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# Overpressure Prediction from Seismic Data and the Implications on Drilling Safety in the Niger Delta, Southern Nigeria

By

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***Abstract***
*High sediment influx rate, rapidly subsiding basin, very thick clayey members in the Agbada and the Akata Formations, as well as prevailing presence of growth faults, have been identified as the main factors responsible for overpressure generation and preservation in the Niger Delta Basin. Analysis of porosity-dependent parameters, such as Interval Transit Times (ITT) and interval velocities derived from the seismic records of 'X' field in the Western Niger Delta, identified an overpressured zone at a depth of 2643 m. The plot of ITT against depth gave a positive deflection from normal at the zone of overpressure while interval velocity plot gave a negative deflection; the ratio of deviations in both cases is as high as 1.52. The pressure gradient in the upper, normally pressured, part of the field was determined to be 10.5 kpa/m, which is within the established normal pressure gradient range in the Niger Delta, while the abnormal formation pressure gradient in the overpressured section is 21.7 kpa/m. Formation fracture pressure gradients from the formation pressure information was calculated to be 14.9 kpa/m in the upper part of the field and 27.1 kpa/m in the overpressured horizon. Mud Weight Window (MWW), the mud density range necessary to prevent formation kick without initiating hydraulic fracturing was determined to be 1017.7 to 1247.2 kg/m3 in the normally pressured part of the field and 2205.1 to 2257.9 kg/m$^3$ in the overpressured horizon.*

*The predicted formation pressure information served as a guide for drilling programme and casing design. The information is also helpful in reducing well construction risks, saving drilling time as well as cut down drilling cost which could arise from a blowout if adequate measures were not taken.*

**Keywords:** Fracture pressure; Agbada Formation; Blowout; Hydrostatic pressure.

## 1.0 Introduction

A formation is said to be overpressured when the formation fluid is higher than the standard theoretical hydrostatic pressure that can be generated by a free column of brine solution with approximate salinity of about 300,000 ppm[1]. Normal reservoir pressure gradient is 9.95 to 11.31 kpa/m.[2] Overburden stress is the main source of reservoir pressure but this alone cannot generate overpressure at present drilling depth. Other factors such as diagenesis, which reduces pore volume, osmosis, dewatering of mudrocks under compaction pressure, epeirogenic movements and thermal expansion of formation fluid, are the major causes of overpressure. Dewatering of adjacent mudrocks has been identified as the major contributor to building formation pressure in excess of the normal hydrostatic pressure. However, the generated excess formation pressure within a reservoir cannot be preserved if the reservoir remains in pressure continuity with the adjacent permeable formations. A seal is therefore necessary for pressure isolation and preservation, for fluid to build up in excess of the normal hydrostatic pressure within a reservoir, otherwise pressure distributive mechanisms will simply transfer the excess pressure to the regions of lower formation pressure and the basin will remain in pressure equilibrium.

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[1] Dickey, P.A., 1976. Abnormal formation pressure: *AAPG Bull*., vol.60, No.7, pp.1124-1128.

[2] Bourgoyne, A.T., Millein, K.K., Chenevert, M.E. and Young, F.S., 1991, *Applied drilling engineering*: 2nd Print, SPE Found., Richardson, Texas, 502p.

Overpressure is rampant in young sediments that did not expel considerable quantity of depositional water through adequate compaction before burial. Overpressured zones are pockets of abnormally high porosity because the high-pressured fluids resist adequate crushing of the pores as commensurate with the overburden stress associated with the depth[3]. The high pore fluid pressure within the overpressured regions also induces dissolution of considerable proportion of the gaseous fractions of the formation fluid and this raises the Gas Oil Ratio (GOR) of the overpressured formation fluid. These two phenomena cause regions of overpressure to be characterised by abnormally low velocity, abnormally high amplitude as well as other porosity-dependent parameters that cannot be related directly to any other causative sedimentary or geologic factors, such as, shaliness of sandstone reservoir rocks or presence of limey/calcitic facies.

## 2.0 **Previous Works**

One of the earliest attempts to determine the variation of compressional wave velocity with overburden pressure was reported by Faust[4] who examined the velocities of shale and sand layers from very thick sediment section in 500 wells and used statistical analysis to define interval velocity V, in a sand-shale section as,

$$V = 125(ZT)^{1/6}$$

where Z is depth in feet and T is the age in years of the sand or shale. Wyllie *et al*.[5] measured compressional wave velocities in sandstone and limestone specimens and observed an inverse relationship between velocity (V) with porosity ($\phi$) in accordance with a time – average equation, given by

$$1/V = \phi/V_f + (1- \phi)/V_m$$

where $V_f$ and $V_m$ are velocities in pore fluid and matrix, respectively. Nur *and* Simmons[6] established that within hydrocarbon saturated horizons, P and S-wave velocities decrease drastically upon increase in formation pressure. Keller[7] discovered that velocity attenuation in fluid-saturated media is higher than for dry materials and depends upon the degree of saturation, viscosity and density of the saturating fluid. Hwang and Lellis[8] showed that gas as well as gas-saturated liquids exerts considerable attenuating influence on the velocity of propagating waves.

## 3.0 **Geologic Setting**

The study area is situated in the Niger Delta in southern Nigeria bordering the Atlantic Ocean. It is located within longitude $3^0$ E – $9^0$ E and latitude $4^0 30^1$ N – $5^0 20^1$ N.[9],[10] The Niger Delta, like

[3] Levorsen A.I & Berry, F.A.F., 1991. Geology of petroleum, 2nd ed. San Francisco, W.H. Freeman, 724p.

[4] Faust, L.Y., 1951. Seismic velocity as a function of depth and geologic time: *Geophysics*, vol.16, pp.192-206.

[5] Wyllie, M.R.J., Gregory, A.R., and Gardner, L.W., 1956. Elastic wave velocities in heterogeneous and porous media: *Geophysics*, vol.21, p.41-70.

[6] Nur, A.M., and Simmons, G., 1969. The effects of viscosity of fluid phase on the velocity in low porosity rocks*: Earth Plan. Sci. Lett*., vol.7, p99-108.

[7] Keller, J.D., 1989. Acoustic wave propagation in composite fluid saturated media: *Geophysics*, vol.54, pp.1554-1563.

[8] Hwang, L.F., and Lellis, P.J., 1988. Bright spots related to high GOR oil reservoir in Green canyon: 58th Ann. Int. Mgt., Soc. Expl.: *Geophysics*. Expanded Abstracts, pp.761-763.

[9] Asseez, O.L., 1976, Review of the stratigraphy and sedimentary structure of the Niger Delta (C.A. Kogbe, ed.) Elizabethan Publishing Co., Lagos.

[10] Reijers, T.J.A., Petters, S.W., and Nwajide, C.S., 1997. The Niger Delta Basin, *in* Selley, R.C., ed., African Basins--Sedimentary Basin of the World 3: Amsterdam, Elsevier Science, pp. 151-172.

most deltas, is characterised by a tripartite stratigraphy represented by the marine Akata Formation, the paralic Agbada Formation and the continental Benin Formation[11]. The basin consists of an overall regressive clastic succession, which reaches a maximum of 12000 meters (40000 ft.) in the central parts where there is maximum subsidence (Fig. 1).

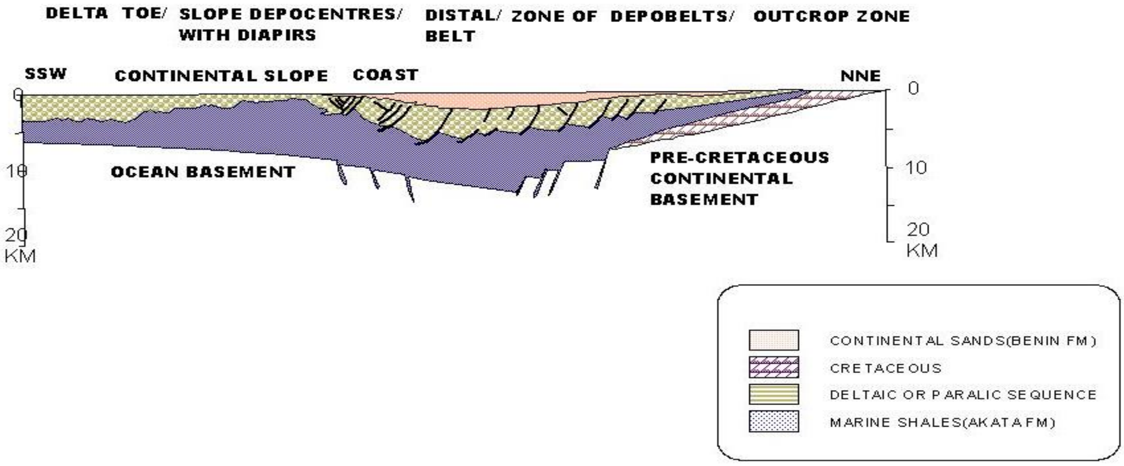


**Fig. 1** Schematic structural section through the axial portion of the Niger Delta (Modified from Merki[12])

## 3.1 **Overpressure in the Niger Delta**

Overpressure is quite rampant in the Niger Delta and it has been encountered at depths as shallow as 1372 meters in the eastern part of the basin[13]. Formation pressure in some overpressured zones is quite high with overpressure gradient ranging from 13.6 to 21.7 kpa/m in some hydrocarbon traps situated close to the top of the overpressured and undercompacted Akata Formation.[13] Nearly all the geologic events which support the accumulation and preservation of overpressure are present in the basin. The rate of sediment influx into the basin is very high; the basin is not stable, still subsiding up till today. The high rates of sedimentation and burial do not allow for adequate settlement and dewatering. These cause the sedimentary units to develop abnormally high porosity with high fluid content and hence easily build up overpressure when lithification commences.

The Akata Formation, consisting exclusively marine shales, is undercompacted and overpressured. It contains a high volume of fluid and is under high overburden stress. It is a major contributor to overpressure generation in the Niger Delta. Little overburden stress exerted on the Akata shale would yield considerable quantity of fluid to the adjacent reservoir rocks. The dominant trapping mechanism in the Niger Delta is the growth fault; the process of trapping is contemporaneous with sedimentation so that sizeable quantity of fluid is trapped alongside the sandstone and clay rocks. The pressure implication of this is that post-depositional processes will build up excess reservoir pressure.

## 4.0 **Study Methodology**

This study reviews the different geological events that support the generation and preservation of formation pressure in excess of normal hydrostatic pressure. It also establishes the theoretical

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[11] Ekweozor, C.M., and Daukoru, E.M. 1994. Northern delta depobelt portion of the Akata-Agbada(!) petroleum system, Niger Delta, Nigeria, in, Magoon, L.B., and Dow, W.G., eds., The Petroleum System—From Source to Trap American Association of Petroleum Geologists Bulletin, v. AAPG Memoir 60, p. 599-614 .

[12] Merki P., 1972. Structural Geology of the Cenozoic Niger delta, *(In) African Geology T.F.J Dessauvagie and A.J. Whiteman Eds) Univ. Of Ibadan Press* p635-648.

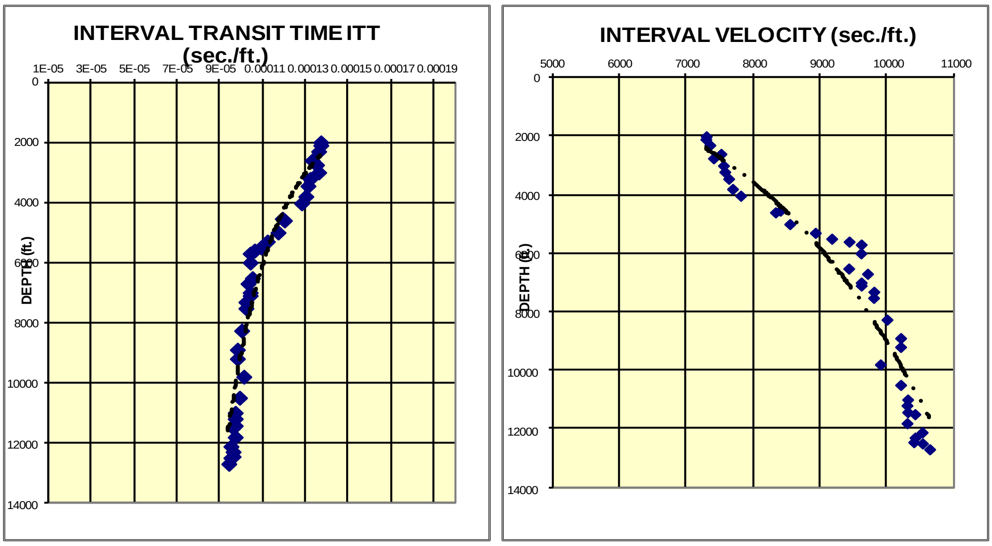
[13] Krusi, H.R.,1994. Overpressure prediction; a contribution to safer drilling: *NAPE Bull.*, vol.9, pp.86-91.

justification for detecting and quantifying the magnitude of formation pressure from formation pressure-dependent seismic attributes such as porosity, velocity and interval transit times (ITT). 3D seismic data (in segy format) and wireline logs (resistivity, sonic and density logs in las format) from a fully developed normally pressured hydrocarbon field, and another field with confirmed history of abnormally high formation pressure, were obtained from an oil and gas prospecting and producing company operating in the Niger Delta. The data from the normally pressured field were used as a control and employed to establish the normal formation trend in the basin, while data from the overpressured field were used to confirm the established theoretical models which relate some measurable seismic attributes with formation pressure.

Formation density log data from both the normally and overpressured fields were employed to generate surface porosity trend in the field. The established porosity trend was subsequently used to determine the compaction trend constant (K) which was afterward applied to determine both porosity and compaction at any other depth of interest. The established surface porosity gradient was then used to generate a mathematical model which relates interval transit time or interval velocity with porosity. The deviation of the interval velocity/interval transit times at the zone of overpressure was used to pick the overpressure top and the measure of deviation was calibrated on the Pennebaker[14] standard formation pressure curve to obtain abnormal pressure gradient that was finally used to determine the magnitude of the abnormal formation pressure.

## 5.0 **Results and Discussion**

The extracted Interval Transit Time (ITT) and interval velocity values from seismic record of a normally pressured field in Niger Delta show a normal trend of decrease and increase with depth respectively, in accordance with Faust[3] velocity-depth relation (Figs. 2a & 2b). Similar plot of ITT and interval velocity values against depth (Figures 3a & 3b) from the overpressured field's seismic record display a normal trend of decrease and increase in ITT and interval velocity values with depth, respectively, to a depth of about 2621.3 m. However, this normal trend becomes obstructed by a reversal at the region of overpressure.

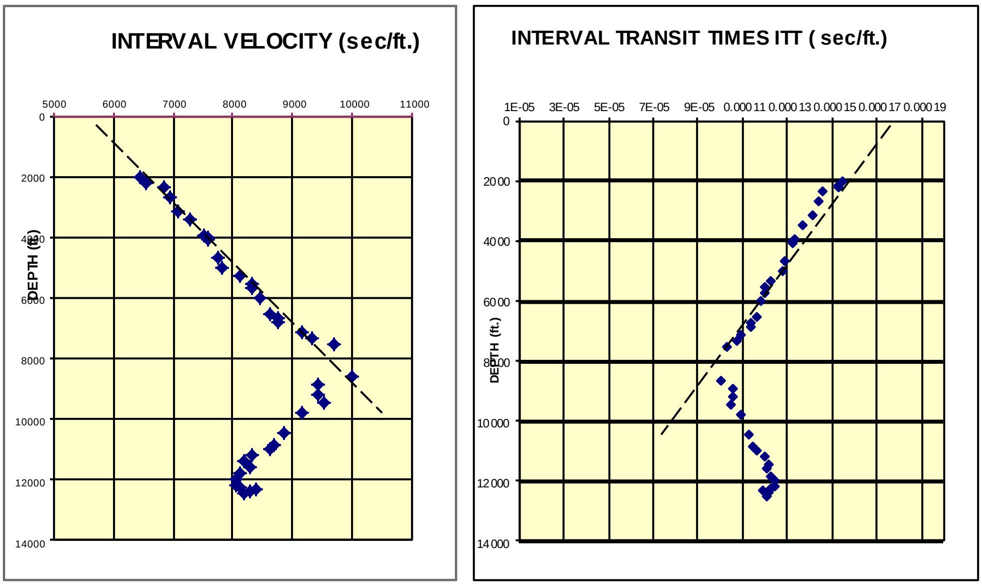



(a) (b)

[14] Pennebaker, E.S., 1968. Seismic data indicate depth, magnitude of abnormal pressures: *World Oil Journal*, pp.73-77.

Fig. 2 Plot of seismic derived ITT and interval velocity against depth for a normally pressured field, southern Niger Delta

Figure 3a indicates a deviation to the right from normal while similar pattern but in the opposite sense is displayed in figure 3b.




(a) (b)

**Fig. 3** Plot of seismic derived ITT and interval velocity against depth of overpressured field, western Niger Delta

### 5.1 **Estimation of Abnormal Formation Pressure**

Abnormal formation pressure was estimated by first establishing the normal porosity trend in the upper part of the field. The equation of straight line obtained from the average surface porosity plot against depth (Fig. 4) was used. The surface porosity values were derived from density log using porosity density relation (equation 1), which relates bulk density measured from well logs to average surface porosity. Any well situated in any part of the basin could be used. The idea is to establish a relation which represents the surface porosity trend within the basin.

$$\phi = \frac{(\rho_b - \rho_m)}{(\rho_f - \rho_m)} \qquad (1)$$

where $\phi$ is porosity and $\rho_m$, $\rho_f$ and $\rho_b$ are matrix, fluid and bulk densities respectively.

Equation of the generated curve gave surface porosity trend ($\phi_O$) in the field, D is depth of interest.

$$D = -39711\phi_O + 15401 \qquad (2)$$

$$\phi_O = \frac{D - 15401}{-39711}$$

The compaction trend constant K, for the upper part of the field was also computed from the mathematical relation in equation 3.

$$\phi = \phi_O e^{-KD} \qquad (3)$$

$$K = \frac{\ln(\phi_O/\phi)}{D}$$

The compaction trend constant (K) at depth of 2928 m (9200 ft.) $K_{9200} = 0.000084$, for example. Therefore, the average surface porosity trend of the overpressured field can be represented with the equation 4.

$$\phi_O = 0.3375e^{-0.000084D} \qquad (4)$$

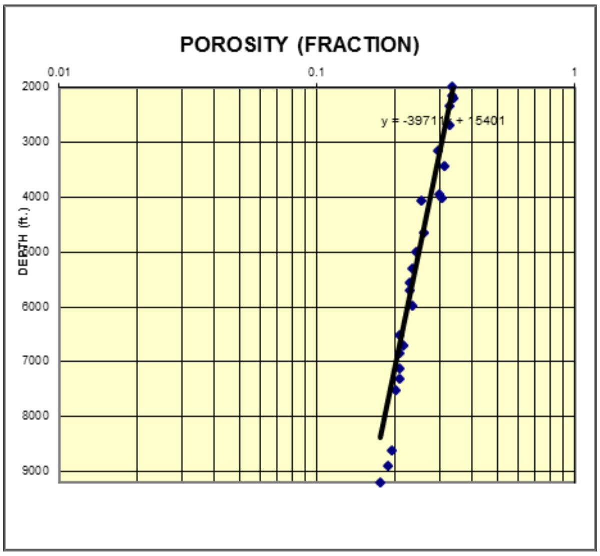



**Fig. 4** Plot of average porosity trend in the upper part of the field, Western Niger Delta

This equation gives the average porosity values at different depths in the field. The apparent matrix transit times trend derived from the surface porosity trend and compaction trend (K) in the field were estimated based on the assumption that brine is the formation fluid within the normally pressured zone above the overpressured zone and has an assumed fluid transit time of $t_f = 0.000209$ secs.[2].

From equation 3

$$e^{-KD} = \frac{t - t_{ma}}{\phi_O(t_f - t_{ma})} \qquad (5)$$

$$t_{ma} = \frac{(t - t_f\phi_O e^{-KD})}{(1 - \phi_O e^{-KD})}$$

Since K = 0.000084 (at 2928 m (9200 ft.).

$$t_{ma} = \frac{(t_n - 0.000209 \times 0.3375e^{-0.000084D})}{(1 - 0.3375e^{-0.000084D})} \qquad (6)$$

$t_n$ is the seismic derived interval transit time for the depth D of interest.

From the mathematical relation presented in equation 5, the apparent matrix transit times at different depths were determined; the obtained apparent matrix transit times plotted against corresponding determined porosities is presented in Figure 5. The plot generated a straight-line graph for the upper part of the field and the equation of the straight-line graph is presented in equation 7.

$$t_{ma} = (20 = 400\phi) \times 10^{-6} \qquad (7)$$

From the Faust[3] time average equation

$t_n = t_{ma}(1 - \phi) + t_f\phi$

if $\qquad t_{ma} = 20 + 400\phi$ and $t_f = 209$

$\qquad t_n = 20 + 589\phi - 400\phi^2$

Since $\qquad \phi = \phi_O e^{-KD}$ and $K = 0.000084$

$$t_n = 20 + 589\phi_0 e^{-0.000084} - 400\phi_O^2 e^{-0.000168D} \qquad (8)$$

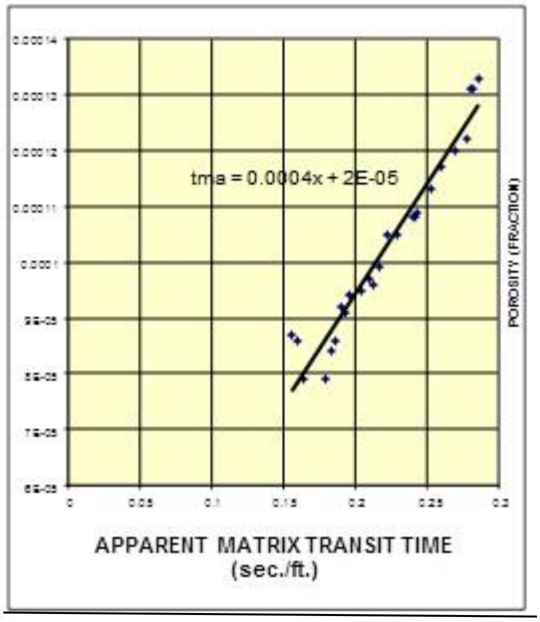



**Fig. 5** Plot of apparent matrix transit time against average porosity value for the upper part of the overpressured field, Western Niger Delta

Equation 7 gives the true formation porosity values from the interval matrix transit time. The porosity value computed from equation 7 is the true formation porosity at the depth of interest, using seismic derived ITT. Formation pressure was determined at a depth of 10000 feet (3048 m), at the overpressured zone where there is visible deviation of the ITT plot from the normal trend.

Equation 7 is a quadratic equation and was solved for $\phi$ by applying quadratic formula.

Since $\qquad \phi = \phi_o e^{-0.000085D}$

$$\frac{t_n}{e^{-0.000084D}} = \frac{20}{e^{-0.000084D}} + \underline{589\phi} - \underline{400\phi^2} \qquad (9)$$

From the graph $t_n = 133.64\times 10^{-6}$ at 3,048 m (10,000 ft).

**$\phi$ = 0.2287**.

Abnormal Formation Pressure (AFP) at depth of 10,000 feet.

$$AFP = g\int[\rho_g(1-\phi) + \rho_f\phi]dD \qquad (10)$$

$$= \rho_g g D - \frac{(\rho_g - \rho_f)g\phi_0}{K}(1-e^{-KD}) \qquad (11)$$

Grain density value of $\rho_g$ = 2.6 g/cm$^3$ was assumed for sand/shale formation and fluid density $\rho_f$ = 1.074 g/cm$^3$ for hydrocarbon formation fluid as well, (g is acceleration due to gravity)

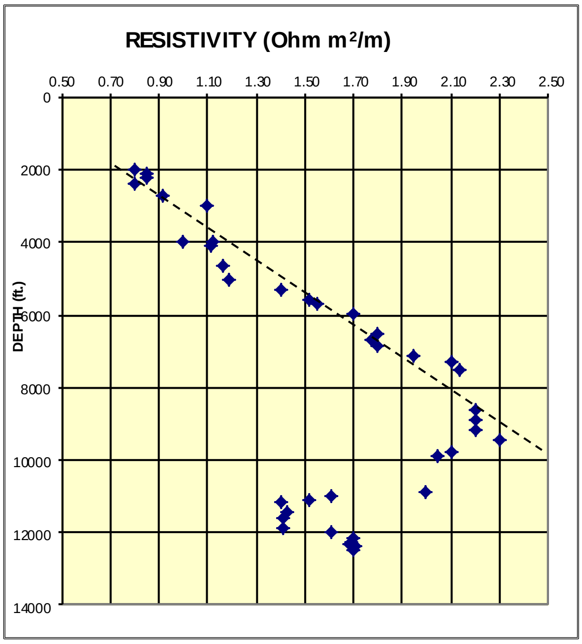
$$AFP = 0.052(8.33)(2.6)(10000) - \frac{0.052(8.33)(1.526)(0.2287)}{0.000084} \times (1 - e^{-0.000084(10000)})$$

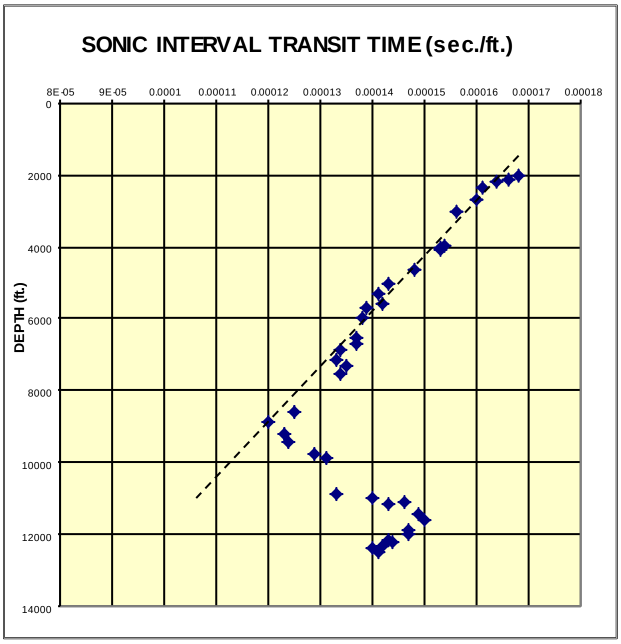
**AFP ≈ 10,000psi. (68,948 kpa)**

**5.2 Verification of Predicted Formation Pressure from Well Data**

Obtained pressure information was verified using directly measured pressure-dependent well log data. This is possible because the field has been fully developed, having many exploratory and development wells with required logs. The verification method involved the use of pressure dependent parameters such as sonic interval transit times, resistivity and bulk density. This verifies the prediction as well as the value of the abnormal formation pressure from the seismic data.

Fig. 6 (a & b) present the plots of porosity dependent parameters measured as resistivity and sonic interval travel time against depth from well logs from the overpressured field. The plots show similar trend as obtained from the predrilled seismic data. Formation pressure value computed from log data gave Abnormal Formation Pressure value of 64,810 kpa (9400 psi) at a depth of 3048 m (10000 ft.) (**$AFP_{(10000)}$ = 9400 psi.).** The derived formation pressure value is very close to that estimated from predrill seismic data, a difference of 200 psi (1379 kpa) could be attributed to error or some assumptions made during the calculations.




(a) (b)

**Fig 6** Sonic interval transit time against depth for overpressured field, Western Niger Delta

**5.3 Role of Overpressure Prediction on Drilling Safety**

A normally weighted drilling fluid will only exert pressure equal to the hydrostatic pressure; therefore, an overpressured formation will force formation fluid into the well annulus during drilling. This process is known as formation kick and if not controlled could displace the drilling fluid in the well and result in a blowout. The best approach to control a formation kick is a proper mud conditioning system and this requires accurate information of the depth to the top of overpressure as well as the magnitude of the formation pressure at the overpressured zone. Adding weighting materials such as calcite powder, hematite or galena usually increases the weight of the drilling mud and enables the mud to generate pressure higher than the hydrostatic pressure[15]. When abnormal formation pressure is encountered, the density of the drilling fluid must be increased to maintain the well-bore pressure above the formation pressure, however, excessively high drilling fluid pressure, higher than the formation fracture pressure could result in formation fracture[15].

The pressure range between pore pressure and the fracture pressure is called the Mud Weight Window (MWW). In theory, both the static and dynamic density of the drilling mud must always remain within this window. Under normal pressure conditions, MWW is fairly wide, making it possible for mud engineers to adjust drilling mud density to avoid formation kick as well as ensure the mechanical stability of the well while also avoiding mud loss. In the case of high formation pressure, the MWW is much narrower, thus making drilling particularly difficult and highly technical.

Formation fracture pressure is the maximum resistant force posed by a formation against an external force, which tends to keep the formation rock elements apart. It is the external force required to cause a formation fracture. Considering the subsurface stress state in relatively young sediments, there are three stress states that are operational in the subsurface; the vertical stress $\sigma_z$, which is due to overburden load. It increases with loading at grain – to-grain contact[2, 13]. There are two horizontal stresses $\sigma_x$ and $\sigma_y$ as shown in the Fig 7.

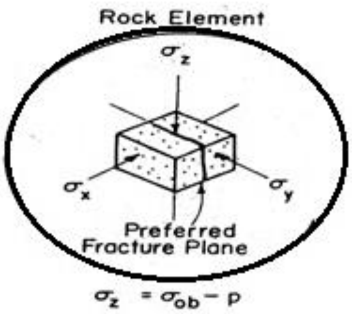



**Fig. 7** Underground stress distribution in relatively young sediments ([2])

The horizontal stresses are the force fields; they prevent the rock elements from expanding upon loading. The rock-resistant forces are generated by the surrounding rocks, which prevent expansion. For compressed rock, the horizontal strain $\varepsilon_x$ is essentially zero as the surrounding rocks will prevent any expansion of the rock element as a result of loading, and horizontal stresses $\sigma_x$ and $\sigma_y$ are approximately equal.

$$\sigma_x = \sigma_y = \sigma_H = \frac{\mu}{(1-\mu)} \sigma_Z \qquad (12)$$

($\mu$ is the Poisson's ratio and $\sigma_Z$ is the vertical stress component)

[15] Hubbert, M.K., and Willis, D.G., 1957. Mechanics of hydraulic fracturing: *Trans. AIME*, vol.210, pp.153-160.

The fracture pressure is therefore the force per unit area required to overcome the horizontal stress $\sigma_H$ so as to cause horizontal strain $\varepsilon_H$. From the relation above, it is obvious that formation fracture pressure is dependent on two factors in a compressed rock and they are Poisson's ratio and vertical overburden stress. Poisson ratio increases with consolidation; so also is the overburden stress which increases with depth. Fracture pressure is slightly higher than formation pressure. Thus where formation pressure is very high, the formation fracture pressure will also be high.

Hydraulic fracturing occurs when a drilling fluid is introduced into a small cavity located in the centre of a rock element as shown in Figure 8. For fluid to enter the rock cavity, the pressure of the drilling fluid must exceed the pressure of the formation fluid in the pore spaces of the rock.[2]

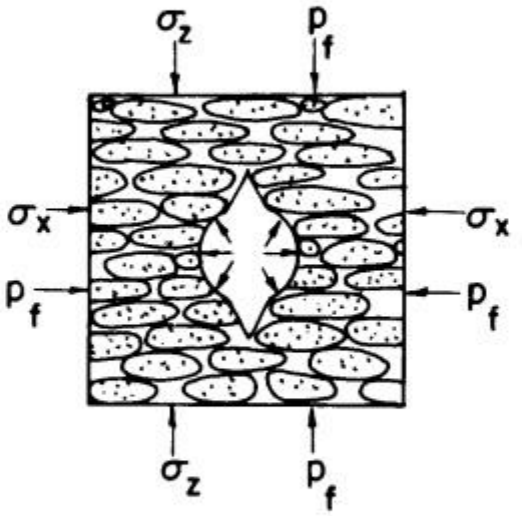



**Fig. 8** Underground stress distribution showing fluid cavity which can initiate hydraulic fracturing (Pressure > Pore Pressure) ([2])

### 5.4 Fracture Pressure Gradient

Determination of formation fracture pressure is essential before embarking on well construction activities because increase in drilling mud density meant to counter a formation kick can result in hydraulic fracturing. Formation fracture is very dangerous and can result in underground blowout which is more difficult to control than a well blowout, especially because underground blowout cannot be stopped by a Blowout Preventer (BOP). This has led to many hydrocarbon fields being abandoned due to uncontrollable gas combustion.[16]

There are several methods of determining formation fracture gradient, but the Hubbert and Willis[13] method was adopted in this study. Detailed information on formation fracture pressure is available in Chenevert[16] and Bradley[17]. Hubbert and Willis[13] related formation fracture, minimum principal stress and formation fracture as.

[16] Chenevert, M.E., 1978. How to run casing and open-hole pressure test: Oil and Gas J. pp.123-134.

[17] Bradley, W.B., 1979, Mathematical concept-stress cloud can predict borehole failure: *Oil and Gas J.* pp.92-100.

Formation fracture pressure $P_{ff}$ = Minimum Principal Stress ($\sigma_{min}$) + Formation Fracture ($P_f$)

$$P_{ff} = \sigma_{min} + P_f \tag{14}$$

where $\sigma_{min}$ is the Horizontal stress ($\sigma_H$)

But horizontal stress in the exposed part of the formation is approximately one-third of the vertical matrix stress resulting from the weight of overburden ($\sigma_{ob}$).

$$\sigma_z = \sigma_{ob} - P_f = (AFP - NFP)$$

(NFP Normal Formation Pressure)

Therefore the fracture pressure in the exposed part of the formation just below the last casing seat can be expressed as,

$$P_{ff} = \frac{(AFP - NFP)}{3} + AFP \tag{15}$$

Thus formation fracture gradient = $P_{ff}$ / Depth. (16)

**5.5 Overpressures Prediction's Role on Well Design**

The success of any well construction activities, whether exploratory or production is highly dependent on proper planning and design before spudding, in order to prevent some well construction disasters. Before embarking on drilling, it is appropriate to determine the formation pressure at different stages, determine the presence of any overpressured horizon so that adequate preparation could be put in place before drilling such horizon. Correct information on the formation pressure aids the determination of the appropriate mud density required to drill the formation at different pressure regimes as well as the pump capacity that can handle the mud densities required for these pressure regimes. The mud weight should be able to keep the formation fluid in place thereby preventing a kick.

In the overpressured region, the formation pressure is higher than normal; hence high density drilling fluid is required to prevent a kick. Excessively weighty or dense drilling fluid can cause hydraulic fracturing capable of causing internal blowout as earlier mentioned. Formation pressure and formation fracture pressure information can be used to determine mud weight window (MWW).

**5.6 Well Design Parameters for the Overpressured Field, Western Niger Delta**

There are two pressure regimes in the field, the upper, which is normally pressured and the lower, which is overpressured.

$NFP = \int \rho g \, dD$

At 3000 feet (for illustration) can be determined,

$$NFP_{(3000)} = (0.052)(8.33)(1.074)(3000)$$

$$= 1395.6 \text{ psi. } (9622 \text{ kpa})$$

**Normal Pressure Gradient (NPG)** = 1395.6 / 3000

NPG = 0.4652 psi/ft. (10.5 kpa/m)

Minimum mud density required to drill the upper part of the field without a formation/well kick is determined,

$$P_{bh} = 0.052\rho D + Pdp$$

$P_{bh}$ is the borehole/formation fluid pressure, estimated to be of magnitude 1395.6 psi at 3000 ft. This is the required drilling fluid pressure that will keep the formation fluid in the reservoir and prevent formation kick.

$P_{dp}$ is the initial pressure at the surface and it is equal to atmospheric pressure at the surface (14.7 psia).

Desired mud density $(0.052\rho(3000)) + 14.7 = 8.85$ lbm/gal.

The value of the mud density determined is the minimum static weight needed just to prevent well kick. However, circulation reduces the mud density, as dynamic mud density is lower than the static mud density.[2]. In addition, there is reduction in mud density due to the presence of drill cuttings. Frictional loss may also result from interaction of the drilling fluid with the mud pump, drilling strings, drill collars and bit nozzles. A complex mathematical expression exists to account for all these factors which reduce the density of a circulating fluid, but in most cases will account for less than 15 per cent reduction.[2] Field procedure usually employed to take care of the possible reduction is to envisage a loss of 15 percent and compensate accordingly when mixing the mud in the chemical tank.

Therefore the static mud density that will yield the needed dynamic drilling fluid density is 10.18 lbm/gal.

Fracture Pressure in the upper part of the field

$$\sigma_H = \sigma_Z / 3$$

$$P_{ff} = \sigma_z / 3 + P_f$$

$$\sigma_z = \sigma_{ob} - P_f$$

$$P_{ff} = \frac{(\sigma_{ob} - P_f)}{3} + P_f$$

$$\sigma_{ob} = 0.052(2.6)(8.33)(3000) - \frac{0.052(0.9)(8.33)(0.259)}{0.000084} \times (1 - e^{-0.000084(3000)})$$

$$= 3378.6 - 1202 \times 0.2227$$

$$\sigma_{ob} = 3110.9 \text{ psi.}, \quad P_f = 1395.6 \text{ psi. (9622 kpa)}$$

$$P_{ff} = 1967.4 \text{ psi at 3000ft.}$$

$$P_{ff} = 0.66 \text{psi/ft. (14.9 kpa/m)}$$

The formation pressure calculated above is the borehole pressure that will initiate hydraulic fracturing. The mud density that can initiate hydraulic fracturing is therefore

$$\rho = \frac{1967.4 - 14.7}{0.052(3000)}$$

$$= 12.52 \text{ lbm/gal.}$$

Although similar reduction should be accounted for in static mud density in order to compensate for the envisaged reduction, it is safer to use the value since the upper mud density boundary is not desired and the static value of 12.5 lbm/gal would give lesser dynamic density that will not initiate hydraulic fracturing.

**Mud Weight Window (MWW)** = 10.2 - 12.5 lbm/gal.
The minimum mud weight needed to drill the upper part of the field successfully is 10.2 lbm/gal, while the mud density that will initiate hydraulic fracturing is 12.5 lbm/gal.

**5.7 Well Construction Parameters in the Overpressured Part of the Field**
The determined abnormal formation pressure is approximately 10,000 psi. (68,948 kpa)
Minimum mud density required to drill the overpressured part of the field without occurrence of a formation kick is determined as,

$$P_{bh} = 0.052\rho D + P_{dp}$$

$$10000 = (0.052 \times \rho \times 10000) + 14.7$$

Mud density $\rho = 9985.3/520$

Static mud density required to generate dynamic mud density of 19.2 lbm/gal. while taking care of about 15 % density reduction is
Static mud density in the mixing tank = 0.15(19.2) + 19.2

= 22.1lbm/gal.

The fracture pressure in the overpressured horizon is also as determined below

$$P_{ff} = \frac{(\sigma_{ob} - NFP)}{3} + AFP$$

NFP at 10000 feet = Normal Pressure Gradient × Depth

$$NFP_{(10000)} = 0.465 \times 10000$$

$$= 4650 \text{ psi. } (32,061 \text{ kpa})$$

$$P_{ff} = \frac{(10000 \times 4650)}{3} + 10000$$

$$P_{ff} = 11783.3 \text{ psi. } (81,241 \text{ kpa})$$

Formation Fracture Pressure gradient is 1.2 psi/ft. (27 kpa/m)

The fracture pressure calculated above is the borehole pressure that will initiate hydraulic fracturing. The mud density that will generate the borehole pressure which will cause hydraulic fracturing, is

$$= \frac{11783.3 - 14.7}{0.052(10000)}$$

= 22.63lbm/gal.

The MWW in the overpressured horizon (22.1 – 22.63lbm/gal) is very narrow as evident from the obtained mud density boundaries, making the excessive shift from the upper limit for safety is very difficult. It therefore behoves the driller to carefully choose the mud window boundaries, to prevent formation kick and not initiate hydraulic fracturing.

The mud window is necessary to choose the type of drilling mud and weighting material that can achieve the desired mud densities. It is also required to select the pump type, capacity, as well as pumping rate at different formation pressure regimes.

**Casing Depths:** in order to prevent hydraulic fracturing of the normally pressured formations at the upper parts of the field, it is essential that casing pipes be installed and cemented before drilling the overpressured zone which is situated in the study area is at 8670 ft. Casing pipes must be installed and cemented to above 8670 ft. before drilling the overpressured horizon. Likewise the overpressured field must be cased and cemented as well, if drilling is to continue beyond the overpressured horizon. The idea behind this is to prevent hydraulic fracturing in the lower normally pressured sections of the well.

## 6.0 Conclusions

Overpressured formation fluid constitutes a dangerous drilling hazard that can result in blowouts and associated loss of lives, money, equipment, drilling time and oil spill, if the zone is not drilled with necessary caution. The conventional methods of estimating formation pressure, though effective, has limited application for drilling in an unfamiliar hydrocarbon field (wildcat drilling). Since the prediction of formation pressure from predrilled (seismic) data measures undisturbed formation pressure, it is devoid of likely errors associated with other post drilled formation pressure estimation methods. Estimated formation pressure from seismic data presents relevant information necessary for adequate well planning before drilling. Blowouts have been identified as one of the major oil production risks in the Niger Delta and these results mostly from improper management of overpressured formation during drilling. It has seriously increased cost of production in the Niger Delta, 60% of which is carried by the Federal government of Nigeria based on the Joint Venture operating agreements with some the oil multinationals. Apart from the production cost, the accompanying oil spill has continuously posed great threat to aquatic lives. Oil pollution has seriously reduced the maximum use to which the aquatic environment can be put, such as tourist attraction centres and source of aquatic food for the inhabitants. This in turn has produced a restive people who wish to survive despite all odds.

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