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Reservoir Fluid analysis of Fajer pool of Nafoora oil field

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Abstract

The substances of interest to the reservoir engineer are oil, gas and water. Normally we would expect these materials to be fluid; i.e., either liquid or vapor. In some instances, though, the oil can be quite viscous or even solid. While we would usually think that the water should be liquid, the interstitial water is solid in some locations. This can occur in permafrost regions.

Hydrocarbons may be gaseous, liquid, or solid at normal temperature and pressure, depending on the number and arrangement of the carbon atoms in the molecules. Those compounds with up to four carbon atoms are gaseous; those with twenty or more are solids; and those in between are liquid. Liquid mixtures, such as crude oils, may contain either gaseous or solid compounds or both in solution. For instance, some oils are liquids at the wellhead, but are solid upon cooling due to crystallization of the solid compounds.

Keywords: *Reservoir Fluid, permafrost regions, wellhead, crystallization, Differential and Flash Liberation.*

1. Reservoir Fluid Properties

The properties of petroleum reservoir fluids depend on their initial state and on conditions created by production operations. Except a very thin and horizon pay, composition could markedly vary in the vertical direction. This gravitational effect goes together with the change in the behavior of fluids even in intact reservoirs.

In reservoir studies, we normally prefer to use data obtained from laboratory analysis of actual fluids recovered from the reservoir early (hopefully) in field life. Where analysis are not available or the accuracy of the information is in question, the reservoir engineer will need to rely on published correlations, analysis of similar fluids nearby reservoirs, etc. .[1]

1.1. Differential and Flash Liberation

Laboratory studies aim at the determination of characteristic properties of hydrocarbon reservoir fluids in order to supply data required for reservoir engineering calculations.

In an oil reservoir, or in a laboratory cell, gas will break out of solution from the oil as pressure is reduced. The quantity of gas liberated, as well as its composition, is somewhat dependent on the manner in which the pressure is reduced.

Differential liberation is that process where as free gas is liberated, it is removed from the proximity of the oil. Assume that a crude oil sample is in a laboratory PVT cell at reservoir temperature and initial reservoir pressure (P>Pb). Now the pressure decreased in steps with the resulting liquid volume noted at each new pressure (Figure 1). When the pressure reaches the point where the first bubble of gas is seen, this is the bubble point pressure. Now from this point on, at each new lower pressure, the gas and oil are allowed to come to equilibrium. At this time the, the gas is withdrawn from the cell. Then the liquid and gas volumes are measured. It is important to note that the gas volume is removed at constant pressure. Differential liberation is also known as a constant volume, variable composition process. .[2]

Now, if the gas were not removed at each pressure decrement, but allowed to remain in intimate contact with the liquid, then we would have a flash or equilibrium liberation. This is also called a constant composition, variable volume process

(Figure.2)

The PVT analysis for oil, provided by most laboratories, usually consists of three parts :

- flash expansion of the fluid sample to determine the bubble point pressure؛
- differential expansion of the fluid sample to determine the basic parameters Bo, Rs, Bg؛
- flash expansion of fluid samples through various separator combinations to enable the modification of laboratory derived PVT data to match field separator conditions.

In addition to the measurement of the oil viscosity at reservoir temperature, over the entire range of pressure steps from above bubble point to atmospheric pressure. .[3]

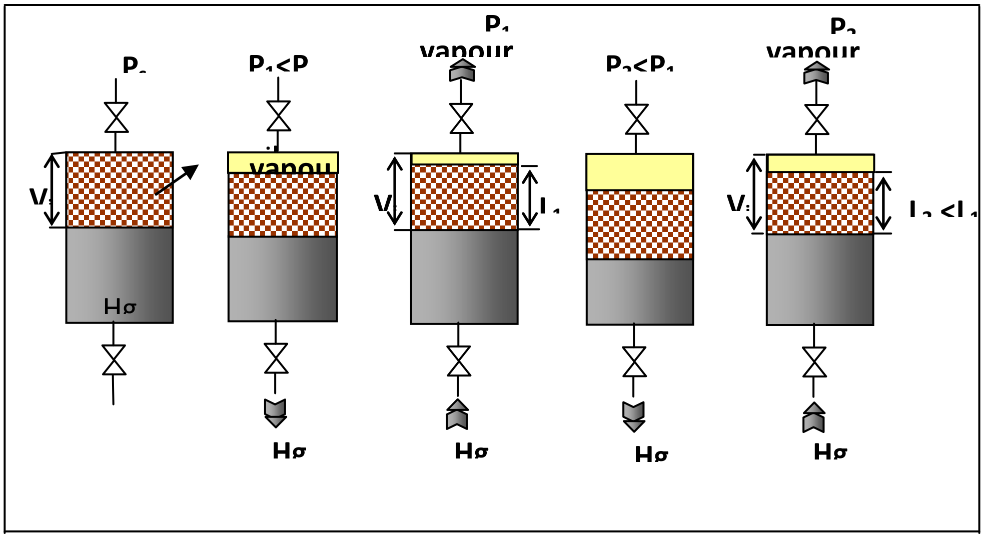


Figure 1. Typical oil differential study at reservoir temperature

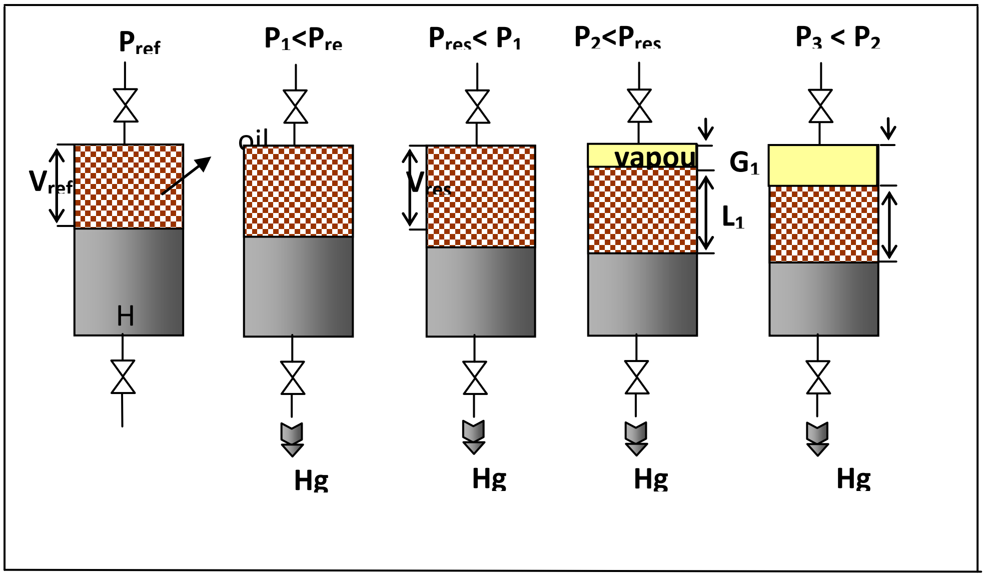


Figure 2. Typical black oil flash study at reservoir temperature

2. Correlations

Correlations developed aim at the prediction of PVT properties when the laboratory data are not available. It is also helpful to construct values even when a PVT analysis is available. They generally apply easily accessible parameters. These parameters are used for the characterization of the produced oil and its dissolved gas. Both are influenced by the production and separation conditions. Correlation's proposed for typical black oils are usually not recommended for high shrinkage oils or for the estimation of the PVT properties of condensates. A special treatment is required if the concentration of non-hydrocarbons exceeds 5 mole % in the dissolved gas. .[4[

2.1 Solution Gas/Oil Ratio

The solution gas/oil ratio, Rs, is defined as the volume of gas dissolved in a unit volume of stock tank oil at reservoir temperature and pressure. Common units are (SCF/STB) and standard cubic meter per stock tank cubic meter. (Figure 3) includes a typical graph of solution gas/oil ratio vs. pressure.

For pressure above the bubble point, all available gas went to solution, or the fluid system "ran out of gas", then, that the solution GOR curve is flat (indicating a constant amount of solution gas). For pressure below the bubble point, with decreasing pressures, the gas comes out of solution, the bubble point is a point of discontinuity (abrupt break in slope) on the Rs curve.

The solution GOR as function of pressure can be calculated by the following correlations: .[5]

2.1.1 Standing's empirical correlation

$$R_s = A_1 \gamma_g \left[(A_2 P + 1.4) 10^{(A_3 - A_4)} \right]^{1.2048} \qquad (1)$$

Where :

P = pressure of interest, psia،

Rs : solution gas/oil ratio, SCF/STB،

γ_g : specific gravity (relative density) of gas، A1 = 1.000, A2 = 0.05495, A3 = 0.0125 ^{o}API, and A4 = 0.00091 ^{o}F.

2.1.2 Vasquez-Beggs Correlation:

First, gas gravity corrected to a separator pressure of 100 psig using the following equation:

$$\gamma_{gs} = \gamma_g P\left[1 + (5.912 * 10^{-5})(API)(T_{sep})\left(log\frac{P_{sep}}{114.7}\right)\right] \tag{2}$$

Then, using the following table of coefficients, the Solution GOR can be calculated

Coefficient	API ≤ 30 °	API > 30 °
C1	0.0362	0.01178
C2	1.0937	1.1870
C3	25.7240	23.9310

$$R_s = (C_1)(\gamma gs)P^{C_2}\left[e^{C_3[API\,(T_f+460]}\right] \tag{3}$$

Where:

P : pressure of interest, psig،

γgs : corrected gas gravity to separator at 100 psig

Rsb : solution gas/oil ratio, SCF/STB،

API : stock tank oil gravity،

Tsep : separator temperature in ^{o}F،

Psep : actual separator pressure, psia, and

T_f : reservoir temperature, ^{o}F.

2.2.2 Formation Volume Factor for Oil

The oil formation volume factor, is the volume in barrels occupied in the reservoir, at the prevailing pressure and temperature, by one stock tank barrel of oil plus its dissolved gas at standard conditions (60 ^{o}F, 14.7 psia). (Figure 3) provides a typical graph of oil formation volume factor both below and above bubble point .

The Formation Volume Factor as a function of pressure can be calculated by the following correlations: .[3]

2.2.2.1 Standing’s correlation:

Standing has provided a correlation that can be used to estimate the oil formation volume factor (Bo :(

$$B_o = 0.9575 + 0.00012\left(A_1 Rs\left(\frac{\gamma_g}{\rho_o}\right)^{0.5} + A_2\right)^{1.2} \qquad (4)$$

Where

Bo: oil formation volume factor (saturated oil), RB/STB،

Rs: solution gas-oil ratio, SCF/STB،

γ_g : specific gravity (relative density) of gas،

ρ_o: oil density, and

A1=1.0, A2=1.25 ^{o}F

2.2.2.2 Vasquez and Beggs correlation

Vasquez and Beggs have estimated a method consists of calculating gas gravity corrected to separator pressure of 100 psig using equation (2). Then the following table of coefficient is used with equation (5), which is valid to calculate the formation volume factor (Bo) for pressures less than or equal to the bubble point pressure. .[4]

Coefficient	**API ≤ 30 ^{o}**	**API > 30 ^{o}**
C1	4.677(10^{-4})	4.670(10^{-4})
C2	1.751(10^{-5})	1.100(10^{-5})
C3	-1.811(10^{-8})	1.337(10^{-9})

$$B_o = 1 + C_{21} R_s + (T_f - 60)\left[\frac{API}{\gamma_{gs}}\right](C_2 + C_3\, R_s) \tag{5}$$

With increasing pressure above the bubble point, the oil formation volume factor decreases from that at the bubble point because no further free gas is available to go into solution. Hence the liquid is compressed. Because this is strictly an isothermal compression, the following equation is applicable:[4]

$$B_o = B_{ob}\, e^{-co(P-P_b)} \tag{6}$$

Where،

Bo: oil formation volume factor, BBL/STB،

Bob: oil formation volume factor, @ Pb, BBL/STB،

Rs: solution gas/oil ratio, SCF/STB،

T_f: reservoir temperature, oF،

API: oil stock tank gravity،

γgs: gas gravity corrected to separator pressure of 100 psig،

co: liquid compressibility above the bubble point, psi-1،

P: pressure (greater than or equal to Pb), psia, and

Pb: bubble point pressure, psia.

2.2.3 Oil Viscosity

Viscosity is the property of resistance to shear stress. Alternatively, viscosity may be viewed as a fluid's internal resistance to flow and therefore, depends greatly on density and composition. Reservoir oil viscosity, □o, is directly related to tank-oil gravity, gas in solution in the oil, pressure, and reservoir temperature. With the wide variety of composition s of crude oil, we should expect to find a large variation in oil viscosities even with oils of similar gravity, solution gas/oil ratio, reservoir temperature. Typical crude oil viscosity characteristics are graphed in (Figure 3). This graph is at reservoir temperature.[5[

Typical viscosity correlations are based on the prediction of viscosity at atmospheric pressure and at the temperature of interest. This value is modified for the solution gas/oil ratio at and below the bubble point and at the given temperature. It is further corrected for pressure above the bubble point for undersaturated oil.

The Oil Viscosity as a function of pressure can be calculated by the following correlations :

2.2.3.1 Standing's correlation

1) Dead Oil Viscosity: depends on API gravity of stock tank oil and temperature

of interest.

$$\mu_T = 0.32 + \frac{1.8\,(10)^7}{{A_0}^{4.53}}\left(\frac{360}{A_1 - 260}\right)^{A_2} \tag{7}$$

Where‹

μ_T : dead oil viscosity, cp‹

A0 : API gravity‹

$$log A_2 = 0.43 + \left(\frac{8.33}{A_0}\right)$$

Log A_2= 0.43 + (8.33 / A_0)

2) Saturated Oil Viscosity (by Beggs and Robinson): (P ≤ Pb)

$$\mu_s = A(\mu_T)^B \tag{8}$$

where‹

μ_s: saturated oil viscosity, cp‹

μ_T: dead-oil viscosity, cp, and

$A=10.715(A_0R_s+100)^{-0.515}$

$B = 5.44\ (A_0\ R_s + 100)^{-0.338}$ With $A_0 = 1.0$

3) Undersaturated Oil Viscosity (by Standing): It was found that oil viscosity increases with pressure above the bubble point. (P > Pb)

$$\mu_p = \mu_s + A_0(P - Pb)\lfloor 0.024(\mu_s)^{1.6} + 0.038(\mu_s)^{0.56}\rfloor \qquad (9)$$

where،

μ_p =undersaturated oil viscosity, cp،

μ_s =saturated oil viscosity, cp, and

A0=0.001

2.2.3.2 Vasquez-Beggs and Robinson Correlations:

a. Dead Oil Viscosity: (by Beggs and Robinson)

$$\mu_{od} = 10^x - 1.0 \qquad (10)$$

Where،

$X = T - 1.163\ exp(6.9824 - 0.04658\gamma API)$

μ_{od} = dead-oil viscosity, cp،

T =temperature of interest, oF, and

API = stock-tank oil gravity, API

b. Saturated Oil Viscosity (by Beggs and Robinson): $(P \le Pb)$

$$\mu_{os} = A(\mu_{od})^B \qquad (11)$$

Where،

μ_{os} =saturated oil viscosity, cp،

μ_{od} = dead-oil viscosity, co, and

$A=10.715(Rs+100^{)-0.515}$

$B=5.44\ (Rs+100^{)-.338}$

c. Undersaturated Oil Viscosity (by Vasquez and Beggs): (P > Pb)

$$\mu_o = \mu_{ob}\left(\frac{P}{Pb}\right)^m \qquad (12)$$

Where،

μ_o: viscosity at P > Pb, cp،

μ_{ob} : viscosity at Pb،

P: pressure of interest, psia

Pb : bubble point pressure, psia

The exponent m is pressure dependent and is calculated from

$$m = C_1 p c_{2\,EXP(C_3+C_4 p)} \qquad (13)$$

Where،

P =pressure of interest, psia،

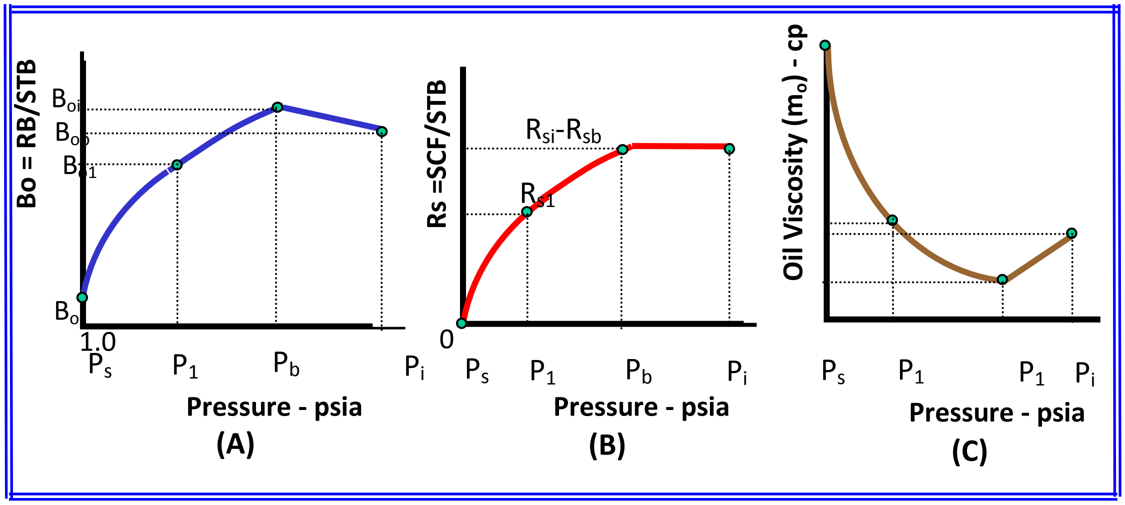
C1 = ،2.6

C2 = ،1.187

C3 = - ،11.513and

$$C4 = -8.98\ (10)^{-5}$$

Figure 3. Graphical presentation of fluid properties of a reservoir oil



3 PVT Analysis of Fajer Pool

3.1 Measured fluid properties

A reservoir fluid study by (Core Laboratories, UK LTD., Aberdeen, Scotland) was conducted on 18th March 1982 on a bottom hole oil samples taken from well G-212 .

(Table 1) shows the measured reservoir fluid parameters of Fajr pool at several pressure steps from above saturation pressure to the atmospheric pressure.

3.2 Calculated fluid properties

The Correlation's of Standing's and Vasquez-Beggs [ref.-1] were applied to the PVT data of Fajr Pool to calculate the fluid properties (using the Microsoft Excel) in order to match the measured fluid properties (Bo, Rs, µw), then, using these calculated fluid properties in the reservoir engineering calculation (i.e. OOIP). The results of the calculated fluid properties in comparison with the measured reservoir fluid properties are summarized in (Table 2) and graphically represented in (Figures: 4, 5 and 6). But as it can be seen in general from these figures, these applications resulted in the discovery that there is a disparity between the calculated and the measured fluid properties. May be this is due to the fact that the correlations were developed on the basis of flash study, where as the measurement is made on the basis of differential study. However, in this case, the mathematical interpolation was the solution to calculate the fluid properties (Bo, Rs, Rw) at the actual time step reservoir pressure. .[5]

Table1.Measuered Fluid Properties (Well G-212)

Pressure	**μo**	**Rs**	**Bo**
psia	**cp**	**cf/bbl**	**rb/stb**
5000	1.249	430	1.308
4000	1.173	430	1.316
3000	1.097	430	1.33
2500		430	1.337
2400		430	1.339
2300		430	1.34
2200		430	1.342
2100		430	1.343
2000	1.021	430	1.345
1900		430	1.347
1800	1.005	430	1.348
1700		430	1.35
1690 (P_b)	**1**	**430**	**1.354**
1600	1.01	411	1.346
1300	1.049	356	1.321
1000	1.098	302	1.295
700	1.162	245	1.269
400	1.263	185	1.238
200	1.379	135	1.209
100	1.548	102	1.185
0	2.234	0	1.086

4. Conclusion

1. Understanding the behavior of those PVT properties (oil formation volume factor(Bo), solution gas oil ratio,(Rs), oil viscosity (μo) versus pressure .
2. Evaluate PVT properties from (later) Field data, Laboratory studies, and Correlations helps in different reservoir studies such simulating the original hydrocarbon in place and recoveries.

5. References

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Table3.Compersion between maesuered and calculated fluid properties (Fajer pool)

Pressure	**Viscosity, cp**				**Pressure**	**Solution GOR, Cf/B**				**Pressure**	**Oil Volume Factor, RB/B**		
psia	**Measured**	**Standing**	**Beggs**		**psia**	**Measured**	**Standing**	**Beggs**		**psia**	**Measured**	**Standing**	**Beggs**
5000	1.249	0.50702	0.73492		5000	430	437.759	409.1		5000	1.308		1.24875
4000	1.173	0.4781	0.63437		4000	430	437.759	409.1		4000	1.316		1.25885
3000	1.097	0.44919	0.55048		3000	430	437.759	409.1		3000	1.33		1.26904
2000	1.021	0.42028	0.48725		2500	430	437.759	409.1		2500	1.337		1.27416
1800	1.005	0.41449	0.47759		2400	430	437.759	409.1		2400	1.339		1.27519
1690	**1**	**0.41157**	**0.47315**		2300	430	437.759	409.1		2300	1.34		1.27622
1600	1.01	0.4238	0.48798		2200	430	437.759	409.1		2200	1.342		1.27725
1300	1.049	0.46733	0.54106		2100	430	437.759	409.1		2100	1.343		1.27828
1000	1.098	0.52422	0.61112		2000	430	437.759	409.1		2000	1.345		1.27931
700	1.162	0.60213	0.70816		1900	430	437.759	409.1		1900	1.347		1.28034
400	1.263	0.71521	0.85103		1800	430	437.759	409.1		1800	1.348		1.28137
200	1.379	0.82172	0.98719		1700	430	437.759	409.1		1700	1.35		1.28241
100	1.548	0.88639	1.06995		**1690**	**430**	**437.759**	**409.1**		**1690**	**1.354**	**1.31063**	**1.28242**
0	2.234	0.9535	1.15039		1600	411	407.662	380.96		1600	1.346	1.29281	1.26809
					1300	356	318.819	297.74		1300	1.321	1.24116	1.2258
					1000	302	234.031	218.07		1000	1.295	1.19329	1.18544
					700	245	154.237	142.8		700	1.269	1.14967	1.14746
					400	185	81.0925	73.491		400	1.238	1.11109	1.11264
					200	135	37.7337	32.278		200	1.209	1.08894	1.092
					100	102	18.6236	14.177		100	1.185	1.07936	1.08291
					0	0	2.72805	0		0	1.086	1.07149	1.07534

A b c

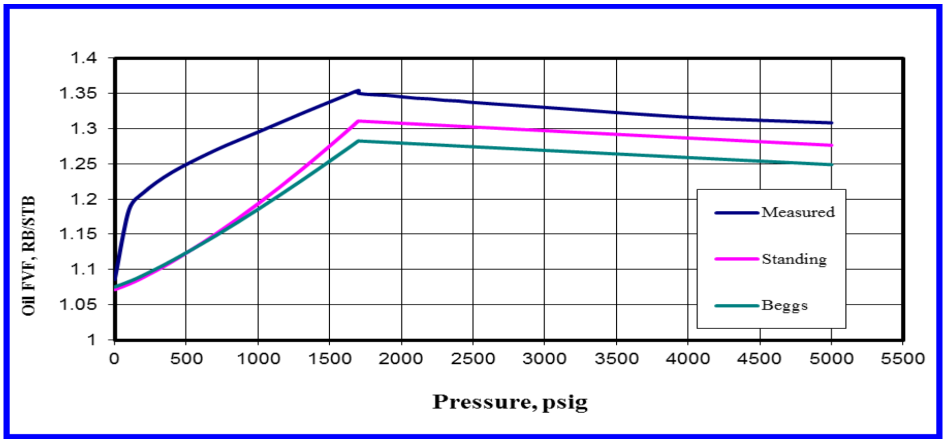

Figure4. Measured and calculated formation volume factor(Well G-212)

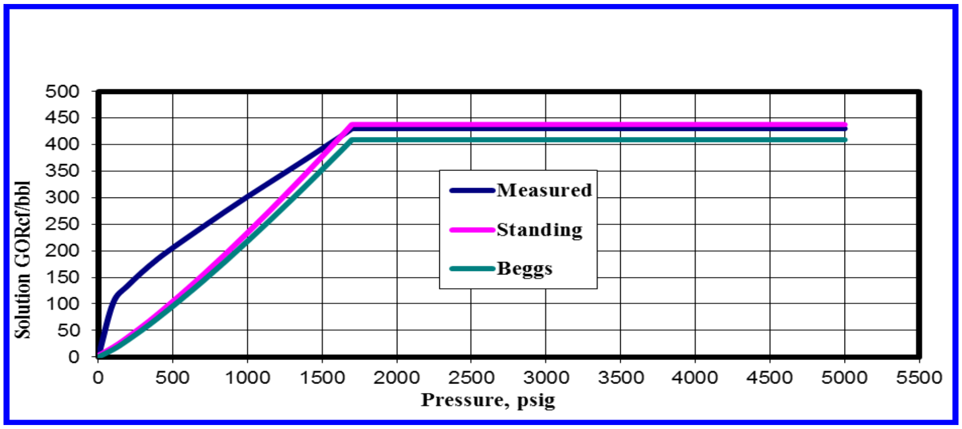

Figure.5. Measured and calculated Gas oil ration (Well G-212)

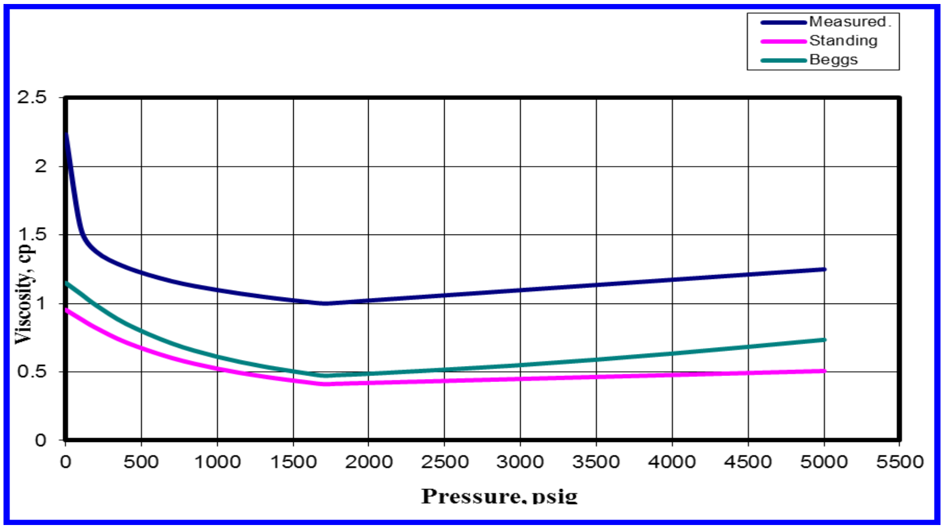

Figure.6. Measured and calculated viscosities (Well G212)