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Determination Of Fracture Pressure And The Type Of Formation Pore Pressure Gradients Of Al Ghani Field In Sirte Basin Using Different Methods

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Abstract- **For future drilling or completion process in the selected area, it is noteworthy to predict the formation pressure gradients. The purposes of this study are 1) predict the formation pore, and fracture pressure gradients, 2) determine the most applicable methods for formation pressure prediction, and 3) determine the casing seating depths and Equivalent Mud Circulation. All of our goals were successfully accomplished. Out of the tested nine different methods, six methods concluded with reliable results, and only two of them were selected to fulfill the other targets. So Eaton's drilling equations were selected to determine the casing seating depths and EMC. According to our results, the formation pore pressure is considered normal, except in the interval depth of 2,438 ft. and 3,653 ft, the pressure is subnormal. No overpressure zone was noticed in this area of study. It is suggested that five casing strings and three EMC values will be suitable for any future development wells in Al Ghani field. It was observed that the highest pore pressure gradient value in the field is 0.474 Psi/ft. and the lowest fracture pressure gradient is 0.64 Psi/ft. So there is enough range of selection to choose the appropriate mud weight for future drilling developments.**

Keywords-Formation pressure gradients; measurement while drilling; Eaton's method; equivalent circulating mud, casing seating depth.

I. Introduction

Safe and economically successful drilling process can be achieved by accurate calculation of formation pore and fracture pressure gradients. Knowing the formation pore pressure is the key to determine the required mud density in the wellbore to control the formation pressure. The fracture pressure determination is important to not crack the formations and result in lost circulation zone.

Pore pressure represents the pressure in the pore spaces that is caused by the presence of the fluids. The value of the pore pressure varies from hydrostatic pressure (0.433 psi/ft.) to critically overpressure or 48 % to 95 % of the overburden pressure. It is considered abnormal if it is noticeably either less or higher than the hydrostatic pressure (normal pressure). When formation pore pressure exceeds the normal pressure it is called overpressure. Practically, the overpressure zones were found worldwide [1]. Normal pore pressure is a result of normal and stable deposition. Subnormal pressure is when the formation pore pressure less than the hydrostatic pressure. In Indian area, it was observed that the subnormal pore pressure occurred in both clastic and non-clastic rock, and that could be due to tectonic movements, variation in the temperature, etc. [2]. When the formation pore pressure is much greater than the hydrostatic pressure (> 0.465 psi/ft.), it is called overpressure. The main reason of the existence of the overpressure is the high sedimentation rate (rapid deposition) [2]. Inaccurate prediction of overpressure or subnormal pressure might result in lost circulation, fluid influx, blowouts, ... etc. [3]. Therefore, formation pressure detection is necessary to avoid mod loss and blowout [2].

The selection of the prediction method of formation pressure gradients is based on the type of data on hand. These data could be seismic, drilling, or well logging. For any developed wells, there is a possibility to find all of the abovementioned data typed. In the case of a newly discovered area, seismic data would be the source information of a wildcat well [3].

In this study, the accuracy of formation pressures prediction was investigated by studying four pore pressure methods, which are Eaton's drilling, Eaton's logging, Zamora, and Ratio methods, and five fracture pressure methods that are Eaton's drilling, Eaton's logging, Hubbert & Willis [min], Hubbert & Willis [max] and Matthew & Kelly methods. Besides, the casing seating depths and equivalent mud circulation were determined after calculating formation pore pressure and fracture pressure.

II. Description and Geology of Al Ghani Field (Concession 11) - Harouge Oil Operations - Sirte Basin

Al Ghani Field is one of Sirte basin fields and it is found in the South Western (S-W) section of Veba's Concession 11 in the western Sirte Basin side, as can be seen in **Fig 1** (**Wenneker *et al*., 1996 study "cited in SWEI, GIUMA, HEDWI (2010)")** [4]. Sirte basin is observed in the north-central division of Libya [5]. It is the modernly discovered basin in Libya with the highest hydrocarbon reserve. The source rocks or the mother rocks are observed in Upper Cretaceous Rachmat and Sirte shale rocks. And the reservoir formations are developed in Cretaceous and Eocene to Miocene rift structures age. In this basin, there are both a clastic (58 %), and non-clastic reservoir rocks (52 %) [6]. Tectonic advancement and other forces dominated the geological structure of Sirte basin since the Upper Jurassic-Lower Cretaceous ages [7]. During the tectonic movements in late Paleocene age, Sirte basin was somewhat impeded by submersed highs in the offshore region; that action resulted in evaporite sedimentation throughout the Lower Eocene everywhere and the Cyrenaica Platform in the basin. These evaporites sedimentations formed the reservoir rocks (Dolomite) in cross-section East to West (**Fig 2**) **(Jurack's 1985 study "cited in Pawellek, T., 2007")** [7], as noticed in the reservoir formation of Al-Ghani area.

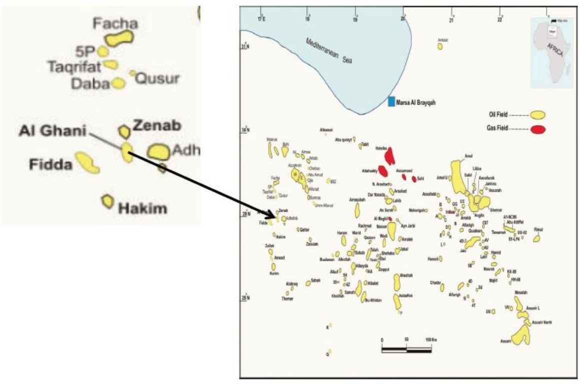

Fig. 1. *Location of oil and gas fields in the Sirte Basin [4] (SWEI, GIUMA, HEDWI, 2010).*

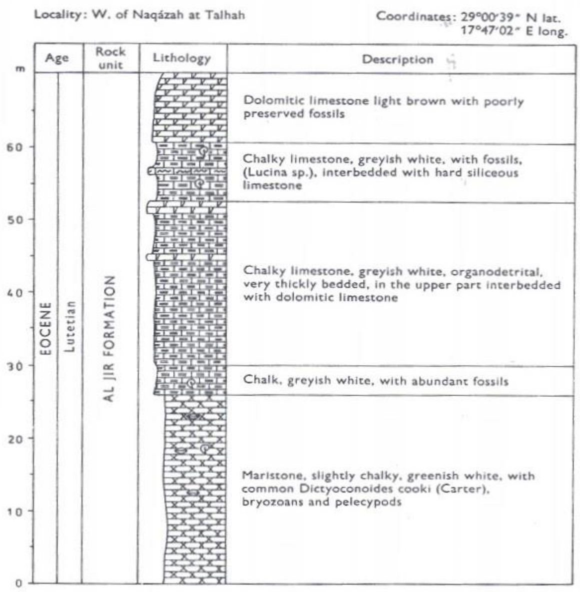

Fig. 2. *Al-Jir reservoir formation structure in western Sirte Basin.[7]*

The lithology column of Al-Ghani field, as shown in **Fig 3** (the nomenclature and ages used in the guide are based on those founded by the IRC [8]), is starting from the bottom with lower Eocene age: Al-Gir Formation that includes Focha formation (reservoir rock) and Hone formation. Buried by Al-Jir formation (Middle Eocene) and Wadi Thamat formation (middle to upper Eocene). Then they are overlapped by lower and upper Oligocene formation, which are Umm Al-Dahiy and Al-Hashish, respectively, and an interruption of continental and marine barriers in some locations. Next to that, it comes Marada formation through lower and middle Miocene Age. And then, Al-Khumis formation is in upper Miocene age. After that, Al-Hishah formation covers the age of lower and upper Pliocene. Then, Quaternary deposits are sitting on the top of this area.

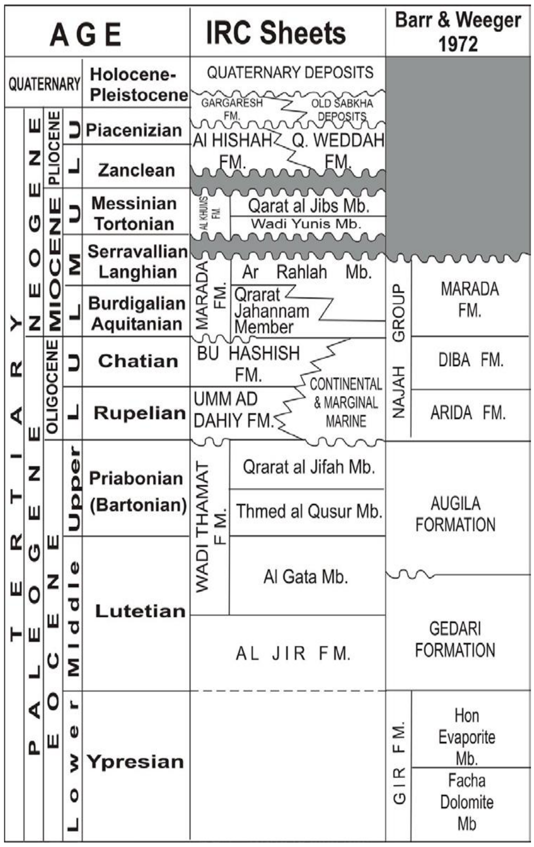

Fig. 3. *Lithology of shallow wells in Sirte Basin.[8]*

III. Methods

In this section, the empirical equations that were used in this study are presented below:

A. Overburden Pressure Prediction

Gardner (1974) found that the calculation of overburden pressure could be done based on seismic and well logging data [9], as shown in Equation (1):

$$\sigma_{ob} = 0.433\ \rho_b D \qquad (1)$$

B. Pore Pressure Prediction

At the beginning, the unusual pore pressure was predicted using an indirect method based on the hardness of the formation that was suggested by Bingham [10]. This method is called the d-exponent method. The technique was improved by **Jorden and Shirley (1966)** to include most of drilling factors such as the normalized rate of penetration (ROP) from the Bingham model, besides other parameters as weight on bit (WOB), rotary speed (RPM) and bit diameter (dbit) [11], as presented in Equation (2) below:

$$d - exponent = \frac{\log\left(\frac{ROP}{60\ RPM}\right)}{\log\left(\frac{12\ WOB}{10^3\ d_{bit}}\right)} \qquad (2)$$

Later, **Jorden and Shirley's** formula was modified to involve the mud weight term [12], as shown in Equation (3):

$$dc_{exponent} = d_{exponent} * \left(\frac{\rho_{normal}}{\rho_{actual}}\right) \qquad (3)$$

To predict formation pore pressure from drilling data, Zamora proposed an empirical equation based on graphical results, as presented in equation (4) [13]:

$$\frac{P_p}{D} = 0.433\left(\frac{d_{cn}}{d_c}\right) \qquad (4)$$

In 1975, an empirical method to predict formation pore pressure was suggested by Eaton. This method is based on drilling raw data (dc-exponent) and well logging (sonic compressional transit time or resistivity measurements) data, respectively. Eaton's dc-exponent and sonic transit time are presented in equations (5) and (6) [14]:

$$\frac{P_p}{D} = \frac{\sigma_{ob}}{D} - \left(\left(\frac{\sigma_{ob}}{D} - \frac{P_{pnormal}}{D}\right)\left(\frac{d_{c,observed}}{d_{c,normal}}\right)^{1.2}\right) \qquad (5)$$

$$\frac{P_p}{D} = \frac{\sigma_{ob}}{D} - \left(\left(\frac{\sigma_{ob}}{D} - \frac{P_{pnormal}}{D}\right)\left(\frac{\Delta t_{normal}}{\Delta t}\right)^{3}\right) \qquad (6)$$

The other method that is employed to predict formation pore pressure is Ratio Method. This method is based on the ratio between the normal and observed data of any factor such as dc-exponent, sonic transit time, resistivity, shale density, etc. In this study, sonic transit time was used for ratio method [15], as presented in equation (7):

$$\frac{P_p}{D} = \frac{P_{hyd}}{D} \star \left(\frac{\Delta t_c}{\Delta t_{cn}}\right) \qquad (7)$$

C. Fracture Pressure Prediction

Fracture pressure is the pressure that the formation starts cracking at. To have a safe and successful drilling process, we need to keep the pressure in the wellbore under the formation fracture pressure. The prediction of formation fracture pressure is significant to determine casing seating depth, equivalent mud circulation, etc. In this section, we are going to present the employed methods to predict the formation fracture pressure. These three methods are (1) Eaton's Equation based on drilling/well logging data, (2) Hubbert and Willis Equations, and (3) Mathew and Kelly Equation.

One of the most recommended methods is the Ben Eaton's approach [14]. This method depends on the pore pressure values that were achieved either by using well logging or drilling data, as shown in equation (8):

$$\frac{P_F}{D} = \frac{v}{1-v}\left(\frac{\sigma_{ob}}{D} - \frac{P_P}{D}\right) + \frac{P_P}{D} \qquad (8)$$

In 1956, Hubbert and Willis proposed a new method to predict formation fracture pressure [16]. According to the experimental results, they recommended that one third of the stress that caused by the overburden weight represents the minimum fracture pressure that create a fracture. They also suggested another equation to represent the maximum fracture pressure of the formation. Both equations (9 and 10) are presented below:

$$\left(\frac{P_F}{D}\right)_{min} = \frac{\left(\frac{\sigma_{ov}}{D} + \left(2 * \frac{P_p}{D}\right)\right)}{3} \qquad (9)$$

$$\left(\frac{P_F}{D}\right)_{max} = 0.5 * \left(\frac{\sigma_{ov}}{D} + \frac{P_p}{D}\right) \qquad (10)$$

The other method that was examined is Mathew and Kelly (Equation (11)) [17]. In this method, the field data were employed to determine the stress coefficient empirically. They introduced the term ki to calculate the fracture pressure in the abnormally pressure depths.

$$\frac{P_F}{D} = k_i\left(\frac{\sigma}{D}\right) + \frac{P_F}{D} \qquad (11)$$

IV. Results and Discussion

A. Formation Pore Pressure and Fracture Pressure Prediction

Based on the combined d-exponent and dc-exponent results of the 10 studied wells in Al-Ghani field, as shown in **Figs 4** and **5**, we possibly can say that the overpressure zone does not occur. The trends of both plots (d-exponent and dc-exponent figures) are similar. It is clear that the low to normal pore pressure zone exists from top to the depth of 195 ft. After that, a regular increase in the d-exponent and dc-exponent values, which represents the normal pore pressure gradient zone, is observed as we go deeper till a clear deviation in the trends has been detected. As shown in d-exponent plot (**Fig 4**), it is apparent that we have a low (subnormal) pore pressure zone in the interval of 1,735 ft and 2,986 ft. Also, the subnormal pore pressure region is clearly noticed in **Fig 5** between 1,573 ft. and 3,251 ft. depths. Beyond those depths, the pressure is considered normal.

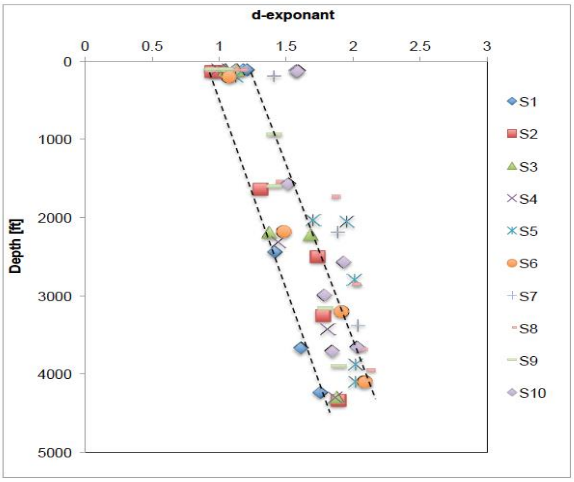

Fig. 4: d-exponent results of Al-Ghani Field.

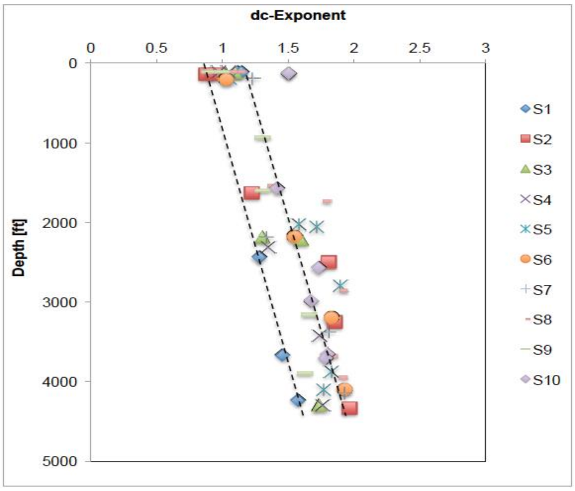

Fig. 5: dc-exponent of Al-Ghani Field.

In this study, four methods were employed to calculate pore pressure and five methods were used to predict the fracture pressure based on either drilling raw or well logging data. The predicted values of formation pressure gradients (pore pressure, fracture pressure, and overburden pressure) and calculated values of hydrostatic pressure gradients for the each investigated well employing those methods were plotted separately, as presented in **Fig 6** for well S5, and the applicable methods were determined. Before interpreting the results, a survey on the used methods was made to determine which methods we can rely on to predict the formation pressure gradients for shallow wells. Our investigation was based on two facts: 1) Pore pressure values of any method should be smaller than the mud weight values that were set by the company, as an over-balanced drilling technique was applied to drill those wells based on previous drilling results in the area. 2) Fracture pressure values must be less than overburden pressure values at the same depths and greater than the mud weight values because no fracture problems were detected in this area of study. According to the results, we found that the ratio method could not be used to predict formation pore pressure at all in this area of study, as the predicted values were either equal to or greater than the employed drilling mud weight values. Also, Hubbert & Willis [min] and Matthew & Kelly methods cannot be used to calculate the formation fracture pressure of the wells. Hubbert & Willis [min] technique resulted in very small fracture pressure values, which were close to the drilling fluid pressure values, and Matthew & Kelly method concluded with fracture pressure values greater than the overburden pressure values. To have a full picture of the results of these methods, the acceptable (Pass ”P”) and unacceptable (Fail “F”) results of formation pore and fracture pressure methods were detailed in **Tables 1** And **2**, respectively. Regarding the results, it is obvious that Eaton’s drilling and logging methods, and Zamora method are applicable in this area of study to calculate the formation pore pressure gradient, as they failed in only one depth of one or two wells. However, it is impossible to employ the Ratio method in our investigated area. For the fracture pressure gradient methods, besides Hubbert & Willis [max] method, again Eaton’s drilling and logging methods were successfully employed. But Hubbert & Willis [min] and Mathew & Kelly failed to comply our goal. To go to the next step and interpret the types of pressure zones those were observed in the area of study, and predict the casing seating depth and equivalent mud circulating (EMC), two methods were selected to calculate pore and fracture pressure gradients. These methods are Eaton’s drilling techniques. The reason for choosing using these equations is the full availability of the required data (drilling raw data) that are needed to employ them. Although Eaton’s well logging techniques are applicable, they were not selected for the next step because we have the date for only one well (S5) and the same source of data was used to estimate the well logging data for the other tested wells.

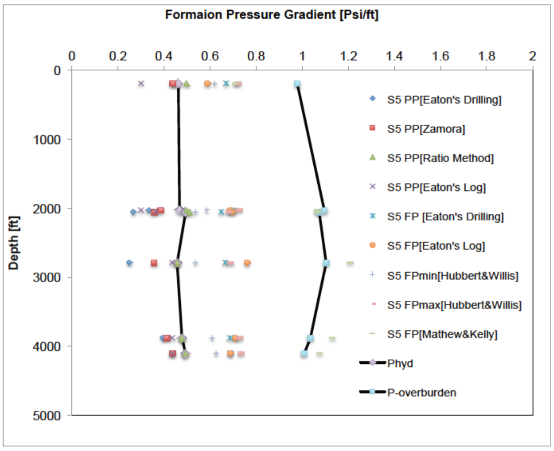

Fig. 6. Hydrostatic and formation pressure gradients for Well S5.

Table. 1. Pore pressure prediction methods

Pore Pressure Gradient [Psi/ft]				
Well Number	Methods			
	Eaton's Drilling	Eaton's Logging	Zamora	Ratio Method
S1	P	P	P	F
S2	P	F	P	F
S3	P	P	P	F
S4	P	P	F	F
S5	P	P	P	F
S6	P	P	P	F
S7	F	F	F	P
S8	P	P	P	F
S9	P	P	P	F
S10	P	P	P	F

Table. 2. Fracture pressure prediction methods.

Fracture Pressure Gradient [Psi/ft]					
Well Number	Methods				
	Eaton's Drilling	Eaton's Logging	Hubbert & Willis [min]	Hubbert & Willis [max]	Matthew & Kelly
S1	P	P	P	P	F
S2	P	P	F	P	F
S3	P	P	F	P	F
S4	P	P	P	P	F
S5	P	P	F	P	F
S6	P	P	P	P	F
S7	P	P	P	P	F
S8	P	P	F	P	F
S9	P	P	F	P	F
S10	P	P	F	P	F

The predicted formation pore and fracture pressure gradients of all wells using Eaton's equations have been collected in one plot (**Fig 7**), the results present a slightly subnormal to normal pore pressure region from the top of these wells to 2,438 ft. The subnormal pore pressure gradient zone is noticed between 2,438 ft. and 3,653 ft. Deeper than 3,653 to the top of the reservoirs is considered as normal. Throughout the reservoirs, the pore pressure is subnormal to normal. It is clear that the overpressure zone does not exist in this area of study. For the fracture pressure gradient, the trend is stable and almost unchangeable with depth. Finally, the outcomes of the dc-exponent and drilling pore are matched and confirm the existence of a subnormal-pressure zone as mentioned above. Faults, high permeable zones, etc. could be the reason for having low pore pressure at any depth [18]. In the area of study, when we look at the lithology column as presented in **Fig 3**, we notice that the formations from the top of the reservoir and go up are Wadi Thamat FM., Umm Dahiy FM. Bu Hashish FM. and Marada FM. These formations composed mainly from carbonates rocks such as micritic limestone in Al Gata member, chalky limestone in Thmed al Qusur member, fossiliferous and coquinoid limestone, dolomitic limestone with traces of gypsum in Qararat al Jifah Member, limestones and dolomites in Umm ad Dahiy Formation, and marly limestones and oolitic limestones in Al Khums Formation. Besides some clastic rocks (e.g., fluvial sandstones, grading into siltstones and silty claystones with traces of gypsum) in Marada formation.[19] It is clear from the composition of these formations that the expected porosity and permeability are high and could be the main reason for having subnormal pore pressure zone that we observed in this study in the interval (2,438 ft. - 3,653 ft.) above the reservoir formation. Finally, it is significant to predict the formation pore pressure to avoid loss circulation and keep the safe drilling process.

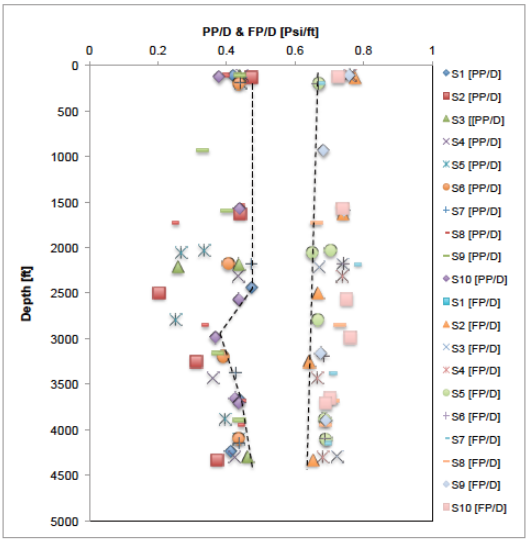

Fig. 7: Formation pore and fracture pressure gradients for ten wells in Al-Ghani field.

B. Casing Setting Depths and Equivalent Mud Circulation

The determination of casing seating depth and Equivalent Mud Circulation (EMC) is obtainable, as long as the pore and fracture pressure trends are available. As presented in **Fig 8**, five strings and three mud weights are needed to drill and case a well in this area of study. Starting with the Conductor casing from the top downwards to the depth of 500 ft to prevent the loose sand formation from collapsing. Next, to that, the Surface casing that can be placed to the depth of 2,500 ft. Then, Intermediate casing and Intermediate liner are placed to 3,500 ft and ~ 3,750 ft depths, respectively. Finally, the Production liner is placed from the bottom of the cap rock to the bottom of the reservoir formation. For the EMC, three different mud weights were chosen for the drilling in this area. These mud weight values present the maximum pressure in that interval depths plus the safety pressure applied by the drilling companies for the drilling processes in Sirte basin, which is 200 psi to 400 psi where it depends on the fracture pressure in the investigated area. In this study, we decided to select the smallest applied pressure (200 psi). So three mud weights (10.2 Ib/g, 9.2 Ib/g and 9.8 Ib/g) were selected for 0 – 2,438, 2,438 – 3,653 ft, and 3,653 – TVD intervals, respectively. It is obvious that all of the chosen EMC values are greater than the normal pore pressure value, which is equal to the water density (8.33 Ib/g). Based on our results, the weakest zone (lowest fracture pressure depth) was noticed in the same region of subnormal pore pressure interval. This fracture pressure value represents the mud weight value (12.3 Ib/g) that might be applied to initiate a fracture in the formation. So to avoid creating a fracture and having a loose circulation zone, the applied mud weight must be less than 12.3 Ib/g. Finally, it is important to mention that the casing seating depths would slightly be different if the prediction procedure was individually used for each well due to the depth differences, but not on the collected plot of the ten wells.

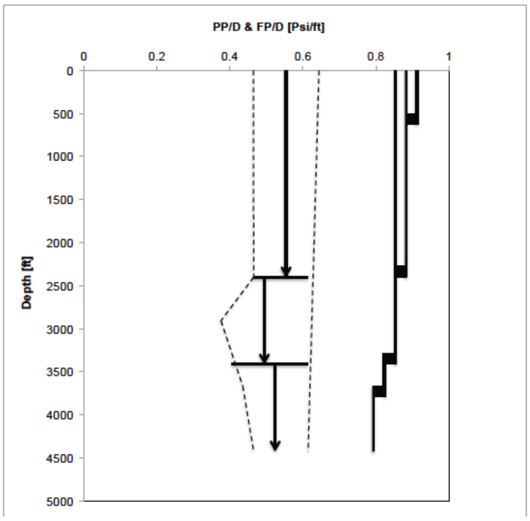

Fig. 8: Casing numbers, casing seating depths, and EMC of Al Ghani field

V. Conclusion

The prediction of formation pore and fracture pressure gradients is significant in terms of safely drilling a well in the studied area. This study demonstrated that the successful application of Eaton's drilling and logging, and Zamora methods to predict the formation pore pressure. Besides, the suitable employment of Eaton's drilling and logging, and Hubert and Willis [max] techniques in estimating formation fracture pressure. According to these methods, it was noticed that Al-Ghani area represents only a subnormal and normal pore pressure, and a consistent fracture pressure with depth. Based on the gathered formation pressure gradients of ten wells, casing seating depths and equivalent mud circulation values have been determined. The results of this study can be employed as a reference for prospect drilling developments in Al-Ghani field-Sirte basin or other close locations.

Nomenclature

D = depth (ft).
d_{bit} = Bit Diameter, (in),
$d_{c,normal}$ = normalized dc-exponent value.
$d_{c,observed}$ = actual dc-exponent value.
P_F = formation fracture pressure (psi).
$P_{pnormal}$ = normal formation pore pressure (psi).
P_p = Pore pressure (psi).
ROP = Penetration Rate (ft/h),
RPM = Round per minute,
WOB = Weight on the bit (lb),
σ_{ob} = Overburden pressure gradient (psi).
σ_v = Effective vertical stress (psi)
Δt_{normal} is the sonic transit time (*m*S/ft).
Δt is the sonic transit time in shales obtained from well logging (*m*S/ft).
ν = Poisson's ratio.
ρ_{normal} = Normal Hydrostatic Gradient (Ib/gal),
ρ_{actual} = Current mud Weight (Ib/gal).

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