

The Application of Peng-Robinson Equation of State to Predict Natural Gas Behaviour in Oil-Based Drilling Fluid

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ABSTRACT

A major problem associated with the use of oil base drilling fluid is the increased difficulty of detecting gas which enters the borehole and dissolves in the drilling fluid. Previous authors have made computer-simulated comparisons between a water-base and an oil-based drilling fluid for one specific field example. However, a method is needed that will permit field personnel to quickly estimate the amount of dissolved gas that can be associated with an observed pit gain for the field conditions present. . In this paper, methods were presented for estimating the swelling of oil based drilling fluid due to dissolved gas. This involves the determination of the formation volume factors of the fluids (oil-gas-drilling fluid mixture) at given subsurface conditions using Peng-Robinson equation of state and hence the detection of the natural gas intrusion into a given well and subsequent calculation of the pit gains.

The results were compared with similar but empirically obtained data. The pressure profile for a well at given conditions have also been made thereby aiding the several predictions that will lead to proper fluid flow control.

INTRODUCTION

One of the greatest challenges for the complex oil and gas exploration and exploitation (scenarios such as deep waters and high pressure - high temperature wells) is related to the drilling fluids, which must combine the technical requirements with environmental regulatory issues. Synthetic based drilling fluids have been developed to provide the technical performance of the convectional oil based drilling mud without their environmental damage, reducing the

impact of cuttings discharge or eventually spill accidents. Among the synthetic oil available for drilling fluids, n-paraffin is the most commonly used around the world.

An important aspect that should be addressed when drilling with a synthetic fluid is the peculiarities concerned with well control. Because of the solubility of formation gas in oil based fluids. It could be completely dissolved in the mud at a bottom hole temperature and pressure conditions making kick detection very difficult. Depending on the pressure-volume-temperature (PVT) behaviour of the gas-oil mixture, the amount of gas in a well could be underestimated and the well control procedures affected. In the worst situation, an uncontrolled kick can turn into a blowout with all the inherent financial and environmental damage and possible casualties.

The study of the PVT properties of the oil based mud is essential for the complete knowledge of the gas-liquid mixture behaviour in kick situation. This includes determination of properties such as bubble point pressure, gas solubility, density of the gas-oil mixture and formation volume factors. These properties can lead to the computation of the amount of dissolved gas in the mud, and the exact depth the gas influx would come out of solution. The thermodynamic model can also be applied to well control computer simulators for personnel training and the study of the best procedures to reduce the associated problems and risk. *It is important to emphasize that the thermodynamics properties and determination are inherent of each formation and drilling fluid pair that will be in contact during well control situation.*

Considering the importance of the subject, the main objective of this work is to present the application of Peng-Robinson equation of state to natural gas behaviour in drilling fluid, and also to predict their PVT behaviour. The developed relationship was applied to illustrate the pit gain calculations.

LITERATURE REVIEW

In previous work done by Thomas *et al.*¹, it was shown using a proprietary computer program, that the surface responses to a gas kick (i.e., annular flow rate and pit gain) are less in oil-based drilling fluids. For one example well geometry, they compared the observed pit gain and annular

flow rate due to a gas kick taken in an oil base and a water-based drilling fluid. In addition, it was concluded that the damping of surface responses when a gas kick is taken in an oil-based drilling fluid occurs due to gas solubility in the drilling fluid.

O'Bryan *et al.*^{4, 8} performed a comprehensive study about the parameters which affect gas solubility in oil based drilling fluids and its effect on kick detection. Their experimental results for the tested fluids showed that gas solubility increases with pressure and decreases with temperature, molecular weight of the oil and the amount of solid, brine and emulsifier in the drilling fluid. Predictions for gas solubility and formation volume factor considering the additivity hypothesis have shown relative differences varying from 1 to 16%. The authors also proposed a methodology for pit gain calculation and showed that it could be 80% less for an oil based mud. Their data are used to validate the present work.

Silva *et al.*¹⁶ studied the mixture of methane – n-paraffin and methane - ester at two temperature (160°F and 190°F) for pressure up to 7,500 psi., their result showed a small influence of the temperature on the PVT properties, for the range of temperatures and pressures of the experiments. Methane solubility in the n-paraffin was shown to be greater than in the ester, requiring a greater attention for kick detection and circulation.

Ribeiro *et al.*²³ reported their experiment conducted on synthetic fluid study presenting experimental data for methane (iso+ paraffin mixtures and discussing the well control consequences of the gas-synthetic fluid mixtures. The authors also presented a thermodynamic modeling of the gas-liquid mixture behaviour based on Krichevsky-Kasarnovsky (KK) correction of Henry's law.

Atolini and Robeiro²⁴ present a comprehensive literature review about the behaviour of the vapour-liquid mixtures at high temperatures and pressures, particularly directed to the well control problem (as in discussion).

Based on the foregoing contributions, the understanding of the gas-synthetic drilling fluid interaction, particularly for the case of methane – n-paraffin unweighted emulsion, would be

very beneficial for the present well control modeling and practice, which is the main objective of the present work.

This paper presents a method that uses an experimentally calibrated EOS² to estimate the swelling of oil-based drilling fluids caused by dissolved methane. With this method, the pit gain associated with a given kick size can be determined

HYDROCARBON-GAS-DRILLING FLUID INTERACTION DURING

The influx fluid (Natural gas) enters the well-bore where it mixes with the fluid phase of the drilling mud and does not saturate that phase .part of the fluid may be miscible with the fluid phase, that is , the sum of the two mixed volumes may not equal the two volumes. The drilling fluid, whether water based, contains opening or intermolecular voids that the influx gas may enter and occupy. There may also be chemical reaction, but this is beyond the scope of this paper.

As the under saturated fluid is circulated up the annulus, both pressure and temperature decline until the resultant decrease in solubility allows any gas to break out of solution and manifest itself as a bubble of gas rather than as a fluid dispersed in the molecular voids of a continuous phase. This sudden release of gas at a specific temperature and pressure is referred to as the bubble point and would normally occur if the fluid were already saturated with gas at another temperature and pressure

Bubble point depth

Bubble point depth is that depth in the annulus/hole at corresponding temperature and pressure at which the first bubble of drilled gas would form from the drilling fluid-gas mixture either as a result of saturation of saturation of the mud by the gas or due to reduced temperature and pressure or vice versa affecting the solubility of the gases in the mud. While it is possible to determine the bubble point pressure with an Equation of State model, it was generally agreed that using an empirical correlation for gas solubilities was easier and more accurate.

Bubble point pressure (P_b) can be obtained from the Oistien-Glaso equation

$$P_b = 18.2 \left[\frac{R_s^{0.83}}{\gamma_g} \left\{ 10^{T/1100 - API/80} \right\} - 1.4 \right] \quad (1)$$

T = Temperature

γ = Specific gravity of methane

API = API gravity for the oil.

R_s = Gas-Oil ratio at bubble point pressure

P_b = Bubble point pressure.

And consequently the bubble point depth D_h is given as,

$$D_h = \frac{P_b}{0.052 \rho_{gm}} \quad (2)$$

GAS-OIL RATIO (R_s)

This ratio describes the fraction of gas to liquid for any given gas-mud mixture whether oil based or water based. If water based then $R_s = GWR =$ Gas-Water ratio. And if oil based the $R_s =$ Gas-Oil ratio.

Experiments show that at low pressure (i.e below 2000 psia) gas solubility increases almost linearly with increasing pressure⁴. This portion of the curve can be estimated by O'Bryan et al.'s⁴ equation:

$$R_s = \{P/(KT^M)\}^n \quad (3)$$

The values of K, M and n for various gases in the equation above are listed below, and applies only below the pressure at which gas becomes miscible with oil in all proportion

Gas	K	M	n
HC gas	1.922	0.2552	$0.376+1.166\gamma_g+(0.0027-0.00492\gamma_g)T-(4.51\times 10^{-6}-8.198\times 10^{-6}\gamma_g)T^2$
CO ₂	0.058	0.7134	1.0

Also the gas free molecular weight of the base oil is adjusted to accurately predict the swelling of the base oil caused by the dissolved gas. The empirically developed formulae from measurements of the swelling of diesel oil caused by various volume of dissolved methane. The molecular weight adjustment term, G, is added to the average gas free molecular weight of the base oil being considered and is given as

$$G = 26.4-0.01607R_s+ (1.641\times 10^{-7}) R_s^2 \quad (4)$$

Oil-based Drilling-Fluid Expansion

Liquid swelling/expansion caused by dissolved gas is usually represented by a Formation Volume Factor, B, defined as the ratio of the volume of liquid and dissolved gas at a given pressure and temperature to the volume of gas-free liquid at standard pressure and temperature. The FVF for an oil-based drilling fluid, B_f is a function of the volume fraction of base oil and water used in the preparation of the drilling fluid and the FVF of each phase.

Swelling of based oil caused by dissolved gas, B_o is calculated with Peng-Robinson equation of state (PREOS), which is out line in the appendix. Table 1 list the composition, critical pressure, critical temperature and the eccentric factors used in the equation of state model for several base oils commonly used in drilling fluids. It also lists the binary interaction coefficients³ used to calibrate the EOS model.

Because the volume of water used in the preparation of most oil based drilling fluids is small compared with the volume of oil used the contribution of water swelling compared to the overall swelling is negligible and was not consider i.e. water FVF was assumed to be constant (B_w = 1.0 bbi/STB).

The Formation Volume Factor for the gas intruded drilling fluid at subsurface conditions was calculated on the basis of unit mass of the drilling fluid. The Formation Volume Factor for the drilling fluid at a given pressure and temperature is equal to the sum of the volumes of each phase of the unit mass at the given pressure and temperature divided by the surface volume of the unit mass.

Generally for practical field conditions, reservoir temperature exceeds the critical temperature and the hydrocarbon is usually in gaseous form. Gas behaviour in the annulus is therefore a function of⁵

- a. Type of gas mixture
- b. Gas-Liquid mixture ratio (liquid = drilling fluid)
- c. Temperature
- d. Pressure
- e. Compressibility factor
- f. Solubility

Field Conditions and Observation Applicable to Drilled Gas- Drilling Fluid Mixture Behaviour.

- a. Any gas intrusion will be reflected as a volume increase in the annulus but may not exactly be a one to one ratio. The volume increase may or may not be deductible on the ability of the drilling crew. Immediate position flow from high permeability formations should be easily detectable as compared with the low permeability formations.
- b. Hydrocarbon gases will dissolve in the drilling fluid. Under-saturation could be encountered and continuous position flow occur undetected until the bubble point is reached at which time gas expansion would occur. This expansion could then be easily detected at the surface and kick control procedures initiated.
- c. A given volume of hydrocarbon gas intrusion, which saturate water based drilling fluid would be at the bubble point. At the surface for an oil based drilling fluid however the same gas volume may not saturate it with respect to (same percent fluid, gas/oil ratio, same temperature and pressure) and consequently mask the intrusion. Now this is

dangerous as the masking makes it difficult to monitor the rate of gas expansion in the drilling and hence the point at which bubble point should occur. For an oil based mud, this bubble point would occur higher up close to the surface, given the drilling little or no time to react and control it.

- d. For any given hydrocarbon gas volume intrusion that does not saturate the oil based mud (with the same percentage fluid, gas/oil ratio, same temperature and pressure) the bubble point will occur higher up the annulus with the oil mud.
- e. The solubility of hydrocarbon gases decrease with increase in temperature and this means that the point could successfully lower in the hole, since for oil wells, the circulating annular temperature increase with increasing depth (due to increase in geothermal gradients and other factors)

Acid gas on the other hand (CO_2 , H_2S) which are also minor constituents of drilled gas increases in solubility with increase in temperature and thus implying that the bubble point would occur higher in the hole close to the surface. Thus it can be said that, for any typical drilled gas mixture (methane (alkanes), acid gases) and drilling mud mixture, the hydrocarbon (alkanes) would be the first to breakout of solution followed by CO_2 and H_2S , as the temperature are further reduced⁶.

Pit-Gain Calculations

The pit gain in an oil-based drilling fluid depends on the volume of mud in which it is mixed. The volume of drilling fluid displaced from the well by a given standard volume of gas tends to decrease as the volume of mud in which it is dissolved increases⁷.

When a kick is taken, the volume of drilling fluid that the gas contacts is controlled to a great extent by the rate at which drilling fluid is being circulated past the bit. The initial gas/drilling fluid ratio F_{gf} when the kick is being taken can be computed with the following equation:

$$F_{gf} = \frac{q_g}{q_f} \quad (5)$$

If this initial gas/drilling fluid ratio is less than the solution gas/drilling fluid ratio, then little additional mixing will occur when the gas goes into solution. If the initial gas/drilling ratio is greater than the solution gas/drilling fluid ratio, then free gas bubbles will tend to rise into previously un-contacted drilling fluid and goes into solution. Natural mixing resulting from bubble rise will cause new drilling fluid to be contacted until the initial gas/drilling fluid ratio is approximately equal to the solution gas/drilling fluid ratio.

MODEL DEVELOPMENT

The pit-gain volume, V_g per 1,000 scf (28.64 stb m³) of gas kick can be estimated with the following equation⁴:

$$V_g = \left(\frac{1000}{F_{gfi}} \right) [f_o (F_{og} - F_o)] \quad (6)$$

F_{gfi} is calculated with equation (6) or is the solution gas/drilling ratio and the FVF's F_{og} and F_o can be determined with the Equation of State model.

The molar volume V_M can be obtained from Peng Robinson Equation of State for fluids

$$P = \frac{RT}{v_M - b} - \frac{a(T)}{v_M(v_M + b) + b(v_M - b)} \quad (7)$$

Where, the equation has the following constants for pure components at the critical point

$$a(T) = a(T_c) (1 + k (1 - Tr^{0.5}))^2$$

$$a(T_c) = 0.45724 R_c^2 T_c^2 P_c^{-1}$$

$$k = 0.37464 - 1.5422\omega + 0.2699\omega^2$$

$$b(T_c) = 0.0778RT_c P_c^{-1}$$

When equation (7) is re-written,

$$Z^3 - (1-B)Z^2 + (A-3B^2-2B)Z - (AB-B^2-B^3) = 0 \quad (8)$$

Where $A = \frac{a(T)P}{R^2T^2}$

$$B = \frac{bP}{RT}$$

$$Z = \frac{Pv_M}{RT} \quad (9)$$

For a mixture: oil based mud-gas mixture

$$F_{og} = \frac{V_{oggc}}{V_{ogsc}}$$

F_{og} is used to characterize the swelling of a liquid resulting from dissolved gas, pressure and temperature.

And

$$V_{oggc} = \frac{ZRT_{oggc}}{P_{oggc}}$$

Also the following mixing rule is applied, in solving for the molecular attraction parameters.

$$a(T) = \sum_i \sum_j X_i X_j a_{ij}$$

$$b = \sum_i X_i b_i$$

$$a_{ij} = (1.0 - C_{ij}) a_i^{0.5} a_j^{0.5}$$

$V_{og\ gc}$ and $V_{og\ sc}$ can be obtained from

Where,

$$V_{og\ gc} = \frac{RT_{og} Z_{og}}{P_{og}} \Big|_{gc}$$

$$V_{og\ sc} = \frac{RT_{og} Z_{og}}{P_{og}} \Big|_{sc}$$

$Z_{og|sc}$ and $Z_{og|gc}$ are obtained from the Peng-Robinson equation (8), using the above mixing rule and solved using Newton iterative method, equation A1 yields one or three roots

For the two phase mixtures the smallest positive factor (Z) is taken as the Compressibility factor for the liquid phase, while the highest positive factor (Z) is taken as the Compressibility factors for the gas phase. Equation 9 is then used to calculate the molar volume, V_M . With the knowledge of the molar volume and the pound moles of the liquid, the volume of the liquid at a given pressure and temperature can be determined

$$V = mV_M$$

When the equation of state model above was used to calculate the pit gain using the data from an experimental procedure in which gas-kick experiments was conducted in a 6,000ft well, in a well design to simulate drilling 3,000ft below the sea floor in a 3,000ft of water. Gas was injected into the bottom of the well through 1.315-in tubing run concentrically inside the drill-string when the gas kick was 4,978scf, Gas/Drilling fluid ratio of 185scf/stb and drilling fluid pump rate of 81.9 gal/min, the predicted pit gain was 1.15stb compared to measured pit gain⁸ of about 1.20stb, and when the kick size was 8,132 , Gas/drilling Ratio of 178 scf/STB and Drilling fluid pump rate of 119.7 gallon/min predicted pit gain was 1.95stb compared to measured pit gain⁸ of about 2.20stb these were reasonably close.

F_{og} and F_o can be computed from

$$F_o = \frac{V_{ogc}}{V_{osc}}$$

Similarly

$$F_{og} = \frac{V_{oggc}}{V_{ogsc}}$$

ANALYSIS OF RESULTS

The formation volume factors exhibit by the base oil without the kicked gas (fig. 1) shows that the formation volume factors at constant temperature decreases with pressure, and at the different temperatures it increases as the temperature increases. This confirms the expansion of the base oil with temperature resulting in the base oil occupying higher volume in the reservoir at increase temperature, for the same equivalent volume at the surface.

But when the base oil contain kicked gas(saturated with gas) the opposite was the case formation volume factor increases with pressure (fig.2) this also confirms that the solubility of the base oil increases with temperature resulting in the base oil with dissolved gas to occupying higher volume in the reservoir at higher temperature eventually leading to higher formation volume factor in comparatively to the formation volume factors of the same base oil with dissolved gas at lower temperature at same pressure (fig. 3).

Fig. 3, fig. 5 and fig 7 show that the formation volume factors at constant temperature increases as the fraction of the base oil in the mud increases this is to show that a given volume of saturated base oil with gas occupied higher volume at the reservoir than equal volume with lower

oil fraction this is due to the facts that higher oil fraction in mud gas mixture dissolved more gas. Figure 4 and figure 6 shows that the gas solubility do not depend much on the temperature (especially at pressure below 5000 psia) as at the higher temperature of 200°C and 300°C, temperature do not have much influence on the values of the Gas-oil ratio.

Figure 8 shows the plots of bubble point pressure (pressure at which the first gas was evolved from the oil) against temperature at different gas-oil ratio, the plots shows that the effects of temperature on the bubble point pressure become more noticeable at higher gas oil ratio than at lower gas oil ratio. These are due to the fact that higher gas-oil ratio indicates higher gas solubility. At a constant gas-oil ratio bubble point pressure increase with temperature this is expected as higher temperature indicates higher solubility of the dissolved gas in the oil. Hence the base oil occupied more volume in the reservoir at higher temperature.

Figure 9 shows the plots of bubble point depth (depth at which the first gas evolved from oil-gas mixture) against temperature at different gas-oil ratio. Results show that at constant temperature the bubble point pressure increases with the gas-oil ratio. These enable the drilling engineer to know at which depth would the gas starts evolving from the base oil so as to plan for how to handle the liberated gas when it gets to the surface (pit gain). The figure also shows that at constant gas-oil ratio the bubble point depth increases with temperature. These are due to the facts that the higher the temperature the lower the solubility of the gas in the base oil. Hence gas will be evolved earlier (i.e. at deeper depth) at higher temperature.

CONCLUSIONS

The prediction of the PVT properties (saturation pressure, solubility and formation volume factor) of methane- n paraffin based drilling fluid mixtures has been performed for pressure as high as 7000 psia and 100 – 300°F temperature range using equation of state.

Effects of temperature on the solubility of methane in n paraffin emulsion were not significant for the range of pressure and temperature analyzed. The mathematical model allowed the handy computation of important parameters for kick detection. Results showed that there were significant differences in term of gas volume when kicks were taken in oil based mud (OBM) compared to water based mud (WBM). Recommended drilling practices would involve reducing

the pit gain alarm set point when dealing with oil based mud and also reevaluating the surface gas separator capacity to handle an eventual gas influx excess.

Gas-OBM interaction during kick situation is pressure, temperature and mixture composition dependent. Precise thermodynamic modeling of gas-liquid phase behaviour is essential to successive well control simulation and prediction

NOMENCLATURE

a_i, a_j, a_{ij} = PREOS molecular-attraction parameters for Components i and j and their mixture, ij, respectively, psia-(ft³)²/ibm-mol² (MPa-(m³)²/kmol²)

A = PREOS constant

b_i, b_j, b_{ij} = PREOS molecular-attraction parameters for Components i and j and their mixture, ij, respectively, ft³/ibm-mol (m³/kmol)

B = FVF, bbl/STB (m³/stock-tank m³)

B_f = oil-based drilling fluid FVF, bbl/STB (m³/stock-tank m³)

B_o = oil FVF, bbl/STB (m³/stock-tank m³)

B_{og} = oil with dissolved gas FVF, bbl/STB (m³/stock-tank m³)

B_w = water FVF, bbl/STB (m³/stock-tank m³)

C = PREOS constants

C_{ij} = binary interaction coefficient, dimensionless

f_i, f_j = mole fraction of component I and j respectively, dimensionless.

f_o = volume fraction of the base oil in drilling fluid, dimensionless

F_{gi} = initial gas/drilling-fluid ratio, scf/STB (std m³/stock-tank m³)

G = molecular-weight adjustment term

K = regression coefficient, dimensionless

m = amount, ibm-mol (kmol)

M = regression coefficient, dimensionless

n = regression coefficient, dimensionless

p = pressure, psia (MPa)

p_c = critical pressure, psia (MPa)

P_{oggc} = Pressure of oil-gas mixture at a given condition

P_{oggs} = Pressure of oil-gas mixture at a standard condition

q_f = drilling-fluid flow rate, STB/min (stock-tank m^3/s)

q_g = gas flow rate, scf/min (std m^3/s)

R = universal gas constant, psia-bbl/ibm-mol- $^{\circ}R$ (MPa- $m^3/kmol-K$)

R_s = solution GOR, ,scf/STB (stb $m^3/stock m^3$)

T = temperature $^{\circ}R$ (K)

T_a = absolute temperature, $^{\circ}R$ (K)

T_c = critical temperature, $^{\circ}R$ (K)

T_r = reduced temperature, $^{\circ}R$ (K)

T_{oggc} = Temperature of oil-gas mixture at a given condition

T_{oggs} = Temperature of oil-gas mixture at a standard condition

V = volume, bbl (m^3)

V_g = pit gain volume, STB/Mscf (stock-tank $m^3/std m^3$)

V_M = molar volume, bbl/ibm-mol ($m^3/kmol$)

V_{sc} = volume at standard pressure and temperature STB (stock-tank m^3)

V_{osc} = Volume occupied by oil based mud without kick gas at standard conditions

V_{ogc} = Volume occupied by oil based mud without kick gas at given conditions

V_{ogsc} = Volume occupied by oil based mud containing kick gas at standard conditions

V_{oggc} = Volume occupied by oil based mud containing kick gas at given conditions

X_i, X_j = mole fraction of component I and j , respectively, dimensionless

Z = gas deviation factor, dimensionless.

α = PREOS constant, dimensionless

γ_g = gas specific gravity, dimensionless

ω = Pitzer eccentric factor, dimensionless

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TABLE 1.-DIESEL OIL, COMPOSITION AND CRITICAL PROPERTIES

Carbon number	Diesel (mol %)	T _c (°F)	P _c (psia)	Acentric factor	Binary interaction coefficient
8	0.22	1007.5	381.8	0.332	0.0381
9	0.88	1049.9	350.4	0.373	0.0407
10	3.79	1090.8	326.4	0.411	0.0427
11	10.68	1125.4	304.7	0.448	0.0442
12	13.45	1156.7	285.4	0.484	0.0458
13	13.73	1185.7	268.1	0.518	0.0488
14	16.01	1212.4	253.4	0.551	0.0502
15	15.18	1237.7	244.4	0.582	0.0512

16	9.10	1261.6	227.1	0.612	0.0523
17	8.53	1283.2	216.4	0.641	0.0500
18	4.19	1303.9	207.1	0.668	0.0537
19	2.40	1323.5	197.7	0.694	0.0544
20	1.16	1342.2	190.7	0.719	0.0551
21	0.42	1360.7	182.4	0.744	0.0558
22	0.12	1387.7	175.4	0.767	0.0565
23	0.11	1395.3	169.0	0.789	0.0565
24	0.02	1410.6	163.0	0.811	0.0571
25	0.01	1426.5	157.0	0.832	0.0575
TOTAL	100				

**TABLE 2. EXPERIMENTAL AND COMPUTED FVF'S FOR METHANE IN DIESEL OIL
AT 100°F**

GOR, scf/STB	Pressure, psia	Experimental FVF, bbl/stb	Predicted FVF, bbl/stb
0	3320	0.993	0.991
	3775	0.991	0.990
	4705	0.987	0.985
	4940	0.986	0.984
234	1225	1.070	1.066
	1585	1.080	1.067
	2205	1.053	1.051
259	1475	1.069	1.067
	2125	1.054	1.053
	2690	1.049	1.048
	3365	1.045	1.042
467	2545	1.137	1.135
	2625	1.127	1.128
	3710	1.117	1.116
	3825	1.197	1.194

695	4120	1.191	1.190
	4660	1.186	1.184
	5305	1.182	1.180
821	4075	1.254	1.248
	4285	1.243	1.242
	4490	1.233	1.230
	5070	1.225	1.232

**TABLE 3-COMPARISON OF EXPERIMENTALLY MEASURED AND COMPUTED FVF'S
FOR METHANE IN 7.95-ibm/gal OIL-BASED DRILLING FLUID**

Gas/Drilling- Fluid Ratio (scf/stb)	Temperature (°F)	Pressure (psia)	Experimental FVF (bbl/stb)	Predicted FVF (bbl/stb)	Deviation
163	100	1340	1.055	1.046	-0.009
		1560	1.052	1.049	-0.003
		1770	1.047	1.046	-0.001
		2020	1.041	1.044	+0.003
		2305	1.036	1.040	+0.004
		2645	1.031	1.035	+0.004
		3025	1.028	1.033	+0.005
119	200	1260	1.068	1.066	-0.002
		1480	1.083	1.080	-0.003
		1690	1.057	1.062	+0.005
		1985	1.052	1.055	+0.003
		2310	1.047	1.052	+0.005
		2680	1.044	1.050	+0.006
		3090	1.140	1.134	-0.006
		1475	1.143	1.137	-0.006
		2080	1.132	1.125	-0.007

142	300	2345	1.127	1.123	-0.004
		2660	1.122	1.118	-0.004
		2985	1.117	1.114	-0.003
		3340	1.114	1.109	-0.005

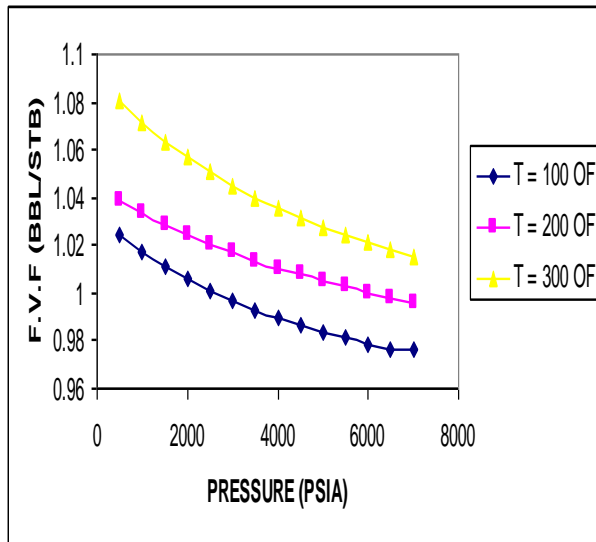


FIG. 1: PLOTS OF FORMATION VOLUME FACTORS OF OIL BASED MUD (WITHOUT DISSOLVED GAS) AGAINST PRESSURE FOR OIL FRACTION OF 0.85 AT DIFFERENT TEMPERATURE

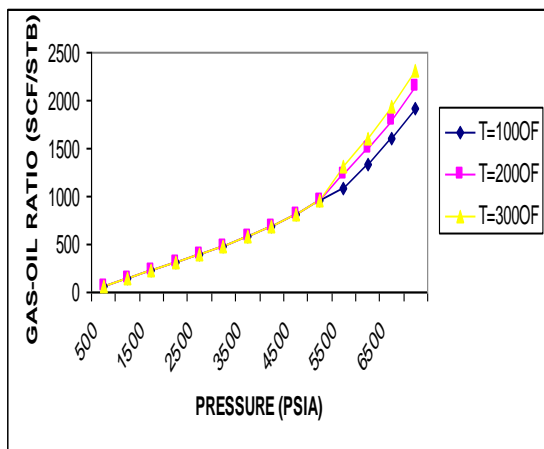


FIG 2: PLOTS OF SATURATED GAS-OIL-RATIO OF OIL BASED MUD AGAINST PRESSURE FOR OIL FRACTION OF 0.75 AT DIFFERENT TEMPERATURE

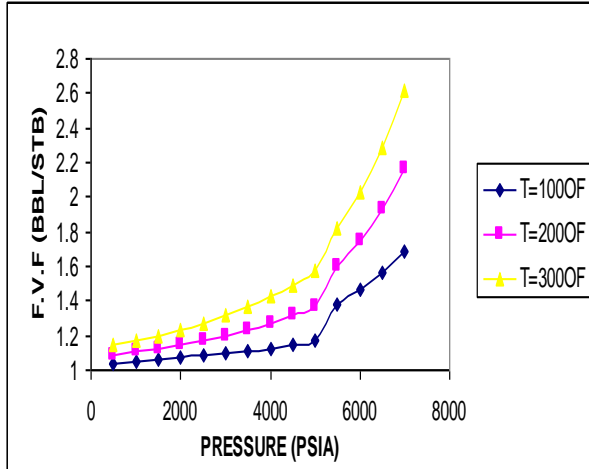


FIG 3: PLOTS OF FORMATION VOLUME FACTORS OF SATURATED OIL BASED MUD (WITH DISSOLVE GAS) AGAINST PRESSURE FOR OIL FRACTION OF 0.75 AT DIFFERENT TEMPERATURE

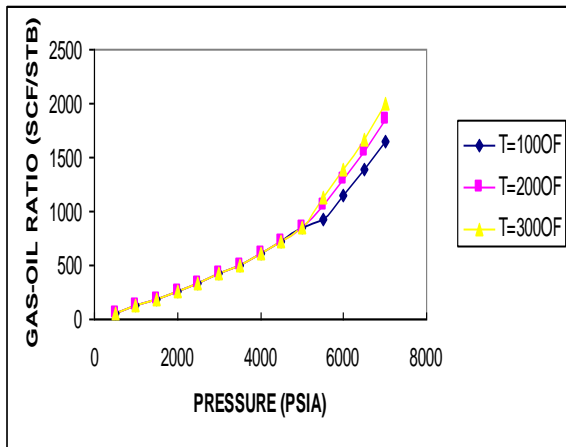


FIG 4: PLOTS OF GAS-OIL-RATIO OF SATURATED OIL BASED MUD AGAINST PRESSURE FOR OIL FRACTION OF 0.85 AT DIFFERENT TEMPERATURE

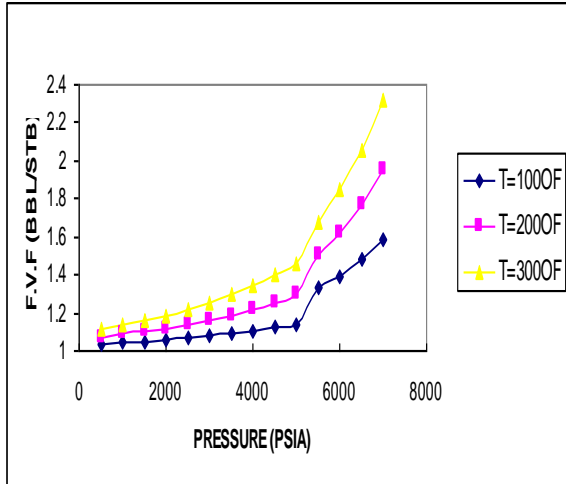


FIG 5: PLOTS OF FORMATION VOLUME FACTORS OF SATURATED OIL BASED MUD (WITH DISSOLVE GAS) AGAINST PRESSURE FOR OIL FRACTION OF 0.85 AT DIFFERENT TEMPERATURE

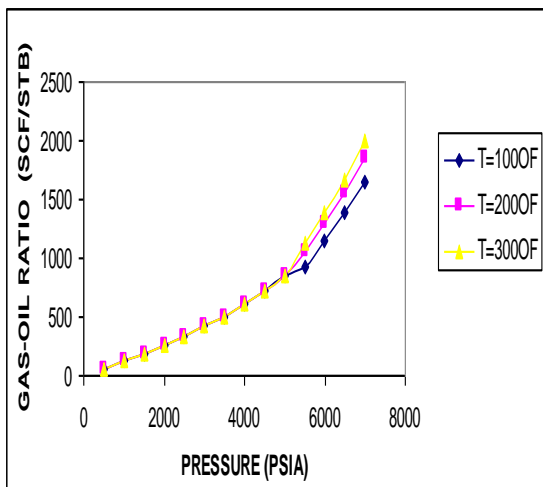


FIG. 6: PLOTS OF GAS-OIL-RATIO OF SATURATED OIL BASED MUD AGAINST PRESSURE FOR OIL FRACTION OF 0.95 AT DIFFERENT TEMPERATURE

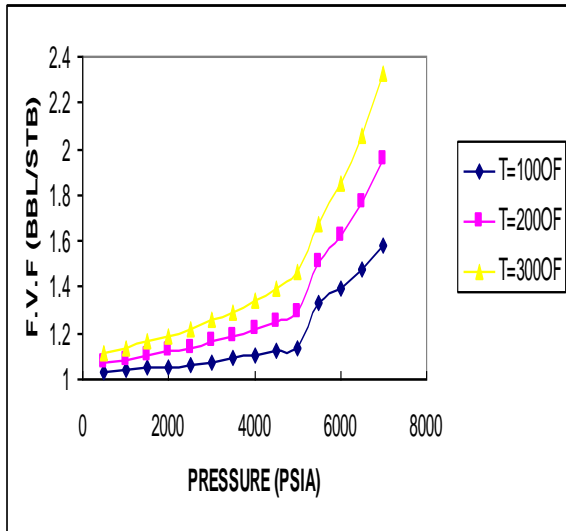


FIG 7: PLOTS OF FORMATION VOLUME FACTORS OF SATURATED OIL BASED MUD (WITH DISSOLVE GAS) AGAINST PRESSURE FOR OIL FRACTION OF 0.95 AT DIFFERENT TEMPERATURE

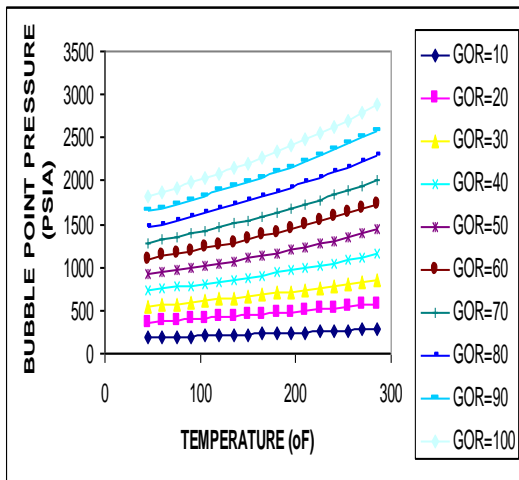


FIG 8: A PLOT OF BUBBLE POINT PRESSURE OF BASE OIL WITH DISSOLVED METHANE VS TEMPERATURE AT DIFFERENT GAS OIL RATIO

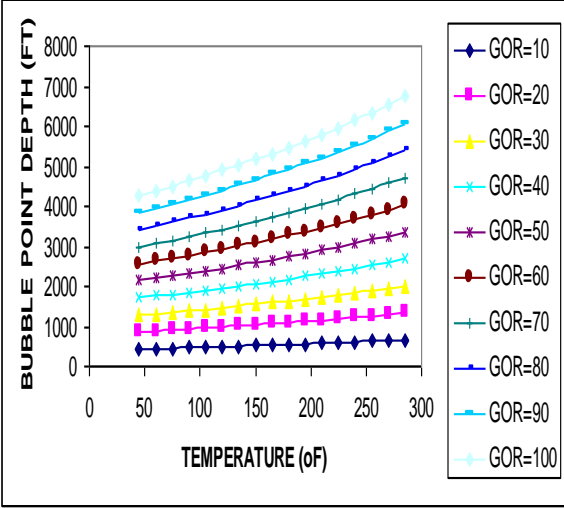


FIG 9: A PLOT OF THE CORRESPONDING BUBBLE POINT DEPTH OF BASE OIL WITH DISSOLVED METHANE VS TEMPERATURE AT DIFFERENT GAS OIL RATIO