand is 60.4 m. The volume of shale value ranges from 0.001 - 0.66, with an average volume of shale value of 0.2. The average net to gross ratio is 0.72. The porosity value ranges from 0.04 - 0.25, with an average porosity value of 0.2, indicating a good porosity value. The permeability value ranges from 52 - 174 md, with an average permeability value of 126 md, indicating a good permeability value. The irreducible water saturation is 0.2. The water saturation ranges from 0.32 - 0.85 with an average water saturation value of 0.45. The hydrocarbon saturation value ranges from 0.22 - 0.67, with an average hydrocarbon saturation value of 0.55. The bulk volume water value is 0.09 while the transmissivity value is 10710 mdft.

5.0. Conclusion

This study has x-rayed the reservoir quality of typical Niger Delta field data by analysing and interpreting log responses from three well log data gathered in the prospect field. The estimation of petrophysical parameters reveals that the reservoirs are of good quality. The average permeability of the reservoirs was greater than 100md, whereas the average porosity ranged from 14 to 20%. A porosity value of 20% is necessary to create any significant permeability and allow hydrocarbon production from these sources. The reservoir's net to gross thickness and transmissivity are both good. The formations are homogeneous and near irreducible water saturation. The field under consideration has a high potential for hydrocarbon production and accumulation.

Declarations

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This research did not receive any grant from funding agencies in the public, commercial, or not-for-profit sectors.

Competing Interests Statement

The authors declare no competing financial, professional and personal interests.

Consent for publication

Authors declare that they consented for the publication of this research work.

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