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RESEARCH ARTICLE

PORE PRESSURE PREDICTION, FRACTURE PRESSURE AND LITHOLOGY OF WELL $X^{0}{}_{1}$ AND $X^{0}{}_{2}$, NIGER DELTA, NIGERIA

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ABSTRACT

The study aims to mitigate the risks associated with operating in a borehole environment. Pore pressure predictions have been conducted using well log traces to identify porous lithological units and the onset of overpressure. The findings of the study indicate a lithology characterised by shaly/sandy structural distributions that significantly influence effective stresses. The top of overpressure for well X01 is located at a depth of 11,450 ft, while for well X02, it is at a depth of 11,801 ft. The forecast for fracture pressure is estimated to range from 9,394 psi for X01 to 9,760 psi for X02. This is substantiated by an estimated fracture pressure gradient of 0.82 psi/ft for well X01 and 0.83 psi/ft for well X02 across parts of the Niger Delta. The results from the assessment of overburden pressure indicate that the study area is over pressured.

KEYWORDS

Pressure, prediction, blowout, Instability, fracture, overpressure.

1. INTRODUCTION

The prediction of pore pressure has been extensively examined, particularly to address production challenges associated with uncertainties inoil fields due to unpredictable stratigraphic and facies variations often encountered in complex fields. The challenges related to pore pressure predictions have been observed globally, predominantly in sedimentary rocks (Buttler et al., 1990). Formation pore pressure is defined as the force exerted by pore fluids on the rock formation. Inadequacies in pore pressure predictions, along with subsequent fracture pressure estimations, have been significant contributors to oil spills in the Niger Delta. Accurate prediction of pore pressure in potential wells and reservoirs is of paramount importance, as it can mitigate uncertainties and reduce the risks associated with blowouts. The accidental damages and losses typically associated with these uncertainties arise from an insufficient understanding of the geological background and the compaction trends ofthe environmental sediments in which drilling activities occur. To better understand and characterise pore pressure and fracture pressure zones in parts of the Niger Delta, researchers have demonstrated that abnormal pore fluid generation is linked to several factors, including structural trends, disequilibrium compaction, and the stratigraphy of the oil fields.

The compaction of shale sediments supports the total overlying rock column, leading to anomalous formation pressures. Formation pressure is estimated during well planning, as it affects mud and casing programmes (Palliet and Cheng, 1999; Jurgen, 2015). Fracture pressure aids in predicting the maximum mud weight required at varying depths to ensure safe drilling. This study, therefore, utilises both seismic and well log data for pore pressure forecasting, specifically to address production challenges related to casing placement, fluid design, and to ensure the stability of the wellbore during drilling and exploration phases.

1.1 The Geology of the Niger Delta

The Niger Delta sedimentary system consists of three primary formations: the Akata Formation (lower marine shale), the Agbada Formation (paralic deltaic sequence), and the Benin Formation (continental sands). The Akata Formation, the basal unit, is composed of organic-rich marine shales with turbiditic sands, serving as the delta's primary hydrocarbon source rock and featuring shale diapirs and growth faults due to sediment loading. Overlying the Akata, the Agbada Formation contains alternating sandstones, siltstones, and shales deposited in fluvial, tidal, and shallow marine environments, forming the delta's main hydrocarbon reservoirs with complex trap structures from growth faulting and roll-over anticlines. The uppermost Benin Formation consists of coarse fluvial sands and gravels, functioning as a major aquifer but with limited hydrocarbon potential. The delta's structural complexity arises from syn-sedimentary deformation, including growth faults and shale tectonics, creating heterogeneous pressure regimes and compartmentalized reservoirs. This tripartite system, deep marine (Akata), deltaic (Agbada), and continental (Benin) reflects the Niger Delta's evolution as a prograding delta since the Cenozoic, making it one of the world's most prolific hydrocarbon provinces (Figure 1).

The upper sections of the field are predominantly composed of sand layers, whereas the deeper horizons consist of a sequence of alternating sand and minimal shale formations, in contrast to the upper section.

The general characteristics of sediments, rocks, and rock types present in a stratigraphic division of the Earth constitute the various lithological units of the formation.

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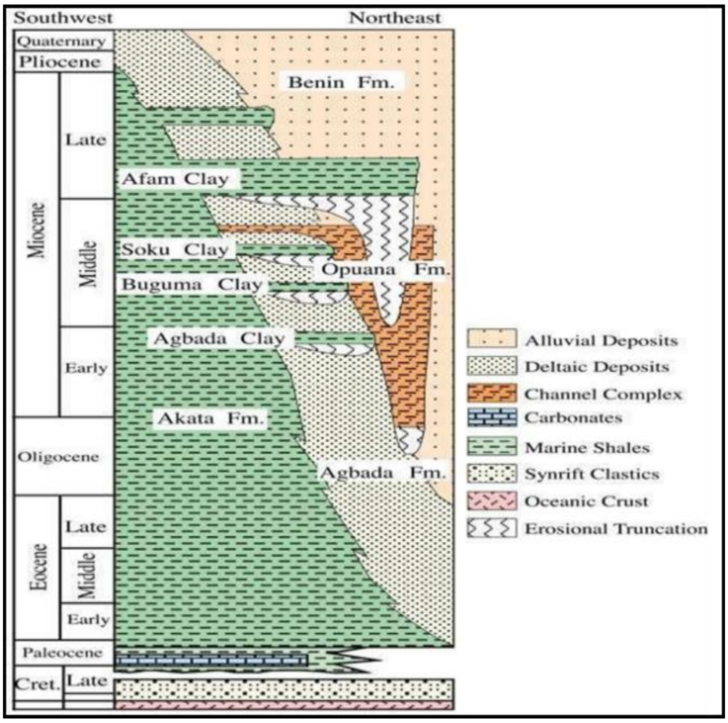

Figure 1: Stratigraphic column showing the three Formations of the Niger Delta (Lawrence et al., 2002).

The Cretaceous lithologies of the Niger Delta Basin are extrapolated from exposed sections in the adjacent Anambra Basin, where the Campanian to Paleocene paleoshoreline formed a concave geometry, resulting in convergent longshore drift systems that facilitated tide-dominated deltaic sedimentation during transgressions and fluvial-dominated deposition during regressions (Reijers, 1997). The Anambra Basin's stratigraphy includes the Albian-Cenomanian Asu River Group (sandy-shale sequence), the Cenomanian-Santonian Eze-Aku Formation and Awgu Shale (interbedded marine shales and turbiditic sandstones), and the Campanian-Maastrichtian Nkporo Shale (marine shales with siltstone intercalations) (Nwachukwu, 1972; Alasi et al., 2022), serving as key analogs for the Niger Delta's obscured Cretaceous deposits, which are overlain by thick Cenozoic sediments.

1.2 The Borehole Environment

The inaccuracy in pore pressure forecasts poses a significant threat to the Niger Delta and, in many cases, has proven hazardous and severe. The overpressured zones are characterised by the invasion of porous and permeable media from the drilling fluid (Figure 2). The permeable media experience an imbalance in hydrostatic pressure as the mud begins to enter the formation. The mud is rapidly halted by the buildup of a mudcake composed of clay particles within the drilling fluid (Stone, 1999; Schlumberger, 2009). As the well is drilled deeper, the invasion zones exhibit cracking, allowing for the entry of mud into the formation. Accurate pore pressure prediction is essential to estimate the mud weight required for safe exploration and to mitigate the influx of formation fluids into the borehole environment. However, excessive mudcake can result in rock fractures and other complexities within the formation. Geophysical surveys, utilising both seismic and well log data, have proven invaluable in understanding wellbore geometry and in predicting potential overpressured regions within the formation rock. Pore pressure prediction necessitates in situ measurements of borehole parameters, such as wave velocity and travel time, followed by a visual inspection of the structural trends of the log facies to identify regions of overpressure and the potential for fracture pressure. The formation log responses are functions of both the characteristics and relative percentages of materials present in the rock, as well as the nature and percentages of fluids occupying the pore volume (Serra, 1986). Recent advancements in geophysical tools designed for use in both cased and uncased well environments have demonstrated the capacity to provide information in the form of three-dimensional (3-D), two-dimensional (2-D), and one-dimensional (1-D) geological and morphological maps (Jurgen, 2015).

Accuracy in the estimation of subsurface overpressure will serve as a guide for overall well management and control. It is essential to consider all aspects of overpressure to develop a more informed and accurate prediction relevant to both pre- and post-drilling activities.

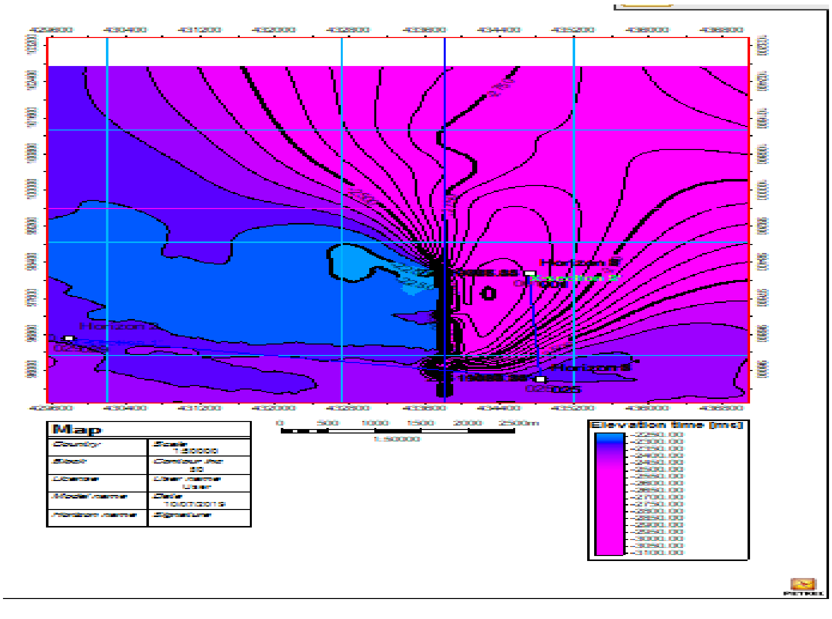

Figure 2: Contour Map Showing Relative Positions of the Wells.

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2. MATERIALS

Well log data were acquired from Shell Petroleum Development Company (SPDC), Rumubiakani, through the Department of Petroleum Resources, Rivers State, Nigeria. This study employed Petrel Version 2014.1 and Interactive Schlumberger Petro-physical software for its interpretation. These tools provide significant performance benefits to users, particularly those engaged in exploration and geological modelling.

3. METHODS

A comprehensive formation pressure prediction was conducted based on the wireline logs obtained from the study area. Shale formations are the preferred lithology for pore pressure prediction due to their greater responsiveness to effective stress compared to most rock types. The most effective approach to pore pressure prediction involves examining the combination of all the available measured data (Figure 3).

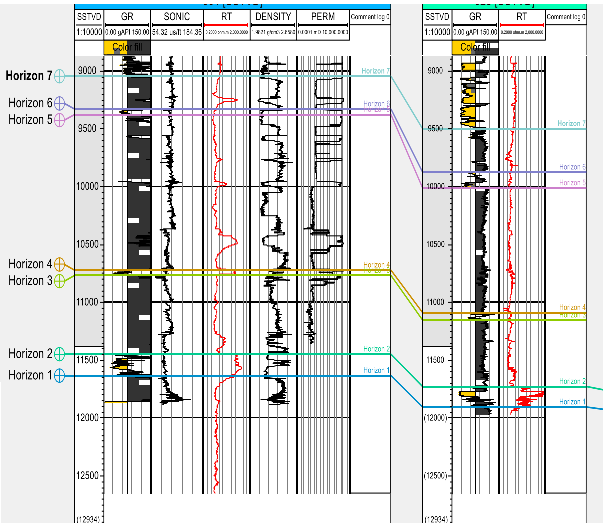

Figure 3: Well logs plotted against depth.

3.1 Normal Compaction Trends

The prediction of overpressure from the resistivity and sonic logs was performed by correlating the degree of deviation from the normal compaction trend (NCT) at a given depth with the observed pressure in adjacent reservoir formations. This methodology entails establishing the normal compaction trends (NCT) that correspond to the normal pore pressure regime when shale resistivity or sonic transit time is plotted against depth on a semi-logarithmic scale (Hottman and Johnson, 1965; Onyishi, et al., 2022). The divergence of observed sonic transit time or resistivity (Figures 4 a and 4 b) from the NCT serves as an indicator of the formation pore pressure.

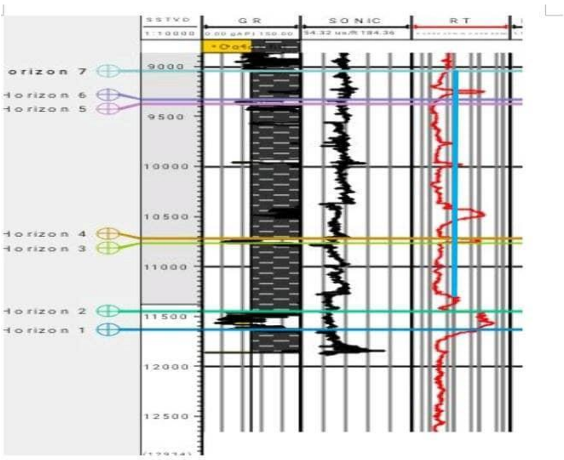

Figure 4 a: Normal compaction trend plot of resistivity log against depth for well $X^{0}{}_{1}$.

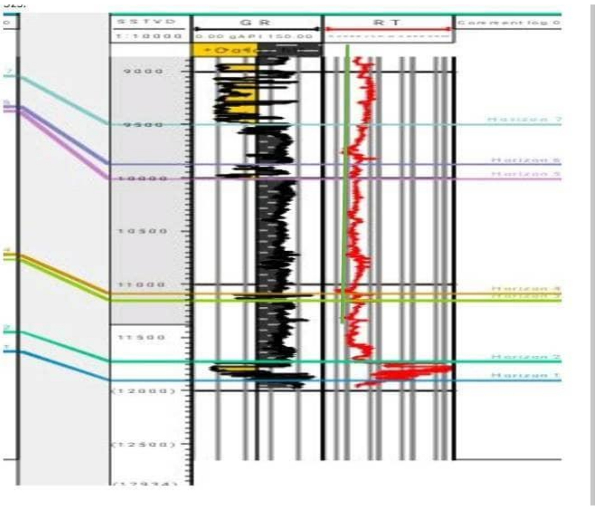

Figure 4 b: Normal compaction trend plot of resistivity log against depth for well $X^{0}{}_{2}$.

3.2 Formation Pore Pressure

It established a model that relates pore pressure, depth, and the ratio of normal shale resistivity to observed values for regions with varying salinity (Foster and Whalen, 1966):

$$\text{Pp} = 0.465 \times Z^2 + \frac{0.535}{Log_b} \times \log\left(\frac{R_n}{R_0}\right) \quad (1)$$

Where Pp represents the formation pore pressure (psi); Z is the true vertical depth (ft); Rn is the normal shale resistivity (Ohm.m). The Logb can be obtained from the slope of formation factor versus depth plot.

Proposed a pore pressure model for cases without unloading which relates formation pore pressure to vertical stress, depth and compressional transit time (Zhang, 2013).

$$\text{Pp} = \left(\frac{\sigma_v - \left(\frac{\sigma_v - \alpha NPp}{CZ}\right) Ln\left(\frac{\Delta t_{ml} - \Delta t_m}{\Delta t_0 - \Delta t_m}\right)}{\propto}\right) \quad (2)$$

Where Pp is the formation pore pressure (psi); σ_v is the vertical stress (psi); NPp is the normal pore pressure (psi); Z is the true depth below the mudline (ft); Δt_m is the mudline compressional transit time; C is the compaction constant; Δt_0 is the observed compressional transit time either from the sonic or seismic velocity ($\mu s/ft$); $\propto$ is the Biot's coefficient.

Petrel and Interactive Schlumberger Petro-physical software were employed to compute the formation pore pressure (Figure 5a and Figure 5b) based on the varying log readings. The interface of the Interactive Schlumberger Petro-physical software was calibrated for a dispersed shaly sand structural distribution, with a cut-off value of less than 0.5.

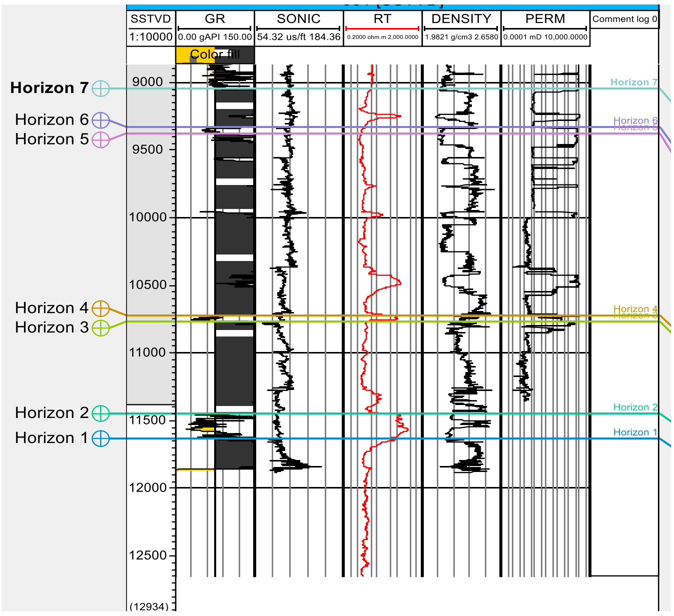

Figure 5a: Well log traces for well $X^0{}_1$ showing top of overpressure at 11450 ft.

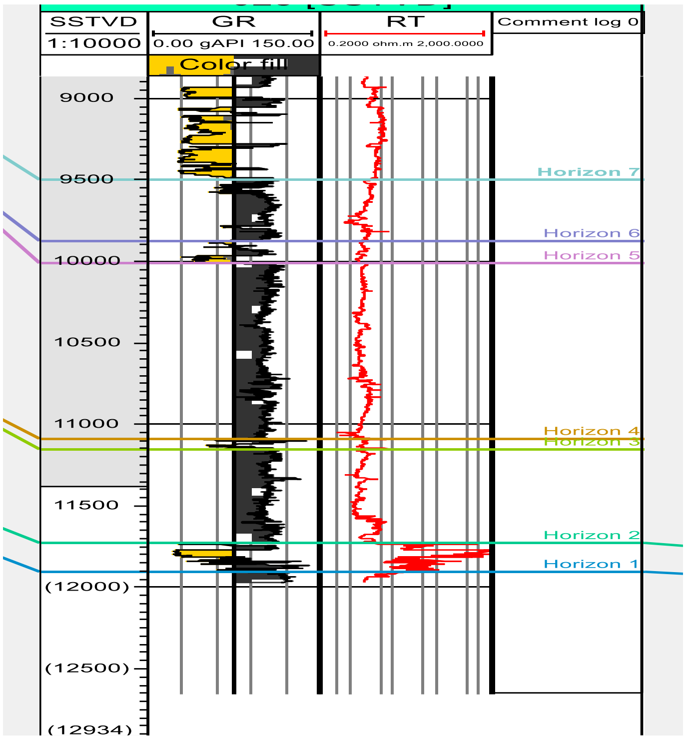

Figure 5b: Well log traces for well $X^0{}_2$ showing top of overpressure at 11801 ft

3.3 Overburden Pressure

The overburden pressure represents the combined weight of the formation matrix and the fluids that overlie the formation. It is also defined as the geostatic pressure exerted by the overburden load upon the underlying formations. Mathematically, this pressure can be determined by integrating the formation bulk density from the surface to the depth of interest (Eaton, 1972; Ugwu, 2015; Oloruntobi et al., 2018; Olalere, 2019).

$$S_v = 0.433\int_0^z P_b dz \quad (3)$$

$$P_b = 0.9526Z^{0.101} \quad (4)$$

Substitute equation (4) into equation 3, we have

$$S_v = \frac{Z^{1.101}}{1.101} \quad (5)$$

Where P_b represents the formation bulk density as a function of depth (g/cc); denotes the depth of interest (m) and S_v signifies overburden pressure.

The gradient of the overburden pressure is derived from the cross-plot of overburden pressure against depth and can be mathematically expressed as follows:

$$\text{Overburden pressure gradient} = \frac{\text{Overburden pressure}}{Z}$$

3.4 Fracture Pressure

Fracture pressure is defined as the bottom hole pressure at which drilling fluid begins to invade the formation, as well as the relationship between mud pressure and the volume at which it starts to deviate from linearity (Couzens-Schultz and Chan, 2010). To estimate fracture pressure, a normally pressured line trend is obtained by fitting a power-law model to the fracture pressure data collected in normally pressured intervals. It provides the fracture pressure equation for the Niger Delta as a function of depth (Olalere, 2019):

$$Fp_{NPT} = 0.06817[D]^{1.2662} \tag{6}$$

Where Fp_{NPT} represents the formation fracture pressure and (D) denotes the depth..

Additionally, the fracture gradient is defined as the minimum total in situ stress divided by depth (Eaton, 1972)

$$\text{Fracture pressure gradient} = \frac{\text{FPnpt}}{D}$$

4. RESULTS

The focus is on obtaining data in "real-time" to optimise drilling decisions, specifically for drill bit guidance ("geo-steering") and the detection of overpressuring prior to extensive invasion (Hanson and Tibbitts, 1991). Shale formations are the preferred lithology for pore pressure prediction due to their greater sensitivity to effective stresses compared to most other rock types. The prediction of formation pressure and the identification of overpressure zones rely on the interpreter's ability to utilise available data in analysing various parameters. Accurate determination of rock mechanical properties is essential for mitigating the risks associated with drilling, completion evaluation, and production procedures. The top of overpressure for well X01 is at a depth of 11,450 ft, with an overburden pressure of 26,727 psi, while the top of overpressure for well X02 is at a depth of 11,801 ft, associated with an overburden pressure of 27,360 psi (Table 1). The fracture pressures for well X01 and well X02 are 9,394 psi and 9,760 psi, respectively. These results align reasonably well with those obtained by Cyril and Stephen (2016), which indicated a top of overpressure ranging from 6,000 ft to 11,017 ft. The lithological results indicated a shaly/sand distribution.

Table 1: Measured geophysical properties from the well data.

Well	Depth (ft)	Porosity (Φ)	Tortuosity (τ) (%)	Overburden Pressure (psi)	Fracture pressure (psi)
$X^0{}_1$	11450	0. 114	8.8	26727	9394
$X^0{}_2$	11801	0. 113	8.8	27360	9760

The normal compaction trend for well X01 ranges from 8999 ft to 11480 ft. It was observed that the pressure transition interval lies between 11480 ft and 11601 ft; consequently, overpressure zones exist beyond 11601 ft. The formation pressure gradient is normal down to 11450 ft. Within the overpressure interval, the formation gradient further increases from 11601 ft to 11699 ft. The formation pressure gradient then remains relatively constant from 11798 ft to the total depth of the well. The normal compaction trend for well X02 ranges from 8999 ft to 11801 ft. It was observed that the pressure transition interval is between 11801 ft and 11850 ft; hence, overpressure zones exist beyond 11850 ft. The formation pressure gradient is normal down to 11801 ft. Within the overpressure interval, the formation gradient increases from 11850 ft to 11904 ft. The formation pressure gradient then remains relatively constant from 11949 ft to the total depth of the well. An overburden gradient of 2.3 psi/ft was estimated for both wells X01 and X02, with corresponding fracture pressure gradients of 0.82 psi/ft and 0.83 psi/ft, respectively.

5. DISCUSSION

This study integrates well log data to provide essential information required for formation pressure prediction and reservoir management. The characteristics of pore space vary from formation to formation; therefore, resistivity logs are employed to explore lithological units. Resistivity logs measure the ability of rocks to conduct electrical current and are scaled in units of ohm-meters. These characteristics are significant due to the process of formation "invasion" that occurs during drilling. Resistance constitutes the impedance to the flow of current and is a function of the geometry and intrinsic resistivity of the material. Current flow in porous rock predominantly occurs through the fluid filling the pore space and is influenced by pore volume, pore connectivity, pore fluid composition, degree of alteration, mineralogy, and temperature. The volume of shale indicates productive zones with clean sand distributions. The existence of fractures (natural or induced) significantly alters permeability. Thus, the detection of fractures and the prediction of the likelihood of fracturing are of great importance in drilling and wellbore geometry.

Within the overpressure zone, rock resistivity and compressional wave velocity decrease while formation porosity increases. This trend is observed when compaction-dependent geophysical properties are plotted against depth. The results indicate that the magnitude of overpressure is directly correlated with the degree of deviation from the normal compaction trend (NCT). This finding is consistent with the results obtained, which indicated that the onset of overpressure occurs beyond 14760 ft by (Chiazor and Beka, 2019). Overburden pressure represents the maximum principal stress derived from the study area. Additionally, the results of this study are in agreement with similar research conducted, which utilised well log data in the onshore central Niger Delta by (Nwankwo and Abdul, 2017).

6. CONCLUSION

The ability to correlate measured data with formation parameters is crucial for accurate pore pressure prediction. Consequently, this necessity has prompted a geophysical approach to subsurface analysis for detailed interpretation of the wellbore. Measured log parameters, including gamma radiation (Gr), natural resistivity (Rt), density, and sonic velocity, were utilised to identify porous litho-units and the upper limits of over-pressured regions, thereby mitigating the risks of wellbore instability and blowouts. Effective pore pressure prediction ensures maximised recovery with fewer wells positioned optimally, while concurrently reducing uncertainties during the drilling and production phases. The mud weight must be maintained between the formation pressure gradient and the fracture gradient. For well X01, the top of overpressure is located at a depth of 11,450 ft, with a fracture pressure of 9,394 psi, whereas for well X02, it is at 11,801 ft, exhibiting a fracture pressure of 9,760 psi. The results derived from the overburden pressure analysis indicate that the study area is indeed over-pressured.

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