Petrophysical Studies of Idah Reservoir Sands, Onshore Coastal Swamp, Niger Delta, Nigeria

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ABSTRACT

This research work is basically based on the use of petrophysical data for the evaluation of the reservoir potential of the Idah well. This research identify the petroleum reservoirs that are capable of holding significant amount of petroleum in the wells, which resulted from the consideration of porosity, hydrocarbon saturation and other petrophysical parameters.

Keywords: Petrophysical data, Idah well and Petrophysical parameters.

1. INTRODUCTION

The Niger Delta Basin occupies the Gulf of Guinea continental margin in equatorial West Africa between Latitude 30 and 60 and N and Longitude 50 and 80E. It ranks among the world’s most prolific petroleum producing Tertiary Deltas (Selley, 1997). The stratigraphy, Sedimentology, structural configuration and paleo environment in which the reservoir rocks accumulated have been studies by various workers. These include (Short and Stauble, 1967; Weber, 1971; Weber and Daukoru, 1975; Evamy et al., 1978; Rider, 1996; Selley, 1997 and many others. Once an accumulation of petroleum has been discovered, it is better to characterize the reservoir as accurately as possible in order to calculate the reserves and to determine the most effective way of recovering as much of the petroleum as possible. Tinker, (1996) defined reservoir characterization as quantification, integration, reduction and analysis of geological, petrochemical, seismic and engineering data.

This research work aims at determining the various depositional environments and creating a conceptual depositional model for the Idah reservoir sand based on sedimentological studies using core and log data. However, increase confidence in reservoir characterization and architecture is provided by integration of a large number of well data. The goal of this study is to provide a better understanding of the distribution of reservoir properties (porosity, permeability) and other sedimentological features likely to have an impact on fluid flow.

1.1 Aims and Objectives of the Study Area

The aims and objectives of this research work are to use petrophysical data to delineate the reservoir oil sand bodies and depositional environment for better understanding of reservoir properties in the study well.

1.2 Study Area

The research area is situated in the onshore coastal swamp depositional belt in the Niger Delta.
1.3 Lithostratigraphy of the Niger Delta:
The Tertiary Niger Delta was deposited in three major sequences which have been shown by well sections drilled vertically within these environments. The Niger Delta lithostratigraphic units have been reported to be strongly diachronous (Stacher, 1995). According to Petters, (1982), Avbovbo (1978), Hosper (1975), Short and Stuable, (1967), many other workers and multinational companies that carried out work in this area have recorded that the major lithostratigraphic sequences or units found within the Niger Delta formation include, the Benin Formation, Agbada and Akata Formations.

These formations showed intercalating of sand, shale, silt and/or sandstone facies equivalents which represent the delta plain, delta front and prodelta environments respectively.

1.4 Benin Formation: Directly overlying the Agbada Formation is the upper continental deltaic plain called the Benin Formation. It is mainly made of fresh water, fluviatile sands and gravels with occasional coal seams, lignites and shale beds of about 2500m (8,250ft) thick. Evamy et al., (1978) reported that this formation has 9:1 sand/shale ratio interbeds. The sand varies in grain size from fine to very coarse and sometimes pebbly in places. Sorting is more or less poor and grains are subangular to well rounded, yellowish brown to clean quartz grains, which are occasionally ferruginized (hematite stains).

Many companies exploring for oil in the Niger Delta had arbitrarily defined the base of Benin Formation by the deepest fresh water bearing sandstone that exhibits high resistivity. However, the base of this formation is defined by the first marine deposit (Short and Stuable, 1967) and this includes massive coarse-grained sands from the

Figure: The location of the field under study in the Niger Delta, Nigeria
non-marine (Coastal deltaic) or continental environment that make up this formation. This formation is commonly cross-bedded and also seldomly faulted. However, Benin Formation is dated Oligocene to Recent in age.

1.5 Agbada Formation: This formation is overlain by the continental sand sequence of the Benin Formation and is characterized by paralic to marine deposits mainly composed of sandstones and shales organized into coarsening (shoaling) upward offlap cycles. The Agbada Formation is diachronous with a thickness of about 4,500m (14,850ft). This formation ranges in age from Upper Miocene in the north to Pliocene – Pleistocene in the south. Oyofo, (1983) and Avbovbo, (1978) documented that the sands of the Agbada Formation are the main reservoirs in the Niger Delta with shale providing lateral and vertical seal.

Table 1: Lithofacies and Ratio scheme for the Niger Delta: (After Stacher, 1995)

<table>
<thead>
<tr>
<th>FORMATION</th>
<th>Sand (%)</th>
<th>Shale (%)</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Benin</td>
<td>90</td>
<td>10</td>
<td>9 : 1</td>
</tr>
<tr>
<td>Agbada</td>
<td>60</td>
<td>40</td>
<td>3 : 2</td>
</tr>
<tr>
<td>Akata</td>
<td>20</td>
<td>80</td>
<td>1 : 4</td>
</tr>
</tbody>
</table>

Figure 2: Paleogeography of Tertiary Niger Delta (After Ejedawe, 1981)
1.6 Akata Formation: The basal sedimentary unit of the Niger Delta is the Akata Formation which includes at least 6,500m (21,400ft) of marine clays with silty and sandy interbeds (Whiteman, 1982). This formation is overlain by the paralic sand/shale sequence of the Agbada Formation representing 3:2 ratio of sand to shale (Evamy et. al., 1978). The paralic sand/shale succession in this formation is attributed to the differential subsidence of these sediment and shifts of the delta depositional axes which cause local transgressions and regressions. In the same vein, Beka and Oti, (1995) reported that this formation has a clastic sediment thickness of about 6,000m

2. METHODOLOGY

Description of Wireline Used
There are different logs used for this research work and, are under listed as follow:- Gamma ray log, Resistivity induction log deep (ILD), Resistivity induction g medium (ILM), Interval transit time (At), Formation factor and Thermal Neutron porosity, Caliper logs. These are the logs, which their raw data given and were used to plot out the log shapes in the interpretation of various sand beds and reservoir sand bodies.

3. RESULTS AND DISCUSSION

3.1 Result and Interpretation
Facies Analysis
The depositional environments have been inferred for the Idah reservoir sand. Reconstruction of the depositional environment is the main aim of facies analysis. Lithofacies can be defined as a body of sediment/rock with specific lithologic and organic characteristics (grain size, sorting, sedimentary structure) which are impacted by a particular set of energy. Lithofacies can be distinguished in cores but cannot always be distinguished from logs because the of the logs (minimum 2ft) does not allow subtle difference between some lithofacies types. Observation from the study well was used in the analysis of the Lithofacies type. This classification is based on four descriptors or facies elements (Rider, 1996). They are lithology, grain size, and dominant sedimentary structure.

The total number of four reservoir sand bodies was identified and all of the four reservoir sand bodies falling within the paralic Agbada formation. They are labeled as reservoir sand bodies A, B, C, and D, according to their stratigraphic position beginning from the bottom to the top.

The alphabetic terms used are to distinguish from one sandbody to the other and which are separated from each other by certain thickness of shale beds. However, the sandbodies are described from the base sand body A to the top sandbody D and their genetic mechanisms are interpreted. In order to interprete the depositional environment of different reservoir sands encountered in well, the modified model of electrofacies classification for deltaic environment from gamma ray logs and schematic representation of log patterns of variety of depositional environment in which sand-shale sequence are developed,
Description of Reservoir Sand bodies And Stratigraphic Position.

3.2 SANDBODY C

The sand body C has thickness variation of 10m in well Fl and 8m in well F2. It has e shallowest top at 3809m in well Fl and the deepest top at 4070m in well F2. Shallowest base of the sand occurs at 3814m in well Fl and the deepest base 4074m in well F2. The shale thickness of about 7m separated sandbody C from Overlying sand body D in well F2 and the shale thickness of about 270m separated sand body C from overlying sand body D in well Fl.

Geometry: Sandbody C has its thickest sand development in well Fl with sand unit thickness of 10m. It has the sand unit thickness of 8m in well C2.

<table>
<thead>
<tr>
<th>Reservoir sandbodies</th>
<th>Average depth (-m)</th>
<th>ILM Ri (Ø-Ø)</th>
<th>ILM Rt (Ø-Ø)</th>
<th>Bulk density (ρb)</th>
<th>Fr</th>
<th>sw</th>
<th>Shy (1-sw)</th>
<th>Porosity Ø</th>
<th>BVW</th>
<th>SxØ</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>3850</td>
<td>1.1</td>
<td>1.2</td>
<td>2.14</td>
<td>6.803</td>
<td>0.957</td>
<td>0.314</td>
<td>0.328</td>
<td>0.314</td>
<td>0.991</td>
</tr>
<tr>
<td>B</td>
<td>3831</td>
<td>17.0</td>
<td>2.0</td>
<td>2.0</td>
<td>6.607</td>
<td>0.922</td>
<td>0.078</td>
<td>0.333</td>
<td>0.307</td>
<td>0.984</td>
</tr>
<tr>
<td>C</td>
<td>3814</td>
<td>10.0</td>
<td>95.0</td>
<td>2.2</td>
<td>14.625</td>
<td>0.324</td>
<td>0.676</td>
<td>0.229</td>
<td>0.075</td>
<td>0.798</td>
</tr>
<tr>
<td>D</td>
<td>3533</td>
<td>1.1</td>
<td>1.1</td>
<td>2.3</td>
<td>15.347</td>
<td>0.791</td>
<td>0.209</td>
<td>0.225</td>
<td>0.177</td>
<td>0.954</td>
</tr>
</tbody>
</table>

3.3 Geological Properties and Hydrocarbon Occurrences.

Facies associations are groups of facies that occur together and are considered to be genetically or environmentally related (Reading, 1979). These associations are related to a range of energy level within an environment of deposition. Due to the resolution of the log data, it is necessary to carry out some grouping or simplification of lithofacies association in order to get a consistent march with logs and reservoir property data.

The Lithofacies described from well are described in terms of lithology, grading feature, sedimentary structure, and then lithofacies association are interpreted in terms of depositional environment. Thus interpreting a facies is in reference to its neighbour.

It reflects combination of processes and environment of deposition, which is the result of the co-occurrence of a set of lithofacies arranged in a particular order. Log interpretation only was used to infer the environment of deposition of reservoir sands not within the cored interval Sandbody A has the minimum porosity value of 27.11% in Well X2 and the maximum porosity value of 32.82% in Well X1.

Sandbody A has low resistivity, Value of 1.20 -m in Well Fl and the high resistivity value of 20 0 -m in Well X2. The bulk volume of water of 31.42% in Well X1 and the bulk volume of water of 20.99% in Well X2. As indicated by the resistivity log value, it is hydrocarbon bearing in Well X2; while it is water bearing in Well X1.
In sandbody B, the porosity values vary between 28.13% in Well X2 and 33.27% in Well X1. As shown by resistivity logs, sandbody B has resistivity value of 20 0-rn in Well X1 and 30 0-rn in Well X2 while the bulk volume of water in Well X1 is 30.67% and in Well X2 is 22.97%. This indicates that, Well X1 and Well X2 are hydrocarbon bearing zones.

Sandbody C has high formation factor value of 14.625 in Well X1 and low formation factor value of 6.607 in Well X2. The porosity range from 22.99% in Well X1 to 33.27% in Well X2. Well X1 and Well X2 have resistivity values of 95 0-rn and 100 0-rn respectively. The bulk volume of water value of 7.46% in Well X1 and bulk volume of water value of 32.93% in Well X2. With an indication of very high resistivity values in Well X1 and Well X2 within the sand body C may shows that sand body C is gas-bearing zone.
Sand body D has formation factor value of 15.347 in Well X1 and formation factor value of 10.697 in Well X2. The resistivity value in Well X1 is 1.60 m, which was very low when compared it with the resistivity value of 600 m in Well X2. This indicates that, Sandbody D is an hydrocarbon bearing zone in Well X2 and water bearing zone in Well X1.

Most of the reservoir sands show similarity in geometry and the lithological interpretation shows that, the reservoir sands are dominantly sand with thin thickness of shale separated the sandbodies A,B,C, and except where there is high thickness of shale separated the sandbody C from sandbody D. Porosity depends on the degree of uniformity of grain size, the shape of the grains, the method of deposition, the manner of packing and the effects of completion during or after deposition. In this research work the sandstone reservoir evaluated are modifications of primary
porosity, which are due principally to the interlocking of grains through compaction, contact solution, re-deposition and cementation. The reservoir sands exhibit a porosity range of 22.48% to 33.27%, which has been considered very good for hydrocarbon production in the Niger Delta region.

Vertically, from the top reservoir sand D to the last bottom reservoir sand A, there is a gradational decrease in values of porosity as depth of burial of sand increased. It was shown from the result obtained that well X2 contain high volume of hydrocarbon more than well X1. For further drilling of new wells in the field, it is highly recommended that, the diamond drilling bits should be used because of thickness of shales before the hydrocarbon reservoir sands.

Similarly, area of reservoir sands with high porosity and good permeability but indicates little hydrocarbon accumulation or non-hydrocarbon accumulation in this research work can still be further evaluated with other sophisticated geophysical data such as cores and ditch cuttings and seismic data.

However, correlation of reservoir sands in field with the closely related or nearby field to determine the continuity of viable hydrocarbon bearing reservoir sands could also be done to facilitate or aid significant oil exploration in the nearby oil fields.

REFERENCES


