
**PETROLEUM AND PETROPHYSICAL CHARACTERISTICS OF AGA-1 WEL, X FIELD ,
NIGER DELTA**

ADIELA, U.P¹ AYODELE MOSES², JACKSON, C.A³

³Department of Petroleum Engineering,, Nigerian Agip Oil Company, Port Harcourt

²Department of Geology, University of Port Harcourt, Port Harcourt, Nigeria

ABSTRACT

There are two hydrocarbon reservoirs found in the well AGA-1 Well. These are reservoirs A and C. Reservoir A occurs at the interval of 5693 – 5813ft (1735-1772m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 110ft (33.5m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 20% and hydrocarbon saturation (S_h) of 80%, porosity (ϕ) and permeability (K) of 18% and 116.2md respectively. Its transmissivity is 14525mdft. Therefore, reservoir A has both good porosity and permeability. Reservoir C occurs at the interval of 7350 – 7619ft (2240-2322m) and has a gross (G) and net (N) thickness of sand, 89ft (27.1m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ϕ) and permeability (K) of 14% and 22.4md. Its transmissivity is 1993.6mdft. Therefore, reservoir C has fair porosity and moderate permeability.

INTRODUCTION

The quest for optimum method of hydrocarbon production has been an issue which many oil and gas companies are interested in. Alvarado and Manr stated that the effort of industries to increase production by the use of large capital investments to enhance oil recovery sometimes proves futile. This hitch needs to be proffered with a sustainable solution. One of the major ways of resolving this issue is through hydrocarbon reservoir properties modeling.

Most of the factors that determine the reservoir conditions are often too dynamic that over a short geologic time span must have been severally altered and must therefore be revisited for quantification. This shows that reservoirs must be regularly revisited with new technical devices, and also the geologic conditions must be rechecked due to the reservoir's heterogeneity in order to evaluate the possible range of uncertainty existing within the reservoirs.

This research work is on the application of wireline logs to identify and quantify hydrocarbon reserves and evaluate rock properties in part of the offshore Niger Delta. The petrophysical analyses of the wireline logs provide reservoir characteristics (porosity, permeability and fluids saturation). Quantitative determination of fluid transmissivity (layer thickness times permeability) will be an added advantage to further characterize reservoir rocks. Integrating these two parameters would guide and provide a good knowledge of the potential of porous media and enhance exploration and development of the reservoir rocks.

LOCATION OF STUDY

The field under study is pseudo-named "X" field. The field is located in the offshore Niger Delta , but the co-ordinates of the location of this field were concealed due to proprietary reasons.

OBJECTIVES OF STUDY

This research is aimed at evaluating the reservoir potential of X-field to determine the petrophysical characteristics of sand bodies Identification and definition of potential reservoirs and key hydrocarbon horizons useful for field development

STRATIGRAPHY OF NIGER DELTA

AKATA FORMATION

The Akata Formation is the under compacted, over pressured, marine prodeltamega facies of the Niger Delta basin. It is composed mainly of marine shale with occasional turbidite sandstone and siltstone (Short and Stauble, 1967). The thickness ranges from 600m to over 6000m and depends on the shale diapirism. It is thought to be the sources rock of the Niger delta complex. Abundance of planktonic foraminifer's assemblage indicates deposition of the Akata shale on a shallow marine environment (Whiteman 1982).

| AGE | | FORMATION | LITHOLOGY | THICKNESS | SEDIMENTARY CYCLE | ENVIRONMENT |
|-----------|-------------|-----------|-----------|-------------|-------------------|------------------------|
| NEOGENE | HOLOCENE | BENIN | | max 2100m | | CONTINENTAL |
| | PLEISTOCENE | | | | | |
| | PLIOCENE | | | | | |
| | MIOCENE | | | | | |
| PALEOGENE | OLIGOCENE | AGBADA | | > 3000m | REGRESSION | TRANSITIONAL TO MARINE |
| | EOCENE | | | | | |
| | PALEOCENE | | | | | |
| | | AKATA | | 600 - 6000m | TRANSGRESSION | MARINE |

Figure 1. Stratigraphic section of the Niger Delta adopted from Doust, 1990

AGBADA FORMATION

The Agbada Formation underlies the Benin formation and consist of interbedded fluviomarine sands, sandstones and siltstone of various proportion and thickness representing cyclic sequence of offlap unit (Weber, 1971). Texturally the sandstone vary from coarse to fine grained, poorly to very well sorted, unconsolidated to slightly consolidated. Lignite streak and limonite coating occur with some shell fragment and glauconitic (Short and Stauble, 1967). The shale are medium to dark grey, fairly consolidated and silty with localized glauconitic. Shaliness increases downward and the formation passes gradually into the Akata formation

BENIN FORMATION

The Benin Formation is the Topmost unit, composed of fluvial gravel and sands. It is described as the coastal plain sands which outcrop at Benin, Onitsha and Owerri province and elsewhere in the Delta area (Reyment, 1965). The deposit is predominantly continental in origin and consist of massive, highly porous, fresh water bearing sandstones with little shale intercalation which increases toward the base of the formation.

NIGER DELTA DEPOBELT AND STRUCTURES

THE DEPOBELTS (Mega structures)

Various integrated studies have shown that several “Depobelts” exist in the Niger Delta basin which are separated by major synsedimentary fault zones that occurred in response to variable rates of subsidence and sediment supply (Doust and Omatsola, 1990; Evamy, 1979; Tuttle, *et al.*, 1999)

The “Depobelts” include:

- Northern Delta
 - Greater Ughelli
 - Central Swamp
 - Coastal Swamp
 - Shallow Offshore
 - Deep Offshore
- } Onshore
- } Offshore

These Depobelts can be thought of as transient basinal areas succeeding one another in space and time as the delta prograded southward. When further subsidence of the basin could no longer be accommodated the focus of sediment deposition shifts seaward forming a new depobelt (Doust and Omatsola, 1990). At the same time synsedimentary and most post-sedimentary faulting would cease within the abandoned depobelt. Therefore, Depobelts form the structural and depositional active portion of the delta at each stages of its development (Doust and Omatsola, 1990; Tuttle *et al.*, 1999). Figure 2 .Schematic diagram of the Niger Delta showing the Depobelts and the regional faults (Modified from Doust and Omatsola, (1990) and Stacher (1995).

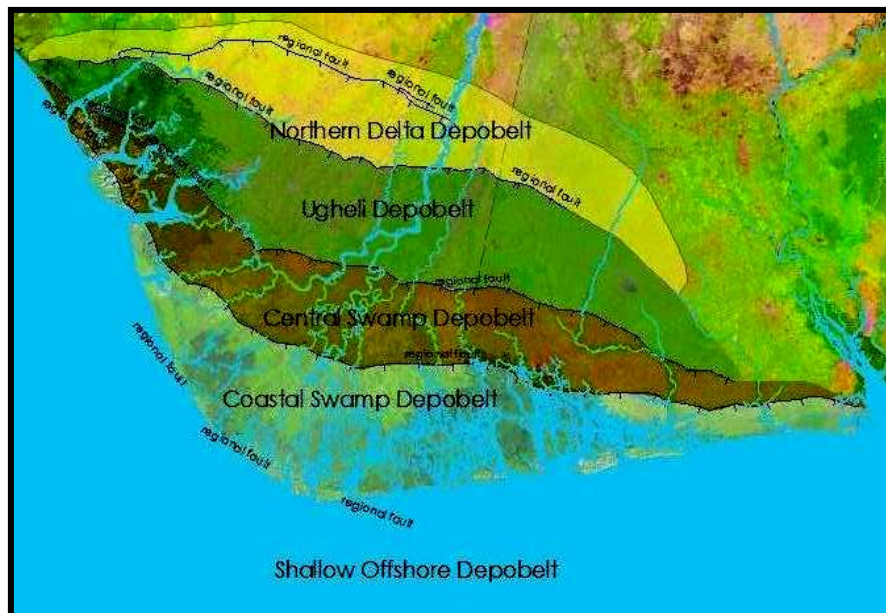


Figure 2: schematic diagram of the Niger Delta showing the Depobelts and the regional faults (Modified from Doust and Omotsola, (1990) and Stacher (1995).

METHODOLOGY

Different methods of study as applied to wireline well logs interpretation within the available materials have been adopted for the evaluation of reservoir sands in this research work. The approach involves both quantitative and qualitative interpretation. Qualitative interpretation entails visual analysis of the log shapes for the identification of reservoir sands and hydrocarbon bearing sands. Quantitative interpretation involves estimation of reservoir parameters and interrelationship between them.

Geophysical well logging is the recording of the properties or characteristics of the rock formations transversed by measuring apparatus in a borehole, which largely obviates the necessity of the expense of coring.

Casing was introduced into the borehole section immediately after drilling to prevent the collapse of the wall rocks in the borehole section lined pipe. Generally, any of the normal geophysical techniques can be adapted in borehole logging. The most commonly used is the techniques are electrical resistivity, electromagnetic induction, and self-potential (SP), natural and induce radioactivity, sonic velocity and temperature.

The instrumentation necessary for borehole logging is housed in a cylindrical metal tube known as *sonde*. Sondes are suspended in the borehole from an armoured multi-core cable. During logging, the sonde is gradually pulled up from the borehole bottom at a certain speed.

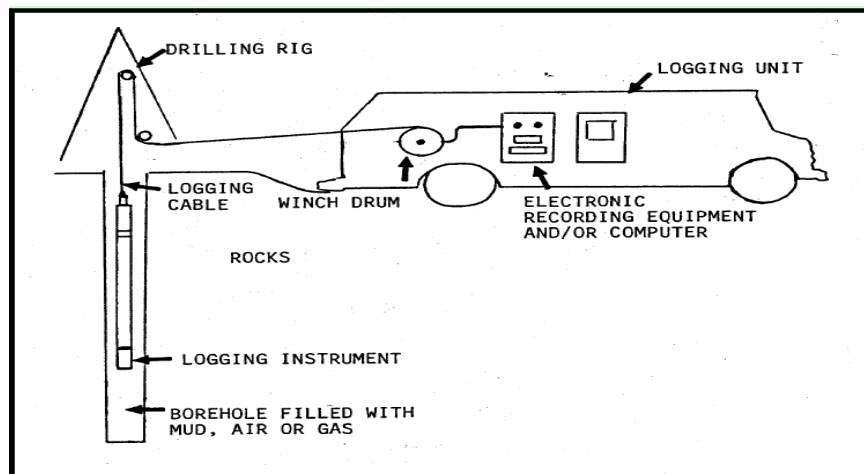


Fig. 3: A schematic diagram of a well logging setup

PETROPHYSICAL ANALYSIS

Petrophysical evaluation was carried out for the reservoir sand bodies in the study area from wireline logs by using relations (formulae) that are universally used in the estimation of reservoir sands bodies of the following petrophysical parameters: Volume of Shale (V_{sh}), Porosity (ϕ), Formation Factor (F), Irreducible Water Saturation (S_{wirr}), Permeability (K), Water Saturation (S_w), Hydrocarbon Saturation (S_h) and Bulk Volume Water (BVW).

VOLUME OF SHALE (V_{sh})

This is the determination of the volume of shale that is contained in sandstones and shaly sandstones. It can be determined from gamma ray and spontaneous potential log, but the best log to use is the gamma ray log. The presence of shale in reservoir makes porosity log to record high porosity, lower water saturation values and also causes low resistivity reading. When this occurs it becomes very difficult, even impossible to determine if a zone is productive. The volume of shale in unconsolidated Tertiary rock of Niger Delta is determined by:

$$V_{sh} = 0.083(2^{(3.7 \times Igr)} - 1.0) \dots\dots\dots (1)$$

Where:

V_{sh} = Volume of shale

$$Igr = \text{Gamma ray index} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \dots\dots\dots (2)$$

GR_{log} = Gamma ray reading of formation

GR_{min} = Minimum gamma ray (clean sand)

GR_{max} = Maximum gamma ray (shale)

POROSITY (ϕ)

Porosity can be defined by the ratio of voids to the total volume of rock. It is represented as a fraction or as percentage. It depends on the degree of uniformity of grain size, the shape of the grains, the method of deposition, the manner in which the grains were packed and the effects of compaction during and after deposition.

The amount of internal space or voids in a given volume of rock is called the total porosity, is a measure of the amount of fluid a rock will hold. The amount of void space that is interconnected and thus able to transmit fluid is called effective porosity.

Density and Neutron logs are used in determining porosity. Neutron porosity can be read directly from the log without any mathematical calculation, while density log porosity is determined by:

$$\phi_{Den} = \left(\frac{\rho_{ma} - \rho_{blog}}{\rho_{ma} - \rho_f} \right) - V_{sh} \times \left(\frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f} \right) \dots\dots\dots (3)$$

Where:

$\phi_{Den} \Rightarrow$ porosity derived from density log

V_{sh} = Volume of shale

ρ_{ma} = Density of matrix

ρ_{sh} = Shale's density

ρ_{blog} = Bulk density value on density log

ρ_f = Density of the fluid (1.0 for fresh mud)

For the common reservoir rock types, the average operating condition of porosity values is in accordance with Dresser Atlas (1982).

FORMATION FACTOR (F)

Formation factor is the constant of proportionality with which resistivity of a clean, water-bearing formation (i.e. one containing no appreciable amount of clay and no hydrocarbons) is proportional to the resistivity of the brine with which it is fully saturated. The formation factor of a porous formation within the target depth interval was determined using Humble's formula for unconsolidated formations, typical of Niger Delta sandstones, and is given as:

$$F = \frac{0.62}{\phi^{2.15}} \dots\dots\dots(4)$$

Where:

F = Formation factor

ϕ = Porosity

IRREDUCIBLE WATER SATURATION (S_{wirr})

When a zone is at irreducible water saturation (S_{wirr}), the water saturation in the uninvaded zone (S_w) will not move because it is held on grains by capillary pressure.

For most reservoir rock, irreducible water saturation ranges from less than 10% to

**RESULTS AND INTERPRETATION
PETROPHYSICAL RESULTS AND INTERPRETATION**

Total of two hydrocarbon reservoirs were identified and evaluated.

Table: 1 PETROPHYSICAL QUANTITATIVE ANALYSIS OF AGA-1 WELL

| Reservoirs | Depth | | Thickness (ft) | Net Thickness of Sands (ft) | N/G Ratio | ϕ (%) | S_{wirr} | SW (%) | SH (%) | BVW | K (MD) | T (mdft) |
|------------|-------|--------|----------------|-----------------------------|-----------|------------|------------|--------|--------|-------|--------|----------|
| | To | Bottom | | | | | | | | | | |
| A | 5693 | 5813 | 125 | 110 | 0.88 | 18 | 0.0008 | 20 | 80 | 0.036 | 116.2 | 14525 |
| C | 7530 | 7619 | 89 | 80 | 0.90 | 14 | 0.001 | 19 | 81 | 0.026 | 22.4 | 1993.6 |

CHARACTERISTICS OF RESERVOIRS OF AGA-1 WELL

There are two hydrocarbon reservoirs found in t AGA-1 Well. These are reservoirs A and C. Reservoir A occurs at the interval of 5693 – 5813ft (1735-1772m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 110ft (33.5m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 20% and hydrocarbon saturation (S_h) of 80%, porosity (ϕ) and permeability (K) of 18% and 116.2md respectively. Its transmissivity is 14525mdft. Therefore, reservoir A has both good porosity and permeability.

Reservoir C occurs at the interval of 7350 – 7619ft (2240-2322m) and has a gross (G) and net (N) thickness of sand, 89ft (27.1m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ϕ) and permeability (K) of 14% and 22.4md. Its transmissivity is 1993.6mdft. Therefore, reservoir C has fair porosity and moderate permeability.

The formation bulk volume water values calculated are nearly constant indicates that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. The transmissivity in reservoir A is higher than C. This means that the hydrocarbon in reservoir A will flow faster to the well bore as compared to reservoir C.

TABLE 2: RESERVOIR SAND/SHALE PERCENTAGE CALCULATIONS AGA-1 WELL.

| AGA-1 WELL | | |
|------------|--------|---------|
| RESERVOIRS | % SAND | % SHALE |
| A | 60 | 40 |
| C | 75 | 25 |

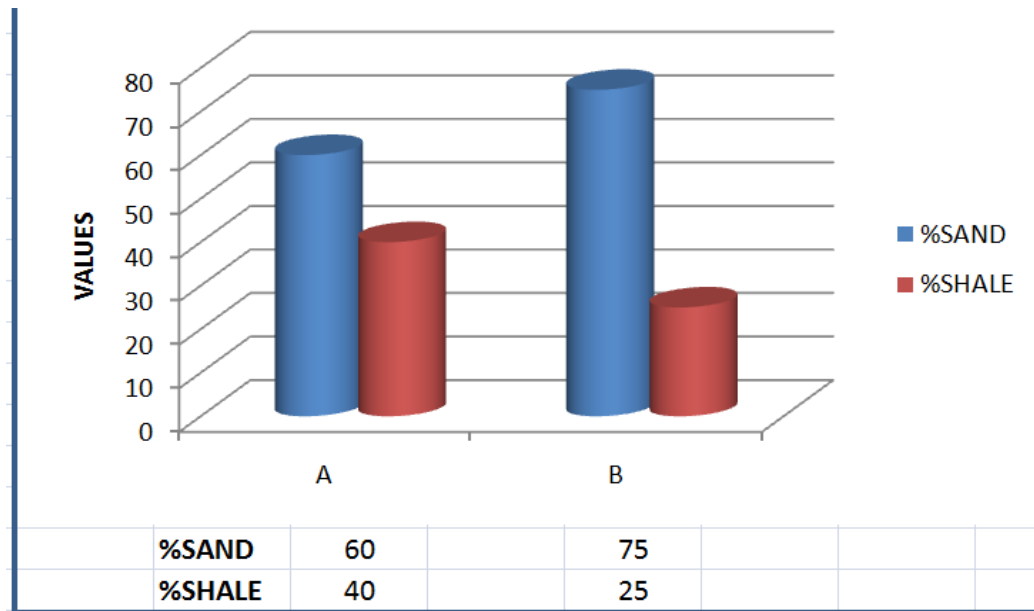


Fig. 4: Graph of reservoir sand / shale percentage for Aga-1 well

DISCUSSION

In characterizing a reservoir, it is relevant to consider all that can be known to better increase knowledge about a reservoir. Its hydrocarbon storing capability, with respect to the porosity and permeability of a formation, when drilled by a well, considering in-situ conditions. Reservoir characterization implies having an understanding of reservoir architecture, its geological and petrophysical conditions, mode and distribution of these properties, and understanding how fluid in the subsurface, if any, would flow considering these properties in the reservoir. It then becomes evident that such information helps in decreasing risk and uncertainty, improving production rate, make proper financial plan, in addition, ensuring that management decision making for future development options are controlled.

The reservoirs for the discovered hydrocarbons in the study area are sandstones within the Agbada Formation. Petrophysical evaluation was carried out on the geophysical wireline logs. A total of three hydrocarbon reservoirs were identified and evaluated.

The petrophysical parameters of reservoir A range from 32-22%, 5024-116.2md, 20-14% and 86 – 80% for porosity (ϕ), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. From the Dresser standard, the porosity (ϕ) ranges from excellent to very good, while the permeability (K) is excellent. Its transmissivity ranges from 50952mdft–648148 mdft.

The petrophysical parameters of the reservoir C ranges from 14-17%, 79.9 – 22.4md, 20-19%, 81-80% for porosity (ϕ), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Its transmissivity ranges 8449 to 1993.6mdft. From the Dresser standard, the porosity (ϕ) ranges from good to fair while its permeability (K) ranges from good to moderate.

The reservoirs bulk volume water (BVW) values calculated are close to constant, this indicates that the reservoir are homogenous and at irreducible water saturation. Therefore, reservoirs can produce water – free

hydrocarbon. When a reservoir is at irreducible water saturation, water saturation (S_w) will not move because it is held on grains by capillary pressure. The petrophysical parameters show a gradual decrease from the top to bottom of the wells, reflecting increase in compaction with depth.

In the course of this research work, nine empirical formulas relating depth, porosity, permeability, and irreducible water saturation were generated. These equations will serve as a guide to estimate the value of permeability and porosity at various depths.

The formulas between the depth (d) and porosity (ϕ) are:

$$(1) \quad D = 289.52 \phi^{-1} \quad \text{Where: } D = \text{depth in feet and } \phi = \text{Porosity (\%)}$$

$$(2) \quad D = 88.25 \phi^{-1} \quad \text{Where: } D = \text{depth in metres}$$

While the formulas between the porosity (ϕ) and depth (d) can be derived from the equation 1 and 2 as:

$$(3) \quad \phi = 289.52 D^{-1} \quad \text{Where: } D = \text{depth in feet and } \phi = \text{Porosity (\%)}$$

$$(4) \quad \phi = 88.25 D^{-1} \quad \text{Where: } D = \text{depth in metres}$$

The formulas between the depth (d) and permeability (K) are:

$$(5) \quad D = 3.7 \times 10^6 K^{-1} \quad \text{Where: } D = \text{depth in feet and } K = \text{Permeability (md)}$$

$$(6) \quad D = 1.1 \times 10^6 K^{-1} \quad \text{Where: } D = \text{depth in metres.}$$

While the formulas between the permeability (K) and depth (d) can be derived from the equation 5 and 6 as:

$$(7) \quad K = 3.7 \times 10^6 D^{-1} \quad \text{Where: } D = \text{depth in feet and } K = \text{Permeability (md)}$$

$$(8) \quad K = 1.1 \times 10^6 D^{-1} \quad \text{Where: } D = \text{depth in metres.}$$

Therefore, empirical formula between Permeability and Porosity is generated when irreducible water saturation constant is derive can be written as: (9) $K = 8.09 \times 10^5 \times \phi^{4.4}$

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