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# INVESTIGATION OF ROCK PHYSICS IN FRACTURE PRESSURE PREDICTION: EXAMPLES FROM THE NIGER DELTA CENTRAL SWAMP AND SHALLOW OFFSHORE DEPOBELTS

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*Abstract*

***The desire of every oil and gas producing company, after exploring and finding the hydrocarbon, is to be able to drill safely to target reservoirs and successfully exploit the hydrocarbon. Having predicted the formation pore pressure pre-drill, the other important information required to achieve success during exploratory and developmental drilling is the formation fracture pressure. Knowledge of the fracture pressure and/or gradient helps in the determination of accurate drilling window to prevent formation breakdown-related well control incidents for safe and cost-effective drilling and completion programs, and to constrain reservoir seal integrity to aid play evaluation. In situ fracture pressure measurement data are not available for most of the wells in the Niger Delta. In most cases, therefore, local fracture pressure predictions are made using statistically-derived fracture measurement trend from offset wells having measured fracture pressure data. In cases where offset wells are not applicable due to the relative distance or geologic setting, use is often made of rock physics model in the determination of the fracture pressure. In this study, rock physics model is utilized to predict fracture pressure in some wells in the central swamp and shallow offshore depobelts of the Niger Delta and the results are compared with in situ fracture pressure measurements in the wells. The aim is to investigate the success rate of resorting to rock physics in the determination of the fracture pressure. Analysis of the results shows that reasonable fracture pressure prediction could be made using rock physics model in the deeper, overpressured zones in the Niger Delta where in situ, offset fracture pressure measurements are not available. The modeled fracture pressures are found to be about 16% and 6% lower than in situ values in the central swamp and shallow offshore areas respectively, and upscaling modeled pressures by these percentages in the respective depobelts would produce reasonable results.***

***Keywords***: Fracture pressure, rock physics, pore pressure, leak-off test, Niger Delta.

## 1.0 Introduction

Fracture pressure is the optimum pressure at which new fractures develop in a rock formation [1]. It is the pressure that causes formations to lose tensile strength and break. Fracture pressure can be described in terms of fracture initiation pressure and fracture propagation pressure. The former is the minimum pressure required to cause formation to lose its strength and fracture (that is, the pressure required to initiate fracture on an intact wellbore or cause pre-existing fractures to reopen) while the latter is pressure required to propagate fractures to the far-field region. Fractures are induced in formations during drilling when the pressure in the drilling mud, determined by the mud weight, is higher than the fracture pressure at a given depth, with the resultant effect of loss of drilling mud from the wellbore into the formation through the induced fractures [2, 3] or even lost circulation. This loss of drilling mud from the wellbore into the formation during drilling or lost circulation is a troublesome and expensive problem[4]. While the drilling mud pressure must be maintained reasonably higher than the formation pore fluid pressure to prevent influx of formation fluids into the wellbore from permeable zones during drilling, the mud pressure must at the same time be reasonably lower than the fracture pressure to prevent fracturing of the formation.

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Knowledge of the fracture pressure at every depth during drilling is very important in the determination of the optimum mud weight, strength of casing shoes and cementation. This information is important for the safe and cost-effective drilling of the entire section of a well, but more especially in drilling through over pressured formations. The fracture pressure at every given depth is the fracture gradient and is obtained by dividing the fracture pressure by the true vertical depth [2].

The main source of in situ fracture gradient measurements are the downhole leak-off tests (LOT), in which wellbore pressure is monitored, usually at the surface, as the drilling mud is pumped into the borehole. The leak-off test is carried out to determine the maximum pressure that can be applied to the well while drilling to the next casing setting depth. It is expected that as the volume of mud pumped into the wellbore is increased, the mud pressure increases proportionately also. The moment there is a deviation from this linear trend, a leak-off pressure (LOP) is recorded, and pumping of the mud is stopped. It is assumed that the deviation from the linear relationship results from opening and propagation of pre-existing fractures or initialization of new ones in the borehole. Extended leak-off test (XLOT) has been used in the place of LOT where available for a more appropriate estimation of the fracture pressure [5]. Extended leak-off tests are rarely available in the exploration and production industries. In situ fracture pressure measurements are also made from hydraulic mini-fracturing tests. These tests are carried out by isolating a mini section of the open wellbore (and if in cased hole, a small section of the casing is perforated) and an injection fluid is pumped at a high rate under fracturing conditions until a mini fracture is created in the formation. The fracture closure pressure determined from such measurements provides information on the fracture pressure and/or gradient. The use of minifrac data has been reported to be more accurate for the estimation of the fracture pressure than the LOT and XLOT data [6, 7]. However, minifrac tests are primarily intended to boost production in very low permeability reservoirs, but significant reservoir porosities up to 30% have been observed in the Niger Delta [8] For this reason, minifrac tests are rarely carried out in the Niger Delta Basin. Information from loss of drilling mud from the wellbore into the formation during drilling can also be used to deduce in situ formation fracture pressure. Leak-off tests are the most commonly performed tests and as such, they provide the most readily available data for determination of formation strength.

There are three (3) in situ stresses that act on a formation at depth, at right angle to each other. One of these acts in the vertical direction, and is known as the vertical stress or overburden, and the other two act horizontally and are known as minimum horizontal stress and maximum horizontal stress, respectively. The Niger Delta is an extensional geological setting. In such a setting, formations would fracture once the minimum horizontal stress is exceeded. Fracture pressure is assumed equal to the minimum horizontal stress [5, 9]. Determination of the minimum in situ horizontal stress is therefore often synonymous with estimate of the fracture pressure.

A number of authors made use of the lower bound to the leak off pressures in vertical wells to make estimates of the minimum horizontal stress [7, 8, 10, 11]. Empirical relationships have also been used in combination with real LOT data to determine the minimum horizontal stress [4, 9, 12, 13, 14]. In this study, we assessed fracture pressure and/or fracture gradient at three (3) petroleum exploration wells located in the central and shallow offshore depobelts of the Niger Delta by evaluating leak-off pressure data in offset wells. We then modeled fracture pressure using rock physics principle on acoustic logs acquired in the respective depobelts to investigate the suitability of rock physics modeling in the determination of fracture pressure in the Niger Delta basin, especially since measured fracture pressure data are not available for the majority of wells in the Niger Delta.

**Location and Geological Setting**

The Niger Delta is a prolific hydrocarbon province located at the eastern part of the Gulf of Guinea. It has a maximum quartz-rich sediment thickness of more than 12 km [15] believed to have been deposited since the Paleocene to present day. The Niger Delta is divided into three major lithostratigraphic units [16] comprising massive sand sequence on top (Benin Formation), a sequence of alternating sands and shales (Agbada Formation) at the middle and a basal sequence of mainly marine shales with minor sand intercalations (Kata Formation). The Agbada Formation is believed to host most of the hydrocarbon potential in the Niger Delta [15]. The regional structural framework of the Niger Delta is characterized by the development of megastructures, called depobelts, which contain characteristic and structural styles developed during repeated phases of delta tectonism and associated sedimentary responses*(Fig. 1)*. These depobelts include Northern Delta and Greater Ughelli depobelts where the dominant structural styles are simple rollover structures, and Central, Swamp and Offshore depobelts where collapsed crest structures, K-type faults, subordinate simple rollover and back-to-back structures constitute the dominant structural styles. The structural pattern and stratigraphy of the Niger Delta are controlled by the interplay between rates of sediment supply and subsidence [15. 17].

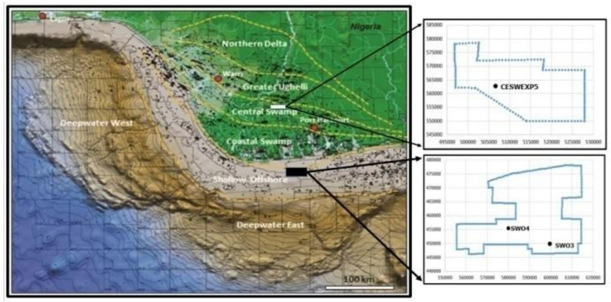



**Fig. 1**: Niger Delta shaded relief and seafloor topography showing megastructures and study areas (adapted from [18])

**Materials and Methods**

Data used for this study include leak-off pressure (LOP) data from leak-off tests (LOTs) recorded at thirty-nine (39) depth points from a total of ten (10) offset petroleum exploration wells in the Niger Delta. Six (6) of these wells are located in the shallow offshore depobelt of the Niger Delta while the remaining four (4) are in the central swamp depobelt. These data provided regional estimates of measured fracture pressure data for the respective depobelts and these were applied to derive local measured fracture pressures at three (3) wells namely SWO3, SWO4 and CESW EXP5, all of which have lithostatic stress and pore fluid pressure data available. SWO3 and SWO4 are located in the shallow offshore depobelt, and CESWEXP5 is in the central swamp depobelt. Compressional and shear sonic logs recorded at SWO3 and an offset well to CESWEXP5 were used to derive rock physics parameters for fracture pressure modeling at the shallow offshore wells SWO3 and SWO4, and central swamp well CESWEXP5 respectively. Well log data used for the rock physics modeling in the respective areas are shown in *Fig. 2*.

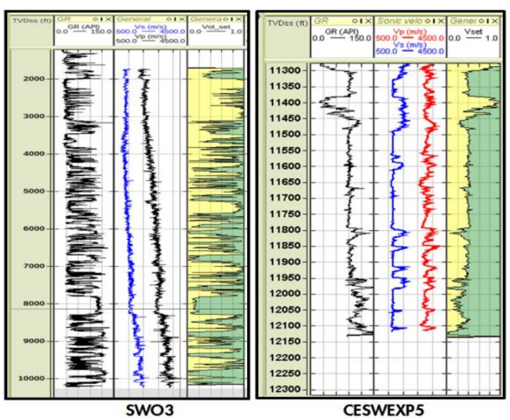



**Fig. 2**: Acoustic log data used for rock physics modeling of effective stress ratio

**Determination of Fracture Pressure**

Leak-off pressures (LOPs) from the leak-off tests were quality-checked to determine the level of variability in the recorded leak-off pressures at each well. The degree of scatter of the measured leak-off data was observed to be reasonable in most of the wells, except at a few depth points which were then excluded from the analysis. The uniaxial poro-elastic model proposed in[4] is one of the most basic techniques for the estimation of the minimum horizontal stress. The model assumes a zero lateral strain boundary condition in response to monotonic loading by the overburden, and horizontal isotropy in which the two components of the horizontal stresses are equal. The increase in overburden tends to cause the rocks to expand laterally but due to the fixed lateral boundary condition constraint, horizontal stresses would develop as a result of Poisson effect. [19] introduced the K notation, also called effective stress ratio, to express the ratio of the minimum horizontal stress to the vertical effective stress. The K parameter is related to the leak-off pressure (LOP) from leak-off test, overburden pressure (OBP) and the pore pressure (PP) by:

$$k = \frac{(LOP - PP)}{(OBP - PP)} \qquad (1)$$

K is related to the minimum horizontal stress [4, 9, 13] by:

$$Sh_{min} = K(OBP - PP) + PP \qquad (2)$$

The three (3) prospective wells which form the basis of this study do not have in situ fracture pressure measurements. To simulate LOT data in these wells, we first computed the effective stress ratio from the offset LOT data closest to the wells based on Equation (1), and plotted the resulting values versus depth below the mudline for the offset wells. We then used an exponential function to fit the effective stress ratio to depth at the offset wells, and applied the trend to derive effective stress ratio at every depth in the prospective wells. These values were thereafter combined with the overburden and pore pressure data at the respective depths to determine in situ minimum horizontal stress profiles at each prospective well using Equation (2), assuming the minimum horizontal stress equals the fracture pressure.

The effective stress ratio, K, in equation (2) is a calibration constant [20]. Rock physics can be employed to determine the Poisson's ratio, $\vartheta$, from compressional and shear sonic velocities acquired in the individual wells based on the poro-elastic model [4] using the following equation:

$$\vartheta = \frac{(V_p^2 - 2V_s^2)}{2(V_p^2 - V_s^2)} \qquad (3)$$

and the effective stress ratio is related to the Poisson's ratio by:

$$K = \frac{\vartheta}{1-\vartheta} \qquad (4)$$

The compressional and sonic velocities acquired in two (2) of the three (3) prospective wells in this study were used to compute Poisson's ratio for the wells using Equation (3). The strategy is such that in the first instance, we made cross-plots of the compressional and shear sonic velocities versus GR respectively, and excluded sands using GR cut-off of 75 API. The resulting compressional and shear sonic velocities were then cross-plotted to obtain well-based Vs-Vp trend in shale for the respective prospective wells. Figure 3 shows this strategy for SWO3 well and Figure 4 shows the Vs-Vpcrossplot in shale for central swamp well.

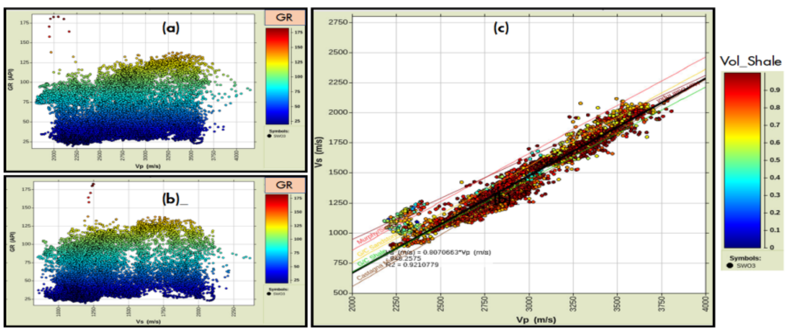



**Fig. 3**: Shale property estimation in SWO3: (a) Vp-GR crossplot (b) Vs-GR crossplot (c) Vs-Vpcrossplot in shales. GR cut of 75API was used to exclude sands to obtain the shale velocities.

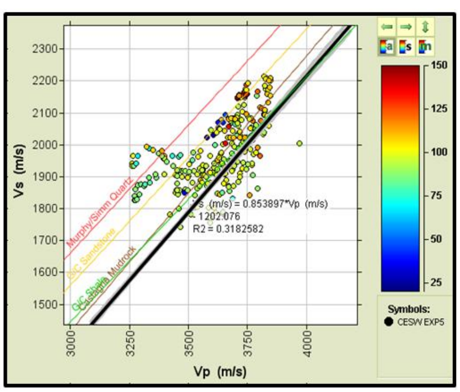
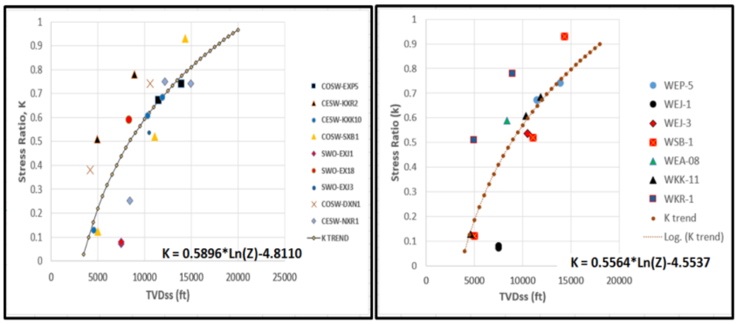



**Figure 4**: Shale compressional and shear sonic velocity crossplot for central swamp well (CESWEXP5)

The Vs-Vp trend was applied to seismic interval velocity function extracted at the well to compute the Poisson's ratio and effective stress ratio using Equations (3) and (4), respectively, and the result was used in Equation (2) to derive rock physics-based fracture pressure profiles for comparison to the profiles predicted from the simulated LOT data.

## Results and Discussion

Figure 5 shows the computed stress ratio from LOT measurements versus depth plots for the central swamp *(Fig. 5a)* and shallow offshore *(Fig. 5b)* areas of study in the Niger Delta.




(a) (b)

**Fig. 5**: Effective stress from LOT data versus depth plots for the central swamp and shallow offshore areas studied

The computed stress ratios from the LOT data range from about 0.1 to 0.9, with most of the values concentrating between 0.5 at about 1,524 m and 0.8 at about 4,724 m subsurface depth. Exponential functions fitted to the points give the following regional effective stress ratio versus depth trends for the central swamp and shallow offshore depobelts, respectively:

Central swamp area: $K = 0.5896 * Ln\,(Z) - 4.8110$

Shallow offshore area: $K = 0.5564 * Ln\,(Z) - 4.5537$

Figure 6 shows plots of Poisson's ratio and effective stress ratio computed at the prospective wells using rock physics model. The shear versus compressional velocity trend in shale derived for the computations is given below for the central swamp and shallow offshore areas, respectively:

Central swamp area: $Vs = 0.8539 * (Vp) - 1202.08$ (m/s)

Shallow offshore area: $Vs = 0.8071 * (Vp) - 946.26$ (m/s)

The results show that Poisson's ratio in the shales generally decrease with depth in the central swamp and shallow offshore areas of the study, the rate of decrease being much faster at shallower depths. The values range from 0.46 to 0.32 and 0.46 to 0.34 atSWO3 and SWO4 respectively in the shallow offshore, and 0.48 to 0.32 at CENSW1 in the central swamp depobelt. Based on the plots, the following analytic relations have been derived for the prediction of Poisson's ratio from seismic data in the central and shallow offshore areas in the absence of LOT data:

Central swamp area: $\vartheta = -0.078 * Ln\,(Z) + 1.0708$

Shallow offshore area: $\vartheta = -0.00001 * (Z) + 0.4557$

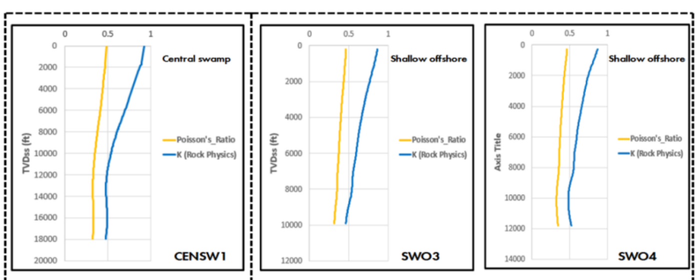



**Fig. 6**: Computed Poisson's Ratio and modeled effective stress ratio versus depth plot for the prospective wells.

The rock physics-based effective stress ratio in the prospective wells, also decrease with depth, varying between 0.86 and 0.46, and 0.86 and 0.52, with an average of 0.86 and 0.48 in the shallow offshore area, and between 0.93 and 0.47 in the central swamp depobelt. Correlation of the computed stress ratio with density-derived porosity in the wells show that the values decrease with porosity as sediment depth of burial increases. An example of the stress ratio versus porosity relationship is shown in *Fig. 7*.

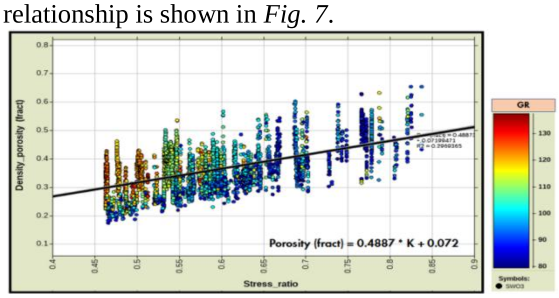



**Fig. 7**: Example of density porosity – effective ratio crossplot for the wells, shown for SWO3. The plot is colour-coded with GR.

Fracture pressure profiles computed using the LOT and rock physics-derived fracture profiles are shown in *Fig. 8* and *Fig. 9*, together with the hydrostatic, overburden and pore pressure profiles for the prospective central swamp and shallow offshore wells respectively.

Fracture pressures predicted using rock physics modeling in the wells show good agreement with LOT-derived fracture pressures in the overpressured sections of CESWEXP5 and SWO4, but the modeled values are lower than the values derived from the LOT data. This trend is not noticeable in SWO3 which is entirely hydrostatic. The overpressured sections of these wells are clearly indicated by the elevated pore pressure profiles above hydrostatic in these wells.

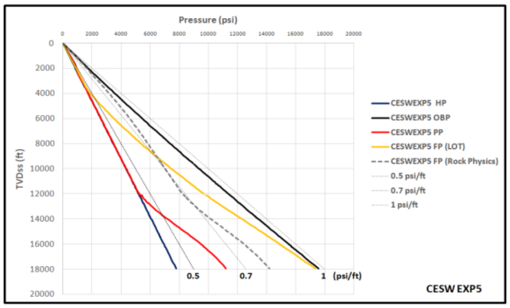



**Fig. 8**: LOT-derived (gold) and rock physics-derived (dashed grey) fracture pressure profiles for Central swamp well 1. The fracture pressures are plotted together with hydrostatic, overburden and pore pressures at the well. Pressures gradients are also indicated for 0.5psi/ft, 0.7 psi/ft and 1 psi/ft.

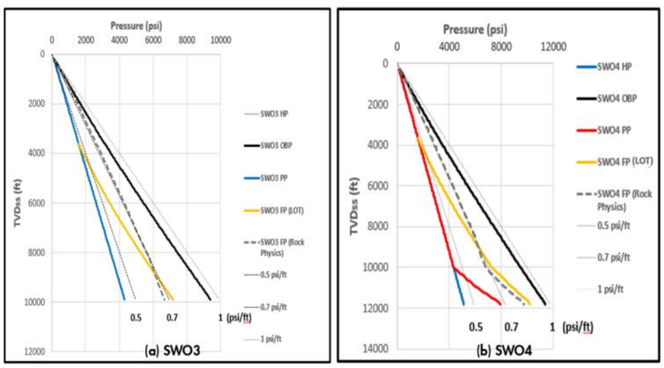



**Fig. 9**: LOT-derived (gold) and rock physics-derived (dashed grey) fracture pressure profiles for Shallow offshore wells SWO3 and SWO4. The fracture pressures are plotted together with
hydrostatic, overburden and pore pressures at the well. Pressures gradients are also indicated for 0.5 psi/ft, 0.7 psi/ft and 1 psi/ft.

Mechanisms that generate pore pressure in sedimentary basins are controlled by shale porosity which in turn, is dependent on the vertical effective stress. Sediments at shallow depths of burial are not well compacted and as such, porosity in shales are poorly constrained at shallow depths. This is likely the cause of the lack of agreement between the measured and modeled fracture pressure profiles at the shallower, hydrostatic sections of the wells. At the deeper, overpressured sections, the rocks have become more compacted to better constrain shale properties, resulting in the observed good agreement in the trends. The measured fracture pressures are about 16% and 6% higher than the modeled fracture pressures in the central and shallow offshore areas respectively*(Table 1* and *Table 2)*. The high percentage difference in the central swamp depobelt may be attributed to the fact that the compressional and shear sonic data used for the rock physics modeling at the central swamp well location were not acquired in the well, but at an offset well, unlike SWO3 in the shallow offshore area which has acquired acoustic log data.

**Table 1**: Comparison of LOT and rock physics-derived (RKP) fracture pressure in overpressured section of CESW EXP5 well. These are shown together with percentage difference in the values. Overburden pressure (OBP), hydrostatic pressure (HP) and pore pressure at the well is also shown.

| TVDSS (ft) | OBP (psi) | PP (psi) | HP (psi) | FP (LOT, psi) | FP (RKP, psi) | FP_diff | % Diff |
|---|---|---|---|---|---|---|---|
| 13030.14 | 12425.35 | 6136.39 | 5668.11 | 11018.00 | 9144.22 | 1873.78 | 17.01 |
| 13306.93 | 12709.37 | 6414.61 | 5788.51 | 11378.75 | 9423.20 | 1955.55 | 17.19 |
| 13309.00 | 12711.50 | 6416.74 | 5789.42 | 11381.46 | 9425.33 | 1956.13 | 17.19 |
| 13531.00 | 12939.74 | 6649.26 | 5885.99 | 11671.97 | 9657.29 | 2014.68 | 17.26 |
| 13582.78 | 12993.03 | 6705.82 | 5908.51 | 11740.08 | 9713.42 | 2026.66 | 17.26 |
| 13767.00 | 13182.80 | 6907.19 | 5988.65 | 11982.02 | 9913.26 | 2068.76 | 17.27 |
| 13800.00 | 13216.83 | 6943.82 | 6003.00 | 12025.40 | 9949.55 | 2075.85 | 17.26 |
| 13847.00 | 13265.29 | 6996.93 | 6023.45 | 12087.31 | 10002.04 | 2085.27 | 17.25 |
| 13857.60 | 13276.22 | 7009.02 | 6028.05 | 12101.29 | 10013.98 | 2087.31 | 17.25 |
| 14131.35 | 13558.89 | 7320.97 | 6147.14 | 12461.40 | 10322.01 | 2139.39 | 17.17 |
| 14404.06 | 13841.05 | 7638.21 | 6265.77 | 12819.66 | 10634.48 | 2185.18 | 17.05 |
| 14670.00 | 14116.72 | 7954.77 | 6381.45 | 13168.54 | 10945.35 | 2223.18 | 16.88 |
| 14675.89 | 14122.83 | 7961.74 | 6384.01 | 13176.23 | 10952.21 | 2224.03 | 16.88 |
| 14851.00 | 14304.64 | 8170.52 | 6460.19 | 13405.10 | 11157.17 | 2247.93 | 16.77 |
| 14861.00 | 14315.03 | 8182.65 | 6464.54 | 13418.18 | 11169.05 | 2249.13 | 16.76 |
| 14946.97 | 14404.37 | 8284.82 | 6501.93 | 13530.21 | 11269.38 | 2260.83 | 16.71 |
| 15132.00 | 14596.85 | 8503.61 | 6582.42 | 13770.65 | 11484.36 | 2286.29 | 16.60 |
| 15217.55 | 14685.92 | 8604.50 | 6619.63 | 13881.54 | 11583.52 | 2298.02 | 16.55 |
| 15254.00 | 14723.89 | 8646.38 | 6635.49 | 13928.60 | 11624.83 | 2303.77 | 16.54 |
| 15300.00 | 14771.82 | 8699.53 | 6655.50 | 13988.00 | 11677.21 | 2310.79 | 16.52 |
| 15310.00 | 14782.24 | 8711.26 | 6659.85 | 14000.92 | 11688.74 | 2312.18 | 16.51 |
| 15400.00 | 14876.06 | 8815.51 | 6699.00 | 14117.04 | 11791.46 | 2325.58 | 16.47 |
| 15432.00 | 14909.43 | 8852.80 | 6712.92 | 14158.31 | 11828.16 | 2330.15 | 16.46 |
| 15487.88 | 14967.72 | 8917.62 | 6737.23 | 14230.31 | 11892.01 | 2338.30 | 16.43 |
| 15758.26 | 15250.07 | 9221.06 | 6854.84 | 14576.76 | 12192.29 | 2384.47 | 16.36 |
| 15928.00 | 15427.58 | 9401.83 | 6928.68 | 14792.70 | 12372.57 | 2420.14 | 16.36 |
| 16029.00 | 15533.29 | 9508.85 | 6972.61 | 14921.01 | 12479.39 | 2441.62 | 16.36 |
| 16170.00 | 15680.99 | 9652.56 | 7033.95 | 15099.43 | 12623.70 | 2475.74 | 16.40 |
| 16187.00 | 15698.81 | 9669.72 | 7041.35 | 15120.92 | 12640.96 | 2479.96 | 16.40 |
| 16230.00 | 15743.88 | 9713.05 | 7060.05 | 15175.26 | 12684.55 | 2490.71 | 16.41 |
| 16292.00 | 15808.89 | 9775.67 | 7087.02 | 15253.61 | 12747.53 | 2506.08 | 16.43 |
| 16300.40 | 15817.69 | 9784.26 | 7090.67 | 15264.23 | 12756.15 | 2508.08 | 16.43 |
| 16396.00 | 15917.99 | 9877.96 | 7132.26 | 15384.75 | 12850.84 | 2533.91 | 16.47 |
| 16460.00 | 15985.17 | 9939.55 | 7160.10 | 15465.33 | 12913.27 | 2552.05 | 16.50 |
| 16572.80 | 16103.62 | 10047.86 | 7209.17 | 15607.30 | 13023.09 | 2584.20 | 16.56 |
| 16766.00 | 16306.71 | 10227.54 | 7293.21 | 15850.02 | 13206.23 | 2643.79 | 16.68 |
| 16846.53 | 16391.43 | 10302.11 | 7328.24 | 15951.19 | 13282.29 | 2668.90 | 16.73 |
| 17121.94 | 16681.48 | 10543.59 | 7448.04 | 16296.41 | 13530.77 | 2765.64 | 16.97 |
| 17399.33 | 16974.08 | 10772.18 | 7568.71 | 16643.77 | 13768.32 | 2875.45 | 17.28 |
| 17678.97 | 17269.53 | 10988.84 | 7690.35 | 16994.08 | 13995.58 | 2998.50 | 17.64 |
| 17961.06 | 17568.05 | 11194.72 | 7813.06 | 17348.03 | 14213.34 | 3134.69 | 18.07 |

**Table 2**: Comparison of LOT and rock physics-derived (RKP) fracture pressure in overpressured section of SWO3 well. These are shown together with percentage difference in the values. Overburden pressure (OBP), hydrostatic pressure (HP) and pore pressure at the well is also shown.

| TVDss | HP | OBP | PP | FP (LOT) | FP (RKP) | FP_Diff | %Diff |
|---|---|---|---|---|---|---|---|
| 10120.00 | 4389.74 | 9614.07 | 4524.25 | 7463.98 | 6969.34 | 494.64 | 6.63 |
| 10200.00 | 4427.71 | 9706.47 | 4693.64 | 7610.86 | 7103.27 | 507.60 | 6.67 |
| 10280.00 | 4459.07 | 9782.80 | 4841.71 | 7738.66 | 7218.58 | 520.08 | 6.72 |
| 10360.00 | 4496.69 | 9874.43 | 5017.86 | 7886.21 | 7355.95 | 530.26 | 6.72 |
| 10440.00 | 4529.23 | 9953.89 | 5141.39 | 8004.31 | 7460.25 | 544.05 | 6.80 |
| 10520.00 | 4564.88 | 10040.99 | 5275.80 | 8130.81 | 7573.99 | 556.83 | 6.85 |
| 10600.00 | 4599.35 | 10125.18 | 5406.18 | 8253.40 | 7685.72 | 567.68 | 6.88 |
| 10680.00 | 4633.09 | 10207.64 | 5539.20 | 8375.45 | 7803.01 | 572.44 | 6.83 |
| 10760.00 | 4669.50 | 10296.82 | 5705.07 | 8513.80 | 7940.93 | 572.87 | 6.73 |
| 10840.00 | 4701.28 | 10374.71 | 5852.11 | 8637.18 | 8063.42 | 573.76 | 6.64 |
| 10920.00 | 4739.64 | 10468.72 | 6028.44 | 8780.98 | 8208.53 | 572.45 | 6.52 |
| 11000.00 | 4771.00 | 10545.61 | 6174.31 | 8901.84 | 8329.46 | 572.39 | 6.43 |
| 11080.00 | 4808.24 | 10637.11 | 6363.96 | 9047.48 | 8479.42 | 568.07 | 6.28 |
| 11160.00 | 4841.16 | 10718.05 | 6535.55 | 9178.88 | 8614.78 | 564.10 | 6.15 |
| 11240.00 | 4876.42 | 10804.73 | 6718.07 | 9317.08 | 8761.14 | 555.93 | 5.97 |
| 11320.00 | 4911.28 | 10890.43 | 6897.82 | 9452.77 | 8906.75 | 546.02 | 5.78 |
| 11400.00 | 4944.63 | 10972.61 | 7075.00 | 9584.43 | 9048.44 | 535.99 | 5.59 |
| 11480.00 | 4981.43 | 11063.36 | 7271.08 | 9727.45 | 9202.97 | 524.48 | 5.39 |
| 11560.00 | 5012.82 | 11140.77 | 7435.63 | 9849.87 | 9334.41 | 515.46 | 5.23 |
| 11640.00 | 5051.56 | 11236.32 | 7635.38 | 9995.54 | 9491.32 | 504.22 | 5.04 |
| 11720.00 | 5082.95 | 11313.90 | 7798.26 | 10115.91 | 9620.34 | 495.57 | 4.90 |
| 11800.00 | 5105.04 | 11368.54 | 7912.86 | 10204.06 | 9714.17 | 489.89 | 4.80 |

**Conclusion**

Accurate pre-drill fracture pressure prediction is as important as pre-drill pore pressure prediction in the planning, design and safe and cost effective drilling of exploratory and developmental wells. Traditional leak-off tests, which are carried out in shales, provide the easiest means of acquiring in situ fracture pressure measurements. However, these data are not available for most of the wells in the Niger Delta. Accurate pre-drill fracture pressure prediction at local wells could sometimes become difficult to make due to lack or inadequate offset LOT data to make such predictions. This would necessitate resorting to rock physics modeling to provide alternatives, especially since most of the wells have compressional sonic measurements. The study has shown that reasonable fracture pressure predictions could be made in overpressured formations using rock physics modeling with sonic velocities. An average of 16% and 6% of the modeled fracture pressures could be added to modeled fracture pressures in the central swamp and shallow offshore depobelts, respectively, to provide more accurate results.

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