Understanding Subsurface Reservoir Pressure through Accurate Geo-Mechanical Characterization

*Dorcas S. Eyinla, Nancy O. Anene and Boris B. Bate
Petroleum Geosciences Unit, Department of Geology, Pan African University Life and Earth Science Institute, University of Ibadan, Ibadan, Oyo State, Nigeria
*Email address: eyinladorcas@yahoo.com

Abstract
So far, Bulk modulus, Shear modulus, combined modulus of strength and shear modulus to compressibility ratio have been actively employed as geo-mechanical parameters that have been used in characterizing subsurface reservoir in Niger delta wells in Nigeria. These can be further utilized to enhance understanding of the pressure in the formation with depth. To successfully maximize hydrocarbon recovery, to minimize sanding rate, and to ensure safety of personnel during and after drilling, pore pressure gradient and its associated fracture pressure has been predicted for each of the abnormally pressured intervals discovered in one of the Niger Delta oil fields by applying Eaton's method. This is aimed at identifying fragile sections. However, empirical relations have been established using geo-mechanical principles.
From the two wells studied, geo-mechanical strength increases with depth and tends toward the acceptable range for a competent formation. In the second well, the fracture pressure increases with increasing pore pressure and decreasing Bulk modulus at various depths, while abnormal formation pressure occurred throughout the formation especially at greater depths.
The relationship established between geo-mechanical factors and fracture pressure is such that as one decreases, the other increases vice versa.
Keywords: Formation strength; fracture; mud weight; pore pressure; sand production and sand control

1 Introduction

Analysis of wellbore instability involves correct evaluation of rock mechanical properties and knowledge of in-situ stresses. Determination of minimum mud weight by rock failure analysis is a vital step to control the wellbore instability. Since wellbore instability is the adverse condition of an open hole that does not maintain its gauge size and shape, maintaining a stable wellbore is therefore an important job for the oil and gas industry (Chen et al., 2003). Study of wellbore stability and geo-mechanical strength help to develop a robust plan before drilling and also assist to identify challenging regions and to improve drilling operation. The essential part of wellbore stability is knowledge of the rock failure criteria (Manshad et al., 2014) which are determined by the in-situ stresses (Das and Chatterjee, 2017). Drilling a borehole disturbs the equilibrium of in-situ stresses, which results in increasing stress around the wall of the hole. However, in order to maintain the stress that will be released while drilling and to prevent hydrocarbon invasion into the cavity, the borehole is filled with fluid, mostly mud, with pressure above the formation pressure. This will result in building new stress pattern around the borehole wall (Das and Chatterjee, 2017). It is therefore imperative to choose proper mud pressure. Work of Das and Chatterjee (2017) presented the prediction of the mud weight. If the mud weight is greater than the predicted value, the mud will enter into the formation, resulting in tensile failure. Nonetheless, a lower mud weight can produce shear failure of the rock, which is identified as borehole breakout (Das and Chatterjee, 2017).

In ensuring cost-effective and safe drilling operations, not only the determination of minimum mud weight is required, it is also essential that a proper pore pressure prediction and fracture gradient estimation be carried out. Reports of several other authors are valuable in understanding the pore pressure regime. Babu and Sircar (2011), Basu et al. (1994) and Law and Spencer (1998) reported how pore pressure and fracture gradient prediction is helpful in choosing appropriate mud weight so that losses and hole collapses can be prevented. The accurate knowledge of this can therefore assist in correct designing of casing scheme to ensure maximum productivity. Dutta (2002) has successfully employed the use of seismic data in geopressure prediction while Huffman (2002) iterated the advances in pore pressure prediction technology and their limitations. Bera (2010) applied the Miller's sonic equation in determining pore pressure from deep water wells of the North Sea. From this study, there is a conclusion that the pore pressure and overburden gradient decrease from shallower to deeper depths.

The Niger Delta Basin is the focus of this study, where geomechanical parameters are calculated from well logs. The abnormal pressure recorded in the Tertiary Niger Delta is as a result of swift loading of the shales of the Akata Formation by the overlying sandy Agbada Formation and Benin Formation. This overloading results into a highly pressured underlying formation where fluids may be expelled, inflating the pressures of the adjacent sands. Hence, drilling through these sections at a considerable depth may be hazardous. It is therefore indispensable to have adequate knowledge of the reservoir pressure, since Pore Pressure and Fracture pressure Gradient considerations impact the technical merits as well as the financial aspect of the well plan. However, a technique for estimating the pore pressure and associated fracture gradient will be helpful in ensuring the entire well planning and drilling safety.

This study is aimed at determining the subsurface pressure and identifying weak zones in an oil filed in the Niger delta Basin, by analyzing the formation mechanical properties and strength, since this is important for accurate sand prediction analysis. Elastic strength is also correlated with fracture pressure to reveal the relationship the former makes with the latter.

Concept of Abnormal Pressure

The different kinds of reservoir pressure which are usually encountered during the course of drilling are broadly divided into three main components: Hydrostatic pressure, Overburden pressure and Formation pressure (Fig. 1) (Ismail, 2010). Overburden Pressure is the pressure exerted by the load upon underlying formations. It is the vertical pressure at any point in the earth.

The different formation pressure encountered in an area play a vital role both during exploration and exploitation of hydrocarbon resources reservoir. However, because the total overburden pressure is supported by both pore pressure and rock grain pressure, the pore pressure of a formation refers to that portion of the overburden pressure which is not supported by the rock matrix, but rather by the fluids or gases which exist in the pore spaces of the formation. Consistent piling up and of sediment steadily occurs during a period of erosion and sedimentation, and as the thickness of the layer of sediments increases, the grains of the sediment are packed closer and tighter, ejecting some water from the available pore spaces. Often times, normal pressure is observed when the pore throats through the sediment are interconnected up to the surface, which implies that the pressure of the fluid at any depth in the sediment will be the same as that which would be found in a simple column of fluid. Normal pore pressure is equal to the hydrostatic pressure of a water column from that depth to the surface. This pressure is dependent on the density of the fluid occupying the pore spaces and also on the depth at which the pressure is being measured. However if the pore pressure lies below normal hydrostatic

pressure or expected pore pressure, the formation is said to be subnormally pressured, but if exceeds the expected hydrostatic pressure at a depth, the zone is said to be abnormally pressured.
Thus, regardless of the factors responsible for sediments compaction, the mechanisms which produce abnormal pore pressures are quite complex and vary regionally.

The most common mechanism of overpressure generation in sedimentary basins is disequilibrium compaction (Swarbrick and Osborne, 1998). Most sediments compact during burial due to increase in the mean effective stress (Goulty, 1998). Faulting redistribute sediments, and place permeable zones opposite impermeable zones, thus creating barriers to fluid movement. This may prevent water being expelled from a shale, which will cause high porosity and pressure within that shale under compaction. Massive rock salt deposition can also be a cause of pore pressure because abnormal pressures are frequently found in zones directly below a salt layer. Phase changes during compaction, repressuring from deeper levels and generation of hydrocarbons can also be classified as sensitive causes of pore pressure.

Need for Pore Pressure and Fracture Gradient Estimation

Drilling under inaccurate mud pressure would entirely increase the possibility of either fracturing of the formation or creating blow outs. Pressure prediction is therefore important in deciding the mud weight, and also to determine the number of casing strings and casing seat selection that would be needed because this preparation would influence the well integrity and budget. However, to maintain hole stability and as well prevent the inward flow of formation fluids into the wellbore, it is of high importance to maintain a borehole pressure which is slighly above the formation pressure. Therefore, a suitable technique for predicting pore pressure and associated fracture gradient would be of huge importance to maintain a balanced drilling and production, so that adequate mud weight can be used, drilling safety can be eunsured, proper rig can be selected and the use of excess mud weights leading to fracture or losses of lives can be circumvented. This would also help to avoid incidence of collpase hole, while correct designing of casing scheme can be employed to ensure optimum completion and maximum productivity.

Pore Pressure Gradient (PPG) analysis can be useful in understanding geological influences on hydrocarbon accumulation (Pritam, 2010). Also, it is better to drill the flank of a structure rather than its highest point where higher pressure within the gas cap present more difficult drilling problems. Further, hydrocarbon accumulation favours slightly lowered pore pressure within zones of elevated pressures. Identification of these zones, aids in the overall exploration of petroleum reserves.
Pore pressure prediction is not only to plan a well but also can be a key to understand the pore pressure profile in the region. In this study, overpressure was evaluated in shale and sand sequences from the sonic log by detecting under-compaction (abnormally high porosity) with reference to a normal compaction trend.

Another application of elastic constants is the determination of fracture pressure gradients. Formation fracture gradient is a measure of how the strength of the rock (i.e. its resistance to break down) varies with depth. In planning the mud programme, it is useful to know the maximum mud weight which can be used at any particular depth. Fracture gradient calculations are essential in minimizing or avoiding lost circulation problems and in selecting proper casing seat depths. Thus, knowledge of the pressure at which formation fracture will occur at all depths in the well is required for planning and drilling a well into abnormally pressured formations.

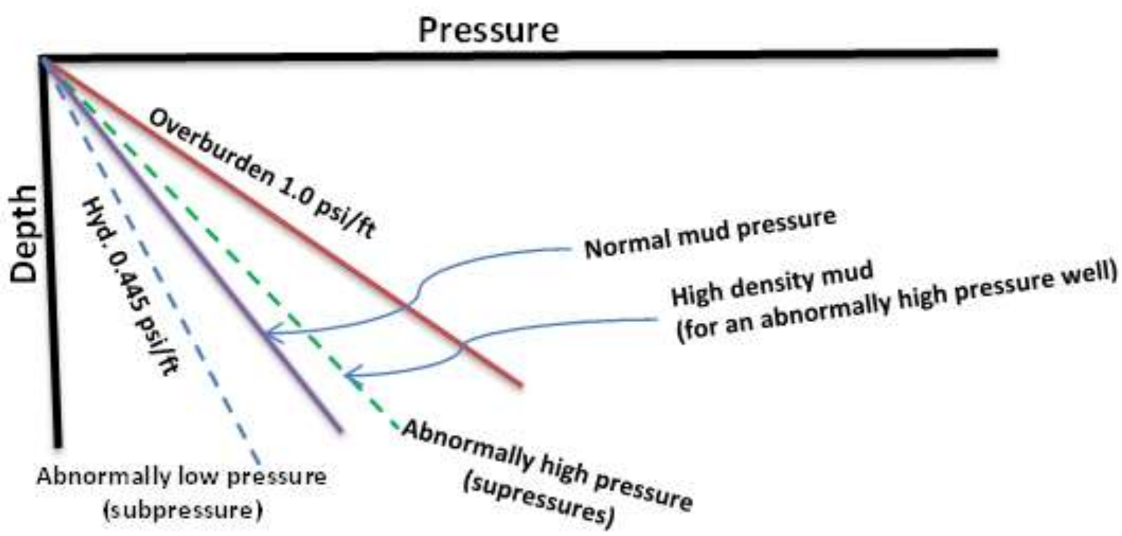

Fig. 1: Components of Pressure and their Relation (Modified after Ismail, 2010)

Methodology

Pore Pressure Gradient and Geo-mechanical Parameters

According to Paul et al. (2009), two types of pressures can be predicted while drilling. These are reservoir pressure and shale pore pressure. The resulting shale pore pressure can be used to predict sand pore pressure. Quantitative pressure analysis using the sonic log can be based on calibrating the observed sonic log value and an expected or normal sonic value with known pressure measurements. For this study, the Eaton (1975) method was used for quantitative pressure estimation. This method is based on the principle that the relationship between the ratio of the normal sonic log value and the observed sonic log value, and the pore pressure depends on changes in the overburden gradient (Eaton, 1975; Mouchet and Mitchell, 1989). The effective stress model of transforming the petrophysical measurement, for instance, sonic slowness, to pore pressure in the fine clastic beds is based on Eaton (1975) findings as shown in equation 1.

$$PPG = OBG - (OBG - P_n) * \left({\Delta T_n}/{\Delta T_o}\right)^3 \quad (1)$$

Where:
PPG = Predicted pore pressure (psi/ft) at depth Z,
OBG = Overburden Gradient (psi/ft) at depth Z,
P_n = the normal pressure at depth Z,
ΔT_n = the assumed normal sonic slowness (µsec/ft) at depth Z (calculated from the NCT),
ΔT_o = the observed (measured) sonic slowness (µsec/ft) at depth Z.

First, sonic log data from two wells (Well SAS 01 and Well SAS 02) were plotted and a curve was picked through the plot in order to establish Normal Compaction Trend (NCT) for the acoustic data. These curves were plotted with respect to depth and the normal compaction trend was established as shown in Figures 2 and 3. The deviation from this trend indicate abnormal pressure (Dutta, 2002;

Huffman, 2002). This NCT helps to calculate Pore Pressure (PP) which also aided the ability to recognize overpressured intervals.
The important process in this prediction is to establish the ratio of ΔTn to ΔTo, which is mainly conveyed as a result of establishing the slope on the NCT.
Pore pressures which are lie above or below the “normal” pore pressure gradient line are called abnormal pore pressures. However, according to the findings of Nwozor et al., (2013), Formation pressures of the Niger Delta Basin may be either Subnormal (i.e. less than 0.445 psi/ft) or Overpressured i.e. greater than 0.445 psi/ft.

Geo-mechanical parameters such as Poisson’s Ratio (P), combined modulus of strength (K), Bulk modulus (B), Shear modulus (S), Shear modulus to compressibility ratio (S/c), among others were estimated from empirical equations relating pseudo factor, density and interval transit time of both P-waves and S-waves using procedures by Eyinla and Oladunjoye (2014) while adopting Eqs. 2-6 by Dresser Atlas (1982).

$$B = \rho_b \left(\frac{3\Delta ts^2 - 4\Delta tc^2}{3\Delta ts^2 \times \Delta tc^2} \right) \times 1.34 \times 10^{10} \text{ psi} \quad (2)$$

$$S = \frac{\rho_b}{\Delta ts^2} \times 1.34 \times 10^{10} \text{ psi} \quad (3)$$

$$P = 0.5 \left(\frac{\Delta ts^2 - 2\Delta tc^2}{\Delta ts^2 - \Delta tc^2} \right) \quad (4)$$

$$K = B + \frac{4}{3} S \quad (5)$$

$$S/c = S \times B \quad (6)$$

Where,
ρ_b is the density
B is the Bulk Modulus/incompressibility
P is the Poisson’s ratio
Δts is the Shear interval transit time
Δtc is the compressional interval transit time
S is the Shear Modulus
K is the combined modulus of strength
C is compressibility

The coefficient 1.34×10^{10} is a factor used to convert the parameters in psi units.

Formation Fracture Pressure Gradient

Formation fracture gradient involves the theoretical calculation of variation of rocks’ strength with depth. A number of theoretical and field-developed equations have been used over the years to approximate this property, many of which are applicable only for immediate application in a given area. In Hubbert and Willis (1957) method, the fracture gradient is a function of overburden stress, formation pressure, and a relationship between the horizontal and vertical stresses.

Having realized that the cohesiveness of the rock matrix is usually related to the matrix stress and varies only with the degree of compaction, Matthews and Kelly (1967) proceeded to develop an equation for calculating fracture gradients in sedimentary formations. Eaton (1975) widened the concepts presented by Matthews and Kelly to introduce a new geomechanical property, Poisson's ratio into the expression.

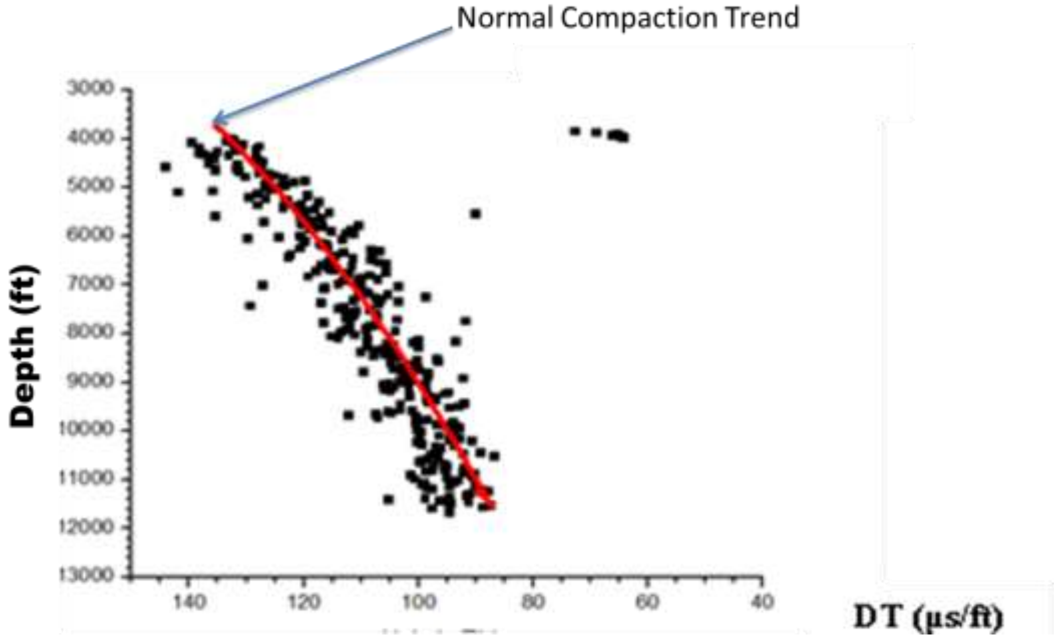

Fig. 2: Fitting Normal Compaction Trend to the sonic data of Well SAS 01

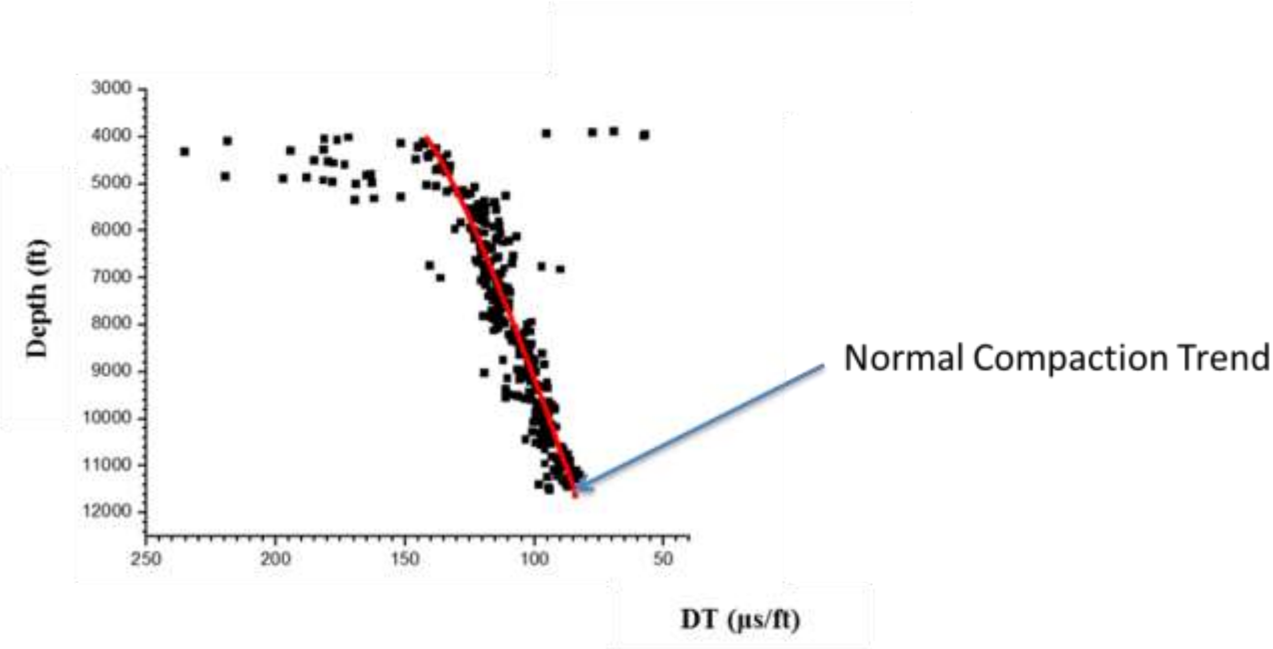

Fig. 3: Fitting Normal Compaction Trend to the sonic data of Well SAS 02

According to Eaton's method, both overburden stress and Poisson's ratio varies with depth. Using actual field fracture data and log-derived values, he prepared graphs illustrating these variables. Using a suitable choice for each variable, the monograph prepared by Eaton can be used to calculate a fracture gradient. The following equation is used in the calculation:

$$\mathbf{FPG} = \mathbf{PPG} + [(\mathbf{OBG} - \mathbf{PPG})\,(\mathbf{P/P-1})] \qquad \textbf{(8)}$$

Where, FPG = Fracture Pressure Gradient (psi/ft),
PPG = Pore Pressure Gradient (psi/ft),
OBG = Overburden Gradient (psi/ft),
P = Poisson's Ratio (dimensionless).

Results and Discussion

The results of geo-mechanical computations and the resulting fracture pressure are presented in Tables 1 and 2 for the two wells respectively. In both wells, geo-mechanical strength increase with depth, though some decreases were noticed at certain intervals. The interval is at depth 7900ft in well SAS 01 and depth 5300ft in well SAS 02 as indicated by black arrow in Figures 4 and 5. However, more stiff materials are at deeper depth because fluid substitution can result in considerable changes in bulk modulus.

For well SAS 01, it is observed that the combined modulus of strength (K) of formation increases with depth although they are found to be less than the threshold value of 3.0 x 10^6 psi (Dresser Atlas, 1982) except at a depth of 11,055 ft. This indicates that fluids will only be produced safely at this depth and beyond. However, above this interval, there would be sanding problem but one which can be controlled because the values fall within the interval of 1.5 X 10^6 and 3.0 x 10^6 psi (Dresser Atlas, 1982)**.**

For well SAS 02, the values of combined modulus of strength (K) indicate that although there could be sand production at a shallower depth, it can be controlled. The values increase with depth and attain a threshold value at depth 10150 ft.

Another approach to the understanding of relative formation strength is the application of the ratio of shear modulus (S) and compressibility (c). A critical value for the S/c where there would be no sanding problem is when the computed value is greater than 0.7 x 10^{12} psi^2 (Dresser Atlas, 1982). Sand control is necessary when S/c is equal to or less than this value. However, for well SAS 01, the range of values is between 0.77 x 10^{12} psi^2 and 2.98 x 10^{12} psi^{12}, indicating that sand control would not be necessary. Whereas, well SAS 02 values show that sand control is necessary at a shallower depth (<7330 ft).

The four geo-mechanical parameters: Bulk Modulus (B), Shear Modulus (S), combined modulus of strength (K) and the shear modulus to compressibility ratio (S/c) increases and decreases concurrently in both wells. Poisson's Ratio decreases with depth.

However, given that the threshold value for Shear Modulus is 0.6 x 10^6 psi, Figure 6 shows that competent zone can be found below depth 6200 ft in Well SAS 01 and at depth 9140 ft in Well SAS 02.

According to Gidley et al., (1989), the modulus of a material is a measure of the stiffness of the material. If the modulus is large, the material is stiff, that is, a higher modulus typically indicates that the material is harder to deform (can withstand compression). For this study, FPG increases as the PPG increases (Figs. 7 and 8). It is obvious that PPG and FPG increase from shallower to deeper depth. In well SAS 02, the fracture pressure increases with increasing pore pressure and decreasing Bulk modulus at various depths (Fig. 8). This explains that stiffer rocks possessing high deformational strength tend to fracture at low Fracture Gradient. These intervals where abnormal formation pressure is encountered, the density of the drilling fluid must be increased to maintain the wellbore pressure above the formation pore pressure to prevent the flow of fluids from permeable formations into the well. However, since the wellbore pressure must be maintained below the pressure that will cause fracture in the shallower, relatively weak, exposed formations just below the casing seat, there is also a maximum drilling fluid density that can be tolerated. This means that the depth into the abnormally pressured zone is the level to which the well can be drilled safely without cementing another casing string in the well.

Table 1: Pore pressure values at various intervals with their elastic properties and corresponding Fracture gradient for Well SAS 01.

Depth (ft)	**V_{sh}**	ρ_b	$\emptyset_{DEN}$	$\emptyset_{AC}$	**P**	**K (psi) ($\times 10^6$)**	**B (psi) ($\times 10^6$)**	**S (psi) ($\times 10^6$)**	**S/c (psi^2) ($\times 10^{12}$)**	**PPG (psi/ft)**	**FPG (psi/ft)**
4038	0.10	2.31	0.20	0.48	0.34	1.78	1.20	0.43	0.77	0.406	0.712
6200	0.11	2.23	0.24	0.38	0.32	2.18	1.41	0.58	1.26	0.487	0.728
7320	0.07	2.28	0.22	0.39	0.33	2.77	1.83	0.71	1.97	0.445	0.718
7900	0.05	2.20	0.28	0.38	0.30	2.23	1.47	0.70	1.61	0.667	0.810
8500	0.06	2.25	0.25	0.30	0.29	2.90	1.76	0.85	2.47	0.619	0.775
11055	0.31	2.11	0.29	0.30	0.27	3.07	1.78	0.97	2.98	0.828	0.892

Table 2: Pore pressure values at various intervals with their elastic properties and corresponding fracture gradient for Well SAS 02.

Depth (ft)	**V_{sh}**	ρ_b	$\emptyset_{DEN}$	$\emptyset_{AC}$	**P**	**K (psi) ($\times 10^6$)**	**B (psi) ($\times 10^6$)**	**S (psi) ($\times 10^6$)**	**S/c (psi^2) ($\times 10^{12}$)**	**PPG (psi/ft)**	**FPG (psi/ft)**
5223	0.19	2.23	0.24	0.68	0.35	1.82	1.26	0.42	0.53	0.419	0.732
5300	0.17	2.15	0.29	0.50	0.32	1.20	0.78	0.32	0.25	0.687	0.834
7330	0.13	2.20	0.27	0.68	0.35	2.31	1.60	0.53	0.85	0.555	0.795
9140	0.75	2.16	0.20	0.38	0.33	2.39	1.58	0.61	0.96	0.744	0.870
10150	0.32	2.30	0.17	0.21	0.30	3.41	2.12	0.97	2.06	0.727	0.844
11100	0.70	2.12	0.23	0.25	0.28	3.42	2.02	1.06	2.14	0.816	0.888

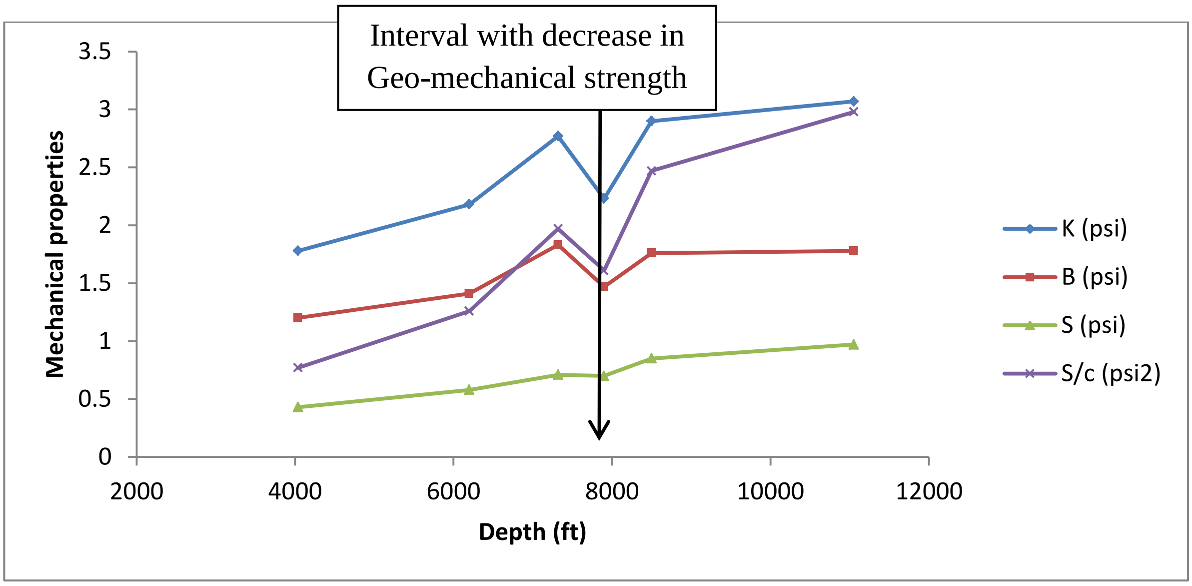

Fig. 4: Increasing sequence of Geo-mechanical strength with depth for well SAS 01

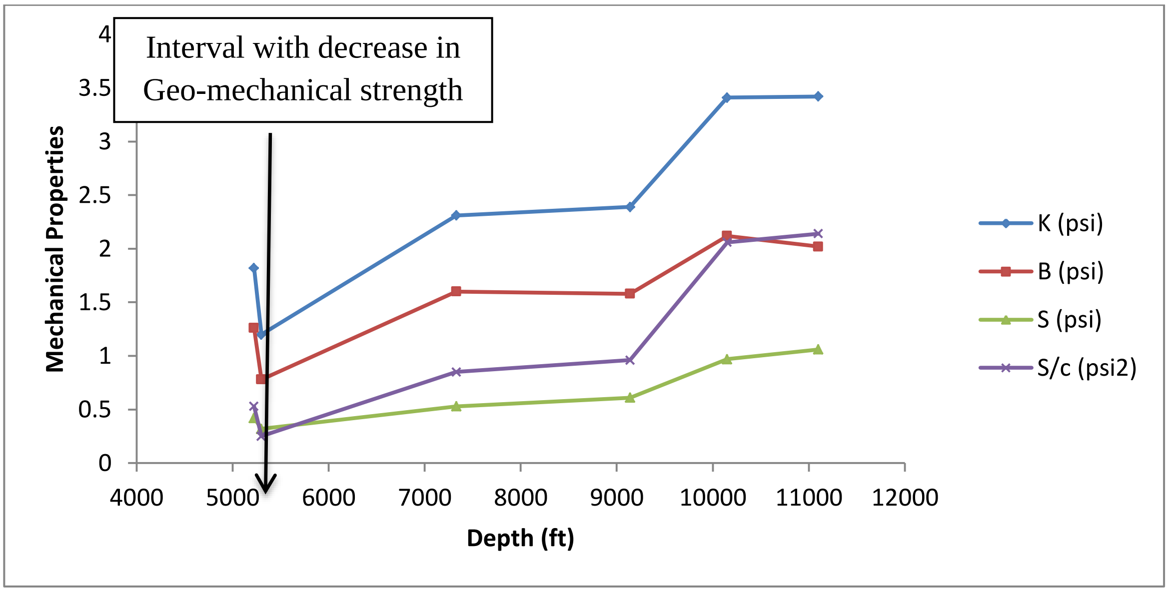

Fig. 5: Increasing sequence of Geo-mechanical strength with depth for well SAS 02

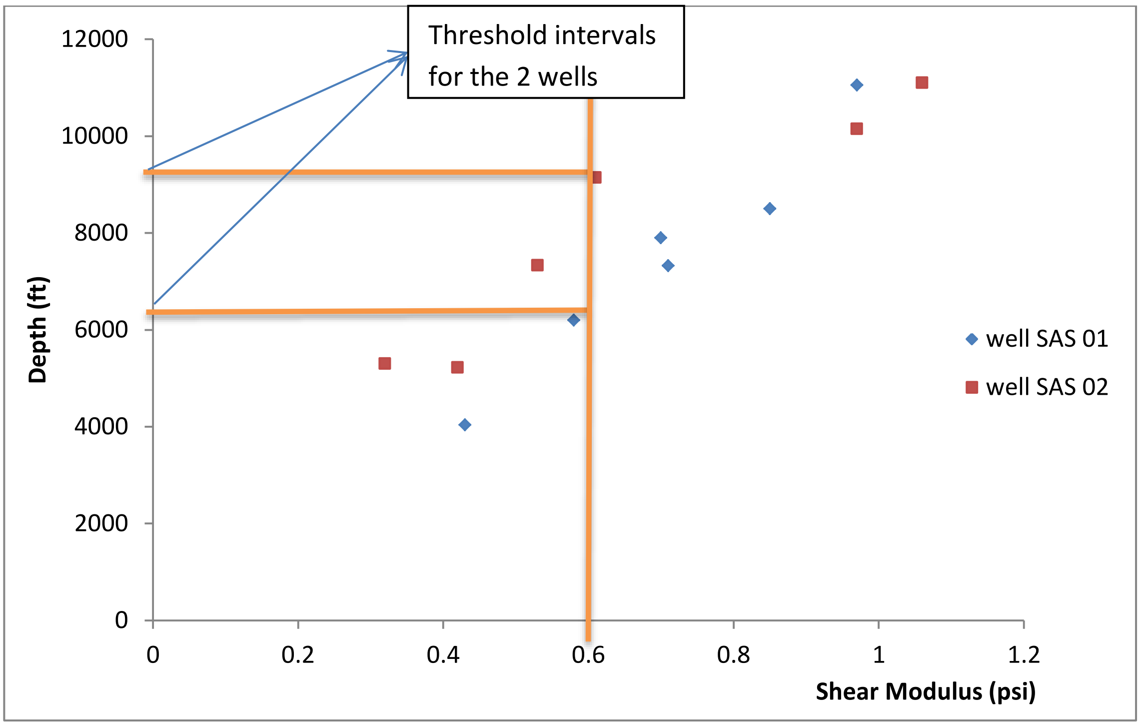

Fig. 6: Shear modulus threshold intervals (at > 0.6×10^6 psi) for the two wells

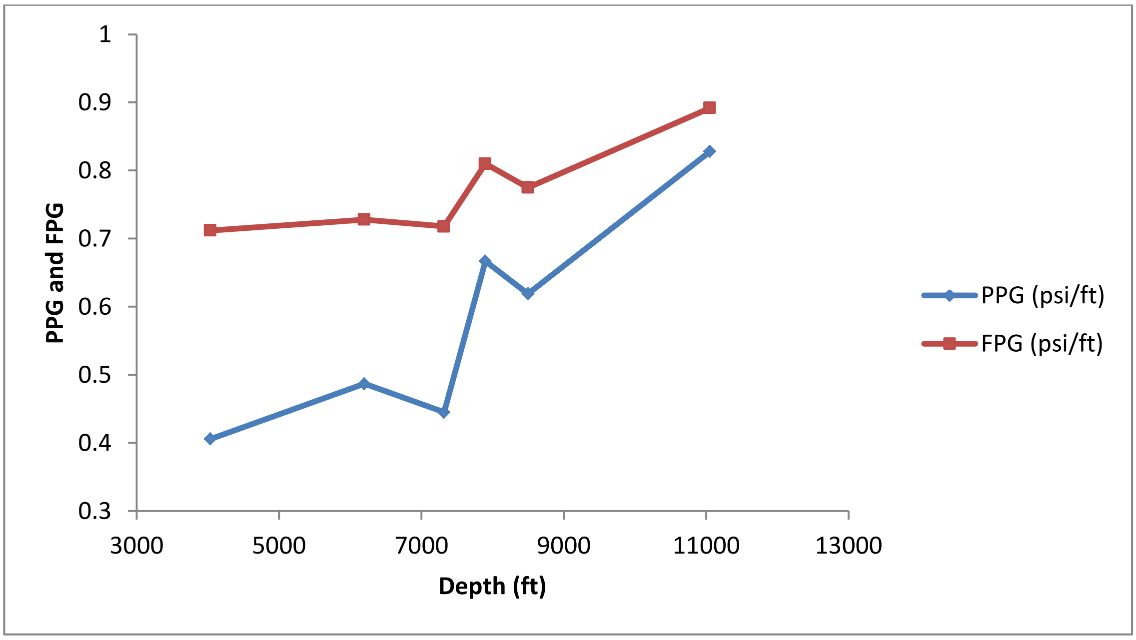

Fig. 6: Increasing – decreasing sequence of PPG and FPG for well SAS 01

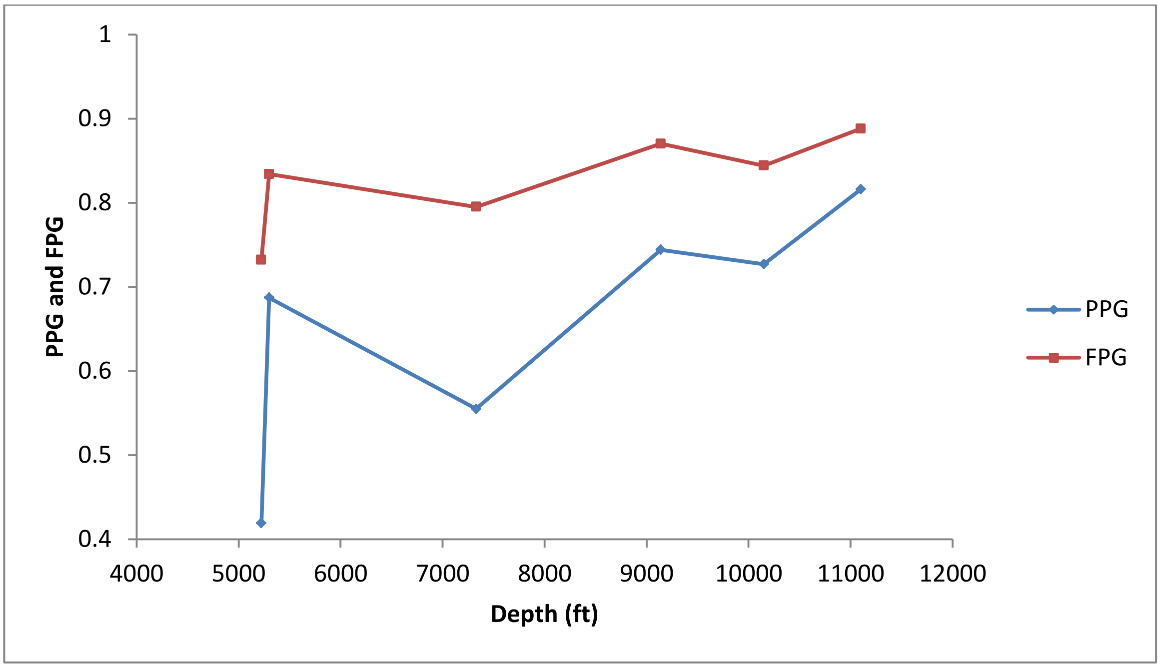

Fig. 7: Increasing – decreasing sequence of PPG and FPG for well SAS 02

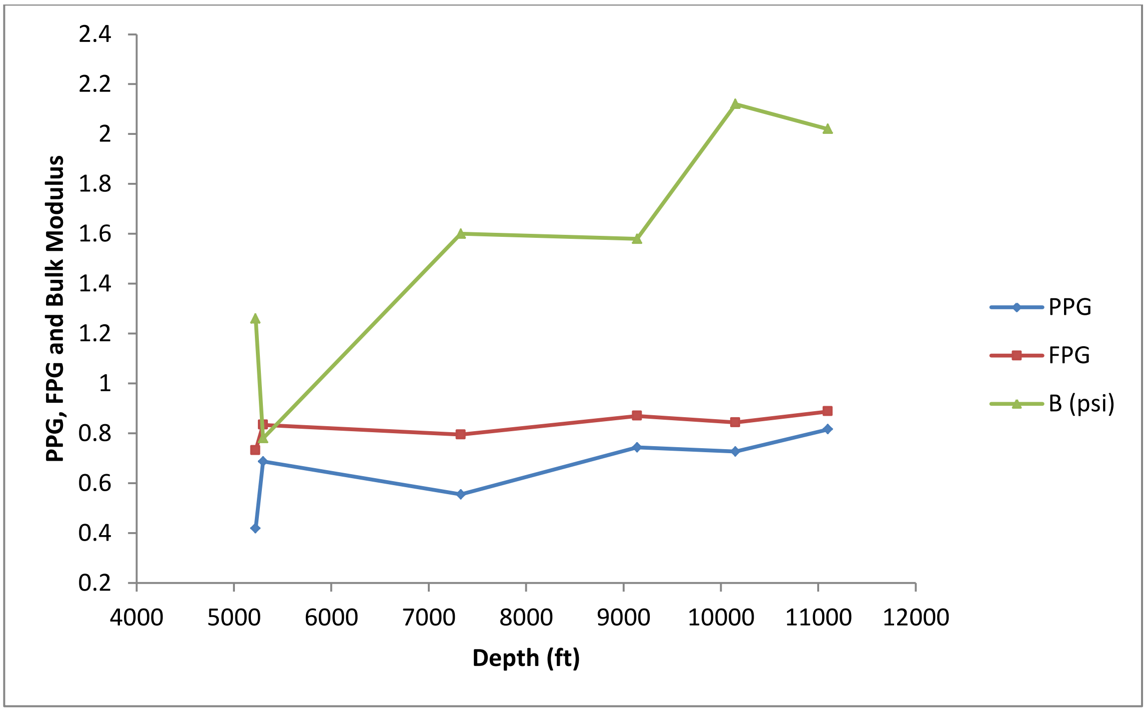

Fig. 8: Increasing sequence of PPG and FPG with decreasing Bulk modulus for well SAS 02

Conclusions

The combined modulus of strength (K) as well as the shear modulus to compressibility ratio (S/c) has been predicted using estimated values of the elastic moduli. These provided information about the competency of the formation in terms of sand production. With this knowledge, risks involved in hydrocarbon exploration can be minimized to ensure safety of the personnel and equipment, in particular minimizing the associated risk to the environment at large. Also, it will help to analyze the well trajectories for optimal well-placement.

Any value less than the threshold should expect sand production. However, interpretation of wellbore pressure is supported by geo-mechanical study. From the wells studied, Pore Pressure and Fracture Gradient decrease as the three Moduli (Young, Bulk and Shear) increases. The pressured interval has been accurately linked with zones where geo-mechanical strength is low.

Therefore, since the pressure in the wellbore has been observed to be abnormal at some depths, it is important that the density of the drilling fluid be taken into consideration so that the wellbore pressure can be above formation pore pressure at the concerned depths.

Conflict of Interest Disclosure

The author declares that there is no conflict of interest regarding the publication of this paper.

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