



## RESERVOIR CHARACTERIZATION OF Z-FIELD CHAD BASIN, NORTH-EASTERN NIGERIA



Dinneya Obinna Christian<sup>1</sup>, Anyadiegwu, Chukwunweike Faustinus<sup>1</sup>, Ijeh, Boniface Ikechukwu<sup>1</sup>,  
Bassey Chimezirim Okor<sup>1</sup> and Daniel Enyinnaya Azunna<sup>2\*</sup>

<sup>1</sup>Department of Physics, Michael Okpara University of Agriculture Umudike, Abia State, Nigeria

<sup>2</sup>Department of Physics, Clifford University Owerrinta, Abia State, Nigeria

\*Corresponding author: [azunnad@clifforduni.edu.ng](mailto:azunnad@clifforduni.edu.ng)

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**Abstract:** Well log data from deep parts of the 5 wells located in Z-Field of Chad basin were used in characterization of available reservoir sands. Well log data used include, sonic, gamma rays, matrix density and resistivity logs. A computer software (PETREL) was used and the wireline log data were studied to characterize the porosity, water saturation, volume of shale of the Z-Field reservoir. The thickness of each sand unit varied between 112 and 309 m, in reservoir 1 and between 128 and 259 m, in reservoir 2. The average water saturation (SW) of reservoirs 1 and 2 were 0.51 and 0.48 m, respectively. Similarly, the average hydrocarbon saturation values for reservoirs 1 and 2 were 26.99 and 48.19%, respectively. Generally the porosity values of the reservoir sandstones in the Z-Field in Chad basin are good enough to accommodate large hydrocarbon yield. The results of the study have shown the thickness of the various sand units (reservoir) and the hydrocarbon saturation values in Z-Field of the Chad basin.

**Keywords:** Petrophysics, well logs, reservoir characterization, reservoir saturation

### Introduction

Reservoir characterization is the process of describing various reservoir characteristics such as geologic, petrophysical, geochemical and engineering properties. It also involves, using all available data to provide reliable reservoir models for accurate reservoir production and performance prediction, in addition to providing economic and safe decision making to determining the viability of the reservoir(s) under study (Lim, 2005). To have a comprehensive understanding of the reservoir, it is important to adopt qualitative and quantitative approach which is one of the thrust of this research.

The 3D reservoir model is a geological model of the reservoir's spatial representation of the reservoir properties capturing key heterogeneity of the reservoir. Models are not precise representation of the real world but merely a computer-aided design showing property distribution of the reservoir characteristics which helps in the prediction of the reservoir's future outcome. Reservoir models also help to identify the best and safest drilling, completion and recovery option for a reservoir as well as the most economic, efficient, and effective field development plan for that reservoir. To build a geologic reservoir model, the reservoir should be described/characterized using available data obtained from well points such as well directional/survey, well logs, drill cuttings, core, pressure point, geochemical and paleontology; and these data, are logged against depth at the well-site.

This research deals with the reservoir characterization of Z-Field of Chad basin. In characterization of reservoir sands, physical logs interpretation are very useful and important tools for selecting, planning and implementing operationally reliable supplementary recovery scheme. The characterization of reservoir rocks in terms of porosity, water saturation and permeability determination, increases the ability to characterize abnormally pressured zones, to estimate hydrocarbon reserve and reservoir bed thickness and to differentiate between gas, oil and water bearing strata, by observing their electrical resistivity and relative permeability values (Hilchie, 1978; Schlumberger, 1996; Uguru *et al.*, 2002). The interest of this work is to correlate the reservoir sands.

In modern reservoir management, reservoir characterization plays a crucial role because it helps making sound reservoir decisions and improves value of the oil and gas assets. As a result of the lack of well data in many frontier exploration areas and seismic data quality problems in intrinsically poor

data areas (e.g. fractured reservoirs, deep-water environments, exploration under basalt), exploration, development and production problems become unavoidable. In such conditions identifying hydrocarbon reservoirs becomes a major challenge. In existing field, accurate reservoir model prediction and production performance become more difficult, and thus the recovery factors in many reservoirs remain unacceptably low (Wong *et al.*, 2002).

In the past, classical data processing tools and physical models were sufficient for solving relatively "simple" problems. The challenge to date is no longer to predict the occurrence of hydrocarbon, but rather, to quantify the uncertainty of reservoir predictions and maximize production with less cost. We are increasingly faced with more complex problems with many interacting parameters in situations where small variability in parameters can change the solution completely. The current technologies based on conventional methodologies are inadequate and/or inefficient to deal with the present and future needs. The issues on data uncertainty, diversity and scales are critical and it becomes necessary to go beyond standard techniques for efficient information processing.

Well logs are very important in reservoir characterization and a vital source of quantitative data on porosity, permeability and fluid saturation. It is also useful in correlation and constructing both structural and stratigraphic cross-sections. Well log shapes are good indicators of reservoir depositional environment whereas seismic data contribute to the geometric description of reservoir structure and stratigraphy by meaningful interpretation of the data (Selley, 2000). Seismic interpretation is useful for structural and stratigraphic analysis; however, the primary objective is to prepare contour maps (Emujakporue *et al.*, 2012).

### Geology of Chad basin

This project work is centred on Z-field Chad basin which is the Nigerian part of Chad basin commonly known as Bornu basin. The Chad Basin is the largest endorheic basin in Africa centred on Lake Chad. It has no outlet to the sea and contains large areas of desert or semi-arid savannah. The drainage basin is roughly coterminous with the sedimentary basin of the same name, but extends further to the northeast and east. The basin spans seven countries, including most of Chad and a large part of Niger. The region has an ethnically diverse population of about 30 million people as at 2011 and it is growing rapidly (Welle, 2017). The geological basin, which is

smaller than the drainage basin, is a Phanerozoic sedimentary basin formed during the plate divergence that opened the South Atlantic Ocean. The basin lies between the West African Craton and Congo Craton, and formed around the same time as the Benue Trough. It covers an area of about 2,335,000 km<sup>2</sup> (Obaje, 2009).

It merges into the Illemmeden Basin to the west at the Damergou gap between the Air and Zindermassifs (Wright, 1985). The floor of the basin is made of Precambrian bedrock covered by more than 3,600 metres of sedimentary deposits. The basin may have resulted from the intersection of an "Air-Chad Trough" running NW-SE and a "Tibesti-Cameroon Trough" running NE-SW. That is, the two deepest parts are an extension of the Benue Trough that runs northeast to the margin of the basin, and another extension running from below the present lake to below the Ténéré rift structure to the east of the Air massif. The southern part of the basin is underlain by another elongated depression. This runs in an ENE direction and extends from the Yola arm of the Benue trough.

At times, parts of the basin were below the sea. In the Northeastern part of the Benue Trough where it enters the Chad basin, there are marine sediments from the late Cretaceous (100.5–66 Ma). These sediments seem to be considerably thicker towards the northeast. Boreholes under Maiduguri have found marine sediments 400 metres deep, lying over continental sediments 600 metres deep. The sea seems to have retreated from the western part of the basin

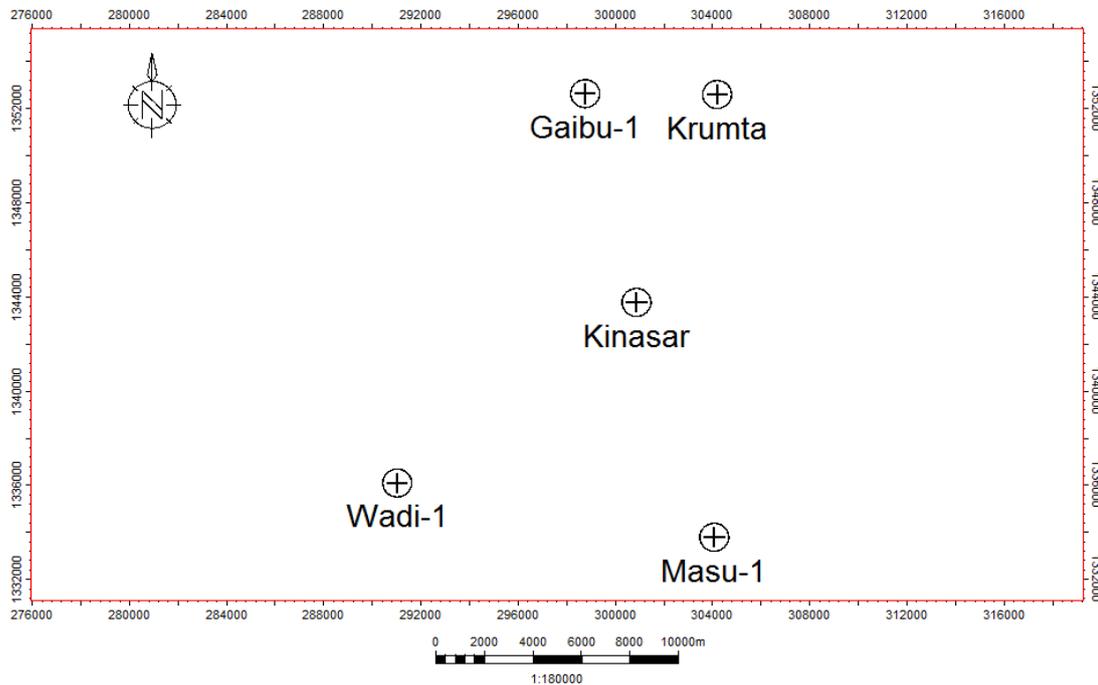
in the Turonian (93.5–89.3 Ma). In the Maastrichtian (72.1–66 Ma) the west was non-marine, but the southeast probably was still marine. No marine sediments have been found from the Paleocene (66–56 Ma).

The eastern part of the basin, showing the Holocene "Mega Chad" lake (blue area) at its maximum size with the Chari in the south and the Benue in the south west. For most of the Quaternary, from 2.6 million years ago to the present, the basin seems to have been a huge, well-watered plain, with many rivers and water bodies, probably rich in plant and animal life. Towards the end of this period the climate became drier. Around 20,000-40,000 years ago, eolianite sand dunes began to form in the north of the basin.

During the Holocene, from 11,000 years ago until recently, a giant "Lake Mega-Chad" covered an area of more than 350,000 km<sup>2</sup> in the basin (Schuster *et al.*, 2005). It would have drained to the Atlantic ocean via the Benue River. Stratigraphic records show that "Mega-Chad" varied in size as the climate changed, with a peak about 2,300 years ago. The remains of fish and molluscs from this period are found in what are now desert regions.

**Materials and Method**

The hydrocarbon saturation of Chad basin reservoirs in the studied area was evaluated in five wells from south to north (MASU-1, WADI-1, KINASAR, KRUMTA and GAIBU-1) as shown in Fig. 1.



**Fig. 1: Base map of the field**

The basis for reservoir oil and gas potentiality evaluation is the petrophysical analysis of drilled targets in all the wells, including the vertical distribution of petrophysical parameters, lithology interpretation from parameters cross plots and lateral distribution changes of various parameters. The available log data for the studied units in all the wells were quality control inspected, including deep and shallow laterologs (LLD, ILD, LLS, LLM and MSFL), neutron porosity, bulk density, acoustic and gamma ray. The borehole environmental corrections and interpretation were carried out using Schlumberger software PETREL (2009).

The lithology components of chad basin Formation in all wells were investigated by using cross-plots of logging parameters (including dia-porosity, density–neutron cross-plots, and tri-porosity M-N and rhomaadmaa cross-plot), the results from different cross-plots are slightly different according to the properties of each parameter. Shale content (Vsh) may be evaluated using a variety of petrophysical indices such as gamma-ray, neutron porosity, resistivity and neutron porosity/density as a double curve clay indicator (Shazly and Elaziz, 2010).

In the present study the corrected porosity was estimated using a combination of the density and neutron logs

(Khadragy *et al*, 2017). Determination of the hydrocarbon saturation ( $S_h$ ) and discrimination of hydrocarbons into the different types of gas or oil are performed. The water Saturation level is calculated using the Archie's equation as stated in equation (1)

$$R_t = \frac{R_w}{\phi^m S_w^n} \quad (1)$$

Where

$$S_w^n = \frac{R_w}{R_t \phi^m} \quad (2)$$

This implies that;

$$S_w = \sqrt[n]{\frac{R_w}{R_t \phi^m}} \quad (3)$$

**Where:**  $R_t$  = the true formation resistivity or total resistivity of the hydrocarbon formation (Hc);  $S_w$  = the water saturation level;  $n$  = the saturation exponent, which describes the geometry of the current flow path through the water body in the presence of hydrocarbon;  $\Phi$  = the total porosity;  $m$  = the cementation exponent;  $R_w$  = the water resistivity

**i) Determination of gross and net sand reservoir thickness:** Gross reservoir thickness interval is the interval covering shale and sand within a reservoir.

Net thickness of sand is the interval covering only sand within a reservoir. It is called net productive sand. The gross reservoir thickness is determined by knowing interval covering both sand and shale within the reservoir studied using gamma ray log. Net sand thickness is determined by subtracting the interval covering the shale from gross reservoir thickness.

Well log data were used in this analysis to generate rock properties using equations (4) and (5)

$$GT \text{ (Gross thickness)} = \text{Base of sand} - \text{Top of sand} \quad (4)$$

NT (Net thickness) = (Base of sand + Top of sand- shale) if shale is present in the formation, if not NT will be the same as GT

$$NTG \text{ (Net to gross)} = \frac{NT}{GT} \quad (5)$$

**ii) Volume of shale (Vsh):** The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step used to determine the volume of shale from a gamma ray log was the calculation of the gamma ray index using equation (6):

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (6)$$

**Where:**  $I_{GR}$  = Gamma ray index,  $GR_{log}$  = Gamma ray reading of the formation,  $GR_{min}$  = Minimum gamma ray (clean sand),  $GR_{max}$  = Maximum gamma ray (shale)

All these values were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated using the Dresser Atlas (1979) formula in equation (7),

$$V_{sh} = 0.083(2^{3.7 \times I_{GR}} - 1.0) \quad (7)$$

**iii) Porosity ( $\phi$ ):** Porosity is defined as the percentage of voids to the total volume of rock. The formation density log was used to determine formation porosity. The porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation 2 (Dresser Atlas, 1979).

$$\phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (8)$$

**Where:**  $\phi_{den}$ : Is the density derived porosity,  $\rho_{ma}$  is the matrix density = 2.65 gm/cm<sup>3</sup> (sandstone),  $\rho_{fl}$  is the fluid density= 1.1 gm/cm<sup>3</sup> (fluid density),  $\rho_b$  = formation bulk density  
The criteria for classifying porosity given by Baker (1992) is:  $\phi < 0.05$  = Negligible,  $0.05 < \phi < 0.1$  = Poor,  $0.1 < \phi < 0.15$  = Fair,  $0.15 < \phi < 0.25$  = Good,  $0.25 < \phi < 0.30$  = Very good  $\phi > 0.30$  = Excellent.

**iv) Formation factor (F):** The formation factor was determined from the Archie's (1942) equation in equation 9;

$$F = \left(\frac{a}{\phi^m}\right) \quad (9)$$

**Where:**  $\phi$  = Porosity,  $a$  = constant (0.62),  $m$  = cementation exponent (2 for sands)

**vi) Hydrocarbon saturation ( $S_h$ ):** This is the percentage of pore volume in a formation occupied by hydrocarbons. It was obtained by subtracting the value obtained for water saturation from 100%.

i.e.,

$$S_h = (100 - S_w) \% \quad (10)$$

**Where:**  $S_h$  = Hydrocarbon saturation,  $S_w$  = Water saturation

### Results and Discussion

Evaluation and identifying reservoir zone is based on the ability of the interpreter to make use of available data in interpreting various parameters, attribute maps extracted on top of key horizons were used for better visualization and interpreting the morphological and reflectivity characteristics of the reservoir.

For Reservoir 1 ( $R_1$ ), the results of the interpreted well logs revealed that the hydrocarbon range in the areas occur between the depth range of 2725 – 3610 m with; gross thickness range of between 112 – 309 m and average gross thickness of 211.25 m, net thickness range of between 110 – 300 and average net thickness of 191 m. The gamma ray and the resistivity logs show no or zero data for the porosity, water saturation and hydrocarbon saturation for Gaibu-1 well but for the remaining wells it gives True Porosity range (poro T) of the reservoir sand between 28 – 38 and Average True Porosity of 32.33, it shows us an Effective Porosity (poro E) range of between 20 – 27 with Average Effective Porosity of 24. The water saturation of  $R_1$  ranges between 0.55 – 0.62 and an average of 0.51 per well. Table 1 shows  $R_1$  to have a hydrocarbon range of 17.50 – 52.12.

The above data gives reservoir  $R_1$  as a productive reservoir with Krumta being the most productive well having a Net to Gross (NTG) of 0.75 and hydrocarbon saturation of 52.12.

**Table 1: Petrophysical parameters for Reservoir 1**

WELL	Top (m)	Base(m)	Gross Thickness (m)	Net Thickness (m)	Poro T	Poro E	SW	NTG	SHC
Krumta	2725	2945	220	176	28	20	0.55	0.75	52.12
Gaibu-1	3498	3610	112	110	–	–	–	–	–
Kinasar	3166	3370	204	178	31	27	0.37	0.82	38.33
Wadi	2909	3218	309	300	38	25	0.62	0.91	17.50

Table 2: Petrophysical parameters for Reservoir 2

WELL	Top (m)	Base(m)	Gross Thickness (m)	Net Thickness (m)	Poro T	Poro E	SW	NTG	S <sup>u</sup> C
Krumta	1398	1526	128	119	31	23	0.21	0.90	86.42
Gaibu-1	1366	1625	259	248	—	—	—	—	—
Kinasar	1444	1662	218	212	33	24	0.41	0.79	62.33
Wadi	1447	1623	176	174	36	25	0.35	0.93	44.21

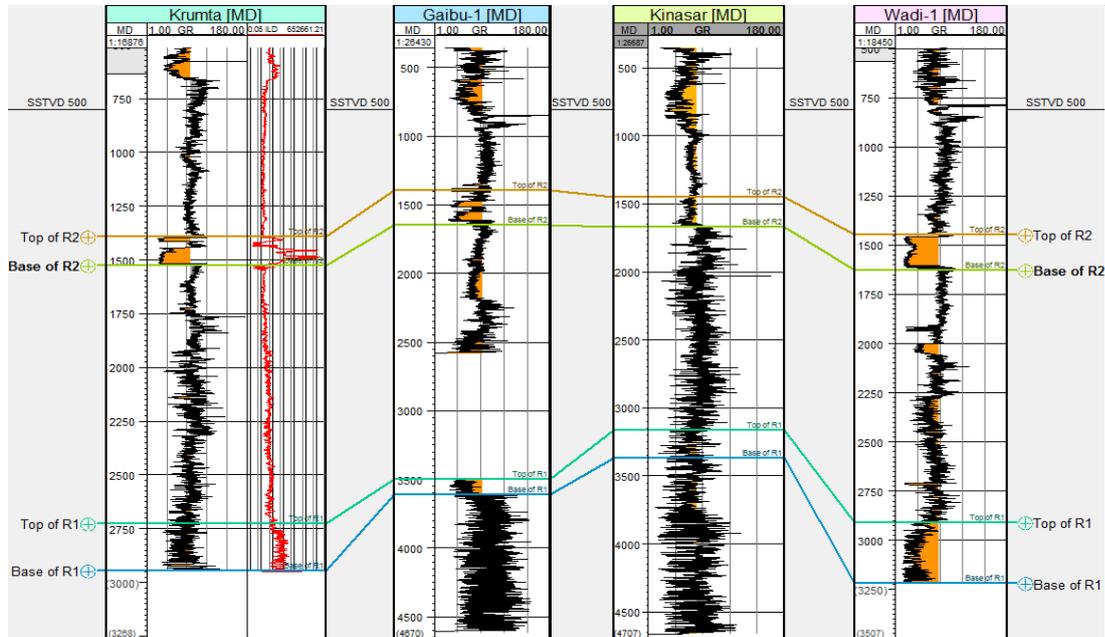


Fig. 2: NE-SW reservoir correlation across the field with GR and deep resistivity (ILD)

For Reservoir 2 (R<sub>2</sub>) shown in Table 2, the results revealed that the hydrocarbon range in the areas occur between the depth of 1366 – 1662 m. Reservoir R<sub>2</sub> has Gross thickness range of between 128 – 259 m and average Gross thickness of 195.25 m, Net thickness range of between 119 - 248 and average Net thickness of 188.25 m. The gamma ray and the resistivity logs in R<sub>2</sub> also show no or zero data for the porosity, water saturation and hydrocarbon saturation in Gaibu-1 well but for the remaining wells it gives the reservoir sands to have Total Porosity range of between 31 – 36 and Average Total Porosity of 33.33. It also shows an Effective Porosity range of 23 – 25 with Average Effective Porosity of 24. Water saturation of the reservoir range between 0.21 – 0.41. There is a hydrocarbon saturation range of between 44.21 – 86.42 showing R<sub>2</sub> to be a very productive reservoir with Krumta well-being the most productive well having an NTG of 0.90 and hydrocarbon saturation of 86.42.

The correlated reservoirs also reveal that the sands are hydrocarbon bearing reservoirs and have hydrocarbon indicators on seismic section.

The well logs used (Fig. 2) and the results obtained (Tables 1 and 2) reflect the reservoir zones and the Petrophysical parameters obtained from the well logs. From the well logs data it was noted that the reservoirs are separated by shales which serves as a seal to the reservoir.

**Conclusion**

The Chad basin holds a considerable prospect for hydrocarbon in terms of reservoir abundance and estimated possible reserves. The basic reservoir parameter (porosity) quality appears good from sonic logs; the reservoir shows evidence of good compaction trend and absence of overpressures. The hydrocarbon type found in most of the reservoir is dominated by gas, followed by oil and 100% saturation by water in few

instances. The other reservoir parameter (permeability) of the reservoirs was not investigated owing to the lack of a log appropriate for carrying out such investigation.

The Nigerian (Borno) Chad Basin may be identified to be a gas province and to adequately predict the hydrocarbon potential of the basin, it is necessary to define the petroleum systems, for which the conventional wireline logs are inadequate.

**Recommendation**

It is recommended that core analysis be fully integrated into formation evaluation, as it is more unequivocal, these should be coupled with every available sedimentological, and geochemical data as well as other geophysical data available in the area in order to obtain a near perfect definition of the overall basin geometry and petroleum system and in the process maximise the output (oil) in the field.

**Conflict of Interest**

On behalf of all authors, the corresponding author states that there is no conflict of interest, and there was no funding source during this research.

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