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Formation Pressure Prediction of an X-Field using Offset Well Data over Onshore Niger Delta, Nigeria

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Abstract
This research focuses on predicting the formation pressure at an onshore oil field (X-Field) in the Niger Delta, Nigeria using offset well data by identifying the abnormal pore pressure zones in the field. The well logs of the three wells (GE_11, GE_12 and GE_13) were utilized for the study. RokDoc software was employed in the data analysis and interpretation. Eaton's and Miller's empirical models were employed in the determination of the abnormal pressure and estimating the formation pressure gradient at a given depth. The overburden trend and normal compaction trend were generated from density and resistivity logs while the shale trend was generated from the gamma ray logs. Sonic logs were used to predict overpressure from velocity trend reversals. Three overpressure zones were identified across the three wells. In Well GE_11, the top of overpressure zones was identified at depth of 9644 ft, 9990 ft and 10290 ft, for Well GE_12 at 7129 ft, 8190 ft, 10369 ft, and for Well GE_13 at 8698 ft, 10117 ft, 11628 ft respectively. Based on our findings, factors responsible for the observed overpressures are mechanical undercompaction, chemical compaction and hydrocarbon generation. The reservoirs correlated across` the wells using the density-neutron porosity log (RHOB-NPHI) shows a slight drift at the overpressured zone which is as a result of entering a more shale bed. The reservoirs also have high density, high porosity, and high resistivity, detailing a characteristically oil reservoir.
Keywords: *Formation Pressure, Normal Compaction Trend, Overpressure, Reservoir, Well data.*

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I. Introduction

Pore pressure also known as the formation pore pressure refers to the fluid (oil, gas, and water) pressures in the pore spaces of porous formations (Sayer *et al.,* 2002). In general, the normal pore pressure increases with depth at a constant gradient (the hydrostatic pressure gradient). In ideal environments, pore pressure is expected to be normal from the surface to the depth of interest. Unfortunately, there are various geological and chemical processes that conspire to produce pore pressure values that are higher or lower than normal hydrostatic pressure (Ma and Chen, 2014; Ma, Chen and Han, 2015). When the pore pressure is higher than the normal pore pressure, we have overpressure or abnormal high pore pressure; but when the pore pressure is lower than the normal pore pressure, it is under pressure or subnormal pore pressure (Zhang, 2011; Zhang and Yin, 2017).

The abnormal pore pressure has so many impacts on the activities of petroleum drilling or petroleum exploitation, geothermal exploitation and many more utilizations. Pore pressure gradient analysis can be useful in understanding geological influences on hydrocarbon accumulation. It is better to drill the flank of a structure rather than its highest point where high pressure within the gas cap presents more difficult drilling challenges. Generally, hydrocarbon accumulation favours slightly low pore pressure within zones of elevated pressures. Identification of these zones aids the overall exploration of petroleum reserves. Gas, due to its buoyancy, can induce abnormally high formation pressures at very shallow depths.

Cases of overpressure and several drilling hazards such as blowouts, lost wells and mud losses have been recorded in some parts of the Niger Delta where certain wells have penetrated deep zones of overpressure (Opara *et al.,* 2013; Nwozor *et al.,* 2013, Ugwu, 2015). This study therefore aims at providing technical geoinformation about future well planning programs in the area for optimized drilling operations that can guarantee safety of personnel, equipment and environment.

II. Geological Setting

The X-field is located onshore in Niger Delta, Nigeria. The Niger Delta basin is one of the seven sedimentary basins in Nigeria. It is considered the most significant owing to its petroliferous nature and consequent active hydrocarbon exploration and production operations occurring both onshore and offshore.

The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province as defined by Klett *et al.* (1997). From the Eocene to the present, the delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2 (Kulke, 1995), a sediment volume of 500,000 km^3 (Hospers, 1965), and a sediment thickness of over 10 km in the basin depocenter (Kaplan *et al.*, 1994). Figure 1 is the geological map of Nigeria showing the location of the Niger Delta basin and the sectional map of the Niger Delta depobelts and structural limits.

The Niger Delta geology has been studied in detail by several workers (Reyment, 1965; Short and Stauble, 1967; Murat, 1972; Doust and Omatsola, 1990, Morley *et al*., 1998; Adeogba *et al.*, 2005; Corredor *et al.*, 2005). The Niger Delta Basin is divided into mainly three lithostratigraphic units, the Akata (Palocene–Recent), Agbada (Eocene–Recent) and the Benin (Oligocene–Recent) formations which conform with a Lower Pro-delta lithofacies, a Middle delta front lithofacies and an Upper delta top facies respectively (Short and Stauble, 1967). These three units extend across the whole delta and each range in age from early Tertiary to Recent. Rollover anticlines in form of growth faults form the main targets of oil exploration; the hydrocarbon being found in sandstone reservoirs of the Agbada formation (Short and Stauble, 1967). The Akata and Agbada petroleum system comprises of the source rock which is the organic rich marine shale of the Akata formation, Agbada formation reservoir rock, and seal rock which is found also in the Agbada Formation due to the intercalation of sand/shale. The trapping mechanism is as a result of growth fault, antithetic faults and collapse structures.

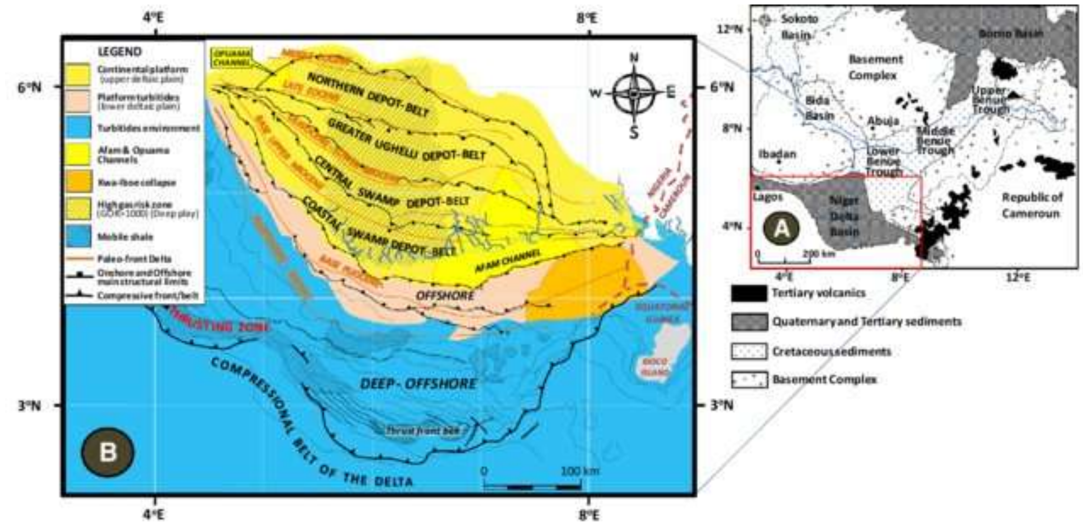

Fig.1. Sectional map of the Niger Delta depobelts and structural limits (Doust and Omatsola, 1990).

III. Materials and Method

Materials

For this study, the materials used include well log data from the study area. The data comprise well logs of Gamma ray (GR), Resistivity (REST), Porosity (RHOB), Density (DST) and Sonic (DT). RokDoc 11.5 (www.ikonscience.com) software and Microsoft Office Excel were used for the data processing and interpretation.

Method

In this research, well based pore pressure prediction workflow (Figure 2) was used to construct overburden profile, drive NCT and the shale trend. Miller's and Eaton's pore pressure prediction models were used to predict the formation pressure.

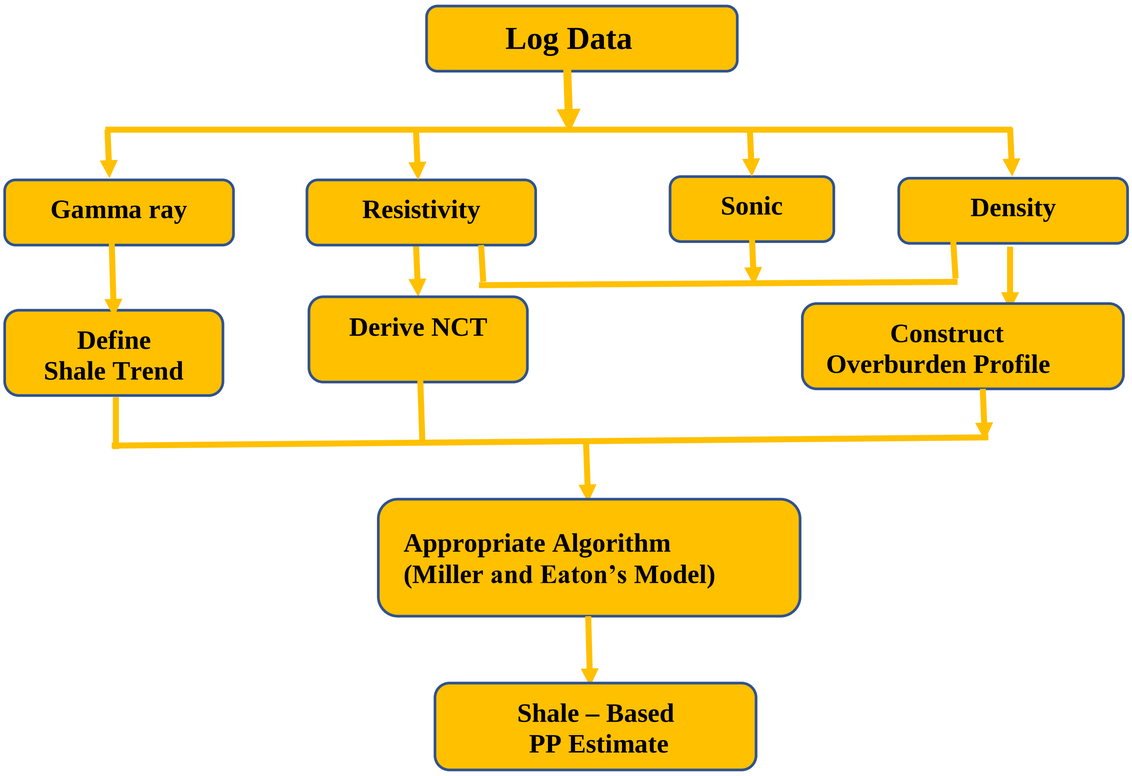

Fig. 2. Well-based pore pressure prediction workflow (Ugwu, 2015).

Overburden Profile Generation

Most pore pressure predictions are based on the relationship between the overburden pressure S, pore pressure P, and the effective stress σ. According to Terzaghi (1943):

$$P = S - \sigma \quad (1)$$

The overburden pressure is the pressure due to the combined weight of the rock matrix and the fluids in the pore space overlying the formation of interest at a given depth. Generation of overburden pressure profile for each well was done using the density log by taking the accretive sum of weight of sediment at every depth. The overburden pressures were estimated using a model fit of the density log (Rho fit) by the equation

$$R_{ho}(Z_{ml}) = R_{hoMatrix} - (R_{hoMatrix} - R_{hoTop})^{*}\exp(-b^{*}Z_{ml}) \quad (2)$$

where, $R_{ho}(Z_{ml})$ is the density at depth z below ground surface mudline, $R_{hoMatrix}$ *is the* density of matrix, R_{hoTop} *is* the density at mudline ground level, and b *is the* compaction coefficient ($1.5 * 10^{-4}$ft).

Normal Compaction Trend (NCT)

The generation of the normal compaction trend was crucial since prognosis of pore pressure in some models is determined by comparing the measured log data with the corresponding value of that measurement in a normally compacted formation. The assumption is that in the shallow section, the sediments are normally pressured and therefore the data from the shallow section can be used to construct the NCT and extrapolate to deep section. In a normally compacted shale, the effective stress increases as the porosity decreases. Thus by defining a normal compaction thread within the shale, one can compare between the porosity expected if the thick shale sequence is normally pressured and compacted, and the measured porosity from the well at the depth of interest. A departure from the normal compaction curve having porosities higher than indicated by the NCT at the same depth is the beginning of overpressure (Ugwu, 2015). The Normal Compaction Trend (NCT) was constructed for all the wells.

Shale Trend

Given that most compaction occurs in the shale formation and a compaction trend is crucial to pore pressure prediction, only the cleanest shale lithology is useful. A volume fraction of shale was generated using Gamma ray log, since the Gamma ray log can discriminate between sand and shale lithology. The volume fraction of shale, V_{sh}, is given by the equation:

$$V_{sh} = \left[\frac{GR_{log} - GR_{sand}}{GR_{shale} - GR_{sand}}\right] \qquad 3$$

where GR_{log} is the response of the gamma ray log, GR_{shale} is the measurement obtained in clean shale and GR_{sand} is the log measurement in clean sand.

Pore Pressure Prediction

Two pore prediction models were employed in this study, the Miller's model and the Eaton's model. These models were chosen based on their compatibility with the sonic compressional velocity log data. Parameters such as the estimated overburden pressure, hydrostatic pressure, and normal compaction trend were utilized as inputs in the models. The RokDoc (version 11.5) software was used for the predictions.

Miller's Model

The Miller sonic model describes a relationship between velocity and effective stress that can be used to relate sonic/seismic transit time to formation pore pressure. In this method, the maximum velocity depth, d_{max}, is the depth at which unloading has occurred. The pore pressure can be obtained from the equation:

$$Pp = P_{ob} - \frac{1}{\lambda} \text{ In } \left(\frac{V_m - V_{ml}}{V_m - V_p}\right) \qquad 4$$

where Pp is the pore pressure, P_{ob} is the overburden pressure, V_{ml} is the interval velocity of sediments in the mudline, V_m is the sonic interval velocity, λ is an empirical parameter for calibrating the model (0.00025) or ratio of increase in velocity with effective stress.

Eaton's Model

The Eaton's model has been described as a horizontal pressure method because it compares an in-situ physical property to a normally compacted equivalent physical property at the same depth. This implies that the method is valid as long as a normal compaction trend can be constructed through the depth of interest. Eaton's model is given by the direct transform of seismic interval velocity into pressure using the equation:

$$Pp = P_{ob} - (P_{ob} - P_{normal})\left(\frac{V_{observed}}{V_{normal}}\right)^x \qquad 5$$

where Pp is the pore pressure, P_{ob} is the overburden pressure, P_{normal} is the normal pressure, $V_{observed}$, is the interval velocity observed at that depth, V_{normal} is the shale velocity at normal pressure and x is exponent value which is dependent on formation properties.

IV. Results and Discussion

Overburden and normal compaction trends were generated from resistivity logs of Well GE_11, GE_12 and GE_13 and presented in Figure 3, 4 and 5 respectively.

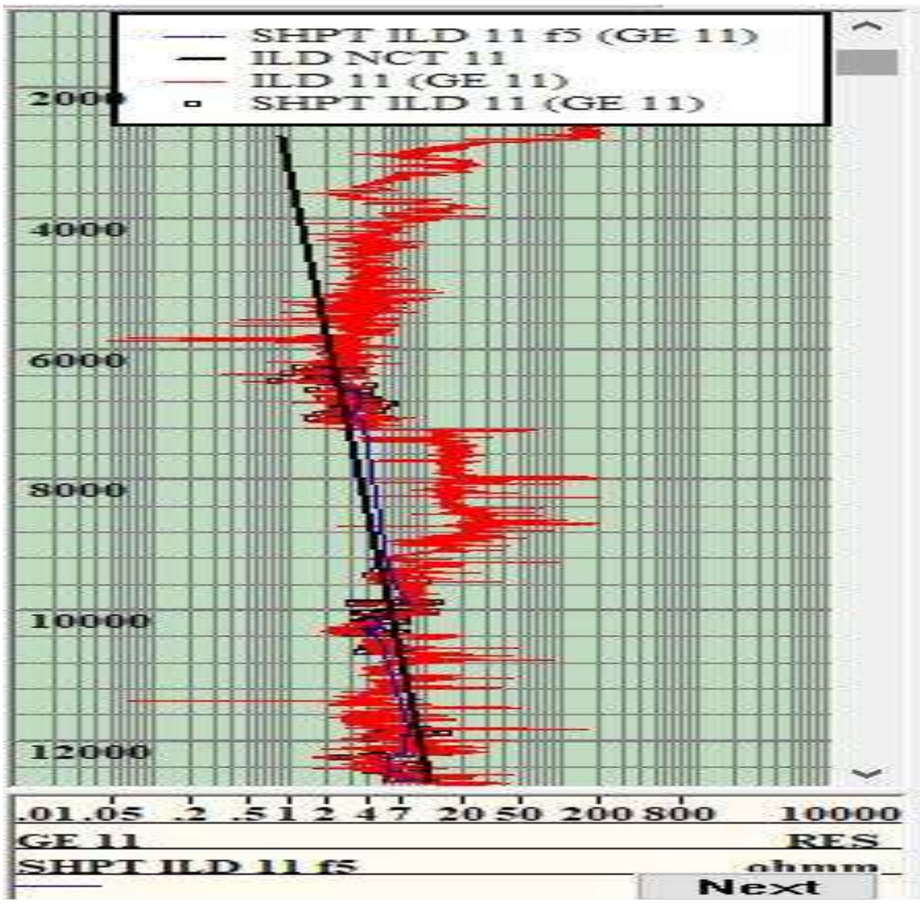

Fig. 3a. NCT generated from resistivity log of Well GE_11.

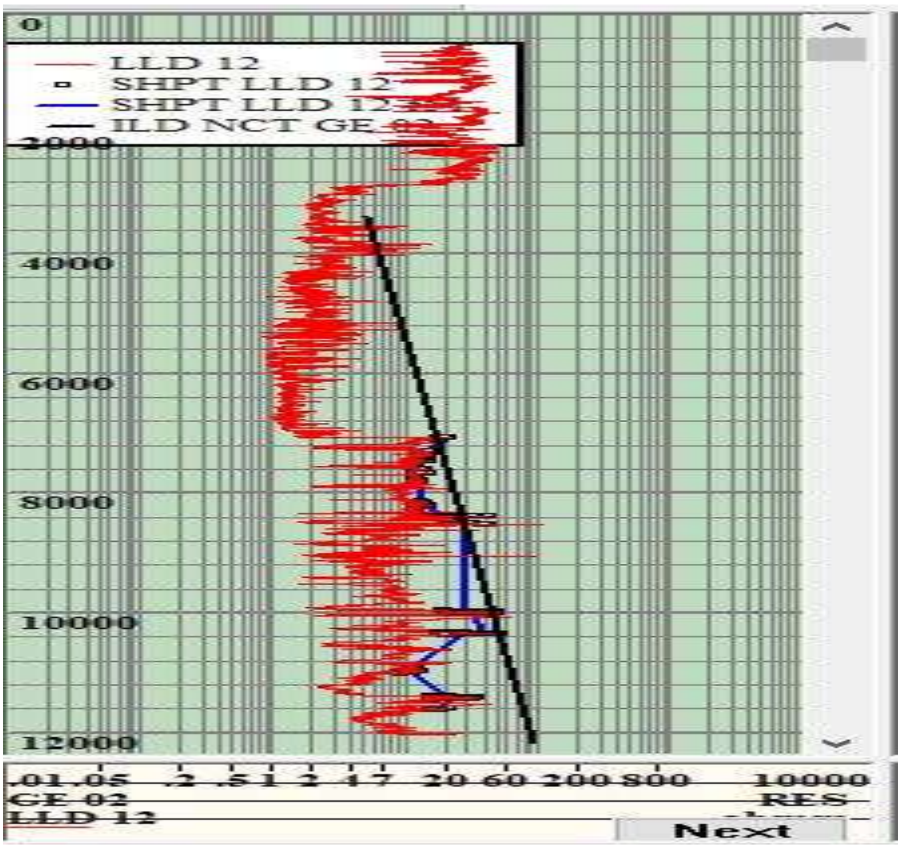

Fig. 3b. NCT generated from resistivity log of Well GE_12.

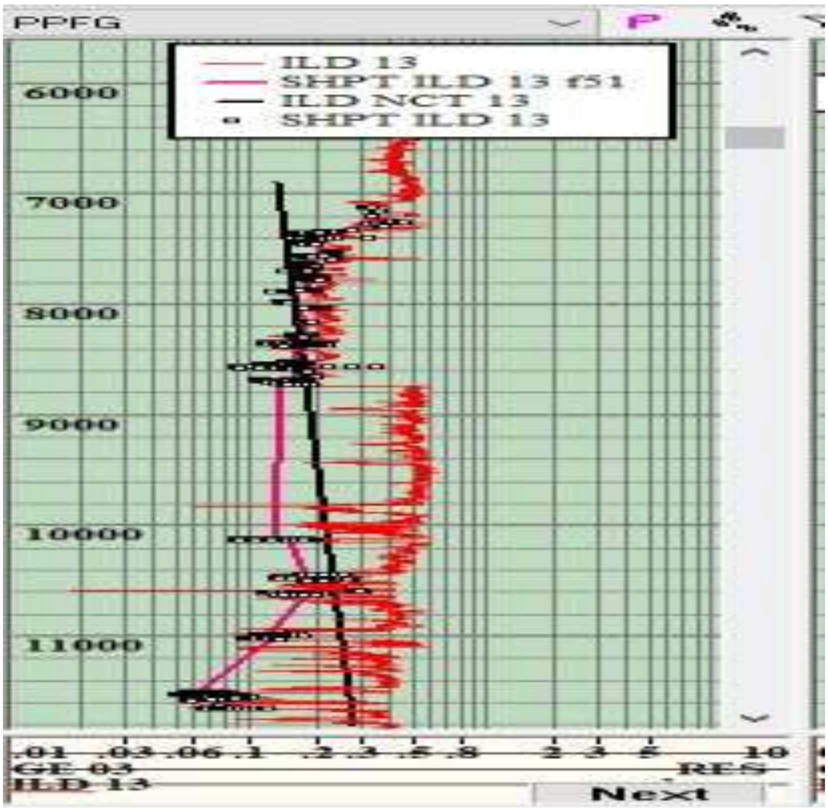

Fig. 3c. NCT generated from resistivity log of Well GE_13.

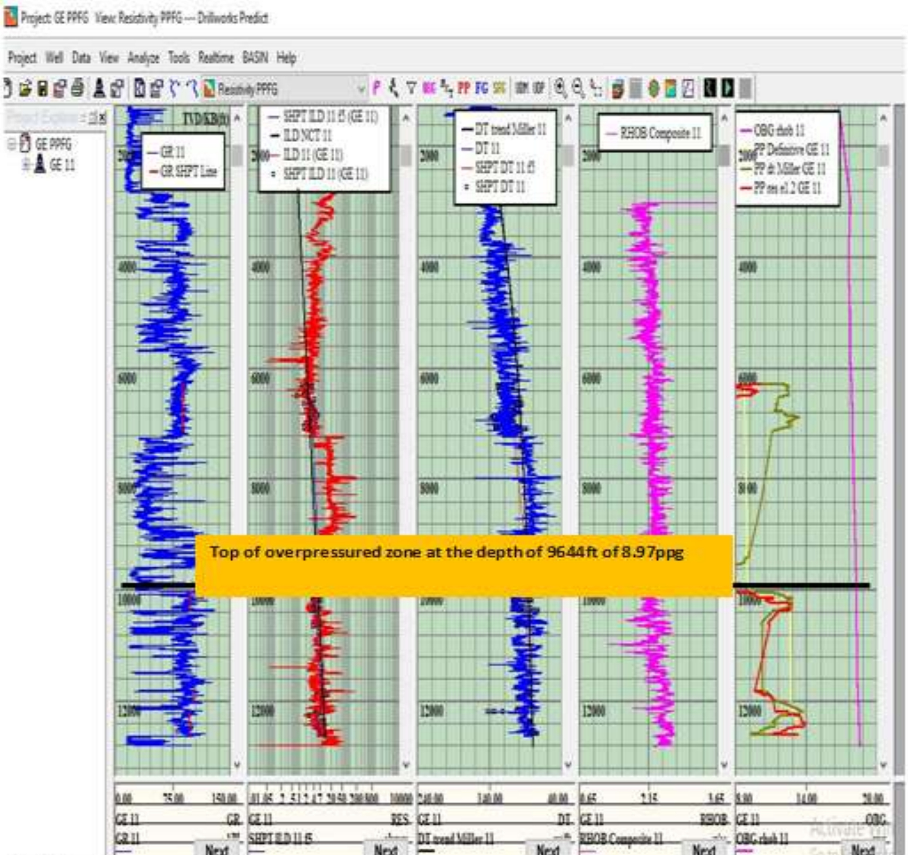

Fig. 4a. Pore pressure gradient of Well GE_11 showing top of overpressure
of 8.97 ppg (4496.73 psi) at 9644 ft.

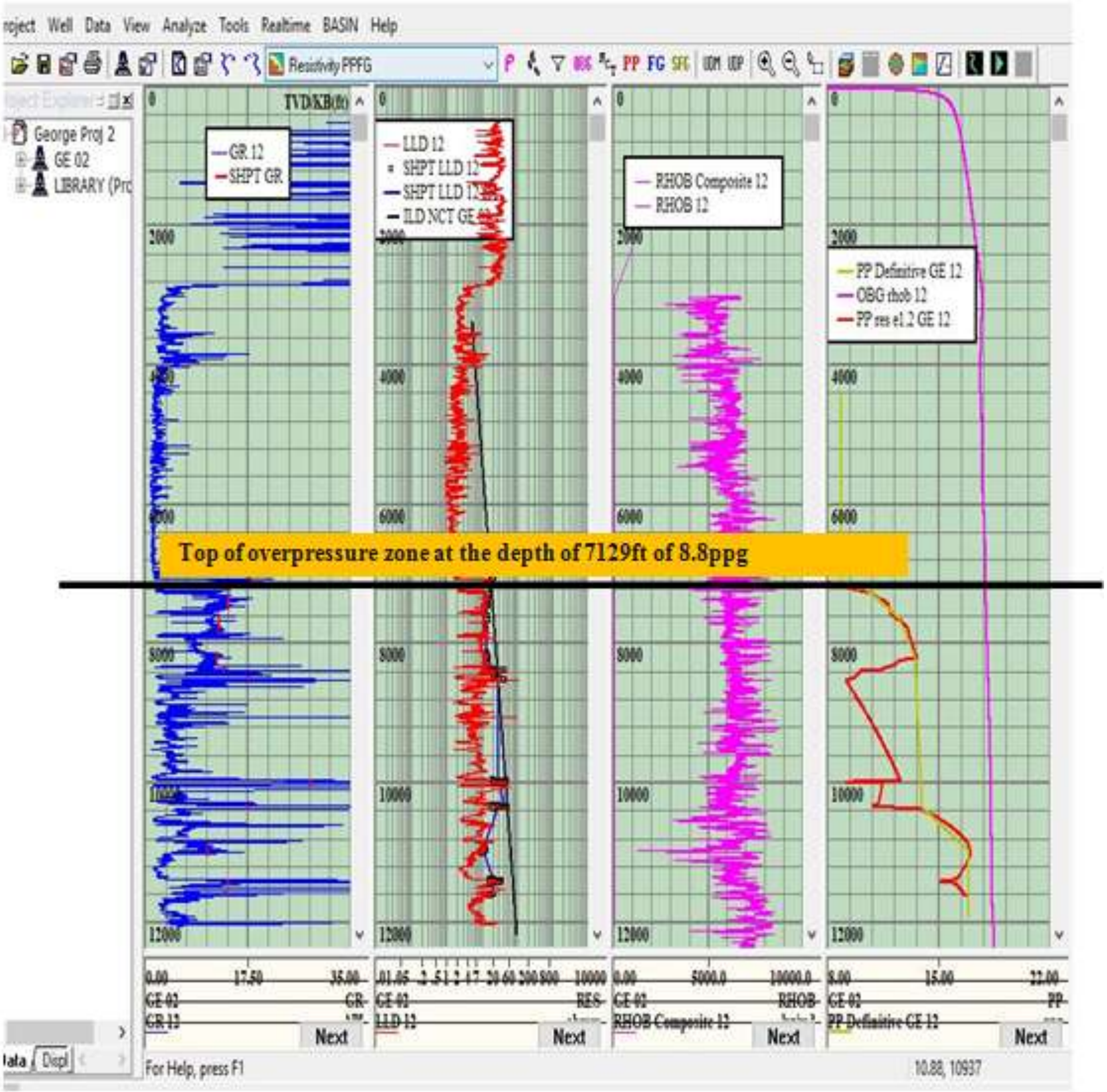

Fig. 4b. Pore pressure gradient result of Well GE 12 showing top of overpressure at 7129 ft with 8.80 ppg (3260.75 psi).

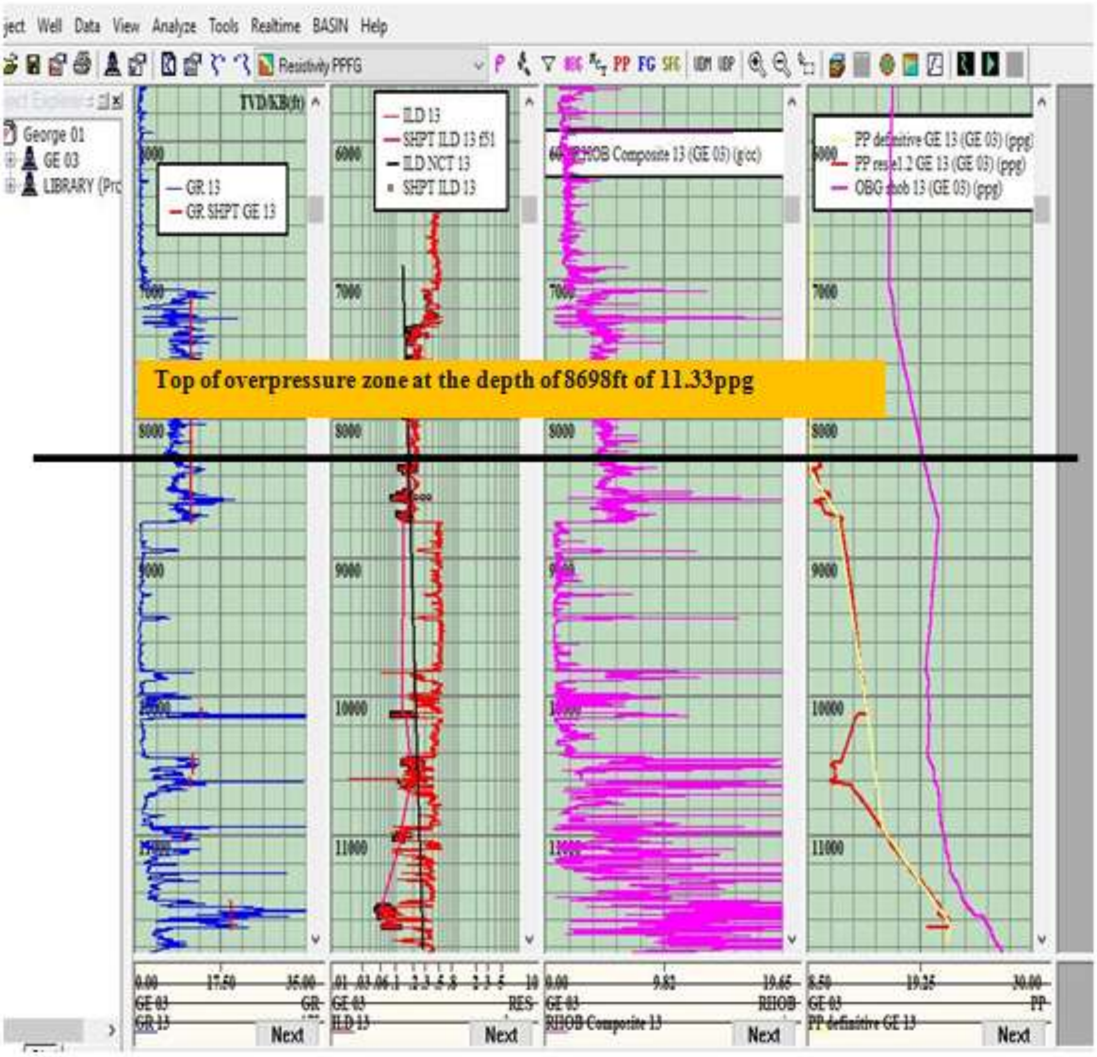

Fig. 4c. Pressure gradient of Well GE_13, showing top of overpressure of 11.33 ppg at 8698 ft.

Figures 4(a-c) show that the formation can be classified as overpressured. Mild overpressure is observed at shallow depths while hard overpressure occurred at depths generally greater than 10290 ft (TVD) from all the three studied wells. The top overpressure zones with thick black lines were identified as 8.97 ppg at 9644 ft, 8.8 ppg at 7129 ft and 11.33 ppg at 8698 ft for Well GE_11, GE_12 and GE_13 respectively. Figures 4(a-c) can also be seen to be in agreement with one another, following significant departure from the normal compaction trends of the rock attributes at those respective depths for the wells. These observations are consistent with those in several literatures that velocity reversals and undercompaction in low permeability sediments are diagnostic features of overpressure in Tertiary sedimentary basins such as the Niger Delta (Ugwu, 2015, Abbey *et al.* 2020). The sonic interval transit times in a normally pressured formation is expected to decrease with depth as the overburden stress increases and following the normal compaction trend (NCT) as the formation becomes increasingly consolidated. Compaction disequilibrium is often recognized by significantly higher than expected travel time at the given depth. The pressure abnormality could therefore be due to increasing porosity with disequilibrium compaction or decreasing sonic compressional velocity due to higher fluid content.

The reservoirs were correlated across the three wells as shown in Figure 5. The density-neutron porosity log (RHOB-NPHI) shows a slight drift at the overpressured zone which is as a result of entering a more shale bed. Above the overpressured zone is the delineated reservoir having the density and neutron logs almost tracking together as well as low tracking gamma ray, suggesting a sandstone unit. The reservoir unit also has higher density, higher porosity, and higher resistivity, detailing a characteristically oil reservoir.

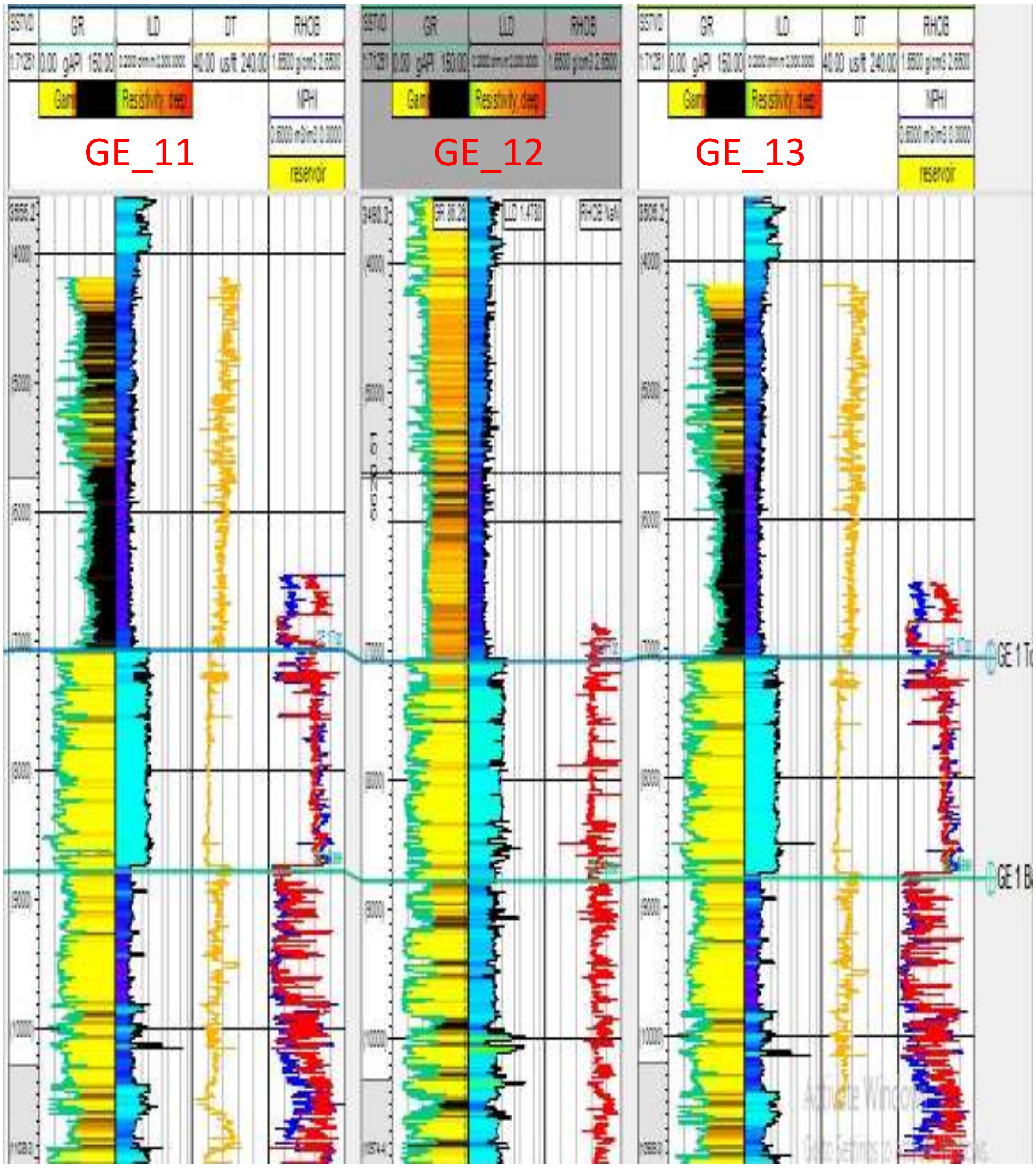

Fig. 5. Top and base of the reservoirs correlated across the three wells.

V. Conclusion

Well data have been used to predict the formation pressure at an X-field in the Niger Delta, Nigeria. The data interpretation showed that the formation in the study area has mild-to-hard overpressure. The top of overpressure, representing the depth at which the overpressure began in each overpressure zone were marked for each well. The mild-to-hard overpressure zones were correlated across the three wells and fall within the depth range estimated by other researchers in the region (Opara, 2011; Ugwu, 2015). Overpressure mechanisms such as disequilibrium compaction and hydrocarbon generation/fluid expansion are the most dominant causes

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