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Hydrocarbon Volumetric Analysis Using Seismic and Borehole Data over Umoru Field, Niger Delta-Nigeria

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Abstract

Wireline signatures were used to identify hydrocarbon bearing sands and evaluate Petrophysical parameters for hydrocarbon pore volume determination. Well to seismic tie revealed that these reservoirs tied direct hydrocarbon indicators –bright and dim spots –on the seismic sections. Three hydrocarbon reservoir were delineated. Estimation of the volume of hydrocarbon in place revealed that reservoir A contained 1675091.54 ± 102 feet of gas in place, while reservoir B contained 163661.83 barrels ± 80 barrels and reservoir C contained 1739170.41 ± 102 cubic feet of gas.

Keywords: Hydrocarbon, Reservoir, Bright and Dim Spots, Well-to-Seismic

1. Introduction

The study area OML61 Located in the Southern Niger Delta falls within the P720 - P740 pollen zones of the mid Miocene age. It covers an area of 850 Sq·km. Blanket, 3D Seismic coverage was acquired over OML61, during the 1996 - 1997 and has allowed detailed mapping of the complex structure.

The data used in this study include digital suites of geophysics well logs, check shot data, 3D seismic data. When a reservoir is discovered a rapid preliminary calculation is made to estimate the approximate volume of hydrocarbon in place. This estimation is reviewed when all the results subsequent to the discovery have been analyzed through interpretation of logs, petro-physical measurement, PVT analysis, geophysical and if necessary geological reinterpretation [1]. Among the information needed to estimate the hydrocarbon volume are the thickness and the area extent of the reservoir [2].

Almost all the oil and gas produced inward today come from accumulations in the pore spaces of lithologies like sand stones, limestone or dolomites. The gamma ray log can be use for the reservoir rock (sand) and the embedding shale differentiation. The resistivity log on the other hand, can be used, as this study for determining the nature of interstitial fluid.

Petroleum in the Niger-Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada formation [3]. The characteristics of the reservoirs in the Agbada are controlled by depositional environment and the depth of burial known reservoir rock are Miocene to Pliocene in age and are often stacked, ranging in thickness from less than 15 meters with about 10% having greater than 45 meters thickness [4,5]. Doust and Omotsola [6] define 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 the reservoir thickness is strongly controlled by growth faults, the reservoir thickening towards the fault within the down thrown block [7].

The mapping of the lateral dimension of the reservoir in this study was obtained from the geophysical well logs and directed hydrocarbon indicators. To use the well logs to map the lateral dimension of the reservoir, the oil water and the gas oil contacts are located on structure maps.

The aim of this study is to define the volume of hydrocarbon in place over Umoru field, Southern Niger Delta – Nigeria by integrity direct hydrocarbon indicator with geophysical well logs.

2. Location and Geology of the Study Area

The study area OML61 Located in the Southern Niger Delta, Nigeria falls within the P720 - P740 pollen zones of the mid Miocene age. It covers an area of 850 Sq·km within the concession.

The Niger Delta forms one of the world's major hydrocarbon province and it is situated on the Gulf of Guinea on the west coast of central Africa (Southern Nigeria).

Details of the geology of the Niger delta has been discussed by several authors, [8-10]. It is basically made up of:

The Benin formation which is a loose fresh water bearing sand with occasional ignite and clay and going up to 7500 ft (2286 m) deep with no over pressure.

The Agbada formations is made up of alternations of sand and shales. The sand are mostly encountered at the upper parts while shales are found mostly at the lower parts. The Agbada formation is thickest at the center of the Delta and goes up to 1500 ft (457 m) this is the seat of most oil reservoirs and center of overpressures.

The Akata formation contains mainly shale's deposited on a shallow marine shelf and usually overpressured, with soft and under-compacted plastic shales. Exploration rarely gets to it because of the absence of commercial oil deposits.

3. Materials and Methods

Techniques used to study hydrocarbon volume in field include composite geophysical well logs seismic sections and check shot data. The composite geophysics logs used are the gamma-ray, spontaneous potential, electrical resistivity and density logs (**Figure 1**).

Hydrocarbon bearing reservoirs were identified using

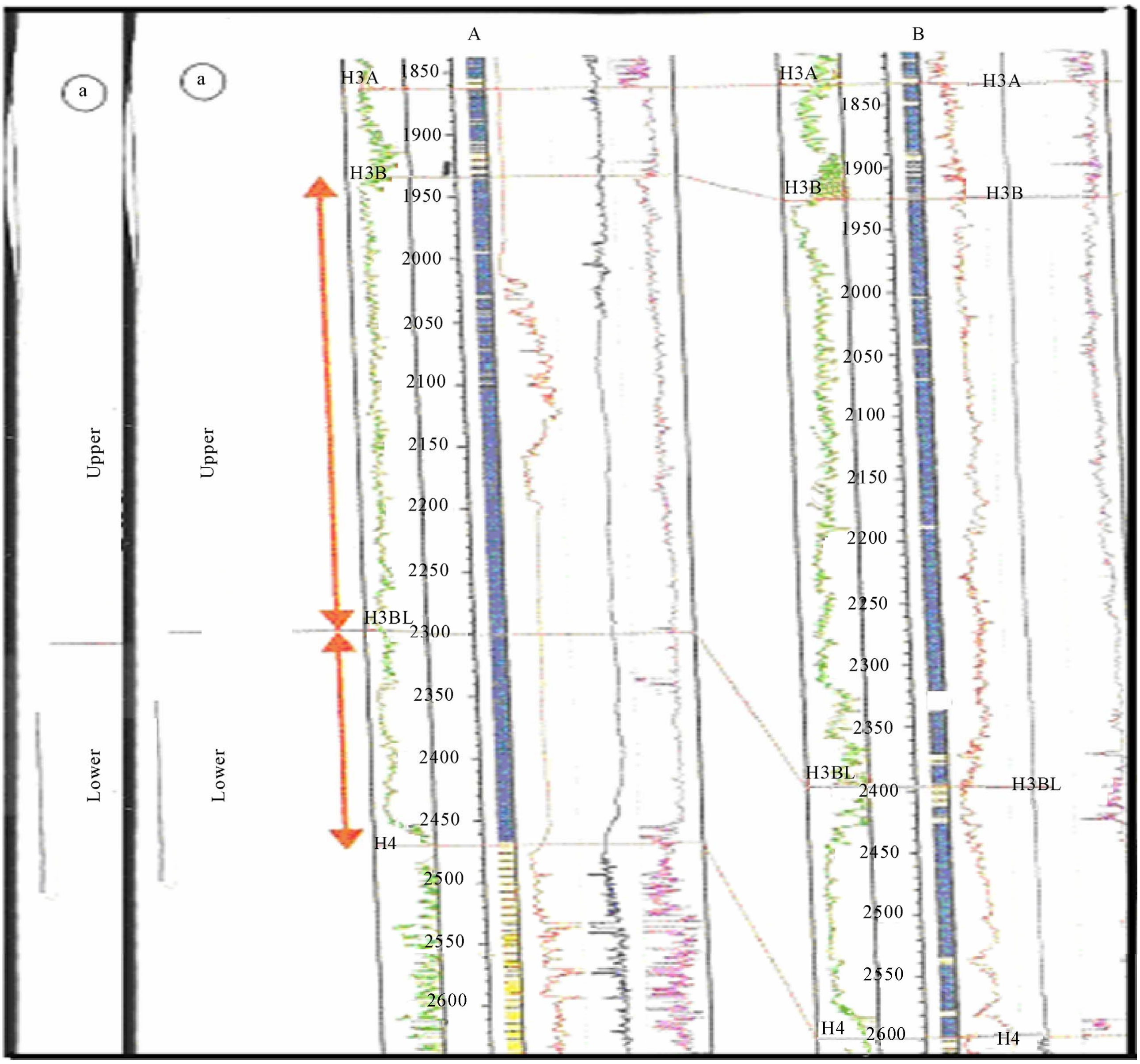

Figure 1. Well sections showing Reservoirs delineated on well logs.

the gamma ray log and the electrical resistivity log. Reservoir Petrophysical analysis was carried using the geophysical log signatures to compute for the water saturation/hydrocarbon saturation porosity, reservoir thickness (net and gross).

The reservoir hydrocarbon was computed using [4]

$$Hc_v = Kv_j\Phi\left(1-S_w\right)$$

where S_w = average water saturation

Φ = Average effective porosity

V_j = net production sand value

K depends on the nature of fluid present which is given as the product of the area and thickness ($A \times L$)

The general form of the error equation for the computed hydrocarbon volume in place is

$$\frac{\Delta Hc_v}{Hc_v} = \frac{2\Delta L}{L} + \frac{\Delta h}{h} + \frac{\Delta\Phi}{\Phi} + \frac{\Delta S_w}{S_w}$$

$$\Delta Hc_v = Hc_v\left(\frac{2\Delta L}{L} + \frac{\Delta h}{h} + \frac{\Delta\Phi}{\Phi} + \frac{\Delta S_w}{S_w}\right)$$

where Δ represent error.

The well-to-seismic tie of the hydrocarbon reservoirs was obtained from the check shot data and displayed on the seismic lines they intersected. The hydrocarbon boundaries were mapped using direct indicators from 3-D seismic. The square grid method was used to determined the area extent of the reservoir.

4. Results

Hydrocarbon bearing reservoirs were formed to be associated with direct hydrocarbon indicators on seismic sections through the well-to-seismic tie. Since the bright and dim spots are indicated of hydrocarbon presence, the lateral boundaries of these reservoirs were mapped from the amplitudes .The total estimated area covered by the gas and was 9.77 km^2 reservoir A. The same analysis was performed for reservoirs B and C that is, reflection amplitude maps were generated from horizon two and three respectively and the zone of anomalous high amplitude were used to map the boundaries of the reservoir (they matched bright spots on seismic sections). The reservoir area extent estimation from the square grid method revealed that reservoir B covered an area of 10.57 km^2 while reservoir C covered an area extent of 12.00 km^2.

5. Results and Discussion

Hydrocarbon bearing reservoirs were found to be associated with direct hydrocarbon indicators on seismic sections through the well-to-seismic tie (**Figures 1** and **2**). The reservoir Petrophysical parameters obtained from the three hydrocarbon bearing reservoir A, B and C are shown in **Tables 1**, **2**, and **3**. The hydrocarbon saturation and effective porosity estimated in reservoir A varied from 0.82 to 0.87 and 0.35 to 0.36 respectively. The net thickness of the reservoir was found to be 50 ft (15 m). In reservoir B, hydrocarbon saturation varied between 0.82 and 0.83, while effective porosity varied between 0.28 and 0.30. The net thickness of the reservoir varied between 22 ft (6.7 m) and 33 ft (10 m). In reservoir C, hydrocarbon saturation varied between 0.72 and 0.70, while effective porosity varied between 0.28 and l0.30. The net thickness of the reservoir varied between

Table 1. Petrophysical parameters from reservoir A.

Well	Top (Md) ft (m)	Bottom (md) ft (m)	Thickness Gross ft (m)	Thickness net ft (m)	True Resistivity	Porosity effective (Φ)	Fluid type	Water saturation	Hydrocarb on saturation
Umoru 01	5150(1570)	5200(1585)	50(15)	50(15)	100	0.35	Gas	0.13	0.87
Umoru 02	5120(1570)	5200(1576)	50(15)	50(15)	110	0.36	Gas	0.18	0.82

Table 2. Petrophysical analysis from reservoir B.

Well	Top (md)	Bottom ft (m)	Thickness (cross) ft (m)	Thickness Net f(t) (m)	True Resistivity ohm-m	Porosity Effective	Fluid type	Water Saturation	Hydrocarbon Saturation
Umoru 01	5355(1632)	5380(1640)	25(7.6)	22(6.7)	150	0.30	Oil	0.18	0.82
Umoru 02	5345(1629)	5379(1640)	34(10.4)	33(10.0)	120	0.28	Oil	0.67	0.83

Table 3. Reservoir C.

Umoru 01	7410(2259)	7470(2277)	60(18.3)	56(17.1)	100	0.26	Gas	0.28	0.72
Umoru 02	7400(2250)	7490(2283)	90(27.4)	89(27.3)	110	0.25	Gas	0.30	0.70

Table 4. Volume estimate in reservoirs A, B and C.

Reservoir	Thickness ft (m)	Area (m^2)	Porosity	Hydrocarbon saturation	Hydrocarbon in place
A	50(15.24)	10120	0.36	0.85	1675091.54 cubic feet of gas
B	27.5(8.38)	12900	0.29	0.83	163661.83 barrels
C	72(21.94)	11453	0.26	0.75	1739170.41 cubic feet of gas

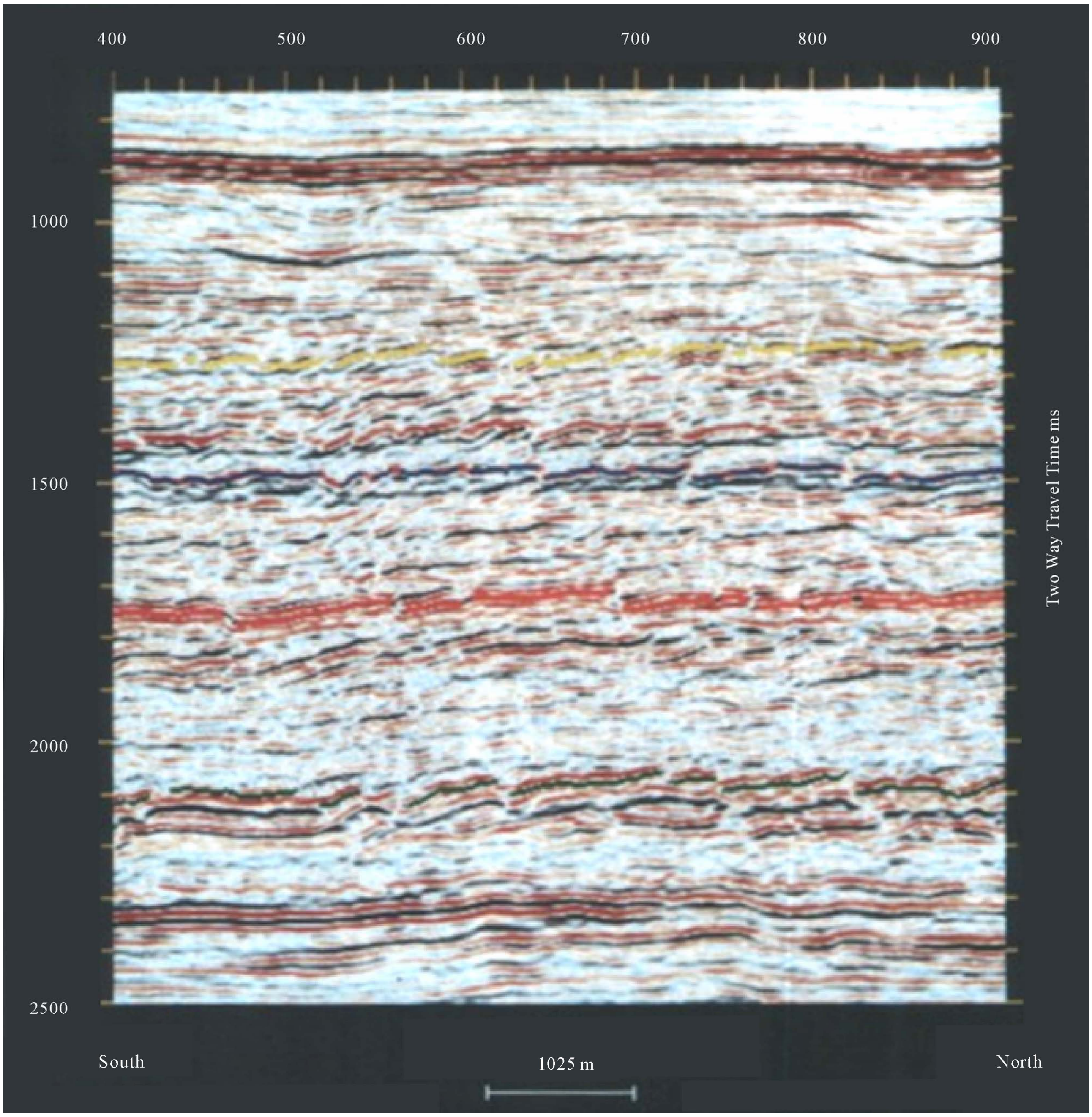

Figure 2. Well to seismic section tie of reservoir showing dim spots.

56 ft (17.1 m) and 89 ft (27.3 m) and 89 ft (27.3 m).

The top of reservoir A tied to a dim spot at the two way travel time of 2513 ms ie depth of 6776 ft (2965.34 m). Similarly top of reservoir B and C tied dim spots on the seismic sections.

6. Conclusions

The integration of well and seismic data provides insight to reservoir hydrocarbon volume which may be utilized in exploration evaluations and in well bore planning. From the well log interpretation, three hydrocarbon producing reservoirs (A, B and C) were identified. Well-to-seismic tie revealed that hydrocarbon bearing reservoirs were associated with directed hydrocarbon indicators (Bright and dim spots) on the seismic sections. The anticlinial structure of the centre of the field was found to be principal structure responsible for hydrocarbon entrapment.

Estimation of the volume of hydrocarbon in place revealed that reservoir A contained an estimate of 1675 091.54 ± 102 cubic feet of gas, while reservoir B contained 163 661.83 barrels ± 80 barrels and reservoir C contained 1739 170.41 ± 102 cubic feet of gas.

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