SHALY SAND ANALYSIS FROM WELL LOGS: CASE STUDY OF A NIGER-DELTA FIELD, NIGERIA.

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Abstract

Accurate prediction of hydrocarbon potential in any field in terms of porosity and water saturation needs to be carefully done. This paper analyses hydrocarbon potential from well logs but incorporates the effects of shale in the estimation of water saturation and porosity. The overlay of the induction resistivity logs helped to differentiate the hydrocarbon zones from water saturated zones. Neutron and density logs overlay were used to differentiate gas and oil in the hydrocarbon zones. The pickett plot was used to predict the water saturation in the hydrocarbon zones. Estimation of porosity within these intervals was prepared from the bulk density log, and compared with the porosity obtained from shaly sand analysis. Also, the water saturation obtained from the pickett plot was compared with those obtained from the shaly sand analysis. Results show that hydrocarbon reservoirs are present in the field. The presence of shale minerals in the reservoirs led to the over estimation of porosity and water saturation. Porosity estimates corrected for shale effect reveals an average value of 0.25 while hydrocarbon saturation obtained from shale corrected water saturation is averaged at 0.63. Shale corrected porosity and saturation can enhance the accurate prediction of volume of hydrocarbon in place when the reservoir area is known.

Keywords: Volume of shale, porosity, water saturation, shaly sand, hydrocarbon potential.

INTRODUCTION

Generally, petrophysical analysis helps to convert the raw log data into estimated quantities of oil and gas in a formation, if they are present in the wellbore (Asquith & Krygowski, 2004). This is done by interpreting lithology logs, resistivity logs and porosity logs. However, accurate determination of petrophysical quantities in a shaly reservoir is not a straightforward task. The Niger Delta is composed of an overall sequence of sand alternated with shale (Ajakaiye, 2002). In the distal parts of the depobelts, significant volumes of hydrocarbon may be trapped in the Agbada Formation where shale intercalations are more frequent. The interpretation of shaly-sand log data is a challenge. This is because the presence of shale within the reservoirs may or may not, affect the accuracy of petrophysical results that are predicted from the logs (Asquith and Krygowski, 2004). The Archie's water saturation equation used by most Geologists and Geophysicists, presupposes that the rock framework is not electrically conductive. In other words, it is a perfect insulator. In reality, the general pervasive presence of clay minerals in sandstones adds a conductive element that causes Archie's equation to overestimate water saturation (Cannon, 2016). In such situations, the presence of shale or clay minerals in a reservoir can cause erroneous overestimation of porosity derived from logs (Alao et al., 2013).
Shale can exist in the form of laminae between which are layers of sand (Petrowiki, 2015). Shale can also exist as grains or nodules in the formation matrix. This matrix shale is termed structural shale; it is usually considered to have properties similar to those of laminar shale and nearby massive shales (Petrowiki, 2015). When shale occurs in these ways, it is easy for conventional lithology logs to detect its presence. However, when the shaly material is dispersed throughout the sand, partially filling the intergranular interstices, it is more difficult to resolve with accuracy from lithology logs except the shale volume is used as an input in correcting the effects of shale. Hydrocarbon pore volume determined without correcting for shale effect may suffer from the incorporated inaccuracy and overestimation of porosity and water saturation. The objective of the study is to make a comparison between rock property values obtained from logs without correcting for shale presence and rock property values generated by correcting for the effect of shale in the reservoir.

LOCATION OF STUDY AREA AND GEOLOGICAL SETTING

The study location is an offshore field, in the Niger Delta. The specific details of the location are not given due to company policies. The Niger Delta is situated on the Gulf of Guinea on the west coast of central Africa (Southern Nigeria). It covers an area within longitudes 4°E – 9°E and latitudes 4°N - 9°N. It is composed of an overall regressive clastic sequence, which reaches a maximum thickness of about 12 km (Evamy et al., 1978).

The Niger Delta consists of three broad Formations (Short & Stauble, 1967): the continental top facies (Benin Formation), the Agbada Formation and the Akata Formation. Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. The characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and the depth of burial. Most known traps in Niger delta fields are structural although stratigraphic traps are also available. The primary seal rock in the Niger delta is the interbedded shale within the Agbada Formation.

The shale provides three types of seals - clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting and vertical seals (Doust & Omatsola, 1990). Detailed studies on structure, stratigraphy, and petroleum system are well documented in the literature (Short & Stauble, 1967).

MATERIALS AND METHODS

The datasets for the study comprise caliper log, gamma ray log, induction resistivity logs, bulk density logs and neutron logs from five wells. Sonic log is provided in three wells. Schlumbege’s Petrel and Interactive Petrophysics were used to interpret the data.

Definition of the sand-shale sequence was done using a cut off of 70 API units on the gamma ray log whose scale ranges from 0 to 150. In the sand units delineated, differentiation between reservoir fluids (hydrocarbon and water) was done by overlying shallow and deep resistivity tools on the same track and interpreting their motifs as well as representative values. Overlying ILS and ILD curve also helped in permeability indication. If the formation is permeable, there is a separation between the curves (Asquith & Krygowski, 2004). The caliper log was also used to indicate permeability.

Many empirical equations are derived to estimate the permeability. The following equation developed by Wyllie & Rose, in 1950, estimates permeability in terms of irreducible water saturation, as follows:

\[ K^{1/2} = 250 \Phi^3 / S_w \] Equation (i).

- \( K \) = Permeability
- \( \Phi \) = Porosity
- \( S_w \) = Irreducible Water Saturation.

If the formation is not at irreducible water saturation, the permeability results obtained from well logs are not valid (Asquith & Krygowski, 2004).
Porosity

Porosity values within the hydrocarbon reservoirs were read on the DPHI log. The DPHI log was generated from the bulk density log (rho log) as shown in the following relationship:
\[ \phi = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_f) \] …….. Equation (ii).

Where,
- \( \phi \): density porosity.
- \( \rho_b \): bulk density of the formation measured from the bulk density log.
- \( \rho_f \): fluid density (from the flushed zone) taken as 2.644g/cm\(^3\) for sandstones (Asquith & Krygwoski, 2004).
- \( \rho_{ma} \): Rock matrix density taken as 2.644g/cm\(^3\) for sandstones (Asquith & Krygwoski, 2004).

To correct porosity for shale effects, volume of shale log was generated from the Gamma-ray logs by determining the

Gamma Ray Index (\( I_{GR} \)):
\[ I_{GR} = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min}) \] …….. Equation (iii).

Where \( I_{GR} \): gamma ray index; 
\( GR_{log} \): Gamma ray reading of the formation from Log; 
\( GR_{min} \): Minimum gamma ray reading. 
\( GR_{max} \): Maximum gamma ray reading.

From the Gamma ray index, Larionov’s [1969] equation for volume of shale was used to generate a volume of shale log:
\[ V_{sh} = 0.083(2.37^{I_{GR}} - 1) \] …….. Equation (iv).

Where \( V_{sh} \): Volume of Shale.

Shale corrected porosity was obtained using Volume of Shale as input according to the equation (Schlumberger, 1975):
\[ \phi_{De} = \phi_D - \left[ \left( \frac{\phi_{Nhale}}{0.45} \right) \times 0.13 \times V_{shale} \right] \] …….. Equation (v).

Where,
- \( \phi_{De} \): Shale corrected Density Porosity
- \( \phi_{Nhale} \): Neutron Porosity of a nearby shale.
- \( V_{shale} \): Volume of Shale.

Water Saturation

Prediction of water saturation values was carried out on the picket plot by first estimating porosity (PHI) from the density logs and true formation resistivity (ILD). The Pickett plot is a visual representation of the Archie equation and therefore is a powerful graphic technique for estimating \( S_w \) ranges within a reservoir. All that is needed to make a Pickett plot is a set of porosities and corresponding resistivities taken from well logs and log-log paper.

Cross plotted points that lie above 1.0 water line have water saturations of less than 100\% and complementary hydrocarbon saturations according to Schlumberger 1989 equation (Equation ix).

Shale corrected water saturation was obtained from the Dispersed Clay Model (Dewan, 1983): 
\[ S_w = \sqrt{0.8 \times \frac{R_w}{\phi_i^2 \times R_0^2 \left( \frac{q^2}{2} - q \right)}} \frac{1}{(1-q)} \]

Where:
- \( S_w \): Shale corrected Water Saturation
- \( R_w \): Formation Water Resistivity obtained from Archies Equation:
\[ R_w = \phi^2 \times R_f \] …….. Equation (vii).
- \( \phi_i \): Porosity read from density porosity (DPHI) Log
- \( R_f \): True formation resistivity read from Deep Resistivity Log.
- \( q \): Fraction of intergranular space filled with clay.

Where \( q \) is given by:
\[ q = \frac{\phi_s - \phi_{D}}{\phi_s} \] …….. Equation (viii).
- \( \phi_s \): Porosity from sonic log
- \( \phi_{D} \): Porosity from bulk density log

\( S_h \) = the hydrocarbon saturation obtained from water saturation (\( S_w \)) from the equation:
\[ S_h = 1 - S_w \] (Schlumberger, 1989) …….. Equation (ix).

Net thickness

Net thickness of hydrocarbon zones was determined by subtracting shale units from the gross reservoir thickness. The net to gross of such zones were determined by adding up net...
sand units \((h_1, h_2, h_3)\) and dividing the gross thickness \((H)\) of the zones (Figure 2.2).

**RESULTS AND DISCUSSION**

A typical example of the analysis of hydrocarbon potential and shaly sand is drawn from Well 6. The sandstone interval in the range of 1725m-2050m (as shown in Figure 1) is an example of a hydrocarbon reservoir interpreted from the response of the resistivity logs. The reservoir is divided into 3 zones (A, B and C). This is because the reservoir zones are alternated with shale units. The resistivity logs show that high resistivity values were in the range of 1700-3475 ohm-m. The high resistivity values are probably indicating hydrocarbon. In addition, the mud filtrate resistivity (resistivity read from ILS curve) is greater than formation water resistivity (resistivity read from the ILD curve); as shown by the invasion patterns of the resistivity curves. This is also characteristic of hydrocarbon bearing formations. The curve illustrates that the interval is permeable by separation of the induction log shallow (ILS) and the induction deep resistivity curve (ILD). Reservoir properties like porosity and water saturation were estimated for the prospective zone. Average density porosity (DPHI) obtained by incorporating RHOB log in the density porosity formula reveals that porosity is high with an average value of 0.35 in zone 1 (Fig. 1.1). However shaly sand analysis reveals that the actual average porosity for the reservoir zone is around 0.23. (Table 1).

The hydrocarbon zones, B and C, at depths 1862-1952m and 1975-2050m respectively also have slight differences revealed between the log estimated reservoir properties (porosity and water saturations) and the shale corrected properties of porosity and water saturation (Table 1). Prior to shaly sand analysis water saturation values was high ranging from 0.50 to 1.0. (Table 1).

![Figure 1.1: (Inset) Diagram showing Density Porosity Log (DPHI Log) generated from Bulk](image-url)
On the Pickett plot, the water saturation estimated at the reservoir zone A is high (Fig 1.2). This is observed from the light blue and deep blue plots clustering around 0.28-1.0 water saturation lines. Some of the plots (Green and brown) are even observed to cluster outside the 100% water saturation zone. After correcting for the effect of shale using appropriate formulas, this water saturation was reduced (Table 1). On the Bulk Volume Water cross plot, between the depths of 1730-2300m, the scatter of data around the hyperbolic line is negligible (Fig 1.3). This indicates that the zone is at irreducible water saturation. Therefore, if permeability is estimated from log, the results would be valid. Permeability estimates from formula records value in the range of 4480mD and 6125mD for the reservoir.

The Volume of shale log was generated and average volume of shale taken for the reservoir zone is high (0.55 in Fig. 1.4). Gas is indicated by the separation and crossing over of the neutron and density logs while oil is indicated by the parallel tracking of the neutron and density log (Fig. 1.5). Oil in the pores probably cause density porosity to be reduced and increases the neutron porosity because there is higher concentration of hydrogen atoms in oil.

Table 1: Table showing log estimates and shaly sand analysis for Water Saturation (Sw) and Porosity (φ) respectively

<table>
<thead>
<tr>
<th>Zones (Well 6)</th>
<th>Log/ Pickett plot Estimate</th>
<th>Shaly Sand Analysis</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>S_w</td>
<td>φ</td>
<td>S_w</td>
</tr>
<tr>
<td>A</td>
<td>0.50</td>
<td>0.33</td>
<td>0.29</td>
</tr>
<tr>
<td>B</td>
<td>0.70</td>
<td>0.38</td>
<td>0.38</td>
</tr>
<tr>
<td>C</td>
<td>1.0</td>
<td>0.34</td>
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</tr>
<tr>
<td>Average</td>
<td>0.73</td>
<td>0.35</td>
<td>0.37</td>
</tr>
</tbody>
</table>

Figure 1.2: Pickett Plot at depth interval of 1730-2060m showing estimated water saturation.

Figure 1.3: Bulk Volume Water (BVW) Plot showing zones that are at irreducible water saturation.
Average Volume of Shale (0.55) is high in the reservoir

**Figure 1.4**: Generated Volume of Shale log is displayed beside the Gamma Ray Log.

**Figure 1.5**: Hydrocarbon typing in the Reservoir Zone.
Another example of the analysis is shown from Well 8. Resistivity curves all show high values in the interval 2365m-2582m (Figure 1.6). The neutron and density porosity log through the interval supports the assumption that hydrocarbons are present (Figure 1.6). The density log reads higher porosity than the neutron log, showing a crossover. This is an indication of gas in the interval.

On the caliper log, between 2690m and 2849m the decrease of hole diameter is probably indicating mudcake suggesting that the rock is invaded and that the unit is porous and permeable (Fig.1.7). Therefore, subsequent porosity estimated from bulk density logs reveals average porosity for the interval as 0.28 (Fig.1.8). However the shale corrected porosity is 0.26 (Table 2). This is believed to be adequate for the production of hydrocarbon in the interval.

In Figure1.9, the crossplots offer information about productive zones within the reservoir. The pickett plot shows the depth at which water saturation within the sands are enough to produce hydrocarbon. The water saturation in these plots are obtained from Archie's formula and have not been corrected for shale effects. Gamma ray values between 0-90 fall between saturation lines 0.35-1.0 with the higher log readings (Gr value: 60-150) falling at the 100 % saturation line and above it. This is expected because shales which give high gamma ray readings are not porous and permeable. However, this water saturation is assumed to be high for the reservoir zone. Shaly sand analysis revealed average water saturation estimates at 0.3 for the reservoir (Table 2).

Bulk Volume Water (BVW) is shown in Figure 2.0. It shows an inconsistent scatter for all zones suggesting that the formation is not at irreducible water saturation. Permeability values estimated from this formation will not be valid because water saturation is not at irreducible value.

**Figure 1.6:** Delineation of the reservoir zone from the Gamma Ray Log (Track 1) and the Deep and shallow Resistivity Logs (Track 2).

**Figure 1.7 (Inset):** Permeability indication by leftward deflection of the Caliper log.
**Figure 1.8:** Bulk Density (RHOB) and Density Porosity (DPHI) log displayed on track one and two respectively.

**Table 2:** Table is showing log estimates and shaly sand analysis for Water saturation (Sw) and porosity (φ) respectively from Well 8.
Figure 1.9: Water saturation plots obtained in the reservoir zone at depth 2365-2582m. The Gamma Ray log (GRN) values are indicated by the colour on the plots.

Figure 2.0: This Diagram shows water saturation plots obtained in the reservoir zone at depth 2365-2582m. The Depth Values are represented by the colour on the plots.

Figure 2.1: Bulk Volume Water (BVW) Plot showing that the reservoir zone is not at irreducible water saturation.
CONCLUSION
Results from both Archie's water saturation and shaly sand estimates show some variation in the obtained petrophysical values of porosity and water saturation. Porosity estimates corrected for shale effect reveals an average value of 0.25 while hydrocarbon saturation obtained from shale corrected water saturation is averaged at 0.36. The variation can make a difference in the accurate estimate of volume of hydrocarbon in place when the area covered by the reservoir is known. Shaly sand analysis has helped to improve accuracy of predicted petrophysical values, and thus, insight was gained into the prospectivity of the formations in the study area.

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REFERENCES


