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Hydrocarbon Investigation Using Petrophysical Parameters And Core Analysis (A Case Study of Umoro Field)

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Abstract

In the last five years, there have been rapid declines in the reservoir production rate of Umoro field. Against this backdrop, activation of the reservoir is expedient so as to enhance its performance. To this end, petrophysical logging and core analysis were carried out to evaluate the Geo - Reservoir conditions. Of the six wells drilled in this oil field, two wells were used to characterize the field. Our investigation reveals a fairly good porosity across the two reservoirs, average water saturation and a high net to gross hydrocarbon ratio (NTG). The average pay porosity was found to be 0.36 in the oil zone and 0.299 in the gas zone. Hydrocarbon saturation was also found to be 0.87 and net to gross of 0.33 (that is the ratio of gross volume to net volume of hydrocarbon). Lithologies identified were sand and shale sequence and the fluids identified were gas and oil. The oil water contact, inserted on the structural map identified the enclosure of the hydrocarbon bearing sand from which the value of the discovery was estimated by calculating stock tank oil initially in place, (STOIP and the recoverable reserves (N).

1.0 Introduction:

A total of six wells have been drilled in this field. Of these six wells only two are presently on stream. These wells have been lost to so many factors:High water cut, high basic sediments, production of wax, low tubing head pressure and low hydrocarbon production [4]. A well was used to characterize the low production rate of Umoro field. Among the various likely sources of information, like well test analysis, field analogy, petrophysical analysis was also used in this research. Obtaining subsurface information through petrophysical analysis remains a daunting task because of lack of direct access of the reservoir rocks [1]. Only indirect methods are mostly employed in the characterization of a reservoir [6]. A petrophysical analysis will be carried out to ascertain the rock and fluid behavior of the reservoir.

This paper aims at evaluating the two reservoirs using petrophysical parameters like porosity, permeability, water saturation , sand thickness and the net pay thickness, oil water contact and gas oil contact to proffer solutions to the fast declining rate of the reservoir.

2.0 Reservoir Characteristcs Of Umoru Field :

The Umoro field is located in the OML 61, some 11 kilometers west of Obiakpu field in Port-harcourt. The field is operated by one of Nigeria leading oil and gas company and was discovered in 1977 .The field penetrated four reservoirs: A,B and C. Since the discovery of this filed, a total of 2.6m/stb of oil and 7.13mmscf of gas have been produced [2].

Among the various likely sources of information, like well test analysis, field analogy, petrophysical analysis was used in this paper. Henceforth only indirect methods are employed. A petrophysical analysis will be carried out to ascertain the rock and fluid behavior of the reservoir. Achieving this lies in taking appropriate management decision that is changed on the information obtained from the reservoir.

In this research, various types of logs were used. Each of these logs has its own contribution to the reservoir description. The more the log data involved, the more the uncertainties surrounding this reservoir are reduced. No log can be treated in isolation as the weak areas of one are complemented by the strong point of the other.

The information obtained from these analyses is only at the various representative points where the wells are drilled. Since a continuous and accurate distribution of reservoir information is so desired, a static modeling is used to achieve this.

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Experience gained from the study can as well be carried over into a nearby field with similar conditions. In similar manner, time and resources spent in carrying out independent studies on other fields, with good geological bases of correlation are reduced.

3.0 METHODOLOGY

Different parameters of the rock can be recorded as:
Formation density
Density
Electricity potential
Radioactivity
Water saturation
Evaluation technique

The interval of interest consists of reservoir rocks with shale intercalation within this interval; the gamma ray (GR) level of the thick shale bed is read as 100%. A straight line through point of maximum shale is called the shale baseline. Similarly, a sand line constructed by reading the average gamma ray level of thick clean sand (sand with lowest GR level) uses the expression:

$$GR_{min}\,\text{sand} = \text{GR sand} + (\text{GR shale} - \text{GR sand})/2 \qquad (1)$$

A vertical line in the middle between the shale and sand line is called the offline. All intervals at the left of the cut off line are the assumed to be reservoir interval.

4.0 EVALUATION OF POROSITY

Reservoir rock consists of a rock matrix and pore fluid. The bulk density of a reservoir is the weighted average density of the present pore fluid (fL) and its rock matrix (ℓma), therefore it is a function of lithology and porosity that is

$$\ell_b = ø\, \ell_{fl} + (1- ø)\, \ell_{ma} \qquad (2)$$

where ℓ_b = Bulk density (read directly from density log)
ℓ_{fl} = Pore Fluid density
ℓ_{ma} = rock matrix density
ø = Porosity

from equation (2)

$$\ell b - \ell ma = ø\, (\ell_{fL} - \ell ma)$$

and hence

$$ø = \frac{(\ell ma - \ell b)}{(\ell ma - \ell fl)} \qquad (3)$$

Density value for sand stone in the Niger Delta is given as 2.65 g/cm^3
Estimation of oil initially in place (OIIP)

$$OIIP = GRV \times \frac{N}{G} \times \phi\left(S_O\right) \qquad (4)$$

Stock Initially In place:

$$STOIIP = \frac{7758 \times \phi \times N}{G \times B_{oi}} \times \frac{S_O \times GRV}{1000000} \qquad (5)$$

Where: 7758 is the conversion factor from cubic meter of OIIP to stock tank barrel from equation 5.

VN = Volume of impregnated rock, or
Gross Rock volume
Ø = porosity
(S_0) = Hydrocarbon saturation
Boi = Formation Volume factor
GR = Gamma ray

Table1: Petrophysical Parameters Obtained From Well Logs

Reservoir	Top	Bottom	Thickness	Φ	Shc	Type	Rw	Sw	K	Rt
A	5150	5160	10	0.37	0.86	Gas	0.32	0.40	1123101.8	100
	5160	5180	20	0.33	0.6	Gas	0.32	0.40	5280667.57	15
	5185	5190	5	0.24	0.36	Gas	0.32	0.64	1.77	10
	5190	5195	5	0.20	0.34	Gas	0.32	0.66	22.02	13
B	5235	5278	43	0.21	0.83	Gas/oil	0.24	0.17	9808362.45	120
	5278	5285	7	0.20	0.82	Gas/oil	0.22	0.18	22.02	120
	5285	5290	5	0.20	0.82	Shale	0.22	0.18	0.00	120
	5290	5305	15	0.22	0.83	Gas/oil	0.22	0.17	34.87	35
C	5355	5380	25	0.31	0.91	Oil	0.14	0.09	521507.07	150
	5380	5395	15	0.31	0.72	Water	0.14	0.28	4213.04	15

From the well logs used in this research, Table 1 above reflects the petrophysical parameters obtained from well logs. The permeability and porosity values obtained from core analysis quite agree with those obtained from core data. The core data values serve as guide to the well log data. Disparity in the values serve as signals of an abnormally in the values obtained from well logs.

Table 2: Petrophysical Parameters Obtained From Core Analysis

Reservoir	Top (m)	Bottom (m)	Thickness (m)	Porosity Core	Permeability (md)	Fluid type	Water Res.
A	5150	5160	10	0.34	1123000	Gas	0.32
	5160	5180	20	0.30	5280527	Gas	0.32
	5185	5190	5	0.26	1.80	Gas	0.32
	5190	5195	5	0.19	22.00	Gas	0.32
B	5235	5278	43	0.22	9808350	Gas/oil	0.32
	5278	5285	7	0.19	20.00	Gas/oil	0.32
	5285	5290	5	0.24	0.00		0.32
	5290	5305	15	0.21	40.00	Gas/oil	0.32
C	5355	5380	25	0.29	521600	Oil	0.32
	5380	5395	15	0.30	3200	Water	0.32

Table 2 above reflects the petrophysical parameters obtained from core analysis. The well cuts across three reservoirs A, B and C. The shallowest reservoir is at depth 5,150meters while the deepest reservoir is at 5,380 meters. The reservoirs are separated by shales as reflected on the table. The highest pay thickness is 43 meters which is quite prolific.

The porosities and permeabilities obtained are indications of good prolific reservoirs. The values obtained from core Analysis serve as check on the petrophysical parameters obtained from well logs.

Table 3: **Umoro Field Volumetrics Averaged Deterministic Properties**

Thickness (m)	Area (m^2)	Gross Rock Vol (m^3)	Porosity (φ)	Net/Gross (N/G)	S_o	S_g	B_{oi}	B_{gi}	STOIIP (10^6)STB	OIIP (10^6)bbl	GIIP (mmSCF)	Fluid Type
22.86	648.99	14836	0.11	0.37		0.54		0.0034			95593.865	Gas
12.4968	5301.04	66246	0.20	0.94		0.83		0.0034			3030544.256	Gas
2.4384	4786.34	11671	0.2	0.29	0.82		2.554		1686082.409	555.073		Oil
20.4216	721.59	14736	0.31	0.91	0.91		2.554		11490871.65	3782.893		Oil
10.668	6206.79	66214	0.34	0.82		0.74		0.0034			4004970.692	Gas

Table 3 above shows the averaged deterministic properties established using the Generalised Niger Delta Model. The reservoir contains hydrocarbon though there were inconsistencies in fluid contacts. This could be as a result of production of a particular well more than the other.

The results from weighted average porosity, oil saturation and average Net to Gross ratio show that the reservoir is homogenous, typifying low overall shale content, possibly deposited during a high energy regime. The weighted average porosity is 0.335 in the oil zone and this could be as a result of grain size matrix, cementation or packing. The weighted average oil saturation of 82% is high which means that the reservoir is sand is prolific.

The recoverable reserve of 1.136×10^3 barrels is high enough and development of the field should be encouraged. This is attributed to the intergranullar petrophysical property of the reservoir and sand temperature. Other factors as viscosity, drive mechanism, pressure of bottom hole reservoir fluids can contribute to the above result. About 7.75×10^7 barrels of oil are irrecoverable; this therefore poses a big challenge in the field. It can be recommended that new well sites can be proposed for more production of oil and this should be done where the net pay of the reservoir under study is thick.

4.0 VOLUMETRICS

The gross and net thicknesses are ascertained to display the fluid distribution of the reservoir and as well as the oil – water contacts (OWC) to get the oil equals Deepest oil water minus shallowest gas oil [Ehigiator 2009]

The Gross rock volume obtained was multiplied by the weighted average of the porosity ø, oil saturation and net/gross ratio to estimate the volume of oil initially in place. From equation 4, we find that OIIP for Reservoir (A) was 555.073 barrels OIIP for Reservoir (B) was 3782.893 bbls

The values of oil initially in place, OIIP for Reservoirs (A and B) converted to stock tank condition using equation(5)were respectively:

OIIP = 1686082.409 bbls

OIIP = 11490871.65bbls

Then the recoverable reserves for Reservoirs (A and B) were derived using equation (6)

$$N = STOIIP \times R_0 \tag{6}$$

$$N = 2.84 \times 10^6 \times 0.40$$

$$N = 1.136 \times 10^6 \text{ Barrels}$$

Where

N = Recoverable Reserve

Ro = Primary recoverable factor

5.0 CONCLUSION AND RECOMMENDATION

This work has looked into an aspect of investigation of hydrocarbon in a reservoir in Niger Delta, which involved subsurface hydrocarbon mapping of reservoir, estimation of oil initially in place (OIIP) and finally, estimation of stock tank oil initially in place (STOIIP)

The volume of hydrocarbon encountered was found from the study to fall within (5150-5380)m. All the identified prolific was found to occur within the Agbada formation.

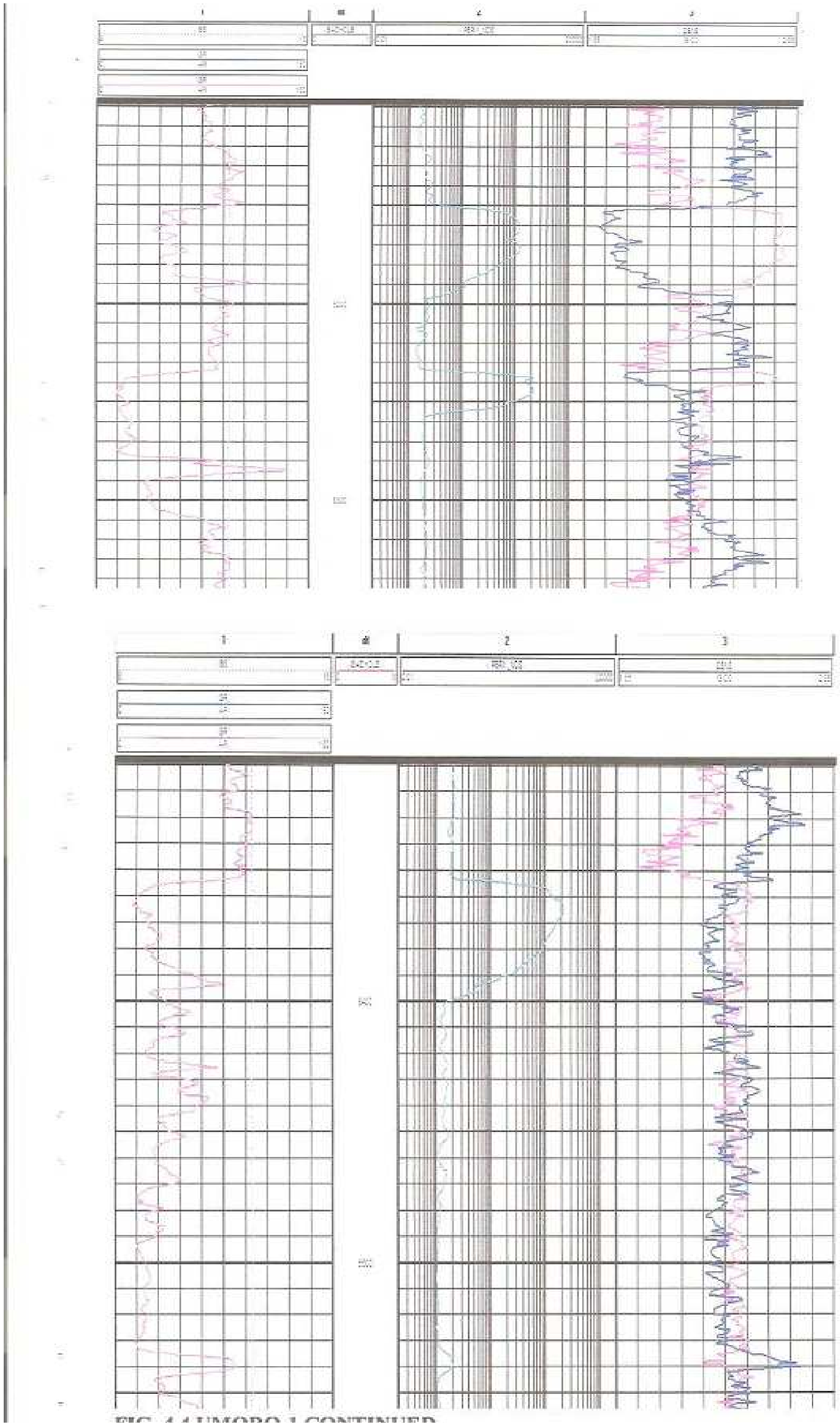

Figure 1: Umoru Well 1

The litology of the study area is basically that of sand – shale sequence as the wells get deeper, there is increasing more shale than sand towards the bottom of the wells. This is because formation progresses to Akata formation. The weighed porosity in the field is generally 27%.

The combination of both neutron and Density logs porosity values will indicate gaseous formation as well as hydrocarbon formation. The permeabilility estimated for the hydrocarbon zone vangs from (0.00-9808362.45)md

RECOMMENDATION

In order to improve confidence in the petrophysical model presented, coring programmes should be planned such that representative core samples can be obtained from the gas, oil and the water bearing zones. Among other things, this will help to establish the fluid density in the gas zones, oil zone for the purpose of porosity calculation. Cores should also include some shales to help determine matrix (sand and shale) density responses. In addition to the conventional core analysis, the programme should include some mineralogy , capillary pressure measurements and relative permeability depending on reservoir engineering needs.

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