A case study of Black oil PVT modeling with Differential Liberation Expansion (DLE) analysis and standing correlations

Comment [DR1]: A topic such as Pressure, Volume and Temperature modeling with differential Liberation Expansion (DLE) analysis and standing correlations: A case study of Black Oil "Q" Field Samples Eastern Niger Delta

ABSTRACT

The black oil pressure, volume, and temperature (PVT) properties of well X were measured in the laboratory in a PT cell with subsurface and surface recombination samples. A jar of black oil samples was collected for the analysis. The PVT analysis was carried out at Reservoir Fluid Laboratory, Port Harcourt. Oil samples were collected from the Q oil field. The PVT analysis results were correlated to validate the bubble point pressure (P_b), oil isothermal combustibility, (C_o), oil formation volume factor (B_o), and the oil viscosity (μ_o. The PVT report gives P_o = 2000 psi while the Standing Correlation gives P_b = 1934.271 psi a difference of 65.7 psi, i.e. 3.3% and solution gas/oil ratio 647.3 SCF/STB while the Standing Correlation gives 671.03 SCF/STB a difference of 3.5%, oil formation volume factor (B_o) of 1.456 reses. Bbl/STB while standing correlations give (B_o) of 1.0675 res bbl/STB a difference of 3.6%. The isothermal compressibility of the oil ranges from 10.12 x 10^{-6} psi^{-1} at P < P_b (at 4500 psi) to 4.1309 x 10^{18} cp at 15 psi. The conclusion is that Gas began evolving at 2000 psig and increased as the pressure decreased. Also, it was noticed that at a high pressure of 4500 psig the black oil viscosity was low at 0.54 cp while at a lower pressure of 15 psiag the viscosity recorded was 1.38 cp. The crude is of high viscosity, with an average absolute error = 3.5% (0.035). The reservoir contains heavy crude oil with an API rating of 30. (Carlton Beal 2013).

Comment [DR2]: It will be better to state what led to this research

Comment [DR3]: Was it high or low

Comment [DR4]: Abstract should not have reference citing pls

Keywords: Pressure; Volume; temperature; crude oil; viscosity; Black Oil, Modeling.

INTRODUCTION

Reservoir is a subsurface rock formation containing liquids and/or gaseous hydrocarbons often found in sedimentary basins. The reservoir can release the hydrocarbon fluids at specific rates when a well is drilled (Okeke and Sylvester, 2016).

Black oils are hydrocarbon fluids in reservoir which exist as liquid with Average GOR of $3000fl^3$/BBL. PVT study is the analysis of pressure, volume and temperature of reservoir fluid with the purpose of assessing the economic worth of the reservoir. (Alomiar et al 2016).

Comment [DR5]: Whenever statement such as this is made pls it is advisable to cite your source

The three main reservoir fluids based on the phase diagram are:

- Oil,
- Gas and
- Condensate Reservoirs.

The Black oil pressure, volume, temperature (PVT) properties are best measured in the laboratory in a PVT cell with a bottom hole sample or recombined sample of oil and gas at the reservoir conditions (Tower, 2002). It is known that the measured properties of the crude oil and its dissolved gases depend on the conditions under which the properties are measured; several standard tests are conducted to determine these properties. (Sulaimon A, et all 2014).

For black oil, a viscosity test was conducted.

An accurate description of physical properties of crude oil is considerably important in the solution of reservoir Engineering studies(Dindoruk and Christman, 2004). These properties include: fluid gravity, specific gravity, solution gas/oil ratio, bubble point pressure, (P_b) oil formation volume factor (Bo), isothermal compressibility of oil (Co) oil density (ρ_o), crude oil viscosity (μ_o). (HemmantiSarapaedah et al 2014).

Comment [DR6]: For each property mentioned what are their usefulness to the oil?

In the absence of experimentally measured data (PVT report), the petroleum Engineer must determine the properties from empirically derived correlations (Standing, 1947).

AIMS AND OBJECTIVES

The aim of this research work is to propose a method for black oil PVTmodelling Differential Liberation Expansion (DLE)analysis results.

Comment [DR7]: What about the objectives; From your introduction you failed to address what lead to the problem you are trying to solve

Methodology

If the oil viscosity is desired at reservoir pressure and temperature, it is necessary to use a high-pressure rolling-ball viscosimeter(Moradi, 2013). This instrument measures the time required for a precision steel ball to roll a given distance in a tube filled with oil. The time of travel is converted to viscosity utilizing a calibration curve for the instrument.(Dindoruk and Christman, 2004). The clearance between the ball and the tube can be changed by changing the ball's diameter. The lower the fluid viscosity, the smaller the clearance used. A summary of the experimental method is given below (RUSKA Engineering Ltd. USA):

1. Vacuum the viscometer for at least one hour to remove air.
2. Set the temperature of the viscosimeter to the reservoir temperature
3. Fill the viscosimeter with the sample at a pressure above the reservoir pressure
4. Rock the housing with the barrel seal open. The ball rolls in the barrel, thereby stirring the liquid and ensuring thermal equilibrium and accurate pressure adjustment.
5. Hold the housing in its inverted position so that the ball comes to and against the barrel seal.

6. Turn the housing to the angle 700 position and shut the barrel seal. Release the ball to drop through the fluid in the barrel and note the fall time on the indicator. Repeat angles 45° and 23°.

Comment [DR8]: ?

7. Drop the pressure to the next lower pressure and take the fall time readings.

8. Shut the outlet valve when rocking the barrel at the bubble-point pressure and below it. Repeat steps 5-6 for each pressure point below the bubble point down to atmospheric pressure

9. The fall time is converted to viscosity values at the various pressure points utilizing calibration curves for the instrument.

Comment [DR9]: This is a poor methodology presentation. No figures

RESULTS AND DISSCUSSION

Validation of Oil Viscosity (μ_o) at Flash Conditions

Table1 shows the tables of Value for Complete PVT Report

Table 1: PVT parameters using standing correlations (Spivey, 2007).

P ***PSIG***	***R_{SO}*** ***SCF/STB***	***B_O*** ***BBL/STB***	***C_O*** ***(PSI^{-1})***	***μ_O*** ***CP***
4500	1781.5	1.041	10.12×10^{-6}	0.524
4000	1545.9	1.041	11.39×10^{-6}	0.5378
3500	1316.3	1.047	13.02×10^{-6}	0.5604
3000	1093.4	1.0514	15.19×10^{-6}	0.5951
2575	909.7	1.057	17.7×10^{-6}	0.6399
2420	844.2	1.0591	18.83×10^{-6}	0.66109
2000	671.03	1.0675	17.31×10^{-6}	0.73767
1600	512.9	1.0661	26.02×10^{-5}	0.8507
1200	362.78	1.0645	43.98×10^{-5}	1.0347
800	222.65	1.0630	92.18×10^{-5}	1.36554
400	96.64	1.0617	32.66×10^{-5}	2.065
15	1.85	1.0607	13.08×10^{-5}	4.1309×10^{18}

Validation of PVT Parameters using Standing Correlations

(i) Estimation of Bubble Point Pressure (P_b)

From standing correlations for the reservoir condition

R_{Sb}= 647.3 SCF/STB, TR – 186^{o}F, γ_g = 1.306, γ_oAPI = 30^{o}API

Comment [DR10]: Is it Rso

$$P_b = 18\left(\frac{R_{Sb}}{\gamma_g}\right)^{0.83} 10^{\gamma_g}$$

y_g = 0.00091 TR – 0.0125 γ_oAPI

y_g = 0.00091 (186) – 0.0125 (30)

y_g = -0.20574

$$P_b = 18\left(\frac{647.3}{1.306}\right)^{0.83} 10^{-0.20574}$$

$P_b = 18(495.6)^{0.83} \times 0.7383$

P_b = 1934.271 psi

The bubble pressure = 1934.271psi

(ii) Validation of Solution Gas/Oil Ratio at Flash Condition Solution Gas/Oil Ratio (R_{SO})

$P < P_b$

P = 2000psi

$$R_{SO} = \gamma_g\left[\frac{P}{18(10)^{-Yg}}\right]^{1.204}$$

γ_g = 1.306, P = 2000PSI, TR = 186^{o}F, γ_oAPI = 30

γ_g = 0.00091TR - γ_o.API

γ_g = 0.00091 (180) – 0.0125 (30)

γ_g = -0.20574

$$\therefore R_{SO} = 1.306\left[\frac{2000}{18(10)^{-0.20574}}\right]^{1.204}$$

= 6710.03 SCF/STB

P = 1600 PSI

$$R_{SO} = 1.306\left[\frac{1600}{18(10)^{-0.20574}}\right]^{1.204}$$

= 512.9 SCF/STB

P = 1200 PSI

$$R_{SO} = 1.306\left[\frac{1200}{18(10)^{-0.20574}}\right]^{1.204}$$

= 362.78 SCF/STB

P = 800 PSI

$$R_{SO} = 1.306\left[\frac{800}{18(10)^{-0.20574}}\right]^{1.204}$$

= 22.65 SCF/STB

P = 400 PSI

$$R_{SO} = 1.306\left[\frac{400}{18(10)^{-0.20574}}\right]^{1.204}$$

= 96.64 SCF/STB

P = 15 PSI

$$R_{SO} = 1.306\left[\frac{15}{18(10)^{-0.20574}}\right]^{1.204}$$

= 1.85 SCF/STB

$P > P_b$

P = 4500 PSI

$$R_{SO} = 1.306\left[\frac{4500}{18(10)^{-0.20574}}\right]^{1.204}$$

= 1781.5 SCF/STB

P = 4000 PSI

$$R_{SO} = 1.306\left[\frac{4000}{18(10)^{-0.20574}}\right]^{1.204}$$

= 1,545.9 SCF/STB

P = 3500 PSI

$$R_{SO} = 1.306\left[\frac{3500}{18(10)^{-0.20574}}\right]^{1.204}$$

= 1,316.3 SCF/STB

P = 3000 PSI

$$R_{SO} = 1.306\left[\frac{3000}{18(10)^{-0.20574}}\right]^{1.204}$$

= 1,093.4 SCF/STB

P = 2575 PSI

$$R_{SO} = 1.306\left[\frac{2575}{18(10)^{-0.20574}}\right]^{1.204}$$

= 909.7 SCF/STB

P = 2420 PSI

$$R_{SO} = 1.306\left[\frac{3000}{18(10)^{-0.20574}}\right]^{1.204}$$

= 844.2 SCF/STB

(iii) Validation of Oil Isothermal Compressibility (C_o) at Flash Condition

$P < P_b$

$$C_O = \frac{(5R_{sb} + 17.2T - 1180\gamma_g + 12.61\gamma_o.API - 1433)}{p(10)^5}$$

RS_{ob} = 647.3 SCF/STB, TR = 186°F, γ_g = 0.698, γ_o.API = 30

FOR P = 4500psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{4500(10)^5}$$

$$C_O = \frac{4{,}557.36}{p(10^5)}$$

$C_O = 10.12 \times 10^{-6}\ Psi^{-1}$

P = 4000 psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{4000(10)^5}$$

$C_O = 11.39 \times 10^{-6}\ Psi^{-1}$

P = 3500 psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{3500(10)^5}$$

$C_O = 13.02 \times 10^{-6}\ Psi^{-1}$

P = 3000 psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{3000(10)^5}$$

$C_O = 15.19 \times 10^{-6}\ Psi^{-1}$

$P = 2575$ psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{2575(10)^5}$$

$C_O = 17.7 \times 10^{-6}\ Psi^{-1}$

$P = 2420$ psi

$$C_O = \frac{[5(647.3) + 17.2\ (186) - 1180\ (0.698) + 12.61(30) - 1433]}{2420\,(10)^5}$$

$C_O = 18.83 \times 10^{-6}\ Psi^{-1}$

FOR = $P \leq P_b$

$InC_O = -0.664 - 1.430\ InP - 0.395\ In\ Pb + 0.390\ InT + 0.455\ In\ (R_{Sob})$

$+ 0.262\ In\ (\gamma_o.API)$

$P = 2000$ psi, $TR = 186^oF$, $\gamma_o.API = 30$

$InC_O = -0.664 - 1.430\ In\ 2000 - 0.395\ In\ 2000 + 0.390\ In\ 186 + 0.455\ )647.3)$

$+ 0.262\ In\ (30)$

$InC_O = - 8.66136$

$InC_O = e^{-8.66136}$

$= 17.31 \times 10^{-5}\ psi^{-1}$

$P = 1600$ psi

$InC_O = -0.664 - 1.430\ In\ 1600 - 0.395\ In\ 1600 + 0.390\ In\ 186 + 0.455\ (647.3)$

$+ 0.262\ In\ (30)$

$InC_O = -8.25412$

$InC_O\ e^{-8.25412}$

$InC_O = 26.02 \times 10^{-5}\ psi^{-1}$

P = 1200 psi

$InC_O = -0.664 – 1.430 \, In \, 1200 – 0.395 \, In \, 1200 + 0.390 \, In \, 186 + 0.455 \, (647.3)$

$+ 0.262 \, In \, (30)$

$InC_O = -7.7291$

$InC_O = e^{7.7291}$

$InC_O = 43\text{-}98 \times 10^{-5} \, Psi^{-1}$

P = 800 psi

$InC_O = -0.664 – 1.430 \, In \, 800 – 0.395 \, In \, 800 + 0.390 \, In \, 186 + 0.455 \, (647.3)$

$+ 0.262 \, In \, (30)$

$InC_O = -60.9813$

$InC_O = e^{-6.9813}$

$InC_O = 92.18 \times 10^{-5} \, Psi^{-1}$

P = 400 psi

$InC_O = -0.664 – 1.430 \, In \, 400 – 0.395 \, In \, 400 + 0.390 \, In \, 186 + 0.455 \, (647.3)$

$+ 0.262 \, In \, (30)$

$InC_O = -5.72414$

$InC_O = e^{-5.72414}$

$InC_O = 32.66 \times 10^{-4} \, Psi^{-1}$

P = 15 psi

$InC_O = -0.664 – 1.430 \, In \, 15 – 0.395 \, In \, 15 + 0.390 \, In \, 186 + 0.455 \, (647.3)$

$+ 0.262 \, In \, (30)$

$InC_O = -0.26809$

$\text{InC}_O = e^{-0.26809}$

$\text{InC}_O = 13.08 \times 10^{-4}\ \text{Psi}^{-1}$

(iii) Validation of Oil Formation Volume Factor (B_o) at Flash Conditions

FROM $B_O = B_{Obe^{[Co(Pb-P)]}}$

Where

$B_{ob} = 0.972 + 0.000147F^{1.175}$

$$F = R_{sob}\left(\frac{\gamma_g}{\gamma_o.API}\right) + 1.25\ TR$$

$R_{ob} = 647.3\ SCF/STB, \gamma_g = 0.698_{\gamma o}, API = 30\ TR = 186^o F$

$$F = 647.3\left(\frac{0.698}{30}\right) + 1.25\ (186)$$

$F = 247.5605$

$B_{ob} = 0.972 + 0.000147\ (247.5605)^{1.175}$

$B_{ob} = 1.0675$ Res. BBL/STB

$P > P_b$

$P = 4500$ psi

$B_{ob} = 1.0675\ BBL/STB$, C O = $10.12 \times 10^{-1}\ \text{Psi}^{-1}$ Pb = 2000 psi

$B_{ob} = .0675_{e^{[10.12\times10^{-6}}}\ (2000 - 4500)$

$B_{ob}\ 1.0675_{e^{-0.0253}}$

$B_{ob} = 1.041$ BBL/STB

$P = 4000$ psi

$B_{ob} = 1.0675$ BBL/STB, $CO = 10.12 \times 10^{-1}$ Psi^{-1} $Pb = 2000$ psi

$B_{ob} = 1.0675_{e^{[11.39\times10^{-6}}} (2000 - 4000)$

$B_{ob}\ 1.0675_{e^{-0.02278}}$

$B_{ob} = 1.041$ BBL/STB

$B_{ob} = 1.0675_{e^{[15.19\times10^{-6}}} (2000 - 3000)$

$B_{ob} = 1.0675_{e^{-0.0159}}$

$B_{ob} = 1.0514$ BBL/STB

$P = 2575$ psi

$B_{ob} = 1.0675_{e^{[17.7\times10^{-6}}} (2000 - 2575)$

$B_{ob} = 1.0675_{e^{-0.0101775}}$

$B_{ob} = 1.057$ BBL/STB

$P = 2000$ psi

$B_{ob} = 1.0675_{e^{[17.31\times10^{-6}}} (2000 - 2575)$

$B_{ob} = 1.0675_{e^{0}}$

$B_{ob} = 1.0675$ BBL/STB

$P < Pb$

$B_o = 0.972 + 0.000147F^{1.175}$

$$F = R_{so} = \left(\frac{\gamma_g}{\gamma_o.API}\right) + 1.25TR$$

P = 1600 Psi

$R_{so} = \gamma$

$$F = 512.9\left(\frac{0.698}{30}\right) + 1.25(186)$$

F = 244.433

$B_o = 0.972 + 0.000147\,(244.433)^{1.175}$

B_o= 1.0661 BBL/STB

P = 1200 Psi

R_{so} = 362.78 SCF/STB

$$F = 362.78\left(\frac{0.698}{30}\right) + 1.25(186)$$

F = 240.9406

$B_o = 0.972 + 0.000147\, F^{1.175}$

B_o= 1.0645 BBL/STB

P = 800 Psi

R_{so} = 222.65 SCF/STB

$$F = 222.65\left(\frac{0.698}{30}\right) + 1.25(186)$$

F = 237.6803

$B_o = 0.972 + 0.000147\ (237.6803)^{1.175}$

$B_o = 1.0630$ BBL/STB

P = 400 Psi

$R_{so} = 96.64$ SCF/STB

$$F = 96.64\left(\frac{0.698}{30}\right) + 1.25(186)$$

F = 234.748

$B_o = 0.972 + 0.000147\ (234.748)^{1.175}$

$B_o = 1.0617$ BBL/STB

P = 15 Psi

$R_{so} = 1.85$ SCF/STB

$$F = 1.85\left(\frac{0.698}{30}\right) + 1.25(186)$$

F = 232.543

$B_o = 0.972 + 0.000147\ (232.543)^{1.175}$

$B_o = 1.067$ BBL/STB

(Spivey JP, et all 2007).

(iv) Validating of the PVT Parameters

(i) The Bubble point pressure P_b

The bubble point pressure P_b has average error of 4.8% plotted for about 105 data point with the following ranges.

130 psia < Pb < 7,000 psia

$100^oF < TR < 258^oF$

(ii) The solution gas/oil ratio (R_{SO}) is valid

For 20 SCF/STB <R_{Sb}< 1,425 SCF/STB

16.5^o API <γ_oAPI< 63.8^{o}API

0.59 <γ_g< 0.95

The solution $\frac{gas}{oil}$ ratio (R_{SO}) is valid with average error of 2.3%.

(iii) The oil formation volume factor B_O is valid for the range of 1.024 < B < 2.05 RB/STB

The oil formation volume factor (B_O) had average error of 26.9%

(iv) The oil compressibility value jumps discontinuously from 18.83 $\times 10^{-6}_{psi^{-1}}$ above the bubble to 26.02 $\times 10^{-6}_{psi^{-1}}$ just below bubble point pressure, because oil is usually much more compressible below the bubble point(Alomiar, 2016).

(iv) The oil viscosity μ_o had an average absolute error for the standing correlation is 7.54% in the range

126psig < P < 9,500psig

0.117 cp <γ_g< 1.351

The oil viscosity jumps from 0.737cp at P_b to 4.1309 × 10^{18} cp at pressure of 15sig because the oil viscosity is sensitive to pressure charges. (Bated, 2012).

DISCUSSION OF RESULT

Crude oil usually contains some dissolved gas when in the reservoir under pressure. As the oil well is drilled and completed and oil begins to flow a time will reach that the gas dissolved in solution in the crude begin to bubble out to form two phase region the pressure at that put is called the bubble point (p_b)(Al-Rawah, 2012).

From the PVT report the P_b usually determine during PVT analysis, the point where the solution gas/oil changes in the analyses. PVT samples must be a representative of the reservoir fluid

Comment [DR11]: When under reservoir pressure

Comment [DR12]: Pls reconstruct

originally in situ. The PVT report gives a bubble point pressure of 2000 psig while the standing correlation gives a P_b of 1937.371 psi, a difference of 65.7 psi error. The difference is due to the representation of PVT sample (Bated, 2012). The expansion of the reservoir fluids is a function of the fluid pressure in any part of the reservoir, calculations should be made by using different total two phase expansion factor, but to determine the average weighting them by volume to obtained reliable results. The equipment currently used by commercial laboratories in PVT analysis determines volume, with maximum error of less than 0.01% and temperature within 1%. (Al-Rawah N. et al 2012).

In many flowing wells, it has been noted that the producing gas/oil ratio is a variable function of the well producing rate, if that is the case no representative sampling procedure is carried out either surface or subsurface even when the representative sample is over duplicated equal GOR can never be obtained(Hemmanti, 2014).

At below P_b the gas is increasing coming out of solutions as well the free phase expands, but oil is shrinking in volume, the formation volume factor (B_O) supposed to be unity at standard conditions of 0 psig and 60^oF, above P_b the undersaturated region the formation volume factor (B_O) increases as the oil compressibility (C_o) decreases until below the P_b where it decrease as the (C_o) increases. (Moradi B. et al 2013).

Formation volume factor (B_o) relate the volume at reservoir condition to the oil volume at stock tank condition and vice versa, therefore it is written Rb/STB the oil compressibility (C_o) determine how much the oil will expand if the pressure drop by 1 psi, therefore it is in PSI^{-1}.

Above P_b, the oil compressibility is low and below P_b the oil compressibility is high. First above the P_b, $C_o = 18.83 \times 10^{-6}$ psi^{-1} and below P_b i.e. at 1600 psi the $C_o = 26.02 \times 10^{-5}$ psi^{-1} and it keep increasing to the final pressure of 15 psig where it decreased to 13.08×10^{-1}. That means that oil compressibility is strongly a function of reservoir pressure (Sulaimon, 2014).

At above P_b the oil viscosity μ_o increases with decrease in pressure to the bubble point pressure (P_b) and below the bubble point pressure (P_b) the oil viscosity μ_o increasing drastically with decrease in pressure from 1.0347cp at 1200 psig to 4.1309×10^{18} cp at 15 psig oil viscosity is strongly a function of reservoir pressure and reservoir temperature, the reservoir temperature is constant throughout the life of the oil well. The viscosity of oil measures the resistance of the oil to flow, the higher the viscosity the lower the flow rate and vice visa; therefore, the mobility of the oil is inversely proportional to the viscosity at constant temperature(Carlton, 2013) .

An adjustment in the gravity of the residual oil is not required.

CONCLUSION AND RECOMMENDATION

The pressure, volume and temperature (PVT) studies of Black oil reservoir was carried out for the purpose of determining the economic worth of a particular reservoir. This is necessary because, without the PVT studies, the reservoir engineers cannot predict or calculate or calculate or compute the probable hydrocarbon reserves available in the reservoir (Tower, 2002).

Comment [DR13]: ?

The analytical test shows that the crude oil is a high viscosity with an average absolute error (AAE) of 3.5% (i.e. 3.5/100 = 0.035). Gas began evolving at 2000psig and increased as the pressure decreased. Also, it was noticed that at higher pressure of 4500psig the black oil viscosity was low as 0.54 cp while at a lower pressure of 15psiag the viscosity recorded was 1.38 cp.

Based on this research work and by opinion the following recommendations can be made for the black oil PVT report analyzed in this research project.

1. The surface sampling method (surface recombination method) will yield more representative sample of the total fluid regardless of the presence of free gas in the flow string, because when free gas is present in the flow string at the point of subsurface sampling, a representative homogeneous immixture of total fluid will not be found, because when gas appears either static or moving column of oil the bottom home sample will usually be underestimated.
2. To check the quality of the sample, duplicate samples should always be taken if the reservoir contains greater number of well and it is or has a high structural relief such duplicate samples should be obtained on several wells 4 to 8.
3. Laboratory result output samples (PVT report) must always be checked against the actual production pressure performance of the reservoir (Standing, 1947).
4. To check the laboratory values by studying and accompany it with actual field production performance by several plots such as a plot of reservoir pressure versus cumulative oil production, a plot of Cumulative production of fluid and pressure drop i.e. NP/DP VNP, a plot flowing pressure gradients versus depth which will all indicate a change in slope at bubble point pressure.
5. A reservoir simulation method should be used to regenerate the require PVT parameters for black oil, gas condensate and other reservoir before the reservoir is put into production.
6. This project work required the used of standing correlations to validate the basic PVT parameters of a black oil reservoir, other correlations can also be applied such as Vasquez and Beggs, Glaso or Marhran correlations can be used. (Okeke H & Sylvester O 2016).

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