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A Case Study of Black oil PVT Modelling with Differential Liberation Expansion (DLE) Analysis and Standing Correlations

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

This study investigates the Pressure, Volume, and Temperature (PVT) modeling of black oil using Differential Liberation Expansion (DLE) analysis and Standing correlations. Black oil, characterized by its complex fluid properties, presents significant challenges in reservoir management and production optimization. Black oil samples were collected for 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 compressibility, (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 psi the viscosity recorded was higher (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.

Keywords: Pressure; volume; temperature; crude oil; viscosity; black oil; modeling.

1. 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).

The study of petroleum fluids, particularly black oil, is critical for the successful exploration and production of hydrocarbons. As one of the most complex fluid types encountered in the petroleum industry, black oil exhibits unique characteristics that require thorough understanding and modeling to optimize extraction processes. The physical and chemical properties of black oil can vary significantly based on its source, depth of formation, and thermal history. Therefore, accurate modeling of black oil properties is essential for reservoir simulation, production forecasting, and the design of surface facilities (Alomiar et al. 2016).

Black oil is typically defined as a mixture of hydrocarbons that can be produced from a well without any significant processing. It is characterized by its relatively high viscosity, low gas-to-oil ratio (GOR), and the presence of heavier components (Alomiar et al. 2016). The behavior of black oil in subsurface reservoirs is influenced by several factors, including pressure, temperature, and the presence of gas and water. As reservoirs are produced, the pressure and temperature conditions change, leading to modifications in the oil's properties. When these changes are well understood, it will help in effective reservoir management.

Black oils are hydrocarbon fluids in reservoir which exist as liquid with Average GOR of 3000fl^3/BBL (Carlton Beal 2013). 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).

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 al. 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). (Hemmanti Sarapaedah et al. 2014).

In the oil industry, each of the mentioned properties plays a crucial role in reservoir characterization and production optimization. Fluid gravity and specific gravity help determine the density of the oil, influencing its quality and market value. The solution gas/oil ratio (GOR) is vital for understanding the amount of gas that can be produced with the oil, impacting production strategies and facility design. Bubble point pressure (Pb) is essential for identifying the conditions under which gas comes out of solution, guiding reservoir management decisions. The oil formation volume factor (Bo) indicates how much volume of oil will be produced at surface conditions, which is critical for production forecasting. Isothermal compressibility (Co) measures how much the volume of oil changes with pressure, aiding in reservoir simulation models. Oil density (ρo) is important for calculating flow rates and designing transport systems. Lastly, crude oil viscosity (μo) affects the ease of flow through pipes and facilities, influencing pumping requirements and operational efficiency. Together, these properties are fundamental for optimizing extraction processes, enhancing recovery techniques, and ensuring economic viability in oil production (Hemmanti Sarapaedah et al. 2014).

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

1.1 Importance of PVT Analysis

Pressure, Volume, Temperature (PVT) analysis is a fundamental aspect of petroleum engineering that focuses on measuring and interpreting the properties of reservoir fluids. PVT data provide insights into how oil will behave under various conditions, which is vital for predicting production performance and designing processing facilities. The PVT analysis of black oil typically involves determining key properties such as bubble point pressure, solution gas-oil ratio, and viscosity at different pressures and temperatures (Dindoruk and Christman, 2004).

Differential Liberation Expansion (DLE) is a key method used in PVT analysis to assess the properties of black oil. DLE involves gradually releasing pressure from a sample of oil to observe the phase behavior and changes in composition. This technique allows engineers to determine crucial properties like the bubble point and the GOR, which are essential for understanding how the oil will behave during production (Dindoruk and Christman, 2004).

1.2 Standing Correlations

In addition to DLE, Standing correlations provide empirical relationships derived from extensive experimental data that estimate the properties of petroleum fluids based on available compositional data. These correlations offer a practical approach to predict PVT properties without needing extensive laboratory testing, making them invaluable in early stages of reservoir evaluation. Standing's correlations, which are widely accepted in the industry, help estimate key parameters such as density, viscosity, and gas solubility based on the oil's specific gravity and other easily measurable properties (Standing, 1947).

1.3 Combining DLE and Standing Correlations

The integration of DLE analysis with standing correlations presents a robust framework for black oil PVT modeling. By combining the detailed insights gained from DLE with the predictive capabilities of standing correlations, petroleum engineers can develop a comprehensive understanding of black oil behavior across varying reservoir conditions. This dual approach enhances the accuracy of simulations and forecasts, ultimately leading to more efficient reservoir management strategies (Standing, 1947).

The accurate modeling of black oil properties is crucial for effective reservoir management and production optimization in the petroleum industry. However, the inherent complexity of black oil, coupled with the dynamic conditions of subsurface reservoirs, poses significant challenges in predicting its behavior accurately. Traditional methods of PVT analysis, such as laboratory experiments, can be time-consuming and costly, often limiting their application in real-time decision-making.

Differential Liberation Expansion (DLE) analysis provides a detailed understanding of black oil phase behavior but requires careful execution and interpretation of experimental data. Moreover, while Standing correlations offer a practical means to estimate PVT properties based on available compositional data, their accuracy can vary significantly depending on the specific characteristics of the oil being analyzed.

1.4 Aims and Objectives

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

The objectives of the study are as follows:

1. To establish the fundamental properties of a specific black oil sample through DLE analysis.
2. To evaluate the effectiveness of standing correlations in predicting PVT properties based on the results obtained from DLE.
3. To compare the results of DLE analysis with the values estimated by Standing correlations, assessing their accuracy and reliability.
4. To discuss the implications of the findings for reservoir management and production optimization.

2. METHODOLOGY

The methodology for this study involves collecting a representative black oil sample from a designated reservoir, conducting DLE experiments to determine PVT properties, and applying Standing correlations to estimate these properties. The DLE process typically involves a series of pressure reductions while monitoring changes in volume and composition. Data from these experiments will be analyzed to derive key parameters that describe the fluid behavior under reservoir conditions.

Following the DLE analysis, the results will be compared to values predicted by Standing correlations. This comparison will not only validate the correlations but also highlight any discrepancies that may arise due to unique characteristics of the specific black oil sample.

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 70^0 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°.
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.

3. RESULTS

3.1 Validation of Oil Viscosity (μ_o) at Flash Conditions

Table 1 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}

3.2 Validation of PVT Parameters using Standing Correlations

(i) Estimation of Bubble Point Pressure (P_b)

From standing correlations for the reservoir condition:

R_{So} = 647.3 SCF/STB, TR – 186°F, γ_g = 1.306, γ_oAPI = 30°API

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

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°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 = 186ºF, 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 = $P \le P_b$
$\text{In}C_O = -0.664 - 1.430\ \text{In}P - 0.395\ \text{In}\ P_b + 0.390\ \text{In}T + 0.455\ \text{In}\ (R_{Sob}) + 0.262\ \text{In}\ (\gamma_o.API)$

P = 2000 psi, TR = 186ºF, γ_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 × 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 × 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$_O$ = 43-98 × 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 × 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 × 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
InC$_O$ = $e^{-0.26809}$
InC$_O$ = 13.08 × 10^{-4} Psi^{-1}

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

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

Where

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

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

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

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

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 × 10^{-1} 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 × 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 + 0.000147$F^{1.175}$

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

P = 1600 Psi
R_{so} = γ

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

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

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

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

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

F = 232.543
B_o = 0.972 + 0.000147 $(232.543)^{1.175}$
B_o = 1.067 BBL/STB

(Spivey JP, et al.l 2007).

(v) 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^oAPI

$0.59 < \gamma_g < 0.95$

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 $\times$ 10^{18} cp at pressure of 15sig because the oil viscosity is sensitive to pressure charges (Bated, 2012).

4. DISCUSSION

Crude oil usually contains some dissolved gas when under reservoir 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 is usually determined during PVT analysis; it is the point where the solution gas/oil changes in the analyses. PVT samples must be a representative of the reservoir fluid 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°F, 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 $\times$ 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 $\times$ 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.

5. 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 compute the probable hydrocarbon reserves available in the reservoir (Tower, 2002).

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 15psig 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).

In summary, the study of black oil PVT modeling through Differential Liberation Expansion analysis and Standing correlations is a critical area of research in petroleum engineering. Understanding the properties of black oil and how they change under various conditions is vital for optimizing production and ensuring the economic viability of oil reservoirs. This case study provided valuable insights into the effective modeling of black oil properties, contributing to the advancement of techniques used in the exploration and production of hydrocarbons. Through the integration of experimental analysis and empirical correlations, this research has bridged the gap between theory and practice, ultimately benefiting the petroleum industry at large.

Future directions for research on black oil PVT modeling include enhancing experimental techniques, such as high-pressure PVT analysis, and integrating machine learning algorithms to improve predictive accuracy. Field case studies applying the combined Differential Liberation Expansion (DLE) and Standing correlation approach can validate findings in real-world scenarios. Exploring alternative empirical correlations and extending research to heavier oils and bitumen can address unique challenges in those fluid types. Additionally, investigating multi-phase flow dynamics and incorporating economic evaluations will quantify the benefits of improved modeling techniques. Collaborating with industry partners can further facilitate the practical application of these advancements, ultimately leading to more efficient hydrocarbon recovery and resource management in the petroleum sector.

DISCLAIMER (ARTIFICIAL INTELLIGENCE)

Author(s) hereby declare that NO generative AI technologies such as Large Language Models (ChatGPT, COPILOT, etc.) and text-to-image generators have been used during the writing or editing of this manuscript.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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