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Validating Subsurface Samples of Volatile Black Oil through PVT Calculations of Surface Separator Samples for Enhanced Reservoir Characterization

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Abstract- This study investigates black oil's pressure, volume, and temperature (PVT) properties from well X, analyzed using subsurface and surface recombination samples. Black oil samples were collected from the Q oil field and subjected to PVT analysis at the Reservoir Fluid Laboratory in Port Harcourt. Key findings include bubble point pressure (Pb) of 2000 psi, with a standing correlation value of 1934.3 psi, resulting in a 3.3% difference. The solution gas/oil ratio was measured at 647.3 SCF/STB, compared to 671.0 SCF/STB from correlations, a difference of 3.5%. The oil formation volume factor (Bo) was 1.456 res Bbl/STB, while standing correlations indicated 1.0675 res Bbl/STB, showing a 3.6% difference. The isothermal compressibility ranged from 10.12 x 10⁻⁶ psi⁻¹ at 4500 psi to 4.1309 x 10¹⁸ cp at 15 psi. Gas evolution began at 2000 psig and increased with decreasing pressure. Viscosity varied significantly, recorded at 0.54 cp at 4500 psig and 1.38 cp at 15 psig.

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Abstract- This study investigates black oil's pressure, volume, and temperature (PVT) properties from well X, analyzed using subsurface and surface recombination samples. Black oil samples were collected from the Q oil field and subjected to PVT analysis at the Reservoir Fluid Laboratory in Port Harcourt. Key findings include bubble point pressure (Pb) of 2000 psi, with a standing correlation value of 1934.3 psi, resulting in a 3.3% difference. The solution gas/oil ratio was measured at 647.3 SCF/STB, compared to 671.0 SCF/STB from correlations, a difference of 3.5%. The oil formation volume factor (Bo) was 1.456 res Bbl/STB, while standing correlations indicated 1.0675 res Bbl/STB, showing a 3.6% difference. The isothermal compressibility ranged from 10.12 x 10⁻⁶ psi⁻¹ at 4500 psi to 4.1309 x 10¹⁸ cp at 15 psi. Gas evolution began at 2000 psig and increased with decreasing pressure. Viscosity varied significantly, recorded at 0.54 cp at 4500 psig and 1.38 cp at 15 psig. The reservoir contains heavy crude oil with an API rating of 30 and an average absolute error of 3.5% (0.035). These results enhance reservoir characterization and validate the use of PVT calculations in analyzing volatile black oil samples.

Keywords: black oil, formation volume factor reservoir heavy crude absolute error.

I. Introduction

A reservoir is a subsurface rock formation containing liquids and gaseous hydrocarbons, typically found in sedimentary basins. When a well is drilled, reservoirs can release hydrocarbon fluids at specific rates. Understanding the properties of these fluids is crucial for effective reservoir management and economic forecasting in petroleum engineering.

Black oils, as defined by Ahmed (2016), are hydrocarbon fluids that exist as liquids with an average gas-to-oil ratio (GOR) of 3000 ft^3/BBL. The analysis of pressure, volume, and temperature (PVT) properties of reservoir fluids is essential for assessing the economic worth of a reservoir. The three main types of reservoir fluids based on phase diagrams are oil, gas, and condensate.

PVT properties of black oil are best measured in a laboratory setting using a PVT cell with bottom-hole or recombined samples under reservoir conditions (Tower, 2002). The measured properties of crude oil and its dissolved gases can vary significantly depending on the measurement conditions. Therefore, a series of standard tests are conducted to determine these properties. For black oil, viscosity tests are particularly critical, as a precise description of physical properties is vital for reservoir engineering studies (El-Hoshoudy, 2019). Key properties include fluid gravity, specific gravity, solution gas/oil ratio, bubble point pressure (Pb), oil formation volume factor (Bo), isothermal compressibility (Co), oil density (ρo), and crude oil viscosity (μo) (Zamani, 2015).

In the absence of experimentally measured data, petroleum engineers must rely on empirically derived correlations to estimate these properties (Standing, 1947). This research aims to validate PVT parameters in saturated black oil reservoirs using standing correlations, as outlined by Nojabaei and Johns (2016). The study seeks to enhance the understanding of black oils and improve reservoir management strategies, ultimately contributing to more accurate economic assessments in the oil industry by confirming these parameters

II. Methodology

a) Viscosity

This section outlines the procedure for measuring the viscosity of black oil at reservoir pressure and temperature using a high-pressure rolling-ball viscosimeter. Accurate viscosity measurements are crucial for understanding fluid behaviour in reservoir engineering, as they directly impact hydrocarbon recovery processes.

b) Equipment

The high-pressure rolling-ball viscosimeter is designed to measure the viscosity of fluids under controlled pressure and temperature conditions. It operates by timing how long a precision steel ball rolls a

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specific distance through the oil. This method is chosen for its reliability in simulating reservoir conditions.

c) Procedure

1. *Vacuum the Viscometer:* Begin by vacuuming the viscometer for at least one hour to remove any air trapped in the system. This step is critical to prevent gas bubbles from affecting the viscosity measurements (Gaganis & Varotsis, 2016).
2. *Set Temperature:* Adjust the viscosimeter to the reservoir temperature. Ensuring the correct temperature is vital, as viscosity is temperature-dependent.
3. *Fill the Viscosimeter:* Introduce the oil sample into the viscosimeter at a pressure above the reservoir pressure. This ensures that the sample remains liquid and prevents gas evolution.
4. *Achieve Thermal Equilibrium:* Gently rock the housing with the barrel seal open. This action helps stir the liquid and ensures thermal equilibrium throughout the sample, allowing for accurate pressure adjustments (Elkatatny & Mahmoud, 2018).
5. *Position the Ball:* Invert the housing so the ball rests against the barrel seal. This setup ensures that the ball is ready to drop through the fluid.
6. *Release the Ball:* Turn the housing to a 70° angle and shut the barrel seal. Release the ball and record the time it takes to fall through the fluid. Repeat this procedure for angles of 45° and 23° (Standing, 1947).
7. *Lower Pressure:* Reduce the pressure to the next lower level and retake fall time readings. This step allows for viscosity measurements at various pressures.
8. *Rocking at Bubble Point:* When working at or below the bubble-point pressure, shut the outlet valve while rocking the barrel to maintain the sample's integrity. Repeat steps 5-6 for each pressure point down to atmospheric pressure (El-Hoshoudy, 2018).
9. *Calculate Viscosity:* Convert the recorded fall times to viscosity values using calibration curves specific to the instrument. These curves are derived from standard fluids with known viscosities to ensure measurement accuracy (El-Hoshoudy&Desouky, 2018).

d) Calibration Process

The calibration curve is established by measuring the fall times of a standard fluid with known viscosity at various pressures and temperatures. This curve is then used to convert the measured fall times of the black oil sample into viscosity values, ensuring consistency and accuracy in the results.

e) Error Mitigation

Temperature fluctuations and improper calibration are potential sources of error in viscosity measurements. To mitigate these issues, ensure that the viscosimeter is properly calibrated before use and that temperature is consistently monitored throughout the testing process.

This methodology provides a reliable framework for measuring the viscosity of black oil under reservoir conditions. Future research could explore advancements in viscosity measurement techniques or alternative methodologies that may enhance accuracy and efficiency.

III. Results and Discussion

a) Validation of Oil Viscosity (μ_o) at Flash Conditions

For $P > P_b$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$M = 2.6P^{1.187}\, e^{[-11.513-8.98(10^{-5})P]}$$

For P = 4500 psi

$$M = 2.6(4500)^{1.187}\, e^{[-11.513-8.98(10^{-5})\times 4500]}$$

$$M = 2.6(4500)^{1.187}\, e^{-11.9171}$$

$$M = 0.3765$$

From $\log_{10}[\log_{10}(\mu_{obd}+1)=1.8653-0.025086(\gamma_o.API)-0.5644\log TR$

$\log_{10}[\log_{10}(\mu_{od}+1)=1.8653-0.025086(30)-0.5644\log(186)$

$$=-0.16819$$

$$\log_{10}(\mu_{od}+1)=\log_{10}{}^{-1}-0.16819$$

$$\log_{10}(\mu_{od}+1)=0.67890$$

$$\mu_{od}+1=\log_{10}{}^{-10.67890}$$

$$\mu_{od}+1=4.7743$$

$$\mu_{od}=4.7743-1$$

$$\mu_{od}=3.7743CP$$

From $\mu_{ob}=A\mu_{ob}{}^{B}$

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

$$B=5.44\ (R_{so}+150)^{-0.338}$$

At $P=4500\ psi,\ R_{so}=1781.5\,SCF/STB$

$$A=0.22061$$

$$B=0.42166$$

$$\mu_{ob}=A\ \mu_{ob}{}^{B}$$

$A=0.2206,\ B=0.42166,\ \mu_{obd}=3.7742CP$

$$\mu_{ob}=0.2206(3.77420)^{0.42166}$$

$$\mu_{ob}=0.3862CP$$

$$\mu_{ob}=\mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$\mu_{ob}=0.3862, P=4500\ psi,\ P_b=2000\ psi, M=0.3765$

$$\mu_{ob}=0.3862\left(\frac{4500}{2000}\right)^{0.3765}$$

$$\mu_{ob} = 0.524 CP$$

For $P = 4000\ psi$

$$M = 2.6P^{1.187} e^{[-11.513 - 8.98(10^{-5})P]}$$

$$M = 2.6(4000)^{1.187} e^{[-11.513 - 8.98(10^{-5}) \times 4000]}$$

$$M = 2.6(4000)^{1.187} e^{-11.8722}$$

$$M = 0.3424$$

$$\log_{10}[\log_{10}(\mu_{od} + 1) = 1.8653 - 0.025086(30) - 0.5644 \log(186)$$

$$= -0.16819$$

$$\log_{10}(\mu_{od} + 1) = \log_{10}{}^{-1} - 0.16819$$

$$\log_{10}(\mu_{od} + 1) = 0.67890$$

$$\mu_{od} + 1 = \log_{10}{}^{-10.67890}$$

$$\mu_{od} + 1 = 4.7743$$

$$\mu_{od} = 4.7724 - 1$$

$$\mu_{od} = 3.7742 CP$$

From $\mu_{ob} = A \mu_{ob}{}^{B}$

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

$$B = 5.44(R_{so} + 150)^{-0.338}$$

For $P = 4000\ psi, R_{so} = 1545.9\ SCF / STB$

$$A = 10.715(1545.9 + 100)^{-0.515}$$

$$A = 0.4406$$

$$B = 5.44(1545.9 + 150)^{-0.338}$$

$$B = 0.4406$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

$$\mu_{od} = 0.2363(3.7742)^{0.4406}$$

$$\mu_{od} = 0.4242\,CP$$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$\mu_{ob} = 0.4723\left(\frac{4000}{2000}\right)^{0.3424}$$

$$\mu_{ob} = 0.5378\,CP$$

$For\ \ P = 3500\ psi$

$$M = 2.6\,P^{1.187}e^{[-11.513-8.98(10^{-5})P]}$$

$$M = 2.6(3500)^{1.187}e^{[-11.513-8.98(10^{-5})\times 3500]}$$

$$M = 2.6(3500)^{1.185}e^{-11.8273}$$

$$M = 0.3057$$

$$\mu_{ob} = 3.7742\,CP$$

$From\ \ \mu_{ob} = A\,\mu_{ob}{}^{B}$

$$A = 10.715\,(R_{so} + 100)^{-0.515}$$

$$B = 5.44\,(R_{so} + 150)^{-0.338}$$

$For\ \ P = 3500\ psi, R_{so} = 1316.3\,SCF\,/\,STB$

$$A = 10.715(1316.3+100)^{-0.515}$$

$$A = 0.2554$$

$$B = 5.44(1316.3+150)^{-0.338}$$

$$B = 0.4628$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$A = 0.2554,\ B = 0.4628,\ \mu_{ob} = 3.7742CP$

$$\mu_{od} = 0.2554\,(3.7742)^{0.4628}$$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$\mu_{ob} = 0.4723\left(\frac{3500}{2000}\right)^{0.3057}$$

$$\mu_{ob} = 0.5604\,CP$$

$For\ \ P = 3000\ psi$

$$M = 2.6(3000)^{1.187}\, e^{[-11.513-8.98(10^{-5})\times 3000]}$$

$$M = 0.2662$$

$$\mu_{obd} = 3.7742\,CP$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so} + 150)^{-0.338}$$

$For\ \ P = 3000\ psi,\ R_{so} = 1093.4\,SCF/STB$

$$A = 10.715(1093.4 + 100)^{-0.515}$$

$$A = 0.2789$$

$$B = 5.44(1093.4 + 150)^{-0.338}$$

$$B = 0.4894$$

$$\mu_{od} = 0.2789(3.7742)^{0.4894}$$

$$\mu_{od} = 0.5342\,CP$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 0.5342\left(\frac{3000}{2000}\right)^{0.2662}$$

$$\mu_{ob} = 0.5951\,CP$$

$$P = 2575\ psi$$

$$M = 2.6(2575)^{1.187}\, e^{[-11.513-8.98(10^{-5})\times 2575]}$$

$$M = 2.6(2575)^{1.187}\, e^{-11.744235}$$

$$M = 0.23073$$

$$\mu_{obd} = 3.7742\,CP$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$A = 10.715(R_{so} + {}^{-0.515}$$

$$B = 5.44(R_{so} + 150)^{-0.338}$$

$$For\ P = 2575\,psi, R_{so} = 909.7\,SCF/STB$$

$$A = 10.715(909.7 + 100)^{-0.515}$$

$$A = 0.30397$$

$$B = 5.44(909.7 + 150)^{-0.338}$$

$$B = 0.51652$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$\mu_{od} = 0.30397\ (3.7742)^{0.51652}$$

$$\mu_{od} = 0.60363$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 0.60363\left(\frac{2575}{2000}\right)^{0.23073}$$

$$\mu_{ob} = 0.6399\,CP$$

$$At\ P = 2420\,psi$$

$$M = 2.6(2420^{1.18})_{e^{[-11.513-8.98(10^{-5})\times 2575}}$$

$$M = 2.6(2420^{1.18})_{e^{-11.730316}}$$

$$M = 0.21735$$

$$\mu_{ob} = 3.7742\,CP$$

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

$$B = 5.44(R_{so} + 150)^{-0.338}$$

$For\ P = 2420\ psi, R_{so} = 844.2\ SCF/STB$

$$A = 10.715(844.2+100)^{-0.515}$$

$$A = 0.31465$$

$$B = 5.44\ (844.2+150)^{-0.338}$$

$$B = 0.52778$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

$$\mu_{od} = 0.31465(3.7742)^{0.4894}$$

$$\mu_{od} = 0634256\ CP$$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$\mu_{ob} = 0.634256\left(\frac{2420}{2000}\right)^{0.21735}$$

$$\mu_{ob} = 0.66109\,CP$$

$$P = 2000\ psi$$

$$M = 2.6(2000^{1.18})_{e^{[-11.513-8.98\,(10^{-5})\times 2575}}$$

$$M = 2.6(2000^{1.18})_{e^{-11.730316}}$$

$$M = 0.180$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so} + 150)^{-0.338}$$

$At\ P = 2000\ psi, R_{so} = 671.03\,SCF/STB$

$$A = 10.715(671.03+100)^{-0.515}$$

$$A = 0.34926$$

$$B = 5.44\,(671.03+150)^{-0.338}$$

$$B = 0.56305$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$\mu_{od} = 0.3492(3.7743)^{0.56305}$$

$$\mu_{od} = 73767\ CP$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 0.73767\left(\frac{2000}{2000}\right)^{0.180}$$

$$\mu_{ob} = 0.73767\,CP$$

For $P < P_b$

$$P = 1600\ psi$$

$$M = 2.6\,P^{1.187}\,e^{[-11.513-8.98(10^{-5})P]}$$

$$M = 2.6(1600)^{1.187}\,e^{[-11.513-8.98(10^{-5})\times 1600]}$$

$$M = 2.6(1600)^{1.187}\,e^{-11.65668}$$

$$M = 0.143163$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so}+150)^{-0.338}$$

At $P = 1600\ psi, R_{so} = 512.9\,SCF/STB$

$$A = 10.715(512.9+100)^{-0.515}$$

$$A = 0.39309$$

$$B = 5.44\,(512.9+150)^{-0.338}$$

$$B = 0.60527$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$\mu_{od} = 0.39309(3.7743)^{0.60527}$$

$$\mu_{od} = 5342\ CP$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 0.87828\left(\frac{1600}{2000}\right)^{0.143163}$$

$$\mu_{ob} = 0.8507\,CP$$

$For\ P = 1200\ psi$

$$M = 2.6(1200)^{1.187}e^{[-11.513-8.98(10^{-5})\times 1200]}$$

$$M = 2.6(1200)^{1.187}e^{-11.63976}$$

$$M = 0.10547$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so}+150)^{-0.338}$$

$For\ P = 1200\ psi, R_{so} = 362.78\,SCF/STB$

$$A = 10.715(362.78+100)^{-0.515}$$

$$A = 0.45428$$

$$B = 5.44\,(362.78+150)^{-0.338}$$

$$B = 0.66015$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$\mu_{od} = 0.45428(3.7743)^{0.66015}$$

$$\mu_{od} = 1.092\ CP$$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$\mu_{ob} = 0.5342\left(\frac{1200}{2000}\right)^{0.10547}$$

$$\mu_{ob} = 1.0347\,CP$$

For $P = 800\ psi$

$$M = 2.6(800)^{1.187} e^{[-11.513-8.98(10^{-5})\times 800]}$$

$$M = 2.6(800)^{1.187} e^{-11.62076}$$

$$M = 0.06756$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so}+150)^{-0.338}$$

For $P = 800\ psi, R_{so} = 222.65 SCF/STB$

$$A = 10.715(222.65+100)^{-0.515}$$

$$A = 0.5470$$

$$B = 5.44\ (222.65+150)^{-0.338}$$

$$B = 0.73539$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

$$\mu_{od} = 0.5470(3.7743)^{0.73539}$$

$$\mu_{od} = 1.45274\ CP$$

$$\mu_o = \mu_{ob}\left(\frac{P}{P_b}\right)^M$$

$$\mu_{ob} = 0.5342\left(\frac{800}{2000}\right)^{0.10547}$$

$$\mu_{ob} = 1.36554\,CP$$

$For \;\; P = 400 \;\; psi$

$$M = 2.6(400)^{1.187} e^{[-11.513-8.98(10^{-5})\times 400]}$$

$$M = 2.6(400)^{1.187} e^{-11.54892}$$

$$M = 0.03076$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so}+150)^{-0.338}$$

$At\, P = 400\; psi, R_{so} = 96.64 SCF / STB$

$$A = 0.93053\, A = 10.715(96.64+100)^{-0.515}$$

$$A = 0.7059$$

$$B = 5.44\;(96.64+150)^{-0.338}$$

$$B = 0.84544$$

$$\mu_{ob} = A\,\mu_{ob}{}^{B}$$

$$\mu_{od} = 0.5470(3.7743)^{0.84544}$$

$$\mu_{od} = 2.1698\;CP$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 0.5342\left(\frac{400}{2000}\right)^{0.03076}$$

$$\mu_{ob} = 2.06499\,CP$$

$$\mu_{o} = 2.0645\,CP$$

$For\ \ P = 15\ \ psi$

$$M = 2.6(15)^{1.187} e^{[-11.513 - 8.98(10^{-5}) \times 15]}$$

$$M = 2.6(800)^{1.187} e^{-11.501247}$$

$$M = 0.6.5467 \times 10^{-4}$$

$$\mu_{obd} = 3.7743\,CP$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

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

$$B = 5.44(R_{so} + 150)^{-0.338}$$

$At\ P = 15\ psi, R_{so} = 1.85SCF / STB$

$$A = 10.715(15 + 100)^{-0.515}$$

$$B = 5.44\ (15 + 150)^{-0.338}$$

$$B = 0.968477$$

$$\mu_{ob} = A\ \mu_{ob}{}^{B}$$

$$\mu_{od} = 0.93053(3.7743)^{0.968477}$$

$$\mu_{od} = 3.36809\ CP$$

$$\mu_{o} = \mu_{ob}\left(\frac{P}{P_b}\right)^{M}$$

$$\mu_{ob} = 3.36809\left(\frac{15}{2000}\right)^{6.5467 \times 10^{-4}}$$

$$\mu_{ob} = 4.1309 \times 10^{-4}\ CP$$

$$\mu_{o} = 4.1309 \times 10^{-4}\ CP$$

$Where\ \ \mu_{ob} = dead\ \ oil\ \ viscosity,\ CP$

$\mu_{ob} = oil\ viscosity\ \ at\ \ bubble\ \ point\ pressure\ \ in\ \ CP$

$\mu_{o} = oil\ \ viscosity\ \ in\ \ CP$

b) Tables of Value for Complete PVT Report

Table 1: Validation of PVT Parameters using Standing Correlations (Dessouky and El-hoshoudy, 2018)

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}

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c) Validation of PVT Parameters using Standing Correlations

i. *Estimation of Bubble Point Pressure (P_b)*

From standing correlations for the reservoir condition (Rafiee-Taghanaki, 2013)

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

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

$$y_g = 0.00091\ TR - 0.0125\ \gamma_o API$$

$$y_g = 0.00091\ (186) - 0.0125\ (30)$$

$$y_g = -0.20574$$

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

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

$$P_b = 1934.271 \text{ psi}$$

The bubble pressure = 1934.271psi

(Dessouky and El-hoshoudy, 2018).

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

$P < P_b$

$$P = 2000\text{psi}$$

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

γ_g = 1.306, P = 2000PSI, TR = 186°F, γ_oAPI = 30

$$\gamma_g = 0.00091TR - \gamma_o.API$$

$$\gamma_g = 0.00091\ (180) - 0.0125\ (30)$$

$$\gamma_g = -0.20574$$

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

$$= 6710.03 \text{ SCF/STB}$$

$$P = 1600 \text{ PSI}$$

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

$$= 512.9 \text{ SCF/STB}$$

$$P = 1200 \text{ PSI}$$

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

$$= 362.78 \text{ SCF/STB}$$

$$P = 800 \text{ PSI}$$

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

$$= 22.65 \text{ SCF/STB}$$

$$P = 400 \text{ PSI}$$

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

$$= 96.64 \text{ SCF/STB}$$

$$P = 15 \text{ PSI}$$

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

$$= 1.85 \text{ SCF/STB}$$

(Zamani, H. et al., 2015).

$P > P_b$

$$P = 4500 \text{ PSI}$$

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

= 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 $= P \leq P_b$

$$InC_O = -0.664 - 1.430\ InP - 0.395\ In\ Pb + 0.390\ InT + 0.455\ In\ (R_{Sob}) + 0.262\ In\ (\gamma_o.API)$$

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

$$InC_O = -0.664 - 1.430\ In\ 2000 - 0.395\ In\ 2000 + 0.390\ In\ 186 + 0.455\ )647.3) + 0.262\ In\ (30)$$

$$InC_O = -8.66136$$

$$InC_O = e^{-8.66136}$$

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

$$P = 1600 \text{ psi}$$

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

$$+ 0.262 \text{ In } (30)$$

$$InC_O = -8.25412$$

$$InC_O\ e^{-8.25412}$$

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

$$P = 1200 \text{ psi}$$

$$InC_O = -0.664 - 1.430 \text{ In } 1200 - 0.395 \text{ In } 1200 + 0.390 \text{ In } 186 + 0.455\ (647.3)$$

$$+ 0.262 \text{ In } (30)$$

$$InC_O = -7.7291$$

$$InC_O = e^{7.7291}$$

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

$$P = 800 \text{ psi}$$

$$InC_O = -0.664 - 1.430 \text{ In } 800 - 0.395 \text{ In } 800 + 0.390 \text{ In } 186 + 0.455\ (647.3)$$

$$+ 0.262 \text{ In } (30)$$

$$InC_O = -60.9813$$

$$InC_O = e^{-6.9813}$$

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

$$P = 400 \text{ psi}$$

$$InC_O = -0.664 - 1.430 \text{ In } 400 - 0.395 \text{ In } 400 + 0.390 \text{ In } 186 + 0.455\ (647.3)$$

$$+ 0.262 \text{ In } (30)$$

$$InC_O = -5.72414$$

$$InC_O = e^{-5.72414}$$

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

$$P = 15 \text{ psi}$$

$$InC_O = -0.664 - 1.430 \text{ In } 15 - 0.395 \text{ In } 15 + 0.390 \text{ In } 186 + 0.455\ (647.3)$$

$$+ 0.262 \text{ In } (30)$$

$$InC_O = -0.26809$$

$$InC_O = e^{-0.26809}$$

$$InC_O = 13.08 \times 10^{-4}\ Psi^{-1}$$

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

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

Where

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

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

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

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

$$F = 247.5605$$

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

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

$P > P_b$

$$P = 4500\ psi$$

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

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

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

$$B_{ob} = 1.041\ BBL/STB$$

$$P = 4000\ psi$$

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

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

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

$$B_{ob} = 1.041\ BBL/STB$$

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

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

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

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

$$F = 237.6803$$

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

$$B_o = 1.0630\ \text{BBL/STB}$$

$$P = 400\ \text{Psi}$$

$$R_{so} = 96.64\ \text{SCF/STB}$$

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

$$F = 234.748$$

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

$$B_o = 1.0617\ \text{BBL/STB}$$

$$P = 15\ \text{Psi}$$

$$R_{so} = 1.85\ \text{SCF/STB}$$

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

$$F = 232.543$$

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

$$B_o = 1.067\ \text{BBL/STB}$$

v. *Validating of the PVT Parameters*

1) 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. (Rafiee-Taghanaki et al 2013).

$$130\ \text{psia} < Pb < 7{,}000\ \text{psia}$$

$$100^{\circ}F < TR < 258^{\circ}F$$

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

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

$$16.5^{\circ}\ \text{API} < \gamma_o \text{API} < 63.8^{\circ}\text{API}$$

$$0.59 < \gamma_g < 0.95$$

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

3) 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%

4) 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 (Oyedeko and Ulaeto, 2011).

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

$$126\text{psig} < P < 9{,}500\text{psig}$$

$$0.117\text{ cp} < \gamma_g < 1.351$$

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.

IV. Discussion of Result

a) Overview of Findings

This study provides critical insights into the behaviour of black oil in a reservoir context, mainly focusing on bubble point pressure, formation volume factor, and viscosity. Understanding these properties is essential for effective reservoir management and hydrocarbon recovery.

b) Bubble Point Pressure

As oil wells are drilled and completed, a point is reached where the gas dissolved in crude oil begins to bubble out, forming a two-phase region. This pressure is called the bubble point (Pb) (El-Hoshoudy & Desouky, 2018). The PVT analysis determined a bubble point pressure of 2000 psig, while the standing correlation provided a Pb of 1937.371 psi, resulting in a difference of 65.7 psi. This discrepancy likely arises from the representativeness of the PVT samples collected. Accurate representation is crucial, as variability in sampling can lead to significant errors in predicted reservoir behaviour (Okoduwa & Ikiensikimama, 2010).

c) PVT Analysis

To ensure reliable results, PVT samples must accurately reflect the reservoir fluid in situ. The expansion of reservoir fluids is a function of pressure, and calculations should be made using various total two-phase expansion factors. To achieve reliable results, these factors must be weighted by volume (El-Hoshoudy, 2019). Current commercial laboratory equipment for PVT analysis can determine volume with a maximum error of less than 0.01% and temperature within 1% (Shokrollahi et al., 2015).

d) Formation Volume Factor

The formation volume factor (Bo) relates the volume of oil at reservoir conditions to its volume at stock tank conditions. At standard conditions of 0 psig and 60°F, Bo should equal unity. Above the bubble point, Bo increases as oil compressibility (Co) decreases, while below the bubble point, Bo decreases as Co increases (Moradi, 2013). The findings indicate that above Pb, Co was measured at 18.83 × 10⁻⁶ psi⁻¹, and below Pb, at 1600 psi, Co increased to 26.02 × 10⁻⁵ psi⁻¹. At atmospheric pressure, Co decreased to 13.08 × 10⁻¹ psi⁻¹. This demonstrates that oil compressibility is significantly influenced by reservoir pressure.

e) Viscosity

Oil's viscosity (μo) is another critical property, as it directly affects the flow rate. Above the bubble point, μo increases as pressure decreases. Below Pb, viscosity increases dramatically from 1.0347 cp at 1200 psig to 4.1309 × 10¹⁸ cp at 15 psig, indicating that viscosity is highly sensitive to pressure changes. The viscosity and flow rate relationship is inversely proportional; higher viscosity results in lower flow rates (Ahmed, 2016).

The reservoir temperature remains constant throughout the oil well's life, further complicating the fluid flow dynamics (Shokrollahi, 2015). Adjustments in the gravity of residual oil are not required (Gaganis&Varotsis, 2016).

f) Implications and Future Directions

The results underscore the importance of accurate PVT analysis for effective reservoir management. Understanding the dynamics of gas evolution, formation volume factor, and viscosity can significantly influence oil recovery strategies. Future research should consider advancements in PVT measurement techniques and methodologies that could enhance accuracy and efficiency. This could include integrating new technologies for real-time monitoring and analysis, which may lead to improved decision-making in reservoir management.

V. Conclusion and Recommendation

a) Conclusion

This study conducted pressure, volume, and temperature (PVT) analyses of a black oil reservoir to determine its economic viability. PVT studies are essential as they enable reservoir engineers to predict and compute the probable hydrocarbon reserves available accurately.

Key findings indicate that the crude oil exhibits high viscosity, with an average absolute error (AAE) of 3.5% (0.035). Gas began evolving at 2000 psig, increasing as the pressure decreased. Notably, at a higher pressure of 4500 psig, the viscosity of black oil was measured at 0.54 cp, while at a lower pressure of 15 psig, it increased to 1.38 cp. This significant variation in viscosity with pressure suggests implications for the reservoir's productivity and economic worth, as higher viscosities can complicate extraction processes.

The observed gas evolution at 2000 psig is particularly relevant, indicating a threshold for gas release that could affect reservoir management strategies. Understanding these dynamics helps in making informed decisions regarding development and extraction practices.

The findings underscore the importance of PVT studies in reservoir management and economic evaluations. Further studies are recommended for future research to validate these findings and explore additional parameters that could enhance our understanding of reservoir behaviours. Innovative approaches, such as advanced PVT measurement technologies and modelling techniques, could further improve the accuracy of these analyses and their implications for reservoir engineering.

In summary, this research contributes valuable insights into the characteristics of black oil reservoirs, providing a foundation for effective management and maximization of hydrocarbon recovery.

b) Recommendations

Based on this research and my personal 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 a 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 a greater number of wells and 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 reports) must always be checked against the reservoir's actual production pressure performance (Okoduwa, 2010).
4) To check the laboratory values by studying them and accompanying them with actual field production performance, several plots, such as a plot of reservoir pressure versus cumulative oil production, a plot of Cumulative fluid production and pressure drop, i.e. NP/DP VNP, and a plot of flowing pressure gradients versus depth, will all indicate a change in slope at bubble point pressure.
5) A reservoir simulation method should be used to regenerate the required PVT parameters for black oil, gas condensate, and other reservoirs before they are put into production.(Elkatatny and Mahmoud, 2018).
6) This project work required using standing correlations to validate the basic PVT parameters of a black oil reservoir. Other correlations, such as Vasquez and Beggs, Glaso, or Marhran correlations, can also be applied.

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